SWIFT ENERGY COMPANY

2007 ANNUAL REPORT

SPOTLIGHT ON VALUE

HIGHLIGHTS

Unless otherwise noted, information provided below relates solely to our continuing operations located in the United States and excludes our discontinued New Zealand operations.

Financial data in thousands except per-share amounts and ratios; prices received exclude the effects of our hedging activities.

	2007	2006	Percent Change
Revenues from Continuing Operations	$654,121	$550,836	19%
Costs & Expenses	$409,565	$302,528	35%
Income from Continuing Operations	$152,588	$151,074	1%
Earnings per Share (Continuing Operations)–Basic	$5.09	$5.16	(1%)
Earnings per Share (Continuing Operations)–Diluted	$4.98	$5.03	(1%)
Total Assets	$1,969,051	$1,585,682	24%
Working Capital	$(10,211)	$(61,688)	83%
Current Ratio	0.95	0.58	64%
Long-Term Debt	$587,000	$381,400	54%
Stockholders' Equity	$836,054	$797,917	5%
Return on Assets			
(Income from Continuing Operations / Average Assets)	8.6%	10.8%	(20%)
Return on Stockholders' Equity			
(Income from Continuing Operations / Average Equity)	18.7%	21.5%	(13%)
Cash Provided by Operating Activities–Continuing Operations	$442,282	$383,241	15%
Total Domestic Production (MBoe)	10,617	9,449	12%
Domestic Natural Gas Production (MMcf)	16,782	13,604	23%
Domestic Oil & Condensate Production (MBbls)	7,045	6,721	5%
Domestic Natural Gas Liquids Production (MBbls)	774	460	68%
Average Composite Prices Received ($/Boe)	$61.49	$56.89	8%
Average Natural Gas Prices Received ($/Mcf)	$6.42	$6.44	-
Average Oil & Condensate Prices Received ($/Bbl)	$71.92	$64.28	12%
Average Natural Gas Liquids Prices Received ($/Bbl)	$49.72	$38.70	28%
Total Domestic Proved Reserves (MBoe)	133,781	118,408	13%
Domestic Proved Natural Gas Reserves (MMcf)	343,798	269,661	27%
Domestic Proved Oil, NGL, & Condensate Reserves (MBbl)	76,482	73,465	4%
Weighted Average Shares Outstanding	29,984	29,265	2%
Year-End Shares Outstanding	30,179	29,743	1%
Number of Shareholders of Record	231	252	(8%)
Number of Shareholders in Street Name (estimated)	19,630	23,300	(16%)
Market Price of Common Stock at Year-End	$44.03	$44.81	(2%)
Price-Earnings Ratio			
(Year-End Stock Price / EPS (Continuing Operations)–Basic)	8.7	8.7	-
Number of Domestic Employees	298	272	10%

See page 35 regarding the forward-looking statements in this report.
See page 78 for a glossary of abbreviations and terms.

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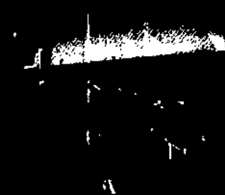
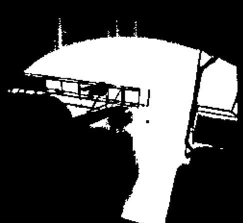




INTERNET ACCESS

Investor information about Swift Energy Company is available on the Internet at www.swiftenergy.com. The information includ press releases, Swift's code of ethics, and company hedging positions. It also includes Swift's annual reports on Form 10-K, quarterly reports on Form 10-Q, and links to other current reports, all available free of charge and updated as soon as practicable after the company's filing of these reports with the U.S. Securities and Exchange Commission. Visitors to swiftenergy.com can register to receive periodic e-mail updates concerning new information available at the web site.

COMPANY PROFILE

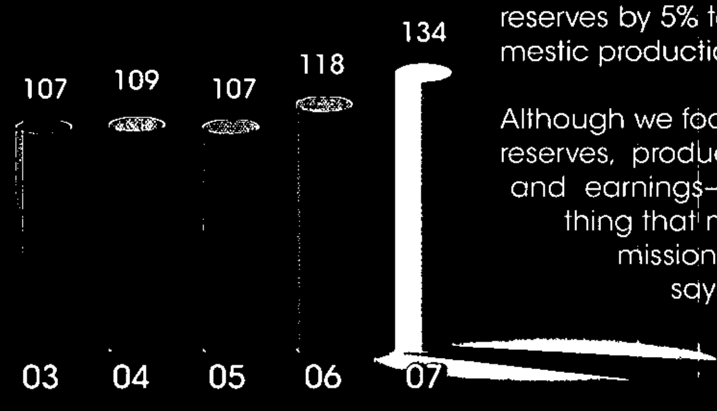
The Value of Experience

One of the first things anyone should know about Swift Energy Company—besides the fact that we are an independent oil and gas company headquartered in Houston, Texas—is that we have been around for a long time. As we look back at our 28-year history, we take pride in the tenacity we exhibited in weathering many turbulent events within our industry. When our founder, A. Earl Swift, first opened our doors back in late 1979, oil and gas prices were strong and supplies were tight, much as they are today. We were barely seven years old when oil prices fell off a cliff in 1986, spiraling down to historic lows from which our industry took nearly two decades to fully recover. It was a trial by fire in which over 85% of our competitors went out of existence.

We not only survived that ordeal, we prospered, and today we are one of the top 50 oil and gas companies in the United States in terms of total assets. At the end of 2007, we had approximately $2 billion of assets and the equivalent of 134 million barrels of domestic proved oil and gas reserves (MMBoe), almost all of which are located along the onshore and inland water areas of the Louisiana and Texas Gulf Coast.

It is important to understand our history, because with that history comes some hard-won experience, and that experience has value. It takes time to build a sense of mission into an organization; it takes time to assemble the knowledge and capabilities needed to execute a strategy; and it takes time to instill a strong sense of values into an organization's culture. Over the last three decades, we've done all of those things, and precisely because vision, capabilities, and values take a lot of time and effort to create, they provide us with a sustainable source of competitive advantage going forward.

Year-End Domestic Proved Oil & Gas Reserves (MMBoe)



MISSION AND GOALS. Take our mission, for example. We've always said that we are a natural resource company committed to achieving efficient, sustained growth in the volume and value of our proved oil and gas reserves. It's one thing to say that reserves growth is our mission, and it's another to achieve reserves growth consistently over a long period of time. From our inception, we've been able to increase our proved reserves per share of common stock at a compounded annual rate of 18% per year and our production per share at a rate of 31% per year. Of course, as we get larger, maintaining high rates of growth becomes increasingly more difficult. In 2008, our goal is to increase our domestic proved reserves by 5% to 9% and our domestic production by 10% to 15%.

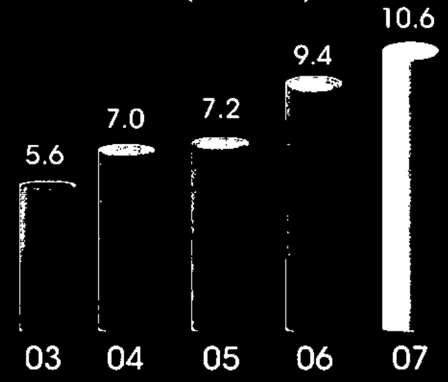
Although we focus on growth—in reserves, production, cash flows and earnings—it isn't the only thing that matters to us. Our mission statement also says that we will maintain high standards for ethical conduct, for the protection of health and safety, and for the preservation of environmental quality. Moreover, we are constantly working on improving the quality of our reserves, in addition to focusing on growth in overall quantity. Our mission statement says that we will seek to optimize stakeholder value by building a balanced portfolio of oil and gas properties—properties with diversified production profiles and an assortment of growth opportunities covering a range of risks and potential rewards. This portfolio approach is one of the reasons we have been able to prosper during both good times and bad. In 2007, we rebalanced our portfolio, acquiring additional properties in South Texas and selling properties in New Zealand's Taranaki Basin. The agreement to sell our New Zealand assets qualifies those assets to be treated as discontinued operations, and they are represented as such throughout this report.

BUSINESS STRATEGY. Experience has taught us that building and maintaining a balanced portfolio also requires a balanced strategy. Our strategy is based upon a mix of exploratory and development drilling and producing property acquisitions, with a continual rebalancing of the specific mix of drilling and acquisitions in response to changing industry conditions and strategic opportunities.

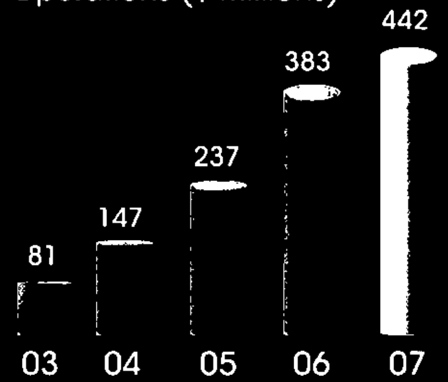
Our operations are generally focused in three regions—South Louisiana, South Texas, and Toledo Bend, a region spanning the Texas-Louisiana border. Within each of these regions are one or more key properties that give us a strong base for developing the surrounding area. These include our Lake Washington and Bay de Chene properties in South Louisiana, our AWP Olmos and Cotulla properties in South Texas, and our Austin Chalk and South Bearhead Creek properties in the Toledo Bend Region.

Over the last several years, we have been focusing primarily on South Louisiana, and during the last three years, we have greatly enhanced our capabilities in that region by assembling and reprocessing a database of three-dimensional seismic data covering over 4,000 square miles. For 2008, we have prepared a $425 million to $475 million capital budget (excluding any acquisitions) that we believe will enable us to take advantage of the knowledge and capabilities we have now put together for South Louisiana.

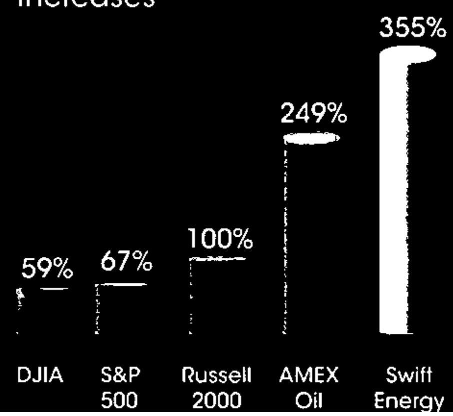
Year End Domestic Oil & Gas Production (MMBoe)



Cash Provided by Operating Activities-Continuing Operations ($ Millions)



Five-Year Cumulative Equity Increases



Our ongoing drilling program is complemented by our acquisition activities. We continually review opportunities to purchase strategic producing properties whose performance can be enhanced by our technical skill and experience or through improved operating efficiencies. In 2007, we acquired our Cotulla properties in the South Texas Region—a property that we believe has significant potential for future growth.

PERFORMANCE COMPARISON. We focus on growth in the volume and value of our proved reserves because we believe that is the best way to create value for our stakeholders. Our policy has always been to reinvest our cash flows rather than pay cash dividends, in order to promote long-term growth in the value of our common stock. Although industry cycles can have a substantial impact on year-to-year performance, we have achieved significant growth in shareholder value in recent years. At the end of 2007, the five-year cumulative growth in our year-end stock price was 355%, comparing favorably with the five-year increases in the AMEX Oil Index (249%), the Russell 2000 Index (100%), the S&P 500 Index (67%), and the Dow Jones Industrial Average (59%).

INVESTOR INFORMATION. Our common stock has been traded under the symbol "SFY" on the New York Stock Exchange (NYSE) since 1991.

LETTER TO
STOCKHO

The Value of Vision

In the business world, we hear a lot of talk about the importance of "vision," but in the competitive environment of today's oil and gas industry, where practical consequences ride on every decision, some could ask, "What is a vision really worth?" We've been in this business for more than a quarter of a century, and during that time, we've learned that a commitment to a vision can become a critical intangible resource—a major source of future productivity embedded within the hearts and minds of our employees. It is a driving force that simultaneously touches our emotions and focuses our intellect, and it is one of the pillars of sustainable competitive advantage—something that is both hard to create and difficult to duplicate.

Vision has value because it defines an organization's purpose. It answers two basic questions that every organization must address: what do we do, and why do we do it? At Swift Energy, our vision is founded on two sweeping trends that are reshaping the world. The first is the transformation of world energy supplies. We have a global economy that runs on oil, and world crude oil supplies are not keeping pace with demand. The second is the advent of the digital age, bringing with it a new knowledge-based economy. Put simply, our vision is to use state-of-the-art technical knowledge to help supply the world with energy.

This vision guides the way we carry out our more specific mission as an oil and gas company, which is to increase the volume and value of our proved oil and gas reserves. Like any business, we ultimately must create value for our stakeholders, and we accomplish that task through reserves growth, believing that growth in reserves holds the key to growth in production, revenues, and earnings.

As we point out elsewhere in this report, we have successfully accomplished this mission throughout our history, and the last five years are no exception. Excluding our New Zealand activities, which are being discontinued after our recent agreement to sell those properties, we've been able to increase our domestic proved reserves at a compounded five-year growth rate of 6% per year. This has allowed us to increase our domestic oil and gas production by 13% per year over that same time frame, which in turn has allowed us to increase our cash flows from continuing operations at a rate of 51% per year and our diluted earnings per share from continuing operations at a rate of 79% per year. With these successes, our year-end stock price over the last five years has increased at an average annual rate of 35%.

These kinds of results flow naturally from the competitive abilities we've developed in pursuit of our vision and mission. The main reason we've seen crude oil prices nearly triple over the last five years is that oil and gas resources are becoming increasingly difficult to find and produce, particularly in the record amounts that our growing global economy requires. The difficulty of the task is compounded by a lack of intellectual infrastructure within our industry, as years of underinvestment have inevitably led to a shortage of skilled workers. Companies that succeed in this highly challenging environment will be those that develop a competitive advantage in professional knowledge and technical capabilities, and that's precisely what our vision mandates that we continue to do.

With this in mind, we've spent a lot of time and effort in recent years building a proprietary knowledge base that will serve as the foundation for future growth. At the core of that knowledge base is over 4,000 square miles of three-dimensional seismic data covering a significant portion of southern Louisiana. We view this region as a tremendous opportunity

outh Louisiana presents a num-
per of challenges, but it is also a premium market that offers the potential for higher-than-average operating margins.

Our focus on South Louisiana s part of a long-term strategic ransition. In the mid-1990s, most of our production came from natural gas, but today the majority of our production comes from crude oil and natural gas liquids. With U.S. oil production peaking in 1970 and undergoing more than three decades of decline, finding new oil production in the United States is not an easy thing to do, but we chose to focus on oil because it brings higher than average rewards, particularly in South Louisiana.

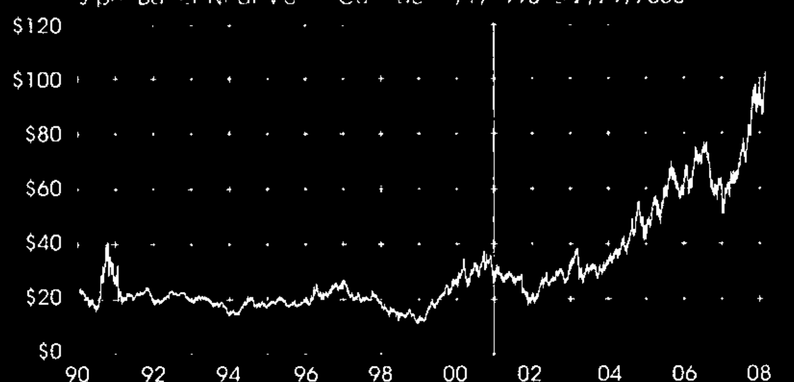
Our approach in South Louisiana has been to acquire three-dimensional seismic data from several sources, including our own proprietary surveys, and merge that data together into integrated datasets. Bringing the data together creates synergies that significantly improve the quality of all the information. We then combine that seismic information with digitized geological data obtained from previous wells. The result is a coherent picture of the subsurface environment that gives our highly skilled geoscience professionals a unique understanding of the opportunities available for creating new value. One could say that we are mapping out an entirely new geography beneath the surface of the earth, and this new geography is located in one of the most prolific oil and gas basins in the world.

Building this knowledge base has been an ongoing, multiyear undertaking involving considerable expense, and exploiting the knowledge we've gained has also required many other investments for future growth, including investments in the acquisition of both proved and unproved leasehold acreage, prospect development, and facility improvements. A significant portion of our knowledge base is now ready for use, and many of the other required investments have already been made, including some important facility improvements that are now nearing completion.

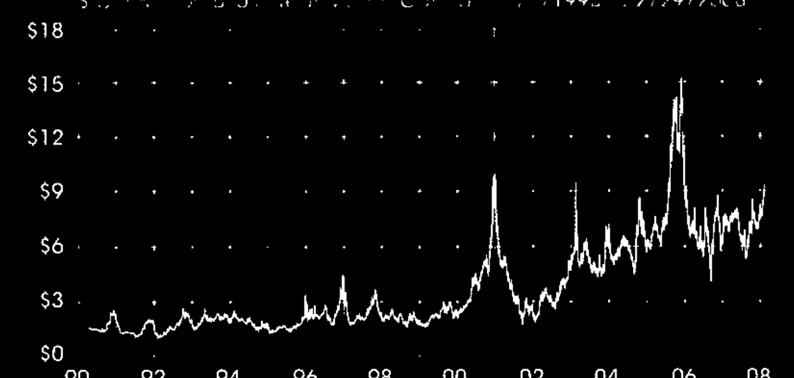
At the same time, we have rebalanced our portfolio through the acquisition of some exciting new properties in South Texas and the sale of our properties in New Zealand. Our new Cotulla acquisition in South Texas builds upon our many years of successful experience in that region, and the strategic decision to sell our New Zealand assets results from the recognition that our New Zealand properties were not competing well on a comparative basis with our domestic assets. Therefore, in 2007 we decided to divest ou
New Zealand assets and focus or our domestic strengths. This decision, which resulted in a non-cash loss of $4.29 per diluted share should enhance our shareholde value and improve our overa market evaluation.

With this foundation in place, we think we are now poised for sever al more years of outstanding per formance. In our South Louisianc region we are already benefitin greatly from our maturing geosc ence databases. Currently ou crown jewel in the region is th Lake Washington Field in Plaque mines Parish, which produce from multiple stacked layers c Miocene sands surrounding c salt dome. In our early drilling i this field, we focused on relativel shallow targets based on geolog ical data from previous wells, bu with our new geoscience data bases, we have the confidence t

NYMEX Crude Oil Futures



NYMEX Natural Gas Futures



ootential for adding new reserves. We are now imaging and map-oing untested deeper structures, ncluding high-potential subsalt orospects. At the same time, we nave the comfort of knowing that many of these same deeper pros-oects also have a high probabil-ty of accessing low-risk targets at shallower depths.

We believe that this approach will help us continue our produc-ion growth in South Louisiana while simultaneously increasing our proved reserves for a lower oer-unit cost. Our costs of add-ng reserves were higher than we olanned in 2007, in part because of the aforementioned invest-ments in acreage, prospects, and acilities, but those investments will help provide us with reserves growth for many years into the fu-ure. In particular, the approach-

tion processing facility in Lake Washington will remove some key production capacity limitations that had prevented us from tar-geting new reserves in areas that were previously constrained. The bottom line is that everything is in place to undertake an aggressive drilling program in South Louisiana during 2008 that has the potential to increase our proved reserves in a very significant manner.

We anticipate that our 2008 drill-ing program not only will add new producing wells, but also will position us for future production growth by adding to our invento-ry of proved undeveloped drilling locations. Each year as we drill wells, we bring a significant por-tion of our undeveloped reserves into production, and we add new undeveloped locations to replace those that we've drilled. About 40% of the current value of our undeveloped reserves has been added within the last two years. The replenishment of our drilling inventory with these developmental op-portunities is one of the important reasons we've been able to consistently increase our production for almost three decades. To use a manufacturing analogy, our development opportunities constitute our work-in-process inven-tory of unfinished goods. They are one of the rea-sons we have confidence that we can reach our pro-duction goals in 2008 and beyond.

The knowledge-based ap-proach to reserves and production growth that we are employing in South Louisiana will also provide us with a model for build-ing our capabilities in

such example. Our new Cotulla acquisition greatly expands this region, which previously held only our AWP Olmos Field in McMul-len County. Like AWP, the Cotulla properties primarily produce from the tight Olmos sands for which we have developed a drilling and production expertise that gives us a competitive edge for operat-ing in the entire region. Over the longer term, we are launching a preliminary seismic acquisition program that we anticipate will lead to the development of an additional integrated seismic and geologic database over another large area.

All of these actions are guided by our vision and values. We use advanced technical knowl-edge to do difficult jobs, creating a competitive advantage that builds value for our stakehold-ers. We have an organization of achievers—skilled people who want a challenge and have the confidence needed to reach lofty goals. We've created a lot of value for our stakeholders over the years, and we are in an excel-lent position to create more value going forward. In 2008 and the years that follow, we believe we will continue to build upon our track record of success. As we do so, the value of our vision will be-come even more clear.

Terry E. Swift
Chairman and Chief Executive Officer,
Swift Energy Company

SHAREHOLDER VALUE

The Value of a Balanced Portfolio

Since 1991, the first year Swift Energy was listed on the New York Stock Exchange, our shareholders have enjoyed significant appreciation of their investment in Swift stock. From year-end 1991 through year-end 2007, our common stock grew at an average compounded rate of 13.3% per year. That's better than the Dow Jones Industrial Average, the Russell 2000 Index, the S&P 500 Index, or the AMEX Oil Index.

Two other important measures of shareholder value in the oil and gas industry are growth in proved reserves and growth in production. After setting record highs in our domestic production for five years in a row, we have replaced more than 187% of what we produced during those years. For 2007, we replaced 245% of our domestic production, illustrating that we're not merely keeping pace but that we're setting the stage for future growth.

If we had to put our finger on the basic approach that has led to this success, it would be our striving for balance in all that we do.

A healthy balance involves a portfolio of investments whose specific mix varies as circumstances change. Our tandem approach to reserves growth through drilling and/or acquisitions is one such example. While we maintain a balance between the two over the long term, during some years we've grown 100% through drilling and in other years 100% through acquisitions, depending on product prices and strategic opportunities. Using inherent industry cycles to our advantage, we generally focused on organic growth through drilling when prices were high and on strategic growth through acquisitions when prices were low. From 2005 through 2007, however, our emphasis on acquisitions and drilling has been more evenly split on an annual basis as the pricing environment has remained strong and U.S. oil and gas resources have matured. In this environment, we focused on drilling while simultaneously seeking strategic acquisitions of producing properties that would benefit from economies of scale and that take advantage of our technological skills honed in specific types of formations.

The composition of our reserves is another area where we create value by building a balanced portfolio. As oil prices have risen over the past few years, we've shifted our emphasis to hydrocarbon liquids, with crude oil and natural gas liquids comprising 57% of our year-end domestic reserves in 2007 and natural gas comprising 43%. In 1998 when the average price we received for a barrel of oil was $11.86—far below the lofty heights of today—our domestic reserves were 81% natural gas.

Our balance between proved developed, proved undeveloped, probable, and possible reserves represent the balance struck between immediate rewards and building for the future. At year-end 2007, our domestic proved reserves were 48% developed and 52% undeveloped, demonstrating our commitment to maintaining cash flow while laying the foundation for long-term growth.

For 2008, our strategic goals for strengthening shareholder value include increasing production from continuing operations by 10% to 15% and proved reserves from continuing operations by 5% to 9% over 2007 levels. Additionally, we aim to improve our margins by controlling both finding and development costs and operating costs relative to oil and gas prices. We expect the increased concentration of our operations in anchor fields in Louisiana and Texas to enable us to better leverage our technical skills while more efficiently controlling costs.

Our level of operational control will also help us in this regard. As 2008 began, we had operational control of 96% of our proved oil and natural gas reserves base, which will allow us to more effectively manage production, allocate capital, pursue field development, and ultimately create value for our shareholders.

The Value of Knowledge

During the four years since we began building large integrated geoscience databases for our South Louisiana Region, our knowledge of the region's subsurface structures has increased enormously and significantly reduced our risks in searching for new pools of crude oil and natural gas.

As shown in the accompanying map (page 10), South Louisiana is one of three domestic regions in which we conduct oil and gas operations. A second region is located in South Texas and a third one, identified as Toledo Bend, spans the Texas-Louisiana boundary. During 2007, we discontinued operations in our only international region, which was located within the Taranaki Basin on New Zealand's North Island. Therefore, except for a brief discussion of New Zealand, the information presented in this section pertains only to our continuing (i.e., domestic) operations.

South Louisiana currently holds over one-half of our company's proved oil and gas reserves and contributes approximately three-fourths of our production, both largely attributable to the region's Lake Washington Field which we acquired in 2001. South Louisiana is also the region that has presented us with the greatest potential for new discoveries in recent years. Recognizing this, we began in 2004 to assemble sets of three-dimensional seismic data for the region, both from our own proprietary seismic surveys and through purchases of existing data from geophysical companies. We subsequently merged the data to create integrated seismic databases for all our South Louisiana fields and surrounding areas. We also began integrating the resulting databases with digitized geological information based on all available well-log data for the same areas, thereby assembling the most comprehensive and up-to-date merged geoscience databases possible. Finally, we are processing the databases using state-of-the-art methodology on banks of supercomputers. The ultimate products are three-dimensional visual images of substructures beneath Louisiana's onshore and inland-water areas shown in more detail than ever seen before and entirely proprietary to Swift Energy.

By early 2007, we had assembled over 40 different seismic datasets that cover more than 4,000 square miles of the onshore and inland waters of the Louisiana Gulf Coast (see map on page 12), and we had already used preliminary data in 2005 to identify and successfully drill two prospects in Lake Washington, one of which (Newport) has led to a number of high-producing development wells. Ever since then we have used the databases not only to identify exploratory prospects, but also to guide much of our development drilling, which includes exploitation wells that target probable and possible reserves. Converting such reserves to the proven category is an important step in increasing our reserves base and one that we plan to vigorously pursue throughout 2008 and beyond.

While our seismic studies thus far have been confined to South Louisiana, it is anticipated that building integrated geophysical and geological databases will become a standard mode of operation throughout the company's areas of operation. In particular, we made a substantial property acquisition in South Texas during 2007 (the Cotulla acquisition), and we have already begun studies to determine which of the new fields should be supported by similar database efforts.

South Texas has been an important region of operation for our company for many years, as has Toledo Bend. All three regions of operation have resulted from our long-term strategy of acquiring controlling (often 100%) working interests in large producing prop-

erties with significant upside po-
ential—frequently with multiple geological horizons—and subsequently exploiting the properties hrough drilling. With the regions separated geographically and producing from different reservoir rends, we maintain a balanced eserves base that is critical for sustained long-term production.

At year-end 2007, our proven domestic reserves totaled 133.8 MMBoe, an increase of 13% from year-end 2006 due to the Cotulla acquisition and our 2007 drilling activities. The reserves (51.8% undeveloped) were comprised of 57.2% oil and natural gas liquids (NGLs) and 42.8% natural gas. South Louisiana's reserves were 65.8% oil and NGLs and represented 55.0% of the company's otal reserves; South Texas' reserves were 61.8% natural gas and represented 29.3% of the otal; and Toledo Bend's reserves were 65.4% oil and NGLs and represented 14.5% of the total.

During 2007, our domestic producion totaled 10.6 MMBoe, a 12.4% ncrease above 2006 production. Of the total, South Louisiana contributed 76.8%, South Texas 14.3%, and Toledo Bend 8.2%.

Our goals for 2008 are to increase our year-end proved reserves by 5% to 9% and our production by 10% to 15% through drilling activiies that could include as many as 90 wells. To accomplish these goals, we have an estimated 2008 capital budget of $425 milion to $475 million, with approximately two-thirds allotted to South Louisiana.

Our 2007 capital expenditures otaled $650.6 million, including a $252.3 million expenditure that was mainly for the Cotulla acquisition. During the year we drilled 69 wells with 61 successes, for a success rate of 88%. Included among the 69 wells were five exploratory wells in South Louisiana, two of which were successful.

At year-end 2007, we had interests in 1,218 producing wells in these three regions. We served as the operator of 1,091 wells, which gave us operational control of 96% of our proved oil and natural gas reserves base.

SOUTH LOUISIANA

In our South Louisiana Region we have interests in producing properties located in eight oil and/or natural gas fields scattered along the Gulf Coast from Plaquemines Parish westward to Cameron Parish. As is our general practice, the acquisition of each property was preceded by careful study by our technical staff to determine the prerequisites for increasing the field's production. As a testimony to our success, the region accounted for 81% of our total domestic oil and gas sales in 2007, an amount boosted by the fact that we receive premium prices owing to the high quality of the crude oil and natural gas from this region.

Our largest operation in South Louisiana is in the first field we acquired—the Lake Washington Field located in inland waters in the northwest of Plaquemines Parish. Following our purchase of interests in that field in 2001, we acquired interests in two additional inland-water fields at the end of 2004—in the Bay de Chene Field located along the common boundary of Jefferson Parish and Lafourche Parish and in the Cote Blanche Island Field in St. Mary Parish. When purchased, all three fields were producing predominantly crude oil from multiple stacked Miocene sand layers that radiate outward and downward from the surface of a centrally located salt dome.

