BLUE DOLPHIN ENERGY CO
Form 10KSB
April 02, 2007

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-KSB

þ **Annual Report Under Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the fiscal year ended December 31, 2006

o **Transition Report Under Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the transition period from _____ to _____

Commission file Number: 0-15905
BLUE DOLPHIN ENERGY COMPANY
(Name of small business issuer in its charter)

Delaware	**73-1268729**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
801 Travis Street, Suite 2100, Houston, Texas	**77002**
(Address of principal executive office)	(Zip Code)

Issuer s telephone number **(713) 227-7660**

Securities registered pursuant to Section 12(b) of the Exchange Act: **common stock, par value $.01 per share**

Securities registered pursuant to Section 12(g) of the Exchange Act: **none**
(Title of Class)

Check whether the issuer is not required to file reports pursuant to Section 13 or 15 (d) of the Exchange Act. o

Check whether the issuer (1) filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the past 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

Check if there is no disclosure of delinquent filers in response to Item 405 of Regulation S-B contained in this form, and no disclosure will be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-KSB or any amendment to this Form 10-KSB. o

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

The issuer s revenues for the year ended December 31, 2006 were $4,298,708.

The aggregate market value of the common stock, par value $.01 per share, held by non-affiliates of the registrant as of March 23, 2007, was approximately $37,930,000.

As of March 30, 2007, there were 11,559,643 shares of common stock, par value $.01 per share, of the issuer outstanding.

Documents Incorporated By Reference

Certain sections of the registrant s definitive proxy statement for the 2007 Annual Meeting of Stockholders of the registrant (sections entitled Ownership of Securities of the Company, Election of Directors, Executive Compensation and Transactions With Related Persons), which is to be filed with the Securities and Exchange Commission pursuant to Regulation 14A, under the Securities and Exchange Act of 1934 within 120 days of the registrant s fiscal year ended December 31, 2006, are incorporated by reference in Part III of this report.

Transitional Small Business Disclosure Format. Yes o No þ

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Subsidiaries
Consent of UHY LLP
Ivar Siem Certification Pursuant to Section 302
Gregory W. Starks Certification Pursuant to Section 302
Ivar Siem Certification Pursuant to Section 906
Gregory W. Starks Certification Pursuant to Section 906

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PART I

Forward Looking Statements. Certain of the statements included in this annual report on Form 10-KSB, including those regarding future financial performance or results or 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, and Section 27A of the Securities Act of 1933, as amended. The words expect, plan, believe, anticipate, project, estimate, and similar expressions are intended to identify forward-looking statements. Blue Dolphin Energy Company (referred to herein, with its predecessors and subsidiaries, as Blue Dolphin, we, us and our) cautions readers that these statements are not guarantees of future performance or events and such statements involve risks and uncertainties that may cause actual results and outcomes to differ materially from those indicated in forward-looking statements. Some of the important factors, risks and uncertainties that could cause actual results to vary from forward-looking statements include:

the level of utilization of our pipelines;

availability and cost of capital;

actions or inactions of third party operators for properties where we have an interest;

the risks associated with exploration;

the level of production from oil and gas properties that we have interests in;

gas and oil price volatility;

uncertainties in the estimation of proved reserves, in the projection of future rates of production, the timing of development expenditures and the amount and timing of property abandonment;

regulatory developments; and

general economic conditions.

Additional factors that could cause actual results to differ materially from those indicated in the forward-looking statements are discussed under the caption Risk Factors . Readers are cautioned not to place undue reliance on these forward-looking statements which speak only as of the date hereof. We undertake no duty to update these forward-looking statements. Readers are urged to carefully review and consider the various disclosures made by us which attempt to advise interested parties of the additional factors which may affect our business, including the disclosures made under the caption Management s Discussion and Analysis of Financial Condition and Results of Operations in this report.

Item 1. Description of Business

THE COMPANY

Blue Dolphin Energy Company, a Delaware corporation formed in 1986, is a holding company and conducts substantially all of its operations through its subsidiaries. We conduct our business activities in two primary business segments: (i) pipeline transportation and related services for producers/shippers, and (ii) oil and gas exploration and production. Substantially all of our assets consist of equity interests in our subsidiaries. Our operating subsidiaries are:

Blue Dolphin Pipe Line Company, a Delaware corporation;

Blue Dolphin Petroleum Company, a Delaware corporation;

Blue Dolphin Exploration Company, a Delaware corporation; and

Blue Dolphin Services Co., a Texas corporation.

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Our principal executive office is located at 801 Travis Street, Suite 2100, Houston, Texas, 77002, and our telephone number is (713) 227-7660. Our shore-based facilities are maintained in Freeport, Texas, and serve our Gulf of Mexico operations. We have seven employees and two consultants. Our common stock is traded on the NASDAQ Capital Market under the ticker symbol BDCO. Our website address is http://www.blue-dolphin.com.

Certain terms that are commonly used in the oil and gas industry, including terms that define our rights and obligations with respect to our properties, are defined in the Glossary of Certain Oil and Gas Terms of this Form 10-KSB.

Recent Developments

In December 2006, we made the final monthly payment of $10,000 on the $250,000 principal amount of the promissory note payable to MCNIC. In early-2005, we entered into an amendment to our purchase agreement with MCNIC to acquire MCNIC s one-third interest in the Blue Dolphin System and the inactive Omega Pipeline. Pursuant to the terms of the amendment, we issued a new promissory note in the principal amount of $250,000 and either (i) MCNIC could have received an additional contingent payment of up to $500,000 from 50% of the net profits, if any, realized from the one-third interest through December 31, 2006, or (ii) the principal amount of the new promissory note could have been increased by up to $500,000 if 50% or more of our 83% interest in the assets was sold before December 31, 2006. We did not make a contingent payment from 50% of the net profits after the end of 2005, and are not required to make a contingent payment after the end of 2006. The $500,000 contingent portion of the promissory note was extinguished effective December 31, 2006.

In November 2006, we entered into gas and condensate transportation agreements with a new shipper on the GA 350 Pipeline to deliver production into the pipeline in Galveston Area Block 350. In May 2006, we entered into gas and condensate transportation and handling agreements with a new shipper on the Blue Dolphin System to deliver production into the pipeline in Galveston Area Block 273. Both of these new shippers commenced deliveries into the pipeline in 2006.

Throughput on the Blue Dolphin System and GA 350 Pipeline increased significantly during 2006. The Blue Dolphin System is currently transporting approximately 26 MMcf per day and the GA 350 Pipeline is currently transporting approximately 20 MMcf per day for a combined 46 MMcf per day. This level of throughput is approximately 280% greater than the combined level of throughput being transported on the pipelines this time last year. Since mid-2005, we have entered into gas and condensate transportation and handling agreements with the operators of five discoveries on the Blue Dolphin System and the GA 350 Pipeline. We entered into agreements with three shippers in 2005 and, as noted above, two shippers in 2006. All five of these shippers have now commenced deliveries of production into our pipelines. Four of the shippers are delivering production into the Blue Dolphin System and one of the shippers is delivering production into the GA 350 Pipeline. During 2006, one new shipper began deliveries into the Blue Dolphin System in each of May, June and November. Also, in July 2006, a shipper that has delivered production into the Blue Dolphin System for a number of years, successfully recompleted an existing well, resulting in an increase of daily production. One of the five new shippers began deliveries into the Blue Dolphin System in August 2005. The shipper contracted with in November 2006 began deliveries into the GA 350 Pipeline in December 2006.

In April 2006, we completed a private placement with an accredited institutional investor of 400,000 shares of our common stock. Net proceeds from the offering were approximately $1.8 million. We incurred commissions and expenses of approximately $160,000 associated with the offering, and issued warrants to purchase an aggregate of 24,000 shares of common stock. These warrants were immediately exercisable upon issuance and 7,560 of the warrants were exercised in 2006. The exercise price varies based on the following conditions: (i) until the later of the registration of the warrants or one year from the issue date, 110% of the purchase price of $4.90 per share; (ii) from the later of (x) the registration of the

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warrants and (y) one year, until two years from the issue date, 120% of the purchase price of $4.90 per share; and (iii) after the expiration of two years from the issue date of the warrants, 130% of the purchase price of $4.90 per share.

In March 2006, we also completed a private placement with certain accredited investors of 1,171,432 shares of our common stock. The net proceeds from the offering after the payment of commissions and expenses were approximately $2.0 million and we issued warrants to purchase an aggregate of 8,572 shares of common stock. The warrants vested immediately upon issuance and the exercise price per share varied based on the following conditions: (i) until the later of the registration of the warrants or one year from the issue date, 110% of the purchase price of $1.75 per share, (ii) from the later of (x) the registration of the warrants and (y) one year, until two years from the issue date, 120% of the purchase price of $1.75 per share and (iii) after the expiration of two years from the issue date of the warrants, 130% of the purchase price of $1.75 per share. All warrants associated with this offering were exercised in 2006 at an exercise price of $1.93 per share.

The net proceeds from these offerings are being used for general corporate and working capital purposes, and may also be used for possible acquisitions and planned expansions of our facilities.

Pipeline Operations and Activities

Our pipeline assets are held in, and operations conducted by, Blue Dolphin Pipe Line Company.

The economic return on our pipeline system investments and the fees chargeable for these services are dependent upon the amounts of gas and condensate gathered and transported through our pipeline systems. Currently, the level of throughput on our pipeline systems is significantly below full capacity. Competition for provision of gathering and transportation services similar to ours is intense in the market areas we serve. See Competition below. Since contracts for gathering and transportation services with third party producers/shippers may be for specified time periods, there can be no assurance that current or future producers/shippers will not subsequently tie-in to alternative transportation systems or that current rates charged will be maintained in the future. We actively market our gathering and transportation services to producers/shippers operating in the vicinity of our pipeline systems. Future utilization of the pipelines and related facilities will depend upon the success of drilling programs around the pipelines, and the attraction, and retention, of producers/shippers to the systems.

Blue Dolphin Pipeline System. The Blue Dolphin Pipeline System includes the Blue Dolphin Pipeline, an offshore platform, the Buccaneer Pipeline, onshore facilities for condensate and gas separation and dehydration, 85,000 Bbls of above-ground tankage for storage of crude oil and condensate, a barge loading terminal on the Intracoastal Waterway and 360 acres of land in Brazoria County, Texas where the Blue Dolphin Pipeline comes ashore and where the pipeline system shore facilities, pipeline easements and rights-of-way are located (the Blue Dolphin System). We own an 83% undivided interest in the Blue Dolphin System. The Blue Dolphin System gathers and transports gas and condensate from various offshore fields in the Galveston Area of the Gulf of Mexico to shore facilities located in Freeport, Texas. After processing, the gas is transported to an end user and a major intrastate pipeline system with further downstream tie-ins to other intrastate and interstate pipeline systems and end users.

The Blue Dolphin Pipeline consists of two segments, an offshore segment and an onshore segment. The offshore segment transports both gas and condensate and is comprised of approximately 34 miles of 20-inch pipeline originating at an offshore platform in Galveston Area Block 288 and running to shore. The offshore segment also includes the platform in Galveston Area Block 288 and 5 field gathering lines totaling approximately 27 miles, connected to the main 20-inch line. An additional 4 miles of 20-inch pipeline onshore connects the offshore segment to the onshore facility at Freeport, Texas. The onshore segment also includes approximately 2 miles of 16-inch pipeline for transportation of gas from the shore facility to a sales point at a Freeport, Texas chemical plants complex and intrastate pipeline system tie-in.

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The Buccaneer Pipeline, an 8-inch liquids pipeline, transports condensate from the onshore facility storage tanks to our barge-loading terminal on the Intracoastal Waterway near Freeport, Texas for sale to third parties.

Various fees are charged to producers/shippers for provision of transportation and shore facility services. The Blue Dolphin System has an aggregate capacity of approximately 160 MMcf per day of gas and 7,000 Bbls per day of crude oil and condensate. Gas throughput for the Blue Dolphin System averaged approximately 9% and 6% of capacity during 2006 and 2005, respectively. The Blue Dolphin System is currently transporting approximately 26 MMcf of gas per day. All gas and liquids volumes transported in 2006 and 2005 were attributable to production from third party producers/shippers. See Note (12), Business Segment Information, in the Notes to Consolidated Financial Statements in Item 7.

Galveston Area Block 350 Pipeline. We own an 83% ownership interest in the Galveston Area Block 350 Pipeline (the GA 350 Pipeline). The GA 350 Pipeline is an 8-inch, 12.78 mile offshore pipeline extending from Galveston Area Block 350 to an interconnect with a transmission pipeline in Galveston Area Block 391, approximately 14 miles south of the Blue Dolphin Pipeline. Current system capacity on the GA 350 Pipeline is 65 MMcf of gas per day. Gas throughput for the GA 350 Pipeline averaged 9.0 MMcf per day, or approximately 14% of capacity, and 11.6 MMCF per day, or approximately 18% of capacity, during 2006 and 2005, respectively. The pipeline is currently transporting approximately 20 MMcf of gas per day. All gas and liquids volumes transported were attributable to production from third party producer/shippers.

Other. We also own an 83% undivided interest in a third offshore pipeline, the Omega Pipeline, which is currently inactive. The Omega Pipeline originates in the High Island Area, East Addition Block A-173 and extends to West Cameron Block 342, where it was previously connected to the High Island Offshore System. Reactivation of the Omega Pipeline will be dependent upon future drilling activity in the vicinity and successfully attracting producers/shippers to the system.

Oil and Gas Exploration and Production Activities

Although we sold substantially all of our producing oil and gas properties in 2002, we continue our oil and gas exploration and production activities, which include the exploration, acquisition, development, operation and, when appropriate, disposition of oil and gas properties. We focus our oil and gas activities in the western Gulf of Mexico, off the coast of Texas. We currently own seismic and other data that may be used to evaluate and develop prospects, including a non-exclusive license to approximately 200 blocks of 3-D seismic data covering 1,152,000 acres in the western Gulf of Mexico and a substantial inventory of close grid 2-D seismic data. Our oil and gas assets are held by Blue Dolphin Petroleum Company.

The leasehold interests we hold in properties are subject to royalty, overriding royalty and interests of others. In the future, our properties may become subject to burdens and encumbrances typical to oil and gas operators, such as liens incident to operating agreements and current taxes, development obligations under oil and gas leases and other encumbrances.