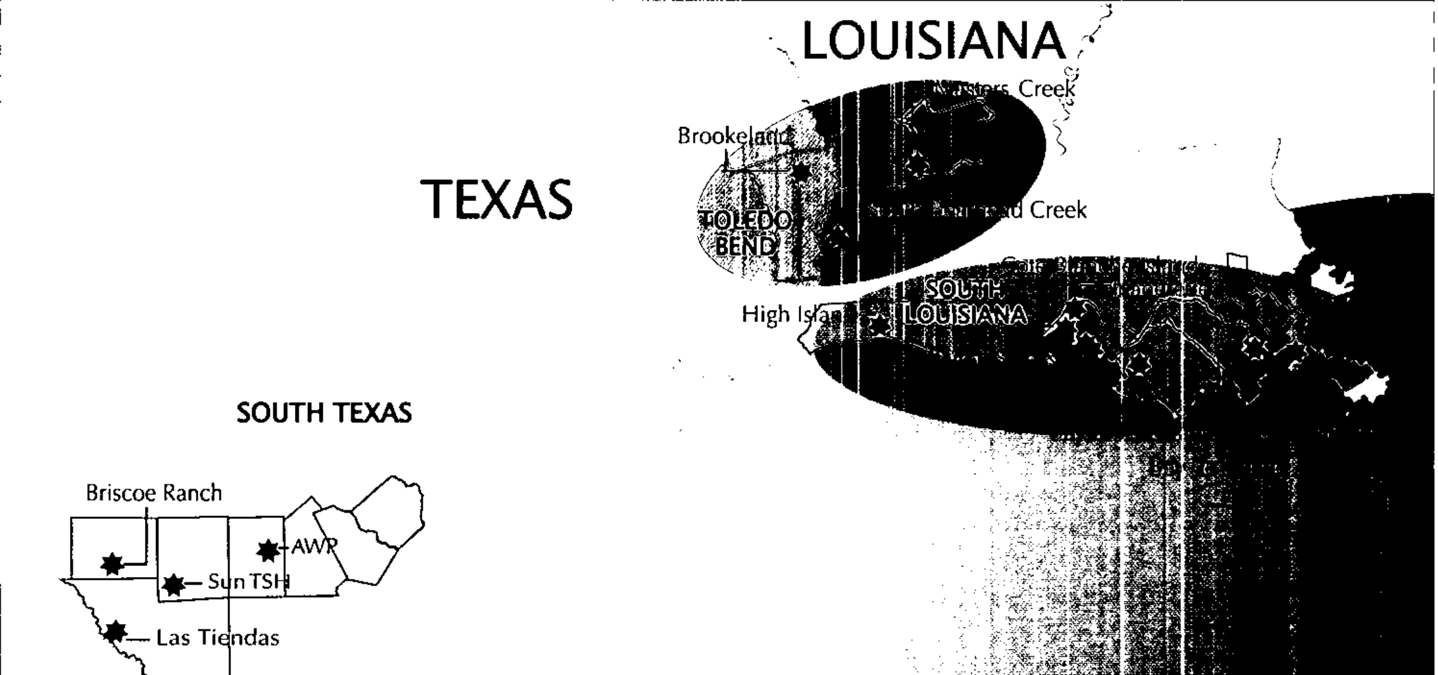
In 2006, we acquired properties in five new South Louisiana fields: Bayou Sale, Horseshoe Bayou, and Jeanerette in St. Mary Parish; Bayou Penchant in Terrebonne Parish; and High Island in Cameron Parish. All land-based, these fields were producing predominantly natural gas from several different formations.

Lake Washington. In the words of our chief executive officer Terry Swift, "Lake Washington is currently the most exciting field that Swift Energy owns, and we expect it to be the crown jewel of our portfolio for many years."

When we purchased our initial properties in the field in 2001, the associated reserves were estimated at 7.7 MMBoe. By year-end 2007, with additions from a 2006 acquisition, the reserves, which are 92.1% oil and NGLs, had increased to 36.4 MMBoe, or to 27.2% of the company's total reserves. Approximately one-half of these reserves (17.9 MMBoe) were undeveloped.

Also at purchase, the properties were producing less than 1,000 gross barrels of oil per day, whereas during 2007, they produced at an average rate of approximately 18,000 Boe per day. In 2007 they contributed 6.6 MMBoe, or 62%, of the company's total production.

Lake Washington, which covers 32,075 net acres, is a highly faulted field, with the stacked Miocene sands contained in hundreds of isolated reservoirs (fault blocks). Many of the fault blocks abut the field's central salt dome, while others are located several miles away from the dome. The salt dome itself has surface depths that vary from 1,200 feet at its peak down to about 14,000 feet, and the inland waters covering the field vary in depth from about 2 feet to 12 feet. Drilling and completion activities



Swift Energy's Gulf Coast Operations

are conducted with barge-based rigs and are greatly facilitated with today's technological advancements, including measurement-while-drilling tools that indicate the drill bit's precise location at all times and completion techniques that maximize hydrocarbon recovery during production.

In order to recover the hydrocarbons in an individual fault block, one or more wells must be drilled within the fault block. The hydrocarbons are typically found trapped in the highest regions of the stacked sand layers, i.e., those closest to the salt dome, and for the fault blocks abutting the salt dome, this frequently means angling the well bore down the side of the dome so that it penetrates the successive layers of sand at their highest points. The individual sands are generally identified by letters of the alphabet, with some named for the depths at which they were first discovered.

Over Lake Washington's history, more than 1,000 wells have been drilled in the field, and its production to date has exceeded 300 million Boe. Since we assumed operations in the field, we have drilled 195 wells with a 77% completion rate, found over 70 productive sands, and made completions in 39 pay zones with an average of 140 feet of net pay in completed wells. Primarily because of our Lake Washington drilling, we are currently the most active drilling company in South Louisiana and the state's largest crude oil producer.

Most of our Lake Washington production to date has come from relatively shallow wells drilled down to approximately 6,000 feet and, prior to 2005, was based almost wholly on geological data. These wells, targeting the A through K series of sands in fault blocks varying in size from 5 acres to 200 acres, generally have initial average production rates of approximately 200 Boe per day. In 2002, our first full year of operation in the field, we completed 23 of the 27 shallow wells we drilled.

In 2003, our Lake Washington drilling program continued with 52 development wells (42 completions) and six exploratory wells (five completions) and expansion into new areas around the dome. One successful exploratory well was drilled to a depth of approximately 8,000 feet on the untested west side.

With the potential of the Lake Washington Field becoming increasingly apparent, we made the strategic decision in 2003 to move toward a seismic-based drilling program. Accordingly, in 2004 we curtailed our drilling to 30 wells (70% completed) and conducted a three-dimensional seismic survey over our entire 55-square-mile Lake Washington area. Our focus was on depths of 6,000 feet to 12,000 feet, a range that we consider to be intermediate sands, but also one that we anticipated would help us identify exploratory targets at deeper depths, where we suspect that large accumulations of natural gas exist.

The Lake Washington three-di-

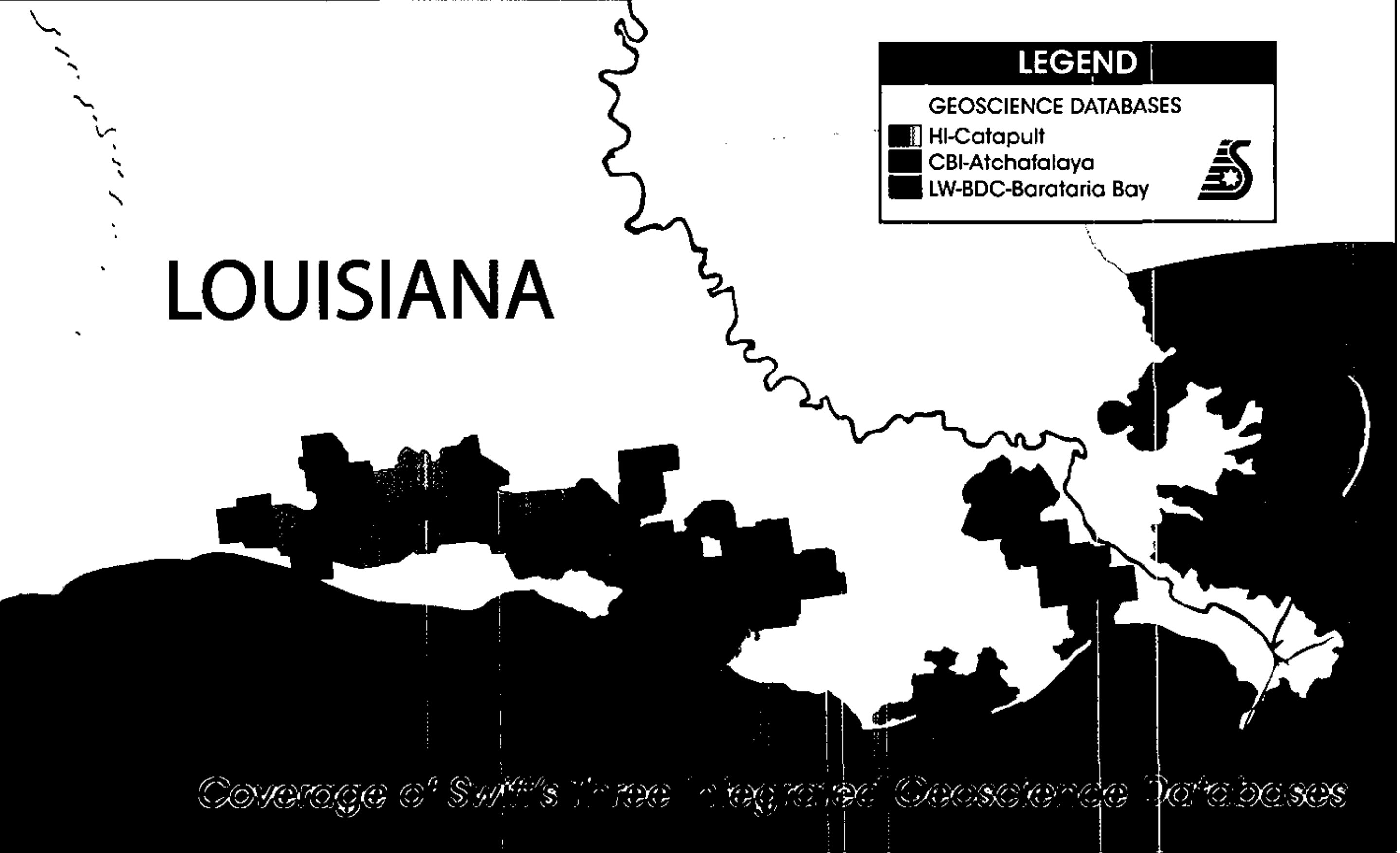
mensional seismic survey was only a first step in our seismic data acquisitions. With our expansion beyond Lake Washington into other South Louisiana fields, our acquisitions of seismic data have exploded and all of our South Louisiana drilling is now based on the analyses of geoscience databases that contain integrated seismic and geological data.

In Lake Washington, we immediately benefited from the earliest analyses of the data in 2005. The results not only guided our overall drilling to intermediate sands, which yielded initial well production rates of 300 Boe to 500 Boe per day, over time they reduced the risks associated with the program. Moreover, we identified and drilled our first exploratory prospects based on the data: the Newport prospect and the Bondi prospect, both reaching new producing sands at depths between approximately 10,300 feet and 12,700 feet. Altogether, we drilled 32 Lake Washington wells in 2005 with a 66% success rate, including a highly successful Newport delineation well at a depth of 12,736 feet that hit three pay sands and had combined initial tests in two sands of 7,429 barrels of oil per day and 5.5 Mcf of natural gas per day.

We have continued to develop the Newport prospect, which is responsible for a large fraction of our current Lake Washington production. Our 2006 Lake Washington program, in which we drilled 21 wells with an 86% success rate, included six successful Newport delineation wells (two nonoperated) with depths ranging down to 16,488 feet, and our 2007 program, in which we drilled 22 wells with an 82% success rate, included five Newport wells. In 2008, we plan to drill up to 27 wells in the field, focusing primarily on the underexplored intermediate depths.

As we continue with our 2008 Lake Washington drilling, the geoscience database that includes Lake Washington has undergone numerous analyses that are allowing us to create new geography at deeper depths in a field that had already been considered to be mature (see geoscience database discussion below). With our three-dimensional subsurface imaging, we are seeing better definition of the salt surface and the faults that provide the containers to hold hydrocarbons. We have also found highly productive sands such as those found at Newport. In addition, we have more accurate imaging of the salt-sediment interface that allows us to drill closer to the salt dome to better exploit the "attics" of some sands. And we can see potential drilling targets underneath the salt, which can be reached either by drilling through the salt or under it with a highly deviated wellbore.

In the majority of the 2008 wells we will be targeting probable and possible reserves, with the intent of converting them to proved and producing reserves. The risks associated with targeting these nonproved reserves will be significantly mitigated both by our increasing knowledge of the subsurface and by the fact that we



Coverage of Swift's Three Integrated Geoscience Databases

also will often target proved reserves in the same wellbores.

In the meantime, we continue to build our inventory of drilling locations in the field. At year-end we had 113 proved undeveloped locations for targets ranging from 3,000 feet to 13,000 feet deep and were assessing deeper targets. The lengthy permitting process required prior to drilling has already been completed for many of our proved undeveloped locations.

To accommodate our increasing Lake Washington production, we have carried out numerous infrastructure upgrades to increase the field's processing and delivery capacities, as well as numerous repairs following damage caused by hurricanes Katrina and Rita. By early 2006, we had upgraded three existing production processing facilities, added new compression for the gas lift system, installed a new oil delivery system, and constructed a barge loading facility for transporting oil to additional markets.

When completed, these improvements had increased the field's processing capacity to approximately 28,000 barrels per day, but rapid expansion of the producing area had already forced us to plan for the addition of a new processing facility on the west side of the field. The new facility, scheduled to be commissioned in mid-2008, will increase the processing capacity another 10,000 barrels per day and will also help us optimize the field for better overall productivity.

In addition, the new facility will help us increase our production from the Newport wells. The Newport area reservoirs are not open to the basin and, as a result, have weak water drives. To improve the recovery rates for the wells, we will be providing pressure support by drilling water injection wells down dip to increase the bottom-hole pressures. The new Westside Facility will provide the platform space for the Newport pressure maintenance project.

We have demonstrated the viability of the pressure maintenance project by introducing a water injection well down dip from a producing well (CM#222) whose initial production rate and reservoir pressure had both declined through normal depletion. Following injection, the reservoir pressure returned and the production rate surpassed its original rate. Reservoir simulation efforts estimate that the increased recovery for the well will be 400 MBoe to 700 MBoe, or 27% to 40%.

Obviously, pressure maintenance is a technique for increasing production recovery in other Lake Washington reservoirs without strong water support and will be used, along with other techniques, as we continue to exploit this field for years to come.

Bay de Chene. The Bay de Chene Field is located in inland waters 30 miles northwest of the Lake Washington Field, and like Lake Washington, produces from stacked Miocene sands surrounding a salt dome, primarily between depths of 6,000 feet and 14,000 feet. When we purchased 100% interests in the field in 2005, it had already produced 142 MMBoe and the reserves we acquired were estimated at 1.23 MMBoe. The field was shut in throughout 2005 for various reasons, but especially because of storm effects that caused us to focus primarily on Lake Washington. Meanwhile, we carried out well workovers and geological studies, and, perhaps more importantly, we licensed seismic data for the field for inclusion in the same geoscience database as the Lake Washington seismic data.

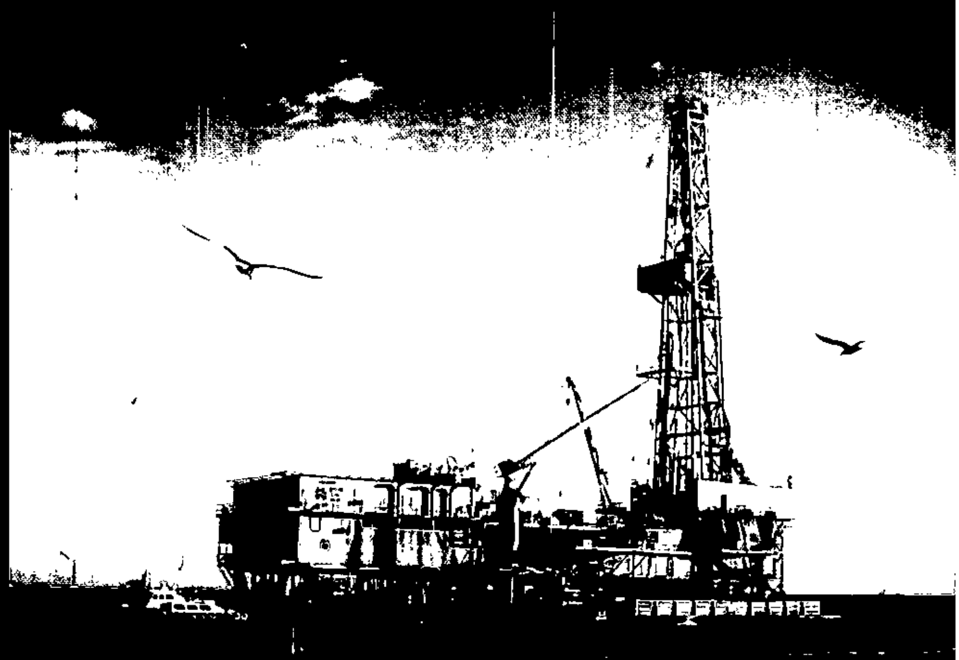
In 2006 we initiated our Bay de Chene exploitation program with the completion of three of six development wells drilled. In 2007, we continued by completing two of two development wells, one of which was a natural gas well in a new fault block discovery in the 8,900-foot sand.

Also in 2007, we drilled five exploration wells in Bay de Chene with two successes. The first, drilled on the Faria prospect in the first quarter, reached a depth of 13,000 feet, finding a total of 136 feet of net pay in two sands and initially testing at 17 MMcf of natural gas and 158 barrels of oil per day from both sands. The second, drilled on the Pisces prospect in the fourth quarter, reached a depth of 14,041 feet and tested at 2.1 MMcf per day of natural gas.

The Faria well was placed on production at a constrained rate because of limited local markets, and the Pisces well is shut in for the same reason. During the first quarter of 2008, we executed a contract that will alleviate near-term capacity concerns late in the second quarter. We are also pursuing the option of an additional pipeline connection for marketing flexibility. During 2007, Bay de Chene provided 5.7% of our total production.

As is the case for Lake Washington, our plans for future drilling in Bay de Chene, where we have drilling and production rights in 18,546 net acres, will be totally based on the results from our geoscience database analyses and will include attic targets against the salt dome and deep targets under it. At year-end 2007 we had seven proved undeveloped locations in the field and plan to drill up to five wells there in 2008 in the depth range of 7,000 feet to 13,000 feet. In addition, we will begin assessing deeper opportunities. Since few wells in the field have gone deeper than 15,000 feet, we will be relying entirely on our new seismic imaging in selecting the deepest targets.

At year-end 2007, Bay de Chene's proved reserves totaled 4.7 MMBoe, or 3.5% of our total domestic reserves. They consisted of 60% natural gas and were 51% undeveloped.



The remaining six South Louisiana fields in which we have interests, five are clustered relatively close together in an area west of Lake Washington and Bay de Chene. We have acquired or purchased three-dimensional seismic data for all these fields and surrounding areas and have merged them to form the geophysical base of our second geoscience database.

Included among these fields is Cote Blanche Island in St. Mary Parish, in which we acquired 100% interests in 2005 along with those in Bay de Chene. Interests in the other four fields were included in a 2006 acquisition. Of these, three fields—Jeanerette, Horseshoe Bayou, and Bayou Sale—are also in St. Mary Parish, and the fourth—Bayou Penchant—is in Terrebonne Parish.

Cote Blanche Island, like Lake Washington and Bay de Chene, is located in inland waters and produces from stacked Miocene sands surrounding a salt dome. Many successful wells have been drilled around the dome, including three by us in 2006.

Of the five fields included in this group, Cote Blanche Island was the only field for which there were no seismic data. To provide the data, we completed a proprietary three-dimensional seismic survey over 77 square miles in and around Cote Blanche Island early in 2006, and a fast-track analysis of the data was performed in 2007 to accelerate drilling plans for the field. We are currently assessing potential targets on all edges of the salt dome and under it. At year-end we had 25 proved undeveloped locations for depths between 11,000 feet and 15,000 feet. We plan to drill one or two wells in the field during 2008.

We have licensed three-dimensional seismic data for the other fields in the group, and while we had not yet drilled in them at year-end 2007, our ongoing analyses are indicating numerous drilling opportunities for Jeanerette and Horseshoe Bayou/Bayou Sale (adjacent fields referred to as HBBS). Jeanerette is positioned on the flank of a large salt dome 12.5 miles north of Cote Blanche Island and produces from the Planulina sands. The HBBS fields, 13 miles southeast of Cote Blanche Island, produce from several formations. We plan to drill up to five wells in these fields during 2008.

Bayou Penchant, which produces from Miocene sands, is a nonoperated field, but is included in our geoscience analyses.

field, High Island, is located in Cameron Parish and produces from the Marg Howei and Camerina sands at depths between 15,000 feet and 17,000 feet. It is the only one of our fields that is included in our third and largest geoscience database, which covers the entire area between High Island and Cote Blanche Island with licensed seismic data from many surveys and geological data from thousands of well logs. This database is scheduled for intensive analysis in 2008.

During 2007, Cote Blanche Island plus the five new fields provided 9.1% of our total production, and at year-end 2007 their combined reserves totaled 32.5 MMBoe, or 24.3% of our domestic reserves

Distribution of Swift Energy's Domestic Proved Reserves
(as of December 31, 2007)

	[illegible] (MMBoe)			[illegible]	[illegible]
	[illegible]	[illegible]	Total	[illegible]	[illegible]
South Louisiana					
Lake Washington	18.5	17.9	36.4	27.2	92.1
Bay de Chene	2.3	2.4	4.7	3.5	39.9
Other South Louisiana	7.3	25.2	32.5	24.3	40.1
Total South Louisiana	28.1	45.5	73.6	55.0	65.8
South Texas					
AWP	16.3	6.1	22.4	16.8	29.1
Cotulla	9.5	6.9	16.4	12.2	51.5
Other South Texas	0.3	0.1	0.4	0.3	5.8
Total South Texas	26.1	13.1	39.2	29.3	38.2
Toledo Bend					
Austin Chalk	4.7	7.9	12.6	9.4	64.3
South Bearhead Creek	[illegible]	2.7	6.8	5.1	67.5
Total Toledo Bend	[illegible]	10.6	19.4	14.5	65.4
Total Texas and Louisiana	[illegible]	69.2	132.2	98.8	57.6
Other	1.4	0.2	1.6	1.2	25.0
Total	[illegible]	69.4	133.8	100	57.2
Total Louisiana	34.6	53.5	88.1	65.9	66.2
Total Texas	28.4	15.7	44.1	32.9	40.2

[illegible] 78 [illegible] 79

The reserves consisted of 40.1% oil and natural gas liquids and were 77.5% undeveloped.

South Louisiana Geoscience Databases. As noted in the foregoing discussion, our entire exploration and development program for South Louisiana is now based on the results we obtain from analyses of the data included in three geoscience databases we are building. We began developing our first database (see map on page 12) in 2005 by merging the data obtained in our 2004 Lake Washington seismic survey with licensed seismic data for an adjacent 530 square miles in the Barataria Bay area northwest of Lake Washington. And with our purchase of interests in the nearby Bay de Chene Field in 2005, we also added licensed data to cover that field, ending up with data from eight different seismic surveys. Finally, we integrated the results with digitized well-log data, referring to the whole as our LW-BDC-Barataria Bay database.

This first database has undergone several types of analyses to produce three-dimensional subsurface images. We performed a prestack time migration (PreSTM) analysis of the entire database during 2007 and a prestack depth migration (PreSDM) analysis for the key areas of Lake Washington and Bay de Chene. These analyses, which require enormous quantities of computational time, correct for distortions in the reflected sound waves that are caused by their time of travel and the properties of the structures through which they pass (rocks, salt, etc.). A PreSTM analysis represents a first step that can be performed with minimal geologic knowledge to obtain first indications of the presence of subsurface structures. But for some images, in particular salt images, there is a high degree of distortion with PreSTM analyses. By contrast, PreSDM analyses, which require significant geologic knowledge as well as in-process interpretation, yield much more detailed images. And with updated geologic data that become available from newly drilled wells, both types of analyses can be repetitively improved. For example, in 2008 we plan to perform an improved PreSDM analysis for Lake Washington with new data obtained from our 2007 drilling program.

Distribution of Domestic Production
(as of December 31, 2007)

	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
South Louisiana					
Lake Washington	170	20	190	27.2	62.0
Bay de Chene	16	0	16	3.5	5.7
Other South Louisiana	64	51	115	24.3	9.1
Total South Louisiana	250	71	321	55.0	76.8
South Texas					
AWP	537	1	538	16.8	10.7
Cotulla	205	0	205	12.2	2.8
Other South Texas	5	6	11	0.3	0.8
Total South Texas	747	7	754	29.3	14.3
Toledo Bend					
Austin Chalk	118	56	174	9.4	4.9
South Bearhead Creek	28	0	28	5.1	3.3
Total Toledo Bend	146	56	202	14.5	8.2
Total Texas & Louisiana	1,143	134	1,277	98.8	99.2
Other	1	3	4	1.2	0.8
Total	1,144	137	1,281	100	100
Total Louisiana	344	101	445	65.9	82.[illegible]
Total Texas	799	33	832	32.9	17.[illegible]
Percent of [illegible]	96	4			
Percent of Production	93	7			

[illegible] 1,091 producing wells and 53 [illegible]

We began building our second geoscience database when four of the five new fields we purchased interests in were in the same general area as Cote Blanche Island. This database, referred to as the CBI-Atchafalaya database, has seismic data from 17 surveys covering Cote Blanche Island, Jeanerette, HBBS, and Bayou Penchant, as well as an expansive area connecting and surrounding these fields. Several of the surveys are embedded in a large dataset called the Atchafalaya dataset that we licensed in 2006 for a 665-square-mile area that includes Bayou Penchant. Others are within a dataset for an adjoining 322 square-mile area surrounding and including HBBS, also licensed in 2006.

Seismic data for Cote Blanche Island came from our own 2006 three-dimensional seismic survey that included surrounding areas and totaled 77 square miles. These data were west of and contiguous with the earlier licensed data. Finally we added

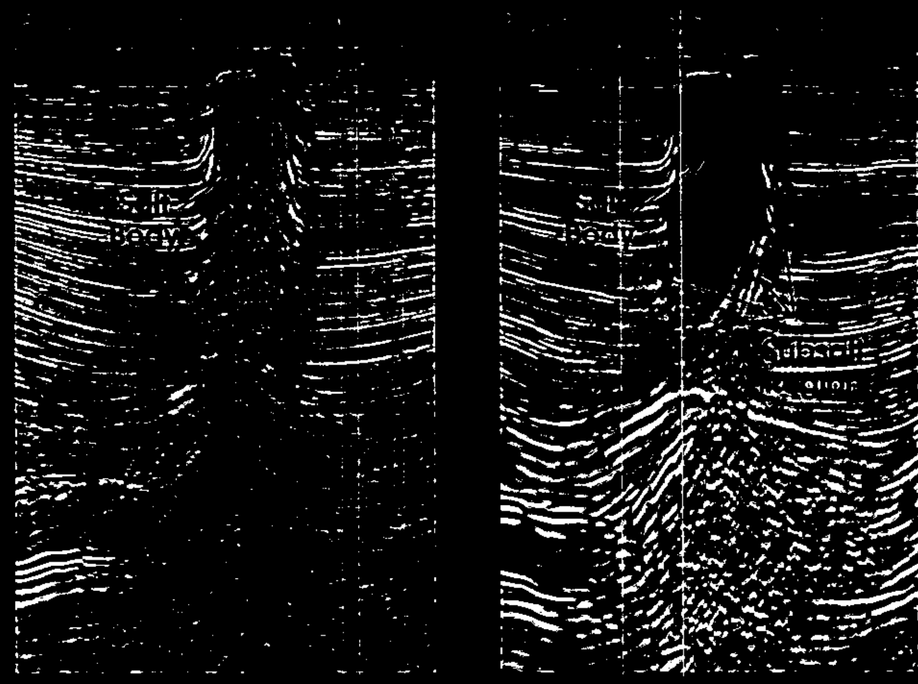
70 square miles of data to the northwest that included Jeanerette and 120 square miles of data for an area southwest of the others. Together, the areas in this second geoscience database cover 1,700 square miles of integrated three-dimensional seismic data that have also been merged with geologic information.

During 2007 we completed a PreSTM analysis of the entire CBI-Atchafalaya database and began working on the corresponding PreSDM analysis, which will be completed in 2008. In the meantime, we performed a fast-track PreSDM analysis for the area that included Cote Blanche Island to better plan our near-term drilling program for that field.

In 2007, we also began work on a third database that includes and extends eastward from our High Island Field. This database consists of a collection of 21 three-dimensional seismic surveys that we licensed together as the Catapult acquisition. Referred to as the HI-Catapult database, it covers 1,765 square miles. The merged seismic and geological data within this area will undergo a PreSTM analysis in 2008, with a PreSDM analysis to follow later in 2008 and possibly extending into 2009.

Following the Catapult purchase, we obtained two additional parcels of seismic data totaling 200 square miles for the CBI-Atchafalaya database, one of which ties the second and third databases together. As we continue to analyze them, the two databases will eventually become a single database covering a contiguous area of approximately 3,500 square miles—again, wholly proprietary to Swift Energy Company.

In assembling the geological information for these databases,



we had the benefit of logs from thousands of wells drilled along the coast. It became apparent, however, that the number of wells drilled to depths greater than 16,000 feet is much, much smaller, emphasizing the importance of having integrated seismic and geologic databases for identifying potential deep targets.

As a next step in our analysis efforts, we have begun correlating our seismic data to rock properties, which with various techniques can be used to predict pore fluids in rocks (oil, gas, or water) and pore pressures, which, in turn, will help us identify faults that seal reservoirs. This work will continue throughout 2008 and further assist us in identifying deeper targets.

As would be expected, this vast knowledge base that we are assembling for the Louisiana Gulf Coast is not only revealing three-dimensional subsurface structures for our own properties but also for areas outside our producing fields. We are developing prospects and obtaining leaseholds for some of these areas, and, in fact, are currently seeking partners for two deep exploration prospects.

During 2007 our South Texas Region expanded from primarily an operation of properties in a single field, the AWP Olmos Field in McMullen County, to operations in three additional fields obtained in our Cotulla acquisition. The three Cotulla fields, located in contiguous counties, consist of the Sun TSH Field in LaSalle County, the Briscoe Ranch Field in Dimmit County, and the Las Tiendas Field in Webb County. With the addition of these fields, our South Texas drilling and production rights increased to 111,093 net acres with total proved reserves of 39.2 MMBoe, or 29.3% of our total domestic reserves.

We first became an operator in AWP in 1989 when we increased our interests in 65 wells on a 4,900-acre leasehold producing from the field's tight Olmos sands. At year-end 2007, after years of development that included several acreage additions and numerous innovations for extracting the field's hydrocarbons, we were operating 536 wells on 29,107 net acres with nearly 100% working interests. The field's 2007 production was 1.14 MMBoe, comprising 10.7% of our total domestic production.

AWP's Olmos sand, located at depths of 9,000 feet to 11,500 feet, is a depletion-driven reservoir of low porosity and very low permeability. Therefore, production is greatly enhanced when the sand around the bore holes is hydraulically fractured to provide pathways into the holes. We have learned that introducing longer fractures as the reservoir pressure declines can significantly increase the wells' ultimate recoveries during their 15- to 20-year production lives. Since fracturing is an intensive operation, we have consistently concentrated on designing fracture techniques that give optimum results at lower costs.

During 2007 we drilled 21 AWP development wells, all successfully completed, and performed 16 fracture enhancements. For 2008, we plan to drill 10 to 15 wells and perform over 20 fracture enhancements. AWP's year-end reserves were 70.9% natural gas and totaled 22.4 MMBoe, or 16.8% of our total proved domestic reserves. Of these, 6.1 MMBoe were still undeveloped, with 98 proved undeveloped drilling locations identified.

The three fields in the Cotulla acquisition—Sun TSH, Briscoe Ranch, and Las Tiendas—added 81,986 net acres to our South Texas operations in the Maverick Basin, and, after being acquired during the fourth quarter of 2007, contributed 0.3 MMBoe, or 2.8%, to our total 2007 production. At year-end we were operating a combined total of 205 wells in the fields, effectively all with 100% working interests and including six that were completed out of seven that we drilled during the fourth quarter of 2007.

All three fields are producing from the Olmos sand at depths varying from 4,500 feet to 5,000 feet for Briscoe Ranch, 6,000 feet to 6,800 feet for Las Tiendas, and 7,000 feet to 8,000 feet for Sun TSH. In addition, Sun TSH produces from the Escondido sands between 5,500 feet and 6,000 feet.

The combined year-end reserves of the three fields, which are 51.5% oil and NGLs, totaled 16.4 MMBoe, or 12.2% of our total proved domestic reserves. Of these, 6.9 MMBoe (42.1%) were still undeveloped, with 89 proved undeveloped drilling locations identified. We plan to drill 30 to 36 wells in the Cotulla area during 2008.

South Texas Seismic Initiatives

With our intention of logically extending our geoscience methodology to all our regions of operation, we have begun developing a seismic program for the South Texas Region. During 2007 we licensed data from many thousands of miles of two-dimensional seismic surveys to develop basin models. From these models, we will decide where we need to acquire three-dimensional data for input into a geoscience database for the region.

TOLEDO BEND REGION

Our Toledo Bend Region consists of a collection of fields that together are called Toledo Bend because the properties acquired

were near the Toledo Bend Res-ervoir along the Texas-Louisiana border. These original properties, all producing from the Austin Chalk Trend, are located in the two Texas counties of Jasper and Newton and the two Louisiana parishes of Vernon and Rapides. In 2005 and 2006, we expanded Toledo Bend with the acquisition of interests in South Bearhead Creek Field in Beauregard Parish that produces primarily from the Wilcox sands. All the fields combined give us drilling and production rights on 126,993 net acres.

Brookeland/Masters Creek. Our Toledo Bend properties produc-ing from the Austin Chalk trend are located in the Brookeland Field in East Texas and the Mas-ters Creek Field in Central Loui-siana and include 119,817 net acres. In Brookeland the reserves are found at depths of 7,000 feet to 12,500 feet, while in Masters Creek they are at depths greater than 14,000 feet.

Upon assuming the operation of these properties in 1998, we embarked upon a comprehen-sive infrastructure upgrade pro-gram and initiated a large drilling program of horizontal wells. The Brookeland reserves are deple-tion driven. The Masters Creek re-serves, however, are water driven, which required that we develop an elaborate salt water disposal system, as well as procedures to reduce the buildup of scale along the interior walls of the well-bore tubulars.

Because the production from Austin Chalk wells typically de-clines rapidly after early payout, we decided in 2002 to shift our drilling focus to long-lived proven reserves such as those found in Lake Washington and AWP to en-

duction profiles. Since then we have drilled only a few wells in the Austin Chalk, with none occurring in 2007 and only one or two wells planned for 2008.

At year-end 2007, we operated 118 Austin Chalk wells that con-tributed 0.52 MMBoe, or 4.9%, of our total 2007 domestic produc-tion. Our year-end Austin Chalk reserves, comprised of 64.3% oil and NGLs, totaled 12.6 MMBoe, or 9.4% of our total proved domestic reserves. Of these, 7.9 MMBoe, or 62.7%, remained undeveloped, with ten proved undeveloped lo-cations in Brookeland and nine in Masters Creek.

South Bearhead Creek. In 2005 and 2006 we acquired 100% work-ing interests in properties in South Bearhead Creek in Beauregard Parish, Louisiana, that produce from the upper and lower Wilcox sands at depths of 10,600 feet to 14,100 feet and from the Cock-field sands at depths of 8,000 feet to 8,500 feet. Our interests give us drilling and production rights in the field of 7,176 net acres.

We began our exploitation of South Bearhead Creek in 2006 with the completion of three de-velopment wells drilled to the Wil-cox sands. We had almost con-tinuous drilling in the field during 2007, with another 10 wells drilled to the Wilcox sands and one well drilled to the Cockfield sands, all with 100% success. At year-end 2007, we were operating 28 wells in the field with plans to drill up to four additional wells in 2008.

During 2007, South Bearhead Creek contributed 3.3% of our to-tal production and at year-end held 5.1% (6.8 MMBoe) of our to-tal proved domestic reserves. The reserves were 67.5% oil and NGLs and 40% undeveloped. Also at

developed locations in the field.

NEW ZEALAND

In December 2007 we signed an agreement to sell the majority of our international operations which were located in the Taranaki Basin of the North Island of New Zealand. We had begun op-erations there in mid-1999 when we drilled a discovery well on a prospect after obtaining our first exploration permit in the region in 1995. Over the years we carried out both a development program building on this and other new field discoveries and, more recent-ly, an exploratory program that focused on deep natural gas op-portunities. We consistently found hydrocarbons but were confront-ed by low-quality rock properties in the targeted formations. Early in 2007, as we performed our annu-al review of all our properties with respect to their past history and potential future contributions, we determined it was time for us to di-vest ourselves of our New Zealand assets and focus on our domes-tic properties. Therefore, while we continued to operate the proper-ties throughout 2007, we took no new initiatives and the produc-tion from the region underwent a natural decline, producing a total of 1.4 MMBoe during the year.

The December 2007 agreement, which was with Origin Energy Lim-ited for our main producing fields, is expected to close early in 2008. This agreement qualifies our New Zealand assets to be treated as discontinued operations in the fourth quarter of 2007 and to be represented as such in our fi-nancial statements. Additional agreements for the sale of the remainder of our New Zealand assets are being negotiated and are anticipated to be in place by the end of 2008.

The Value of Discipline

Our disciplined approach to financing has long been one of the cornerstones of our strategy for achieving sustained growth in shareholder value. As with any kind of discipline, the key to effective financial discipline is to maintain a healthy balance between the present and the future—on the one hand to reap immediate rewards from current opportunities and on the other hand to make the investments required for even better results down the road.

Since we've outlived the vast majority of our competitors in our 28-year history, we think it's clear that our emphasis on financial discipline gives us a competitive advantage. We preserve our conservative balance sheet by proactively controlling our mix of equity and debt; we monitor our credit profile and work to continually improve it; and we manage the risk of short-term price fluctuations by protecting against sudden price declines while retaining the potential of upside gains. Together, these efforts provide the financial flexibility to take advantage of immediate opportunities, while simultaneously preserving our financial integrity for long-term growth.

A look at some year-end benchmarks for 2007 illustrates our ability to set records while staying the course with a conservative financial strategy. In a year in which we achieved all-time highs in both operational and financial performance, we were also able to end the year with a very sound balance sheet. Our current ratio was 0.95 at the end of 2007, up 64% from 0.58 in 2006. And though our fourth-quarter acquisition increased long-term debt levels, the ratio of our debt to our domestic reserves value (domestic PV-10 ratio) was 15% at year-end, well below our target of less than 25%. Our debt to capitalization ratio was 41% at year-end 2007, and our debt per domestic Boe was $4.39. All of these long-term debt ratios will further improve once we receive the proceeds from the sale of the majority of our New Zealand assets. These proceeds, which we expect to receive in the first half of 2008 when the transaction is complete, will be used to reduce our outstanding borrowings under our bank facility.

This financial strength was made possible by years of record cash flows. In 2007, for the fourth year in a row, we set an all-time high in cash flow from continuing operations, allowing us to achieve a five-year average growth rate for cash flows of 51% per year. This record cash flow performance—along with cash balances and bank borrowings for our fourth-quarter acquisition—allowed us to expand our capital budget during the year. Our capital expenditures for continuing operations were $650.6 million in 2007, up from initial projections of $350 million to $400 million, which excluded acquisitions, and up from our 2006 capital expenditures of $488.2 million.

We strengthened our liquidity in 2007 by increasing the borrowing base of our $500 million bank credit facility held with a syndicate of 10 banks. In April of 2007 we increased our borrowing base from $250 million to $350 million, and then in November we raised it again to $400 million. At year-end 2007, we had $187 million outstanding on this facility. Other long-term debt at year-end 2007 included $150 million of 7-5/8% senior notes issued in 2004 and due 2011, and $250 million of 7-1/8% senior notes issued in 2007 and due 2017. The latter replaced senior subordinated notes at 9-3/8% due in 2012 that we redeemed in mid-2007 to take advantage of lower interest rates.

Our objectives for preserving our financial integrity in 2008 include enhancing our balance sheet to maintain liquid-ity, holding our debt/PV-10 ratio to less than 25% as we have done for many years, and continuing our price-risk management strategy to protect our capital budget.

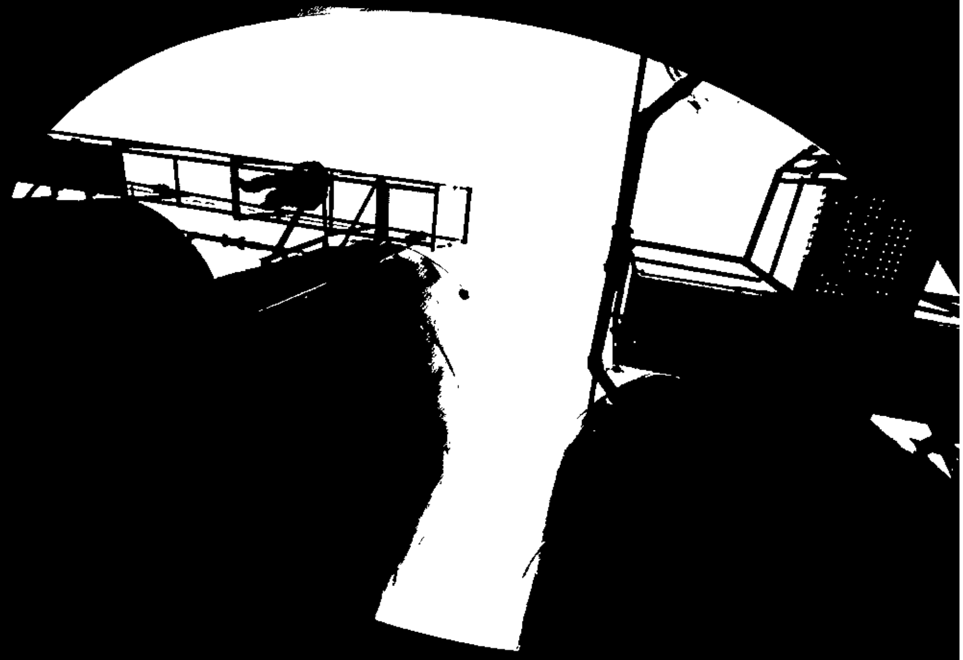
In regard to the latter, we're aiming in 2008 to improve both our finding and development costs and our per-unit operating costs as a percentage of oil and gas prices, a difficult task given the inflationary cost environment prevalent in our industry during recent years. We believe we are now well positioned to better control costs because of our recent investments in seismic data, technology, and facilities. These advances are expected to lead to lower costs as a percentage of oil and gas prices by enabling us to more effectively increase production and add reserves.

Our projected capital expenditure budget for 2008 is $425 million to $475 million, net of minor non-core dispositions and excluding any property acquisitions. We expect to fund these expenditures with our anticipated cash flow from continuing operations. As we have done in recent years, we may increase our capital expenditure budget if conditions warrant. Such conditions would include higher than expected cash flow—from either an increase in oil and gas prices during the year or higher than expected production volumes—and any opportunities that might arise to make strategic acquisitions financed through cash flows or our bank credit facility.

Our price-risk management strategy targets 20% to 50% of our oil and gas production using low-cost floors, near-term forward sales, or participating costless collars to protect our cash flow and capital budget against short-term price declines. At the beginning of 2008, we purchased natural gas floors covering about 30% to 35% of expected domestic natural gas production in the first quarter of 2008 and about 40% to 44% of natural gas production expected in the second quarter of 2008. For crude oil production, we purchased floors covering 40% to 43% of expected first-quarter 2008 oil production.

We believe our disciplined financial strategy has helped put us in a good position to grow. In our operations, we've become digitally integrated, broadened our high-tech capabilities, built geoscience databases, and developed a sound portfolio of exploration and development opportunities. We are poised to grow organically through drilling and strategically through acquisitions, and because of our financial discipline, we have the liquidity to augment our cash flow as needed. As we have said in the past, our conservative capital structure is one of the reasons we've been in business so long, outliving some 85% of our competitors, and it's also a reason why we'll continue to build shareholder value for many years to come.

The Value of Core Values



We are very proud of what we've achieved over the last 28 years. We've consistently succeeded in one of the most challenging and volatile industries in the world. When we ask ourselves what allowed us to go the distance when so many U.S. oil and gas companies have ceased to exist, we always come back to our core values for one of the answers. Our values, like our vision and mission, have become intangible resources, something that doesn't show up on the balance sheet but which does provide far-reaching benefits impacting our bottom line.

As we've undergone tremendous transformation and growth over the past quarter century, our core values have remained the same. Built on the principles and philosophy of our late founder and carried forward by our current management team, our values represent who we are and what sets us apart. When we say that our financial strategy is built on discipline, our shareholder value on balance, and our operations on innovation and knowledge, we are talking about values that have guided our actions throughout our history. These values help us attract new employees, assist us in developing good relationships with property owners and vendors, and help us to build trust with the investment community. Our values shape who we are and what we do, and in a very practical way, they are the most valuable thing we possess as a company.

We've identified several key character traits that illustrate these core values.

First, we embrace change, seeking out fresh opportunities created by a dynamic environment. One of many ways we've done this through the years is our tandem approach of adding reserves through drilling or acquisitions, adjusting the balance between the two depending on price fluctuations and changes in strategic opportunities.

In order to profit from change, we also have to hone our skills, consistently sharpening our professional expertise and learning new technologies as an ongoing part of our jobs. In recent years, we've created a series of internal "knowledge networks" to help our employees develop themselves professionally and to help them embrace the many kinds of digital technology that are revolutionizing the hunt for oil and gas.

Another key trait of our corporate character is that we seek to constantly improve by learning lessons from our previous successes and failures. From the oil field to the boardroom, we review our performance results in detail—reinforcing what works as well as mapping out new ways to do things better.

From the earliest days of our organization, we have also sought to develop a participatory corporate culture that encouraged teamwork and cooperation. Our matrix structure is designed to promote teamwork, and developing team skills is an important part of our professional development activities.

One of the most important values we hold is the necessity of protecting people and the environment in everything we do. Our commitment to health, safety, and the environment was perhaps best illustrated in August 2005 when Hurricane Katrina struck our Lake Washington property in South Louisiana. We activated our emergency response plans well in advance of the hurricane, buttoned down our facilities, and rushed aid to our local employees soon after the storm had passed, including providing many of them with mobile housing.

We also aim to be a good cor-porate citizen, having put ethical guidelines and controls in place long before Sarbanes-Oxley actually required them. We want to make meaningful contributions to the geographical and professional communities where we operate, and we strive to be an organization of role models for young people, participating in mentoring programs and offering internships for qualified students.

Above all, we pursue balance. In each facet of our operations, from the composition of our reserves to the way we reach decisions, we strive to maintain a balance between competing demands. We believe that a healthy corporate culture hinges on balanced decision making. By "balanced" we mean that some decisions are decentralized and flexible in order to allow individual initiative and creativity, some are based on consensus to enhance cooperative relationships and promote teamwork, and some are guided by leadership as they set forth the company's vision and values.

In the end, it is a combination of our leadership team and our system of formal authority that is responsible for upholding and advancing the values that guide us. At Swift Energy, our ultimate authority is founded upon our system of corporate governance—which in turn resides in our board of directors, who are elected by the shareholders, and in our company officers, who are guided by the board, our bylaws, and our corporate policies.

Within our board of directors, we've weighted the balance of external and internal directors to favor a strong measure of outside control, with three-fourths of our board members being independent outside directors. We seek our members who will effectively represent the core values we believe, and who, amongst themselves as a group, are diverse in both their age and skill sets. Currently, our members range from 47 to 76 years of age and have diverse experience in fields such as finance, technology, and diplomacy, as well as in oil and gas operations.

Likewise, our executives and managers exemplify our company's core values and have technical skills in their areas of expertise that are second to none. Most of our leadership team has been together for many years, and we continually develop people internally who can take over for our more experienced team members as they retire.

In early 2008, Robert J. Banks was promoted to executive vice president and chief operating officer when Joe D'Amico, a 20-year veteran of Swift, announced his retirement. Mr. Banks, who joined Swift in 2004 to oversee international operations and strategic ventures, has over 30 years of experience in the oil and gas industry. His experience before joining Swift included holding senior-level positions and leading international units for Vanco Energy Company, Mosbacher Energy Company, Kuwait Foreign Petroleum Company, and Santa Fe International Corporation.

Also in early 2008, John C. Branca was promoted to vice president–exploration and development. Mr. Branca first joined Swift in 2006 as exploration manager, with his title later revised to director of exploration and development. Before joining Swift, Mr. Branca had 25 years of experience with BP in various positions, primarily focused on exploration and development.

Another important change to our management team was the promotion in 2007 of Steven B Yakle to the position of vice pres ident–corporate administration Mr. Yakle joined Swift Energy in August 1989, serving first as man ager of partnership accounting and later as assistant controlle for compliance, with responsibili ties for both corporate and part nership reporting. He transferred to SENZ in New Zealand in 2001 remaining there until he returned to Swift Energy's corporate offices in February 2006. Before joining Swift Energy, Mr. Yakle worked fo Goldking Production Company and the Internal Revenue Ser vice.

Overall, our team of professionals grew in 2007 as the size of our do mestic staff increased 10% to 29 employees. Throughout the year we improved our collective skil level as a company by recruiting new people and by encouraging individuals to further develop thei personal expertise.

In addition to our people, we de velop and maintain internal pro cesses to ensure that our vision and values are upheld. These in clude a strategic plan, our annua budget process, and an author ity-for-expenditure process tha involves both operational and financial reviews. Our processes were created to push cooperation and transparency throughout ou organization, and we believe they are succeeding.

Ultimately, our employees and processes must be guided by the vision and values embedded within our culture. It is our cultura values—passed down from ou leadership and management to our employees and stakehold ers—that form the foundation o all our achievements.

BOARD OF DIRECTORS

Terry E. Swift
Chairman of the Board &
Chief Executive Officer,
Swift Energy Company,
Age 52

Bruce H. Vincent
President & Secretary,
Swift Energy Company,
Age 60

Raymond E. Galvin
Vice Chairman of the Bo
Swift Energy Company,
Retired President, Chevro
Production Company, A

Deanna L. Cannon
Shareholder & Director,
Corporate Finance Associates
of Northern Michigan,
Age 47

Douglas J. Lanier
Retired Vice President,
Gulf of Mexico Business Unit,
ChevronTexaco Exploration &
Production Company, Age 58

Greg Matiuk
Retired Executive Vice
President, Administrative &
Corporate Services, Chevron-
Texaco Corporation, Age 62

Henry C. Montgomery
Chairman & Founder,
Montgomery Professio
Services Corporation,
Age 72

Clyde W. Smith, Jr.
President,
Ascentron, Inc.,
Age 59

Charles J. Swindells
Vice Chairman, Western Region,
U.S. Trust, Bank of America
Private Wealth Management, Age 65

Board of Directors Committees:

Audit Committee:
Henry C. Montgomery-Chairman
Deanna L. Cannon, Clyde W. Smith, Jr.

Corporate Governance Committee:
Greg Matiuk-Chairman
Deanna L. Cannon, Raymond E. Galvin,
Charles J. Swindells

Compensation Committee:
Clyde W. Smith, Jr.-Chairman
Douglas J. Lanier, Greg Matiuk, Henry C. Montgom
Charles J. Swindells

Executive Committee:
Terry E. Swift-Chairman
Raymond E. Galvin, Douglas J. Lanier

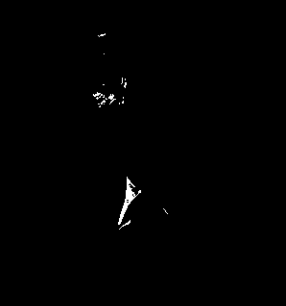
COMPANY OFFICERS

Terry E. Swift
Chairman & Chief
Executive Officer

Bruce H. Vincent
President & Secretary

Robert J. Banks
Executive Vice President &
Chief Operating Officer

ton D. Heckaman, Jr.
ecutive Vice President
Chief Financial Officer



Joseph A. D'Amico
Executive Vice President

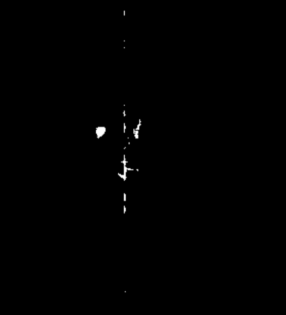
James M. Kitterman
Senior Vice President-
Operations

James P. Mitchell
Senior Vice President-
Commercial Transactions & L

hn C. Branca
ce President-
ploration & Development

David P. Coatney
Vice President-
Production

Thomas E. Schmidt
Vice President-Operating
Compliance & External Relations



Tara L. Seaman
Vice President-
Reserves & Evaluations

even B. Yakle
ce President-
orporate Administration

Laurent A. Baillargeon
General Counsel

Adrian D. Shelley
Treasurer

David W. Wesson
Controller

FINANCIAL REPORT

Selected Financial and Operating Data

(Financial data in thousands except per-share amounts)

	2007	2006	2005	2004	2003
Total Revenues from Continuing Operations[1]	$654,121	$550,836	$354,365	$257,313	$161,092
Income from Continuing Operations, Before Income Taxes and Change in Accounting Principle[1]	$244,556	$248,308	$156,129	$86,083	$37,688
Income from Continuing Operations[1]	$152,588	$151,074	$97,880	$54,340	$22,396
Net Cash Provided by Operating Activities – Continuing Operations	$442,282	$383,241	$236,791	$147,114	$81,376
Per Share and Share Data					
Weighted Average Shares Outstanding[1]	29,984	29,265	28,496	27,822	27,358
Earnings per Share—Basic[1]	$5.09	$5.16	$3.43	$1.95	$0.82
Earnings per Share—Diluted[1]	$4.98	$5.03	$3.34	$1.92	$0.81
Shares Outstanding at Year-End	30,179	29,743	29,010	28,090	27,484
Book Value per Share at Year-End	$27.70	$26.83	$20.94	$16.88	$14.46
Market Price					
High	$47.72	$51.84	$50.01	$30.34	$18.00
Low	$35.98	$35.48	$24.77	$15.90	$7.60
Year-End Close	$44.03	$44.81	$45.07	$28.94	$16.85
Effect on Income from Continuing Operations and Earnings per Share from Changes in Accounting Principles[2]					
Cumulative Effect of Change in Accounting Principle (Net of Taxes)	—	—	—	—	$(4,145)
Effect per Share—Basic	—	—	—	—	$(0.15)
Effect per Share—Diluted	—	—	—	—	$(0.15)
Assets					
Current Assets	$199,950	$83,783	$110,199	$51,694	$31,398
Property & Equipment, Net of Accumulated Depreciation, Depletion, and Amortization	$1,760,195	$1,239,722	$862,717	$731,868	$641,366
Total Assets	$1,969,051	$1,585,682	$1,204,413	$990,573	$859,839
Liabilities					
Current Liabilities	$210,161	$145,471	$98,421	$68,618	$69,353
Long-Term Debt	$587,000	$381,400	$350,000	$357,500	$340,255
Total Liabilities	$1,132,997	$787,765	$597,094	$516,401	$462,447
Stockholders' Equity	$836,054	$797,917	$607,318	$474,172	$397,391
Number of Domestic Employees	298	272	236	203	183
Domestic Producing Wells					
Swift Operated	1,091	926	854	798	820
Outside Operated	127	112	69	97	113
Total Domestic Producing Wells	1,218	1,038	923	895	933
Domestic Wells Drilled (Gross)	69	55	54	54	71
Domestic Proved Reserves					
Natural Gas (Bcf)	343.8	269.7	225.3	237.9	242.3
Oil, NGL, & Condensate (MMBbls)	76.5	73.5	69.8	69.1	67.0
Total Domestic Proved Reserves (MMBoe)	133.8	118.4	107.3	108.8	107.4
Domestic Production (MMBoe)	10.6	9.4	7.2	7.0	5.6
Domestic Average Sales Price[3]					
Natural Gas (per Mcf)	$6.42	$6.44	$7.40	$5.74	$5.07
Natural Gas Liquids (per barrel)	$49.72	$38.70	$34.00	$24.84	$19.75
Oil (per barrel)	$71.92	$64.28	$53.45	$40.04	$29.95
Composite Price (per Boe)	$61.49	$56.89	$49.61	$36.90	$29.17

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

[2]We adopted SFAS No. 143, "Accounting for Asset Retirement Obligations" on January 1, 2003.

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

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, 2007, 2006, and 2005 included with this report. The following information contains forward-looking statements; see "Forward-Looking Statements" on page 35 of this report.

Overview

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

We are the largest producer of oil in the state of Louisiana, and due to increasing emphasis on our South Louisiana operations, we have become predominantly an oil producer, with oil constituting 66% of our 2007 domestic production, and oil and natural gas liquids ("NGLs") together making up 74% of our 2007 domestic production. This emphasis has allowed us to benefit from better margins for oil production than natural gas production in recent periods.

In December 2007, we agreed to sell substantially all of our New Zealand assets to Origin Energy Limited for a minimum of $87.8 million, with an expected closing towards the end of the first quarter of 2008. Accordingly, the New Zealand operations have been classified as discontinued operations in the consolidated statements of income and cash flows and the assets and associated liabilities have been classified as held for sale in the consolidated balance sheets. The pending sale of these assets resulted in a fourth quarter 2007 non-cash charge of approximately $131 million (net of tax effects) based on the selling price and terms of the sales agreement. We expect to realize total cash proceeds of between $100 and $110 million from the sale of all of our New Zealand assets, which we anticipate completing later this year. Proceeds from the New Zealand assets sale will most likely be used to pay down a portion of our credit facility.