The following is a description of our oil and gas exploration and production assets and activities:

High Island Block 37. High Island Block 37 is located 15 miles south of Sabine Pass, offshore Texas, in an average water depth of 36 feet. We are entitled to an approximate 2.8% working interest in this lease that covers approximately 5,760 acres. The lease contains two producing wells which are operated by Seneca Resources Corporation. The rate of production from the wells declined by approximately 65% during 2006. The wells are currently producing approximately 8 MMcf per day combined. We recorded gross revenues from sales of oil and natural gas in High Island Block 37 of approximately $890,000 and $2,414,000 for the years ended December 31, 2006 and 2005, respectively.

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High Island Block A-7. High Island Block A-7 is located 33 miles southeast of Bolivar Peninsula, offshore Texas, in an average water depth of 39 feet. We own an approximate 8.9% working interest in this lease that covers approximately 5,760 acres. The lease contains one currently producing well which is operated by Hydro Gulf of Mexico, LLC (formerly Spinnaker Exploration Company). Production from the well has declined by approximately 60% since the end of 2006. The well is currently producing approximately 2 MMcf per day and has provided evidence that it is reaching the end of its production life. During the years ended December 31, 2006 and 2005, we recorded gross revenues from oil and natural gas sales of approximately $1,469,000 and $722,000, respectively, from this field.

Unproved Leasehold Interests. In May 2006, the lease covering our interests in West Cameron Block 212 expired. In November 2005, the leases covering our interests in Galveston Area Blocks 271 and 284 expired.

In December 2004, we placed our interest in Galveston Area Blocks 287 and 297 in the Gulf of Mexico with third parties. These blocks were part of a prospect we generated which also included Galveston Area Block 298. A well was drilled in Galveston Area Block 297 in early 2005, which was not successful. As a result of the placement of our working interest in Galveston Area Blocks 287 and 297, we received proceeds of approximately $160,000 in 2005. The leases for Galveston Area Blocks 287 and 297 have now expired.

Proved Oil and Gas Reserves. We have prepared estimates of proved reserves, future net revenues, and discounted present value of future net revenues to our net interest as of December 31, 2006.

The quantities of proved oil and gas reserves presented below include only those amounts which we reasonably expect to recover in the future from known oil and gas reservoirs under existing economic and operating conditions. Therefore, proved reserves are limited to those quantities that are believed to be recoverable at prices and costs, and under regulatory practices and technology existing at the time of the estimate. Accordingly, changes in oil and gas prices, operation and development costs, regulations, technology, future production and other factors, many of which are beyond our control, could significantly affect the estimates of proved reserves and the discounted present value of future net revenues attributable thereto.

Estimates of production and future net revenues cannot be expected to represent accurately the actual production or revenues that may be recognized with respect to oil and gas properties or the actual present market value of such properties. For further information concerning our proved reserves, changes in proved reserves, estimated future net revenues and costs incurred in our oil and gas activities and the discounted present value of estimated future net revenues from our proved reserves, see Note (13), Supplemental Oil and Gas Information, in the Notes to Consolidated Financial Statements in Item 7.

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The following table presents the estimates of proved reserves, proved developed reserves, and proved undeveloped reserves (as hereinafter defined), future net revenues and the discounted present value of future net revenues from proved reserves after income taxes (in thousands) to our net interest in oil and gas properties as of December 31, 2006. The discounted present value of future net revenues and future net revenues are calculated using the SEC Method (defined below) and are not intended to represent the current market value of the oil and gas reserves we own.

PROVED RESERVES
As of December 31, 2006[1][2]

	Net Oil Reserves (Mbbls)	Net Gas Reserves (MMcf)	Present Value of Future Net Cash Inflows (Outflows) After Income Taxes [1]
Total Proved Reserves			
High Island Block A-7	0.1	39	$ (63)
High Island Block 37	0.1	69	122
	0.2	108	$ 59
Total Proved Developed			
High Island Block A-7	0.1	39	$ (63)
High Island Block 37	0.1	69	122
	0.2	108	$ 59

(1) The estimated present value of future net cash outflows after income taxes from our proved reserves has been determined by using prices of $58.99 per barrel of oil and $5.52 per Mcf of gas, representing the December 31, 2006 prices for oil and gas and discounted at a 10% annual rate in accordance

with requirements for reporting oil and gas reserves pursuant to regulations promulgated by the United States Securities and Exchange Commission (the SEC Method).

(2) As of December 31, 2006, we reported no proved undeveloped reserves.

Capital Expenditures for Proved Reserves. The following table presents information regarding the costs we expect to incur in activities associated with our proved reserves. These expenditures represent costs associated with the plugging and abandonment of wells. The information regarding proved reserves summarized in the preceding table assumes the following estimated undiscounted capital expenditures in the years indicated (in thousands).

ESTIMATED UNDISCOUNTED CAPITAL EXPENDITURES
TO DEVELOP PROVED RESERVES

	Years Ending December 31,				
	2007	2008	2009	2010	2011
High Island Block A-7		340			
High Island Block 37			92		

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Production, Price and Cost Data. The following table presents information regarding production volumes and revenues, average sales prices and costs (after deduction of royalties and interests of others) with respect to crude oil, condensate, and gas attributable to our interest for each of the periods indicated.

NET PRODUCTION, PRICE AND COST DATA

	Years Ended December 31,		
	2006	2005	2004
Gas:			
Production (Mcf)	312,146	378,791	66,491
Revenue	$2,131,415	$3,071,811	$338,808
Average production (Mcf) per day (*)	772.3	1,037.8	182.2
Average sales price per Mcf	$ 6.83	$ 8.11	$ 5.10
Condensate:			
Production (Bbls)	1,823	781	810
Revenue	$ 114,114	$ 40,481	$ 28,089
Average production (Bbls) per day (*)	5.0	2.1	2.2
Average sales price per Bbl	$ 62.60	$ 51.83	$ 34.68
NGLs:			
Production (gallons)	137,139	27,935	45,675
Revenue	$ 113,285	$ 23,718	$ 28,803
Average production (gallons) per day (*)	375.7	76.5	125.1
Average sales price per gallon	$ 0.83	$ 0.85	$ 0.63
Production costs (**):			
Per Mcfe:	$ 1.34	$ 0.40	$ 1.88

(*) Average production is based on a 365 day year. However, 2005 average production per day contains 549 days of production for High Island Block 37.

(**) Production costs, exclusive of workover costs, are costs incurred to operate and maintain wells and equipment and to pay production

taxes.

Drilling Activity. During September 2005, two wells in High Island Block A-7 were successfully recompleted and resumed production at a significantly higher rate than the single well that produced through the first and second quarters of 2005. The single well averaged less than 1 MMcf per day during the first and second quarters of 2005. The two recompleted wells averaged 5.4 MMcf per day combined during the fourth quarter of 2005, including the period of time that the wells were shut in. During 2006, one of the wells ceased production and we non-consented on participating in the recompletion of that well. Capital expenditures for the recompletions in 2005 net to our interest totaled approximately $71,000.

Employees

We have a total of seven employees and two consultants. Our employees are capable of supervising and coordinating the operation and administration of our oil and gas properties and pipeline and other assets. From time to time, major maintenance, engineering and construction projects are contracted to third-party engineering and service companies.

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Customers

We generated revenues from both of our primary business segments. Hydro Gulf, LLC and Fidelity Exploration and Production Company accounted for approximately 34.2% and 20.7%, respectively, of our revenues in 2006. Revenues from customers exceeding 10% of revenues were as follows for 2006 and 2005:

	Oil and Gas Sales	Pipeline Operations	Total
Year Ended December 31, 2006:			
Hydro Gulf, LLC (formerly Spinnaker Exploration Company)	$1,469,132	$	$1,469,132
Fidelity Exploration and Production Company	$ 889,682	$	$ 889,682
Year Ended December 31, 2005:			
Hydro Gulf, LLC (formerly Spinnaker Exploration Company)	$ 722,499	$	$ 722,499
Fidelity Exploration and Production Company	$2,413,511	$	$2,413,511

Competition

All segments of our business are highly competitive. Vigorous competition occurs among oil, gas and other energy sources, and between producers, transporters, and distributors of oil and gas. Our pipeline business faces competition from other pipelines in the markets that we serve. The principal elements of competition among pipelines are rates, terms of service, access to markets, flexibility and reliability of service. Our oil and natural gas business competes for the acquisition of oil and natural gas properties with numerous entities, including major oil companies, independent oil and natural gas concerns and individual producers and operators, primarily on the basis of the price to be paid for such properties. Many of these competitors are large, well-established companies and have financial and other resources substantially greater than ours, which give them an advantage over us in evaluating and obtaining properties and prospects. Our ability to acquire additional pipelines and oil and natural gas properties and to discover reserves in the future will depend upon our ability to evaluate and select suitable properties and consummate transactions in a highly competitive environment. There is also competition for the hiring of experienced personnel to manage and operate our assets. Several highly competitive alternative transportation and delivery options exist for current and potential customers of our traditional gas and oil gathering and transportation business. Competition also exists with other industries in supplying the energy and fuel needs of consumers.

Markets

The availability of a ready market for oil and natural gas, and the prices of oil and natural gas, depend upon a number of factors, which are beyond our control. These include, among other things:

the level of domestic production;

actions taken by foreign oil and gas producing nations;

the availability of pipelines with adequate capacity;

the availability of vessels for direct shipment;

lightering, transshipment and other means of transportation;

the availability and marketing of other competitive fuels;

fluctuating and seasonal demand for oil, natural gas and refined products; and

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the extent of governmental regulation and taxation (under both present and future legislation) of the production, importation, refining, transportation, pricing, use and allocation of oil, gas, refined products and alternative fuels.

In view of the many uncertainties affecting the supply and demand for crude oil, natural gas and refined petroleum products, it is not possible to predict accurately the prices or marketability of the oil and natural gas produced for sale or prices chargeable for transportation and storage services, which we provide. Our sale of natural gas is generally made at the market prices at the time of sale. Therefore, even though we sell natural gas to major purchasers, we believe other purchasers would be willing to buy our natural gas at comparable market prices.

Governmental Regulation

The production, processing, marketing, and transportation of oil and gas by us are subject to federal, state and local regulations which can have a significant impact upon our operations.

Federal Regulation of Natural Gas Transportation. The transportation and resale of gas in interstate commerce have been regulated by the Natural Gas Act (NGA), the Natural Gas Policy Act (NGPA), and the rules and regulations promulgated by the Federal Energy Regulatory Commission (FERC). In the past, the federal government has regulated the prices at which gas could be sold. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining Natural Gas Act and Natural Gas Policy Act price and non-price controls affecting producer sales of gas, effective January 1, 1993. The Energy Policy Act of 2005 did not alter our non-FERC-jurisdictional status, but has greatly expanded FERC s authority, including enforcement authority against market manipulation in connection with FERC-jurisdictional transactions. The nature and extent of FERC s implementation of its new authorities is not yet known. Additionally, energy pricing has attracted renewed political interest. Thus Congress could reenact price controls in the future. The rates, terms and conditions applicable to interstate transportation of gas by pipelines are regulated by the FERC under the NGA, as well as under Section 311 of the NGPA. In February 2007, FERC issued a policy order acknowledging its lack of jurisdiction over offshore gathering, but stating that FERC would intervene in the event that interstate pipelines with affiliated offshore gathering lines engage in anticompetitive behavior, such as conditioning access to interstate pipeline service upon use of the affiliated gathering line.

All of our pipelines located offshore in federal waters are subject to the requirements of the Outer Continental Shelf Lands Act (OCSLA). The FERC has stated that non-jurisdictional gathering lines, as well as interstate pipelines, are fully subject to the open access and nondiscrimination requirements of OCSLA s Section 5, which generally authorizes the FERC to insure that gas pipelines on the Outer Continental Shelf (OCS) will transport for non-owner shippers in a nondiscriminatory manner and will be operated in accordance with certain pro-competitive principles. Since all of our offshore pipelines fall within the exemption for feeder facilities and already operate on the basis required under OCSLA, we do not anticipate significant changes directly resulting from requirements concerning nondiscriminatory open access transportation.

Aside from the OCSLA requirements and federal safety and operational regulations, regulation of gas gathering activities is primarily a matter of state oversight. Regulation of gathering activities in Texas includes various transportation, safety, environmental and non-discriminatory purchase/transport requirements.

Federal Regulation of Oil Pipelines. Our operation of the Buccaneer Pipeline has been subject to a variety of regulations promulgated by the FERC and imposed on all oil pipelines pursuant to federal law. Recently, however, oil pipelines have been granted permanent exemptions from certain FERC filing requirements because of rulings that oil pipeline transportation tariff movements of crude petroleum

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occurring solely on or across the OCS, or across the OCS to onshore points where transportation ends are not subject to FERC jurisdiction under the OCSLA or the Interstate Commerce Act.

Safety and Operational Regulations. Our operations are generally subject to safety and operational regulations administered primarily by the United States Minerals Management Service (MMS), the U.S. Department of Transportation, the U.S. Coast Guard, the FERC and/or various state agencies. In addition, the OCSLA authorizes regulations relating to safety and environmental protection applicable to leases and permittees operating on the OCS. Specific design and operational standards may apply to OCS vessels, rigs, platforms and structures. Violations of lease conditions or regulations issued pursuant to the OCSLA can result in substantial civil and criminal penalties, as well as potential court injunctions curtailing operations and the cancellation of leases. Such enforcement liabilities can result from either governmental or private prosecution. Currently, we believe that we are in material compliance with the various safety and operational regulations to which we are subject. However, as safety and operational regulations are frequently changed, we are unable to predict the future effect changes in these regulations will have on our operations, if any.