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

In our 2007 continuing operations we had record income, cash flows, and production. Income from continuing operations increased 1% to $152.6 million and cash flows from operating activities from continuing operations increased 15% to $442.3 million, in each case compared to 2006 amounts. Production increased 12% to 10.6 MMBoe, due to increased production in our South Louisiana, Toledo Bend, and South Texas regions. We ended 2007 with domestic proved reserves of 133.8 MMBoe, an increase of 13% over year-end 2006 domestic reserves. We also had record revenues of $654.1 million for 2007, an increase of 19% over comparable 2006 levels. Our weighted average sales price received increased 8% to $61.49 per Boe for 2007 from $56.89 in 2006. Our $115.3 million, or 21%, increase in oil and gas sales revenues primarily resulted from both a 1.2 million Boe increase in production volumes and from 12% higher oil prices during 2007.

In October 2007, we acquired interests in three South Texas fields in the Maverick Basin from Escondido Resources, LP, which we collectively identify as the Cotulla properties. The total price for these interests was approximately $248.2 million after purchase price adjustments. The 12.9 MMBoe of proved reserves added through this acquisition 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, of which 42% were proved undeveloped and which are predominantly natural gas and natural gas liquids. These properties added 0.3 MMBoe of production to our total production quantities for 2007. We plan to acquire more producing acreage in this area as well, and maintain a two rig drilling program in this area into 2008.

Our overall costs and expenses increased in 2007 by 35%. In 2008, we will continue to focus upon our capital efficiency to better manage our costs and expenses, a difficult task in the inflationary cost environment prevalent in the industry over the last several years. The largest increase in these costs and expenses in 2007 was attributable to 35% higher depreciation, depletion and amortization expense, not only due to our larger depletable property base and higher production, but also due to increases in future development costs, which reflect industry cost inflation. We expect cost pressures to continue to affect the industry throughout 2008, with tightening availability of crews as well as increasing costs of services, goods, and basic equipment.

Lake Washington is our most significant field and provides approximately 62% of our domestic production. In the fourth quarter of 2007, its production fell 13% from third quarter 2007 levels. In the fourth quarter of 2007, along with experiencing natural declines in production as our wells mature, we reduced the choke size of several wells in the Newport area to preserve reservoir pressure in anticipation of the pressure maintenance program that will commence with the Westside facility start-up by mid 2008. We continue to drill deeper wells, higher flowing pressure wells, and wells with higher associated natural gas content, and our system must also handle more mature wells that may produce larger volumes of water that require artificial lift. We believe the pressure maintenance activities planned for 2008 and Westside facility start-up by mid 2008 will improve the majority of these production constraints.

Our year-end 2007 domestic proved reserves were 44% crude oil, 43% natural gas, and 13% NGLs, compared to 52% crude oil, 38% natural gas, and 10% NGLs a year earlier, with 48% of our domestic proved reserves being proved developed at December 31, 2007. Our 2007 domestic production was 66% crude oil, down from 71% in 2006. Domestic proved reserves increased to 133.8 MMBoe at year-end 2007 from 118.4 MMBoe at year-end 2006.

Our financial position remains strong even with our recent increase in debt levels during the fourth quarter of 2007. Our debt to capitalization ratio was 41% at December 31, 2007, compared to 32% at year-end 2006, as debt levels increased in 2007, with debt per domestic Boe of $4.39 at year-end 2007 a 36% increase compared to $3.22 a year earlier. Our debt to domestic PV-10 ratio decreased to 15% at December 31, 2007 from 16% compared to a year earlier, as higher year-end reserves volumes and prices were largely offset by increased borrowings against our line of credit at that date.

Our capital expenditures from continuing operations of $650.6 million increased by $162.4 million from 2006 to 2007, primarily due to our acquisition of the Cotulla properties in South Texas and the increase in our spending on drilling and development, predominantly in our South Louisiana region. These expenditures were primarily funded by $442.3 million of cash provided by operating activities from continuing operations, and an increase in debt levels of $205.6 million.

Our current 2008 capital expenditure budget is $425 million to $475 million, net of minor non-core dispositions and excluding any property acquisitions. Based upon current market conditions and our estimates, our capital expenditures for 2008 should be within our anticipated cash flow from operations and currently we have budgeted approximately two-thirds of these amounts for our South Louisiana region, and on an overall basis three-fourths for developmental activities. For 2008, we are targeting production from our continuing operations to increase 10% to 15% and domestic proved reserves to increase 5% to 9% both over 2007 levels. We may also increase our capital expenditure budget if commodity prices rise during the year or if strategic opportunities warrant. If 2008 capital expenditures exceed our cash flow from operating activities, we can fund these expenditures with our credit facility.

During 2008, we plan to further develop our inventory of properties in South Louisiana using our expertise and experience gained in expanding and producing in Lake Washington, together with significant 3-D seismic information, to exploit our other prospect areas covered by similar geological features. This broad prospect inventory will allow us to be selective in choosing drilling opportunities so we can create long-life reserves while at the same time raising our production.

Results of Continuing Operations — Years Ended 2007, 2006, and 2005

Revenues. Our revenues in 2007 increased by 19% compared to revenues in 2006 primarily due to increased production from our South Louisiana region and higher oil prices, and our revenues in 2006 increased by 55% compared to 2005 revenues due to increases in oil production from our South Louisiana area and increases in oil prices. Revenues for 2007, 2006, and 2005 were substantially comprised of oil and gas sales. Crude oil production was 66% of our production volumes in 2007, 71% in 2006, and 66% in 2005. Natural gas production was 26% of our production volumes in 2007, 24% in 2006, and 27% in 2005.

The following table provides information regarding the changes in the sources of our oil and gas sales and volumes for the years ended December 31, 2007, 2006, and 2005:

	Oil and Gas Sales (In millions)			Net Oil and Gas Sales Volumes (MBoe)		
Regions	2007	2006	2005	2007	2006	2005
South Texas	$ 72.0	$ 61.8	$ 73.2	1,517	1,438	1,510
Toledo Bend	48.7	35.1	38.9	872	745	895
South Louisiana	527.2	434.7	236.6	8,139	7,138	4,611
Other	5.0	5.9	7.2	89	128	158
Total	$ 652.9	$ 537.5	$ 355.9	10,617	9,449	7,174

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

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

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

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

Oil and gas sales in 2006 increased by 51%, or $181.6 million, from the level of those revenues for 2005, and our net sales volumes in 2006 increased by 32%, or 2.3 MMBoe, over net sales volumes in 2005. Average prices for oil increased to $64.28 per Bbl in 2006 from $53.45 per Bbl in 2005. Average natural gas prices decreased to $6.44 per Mcf in 2006 from $7.40 per Mcf in 2005. Average NGL prices increased to $38.70 per Bbl in 2006 from $34.00 per Bbl in 2005.

In 2006, our $181.6 million increase in oil, NGL, and natural gas sales resulted from:

- Volume variances that had a $119.7 million favorable impact on sales, with $107.5 million of increases attributable to the 2.0 million Bbl increase in oil sales volumes, and $13.8 million due to the 1.9 Bcf increase in natural gas sales volumes, partially offset by a decrease of $1.6 million due to the 48,000 Bbl decrease in NGL sales volumes; and

- Price variances that had a $61.9 million favorable impact on sales, of which $72.8 million was attributable to the 20% increase in average oil prices received and $2.2 million was attributable to the 14% increase in NGL prices, both slightly offset by a decrease of $13.1 million attributable to the 13% decrease in natural gas prices.

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

		Sales Volume				Average Sales Price		
		Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (MBoe)	Oil (Bbl)	NGL (Bbl)	Natural Gas (Mcf)
2005:	First	1,184	143	3.0	1,831	$47.20	$31.79	$5.41
	Second	1,339	118	3.2	1,992	$50.21	$25.74	$6.13
	Third	925	119	2.8	1,519	$59.44	$40.58	$7.68
	Fourth	1,261	128	2.7	1,832	$58.36	$37.99	$10.89
	Total	4,709	508	11.7	7,174	$53.45	$34.00	$7.40
2006:	First	1,487	90	3.3	2,127	$60.56	$39.75	$7.42
	Second	1,554	70	3.4	2,184	$69.40	$40.85	$6.12
	Third	1,825	159	3.3	2,537	$69.54	$42.37	$6.07
	Fourth	1,855	141	3.6	2,601	$57.82	$32.82	$6.20
	Total	6,721	460	13.6	9,449	$64.28	$38.70	$6.44
2007:	First	1,773	133	3.8	2,534	$57.87	$39.90	$5.92
	Second	1,872	134	3.5	2,589	$66.20	$44.22	$7.56
	Third	1,783	190	4.4	2,702	$76.20	$48.89	$5.68
	Fourth	1,617	317	5.1	2,792	$89.23	$56.65	$6.62
	Total	7,045	774	16.8	10,617	$71.92	$49.72	$6.42

During 2007, 2006, and 2005, we recognized net gains of $0.2 million and $4.0 million and net losses of $1.1 million, respectively, related to our derivative activities. This activity is recorded in "Price-risk management and other, net" on the accompanying statements of income. Had these gains and losses been recognized in the oil and gas sales account, our average oil sales price would have been $71.91, $64.58, and $53.42 for 2007, 2006, and 2005, respectively, and our average natural gas sales price would have been $6.43, $6.59, and $7.32 for 2007, 2006, and 2005, respectively.

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

Costs and Expenses. Our expenses in 2007 increased $107.0 million, or 35%, compared to 2006 expenses for the reasons noted below.

Our 2007 general and administrative expenses, net, increased $6.5 million, or 24%, from the level of such expenses in 2006, while 2006 general and administrative expenses, net, increased $8.8 million, or 46%, over 2005 levels. The increases in both 2007 and 2006 were primarily due to increased salaries and burdens associated with our expanded workforce, but were also impacted by increased restricted stock grants each year and the expensing of stock options that began in 2006. Costs also increased in 2007 due to ongoing support costs of our new computer system implemented in 2007. For the years 2007, 2006, and 2005, our capitalized general and administrative costs totaled $26.4 million, $24.1 million, and $14.5 million, respectively. Our net general and administrative expenses per Boe produced increased to $3.22 per Boe in 2007 from $2.92 per Boe in 2006 and $2.63 per Boe in 2005. The portion of supervision fees recorded as a reduction to general and administrative expenses was $11.8 million for 2007, $8.7 million for 2006, and $7.4 million for 2005.

DD&A increased $49.1 million, or 35%, in 2007, from 2006 levels and increased $58.1 million, or 72%, from 2005 levels. The increases in both years are due to increases in the depletable oil and natural gas property base, including future development costs, and higher production, partially offset by higher reserves volumes. Industry costs for services and goods have increased over the last three year period and have contributed to the increase in our DD&A

expense. Our DD&A rate per Boe of production was $17.74 in 2007, $14.74 in 2006, and $11.31 in 2005, resulting from increases in per unit cost of reserves additions.

We recorded $1.4 million, $0.9 million, and $0.6 million of accretions to our asset retirement obligation in 2007, 2006, and 2005, respectively.

Our lease operating costs increased $20.9 million, or 42%, over the level of such expenses in 2006, while 2006 costs increased $15.0 million, or 43%, over 2005 levels. Lease operating costs increased during 2007 and 2006 due to higher production from our three domestic regions, including costs from properties acquired in the fourth quarters of 2006 and 2007, increasing costs for industry goods and services, and higher natural gas and NGL processing costs in 2007. A portion of the increase in 2007 and 2006 was from increased well insurance premiums which increased after hurricanes Katrina and Rita. Our lease operating costs per Boe produced were $6.68, $5.29, and $4.87 in 2007, 2006, and 2005, respectively.

Severance and other taxes increased $12.6 million, or 21%, over 2006 levels, while in 2006 these taxes increased $23.4 million, or 62%, over 2005 levels. The increases in each year were due primarily to higher commodity prices and increased production in our three domestic regions. Severance and other taxes, as a percentage of oil and gas sales, were approximately 11.3%, 11.4% and 10.6% in 2007, 2006 and 2005, respectively. Severance taxes on oil in Louisiana are 12.5% of oil sales, which is higher than in the other states where we have production. As our percentage of oil production in Louisiana increased in 2006, the overall percentage of severance costs to sales also increased.

Our total interest cost in 2007 was $37.6 million, of which $9.5 million was capitalized. Our total interest cost in 2006 was $32.8 million, of which $9.2 million was capitalized. Our total interest cost in 2005 was $32.1 million, of which $7.2 million was capitalized. Interest expense on our 7-5/8% senior notes due 2011 issued in June 2004, including amortization of debt issuance costs, totaled $12.0 million in 2007 and $11.9 million in both 2006 and 2005. Interest expense on our 9-3/8% senior subordinated notes due 2012 issued in April 2002 and retired in 2007, including amortization of debt issuance costs, totaled $8.9 million in 2007 and $19.2 million in both 2006 and 2005. Interest expense on our 7-1/8% senior notes due 2017 and issued in June 2007, including amortization of debt issuance costs, totaled $10.6 million in 2007. Interest expense on our bank credit facility, including commitment fees and amortization of debt issuance costs, totaled $6.1 million in 2007, $1.5 million in 2006, and $1.0 million in 2005. Other interest cost was $0.1 million in each of 2007, 2006 and 2005. We capitalize a portion of interest related to unproved properties. The increase in interest expense in 2007 was primarily due to an increase in borrowings against our line of credit facility, partially offset by an increase in capitalized interest costs. The decrease in interest expense in 2006 was primarily due to an increase in capitalized interest costs, partially offset by an increase in borrowings against our line of credit facility.

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.

Our overall effective tax rate was 37.6% for 2007, 39.2% for 2006 and 37.3% for 2005. The effective tax rate for 2007 and 2006 was higher than the statutory rate primarily because of state income taxes and valuation allowances. For 2005, the effective tax rate was higher than the statutory rate primarily because of state income taxes.

Income from Continuing Operations. Our income from continuing operations for 2007 of $152.6 million was 1% higher than our 2006 income from continuing operations of $151.1 million due to higher oil prices and increased production, partially offset by increased costs including the retirement of our 9-3/8% senior notes due 2012.

Our income from continuing operations in 2006 of $151.1 million was 54% higher than our 2005 income from continuing operations of $97.9 million due to higher commodity prices and increased production.

Net Income. Our net income in 2007 of $21.3 million was 87% lower than our 2006 net income of $161.6 million, mainly due to our loss from discontinued operations of $131.3 million. Our net income in 2006 of $161.6 million was 40% higher than our 2005 net income of $115.8 million due to higher oil prices and increased production.

Discontinued Operations

In December 2007, Swift agreed to sell substantially all of our New Zealand assets for approximately $87.8 million. Accordingly, the New Zealand operations have been classified as discontinued operations in the consolidated statements of income and cash flows and the assets and associated liabilities have been classified as held for sale in the consolidated balance sheets. We began a strategic review of our New Zealand assets in the second quarter of 2007 which culminated in the agreement to sell substantially all of these assets in the fourth quarter of 2007, with an expected closing towards the end of the first quarter of 2008. Proceeds from the New Zealand assets sale will most likely be used to pay down a portion of our credit facility. We expect to sell the remaining New Zealand assets sometime in 2008.

In accordance with SFAS No. 144, "*Accounting for the Impairment or Disposal of Long-lived Assets*" ("SFAS 144"), the results of operations and the non-cash asset write-down for the New Zealand operations have been excluded from continuing operations and reported as discontinued operations for the current and prior periods. Furthermore, the assets included as part of this divestiture have been reclassified as held for sale in the Balance Sheet for prior periods. During the fourth quarter of 2007, the Company assessed its long-lived assets in New Zealand based on the selling price and terms of the sales agreement and recorded a non-cash asset write-down of $143.2 million related to these assets. This write-down is recorded in "Income (loss) from discontinued operations, net of taxes" on the accompanying statement of income.

As of December 31, 2007, operations in New Zealand had represented approximately 6% of our total assets and 12% of our 2007 sales volumes. These revenues and expenses were historically reported under our New Zealand operating segment and are now reported under discontinued operations. The following table summarizes selected data pertaining to discontinued operations (in thousands except per share and per Boe amounts):

	2007	2006	2005
Oil and gas sales	$ 42,394	$ 64,039	$ 67,894
Other revenues	1,221	862	999
Total revenues	43,615	64,901	68,893
Depreciation, depletion, and amortization	23,147	30,051	26,354
Other operating expenses	22,491	20,872	20,230
Non-cash write-down of property and equipment	143,152	—	—
Total expenses	188,790	50,923	46,584
Income (loss) from discontinued operations before income taxes	(145,175)	13,978	22,309
Income tax expense (benefit)	(13,874)	3,487	4,412
Income (loss) from discontinued operations, net of taxes	$ (131,301)	$ 10,491	$ 17,898
Earnings per common share from discontinued operations, net of taxes – diluted	$ (4.29)	$ 0.35	$ 0.61
Total sales volumes (MBoe)	1,387	2,252	2,758
Oil sales volumes (MBbls)	225	469	450
Natural gas sales volumes (Bcf)	5.9	9.2	11.9
NGL sales volumes (MBbls)	177	253	329
Average sales price per Boe	$ 30.56	$ 28.43	$ 24.60
Oil sales price per Bbl	$ 75.78	$ 67.06	$ 55.57
Natural gas sales price per Mcf	$ 3.36	$ 2.99	$ 3.09
NGL sales price per Bbl	$ 30.91	$ 20.22	$ 18.84
Lease operating cost per Boe	$ 9.93	$ 5.56	$ 4.49
Total assets	$ 110,585	$ 235,997	$ 241,943
Cash flow provided by operating activities	$ 25,620	$ 41,680	$ 48,543
Capital expenditures	$ 9,466	$ 56,707	$ 50,844

Income (loss) from discontinued operations, net of tax, for 2007 decreased compared to the same period of 2006 primarily due to the non-cash write-down of property and equipment, a decrease in produced oil and natural gas volumes that reduced revenues, partially offset by a tax benefit associated with the non-cash write-down of property and equipment, along with lower depletion expense due to lower production volumes. For the years 2007, 2006, and 2005, our capitalized general and administrative expenses totaled $4.2 million, $4.1 million, and $4.3 million.

Income from discontinued operations, net of tax, for 2006 decreased 41% compared to the same period of 2005 primarily due to a decrease in produced oil and natural gas volumes that reduced revenue, along with higher depletion expense in the 2006 period due to an increase in the depletable oil and natural gas property base and lower reserves.

Liquidity and Capital Resources

During 2007, we relied upon our net cash provided by operating activities from continuing operations of $442.9 million, credit facility borrowings of $155.6 million, and cash balances to fund capital expenditures of $650.6 million including $252.3 million of acquisitions. During 2006, we relied upon our net cash provided by operating activities from continuing operations of $383.2 million, credit facility borrowings of $31.4 million, property sales proceeds of $24.7 million, and cash balances to fund capital expenditures of $488.2 million including $194.3 million of acquisitions.

Net Cash Provided by Operating Activities. For 2007, our net cash provided by operating activities from continuing operations was $442.3 million, representing a 15% increase as compared to $383.2 million generated during 2006. The $59.0 million increase in 2007 was primarily due to an increase of $115.3 million in oil and gas sales, attributable to higher oil prices and production, offset in part by higher lease operating costs and severance taxes due to higher oil prices and higher production. For 2006, our net cash provided by operating activities from continuing operations was $383.2 million, representing a 62% increase as compared to $236.8 million generated during 2005. The $146.5 million increase in 2006 was primarily due to an increase of $181.6 million in oil and gas sales, attributable to higher oil prices and production, offset in part by higher lease operating costs and severance taxes due to higher oil prices and higher production.

Accounts Receivable. We assess the collectibility 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, 2007 and 2006, we had an allowance for doubtful accounts of less than $0.1 million. The allowance for doubtful accounts has been deducted from the total "Accounts receivable" balances on the accompanying balance sheets.

Existing Credit Facility. We had borrowings of $187.0 million under our bank credit facility at December 31, 2007, and $31.4 million in borrowings at December 31, 2006. Our bank credit facility at December 31, 2007 consisted of a $500.0 million revolving line of credit with a $400.0 million borrowing base based entirely on assets from our continuing operations. The borrowing base is re-determined at least every six months and was increased by our bank group from $350.0 million to $400.0 million in November 2007. Under the terms of our bank credit facility, we can increase this commitment amount to the total amount of the borrowing base at our discretion, subject to the terms of the credit agreement. In September 2007, we increased the commitment amount from $250.0 million to $350.0 million. Our revolving credit facility includes requirements to maintain certain minimum financial ratios (principally pertaining to adjusted working capital ratios and EBITDAX), and limitations on incurring other debt. We are in compliance with the provisions of this agreement.

Our access to funds from our credit facility is not restricted under any "material adverse condition" clause, a clause that is common for credit agreements to include. A "material adverse condition" clause can remove the obligation of the banks to fund the credit line if any condition or event would reasonably be expected to have an adverse or material effect on operations, financial condition, prospects or properties, and would impair the ability to make timely debt repayments. Our credit facility includes covenants that require us to report events or conditions having a material adverse effect on our financial condition. The obligation of the banks to fund the credit facility is not conditioned on the absence of a material adverse effect.

Working Capital. Our working capital increased from a deficit of $61.7 million at December 31, 2006, to a deficit of $10.2 million at December 31, 2007. The improvement primarily resulted from a reclassification of New Zealand oil and natural gas properties to assets held for sale within current assets, partially offset by an increase in accounts payable and accrued capital costs.

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

Debt Maturities. Our credit facility, with a balance of $187.0 million at December 31, 2007, extends until October 3, 2011. Our $150.0 million of 7-5/8% senior notes mature July 15, 2011, and our $250.0 million of 7-1/8% senior notes mature June 1, 2017.

Capital Expenditures. In 2007 we relied upon our net cash provided by operating activities from continuing operations of $442.3 million, credit facility borrowings of $155.6 million, and cash balances to fund capital expenditures of $650.6 million including $252.3 million of acquisitions.

We have spent considerable time and capital on facility capacity upgrades and additions in the Lake Washington field. Since acquiring the property, we have upgraded three production platforms, added new compression for the gas lift system, and installed a new oil delivery system and permanent barge loading facility. During 2006, we began planning for the addition of a fourth production platform, the Westside facility, which will increase our processing capacity another 10,000 barrels per day by mid-2008.

We completed 61 of 69 wells in 2007, for a success rate of 88%. A total of 22 development wells were drilled in the Lake Washington area, of which 18 were completed, and 21 development wells were drilled successfully in the AWP Olmos area. In Bay de Chene, we successfully drilled two development wells and drilled five exploratory wells, of which two were completed. We also drilled 11 successful development wells in the South Bearhead Creek area, drilled seven development wells in the Cotulla area, of which six were completed, and drilled one successful development well in the Bayou Sale field.

Our capital expenditures were approximately $488.2 million in 2006 and $197.8 million in 2005. In 2006, we relied upon our net cash provided by operating activities from continuing operations of $383.2 million, bank borrowings of $31.4 million, and cash balances to fund capital expenditures of $488.2 million, including acquisitions of $194.3 million. During 2005, we relied upon our net cash provided by operating activities of $236.8 million to fund capital expenditures of $197.8 million, including acquisitions of $28.9 million.

In 2006, we participated in drilling 49 development wells and six exploratory wells, of which 42 development wells were completed.

Contractual Commitments and Obligations

Our contractual commitments for the next five years and thereafter as of December 31, 2007 are as follows:

	2008	2009	2010	2011	2012	Thereafter	Total
				(In thousands)			
Non-cancelable operating leases[1]	$ 7,706	$ 4,890	$ 3,354	$ 3,213	$ 3,213	$ 6,963	$ 29,339
Asset retirement obligation[2]	3,393	1,878	2,047	2,419	2,604	30,183	42,524
Drilling rigs, seismic and pipe inventory	34,196	—	—	—	—	—	34,196
7-5/8% senior notes due 2011[3]	—	—	—	150,000	—	—	150,000
7-1/8% senior notes due 2017[3]	—	—	—	—	—	250,000	250,000
Credit facility[4]	—	—	—	187,000	—	—	187,000
Total	$ 45,295	$ 6,768	$ 5,401	$ 342,632	$ 5,817	$ 287,146	$ 693,059

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

[2]Amounts shown by year are the fair values at December 31, 2007.

[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.

Domestic Proved Oil and Gas Reserves

At year-end 2007, our domestic proved reserves were 133.8 MMBoe with a PV-10 Value of $3.8 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 2007, our domestic proved natural gas reserves increased 74.1 Bcf, or 27%, while our proved oil reserves decreased 3.7 MMBbl, or 6%, and our NGL reserves increased 6.7 MMBbl, or 58%, for a total equivalent increase of 15.4 MMBoe, or 13%. In 2006, our domestic proved natural gas reserves increased 44.4 Bcf, or 20%, while our proved oil reserves increased 4.4 MMBbl, or 8%, and our NGL reserves decreased 0.7 MMBbl, or 6%, for a total equivalent increase of 11.1 MMBbl, or 10%. We added reserves over the past three years through both our drilling activity and purchases of minerals in place. Through drilling we added 12.9 MMBoe of proved reserves in 2007, 11.9 MMBoe in 2006, and 4.9 MMBoe in 2005. Through acquisitions we added 12.9 MMBoe of proved reserves in 2007, 13.0 Bcfe in 2006, and 4.8 Bcfe in 2005. At year-end 2007, 48% of our total proved reserves were proved developed, compared with 47% at year-end 2006 and 52% at year-end 2005.

The PV-10 Value of our domestic proved reserves at year-end 2007 increased 55% from the PV-10 Value at year-end 2006. Natural gas prices increased in 2007 to $6.65 per Mcf from $5.84 per Mcf at year-end 2006, compared to $10.36 per Mcf at year-end 2005. Oil prices increased in 2007 to $93.24 per Bbl from $60.07 per Bbl at year-end 2006, compared to $60.00 in 2005. Under SEC guidelines, estimates of proved reserves must be made using year-end oil and gas sales prices and are held constant for that year's reserves calculation throughout the life of the properties. Subsequent changes to such year-end oil and natural gas prices could have a significant impact on the calculated PV-10 Value.

Commodity Price Trends and Uncertainties

Oil and natural gas prices historically have been volatile and are expected to continue to be volatile in the future. The price of oil has increased over the last three years and is at historical highs when compared to longer-term historical prices. Factors such as worldwide supply disruptions, worldwide economic conditions, 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 have fallen from highs in 2005 but continue to remain high when compared to longer-term historical prices. North American weather conditions, the industrial and consumer demand for natural gas, 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.

Income Taxes

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

On January 1, 2007, we adopted the recognition and disclosure provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement No. 109" ("FIN 48"). Under FIN 48, tax positions are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than fifty percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. As a result of adopting FIN 48, we reported a $1.0 million decrease to our January 1, 2007 retained earnings balance and a corresponding increase to other long-term liabilities. This was also the total balance of our unrecognized tax benefits, which would fully impact our effective tax rate if recognized. There were no increases or decreases in unrecognized tax benefits during the year ended December 31, 2007.

Our policy is to record interest and penalties relating to income taxes in income tax expense. As of December 31, 2007 and 2006 no interest or penalties relating to income taxes have been incurred or recognized. Our cumulative interest exposure on unrecognized tax benefits is not material.

Our U.S. Federal and State of Louisiana income tax returns from 1998 forward, our New Zealand income tax returns after 2001, and our Texas franchise tax returns after 2005 remain subject to examination by the taxing authorities. There are no unresolved items related to periods previously audited by these taxing authorities. No other state returns are significant to our financial position.

In the third quarter of 2007 we increased the valuation allowance for our capital loss carryforward assets by $2.6 million to cover the full value of the carryforward. The increase in the valuation allowance was due to changes in the Company's property disposition plans and increased income tax expense of $2.6 million in that period.

Critical Accounting Policies

The following summarizes several of our critical accounting policies. See a complete list of significant accounting policies in Note 1 to the consolidated financial statements.

Use of Estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States ("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 of future costs to develop and produce reserves,
- accruals related to oil and gas revenues, capital expenditures and lease operating expenses,
- 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, and
- estimates made in our income tax calculations.

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 changes in new accounting pronouncements, 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 2007, 2006, and 2005, such internal costs capitalized totaled $26.4 million, $24.1 million, and $14.5 million, respectively. Interest costs are also capitalized to unproved oil and natural gas properties. For the years 2007, 2006, and 2005, capitalized interest on unproved properties totaled $9.5 million, $9.2 million, and $7.2 million, respectively. Interest not capitalized and general and administrative costs related to production and general overhead are expensed as incurred.

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and natural gas properties (including 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 December 31, 2007 consisted of oil and natural gas price floors with strike prices lower than the period-end price and did not materially affect this calculation. This calculation is done on a country-by-country basis.

The calculation of the Ceiling Test and provision for 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. Our reserves estimates are prepared in accordance with Securities and Exchange Commission guidelines and are audited on an annual basis at year-end by a firm of independent petroleum engineers in accordance with standards approved by the Board of Directors of the Society of Petroleum Engineers.