Federal Oil and Gas Leases. All of our exploration and production operations are currently located on federal oil and gas leases in the OCS, which are administered by the MMS. Such leases are issued through competitive bidding, contain relatively standardized terms and require compliance with detailed MMS regulations and orders pursuant to the OCSLA that are subject to interpretation and change by the MMS. For offshore operations, lessees must obtain MMS approval for exploration plans and development and production plans prior to the commencement of such operations. In addition to permits required from other agencies such as the Coast Guard, the Army Corps of Engineers and the Environmental Protection Agency, lessees must obtain a permit from the MMS prior to the commencement of drilling. The MMS has promulgated regulations requiring offshore production facilities located on the OCS to meet stringent engineering and construction specifications. To cover the various obligations of lessees on the OCS, the MMS generally requires that lessees have substantial net worth or post bonds or other acceptable assurance that such obligations will be met. The cost of these bonds or other surety can be substantial, and there is no assurance that bonds or other surety can be obtained in all cases. We are currently in compliance with the bonding requirements of the MMS. Under some circumstances, the MMS may require any of our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially adversely affect our financial condition and results of operations.

With respect to our operations conducted on offshore federal leases, liability may generally be imposed under OCSLA for costs of clean-up and damages caused by pollution resulting from such operations, other than damages caused by acts of war or the negligence of third parties. Under certain circumstances, including but not limited to conditions deemed a threat or harm to the environment, the MMS may also require any of our operations on federal leases to be suspended or terminated in the affected area. Furthermore, the MMS generally requires that offshore facilities be dismantled and removed within one year after production ceases or the lease expires.

Environmental Regulation. Our activities with respect to (1) exploration, development and production of oil and natural gas and (2) the operation and construction of pipelines, plants, and other facilities for the transportation and processing, and storage of oil and natural gas are subject to stringent environmental regulation by local, state and federal authorities, including the U.S. Environmental Protection Agency (EPA). Such regulation has increased the cost of planning, designing, drilling, operating and in some instances, abandoning wells and related equipment. Similarly, such regulation has also increased the cost of design, construction, and operation of crude oil and natural gas pipelines and processing facilities. Although we believe that compliance with existing environmental regulations will not have a material adverse affect on operations or earnings, there can be no assurance that significant costs and liabilities, including civil and criminal penalties, will not be incurred. Moreover, future developments, such as stricter environmental laws and regulations or claims for personal injury or property damage resulting from our operations, could result in substantial costs and liabilities. It is not anticipated that, in response to such

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regulation, we will be required in the near future to expend amounts that are material relative to our total capital structure.

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) imposes liability, without regard to fault or the legality of the original conduct, on responsible parties with respect to the release or threatened release of a hazardous substance into the environment. Responsible parties, which include the present owner or operator of a site where the release occurred, the owner or operator of the site at the time of disposal of the hazardous substance, and persons that disposed or arranged for the disposal of a hazardous substance at the site, are liable for response and remediation costs and for damages to natural resources. Petroleum and natural gas are excluded from the definition of hazardous substances ; however, this exclusion does not apply to all materials used in our operations. At this time, neither we nor any of our predecessors have been designated as a potentially responsible party under CERCLA.

The federal Resource Conservation and Recovery Act (RCRA) and its state counterparts regulate solid and hazardous wastes and impose civil and criminal penalties for improper handling and disposal of such wastes. EPA and various state agencies have promulgated regulations that limit the disposal options for such wastes. Certain wastes generated by our oil and gas operations are currently exempt from regulation as hazardous wastes, but in the future could be designated as hazardous wastes under RCRA or other applicable statutes and therefore may become subject to more rigorous and costly requirements.

We currently own or lease, or have in the past owned or leased, various properties used for the exploration and production of oil and gas or used to store and maintain equipment regularly used in these operations. Although our past operating and disposal practices at these properties were standard for the industry at the time, hydrocarbons or other substances may have been disposed of or released on or under these properties or on or under other locations. In addition, many of these properties have been operated by third parties whose waste handling activities were not under our control. These properties and any waste disposed of thereon may be subject to CERCLA, RCRA, and state laws which could require us to remove or remediate wastes and other contamination or to perform remedial plugging operations to prevent future contamination.

The Oil Pollution Act of 1990 (OPA) and regulations promulgated thereunder include a variety of requirements related to the prevention of oil spills and impose liability for damages resulting from such spills. OPA imposes liability on owners and operators of onshore and offshore facilities and pipelines for removal costs and certain public and private damages arising from a spill. OPA establishes a liability limit for onshore facilities of $350 million and for offshore facilities of all removal costs plus $75 million, and lesser liability limits for vessels depending upon their size. A party cannot take advantage of the liability limits if the spill is caused by gross negligence or willful misconduct or resulted from a violation of federal safety, construction, or operating regulations. If a party fails to report a spill or cooperate in the cleanup, liability limits likewise do not apply. OPA imposes ongoing requirements on responsible parties, including proof of financial responsibility for potential spills. The amount of financial responsibility required depends upon a variety of factors including the type of facility or vessel, its size, storage capacity, oil throughput, proximity to sensitive areas, type of oil handled, history of discharges, worst-case spill potential and other factors. We believe we have established adequate financial responsibility. While the financial responsibility requirements under OPA may be amended to impose additional costs on us, the impact of such a change is not expected to be any more burdensome on us than on others similarly situated.

The Clean Air Act and state air quality laws and regulations contain provisions that impose pollution control requirements on emissions to the air and require permits for construction and operation of certain emissions sources, including sources located offshore. We may be required to incur capital expenditures for air pollution control equipment in connection with maintaining or obtaining operating permits and

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approvals addressing emission-related issues, although we do not expect to be materially adversely affected by such expenditures.

The Clean Water Act (CWA) regulates the discharge of pollutants to waters of the United States and imposes permit requirements on such discharges, including discharges to wetlands. Federal regulations under the CWA and OPA require certain owners or operators of facilities that store or otherwise handle oil, to prepare and implement spill prevention, control and countermeasure plans and facility response plans relating to the possible discharge of oil into surface waters. With respect to certain of our operations, we are required to prepare and comply with such plans and to obtain and comply with permits. The CWA also prohibits spills of oil and hazardous substances to waters of the United States in excess of levels set by regulations and imposes liability in the event of a spill. State laws further provide varying civil and criminal penalties and liabilities for the spills to both surface and groundwaters. We believe we are in substantial compliance with the requirements of the CWA, OPA, and state laws, and that any non-compliance would not have a material adverse effect on us.

Various federal and state programs regulate the conservation and development of coastal resources. The federal Coastal Zone Management Act was passed to preserve and, where possible, restore the natural resources of the coastal zone of the United States of America and to provide for federal grants for state management programs that regulate land use, water use and coastal development. Under the Louisiana Coastal Zone Management Program, coastal use permits are required for certain activities, even if the activity only partially infringes on the coastal zone. Among other things, projects involving use of state lands and water bottoms, dredge or fill activities that intersect with more than one body of water, mineral activities, including the exploration and production of oil and gas, and pipelines for the gathering, transportation or transmission of oil, gas and other minerals require such permits. General permits, which entail a reduced administrative burden, are available for a number of routine oil and gas activities. The Texas Coastal Coordination Act (CCA) establishes the Texas Coastal Management Program that applies in the nineteen Texas counties that border the Gulf of Mexico and its tidal bays. The CCA provides for the review of state and federal agency rules and agency actions for consistency with the goals and policies of the Coastal Management Plan. These coastal programs may affect agency permitting of our facilities.

Legislation and Rulemaking. In October 1996 the U.S. Congress enacted the Coast Guard Authorization Act of 1996 (P.L. 104-324) which amended the OPA to establish requirements for evidence of financial responsibility for certain offshore facilities. The amount required is $35 million for certain types of offshore facilities located seaward of the seaward boundary of a state, including properties used for oil transportation. We currently maintain this statutory $35 million coverage.

Federal and state legislative rules and regulations are pending that, if enacted, could significantly affect the oil and gas industry. It is impossible to predict which of those federal and state proposals and rules, if any, will be adopted and what effect, if any, they would have on our operations.

In addition, various federal, state and local laws and regulations covering the discharge of materials into the environment, occupational health and safety issues, or otherwise relating to the protection of public health and the environment, may affect our operations, expenses and costs. The trend in such regulation has been to place more restrictions and limitations on activities that may impact the general or work environment, such as emissions of pollutants, generation and disposal of wastes, and use and handling of chemical substances. It is not anticipated that, in response to such regulation, we will be required in the near future to expend amounts that are material relative to our total capital structure. However, it is possible that the costs of compliance with environmental and health and safety laws and regulations will continue to increase. Given the frequent changes made to environmental and health and safety regulations and laws, we are unable to predict the ultimate cost of compliance.

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RISK FACTORS

We are primarily dependent on revenues from our pipeline systems and our working interests in two oil and gas producing properties.

Although revenues from oil and gas sales accounted for approximately 54.9% and 69.5% of our total revenues in 2006 and 2005, respectively, as a result of our sale of substantially all of our proved oil and gas reserves in 2002 and the limited amount of reserves on properties we own interests in, we expect that our future revenues will be primarily dependent on the level of use of our pipeline systems. Various factors will influence the level of use of our pipeline systems including the success of drilling programs in the areas near our pipelines and our ability to attract new producers/shippers. There are various pipelines in and around our pipeline systems that we vigorously compete with to attract new producers/shippers to our pipeline systems. There can be no assurance that we will be successful in attracting new producers/shippers to our pipeline systems.

Furthermore, the rate of production from oil and gas properties generally declines as reserves are depleted. Our working interests are in properties in the Gulf of Mexico where, generally, the rate of production declines more rapidly than in many other producing areas of the world. As the level of production from these properties continues to decline, our revenue from these interests will decrease. The rate of production from High Island Block 37 declined by approximately 65% in 2006. The rate of production from High Island Block A-7 has declined by approximately 60% since the end of 2006. Recent production data from High Island Block A-7 has provided evidence that the producing well is reaching the end of its production life. We currently believe that the High Island Block A-7 well could cease production before mid 2007. We believe that production from one of the two producing High Island Block 37 wells could continue to produce into early 2008 and the other well could produce until mid 2008. However, the wells could deplete faster than anticipated or could develop production problems resulting in the cessation of production. Unless we are able to replace this revenue with revenue from interests in other oil and gas properties, increase the level of utilization of our pipelines or acquire other revenue generating assets at an acceptable cost, our revenues and cash flow from operations will decrease and our financial condition will be materially adversely affected.

The geographic concentration of our assets may have a greater effect on us as compared to other companies.

All of our assets are located in the Western Gulf of Mexico and the onshore gulf coast of Texas. Because our assets are not as diversified geographically as many of our competitors, our business is subject to local conditions more than other, more geographically diversified companies. Any regional event, including price fluctuations, natural disasters and restrictive regulations that increase costs may adversely impact our business more than if our assets were geographically diversified.

If we are not able to generate sufficient funds from our operations and other financing sources, we may not be able to finance our operations.

We have historically needed substantial amounts of cash to fund our working capital requirements. Because we have experienced a negative working capital position in past years, we have been dependent on debt and equity financing and sales of revenue generating assets to meet our working capital requirements that were not funded from operations. Low commodity prices, production problems, declines in production, disappointing drilling results and other factors beyond our control could reduce our funds from operations. As a result we may have to seek debt and equity financing to meet our working capital requirements. Furthermore, we have incurred losses in the past that may affect our ability to obtain financing. In addition, financing may not be available to us in the future on acceptable terms or at all. In the event additional capital is not available, we may be forced to sell some of our assets on unfavorable terms or on an untimely basis.

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We face strong competition from larger companies that may negatively affect our ability to carry on operations.
We operate in a highly competitive industry. Our competitors include major integrated oil companies, substantial independent energy companies, affiliates of major interstate and intrastate pipelines and national and local gas gatherers, many of which possess greater financial and other resources than we do. Our ability to successfully compete in the marketplace is affected by many factors including:

- most of our competitors have greater financial resources than we do, which gives them better access to capital to acquire assets; and

- we often establish a higher standard for the minimum projected rate of return on invested capital than some of our competitors since we cannot afford to absorb certain risks. We believe this puts us at a competitive disadvantage in acquiring pipelines and oil and gas properties.

Oil and gas prices are volatile and a substantial and extended decline in the price of oil and gas would have a material adverse effect on us.
The tightening of natural gas supply and demand fundamentals has resulted in higher, but extremely volatile natural gas prices, and this volatility in natural gas prices is expected to continue. Our revenues, profitability, operating cash flow and our potential for growth are largely dependent on prevailing oil and natural gas prices. Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply and demand for oil and natural gas, uncertainties within the market and a variety of other factors beyond our control. These factors include:

- weather conditions in the United States;

- the condition of the United States economy;

- the actions of the Organization of Petroleum Exporting Countries;

- governmental regulation;

- political stability in the Middle East, South America and elsewhere;

- the foreign supply of oil and natural gas;

- the price of foreign imports; and

- the availability of alternate fuel sources.

In addition, low or declining oil and natural gas prices could have collateral effects that could adversely affect us, including the following:

- reducing the exploration for and development of oil and gas reserves held by third party companies around our pipeline systems;

- increasing our dependence on external sources of capital to meet our cash needs; and

- generally impairing our ability to obtain needed capital.

Reserve estimates depend on many assumptions that may prove to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated.
Estimating reserves of oil and gas is complex. The process relies on interpretations of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this data can vary. The process also requires certain economic assumptions, some of which are mandated by the SEC regarding oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The accuracy of a reserve estimate is a

function of:

the quality and quantity of available data;

the interpretation of that data;

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the accuracy of various mandated economic assumptions; and

the judgment of the persons preparing the estimate.

The proved reserve information set forth in this report is based on estimates we prepared. Estimates prepared by others might differ materially from our estimates.

Actual quantities of recoverable oil and gas reserves, future production, oil and gas prices, taxes, development expenditures and operating expenses most likely will vary from our estimates. Any significant variance could materially affect the quantities and net present value of our reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development and prevailing oil and gas prices. Our reserves also may be susceptible to drainage by operators on adjacent properties.

The present value of future net cash flows will most likely not equate to the current market value of our estimated proved oil and gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from proved reserves on prices and costs in effect at December 31. Actual future prices and costs may be materially higher or lower than the prices and costs we used.

We cannot control the activities on properties we do not operate.

Currently, other companies operate or control the development of the oil and gas properties in which we have an interest. As a result, we depend on the operator of the wells or leases to properly conduct lease acquisition, drilling, completion and production operations. The failure of an operator, or the drilling contractors and other service providers selected by the operator to properly perform services, or an operator s failure to act in ways that are in our best interest, could adversely affect us, including the amount and timing of revenues, if any, we receive from our interests.