Given the volatility of oil and natural gas prices, it is reasonably possible that our estimate of discounted future net cash flows from proved oil and natural gas reserves could change in the near term. If oil and natural gas prices decline significantly from our period-end prices used in the Ceiling Test, even if only for a short period, it is possible that 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, a non-cash write-down 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 sizable 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 collectibility of the revenue is probable. The Company uses the entitlement method of accounting in which the Company recognizes its ownership interest in production as revenue. If our sales exceed our ownership share of production, the natural gas balancing payables are reported in "Accounts payable and accrued liabilities" on the accompanying balance sheet. Natural gas balancing receivables are reported in "Other current assets" on the accompanying balance sheet when our ownership share of production exceeds sales. As of December 31, 2007, we did not have any material natural gas imbalances.

New Accounting Pronouncements

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. SFAS No. 157 defines fair value, establishes guidelines for measuring fair value and expands disclosures regarding 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. SFAS No. 157 was effective for fiscal periods beginning after November 15, 2007. On February 12, 2008, the FASB delayed the effective date of SFAS No. 157 for non-financial assets and non-financial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis, at least annually. For Swift, this action defers the effective date for those assets and liabilities until January 1, 2009. We believe that the adoption of this statement will not have a material impact on our financial position or results of operations.

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

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations. SFAS No. 141(R) provides enhanced guidance related to the measurement of identifiable assets acquired, liabilities assumed and disclosure of information related to business combinations and their effect on the Company. This Statement, together with the International Accounting Standards Board's IFRS 3, Business Combinations, completes a joint effort by the FASB and IASB to improve financial reporting about business combinations and promotes the international convergence of accounting standards. For Swift, SFAS No. 141(R) applies prospectively to business combinations in 2009 and is not subject to early adoption. We are currently evaluating the potential impact of SFAS No. 141(R) on business combinations and related valuations.

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 2007, $0.5 million in 2006 and $0.4 million in 2005. 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.

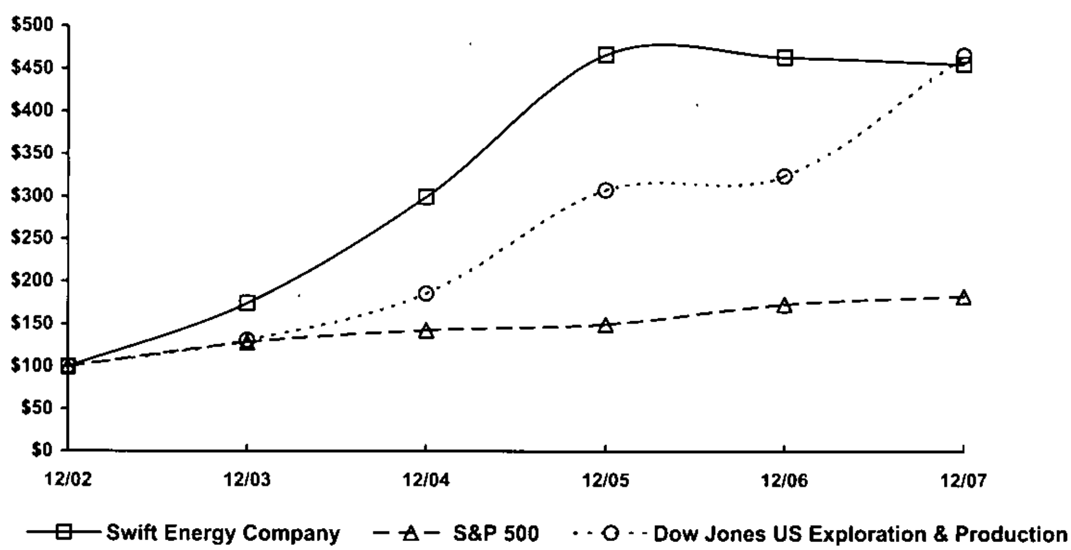
As a matter of corporate governance policy and practice, related party transactions are presented and considered by the Corporate Governance Committee of our Board of Directors.

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, 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," "should," "believe," or other words that convey the uncertainty of future events or outcomes. Such forward-looking information is based upon management's current plans, expectations, estimates, and assumptions, upon current market conditions, and upon engineering and geologic information available at this time, and is subject to change and to a number of risks and uncertainties, and, therefore, actual results may differ materially 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; 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.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among Swift Energy Company, The S&P 500 Index
And The Dow Jones US Exploration & Production Index



* $100 invested on 12/31/02 in stock or index-including reinvestment of dividends. Fiscal year ending December 31.

Quantitative and Qualitative Disclosures About Market Risk

Commodity Risk. Our major market risk exposure is the commodity pricing applicable to our oil and natural gas production. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to natural gas. The effects of such pricing volatility are expected to continue.

Our price-risk management policy permits the utilization of agreements and financial instruments (such as futures, forward contracts, swaps and options contracts) to mitigate price risk associated with fluctuations in oil and natural gas prices. Below is a description of the financial instruments we have utilized to hedge our exposure to price risk.

- *Price Floors* – At December 31, 2007, we had in place price floors in effect through the March 2008 contract month for oil and natural gas. The oil price floors cover notional volumes of 639,000 barrels, with a weighted average floor price of $71.22 per barrel. Our oil price floors in place at December 31, 2007, are expected to cover approximately 40% to 45% of our estimated oil production from January 2008 to March 2008. The natural gas price floors cover notional volumes of 1,330,000 MMBtu, with a weighted average floor price of $6.90 per MMBtu. Our natural gas price floors in place at December 31, 2007, are expected to cover approximately 40% to 45% of our natural gas production in February 2008 and March 2008. The fair value of these instruments at December 31, 2007, was $0.3 million and is recognized on the accompanying balance sheet in "Other current assets." There are no additional cash outflows for these price floors, as the cash premium was paid at inception of the hedge. The maximum loss that could be sustained on our financial statements from these price floors in 2008 would be their fair value at December 31, 2007 of $0.3 million.

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, 2007, we had borrowings of $187.0 million under our credit facility, which bears a floating rate of interest and therefore is susceptible to interest rate fluctuations. The result of a 10% fluctuation in the bank's base rate would constitute 73 basis points and would not have a material adverse effect on our 2008 cash flows based on this same level of borrowing.

Income Tax Carryforwards. During 2007, the Company recorded a write-down and valuation allowance totaling $2.6 million for capital loss carryforwards as detailed in Note 3 of the accompanying consolidated financial statements. The Company has other net tax carryforwards for federal alternative minimum tax credits ($5.1 million) and state tax net operating loss carryforwards ($4.3 million) 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, a portion of which will offset the sales proceeds from the liquidation of assets. We have estimated a net loss carryover asset of $33.5 million will remain after closing of the pending transaction. In management's judgment it is less than more likely than not that the remaining carryover will be utilized. Accordingly, this carryover asset has 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, 2007 and 2006, 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, 2007, the fair value of our senior notes due 2017, which were issued during 2007, was $237.5 million, or 95.0% of face value. Based upon quoted market prices as of December 31, 2007 and 2006, the fair values of our senior notes due 2011 were $150.8 million, or 100.5% of face value, and $152.6 million, or 101.75% of face value. The carrying value of our senior notes due 2017 was $250.0 million at December 31, 2007. The carrying value of our senior notes due 2011 was $150.0 million at December 31 for both 2007 and 2006.

Foreign Currency Risk. We are exposed to the risk of fluctuations in foreign currencies, most notably the New Zealand Dollar. Fluctuations in rates between the New Zealand Dollar and U.S. Dollar may impact our financial results from our New Zealand subsidiaries since we have receivables, liabilities, natural gas and NGL sales contracts, and New Zealand income tax calculations, all denominated in New Zealand Dollars. We use the U.S. Dollar as our functional currency in New Zealand and as currency rate changes between the U.S. Dollar and the New Zealand Dollar, we recognize transaction gains and losses in "Income (loss) from discontinued operations, net of taxes" on the accompanying statements of income.

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. To manage customer credit risk, we monitor credit ratings of customers and seek to minimize exposure to any one customer where other customers are readily available. Due to availability of other purchasers, we do not believe the loss of any single oil or natural gas customer would have a material adverse effect on our results of operations.

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, 2007. 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, 2007.

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, 2007, 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 on Internal Control Over Financial Reporting

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, 2007, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). The Company's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, 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, 2007 and 2006, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2007 and our report dated February 27, 2008 expressed an unqualified opinion thereon.

Ernst + Young LLP

ERNST & YOUNG LLP

Houston, Texas
February 27, 2008

Report of Independent Registered Public Accounting Firm on Consolidated Financial Statements

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, 2007 and 2006, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2007. 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, 2007 and 2006, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2007 the Company adopted Financial Accounting Standards Board Interpretation No. 48, Accounting for Uncertainty in Income Taxes, an interpretation of Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes, and effective January 1, 2006 the Company adopted Statement of Financial Accounting Standards No. 123 (revised 2004), Share-Based Payment.

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, 2007, 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 27, 2008 expressed an unqualified opinion thereon.

Ernst + Young LLP

ERNST & YOUNG LLP

Houston, Texas
February 27, 2008

Consolidated Balance Sheets

Swift Energy Company and Subsidiaries
(In thousands, except share amounts)

	Year Ended December 31, 2007	2006
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 5,623	$ 1,058
Accounts receivable—		
Oil and gas sales	72,916	63,935
Joint interest owners	1,587	1,844
Other receivables	1,324	1,231
Deferred tax asset	8,055	2,383
Other current assets	13,896	13,332
Current assets held for sale	96,549	—
Total Current Assets	199,950	83,783
Property and Equipment:		
Oil and gas, using full-cost accounting		
Proved properties	2,610,469	1,918,375
Unproved properties	106,643	95,569
	2,717,112	2,013,944
Furniture, fixtures, and other equipment	33,064	26,020
	2,750,176	2,039,964
Less — Accumulated depreciation, depletion, and amortization	(989,981)	(800,242)
	1,760,195	1,239,722
Other Assets:		
Debt issuance costs	7,252	7,382
Restricted assets	1,654	2,415
Long-term assets held for sale	—	252,380
	8,906	262,177
	$ 1,969,051	$ 1,585,682
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 89,281	$ 73,921
Accrued capital costs	94,947	55,282
Accrued interest	7,558	8,764
Undistributed oil and gas revenues	10,309	7,504
Current liabilities associated with assets held for sale	8,066	—
Total Current Liabilities	210,161	145,471
Long-term debt	587,000	381,400
Deferred income taxes	302,303	212,458
Asset retirement obligation	31,066	28,533
Other long-term liabilities	2,467	1,728
Long-term liabilities associated with assets held for sale	—	18,175
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, 30,615,010 and 30,170,004 shares issued, and 30,178,596 and 29,742,918 shares outstanding, respectively	306	302
Additional paid-in capital	407,464	387,556
Treasury stock held, at cost, 436,414 and 427,086 shares, respectively	(7,480)	(6,125)
Retained earnings	436,178	415,868
Accumulated other comprehensive income (loss), net of income tax	(414)	316
	836,054	797,917
	$ 1,969,051	$ 1,585,682

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Income

Swift Energy Company and Subsidiaries
(In thousands, except share amounts)

	Year Ended December 31, 2007	2006	2005
Revenues:			
Oil and gas sales	$ 652,856	$ 537,513	$ 355,873
Price-risk management and other, net	1,265	13,323	(1,508)
	654,121	550,836	354,365
Costs and Expenses:			
General and administrative, net	34,182	27,634	18,866
Depreciation, depletion, and amortization	188,393	139,245	81,124
Accretion of asset retirement obligation	1,437	884	626
Lease operating cost	70,893	49,948	34,941
Severance and other taxes	73,813	61,235	37,806
Interest expense, net	28,082	23,582	24,873
Debt retirement cost	12,765	—	—
	409,565	302,528	198,236
Income from Continuing Operations Before Income Taxes	244,556	248,308	156,129
Provision for Income Taxes	91,968	97,234	58,249
Income from Continuing Operations	152,588	151,074	97,880
Income (Loss) from Discontinued Operations, Net of Taxes	(131,301)	10,491	17,898
Net Income	$ 21,287	$ 161,565	$ 115,778
Per Share Amounts—			
Basic: Income from Continuing Operations	$ 5.09	$ 5.16	$ 3.43
Income (Loss) from Discontinued Operations, Net of Taxes	(4.38)	0.36	0.63
Net Income	$ 0.71	$ 5.52	$ 4.06
Diluted: Income from Continuing Operations	$ 4.98	$ 5.03	$ 3.34
Income (Loss) from Discontinued Operations, Net of Taxes	(4.29)	0.35	0.61
Net Income	$ 0.69	$ 5.38	$ 3.95
Weighted Average Shares Outstanding	29,984	29,265	28,496

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Stockholders' Equity

Swift Energy Company and Subsidiaries
(In thousands, except share amounts)

	Common Stock[1]	Additional Paid-in Capital	Treasury Stock	Unearned Compen-sation	Retained Earnings	Accumulated Other Com-prehensive Income (Loss)	Total
Balance, December 31, 2004	$ 286	$ 343,536	$ (6,896)	$ (1,729)	$ 138,524	$ 451	$ 474,172
Stock issued for benefit plans (31,424 shares)	—	435	450	—	—	—	885
Stock options exercised (840,847 shares)	9	9,805	—	—	—	—	9,814
Tax benefits from exercise of stock options	—	4,366	—	—	—	—	4,366
Employee stock purchase plan (32,495 shares)	—	642	—	—	—	—	642
Issuance of restricted stock (15,000 shares)	—	—	—	—	—	—	—
Grants of restricted stock (158,500 shares)	—	6,669	—	(6,072)	—	—	597
Forfeitures of restricted stock	—	(367)	—	367	—	—	—
Amortization of stock compensation	—	—	—	1,584	—	—	1,584
Comprehensive income:							
Net income	—	—	—	—	115,779	—	115,779
Change in fair value of other comprehensive loss	—	—	—	—	—	(521)	(521)
Total comprehensive income	—	—	—	—	—	—	115,258
Balance, December 31, 2005	$ 295	$ 365,086	$ (6,446)	$ (5,850)	$ 254,303	$ (70)	$ 607,318
Stock issued for benefit plans (22,358 shares)	—	714	321	—	—	—	1,035
Stock options exercised (652,829 shares)	7	11,831	—	—	—	—	11,838
Adoption of SFAS No. 123R	—	(5,875)	—	5,850	—	—	(25)
Excess tax benefits from stock-based awards	—	4,811	—	—	—	—	4,811
Employee stock purchase plan (22,425 shares)	—	671	—	—	—	—	671
Issuance of restricted stock (35,776 shares)	—	—	—	—	—	—	—
Amortization of stock compensation	—	10,318	—	—	—	—	10,318
Comprehensive income:							
Net income	—	—	—	—	161,565	—	161,565
Other comprehensive income	—	—	—	—	—	386	386
Total comprehensive income	—	—	—	—	—	—	161,951
Balance, December 31, 2006	$ 302	$ 387,556	$ (6,125)	$ —	$ 415,868	$ 316	$ 797,917
Stock issued for benefit plans (32,817 shares)	—	953	471	—	—	—	1,424
Stock options exercised (239,650 shares)	2	3,168	—	—	—	—	3,170
Purchase of treasury shares (42,145 shares)	—	—	(1,826)	—	—	—	(1,826)
Adoption of FIN 48	—	—	—	—	(977)	—	(977)
Excess tax benefits from stock-based awards	—	613	—	—	—	—	613
Employee stock purchase plan (17,678 shares)	—	619	—	—	—	—	619
Issuance of restricted stock (187,678 shares)	2	(2)	—	—	—	—	—
Amortization of stock compensation	—	14,557	—	—	—	—	14,557
Comprehensive income:							
Net income	—	—	—	—	21,287	—	21,287
Other comprehensive loss	—	—	—	—	—	(730)	(730)
Total comprehensive income	—	—	—	—	—	—	20,557
Balance, December 31, 2007	$ 306	$ 407,464	$ (7,480)	$ —	$ 436,178	$ (414)	$ 836,054

[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, 2007	2006	2005
Cash Flows from Operating Activities:			
Net income	$ 21,287	$ 161,565	$ 115,778
Plus (income) loss from discontinued operations, net of taxes	131,301	(10,491)	(17,898)
Adjustments to reconcile net income to net cash provided by operating activities—			
Depreciation, depletion, and amortization	188,393	139,245	81,124
Accretion of asset retirement obligation	1,437	884	626
Deferred income taxes	86,474	86,541	57,499
Stock-based compensation expense	10,317	6,905	1,451
Debt retirement cost – cash and non-cash	12,765	—	—
Other	(4,314)	7,117	(334)
Change in assets and liabilities—			
Increase in accounts receivable	(9,114)	(20,571)	(5,826)
Increase in accounts payable and accrued liabilities	5,748	10,906	5,072
Increase (decrease) in income taxes payable	(806)	884	—
Increase (decrease) in accrued interest	(1,206)	256	(701)
Cash provided by operating activities – continuing operations	442,282	383,241	236,791
Cash provided by operating activities – discontinued operations	25,620	41,680	48,543
Net Cash Provided by Operating Activities	467,902	424,921	285,334
Cash Flows from Investing Activities:			
Additions to property and equipment	(398,295)	(293,957)	(168,914)
Proceeds from the sale of property and equipment	250	24,678	7,297
Acquisition of properties	(252,299)	(194,269)	(28,927)
Net cash received (distributed) as operator of partnerships and joint ventures	485	410	(948)
Other	—	(528)	255
Cash used in investing activities – continuing operations	(649,859)	(463,666)	(191,237)
Cash used in investing activities – discontinued operations	(7,827)	(59,881)	(48,837)
Net Cash Used in Investing Activities	(657,686)	(523,547)	(240,074)
Cash Flows from Financing Activities:			
Proceeds from long-term debt	250,000	—	—
Payments of long-term debt	(200,000)	—	—
Net proceeds from (payments of) bank borrowings	155,600	31,400	(7,500)
Net proceeds from issuances of common stock	3,789	12,509	10,325
Excess tax benefits from stock-based awards	613	3,328	—
Purchase of treasury shares	(1,826)	—	—
Payments of debt retirement costs	(9,376)	—	—
Payments of debt issuance costs	(4,451)	(558)	—
Cash provided by financing activities – continuing operations	194,349	46,679	2,825
Cash provided by financing activities – discontinued operations	—	—	—
Net Cash Provided by Financing Activities	194,349	46,679	2,825
Net Increase (Decrease) in Cash and Cash Equivalents	$ 4,565	$ (51,947)	$ 48,085
Cash and Cash Equivalents at Beginning of Year	1,058	53,005	4,920
Cash and Cash Equivalents at End of Year	$ 5,623	$ 1,058	$ 53,005
Supplemental Disclosures of Cash Flows Information:			
Cash paid during year for interest, net of amounts capitalized	$ 28,092	$ 22,691	$ 24,483
Cash paid during year for income taxes	$ 2,113	$ 9,780	$ 750

See accompanying Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

Swift Energy Company and Subsidiaries

1. Summary of Significant Accounting Policies

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

Holding Company Structure. In December 2005, we implemented a holding company structure pursuant to Texas and federal law in a manner designed to be a non-taxable transaction. The new parent holding company assumed the Swift Energy Company name and its common stock and continued to trade on the New York Stock Exchange. The purposes of this holding company structure are to align Swift Energy's operations to better reflect management practices, to improve our economics, and to provide greater administrative and organizational flexibility. Under the new organizational structure, four new subsidiaries were formed with the Texas parent holding company wholly owning four Delaware subsidiaries, which in turn wholly own Swift Energy's operating subsidiaries. Swift Energy Operating, LLC is the operator of record for Swift Energy's domestic properties. Swift Energy's name, charter, bylaws, officers, board of directors, authorized shares and shares outstanding remain substantially identical. The Company's international operations continue to be conducted through Swift Energy International, Inc. Swift Energy made amendments to its bank credit agreement, debt indentures and various other plans and documents to accommodate the internal reorganization, but the Company's day-to-day conduct of business was not impacted. Accordingly, there was no impact on our financial position or results of operations.

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

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

- the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties and the related present value of estimated future net cash flows there-from,
- estimates 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,
- 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 2007, 2006, and 2005, such internal costs capitalized totaled $26.4 million, $24.1 million, and $14.5 million, respectively. Interest costs are also capitalized to unproved oil and natural gas properties. For the years 2007, 2006, and 2005, capitalized interest on unproved properties totaled $9.5 million, $9.2 million, and $7.2 million, respectively. Interest not capitalized and general and administrative costs related to production and general corporate overhead are expensed as incurred.

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

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

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

Geological and geophysical ("G&G") costs incurred on developed properties are recorded in "Proved properties" and therefore subject to amortization. G&G costs incurred that are directly associated with specific unproved properties are capitalized in "Unproved properties" and evaluated as part of the total capitalized costs associated with a prospect. The cost of unproved properties not being amortized is assessed quarterly, on a property-by-property basis, to determine whether such properties have been impaired. In determining whether such costs should be impaired, we evaluate current drilling results, lease expiration dates, current oil and gas industry conditions, international economic conditions, capital availability, and available geological and geophysical information. Any impairment assessed is added to the cost of proved properties being amortized.

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and natural gas properties (including natural gas processing facilities, capitalized asset retirement obligations, net of related salvage values and deferred income taxes, and excluding the recognized asset retirement obligation liability) is limited to the sum of the estimated future net revenues from proved properties (excluding cash outflows from recognized asset retirement obligations, including future development and abandonment costs of wells to be drilled, using period-end prices, adjusted for the effects of hedging, discounted at 10%, and the lower of cost or fair value of unproved properties) adjusted for related income tax effects ("Ceiling Test"). Our hedges at December 31, 2007 consisted of oil and natural gas price floors with strike prices lower than the period-end price and did not materially affect this calculation. 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.

Given the volatility of oil and natural gas prices, it is reasonably possible that our estimate of discounted future net cash flows from proved oil and natural gas reserves could change in the near term. If oil and natural gas prices decline significantly from our period-end prices used in the Ceiling Test, even if only for a short period, it is possible that 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, a non-cash write-down 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 sizable 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 collectibility 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 balance sheet. Natural gas balancing receivables are reported in "Other current assets" on the accompanying balance sheet when our ownership share of production exceeds sales. As of December 31, 2007, we did not have any material natural gas imbalances.

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, 2007 and 2006, we had an allowance for doubtful accounts of approximately $0.1 million. The allowance for doubtful accounts has been deducted from the total "Accounts receivable" balances on the accompanying balance sheets.

Debt Issuance Costs. Legal and accounting fees, underwriting fees, printing costs, and other direct expenses associated with the June 2004 extension of our bank credit facility, the public offering in June 2004 of our 7-5/8% senior notes due 2011, and the public offering in June 2007 of our 7-1/8% senior subordinated notes due 2017, were capitalized and are amortized on an effective interest basis over the life of each of the respective note offerings and credit facility. The 7-1/8% senior notes due 2017 mature on June 1, 2017, and the balance of their issuance costs at December 31, 2007, was $4.0 million, net of accumulated amortization of $0.2 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, 2007, was $1.0 million, net of accumulated amortization of $2.2 million. The 7-5/8% senior notes due 2011 mature on July 15, 2011, and the balance of their issuance costs at December 31, 2007, was $2.3 million, net of accumulated amortization of $1.7 million.

Settlement of Insurance Claims. In 2006, we settled all insurance claims with our insurers relating to hurricanes

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

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

We have a price-risk management policy to use derivative instruments to protect against declines in oil and gas prices, mainly through the purchase of price floors and collars. During 2007, 2006 and 2005, we recognized net gains of $0.2 million and $4.0 million and a net loss of $1.1 million, respectively, relating to our derivative activities. This activity is recorded in "Price-risk management and other, net" on the accompanying statements of income. Had these gains and losses been recognized in the oil and gas sales account they would not materially change our per unit sales prices received. At December 31, 2007, the Company had recorded $0.4 million, net of taxes of $0.2 million, of derivative losses in "Accumulated other comprehensive income (loss), net of income tax" on the accompanying balance sheet. This amount represents the change in fair value for the effective portion of our hedging transactions that qualified as cash flow hedges. The ineffectiveness reported in "Price-risk management and other, net" for 2007, 2006, and 2005 was not material. All amounts currently held in "Accumulated other comprehensive income (loss), net of income tax" will be realized within the next three months when the forecasted sale of hedged production occurs.

At December 31, 2007, we had in place oil price floors in effect for the contract months of January 2008 through March 2008 that cover a portion of our oil production for January 2008 to March 2008. We also had in place natural gas price floors in effect for the contract months of February 2008 through March 2008 that cover a portion of our natural gas production for February to March 2008. The oil price floors cover notional volumes of 639,000 barrels, with a weighted average floor price of $71.22 per barrel. Our oil price floors in place at December 31, 2007 are expected to cover approximately 40% to 45% of our estimated oil production from January 2008 to March 2008. The natural gas price floors cover notional volumes of 1,330,000 MMBtu, with a weighted average floor price of $6.90 per MMBtu. Our natural gas price floors in place at December 31, 2007 are expected to cover approximately 40% to 45% of our estimated natural gas production from February 2008 to March 2008.

When we entered into these transactions discussed above, they were designated as a hedge of the variability in cash flows associated with the forecasted sale of oil and natural gas production. Changes in the fair value of a hedge that is highly effective and is designated and documented and qualifies as a cash flow hedge, to the extent that the hedge is effective, are recorded in "Accumulated other comprehensive income (loss), net of income tax." When the hedged transactions are recorded upon the actual sale of the oil and natural gas, these gains or losses are reclassified from "Accumulated other comprehensive income (loss), net of income tax" and recorded in "Price-risk management and other, net" on the accompanying statements of income. The fair value of our derivatives are computed using the Black-Scholes-Merton option pricing model and are periodically verified against quotes from brokers. The fair value of these instruments at December 31, 2007, was $0.3 million and is recognized on the accompanying balance sheet in "Other current assets."

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 2007 and 2006 did not exceed our actual costs incurred. The total amount of supervision fees charged to the wells we operate was $11.8 million in 2007, $8.7 million in 2006, and $7.4 million in 2005.

Inventories. We value inventories at the lower of cost or market value. Inventory is accounted for using the first in, first out method ("FIFO"). Inventories consisting of materials, supplies, and tubulars are included in "Other current assets" on the accompanying balance sheets totaling $4.2 million at December 31, 2007 and $1.8 million at December 31, 2006.

Income Taxes. Under SFAS No. 109, "Accounting for Income Taxes," deferred taxes are determined based on the estimated future tax effects of differences between the financial statement and tax basis of assets and liabilities, given the provisions of the enacted tax laws.

On January 1, 2007, we adopted the recognition and disclosure provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement No. 109" ("FIN 48"). Under FIN 48, tax positions are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than fifty percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. As a result of adopting FIN 48, we reported a $1.0 million decrease to our January 1, 2007 retained earnings balance and a corresponding increase to other long-term liabilities. This was also the total balance of our unrecognized tax benefits, which would fully impact our effective tax rate if recognized. We did not recognize significant increases or decreases in unrecognized tax benefits during the year ended December 31, 2007.

Our policy is to record interest and penalties relating to income taxes in income tax expense. As of December 31, 2007 no interest or penalties relating to income taxes have been incurred or recognized. Our cumulative interest exposure on unrecognized tax benefits is not material.

Our U.S. Federal and State of Louisiana income tax returns from 1998 forward, our New Zealand income tax returns after 2001, and our Texas franchise tax returns after 2005 remain subject to examination by the taxing authorities. There are no unresolved items related to periods previously audited by these taxing authorities. No other state returns are significant to our financial position.

In the third quarter of 2007 we increased the valuation allowance for our capital loss carryforward assets by $2.6 million to cover the full value of the carryforward. The increase in the valuation allowance was due to changes in the Company's property disposition plans and increased income tax expense of $2.6 million in that period.

Accounts Payable and Accrued Liabilities. Included in "Accounts payable and accrued liabilities," on the accompanying balance sheets, at December 31, 2007 and 2006 are liabilities of approximately $12.6 million and $13.9 million, respectively, which represent the amounts by which checks issued, but not presented by vendors to the Company's banks for collection, exceeded balances in the applicable disbursement bank accounts.

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

Credit Risk Due to Certain Concentrations. We extend credit, primarily in the form of uncollateralized oil and natural gas sales and joint interest owners receivables, to various companies in the oil and gas industry, which results in a concentration of credit risk. The concentration of credit risk may be affected by changes in economic or other conditions within our industry and may accordingly impact our overall credit risk. However, we believe that the risk of these unsecured receivables is mitigated by the size, reputation, and nature of the companies to which we extend credit. During 2007 and 2006, oil and gas sales to Shell Oil Company and affiliates were $290.1 million and $180.4 million, or 42% and 30% of total oil and gas sales, respectively. During 2007 and 2006, Chevron Corporation and its affiliates accounted for $151.0 million and $193.9 million, or 22% and 32% of our total oil and gas sales. Credit losses in 2007, 2006 and 2005 were immaterial.

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

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

Foreign Currency. We use the U.S. Dollar as our functional currency in New Zealand. The functional currency is determined by examining the entities' cash flows, commodity pricing, environment and financing arrangements. We have both assets and liabilities denominated in New Zealand Dollars, the New Zealand "Assets held for sale" and a portion of our "Liabilities associated with assets held for sale" on the accompanying balance sheets. As the exchange rate moves between the U.S. Dollar and the New Zealand Dollar, we recognize transaction gains and losses in "Income (loss) from discontinued operations, net of taxes" on the accompanying statements of income.

Fair Value of Financial Instruments. Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, bank borrowings, and senior notes. The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the highly liquid or short-term nature of these instruments. The fair values of the bank borrowings approximate the carrying amounts as of December 31, 2007 and 2006, 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, 2007 the fair value of our senior notes due 2017, which were issued in June 2007, was $237.5 million, or 95.0% of face value. Based upon quoted market prices as of December 31, 2007 and 2006, the fair values of our senior notes due 2011 were $150.8 million, or 100.5% of face value, and $152.6 million, or 101.75% of face value.

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

Accumulated Other Comprehensive Income (Loss), Net of Income Tax. We follow the provisions of SFAS No. 130, "Reporting Comprehensive Income," which establishes standards for reporting comprehensive income. In addition to net income, comprehensive income or loss includes all changes to equity during a period, except those resulting from investments and distributions to the owners of the Company. At December 31, 2007, we recorded $0.4 million, net of taxes of less than $0.2 million, of derivative losses in "Accumulated other comprehensive income (loss), net of income tax" on the accompanying balance sheet. The components of accumulated other comprehensive income (loss) and related tax effects for 2007 were as follows (in thousands):

	Gross Value	Tax Effect	Net of Tax Value
Other comprehensive income at December 31, 2006	$ 503	$ (187)	$ 316
Change in fair value of cash flow hedges	(842)	312	(530)
Effect of cash flow hedges settled during the period	(319)	119	(200)
Other comprehensive income (loss) at December 31, 2007	$ (658)	$ 244	$ (414)

Total comprehensive income was $20.6 million, $162.0 million, and $115.3 million for 2007, 2006, and 2005, respectively.

Stock Based Compensation. Effective January 1, 2006, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 123 (R), "Share-Based Payment" (SFAS No. 123R) utilizing the modified prospective approach. Under the modified prospective approach, SFAS No. 123R applies to new awards and to awards that were outstanding on January 1, 2006, as well as those that are subsequently modified, repurchased or cancelled. Under the modified prospective approach, compensation cost recognized for the years ended December 31, 2007 and 2006 includes compensation cost for all share-based awards granted prior to, but not yet vested as of January 1, 2006, based on the grant-date fair value estimated in accordance with the original provisions of SFAS No. 123, and compensation cost for all share-based awards granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS No. 123R. Prior periods were not restated to reflect the impact of adopting SFAS No. 123R.

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

Prior to 2006, we accounted for those plans under the recognition and measurement principles of APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. No stock-based employee compensation cost is reflected in net income for employee stock options prior to 2006, as all options granted under those plans had an exercise price equal to the fair market value of the underlying common stock on the date of the grant; or in the case of the employee stock purchase plan, the purchase price is 85% of the lower of the closing price of our common stock as quoted on the New York Stock Exchange at the beginning or end of the plan year. Had compensation expense for these plans been determined based on the fair value of the options consistent with SFAS No. 123, "Accounting for Stock-Based Compensation," our net income and earnings per share would have been adjusted to the following pro forma amounts (in thousands, except per share amounts):

		2005
Net Income:	As Reported	$115,778
	Stock-based employee compensation expense determined under fair value method for all awards, net of tax	(2,712)
	Pro Forma	$113,066
Basic EPS:	As Reported	$4.06
	Pro Forma	$3.97
Diluted EPS:	As Reported	$3.95
	Pro Forma	$3.86

Pro forma compensation cost reflected above may not be representative of the cost to be expected in future years. The fair value of each option grant, as opposed to its exercise price, is estimated on the date of grant using the Black-Scholes-Merton option-pricing model with the following weighted average assumptions in 2007, 2006, and 2005, respectively: no dividend yield; expected volatility factors of 38.5%, 39.3%, and 41.6%; risk-free interest rates of 4.7%, 4.8%, and 3.8%; and expected lives of 6.0, 4.8, and 3.9 years. We viewed all awards of stock compensation as a single award with an expected life equal to the average expected life of underlying awards and amortized the award on a straight-line basis over the life of the award.

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

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

Asset Retirement Obligation as of January 1, 2005	$ 13,987
Accretion expense for 2005	626
Liabilities incurred for new wells and facilities construction	142
Liabilities incurred for acquisitions	426
Reductions due to sold and abandoned wells	(465)
Revisions in estimated cash flows	708
Asset Retirement Obligation as of December 31, 2005	$ 15,424
Accretion expense for 2006	884
Liabilities incurred for new wells and facilities construction	190
Liabilities incurred for acquisitions	12,207
Reductions due to sold and abandoned wells	(177)
Revisions in estimated cash flows	265
Asset Retirement Obligation as of December 31, 2006	$ 28,793
Accretion expense for 2007	1,438
Liabilities incurred for new wells and facilities construction	981
Liabilities incurred for acquisitions	620
Reductions due to sold and abandoned wells	(808)
Revisions in estimated cash flows	3,435
Asset Retirement Obligation as of December 31, 2007	$ 34,459

At December 31, 2007 and 2006, approximately $3.4 million and $0.3 million, respectively, of our asset retirement obligation is classified as a current liability in "Accounts payable and accrued liabilities" on the accompanying consolidated balance sheets.

New Accounting Pronouncements. In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. SFAS No. 157 defines fair value, establishes guidelines for measuring fair value and expands disclosures regarding 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. SFAS No. 157 was effective for fiscal periods beginning after November 15, 2007. On February 12, 2008, the FASB delayed the effective date of SFAS No. 157 for non-financial assets and non-financial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis, at least annually. For Swift, this action defers the effective date for those assets and liabilities until January 1, 2009. We believe that the adoption of this statement will not have a material impact on our financial position or results of operations.

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

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations. SFAS No. 141(R) provides enhanced guidance related to the measurement of identifiable assets acquired, liabilities assumed and disclosure of information related to business combinations and their effect on the Company. This Statement, together with the International Accounting Standards Board's IFRS 3, Business Combinations, completes a joint effort by the FASB and IASB to improve financial reporting about business combinations and promotes the international convergence of accounting standards. For Swift, SFAS No. 141(R) applies prospectively to business combinations in 2009 and is not subject to early adoption. We are currently evaluating the potential impact of SFAS No. 141(R) on business combinations and related valuations.

2. Earnings Per Share

Basic earnings per share ("Basic EPS") have been computed using the weighted average number of common shares outstanding during the respective periods. Diluted earnings per share ("Diluted EPS") for all periods also assumes, as of the beginning of the period, exercise of stock options and restricted stock grants using the treasury stock method. Certain of our stock options and restricted stock that would potentially dilute Basic EPS in the future were also antidilutive for the 2007, 2006, and 2005 periods 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, 2007, 2006, and 2005 (in thousands, except per share amounts):

	2007			2006			2005		
	Income from Continuing Operations	Shares	Per Share Amount	Income from Continuing Operations	Shares	Per Share Amount	Income from Continuing Operations	Shares	Per Share Amount
Basic EPS:									
Net income from continuing operations, and share amounts	$152,588	29,984	$5.09	$151,074	29,265	$5.16	$97,880	28,496	$3.43
Dilutive Securities:									
Restricted stock	—	218		—	169		—	62	
Stock options	—	438		—	582		—	737	
Diluted EPS:									
Net income from continuing operations, and assumed share conversions	$152,588	30,640	$4.98	$151,074	30,016	$5.03	$97,880	29,295	$3.34

Options to purchase approximately 1.4 million shares at an average exercise price of $28.47 were outstanding at December 31, 2007, while options to purchase 1.5 million shares at an average exercise price of $24.59 were outstanding at December 31, 2006, and options to purchase 2.1 million shares at an average exercise price of $21.28 were outstanding at December 31, 2005. Approximately 1.0 million, 1.0 million, and 0.1 million stock options to purchase shares were not included in the computation of Diluted EPS for the years ended December 31, 2007, 2006, and 2005, respectively, because these stock options were antidilutive, in that the sum of the stock option price, unrecognized compensation expense and excess tax benefits recognized as proceeds in the treasury stock method was greater than the average closing market price for the common shares during those periods. Employee restricted stock grants of 0.4 million shares, 0.3 million shares and less than 0.1 million shares, were not included in the computation of Diluted EPS for the year ended December 31, 2007, 2006, and 2005, respectively, because these restricted stock grants were antidilutive in that the sum of the unrecognized compensation expense and excess tax benefits recognized as proceeds under the treasury stock method was greater than the average closing market price for the common shares during that period.

3. Provision for Income Taxes

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

	Year Ended December 31,		
	2007	2006	2005
Income from Continuing Operations Before Income Taxes	$ 244,556	$ 248,308	$ 156,129

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

	Year Ended December 31,		
	2007	2006	2005
Current	$ 6,902	$ 2,860	$ 644
Deferred	85,066	94,374	57,605
Total	$ 91,968	$ 97,234	$ 58,249

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

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

	2007	2006	2005
Income taxes computed at U.S. statutory rate (35%)	$ 85,595	$ 86,908	$ 54,645
State tax provisions, net of federal benefits	3,396	3,921	2,145
Cumulative impact of adjustments to net state income tax rate	—	1,547	1,008
Write-offs and valuation allowance of carryover tax assets	2,585	3,200	—
Other, net	392	1,658	451
Provision for income taxes	$ 91,968	$ 97,234	$ 58,249
Effective rate	37.6%	39.2%	37.3%

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 $3.4 million, $3.9 million and $2.1 million for 2007, 2006, and 2005, respectively. In 2007, the company recorded write-offs and valuation allowances totaling $2.6 million as discussed further below. In 2006 the Company recorded a valuation allowance of $3.2 million due to changes in the Company's tax planning strategies. Additionally, the Company recorded adjustments to the cumulative state deferred tax liability in the amounts of $1.5 million and $1.0 million for 2006 and 2005, respectively.

The tax effects of temporary differences representing the net deferred tax liability (asset) at December 31, 2007 and 2006 were as follows (in thousands):

	2007	2006
Current deferred tax assets:		
Alternative minimum tax credits	$ 5,094	$ —
Unrealized stock compensation	2,403	—
Other	558	2,383
Total current deferred tax assets	$ 8,055	$ 2,383
Non-current deferred tax assets:		
Carryover items, net of valuation allowance	$ 4,334	$ 2,648
Unrealized stock compensation	1,294	2,680
Other	749	2,527
Total non-current deferred tax assets	$ 6,377	$ 7,855
Non-current deferred tax liabilities:		
Oil and gas exploration and development costs	$ 307,083	$ 218,924
Other	1,597	1,389
Total deferred tax liabilities	$ 308,680	$ 220,313
Net non-current deferred tax liabilities	$ 302,303	$ 212,458

The total change in the net non-current deferred liability from 2006 to 2007 was $89.8 million. This increase is primarily attributable to an $88.2 million increase in the deferred liability for accelerated tax deductions for oil and natural gas exploration and development costs.

Current deferred tax assets increased by $5.7 million, primarily due to alternative minimum tax credits of $5.1 million that are expected to be utilized during 2008. Changes in market prices for oil and natural gas along with other economic and operational factors could result in the current deferred tax assets not being fully utilized to reduce 2008 income taxes.

The primary non-current deferred tax assets are $4.3 million for State of Louisiana net operating loss carryovers. These loss carryforwards are scheduled to expire between 2013 and 2020.

Unrealized stock compensation accounts for $2.4 million in current deferred tax assets and $1.3 million in non-current deferred tax assets. These amounts are attributable to stock compensation expenses accrued for employee stock options and restricted stock that are not realized for income tax purposes until exercised (for stock options) or vested (for restricted stock). The actual tax deductions realized may be significantly different than the accrued amounts depending on the market value of the stock on the date of exercise or vesting.

There is also a deferred tax asset of $1.1 million for a capital loss carryforward which is fully offset by a valuation allowance. This carryover is scheduled to expire in 2010. At the end of 2006 the Company had total capital loss carryforward assets of $6.1 million which included $5.0 million that expired at the end of 2007. At the end of 2006, the tax asset net of valuation allowances was $2.4 million. During 2007, the Company elected not to pursue previously planned property dispositions that would have utilized these loss carryforwards. Accordingly, tax expense was increased in 2007 to adjust for the carryovers that expired and to reserve a full valuation allowance against the unexpired portion.

On January 1, 2007, we adopted the recognition and disclosure provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109" ("FIN 48"). Under FIN 48, tax positions are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than fifty percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. As a result of adopting FIN 48, we reported a $1.0 million decrease to our January 1, 2007 retained earnings balance and a corresponding increase to our other long-term liabilities.

The $1.0 million decrease is also the total balance of our unrecognized tax benefits, which would impact our effective tax rate if recognized. We do not anticipate any significant increases or decreases in unrecognized tax benefits during 2008. Our policy is to record interest and penalties relating to income taxes in income tax expense. As of December 31, 2007, no interest or penalties relating to income taxes have been incurred or recognized. Our cumulative interest exposure on unrecognized tax benefits is not material.

There were no changes to unrecognized tax benefits recorded during 2007.

Our U.S. Federal and State of Louisiana income tax returns from 1998 forward, our New Zealand income tax returns after 2001, and our Texas franchise tax returns after 2005 remain subject to examination by the taxing authorities. There are no unresolved items related to periods previously audited by these taxing authorities. No other state returns are significant to our financial position.

4. Long-Term Debt

Our long-term debt as of December 31, 2007 and 2006, is as follows (in thousands):

	2007	2006
Bank borrowings	$ 187,000	$ 31,400
7-5/8% senior notes due 2011	150,000	150,000
9-3/8% senior subordinated notes due 2012	—	200,000
7-1/8% senior notes due 2017	250,000	—
Long-term debt	$ 587,000	$ 381,400

Bank Borrowings. At December 31, 2007, we had borrowings of $187.0 million under our $500.0 million credit facility with a syndicate of ten banks that has a borrowing base of $400.0 million, based entirely on assets from continuing operations, and expires in October 2011. At December 31, 2006, we had borrowings of $31.4 million under our credit facility. The interest rate is either (a) the lead bank's prime rate (7.25% at December 31, 2007) or (b) the adjusted London Interbank Offered Rate ("LIBOR") plus the applicable margin depending on the level of outstanding debt. The applicable margin is based on the ratio of the outstanding balance to the last calculated borrowing base. In October 2006, we increased, renewed and extended this credit facility, increasing the facility to $500 million from $400 million, increasing the commitment amount under the borrowing base to $250 million from $150 million, and extending its expiration to October 3, 2011 from October 1, 2008. The other terms of the credit facility stayed largely the same. In April 2007 we increased the borrowing base to $350.0 million; and effective November 2007, we further increased it to $400.0 million. In September 2007, we increased the commitment amount under the borrowing base to $350.0 million from $250.0 million. The covenants related to this credit facility changed somewhat with the extension of the facility and are discussed below. We incurred $0.3 million of debt issuance costs related to the increase of the commitment amount in 2007, and $0.6 million of debt issuance costs related to the extension of this facility in 2006, which is included in "Debt issuance costs" on the accompanying consolidated balance sheets and will be amortized to interest expense over the life of the facility.

The terms of our credit facility include, among other restrictions, a limitation on the level of cash dividends (not to exceed $15.0 million in any fiscal year), a remaining aggregate limitation on purchases of our stock of $50.0 million, requirements as to maintenance of certain minimum financial ratios (principally pertaining to adjusted working capital ratios and EBITDAX), and limitations on incurring other debt or repurchasing our 7-5/8% senior notes due 2011. Since inception, no cash dividends have been declared on our common stock. We are currently in compliance with the provisions of this agreement. The credit facility is secured by our domestic oil and natural gas properties. Under the terms of the credit facility, we can increase this 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 2008.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $6.1 million in 2007, $1.5 million in 2006, and $1.0 million in 2005. The amount of commitment fees included in interest expense, net was $0.5 million in 2007, $0.6 million in 2006 and $0.5 million in 2005.

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

Interest expense on the 7-5/8% senior notes due 2011, including amortization of debt issuance costs totaled $12.0 million in 2007 and $11.9 million in both 2006 and 2005.

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

Interest expense on the 9-3/8% senior subordinated notes due 2012, including amortization of debt issuance costs totaled $8.9 million in 2007 and $19.2 million in both 2006 and 2005.

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 commencing on December 1, 2007. On or after June 1, 2012, we may redeem some or all of these notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 103.563% of principal, declining in twelve-month intervals to 100% in 2015 and thereafter. In addition, prior to June 1, 2010, we may redeem up to 35% of the principal amount of the notes with the net proceeds of qualified offerings of our equity at a redemption price of 107.125% of the principal amount of the notes, plus accrued and unpaid interest. We incurred approximately $4.2 million of debt issuance costs related to these notes, which is included in "Debt issuance costs" on the accompanying balance sheets and will be amortized to interest expense, net over the life of the notes using the effective interest method. In the event of certain changes in control of Swift Energy, each holder of notes will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of these notes include, among other restrictions, a limitation on how much of our own common stock we may repurchase. We are currently in compliance with the provisions of the indenture governing these senior notes.

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

The maturities on our long-term debt are $0 for 2008, 2009 and 2010, $337 million for 2011, and $250 million thereafter.

We have capitalized interest on our unproved properties in the amount of $9.5 million, $9.2 million, and $7.2 million, in 2007, 2006, and 2005, respectively.

5. Commitments and Contingencies

Rental and lease expenses which were included in "General and administrative, net" on our accompanying consolidated statements of income were $3.7 million in 2007, $2.7 million in 2006, and $2.5 million in 2005. Rental and lease expenses which were included in "Lease operating cost" on our accompanying consolidated statements of income were $6.7 million in 2007, $3.6 million in 2006, and $1.9 million in 2005. Our remaining minimum annual obligations under non-cancelable operating lease commitments are $7.7 million for 2008, $4.9 million for 2009 and $3.4 million for 2010, $3.2 million for both 2011 and 2012, and $7.0 million thereafter or $29.3 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 for such services and tubing and pipe inventory commitments. The remaining commitments at December 31, 2007 for these services and materials totaled $34.2 million for 2008.

In the ordinary course of business, we have been party to various legal actions, which arise primarily from our activities as operator of oil and natural gas wells. In management's opinion, the outcome of any such currently pending legal actions will not have a material adverse effect on our financial position or results of operations.

6. Stockholders' Equity

Stock-Based Compensation Plans. We have three stock option plans that awards are currently granted under, the 2005 Stock Compensation Plan, which was adopted by our Board of Directors in March 2005 and was approved by shareholders at the 2005 annual meeting of shareholders, the 2001 Omnibus Stock Compensation Plan, which was adopted by our Board of Directors in February 2001 and was approved by shareholders at the 2001 annual meeting of shareholders, and the 1990 Non-Qualified Stock Option Plan solely for our independent directors. No further grants, other than stock option reload grants, 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, stock options become exercisable in various terms ranging from one year to five years. Options granted typically expire ten years after the date of grant or earlier in the event of the optionee's separation from employment. At the time the stock options are exercised, the cash received is credited to common stock and additional paid-in capital. Options issued under these plans also include a reload feature where additional options are granted at the then current market price when mature shares of Swift Energy common stock are used to satisfy the exercise price of an existing stock option grant. When Swift Energy common stock is used to satisfy the exercise price, the net shares actually issued are reflected in the accompanying Statement of Stockholders' Equity (see note 1 to table below). We view all awards of stock compensation as a single award with an expected life equal to the average expected life of component awards and amortize the award on a straight-line basis over the life of the award.

The employee stock purchase plan, which began in 1993, provides eligible employees the opportunity to acquire shares of Swift Energy common stock at a discount through payroll deductions. Through May 31, 2006, the prior plan year was from June 1 to the following May 31. A transition period from June 1 to December 31 was used during the second half of 2006 and a new plan year, from January 1 to December 31, began being used in 2007. To date, employees have been allowed to authorize payroll deductions of up to 10% of their base salary during the plan year by making an election to participate prior to the start of a plan year. The purchase price for stock acquired under the plan is 85% of the lower of the closing price of our common stock as quoted on the New York Stock Exchange at the beginning or end of the plan year (or a date during the year chosen by the participant 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 17,678 shares at a price of $35.00 in 2007, 22,425 shares at a price range of $29.84 to $32.80 in 2006, and 32,495 shares at a price range of $15.56 to $18.12 in 2005. As of December 31, 2007, 58,721 shares remained available for issuance under this plan.

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

We receive a tax deduction for certain stock option exercises during the period the options are exercised, generally for the excess of the price at which the stock is sold over the exercise price of the options. In addition, we receive an additional tax deduction when restricted stock vests at a higher value than the value used to recognize compensation expense at the date of grant. Prior to adoption of SFAS No. 123R, we reported all tax benefits resulting from the award of equity instruments as operating cash flows in our consolidated statements of cash flows. In accordance with SFAS No. 123R, we are required to report excess tax benefits from the award of equity instruments as financing cash flows. These benefits were $3.3 million for the year ended December 31, 2006. For 2007 an estimated excess benefit of $0.6 million has been realized and credited to paid-in capital. Unrealized benefits of $1.2 million will not be recognized until the period in which the related carryover tax assets are realized.

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

Stock compensation expense for both stock options and restricted stock issued to both employees and non-employees is recorded in "General and Administrative, net" in the accompanying consolidated statements of income, and was $9.4 million, $6.3 million, and $1.5 million for the years ended December 31, 2007, 2006, and 2005 respectively. We also capitalized $4.2 million, $3.4 million, and $1.0 million of stock compensation in 2006, 2005, and 2004, respectively.

Our shares available for future grant under our stock compensation plans were 714,103 at December 31, 2007. 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,		
	2007	2006	2005
Dividend yield	0%	0%	0%
Expected volatility	38.5%	39.3%	41.6%
Risk-free interest rate	4.7%	4.8%	3.8%
Expected life of options (in years)	6.0	4.8	3.9
Weighted-average grant-date fair value	$ 19.61	$ 18.03	$ 12.84

The expected term has been 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 use a three-year period to estimate expected volatility of our stock option grants.

At December 31, 2007, $2.9 million of unrecognized compensation cost related to stock options is expected to be recognized over a weighted-average period of 1.5 years.

The following table represents stock option activity for the years ended December 31, 2007, 2006 and 2005:

	2007		2006		2005	
	Shares	Wtd. Avg. Exer. Price	Shares	Wtd. Avg. Exer. Price	Shares	Wtd. Avg. Exer. Price
Options outstanding, beginning of period	1,549,140	$ 24.59	2,118,179	$ 21.28	2,998,668	$ 18.51
Options granted	201,691	$ 43.40	234,110	$ 45.73	176,262	$ 35.17
Options canceled	(41,800)	$ 37.15	(51,739)	$ 22.25	(45,142)	$ 18.94
Options exercised[1]	(259,791)	$ 18.13	(751,410)	$ 22.02	(1,011,609)	$ 9.78
Options outstanding, end of period	1,449,240	$ 28.47	1,549,140	$ 24.59	2,118,179	$ 21.28
Options exercisable, end of period	967,429	$ 25.70	884,876	$ 22.60	1,085,509	$ 20.98

[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 2007, 2006 and 2005 respectively, 19,191, 98,581 and 170,762 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, 2007 was $23.2 million and 5.2 years and $18.3 million and 4.1 years, respectively. The total intrinsic value of options exercised during the year ended December 31, 2007 was $6.1 million.

The following table summarizes information about stock options outstanding at December 31, 2007:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at 12/31/07	Wtd. Avg. Remaining Contractual Life	Wtd. Avg. Exercise Price	Number Exercisable at 12/31/07	Wtd. Avg. Exercise Price
$ 6.00 to $20.99	503,471	4.7	$ 13.64	401,371	$ 13.35
$21.00 to $35.99	473,870	4.4	$ 28.14	382,790	$ 28.88
$36.00 to $52.00	471,899	6.6	$ 44.62	183,268	$ 46.08
$ 6.00 to $52.00	1,449,240	5.2	$ 28.47	967,429	$ 25.70

Restricted Stock. In 2007, 2006 and 2005, the Company issued 329,290, 324,640 and 158,500 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 $43 per share in 2007 and 2006 and $38 per share in 2005.

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, 2007, we have unrecognized compensation expense of approximately $16.2 million associated with these awards which are expected to be recognized over a weighted-average period of 1.6 years. The total fair value of shares vested during the year ended December 31, 2007 was $7.5 million.

The following is a summary of our restricted stock issued to employees, consultants, and directors under these plans as of December 31, 2007, 2006, and 2005:

	2007		2006		2005	
	Shares	Wtd. Avg. Grant Price	Shares	Wtd. Avg. Grant Price	Shares	Wtd. Avg. Grant Price
Restricted shares outstanding, beginning of period	503,184	$ 40.04	236,950	$ 34.79	100,900	$ 23.92
Restricted shares granted	329,290	$ 43.17	324,640	$ 43.21	158,500	$ 38.31
Restricted shares canceled	(47,595)	$ 39.63	(22,630)	$ 38.01	(7,450)	$ 39.03
Restricted shares vested	(188,289)	$ 40.05	(35,776)	$ 24.57	(15,000)	$ —
Restricted shares outstanding, end of period	596,590	$ 41.60	503,184	$ 40.04	236,950	$ 34.79

Employee Stock Ownership Plan. In 1996, we established an Employee Stock Ownership Plan ("ESOP") effective January 1, 1996. All employees over the age of 21 with one year of service are participants. This plan has a five-year cliff vesting. The ESOP is designed to enable our employees to accumulate stock ownership. While there will be no employee contributions, participants will receive an allocation of stock that has been contributed by Swift Energy. Compensation expense is recognized upon vesting when such shares are released to employees. The plan may also acquire Swift Energy common stock, purchased at fair market value. The ESOP can borrow money from Swift Energy to buy Swift Energy common stock. ESOP payouts will be paid in a lump sum or installments, and the participants generally have the choice of receiving cash or stock. At December 31, 2007, 2006, and 2005, all of the ESOP compensation was earned. Our contribution to the ESOP plan totaled $0.4 million for the years ended December 31, 2007 and 2006 and $0.2 million for the year ended December 31, 2005, and were made all in common stock, and are recorded as "General and administrative, net" on the accompanying consolidated statements of income. The shares of common stock contributed to the ESOP plan totaled 9,218, 8,927, and 4,438 shares for the 2007, 2006, and 2005 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 2007, $1.0 million for 2006, and $0.8 million for 2005, and are recorded as "General and administrative, net" on the accompanying consolidated statements of income. The contributions in 2007, 2006, and 2005 were made all in common stock. The shares of common stock contributed to the 401(k) savings plan totaled 29,934, 23,890, and 17,920 shares for the 2007, 2006, and 2005 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, 2007, 436,414 shares remain in treasury (net of 533,505 shares used to fund the ESOP, 401(k) contributions and acquisitions) with a total cost of $7.5 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 from 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 2007, $0.5 million in 2006 and $0.4 million in 2005. 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 agreed to sell substantially all of our New Zealand assets for approximately $87.8 million. Accordingly, the New Zealand operations have been classified as discontinued operations in the consolidated statements of income and cash flows and the assets and associated liabilities have been classified as held for sale in the consolidated balance sheets. We began a strategic review of our New Zealand assets in the second quarter of 2007 which culminated in the agreement to sell substantially all of these assets, with an expected closing towards the end of the first quarter of 2008. Proceeds from the New Zealand assets sale will most likely be used to pay down a portion of our credit facility.

In accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-lived Assets" ("SFAS 144"), the results of operations and the non-cash asset write-down for the New Zealand operations have been excluded from continuing operations and reported as discontinued operations for the current and prior periods. Furthermore, the assets included as part of this divestiture have been reclassified as held for sale in the Balance Sheet for prior periods. During the fourth quarter of 2007, the Company assessed its long-lived assets in New Zealand based on the selling price and terms of the sales agreement and recorded a non-cash asset write-down of $143.2 million related to these assets. This write-down is recorded in "Income (loss) from discontinued operations, net of taxes" on the accompanying statements of income.

We expect to sell our remaining permit in New Zealand sometime in 2008. The remaining book value for this permit is approximately $0.5 million which we believe is less than the current fair value of the property. If net proceeds from the sale of this permit exceed $0.5 million then a gain on sale of property will be recorded. If net proceeds from the sale of this permit are less than $0.5 million then a loss on sale of property will be recorded.

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

	2007	2006	2005
Oil and gas sales	$ 42,394	$ 64,039	$ 67,894
Other revenues	1,221	862	999
Total revenues	43,615	64,901	68,893
Depreciation, depletion, and amortization	23,147	30,051	26,354
Other operating expenses	22,491	20,872	20,230
Non-cash write-down of property and equipment	143,152	—	—
Total expenses	188,790	50,923	46,584
Income (loss) from discontinued operations before income taxes	(145,175)	13,978	22,309
Income tax expense (benefit)	(13,874)	3,487	4,412
Income (loss) from discontinued operations, net of taxes	$ (131,301)	$ 10,491	$ 17,898
Earnings per common share from discontinued operations – diluted	$ (4.29)	$ 0.35	$ 0.61
Annual sales volumes (MBoe)	1,387	2,252	2,758
Total assets	$ 110,585	$ 235,997	$ 241,943
Cash flow provided by operating activities	$ 25,620	$ 41,680	$ 48,543
Capital expenditures	$ 9,466	$ 56,707	$ 50,844

For the years 2007, 2006, and 2005, our capitalized general and administrative expenses totaled $4.2 million, $4.1 million, and $4.3 million.