We own and generally anticipate that we will typically continue to own substantially less than a 50% working interest in our prospects and will therefore engage in joint operations with other working interest owners. Since we own or control less than a majority of the working interest in a prospect, decisions affecting the prospect could be made by the owners of a majority of the working interest. For instance, if we are unwilling or unable to participate in the costs of operations approved by a majority of the working interests in a well, our working interest in the well (and possibly other wells on the prospect) will likely be subject to contractual non-consent penalties. These penalties may include, for example, full or partial forfeiture of our interest in the well or a relinquishment of our interest in production from the well in favor of the participating working interest owners until the participating working interest owners have recovered a multiple of the costs which would have been borne by us if we had elected to participate, which often ranges from 400% to 600% of such costs.

We have pursued, and intend to continue to pursue, acquisitions. Our business may be adversely affected if we cannot effectively integrate acquired operations.

One of our business strategies has been to acquire operations and assets that are complementary to our existing businesses. Acquiring operations and assets involves financial, operational and legal risks. These risks include:

inadvertently becoming subject to liabilities of the acquired company that were unknown to us at the time of the acquisition, such as later asserted litigation matters or tax liabilities;

the difficulty of assimilating operations, systems and personnel of the acquired businesses; and

maintaining uniform standards, controls, procedures and policies.

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Competition from other potential buyers could cause us to pay a higher price than we otherwise might have to pay and reduce our acquisition opportunities. We are often out-bid by larger, better capitalized companies for acquisition opportunities we pursue. Moreover, our past success in making acquisitions and in integrating acquired businesses does not necessarily mean we will be successful in making acquisitions and integrating businesses in the future.

Operating hazards, including those peculiar to the marine environment, may adversely affect our ability to conduct business.

Our operations are subject to inherent risks normally associated with those operations, such as:

pipeline ruptures;

sudden violent expulsions of oil, gas and mud while drilling a well, commonly referred to as a blowout;

a cave in and collapse of the earth s structure surrounding a well, commonly referred to as cratering;

explosions;

fires;

pollution; and

other environmental risks.

If any of these events were to occur, we could suffer substantial losses from injury and loss of life, damage to and destruction of property and equipment, pollution and other environmental damage and suspension of operations. Our offshore operations are also subject to a variety of operating risks peculiar to the marine environment, such as hurricanes or other adverse weather conditions and more extensive governmental regulation. These regulations may, in certain circumstances, impose strict liability for pollution damage or result in the interruption or termination of operations.

Losses and liabilities from uninsured or underinsured drilling and operating activities could have a material adverse effect on our financial condition and results of operations.

We maintain several types of insurance to cover our operations, including maritime employer s liability and comprehensive general liability. Amounts over base coverages are provided by primary and excess umbrella liability policies. We also maintain operator s extra expense coverage, which covers the control of drilled or producing wells as well as re-drilling expenses and pollution coverage for wells out of control.

We may not be able to maintain adequate insurance in the future at rates we consider reasonable or losses may exceed the maximum limits under our insurance policies. In 2004, in connection with the implementation of certain cost saving measures, we cancelled the property insurance coverage on our pipelines. In 2005 and 2006, we did not obtain property insurance coverage on our pipelines since we were not able to acquire the coverage at what we believed to be reasonable terms. If a significant event that is not fully insured or indemnified occurs, it could materially and adversely affect our financial condition and results of operations.

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Compliance with environmental and other government regulations could be costly and could negatively impact our operations.

Our operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may:

- require the acquisition of a permit before operations can be commenced;
- restrict the types, quantities and concentration of various substances that can be released into the environment from drilling and production activities;
- limit or prohibit drilling and pipeline activities on certain lands lying within wilderness, wetlands and other protected areas;
- require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells and abandoning pipelines; and
- impose substantial liabilities for pollution resulting from our operations.

The recent trend toward stricter standards in environmental legislation and regulation is likely to continue. The enactment of stricter legislation or the adoption of stricter regulations could have a significant impact on our operating costs, as well as on the oil and gas industry in general.

Our operations could result in liability for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. We could also be liable for environmental damages caused by previous property owners. As a result, substantial liabilities to third parties or governmental entities may be incurred which could have a material adverse effect on our financial condition and results of operations. We maintain insurance coverage for our operations, including limited coverage for sudden and accidental environmental damages, but we do not believe that insurance coverage for all environmental damages that occur over time or complete coverage for sudden and accidental environmental damages is available at a reasonable cost. Accordingly, we may be subject to liability or may lose the privilege to continue to operate on substantial portions of our properties if certain environmental damages occur.

The OPA imposes a variety of regulations on responsible parties related to the prevention of oil spills. The implementation of new, or the modification of existing, environmental laws or regulations, including regulations promulgated pursuant to the OPA, could have a material adverse impact on us.

GLOSSARY OF CERTAIN OIL AND GAS TERMS

The following are abbreviations and definitions of certain terms commonly used in the oil and gas industry.

Back-in After Payout Interest. A contractual right of a non-participating partner to participate in a well or wells after the wells have produced enough for the participating partners to recover their capital costs of drilling, completing, and operating the wells.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

Bcf. One billion cubic feet of gas.

Btu or British Thermal Unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Condensate. Liquid hydrocarbons associated with the production of a primarily gas reserve.

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Development Well. A well drilled within the proved area of a gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.
Exploratory Well. A well drilled to find and produce gas or oil in an unproved area, to find a new reservoir in a field previously found to be productive of gas or oil in another reservoir or to extend a known reservoir.
Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.
Leasehold Interest. The interest of a lessee under an oil and gas lease.
Mbbls. One thousand barrels of oil or other liquid hydrocarbons.
Mcf. One thousand cubic feet of gas.
Mcfe. One thousand cubic feet equivalent, determined using the ratio of six Mcf of gas to one barrel of oil, condensate or gas liquids.
MMbtu. One million British Thermal Units.
MMcf. One million cubic feet of gas.
MMcfe. One million cubic feet equivalent, determined using the ratio of six Mcf of gas to one Bbl of oil, condensate or gas liquids.
Net Revenue Interest. The percentage of production to which the owner of a working interest is entitled.
Nonoperating Working Interest. A working interest, or a fraction of a working interest, in a lease where the owner is not the operator of the lease.
Overriding Royalty. An interest in oil and gas produced at the surface, free of the expense of production that is in addition to the usual royalty interest reserved to the lessor in an oil and gas lease.
Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of oil, gas or both.
Proved Developed Reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved developed reserves are further categorized into two sub-categories, proved developed producing reserves and proved developed non-producing reserves.
Proved Developed Producing. Reserves sub-categorized as producing are expected to be recovered from completion intervals which are open and producing at the time of the estimate.
Proved Developed Non-producing. Reserves sub-categorized as non-producing include shut-in and behind pipe reserves. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells which were shut-in awaiting pipeline connections or as a result of a market interruption, or (3) wells not capable of producing for mechanical reasons.
Proved Reserves. The estimated quantities of oil, gas and condensate that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

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Proved Undeveloped Reserves. Reserves that are expected to be recovered from new wells or from existing wells where a relatively major expenditure is required for recompletion.

Reversionary Interest. A form of ownership interest in property that reverts back to the transferor after expiration of an intervening income interest or the occurrence of another triggering event.