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):

	2007	2006	2005
Income (loss) before tax from discontinued operations	$ (145,175)	$ 13,978	$ 22,309
Income taxes computed at U.S. statutory rate (35%)	$ (50,811)	$ 4,892	$ 7,809
Effect of foreign operations	6,336	(293)	(452)
Currency exchange impact on foreign tax calculation	(1,659)	(1,346)	(2,769)
Valuation allowance	33,502	—	—
Other	(1,242)	234	(176)
Total income tax expense related to discontinued operations	$ (13,874)	$ 3,487	$ 4,412
Effective tax rate	9.6%	24.9%	19.8%

The tax effects of temporary differences that give rise to significant portions of the deferred assets (liabilities) associated with assets held for sale at December 31, 2007 and 2006 are as follows (in thousands):

	2007	2006
Non-current deferred tax assets		
Loss carryover items net of valuation allowance	$ —	$ (55,197)
Other	—	(1,204)
Total deferred tax assets	—	(56,401)
Non-current deferred tax liabilities		
Oil and gas exploration and development costs	—	68,910
Total deferred tax liabilities	—	68,910
Net deferred tax liabilities	$ —	$ 12,509

The 2007 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 is attributable to New Zealand tax loss carryovers in excess of the amounts that will be utilized to offset the proceeds from the $87.8 million asset sale. As of December 31, 2007, management assessed that the probability of generating additional taxable income to utilize these loss carryovers was less than more likely than not. Accordingly, the provision for income tax for discontinued operations includes a valuation allowance charge for the full amount of the deferred tax asset. If the Company's remaining assets are sold in excess of tax basis, these loss carryovers will be available to offset such a gain.

Until the decision was made to sell the Company's New Zealand assets, no provision had been made for U.S. income tax on New Zealand earnings. Management had maintained a plan to reinvest earnings from New Zealand indefinitely. Because of the losses on liquidation, we anticipate that the distribution of sales proceeds to the U.S. will be deemed a return of capital for U.S. income tax purposes. Accordingly, no provision has been made for U.S. income tax.

The following presents the main classes of assets and liabilities associated with the New Zealand operations that are held for sale as of December 31, 2007 and 2006 (in thousands).

	2007	2006
Assets		
Property and equipment, net	$ 96,549	$ —
Total current assets held for sale	$ 96,549	$ —
Property and equipment, net	$ —	$ 252,380
Total long-term assets held for sale	$ —	$ 252,380
Liabilities		
Asset retirement obligation	$ 8,066	$ —
Deferred income taxes	—	—
Total current liabilities associated with assets held for sale	$ 8,066	$ —
Asset retirement obligation	$ —	$ 5,666
Deferred income taxes	—	12,509
Total long-term liabilities associated with assets held for sale	$ —	$ 18,175

9. Acquisitions and Dispositions

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 refer to these properties as the Cotulla properties. 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" and $8.9 million to "Unproved Properties" and recorded a liability for $0.6 million to "Asset retirement obligation" on our accompanying consolidated balance sheet. These acquisitions were accounted for by the purchase method of accounting. We made these acquisitions to increase our exploration and development opportunities in South Texas. The revenues and expenses from these properties have been included in our accompanying consolidated statement of income from the date of acquisition forward; however, given that the acquisitions closed in the fourth quarter of 2007, these amounts were not material to our full year 2007 results.

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

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

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

In November 2005, we acquired interests in the South Bearhead Creek field in Central Louisiana. We paid approximately $24.3 million in cash for these interests. After taking into account internal acquisition costs of $2.6 million and assumed liabilities of $1.4 million, our total cost was $28.3 million. We allocated $26.2 million of the acquisition price to "Proved Properties" and $2.5 million to "Unproved Properties" and recorded a liability for $0.4 million to "Asset retirement obligation" on our accompanying consolidated balance sheet. In December 2006, we acquired additional interests in this field. We paid approximately $4.5 million in cash for these additional interests. After taking into account internal acquisition costs of $0.1 million, our total cost was $4.6 million. We allocated $4.1 million of the acquisition price to "Proved Properties" and $0.5 million to "Unproved Properties" 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 this area. The revenues and expenses from these properties have been included in our accompanying consolidated statements of income from the date the acquisition closed. However, given the acquisitions closed in November 2005 and December 2006, these amounts were immaterial for both the 2005 and 2006 periods.

10. Condensed Consolidating Financial Information

In December 2005, we amended the indenture for our 9-3/8% Senior Subordinated Notes due 2012, which were redeemed in June 2007, and our 7-5/8% Senior Notes due 2011 to reflect our new holding company organizational structure (as discussed in Note 1). As part of this restructuring our indentures were amended so that both Swift Energy Company and Swift Energy Operating, LLC (a wholly owned indirect subsidiary of Swift Energy Company) became co-obligors of these senior notes and senior subordinated debt. The co-obligations on our Notes due 2011 are full and unconditional and are joint and several. Prior to this restructure, Swift Energy Company was the sole obligor. The following is condensed consolidating financial information for Swift Energy Company, Swift Energy Operating, LLC, and other subsidiaries:

Condensed Consolidating Balance Sheets

(in thousands)	December 31, 2007				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
ASSETS					
Current assets	$ —	$ 89,513	$ 110,437	$ —	$ 199,950
Property and equipment	—	1,760,195	—	—	1,760,195
Investment in subsidiaries (equity method)	836,054	—	760,158	(1,596,212)	—
Other assets	—	28,828	—	(19,922)	8,906
Total assets	$ 836,054	$ 1,878,536	$ 870,595	$(1,616,134)	$ 1,969,051
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$ —	$ 195,542	$ 34,541	$ (19,922)	$ 210,161
Long-term liabilities	—	922,836	—	—	922,836
Stockholders' equity	836,054	760,158	836,054	(1,596,212)	836,054
Total liabilities and stockholders' equity	$ 836,054	$ 1,878,536	$ 870,595	$(1,616,134)	$ 1,969,051

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

(in thousands)	December 31, 2005				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
ASSETS					
Current assets	$ —	$ 92,788	$ 17,410	$ —	$ 110,198
Property and equipment	—	862,717	—	—	862,717
Investment in subsidiaries (equity method)	607,318	—	410,612	(1,017,930)	—
Other assets	—	31,955	221,855	(22,313)	231,497
Total assets	$ 607,318	$ 987,460	$ 649,877	$(1,040,243)	$ 1,204,412
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$ —	$ 85,472	$ 12,949	$ —	$ 98,421
Long-term liabilities	—	491,376	29,610	(22,313)	498,673
Stockholders' equity	607,318	410,612	607,318	(1,017,930)	607,318
Total liabilities and stockholders' equity	$ 607,318	$ 987,460	$ 649,877	$(1,040,243)	$ 1,204,412

Condensed Consolidating Statements of Income

(in thousands)	Year Ended December 31, 2007				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$ —	$ 654,121	$ —	$ —	$ 654,121
Expenses	—	409,565	—	—	409,565
Income (loss) before the following:	—	244,556	—	—	244,556
Equity in net earnings of subsidiaries	21,287	—	152,588	(173,875)	—
Income from continuing operations, before income taxes	21,287	244,556	152,588	(173,875)	244,556
Income tax provision	—	91,968	—	—	91,968
Income from continuing operations	21,287	152,588	152,588	(173,875)	152,588
Loss from discontinued operations, net of taxes	—	—	(131,301)	—	(131,301)
Net income	$ 21,287	$ 152,588	$ 21,287	$ (173,875)	$ 21,287

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

(in thousands)	Year Ended December 31, 2005				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$ —	$ 354,365	$ —	$ —	$ 354,365
Expenses	—	198,236	—	—	198,236
Income (loss) before the following:	—	156,129	—	—	156,129
Equity in net earnings of subsidiaries	115,778	—	97,880	(213,658)	—
Income from continuing operations, before income taxes	115,778	156,129	97,880	(213,658)	156,129
Income tax provision	—	58,249	—	—	58,249
Income from continuing operations	115,778	97,880	97,880	(213,658)	97,880
Income from discontinued operations, net of taxes	—	—	17,898	—	17,898
Net income	$ 115,778	$ 97,880	$ 115,778	$ (213,658)	$ 115,778

Condensed Consolidating Statements of Cash Flows

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

(in thousands)	Year Ended December 31, 2006				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Cash flow from operations	$ —	$ 383,241	$ 41,680	$ —	$ 424,921
Cash flow from investing activities	—	(474,781)	(59,881)	11,115	(523,547)
Cash flow from financing activities	—	46,679	11,115	(11,115)	46,679
Net increase in cash	—	(44,861)	(7,086)	—	(51,947)
Cash, beginning of period	—	44,911	8,094	—	53,005
Cash, end of period	$ —	$ 50	$ 1,008	$ —	$ 1,058

(in thousands)	Year Ended December 31, 2005				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Cash flow from operations	$ —	$ 236,791	$ 48,543	$ —	$ 285,334
Cash flow from investing activities	—	(194,909)	(48,837)	3,672	(240,074)
Cash flow from financing activities	—	2,825	3,672	(3,672)	2,825
Net increase in cash	—	44,706	3,379	—	48,085
Cash, beginning of period	—	205	4,715	—	4,920
Cash, end of period	$ —	$ 44,911	$ 8,094	$ —	$ 53,005

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, 2007:			
Proved oil and gas properties	$ 2,951,712	$ 2,610,469	$ 341,243
Unproved oil and gas properties	107,095	106,643	452
	3,058,807	2,717,112	341,695
Accumulated depreciation, depletion, and amortization	(1,234,401)	(981,449)	(252,952)
Net capitalized costs	$ 1,824,406	$ 1,735,663	$ 88,743
December 31, 2006:			
Proved oil and gas properties	$ 2,264,831	$ 1,932,336	$ 332,495
Unproved oil and gas properties	112,137	95,569	16,568
	2,376,968	2,027,905	349,063
Accumulated depreciation, depletion, and amortization	(915,397)	(808,708)	(106,689)
Net capitalized costs	$ 1,461,571	$ 1,219,197	$ 242,374

Of the $106.6 million of domestic Unproved property costs (primarily seismic and lease acquisition costs) at December 31, 2007, excluded from the amortizable base, $42.6 million was incurred in 2007, $49.2 million was incurred in 2006, $4.5 million was incurred in 2005, and $10.3 million was incurred in prior years. When we are in an active drilling mode, we evaluate the majority of these unproved costs within a two to four year time frame.

Of the $0.5 million of New Zealand Unproved property costs at December 31, 2007, excluded from the amortizable base, $0.1 million was incurred in 2007, $0.1 million was incurred in 2006, $0.1 million was incurred in 2005, and $0.2 million was incurred in prior years.

Capitalized asset retirement obligations have been included in the Proved properties as of December 31, 2007, 2006, and 2005.

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

	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

	Year Ended December 31, 2006		
	Total	Domestic	Discontinued Operations
Acquisition of proved and unproved properties	$ 212,499	$ 212,499	$ —
Lease acquisitions and prospect costs[1]	79,183	68,594	10,589
Exploration	29,286	13,225	16,061
Development[2]	261,143	231,086	30,057
Total acquisition, exploration, and development[3,4]	$ 582,111	$ 525,404	$ 56,707

	Year Ended December 31, 2005		
	Total	Domestic	Discontinued Operations
Acquisition of proved and unproved properties	$ 31,429	$ 31,429	$ —
Lease acquisitions and prospect costs[1]	41,397	34,502	6,895
Exploration	52,350	38,425	13,925
Development[2]	141,082	111,058	30,024
Total acquisition, exploration, and development[3,4]	$ 266,258	$ 215,414	$ 50,844

[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 2007, 2006, and 2005 were $50.2 million, $70.5 million, and $30.4 million, respectively. Domestic costs for seismic data acquisition, included above, were $11.6 million, $23.1 million, and $4.2 million in 2007, 2006 and 2005, respectively. New Zealand costs for seismic data acquisition, included above were $0.5 million in 2007 and $3.8 million in 2006.

[2]Facility construction costs and capital costs have been included in development costs, and totaled $71.3 million, $16.5 million, and $26.9 million for the years ended December 31, 2007, 2006 and 2005.

[3]Includes capitalized general and administrative costs directly associated with the acquisition, exploration, and development efforts of approximately $30.6 million, $28.3 million, and $18.8 million in 2006, 2005, and 2004, respectively. In addition, the total includes $9.5 million, $9.2 million, and $7.2 million in 2007, 2006, and 2005, 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, 2007, 2006, and 2005.

Results of Operations (in thousands).

	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 for income taxes	(108,056)	(121,518)	13,462
Results of producing activities	$ 72,343	$ 199,109	$ (126,766)
Amortization per physical unit of production (equivalent Bbl of oil)	$ 17.39	$ 17.53	$ 16.34

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

	Year Ended December 31, 2005		
	Total	Domestic	Discontinued Operations
Oil and gas sales	$ 423,767	$ 355,373	$ 67,894
Lease operating cost	(47,321)	(34,941)	(12,380)
Severance and other taxes	(42,177)	(37,806)	(4,371)
Depreciation, depletion, and amortization	(106,038)	(79,926)	(26,112)
Accretion of asset retirement obligation	(762)	(627)	(135)
	227,469	202,573	24,896
Provision for income taxes	(80,484)	(75,560)	(4,924)
Results of producing activities	$ 146,985	$ 127,013	$ 19,972
Amortization per physical unit of production (equivalent Bbl of oil)	$ 10.68	$ 11.14	$ 9.47

These results of operations do not include the gains from our hedging activities of $0.2 million and $4.0 million for 2007 and 2006, and losses from our hedging activities of $1.1 million for 2005, respectively. Our lease operating costs per Boe produced were $6.68 in 2007, $5.29 in 2006, and $4.87 in 2005.

The accretion of asset retirement obligation has been included in the 2007, 2006 and 2005 periods.

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

Supplementary Reserves Information. The following information presents estimates of our proved oil and natural gas reserves. Reserves were determined by us and audited by H. J. Gruy and Associates, Inc. ("Gruy"), independent petroleum consultants. Gruy has audited 100% of our domestic proved reserves in each of the last three years, and 100% of our New Zealand proved reserves for 2006 and 2005. Gruy's audit was conducted according to standards approved by the Board of Directors of the Society of Petroleum Engineers, Inc. and included examination, on a test basis, of the evidence supporting our reserves. Gruy's audit was based upon review of production histories and other geological, economic, and engineering data provided by us. Gruy's report dated January 23, 2008, is set forth as an exhibit to the Form 10-K Report for the year ended December 31, 2007, 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, 2004	318,246,294	80,267,208	237,891,835	69,139,043	80,354,459	11,128,165
Revisions of previous estimates[1]	(21,461,605)	(2,199,673)	(13,751,124)	(1,023,808)	(7,710,481)	(1,175,866)
Purchases of minerals in place	9,336,088	3,262,761	9,336,088	3,262,761	—	—
Sales of minerals in place	(3,737,714)	(100,121)	(3,737,714)	(100,121)	—	—
Extensions, discoveries, and other additions	8,699,329	3,819,595	7,275,207	3,722,744	1,424,122	96,851
Production	(23,609,242)	(5,996,714)	(11,739,485)	(5,217,343)	(11,869,757)	(779,371)
Proved reserves as of December 31, 2005	287,473,150	79,053,056	225,274,807	69,783,276	62,198,343	9,269,779
Revisions of previous estimates[1]	(33,631,025)	3,127,635	(34,542,219)	3,135,885	911,194	(8,250)
Purchases of minerals in place	60,187,095	2,922,553	60,187,095	2,922,553	—	—
Sales of minerals in place	(6,122,283)	(708,691)	(6,122,283)	(708,691)	—	—
Extensions, discoveries, and other additions	39,012,428	5,627,297	38,466,980	5,512,795	545,448	114,502
Production	(22,787,948)	(7,902,766)	(13,603,589)	(7,181,287)	(9,184,359)	(721,479)
Proved reserves as of December 31, 2006	324,131,417	82,119,084	269,660,791	73,464,531	54,470,626	8,654,552
Revisions of previous 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
Proved developed reserves:[2]						
December 31, 2004	193,310,761	42,037,852	140,549,052	36,628,873	52,761,709	5,408,979
December 31, 2005	152,001,133	37,989,821	125,367,690	35,298,324	26,633,443	2,691,497
December 31, 2006	151,276,834	34,956,469	133,815,108	33,345,567	17,461,726	1,610,902
December 31, 2007	187,152,308	36,752,529	172,973,952	35,547,583	14,178,356	1,204,946

[1]Revisions of previous estimates are related to upward or downward variations based on current engineering information for production rates, volumetrics, and reservoir pressure. Additionally, changes in quantity estimates are affected by the increase or decrease in crude oil, NGL, and natural gas prices at each year-end. Proved reserves, as of December 31, 2007, were based upon prices in effect at year-end. Our hedges at year-end 2007 consisted of oil and natural gas price floors with strike prices lower than the period end price and did not affect prices used in these calculations. The weighted average of 2007 year-end prices for total, domestic, and discontinued operations were $6.19, $6.65, and $3.08 per Mcf of natural gas, $93.24, $93.24, and $93.20 per barrel of oil, and $54.63, $56.28 and $36.98 per barrel of NGL, respectively. This compares to $5.46, $5.84, and $3.59 per Mcf of natural gas, $60.41, $60.07, and $63.51 per barrel of oil, and $30.93, $31.54 and $26.84 per barrel of NGL as of December 31, 2006, for total, domestic, and discontinued operations, respectively. The weighted average of 2005 year-end prices for total, domestic, and discontinued operations were $8.94, $10.36, and $3.79 per Mcf of natural gas, $60.12, $60.00, and $60.98 per barrel of oil, and $31.40, $33.28 and $19.20 per barrel of NGL, respectively.

[2]At December 31, 2007, 45% of our total reserves were proved developed, compared to 44% at December 31, 2006, and 50% at December 31, 2005. At December 31, 2007, 48% of our domestic reserves were proved developed, compared to 47% at December 31, 2006, and 52% at December 31, 2005. At December 31, 2007, 22% of our New Zealand reserves were proved developed, compared to 25% at December 31, 2006, and 36% at December 31, 2005.

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

	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 gas reserves	$ 2,636,443	$ 2,540,080	$ 96,363

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

	Year Ended December 31, 2005		
	Total	Domestic	Discontinued Operations
Future gross revenues	$ 6,917,104	$ 6,194,561	$ 722,543
Future production costs	(1,334,823)	(1,122,638)	(212,185)
Future development costs	(710,344)	(667,527)	(42,817)
Future net cash flows before income taxes	4,871,937	4,404,396	467,541
Future income taxes	(1,538,800)	(1,461,578)	(77,222)
Future net cash flows after income taxes	3,333,137	2,942,818	390,319
Discount at 10% per annum	(1,173,767)	(1,048,194)	(125,573)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 2,159,370	$ 1,894,624	$ 264,746

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

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

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

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

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

The estimates of cash flows and reserves quantities shown above are based on year-end oil and natural gas prices for each period. Our hedges at year-end 2007 consisted mainly of oil and natural gas price floors with strike prices lower than the period end price and did not affect prices used in these calculations. Subsequent changes to such year-end oil and natural gas prices could have a significant impact on discounted future net cash flows. Under Securities and Exchange Commission rules, companies that follow the full-cost accounting method are required to make quarterly Ceiling Test calculations using hedge adjusted prices in effect as of the period end date presented (see Note 1 to the consolidated financial statements). Application of these rules during periods of relatively low oil and natural gas prices, even if of short-term seasonal duration, may result in non-cash write-downs.

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

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

	Year Ended December 31,		
	2007	2006	2005
Beginning balance	$ 1,868,660	$ 2,159,369	$ 1,464,945
Revisions to reserves proved in prior years—			
Net changes in prices and production costs	1,259,492	(658,283)	1,232,877
Net changes in future development costs	(227,032)	(166,891)	(173,219)
Net changes due to revisions in quantity estimates	7,013	(60,714)	(138,969)
Accretion of discount	266,852	314,345	199,799
Other	(337,698)	(98,479)	17,191
Total revisions	968,627	(670,022)	1,137,679
New field discoveries and extensions, net of future production and development costs	305,843	212,629	152,462
Purchases of minerals in place	209,369	289,339	99,129
Sales of minerals in place	—	(20,378)	(10,164)
Sales of oil and gas produced, net of production costs	(533,934)	(473,625)	(334,268)
Previously estimated development costs incurred	230,046	187,134	100,615
Net change in income taxes	(412,168)	184,214	(451,029)
Net change in standardized measure of discounted future net cash flows	767,783	(290,709)	694,424
Ending balance	$ 2,636,443	$ 1,868,660	$ 2,159,369

Selected Quarterly Financial Data (Unaudited). The following table presents summarized quarterly financial information for the years ended December 31, 2007 and 2006 (in thousands, except per share data):

	Revenues	Income from Continuing Operations Before Income Taxes	Income from Continuing Operations	Income (Loss) from Discontinued Operations	Basic EPS from Continuing Operations	Diluted EPS from Continuing Operations
2007:						
First	$ 130,079	$ 41,917	$ 26,445	$ 1,143	$ 0.89	$ 0.87
Second	156,410	48,557	30,523	987	1.02	1.00
Third	171,272	71,079	42,915	(633)	1.43	1.40
Fourth	196,360	83,003	52,705	(132,798)	1.75	1.71
Total	$ 654,121	$ 244,556	$ 152,588	$ (131,301)	$ 5.09	$ 4.98
2006:						
First	$ 119,440	$ 53,641	$ 33,829	$ 3,487	$ 1.16	$ 1.13
Second	133,361	58,179	36,640	1,528	1.26	1.22
Third	153,447	75,870	46,342	4,469	1.58	1.54
Fourth	144,588	60,618	34,263	1,007	1.16	1.13
Total	$ 550,836	$ 248,308	$ 151,074	$ 10,491	$ 5.16	$ 5.03

There were no extraordinary items in 2007 or 2006. Our New Zealand operations are accounted for as discontinued operations.

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

Form 10-K Excerpts

Item 1. Business

See pages 78 and 79 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 with an expected closing date towards the end of the first quarter of 2008. At year-end 2007, we had estimated proved reserves from our domestic continuing operations of 133.8 MMBoe with a PV-10 of $3.8 billion, while our total estimated proved reserves, both domestically and in New Zealand, were 150.1 MMBoe with a PV-10 Value of $3.9 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 2007 were comprised of approximately 43% crude oil, 44% natural gas, and 13% NGLs; and 45% of our total proved reserves were proved developed. Our proved reserves are concentrated with 59% of the total in Louisiana, 29% in Texas, 1% in other states, and 11% in New Zealand.

We currently focus primarily on development and exploration of fields in three domestic regions:

- South Louisiana Region
  - Bay de Chene Area
  - Bayou Penchant Area
  - Bayou Sale Area
  - Cote Blanche Island Area
  - High Island Area
  - Horseshoe Bayou Area
  - Jeanerette Area
  - Lake Washington Area
- South Texas Region
  - AWP Olmos Area
  - Cotulla Area
- Toledo Bend Region
  - Brookeland Area
  - Masters Creek Area
  - South Bearhead Creek Area

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 domestic proved reserves from 99.0 MMBoe to 133.8 MMBoe over the five-year period ended December 31, 2007. Over the same period, our annual domestic production has grown from 5.7 MMBoe to 10.6 MMBoe. Our growth in reserves and production over this five-year period has resulted primarily from drilling activities and acquisitions in our three core domestic regions. During 2007, our domestic proved reserves increased by 13%, due to acquisitions of properties in our South Texas region and our 2007 drilling results. Based on our long-term historical performance and our business strategy going forward, we believe that we have the opportunities, experience, and knowledge to grow 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 our anchor assets in each of our three domestic regions 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, and in 2007 we replaced 245% of our domestic 2007 production and over the last five years we have replaced 187% of our domestic production.

For 2008, we are targeting total production from continuing operations to increase 10% to 15% and proved reserves from continuing operations to increase 5% to 9% over 2007 levels.

Our 2008 capital expenditures are currently budgeted at $425 million to $475 million, net of minor non-core dispositions and excluding any property acquisitions.

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 adverse weather conditions, commodity market factors, and governmental regulations, could limit our ability to drill wells and acquire proved properties in the future. We have included below a listing of the vintages of our proved undeveloped reserves in the table titled "Proved Undeveloped Reserves" and believe this table will provide an understanding of the time horizon required to convert proved undeveloped reserves to oil and natural gas production. Our reserves additions for each year are estimates. Reserves volumes can change over time and therefore cannot be absolutely known or verified until all volumes have been produced and a cumulative production total for a well or field can be calculated. Many factors will impact our ability to access these reserves, such as availability of capital, commodity prices, new and existing government regulations, adverse weather conditions, competition within our industry, the requirement of new or upgraded infrastructure at the production site, and technological advances.

Concentrated Focus on Regions with Operational Control

The concentration of our operations in three domestic regions 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 $6.68, $5.29, and $4.87 per Boe in 2007, 2006, and 2005, respectively. Each of our three regions includes at least one anchor asset, previously termed a core area, and several diversity 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, 2007. 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 three domestic regions. 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 15,900 Boe for the quarter ended December 31, 2007. We have also increased our proved reserves in the area from 7.7 million Boe to approximately 36.4 million Boe as of December 31, 2007. When we first acquired our interests in AWP Olmos, Brookeland, and Masters Creek, these areas also had significant additional development potential. In December 2004, we acquired our Bay de Chene and Cote Blanche Island fields, which hold mainly 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 in the Maverick Basin that total approximately 82,000 acres. These properties are located in the Sun TSH area in La Salle County, the Briscoe Ranch area primarily in Dimmitt County, and the Las Tiendas area 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 three domestic regions.

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, 2007, our debt to capitalization was approximately 41%, while our debt to domestic proved reserves ratio was $4.39 per Boe, and our debt to domestic PV-10 ratio was 15%. 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. The combination of hedging with collars, floors, and forward sales will provide for a more stable cash flow for the periods covered as described in the "Commodity Risk" section of this report.

Experienced Technical Team and Technology Utilization

We employ 61 oil and gas professionals, including geophysicists, petrophysicists, geologists, petroleum engineers, and production and reservoir engineers, who have an average of approximately 24 years of experience in their technical fields and have been employed by us for an average of over 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 seismic technology to enhance the results of our drilling and production efforts, including two- and three-dimensional seismic acquisition, pre-stack image enhancement reprocessing, amplitude versus offset datasets, coherency cubes, and detailed field reservoir depletion planning. In 2004, we completed our 3-D seismic survey covering our Lake Washington area. In 2007 we utilized this seismic data to drill all of our exploratory and development wells. In 2005, we began a seismic program that encompasses 77 square miles in our Cote Blanche Island area, which was completed in 2006, and have used this data to drill new wells in that area. We now have seismic data covering over 4,000 square miles in South Louisiana that has been merged into two data sets, inclusive of data covering five fields we acquired in 2006 that will form the base dataset for our regional exploration and development program. This data will be analyzed over the next several years, feeding our acquisition and organic growth led strategies.

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 Olmos area.

We also employ measurement-while-drilling techniques extensively in our South Louisiana region, which allows us to guide the drill bit during the drilling process. This technology allows the well bore path to be steered parallel to the salt face and to intersect multiple targeted sands in a single well bore.

Item 2. Properties

Domestic Operating Areas (Continuing Operations)

The following table sets forth information regarding our 2007 year-end proved reserves from continuing operations of 133.8 MMBoe and production of 10.6 MMBoe by area:

Area	Developed (MMBoe)	Undeveloped (MMBoe)	Total (MMBoe)	% of Domestic Reserves	% of Domestic Production	% Oil and NGLs
Lake Washington	18.5	17.9	36.4	27.2%	62.0%	92.1%
Bay de Chene	2.3	2.4	4.7	3.5%	5.7%	39.9%
Other South Louisiana	7.3	25.2	32.5	24.3%	9.1%	40.1%
Total South Louisiana	28.1	45.5	73.6	55.0%	76.8%	65.8%
AWP	16.3	6.1	22.4	16.8%	10.7%	29.1%
Cotulla	9.5	6.9	16.4	12.2%	2.8%	51.5%
Other South Texas	0.3	0.1	0.4	0.3%	0.8%	5.8%
Total South Texas	26.1	13.1	39.2	29.3%	14.3%	38.2%
Austin Chalk	4.7	7.9	12.6	9.4%	4.9%	64.3%
South Bearhead Creek	4.1	2.7	6.8	5.1%	3.3%	67.5%
Total Toledo Bend	8.8	10.6	19.4	14.5%	8.2%	65.4%
Total	63.0	69.2	132.2	98.8%	99.2%	57.6%
Total Louisiana	34.6	53.5	88.1	65.9%	82.1%	66.2%
Total Texas	28.4	15.7	44.1	32.9%	17.1%	40.2%

Domestic Regional Focus Areas

Our domestic regions consist of three main regions located in South Louisiana, South Texas and Toledo Bend, which straddles the Texas and Louisiana border. South Texas is the oldest of our core regions, with our operations being established in the AWP Olmos area in 1989 and the acquisition of the Sun TSH, Briscoe Ranch, and Las Tiendas fields during 2007, which comprise our Cotulla area. In mid-1998, we acquired the Masters Creek and Brookeland areas in the Toledo Bend region, with South Bearhead Creek being our most recent acquisition in this region during late 2005. In South Louisiana, we established our operations when we acquired majority interests in producing properties in the Lake Washington field in early 2001, adding Bay de Chene and Cote Blanche Island in December 2004, and adding five fields in 2006: Bayou Sale, Bayou Penchant, High Island, Horseshoe Bayou, and Jeanerette.

South Louisiana

Lake Washington Area. As of December 31, 2007, we owned drilling and production rights in 32,075 net acres in the Lake Washington area located in Plaquemines Parish in South Louisiana. Approximately 92% of our proved reserves of 36.4 MMBoe in this area at December 31, 2007, were oil and NGLs. To date, we have primarily produced from multiple Miocene sands ranging in depth from greater than 2,000 feet to 13,000 feet. The field is located on a salt dome and has produced over 300 million Boe since its discovery in the 1930s. The area around the dome is heavily faulted, thereby creating a large number of potential traps. Oil and natural gas from approximately 141 producing wells and 35 shut-in wells is gathered to three platforms located in water depths from two to 12 feet, with drilling and workover operations performed with rigs on barges.

In 2007, we drilled 22 development wells, of which 18 wells were completed. At year-end 2007, we had 113 proved undeveloped locations in this field. Our planned 2008 capital expenditures in this area will focus on drilling from 23 to 27 wells, along with the construction of a facility on the west side of the field, which is expected to be commissioned in the first half of 2008, to further improve the deliverability and efficiency in this area.

Bay de Chene Area. Bay de Chene is located in Jefferson Parish and Lafourche Parish in South Louisiana in close proximity to Lake Washington. As of December 31, 2007, we owned drilling and production rights in 18,546 net acres in Bay de Chene, and successfully drilled two development wells in this field. At year-end 2007, we had seven proved undeveloped locations in the Bay de Chene field. During 2008, we plan to drill up to five wells in Bay de Chene. Production in the Bay de Chene area is currently constrained by the market capacity, and alternative outlets are being pursued by the Company.

*Other South Louisiana Areas.*Cote Blanche Island is in St. Mary Parish which is in South Louisiana. This field holds predominately undeveloped reserves. As of December 31, 2007, we owned drilling and production rights in 15,498 net acres in the Cote Blanche Island field, along with options covering another 8,817 acres. At year-end 2007, we had 25 proved undeveloped locations in the Cote Blanche Island field. During 2008, we plan to drill up to two wells in this area along with processing the 3-D seismic data covering this area that was shot in 2006. In October 2006, we acquired interests in five fields located in five primarily onshore South Louisiana fields: Bayou Sale, Horseshoe Bayou and Jeanerette fields (all located in St. Mary Parish), High Island Field in Cameron Parish and Bayou Penchant Field in Terrebonne Parish. Bayou Sale and Horseshoe Bayou fields are adjacent to each other and located 13 miles southeast of our Cote Blanche Island field. Production in these fields is from formations at depths ranging from 10,000 to 14,000 feet. The Bayou Penchant field was discovered in the 1930s and produces from a number of Middle Miocene sands at depths of 7,000 to 10,000 feet. Bayou Penchant is located approximately 44 miles southeast of Cote Blanche Island and is a non-operated field with Swift holding an average

50% working interest. The High Island field is located 65 miles west of Cote Blanche Island and was discovered in 1983. The Jeanerette field is positioned on the flank of a large salt dome and approximately 12 miles north of Cote Blanche Island. Jeanerette Field produces from the Planulina sands in the 10,000 feet to 15,000 feet depth range. We plan to initiate an exploration and development program in 2008 to drill proved undeveloped and probable locations, recomplete several wells, enhance facilities and improve per unit operating costs in these five fields. During 2008, we plan to drill up to five wells in these areas.

In 2007, we successfully drilled one well in the Bayou Sale field.

South Texas

AWP Olmos Area. As of December 31, 2007, we owned drilling and production rights in 29,107 net acres in the AWP Olmos Area in South Texas. We have extensive experience with low-permeability, tight-sand formations typical of this area, having acquired our first acreage there in 1988. These reserves are approximately 71% natural gas. At year-end 2007, we owned interests in and operated 536 wells in this area producing oil and natural gas from the Olmos sand formation at depths of approximately 9,000 to 11,500 feet. We own nearly 100% of the working interests in all these operated wells.

In 2007, we completed 21 development wells in this area and performed 16 fracture enhancements. At year-end 2007, we had 98 proved undeveloped locations. Our planned 2008 capital expenditures will focus on drilling 10 to 15 wells in this area.

Cotulla Area. In October 2007, we acquired interests in three South Texas properties in the Maverick Basin. These properties are located in the Sun TSH area in La Salle County, the Briscoe Ranch area primarily in Dimmitt County, and the Las Tiendas area in Webb County.

As of December 31, 2007, we owned drilling and production rights in 81,986 net acres in the Cotulla area, owned interests in and operated 205 wells, and had 89 proved undeveloped locations. In 2007, we drilled seven development wells in this area, of which six were completed. Our planned 2008 capital expenditures will focus on drilling 30 to 36 wells in this area.

Toledo Bend

Brookeland Area. As of December 31, 2007, we owned drilling and production rights in 79,308 net acres and 3,500 fee mineral acres in the Brookeland area. This area is located in East Texas near the border of Louisiana in Jasper and Newton counties. We primarily drill horizontal wells and produce from the Austin Chalk formation in this area. The reserves are approximately 57% oil and natural gas liquids. At year-end 2007, we had ten proved undeveloped locations.

Masters Creek Area. As of December 31, 2007, we owned drilling and production rights in 40,509 net acres and 91,534 fee mineral acres in the Masters Creek area. This area is located in Central Louisiana near the Texas-Louisiana border in the two parishes of Vernon and Rapides. It contains horizontal wells producing both oil and natural gas from the Austin Chalk formation. The reserves are approximately 69% oil and NGLs. At year-end 2007, we had nine proved undeveloped locations. We plan on drilling one to two wells in the Austin chalk area in 2008.

South Bearhead Creek Area. In November and December 2005, and then in December 2006, we acquired interests in the South Bearhead Creek field, which is located in the Toledo Bend region approximately 50 miles south of our Masters Creek field and 30 miles north of Lake Charles, Louisiana. Oil and natural gas are produced in this area predominantly from the upper and lower Wilcox sands at depths ranging from approximately 10,600 to 14,100 feet. The field also has production in the Cockfield sands at approximately 8,000 to 8,500 feet. South Bearhead Creek field was discovered in 1958 by a major oil company. It is a large east-west trending anticlinal closure and has had cumulative production of over 4 million Boe.

In 2007, we drilled 11 development wells in the area, all of which were successful. As of December 31, 2007, we owned drilling and production rights in 7,176 net acres in the South Bearhead Creek area. At year-end 2007, we had 18 proved undeveloped locations in this field. Our 2008 plans for this area include drilling up to four wells.

Domestic Dispositions. In April 2006, we sold our minority interest in the natural gas processing plant and related infrastructure that serves the Brookeland and the Masters Creek areas within our Toledo Bend region. In December 2006, we sold our interest in wells in the Garcia Ranch area within the South Texas region.

New Zealand Areas (Discontinued Operations)

In December 2007, Swift agreed to sell substantially all of our New Zealand assets for approximately $87.8 million. Accordingly, the New Zealand operations have been classified as discontinued operations in the consolidated statements of income and cash flows and the assets and associated liabilities have been classified as held for sale in the consolidated balance sheets. We began a strategic review of our New Zealand assets in the second quarter of 2007 which culminated in the agreement to sell the majority of these assets in the fourth quarter of 2007, with an expected closing towards the end of the first quarter of 2008. The remaining assets are expected to be sold in the later part of 2008. Proceeds from the New Zealand assets sale will most likely be used to pay down a portion of our credit facility.

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 and in New Zealand as of December 31, 2007, 2006, and 2005. The information set forth in the tables regarding reserves is based on proved reserves reports prepared by us. H.J. Gruy and Associates, Inc., Houston, Texas, independent petroleum engineers, has audited 100% of our domestic proved reserves in each of the last three years and 100% of our New Zealand proved reserves for 2006 and 2005. The audit by H.J. Gruy and Associates, Inc. was conducted according to the *Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information* approved by the Board of Directors of the Society of Petroleum Engineers, Inc. Based on its investigations, it is the judgment of H.J. Gruy and Associates, Inc. that Swift used appropriate engineering, geologic, and evaluation principles and methods that are consistent with practices generally accepted in the petroleum industry. Reserves estimates are based on extrapolation of established performance trends, material balance calculations, volumetric calculations, analogy with the performance of comparable wells, or a combination of these methods. The classification and definitions of all proved reserves estimates are in accordance with Rule 4-

10 of Regulation S-X and the auditing process as described in the Society of Petroleum Engineers document *Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information*.

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

Estimates of future net revenues from our proved reserves and their PV-10 Value are made using oil and natural gas sales prices in effect as of the dates of such estimates excluding the effects of hedging and are held constant, for that year's reserves calculation, throughout the life of the properties, except where such guidelines permit alternate treatment, including, in the case of natural gas contracts, the use of fixed and determinable contractual price escalations. We have interests in certain tracts that are estimated to have additional hydrocarbon reserves that cannot be classified as proved and are not reflected in the following tables. Our hedges at year-end 2007 consisted of oil and natural gas price floors with strike prices lower than the period-end price and did not affect prices used in these calculations. The weighted averages of such year-end 2007 prices domestically were $6.65 per Mcf of natural gas, $93.24 per barrel of oil, and $56.28 per barrel of NGL, compared to $5.84, $60.07, and $31.54 at year-end 2006 and $10.36, $60.00, and $33.28 at year-end 2005, respectively. The weighted averages of such year-end 2007 prices for New Zealand were $3.08 per Mcf of natural gas, $93.20 per barrel of oil, and $36.98 per barrel of NGL, compared to $3.59, $63.51, and $26.84 in 2006 and $3.79, $60.98, and $19.20 in 2005, respectively. The weighted averages of such year-end 2007 prices for all our reserves, both domestically and in New Zealand, were $6.19 per Mcf of natural gas, $93.24 per barrel of oil, and $54.63 per barrel of NGL, compared to $5.46, $60.41, and $30.93 in 2006 and $8.94, $60.12, and $31.40 in 2005, respectively.

The following tables set forth estimates of future net revenues presented on the basis of unescalated prices and costs in accordance with criteria prescribed by the SEC and their PV-10 Value as of December 31, 2007, 2006, and 2005. Operating costs, development costs, asset retirement obligation costs, and certain production-related taxes were deducted in arriving at the estimated future net revenues. No provision was made for income taxes. The estimates of future net revenues and their present value differ in this respect from the standardized measure of discounted future net cash flows set forth in supplemental information to our consolidated financial statements, which is calculated after provision for future income taxes. We combine NGL volumes with oil volumes solely for reserves volumes reporting purposes. We apply oil prices to proved oil reserves volumes and apply NGL prices to proved NGL reserves volumes in determining both the PV-10 and standardized measure values. PV-10 is a non-GAAP measure; see the reconciliation of this non-GAAP measure to the closest GAAP measure, the standardized measure, in the section below this table.

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

	As of December 31, 2006		
Estimated Proved Oil and Natural Gas Reserves	Total	Domestic	Discontinued Operations
Natural gas reserves (MMcf):			
Proved developed	151,276	133,815	17,462
Proved undeveloped	172,855	135,846	37,009
Total	324,131	269,661	54,471
Oil reserves (MBbl):			
Proved developed	34,956	33,346	1,611
Proved undeveloped	47,163	40,119	7,044
Total	82,119	73,465	8,655
Total Estimated Reserves (MBoe)	136,141	118,408	17,733
Estimated Discounted Present Value of Proved Reserves (in millions)			
Proved developed	$ 1,382	$ 1,307	$ 75
Proved undeveloped	1,326	1,137	189
PV-10 Value	$ 2,708	$ 2,444	$ 264

	As of December 31, 2005		
Estimated Proved Oil and Natural Gas Reserves	Total	Domestic	Discontinued Operations
Natural gas reserves (MMcf):			
Proved developed	152,001	125,368	26,633
Proved undeveloped	135,472	99,907	35,565
Total	287,473	225,275	62,198
Oil reserves (MBbl):			
Proved developed	37,990	35,298	2,691
Proved undeveloped	41,063	34,485	6,579
Total	79,053	69,783	9,270
Total Estimated Reserves (MBoe)	126,965	107,329	19,636
Estimated Discounted Present Value of Proved Reserves (in millions)			
Proved developed	$ 1,721	$ 1,612	$ 109
Proved undeveloped	1,450	1,248	202
PV-10 Value	$ 3,171	$ 2,860	$ 311

Proved reserves are estimates of hydrocarbons to be recovered in the future. Reservoir engineering is a subjective process of estimating the sizes of underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Reserves reports of other engineers might differ from the reports contained herein. Results of drilling, testing, and production subsequent to the date of the estimate may justify revision of such estimates. Future prices received for the sale of oil and natural gas may be different from those used in preparing these reports. The amounts and timing of future operating and development costs may also differ from those used. Accordingly, reserves estimates are often different from the quantities of oil and natural gas that are ultimately recovered. There can be no assurance that these estimates are accurate predictions of the present value of future net cash flows from oil and natural gas reserves.

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

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

	As of December 31, 2006		
(In millions)	Total	Domestic	Discontinued Operations
PV-10 Value	$ 2,708	$ 2,444	$ 264
Future income taxes (discounted at 10%)	(800)	(778)	(22)
Asset retirement obligations (discounted at 10%)	(39)	(34)	(5)
Standardized Measure of Discounted Future Net Cash Flows Relating to Oil and Gas Reserves	$ 1,869	$ 1,632	$ 237

	As of December 31, 2005		
(In millions)	Total	Domestic	Discontinued Operations
PV-10 Value	$ 3,171	$ 2,860	$ 311
Future income taxes (discounted at 10%)	(984)	(942)	(42)
Asset retirement obligations (discounted at 10%)	(27)	(23)	(4)
Standardized Measure of Discounted Future Net Cash Flows Relating to Oil and Gas Reserves	$ 2,159	$ 1,895	$ 265

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, 2007:

Year Added	Volume (MMBoe)	% of PUD Volumes	PV-10 Value (in millions)	% of PUD PV-10 Value
2007	17.1	25%	$ 351.1	20%
2006	13.5	19%	372.5	21%
2005	12.6	18%	410.9	23%
2004	11.9	17%	339.1	19%
2003	2.9	4%	111.3	6%
Prior to 2003	11.4	17%	205.3	11%
Total	69.4	100%	$1,790.2	100%

Sensitivity of Domestic Reserves to Pricing

As of December 31, 2007, a 5% increase in oil and NGL pricing would increase our total estimated domestic proved reserves of 133.8 MMBoe by approximately 0.1 MMBoe, and increase the domestic PV-10 Value of $3.8 billion by approximately $186 million. Similarly, a 5% decrease in oil and NGL pricing would decrease our total estimated domestic proved reserves by approximately 0.1 MMBoe and decrease the domestic PV-10 Value by approximately $186 million.

As of December 31, 2007 a 5% increase in natural gas pricing would increase our total estimated domestic proved reserves by approximately 0.1 MMBoe and increase the domestic PV-10 Value by approximately $59 million. Similarly, a 5% decrease in natural gas pricing would decrease our total estimated domestic proved reserves by approximately 0.1 MMBoe and decrease the domestic PV-10 Value by approximately $59 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, 2007:			
Gross	504	761	1,265
Net	437.4	719.9	1,157.3
December 31, 2006:			
Gross	423	662	1,085
Net	353.4	562.4	915.8
December 31, 2005:			
Gross	402	565	967
Net	324.8	497.5	822.3

[1]Excludes 65 service wells in 2007, 51 service wells in 2006, and 49 service wells in 2005.

[2]Includes 49 wells in New Zealand in both 2007 and 2006, and 45 wells in 2005.

Oil and Gas Acreage

The following table sets forth the developed and undeveloped leasehold acreage held by us at December 31, 2007:

	Developed[1]		Undeveloped[1]	
	Gross	Net	Gross	Net
Alabama	9,629	2,600	81	80
Alaska	—	—	41,194	14,017
Louisiana	123,917	106,456	57,306	52,180
Texas	145,002	105,400	82,942	78,152
Wyoming	640	151	27,711	25,916
All other states	320	267	400	258
Offshore Louisiana	4,609	277	5,000	258
Total Domestic	284,117	215,151	214,634	170,861
New Zealand	9,960	9,912	580,169	310,354
Total	294,077	225,063	794,803	481,215

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

Drilling Activities

The following table sets forth the results of our drilling activities during the three years ended December 31, 2007:

Year	Type of Well	Gross Wells Total	Gross Wells Producing	Gross Wells Dry	Net Wells Total	Net Wells Producing	Net Wells Dry
2007	Exploratory–Domestic	5	2	3	5.0	2.0	3.0
	Development–Domestic	64	59	5	62.6	58.1	4.5
	Exploratory–New Zealand	—	—	—	—	—	—
	Development–New Zealand	—	—	—	—	—	—
2006	Exploratory–Domestic	6	—	6	5.5	—	5.5
	Development–Domestic	49	42	7	47.6	40.6	7.0
	Exploratory–New Zealand	4	—	4	4.0	—	4.0
	Development–New Zealand	4	3	1	4.0	3.0	1.0
2005	Exploratory–Domestic	9	5	4	9.0	5.0	4.0
	Development–Domestic	45	37	8	44.3	36.3	8.0
	Exploratory–New Zealand	5	1	4	3.7	1.0	2.7
	Development–New Zealand	5	2	3	5.0	2.0	3.0

Operations

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

Oil and natural gas properties are customarily operated under the terms of a joint operating agreement. These agreements usually provide for reimbursement of the operator's direct expenses and for payment of monthly per-well supervision fees. Supervision fees vary widely depending on the geographic location and depth of the well and whether the well produces oil or natural gas. The fees for these activities in 2007 totaled $11.8 million and ranged from $500 to $2,495 per well per month.

Marketing of Production

Domestically, we typically sell our oil and natural gas production at market prices near the wellhead or at a central point after gathering and/or processing. We usually sell our natural gas in the spot market on a monthly basis, while we sell our oil at prevailing market prices. We do not refine any oil we produce. In 2007 and 2006, several companies accounted for 10% or more of our total revenues. Shell Oil Company and its affiliates, both domestically and in New Zealand, accounted for approximately 42% and 30% of our total oil and gas sales in 2007 and 2006, respectively. In 2007 and 2006, Chevron and its domestic affiliates accounted for 22% and 32% of our total oil and gas sales, respectively. However, due to the demand for oil and natural gas and availability of other purchasers, we do not believe that the loss of any single oil or natural gas purchaser or contract would materially affect our revenues.

Our oil production from the Lake Washington area 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 area is either consumed on the lease or is delivered into El Paso's Tennessee Gas Pipeline system and then sold in the spot market at prevailing prices. Natural gas delivered into Tennessee Gas Pipeline is processed at the Yscloskey plant. In the first half of 2008, we plan to complete a connection which will also provide for the delivery of natural gas from this area to El Paso's Southern Natural Gas pipeline system.

In 1998, we entered into gas processing and gas transportation agreements for our natural gas production in the AWP Olmos area with PG&E Energy Trading Corporation, which was assumed in December 2000 by El Paso Hydrocarbon, LP, and El Paso Industrial, LP, and then assumed by Enterprise Hydrocarbons L.P. in September 2004, for up to 75,000 Mcf per day, which provided for a ten-year term with automatic one-year extensions unless terminated earlier. Discussions regarding replacement gas processing and gas transportation agreements are ongoing with Enterprise and other providers of such services in the area.

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

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

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

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

The following table summarizes domestic 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, 2007:

	Year Ended December 31,		
	2007	2006	2005
Domestic Net Sales Volume:			
Oil (MBbls)	7,045	6,721	4,709
Natural Gas Liquids (MBbls)	774	460	508
Natural Gas (MMcf)	16,782	13,604	11,739
Total (MBoe)	10,617	9,449	7,174
Domestic Average Sales Price:			
Oil (per Bbl)	$71.92	$64.28	$53.45
Natural Gas Liquids (per Bbl)	$49.72	$38.70	$34.00
Natural Gas (per Mcf)	$6.42	$6.44	$7.40
Average Production Cost (per Boe)	$13.63	$11.77	$10.14

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 annual report. The prices above do not include the effects of hedging. The hedge adjusted prices are detailed in the "Management's Discussion and Analysis of Financial Condition and Results of Operations" section of this annual report.

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. 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. At December 31, 2007, we had price floors in place through the March 2008 contract month for oil and natural gas; these cover a portion of our domestic oil and natural gas production for January 2008 through March 2008. The oil floors cover notional volumes of 639,000 barrels, with a weighted average floor price of $71.22 per barrel, and the natural gas price floors cover notional volumes of 1,330,000 MMBtu, with a weighted average floor price of $6.90 per MMBtu. Our oil price floors in place at December 31, 2007 are expected to cover approximately 40% to 45% of our domestic oil production during the first quarter of 2008, and our natural gas price floors in place at December 31, 2007 are expected to cover approximately 40% to 45% of our domestic natural gas production from February 2008 to March 2008.

Employees

At December 31, 2007, we employed 360 persons. Of these employees, 62 were in New Zealand, including two expatriate employees. Eleven of our New Zealand employees are members of a union. None of our other employees are represented by a union. Relations with employees are considered to be good. Upon closing of the sale of our New Zealand assets; we will have no employees in New Zealand other than expatriate employees.

Available Information

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, amendments to those reports, changes in and stock ownership of our directors and executive officers, together with other documents filed with the Securities and Exchange Commission under the Securities Exchange Act can be accessed free of charge on our web site at www.swiftenergy.com as soon as reasonably practicable after we electronically file these reports with the SEC. All exhibits and supplemental schedules to these reports are available free of charge through the SEC web site at www.sec.gov. In addition, we have adopted a Code of Ethics for Senior Financial Officers and Principal Executive Officer. We have posted this Code of Ethics on our website, where we also intend to post any waivers from or amendments to this Code of Ethics.

Glossary of Abbreviations and Terms

The following abbreviations and terms have the indicated meanings when used in this report:

Bbl — Barrel or barrels of oil.

Bcf — Billion cubic feet of natural gas.

Bcfe — Billion cubic feet of natural gas equivalent (see Mcfe).

Boe — Barrels of oil equivalent.

Development Well — A well drilled within the presently proved productive area of an oil or natural gas reservoir, as indicated by reasonable interpretation of available data, with the objective of completing in that reservoir.(1)

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

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

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

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

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

FASB — The Financial Accounting Standards Board.

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

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

MBbl — Thousand barrels of oil.

MBoe — Thousand barrels of oil equivalent.

Mcf — Thousand cubic feet of natural gas.

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

MMBbl — Million barrels of oil.

MMBoe — Million barrels of oil equivalent.

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

MMcf — Million cubic feet of natural gas.

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

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

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

NGL— Natural gas liquid.

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

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

Proved Oil and Gas Reserves — The estimated quantities of crude oil, natural gas, and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, that is, prices and costs as of the date the estimate is made.(4)

Proved Undeveloped Oil and Gas Reserves — Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.(5)

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

PV-10 Value — The estimated future net revenues to be generated from the production of proved reserves discounted to present value using an annual discount rate of 10%. These amounts are calculated net of estimated production costs and future development costs, using prices and costs in effect as of a certain date, without escalation and without giving effect to non-property related expenses, such as general and administrative expenses, debt service, future income tax expense, or depreciation, depletion, and amortization.

SFAS — Statement of Financial Accounting Standards.

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(1) This is only an abbreviated definition. Please refer to Securities and Exchange Commission's definition of this term at Rule 4-10(a)(11) of Regulation S-X.
(2) This is only an abbreviated definition. Please refer to Securities and Exchange Commission's definition of this term at Rule 4-10(a)(10) of Regulation S-X.
(3) This is only an abbreviated definition. Please refer to Securities and Exchange Commission's definition of this term at Rule 4-10(a)(3) of Regulation S-X.
(4) This is only an abbreviated definition. Please refer to Securities and Exchange Commission's definition of this term at Rule 4-10(a)(2) of Regulation S-X.
(5) This is only an abbreviated definition. Please refer to Securities and Exchange Commission's definition of this term at Rule 4-10(a)(4) of Regulation S-X.

NOTICE

Those portions (other than Items 10-14 incorporated by reference to Swift's proxy statement for its 2007 Annual Meeting of Shareholders) of the Form 10-K Report for the year ended December 31, 2007, not included in this Annual Report to Shareholders (including certain portions of Item 1–Business pertaining to "Competition," "Regulations," "Federal Leases," "Facilities," "Litigation," Item 1A–Risk Factors, Item 1B-Unresolved Staff Comments, Item 3–Legal Proceedings, Item 4–Submission of Matters to a Vote of Security Holders, Item 5–Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities pertaining to "Share Performance Graph," Item 9–Changes in and Disagreements with Accountants on Accounting and Financial Disclosure, Item 9A–Controls and Procedures, Item 9B–Other Information, and Item 15–Exhibits, and Financial Statement Schedules), with no disclosures having been made as to Item 4, will be provided without charge to shareholders making a written request to Scott Espenshade, Director of Corporate Development and Investor Relations, Swift Energy Company, 16825 Northchase Drive, Suite 400, Houston, Texas 77060. Exhibits filed as part of the Form 10-K will be provided to shareholders making a written request as set forth above at a reasonable charge sufficient to cover the Company's cost in providing such exhibits.

NYSE Listing Standards

During 2007, our Chief Executive Officer certified to the New York Stock Exchange (NYSE) that he is not aware of any violation by the Company of the NYSE's corporate governance listing standards. The certifications pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 for the year ended December 31, 2007, by our Chief Executive Officer and Chief Financial Officer were included as exhibits to Swift Energy Company's Annual Report on Form 10-K for the year ended December 31, 2007, which was filed with the Securities and Exchange Commission.

INVESTOR INFORMATION

BOARD OF DIRECTORS

Terry E. Swift
Chairman of the Board &
Chief Executive Officer,
Swift Energy Company

Bruce H. Vincent
President & Secretary,
Swift Energy Company

Raymond E. Galvin
Vice Chairman of the Board,
Swift Energy Company,
Retired President,
Chevron U.S.A. Production Company

Deanna L. Cannon
Shareholder & Director, Corporate Finance
Associates of Northern Michigan

Douglas J. Lanier
Retired Vice President,
Gulf of Mexico Business Unit,
ChevronTexaco Exploration &
Production Company

Greg Matiuk
Retired Executive Vice President,
Administrative & Corporate Services,
ChevronTexaco Corporation

Henry C. Montgomery
Chairman & Founder,
Montgomery Professional
Services Corporation

Clyde W. Smith, Jr.
President,
Ascentron, Inc.

Charles J. Swindells
Vice Chairman, Western Region,
U.S. Trust, Bank of America
Private Wealth Management

Raymond O. Loen
Director Emeritus

Virgil N. Swift
Director Emeritus

OFFICERS

Terry E. Swift
Chief Executive Officer

Bruce H. Vincent
President & Secretary

Robert J. Banks
Executive Vice President &
Chief Operating Officer

Alton D. Heckaman, Jr.
Executive Vice President &
Chief Financial Officer

Joseph A. D'Amico
Executive Vice President

James M. Kitterman
Senior Vice President–Operations

James P. Mitchell
Senior Vice President–Commercial
Transactions & Land

John C. Branca
Vice President–Exploration & Development

David P. Coatney
Vice President–Production

Thomas E. Schmidt
Vice President–Operating Compliance &
External Relations

Tara L. Seaman
Vice President–Reserves & Evaluations

Steven B. Yakle
Vice President–Corporate Administration

Laurent A. Baillargeon
General Counsel

Adrian D. Shelley
Treasurer

David W. Wesson
Controller

CORPORATE HEADQUARTERS

Swift Energy Company
16825 Northchase Drive, Suite 400
Houston, Texas 77060
Telephones: (281) 874-2700
(800) 777-2412

PRINCIPAL SUBSIDIARY COMPANIES

Swift Energy Operating, LLC.
Houston, Texas

Swift Energy International, Inc.
Houston, Texas

TRANSFER AGENT AND REGISTRAR

American Stock Transfer
& Trust Company
59 Maiden Lane
Plaza Level
New York, New York 10038

EXCHANGE LISTING

New York Stock Exchange, Inc.
Symbol "SFY"

INDEPENDENT AUDITOR

Ernst & Young LLP
1401 McKinney, Suite 1200
Houston, Texas 77010

COUNSEL

Baker & Hostetler, LLP
1000 Louisiana, Suite 2000
Houston, Texas 77002

COMMON STOCK, 2006 AND 2007

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 2006 and 2007 were as follows:

	2006				2007			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Low	$35.48	$35.61	$40.06	$39.10	$37.37	$39.09	$35.98	$39.89
High	$49.50	$45.22	$48.00	$51.84	$44.91	$45.78	$47.31	$47.72

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 231 stockholders of record as of December 31, 2007.

Annual Meeting
4 p.m., Tuesday, May 13, 2008
The Wyndham Greenspoint Hotel
12400 Greenspoint Dr.
Houston, Texas 77060

SWIFT ENERGY COMPANY

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