Royalty Interest. An interest in a gas and oil property entitling the owner to a share of gas and oil production free of costs of production.

Undivided Interest. A form of ownership interest in which more than one person concurrently owns an interest in the same oil and gas lease or pipeline.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production.

Item 2. Description of Property

Information appearing in Item 1 describing our oil and gas properties, pipelines and other assets under the caption Description of Business is incorporated herein by reference.

We lease our executive offices in Houston, Texas, under an operating lease expiring April 30, 2017. Our average annual lease payment under this lease is approximately $107,000.

Item 3. Legal Proceedings

We are a party to litigation that is incidental to our business and neither we nor any of our property is subject to any material pending legal proceedings.

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PART II

Item 5. Market for Common Equity and Related Stockholder Matters

Market Price for Common Stock

Our common stock is quoted on the NASDAQ Capital Market under the ticker symbol BDCO . As of March 23, 2007, there were an estimated 500 stockholders of record and we estimate that there are more than 1,000 beneficial owners of our common stock. NASDAQ quotations reflect inter-dealer prices, without adjustment for retail mark-ups, markdowns or commissions and may not represent actual transactions. The following table sets forth, for the periods indicated, the high and low closing bid price for our common stock as reported by the NASDAQ.

Quarter Ended	High	Low
March 31, 2005	$4.15	$0.76
June 30, 2005	$4.26	$1.35
September 30, 2005	$3.52	$2.04
December 31, 2005	$3.06	$1.95
March 31, 2006	$3.32	$1.91
June 30, 2006	$8.00	$3.45
September 30, 2006	$6.14	$3.65
December 31, 2006	$4.34	$2.91

On February 16, 2005, we received a notice from NASDAQ that because our common stock traded below the minimum $1.00 bid price for 30 consecutive trading days the common stock would be delisted if our bid price did not close above $1.00 for 10 consecutive trading days by August 15, 2005. On March 17, 2005, we received a notice from NASDAQ that we regained compliance with the listing requirements as a result of the bid price of our common stock closing above $1.00 for 10 consecutive trading days.

Dividend Policy

We have not declared or paid any dividends on our common stock since our incorporation. We currently intend to retain earnings for our capital needs and expansion of our business and do not anticipate paying cash dividends on the common stock in the foreseeable future. We expect that any loan agreements we enter into in the future will likely contain restrictions on the payment of dividends on our common stock. Future policy with respect to dividends will be determined by our Board of Directors based upon our earnings and financial condition, capital requirements and other considerations. We are a holding company that conducts substantially all of our operations through our subsidiaries. As a result, our ability to pay dividends on the common stock will also be dependent upon the cash flow of our subsidiaries.

Recent Sales of Unregistered Securities

In March 2006, we completed a private placement with certain accredited investors of 1,171,432 shares of our common stock. The net proceeds from the offering after the payment of commissions and expenses were approximately $2.0 million and we issued warrants to purchase an aggregate of 8,572 shares of common stock. The warrants vested immediately and the exercise price per share varied based on the following conditions: (i) until the later of the registration of the warrants or one year from the issue date, 110% of the purchase price of $1.75 per share, (ii) from the later of (x) the registration of the warrants and (y) one year, until two years from the issue date, 120% of the purchase price of $1.75 per share and (iii) after the expiration of two years from the issue date of the warrants, 130% of the purchase price of $1.75 per share. The 8,572 warrants were exercised in a cashless manner in 2006 at an exercise price of $1.93 per share.

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In April 2006, we completed a private placement with an accredited institutional investor of 400,000 shares of our common stock. Net proceeds from the offering were approximately $1.8 million and we issued warrants to purchase an aggregate of 24,000 shares of common stock. These warrants were immediately exercisable upon issuance and 7,560 were exercised in a cashless manner in 2006 at an exercise price of $5.39 per share. The exercise price varies based on the following conditions: (i) until the later of the registration of the warrants or one year from the issue date, 110% of the purchase price of $4.90 per share; (ii) from the later of (x) the registration of the warrants and (y) one year, until two years from the issue date, 120% of the purchase price of $4.90 per share; and (iii) after the expiration of two years from the issue date of the warrants, 130% of the purchase price of $4.90 per share.

The net proceeds from both offerings are being used for general corporate and working capital purposes, and may also be used for possible acquisitions and planned expansions of our facilities.

Purchases of Equity Securities

The following table represents information with respect to purchases of our common stock made during the three months ended December 31, 2006 by us or any affiliated purchaser of ours as defined in Rule 10b-18(a)(3) under the Exchange Act:

Period	Total Number of Shares Purchased [1]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet be Purchased Under the Plans or Programs
October 1-31, 2006		$		
November 1-30, 2006	2,618	3.16		
December 1-31, 2006				
Total	2,618	$ 3.16		

(1) Shares surrendered upon exercise of warrants outstanding.

Equity Compensation Plan Information

The following table represents information with respect to the 2000 Stock Incentive Plan as of December 31, 2006:

	Number of Securities to be Issued upon	Weighted-Average	Number of Securities Remaining Available for Future Issuance under

	Exercise of Outstanding Options	Exercise Price of Outstanding Options	Equity Compensation Plans
Equity compensation plans approved security holders	143,997	$ 1.56	99,540

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Item 6. Management s Discussion and Analysis of Financial Condition and Results of Operations

The following is a review of certain aspects of our financial condition and results of operations and should be read in conjunction with the Notes to Consolidated Financial Statements in Item 7 and Description of Business in Item 1.

Executive Summary

We are engaged in two lines of business: (i) provision of pipeline transportation services to producers/shippers, and (ii) oil and gas exploration and production. We conduct our operations through our subsidiaries. Our assets are located offshore and onshore in the Texas Gulf coast area. Our goal is to create greater long-term value for our stockholders by increasing the utilization of our existing pipeline assets, acquiring additional strategic assets to diversify our asset base and improve our competitive position, and continuing strict control over our operating and general and administrative costs. Although we are primarily focusing on acquisitions of pipeline assets, we will continue to review and evaluate opportunities to acquire producing oil and gas properties.

In 2006, several significant events have provided additional working capital and additional revenues that we may use for possible acquisitions and planned expansions of existing facilities. Significant events in 2006 were:

In March and April 2006, we completed private placements of 1,571,432 shares of our common stock. Net proceeds from these offerings after payment of commissions and expenses were approximately $3.8 million.

In May 2006, we entered into gas and condensate transportation and handling agreements with a new shipper to deliver production into the Blue Dolphin System. In June 2006, this new shipper began deliveries of production into the Blue Dolphin System.

Also in May 2006, a shipper that we contracted with in 2005 began deliveries of production into the Blue Dolphin System.

In July 2006, a shipper on the Blue Dolphin System recompleted an existing well, which resulted in an increase in the rate of production.

In November 2006, another shipper we contracted with in 2005 began deliveries of production into the Blue Dolphin System.

Also, in November 2006, we entered into gas and condensate transportation and handling agreements with a new shipper to deliver production into the GA350 Pipeline. In December 2006, this new shipper began deliveries into the GA 350 Pipeline.

We have benefited from a significant increase in revenues from our pipeline operations in 2006 as a result of the additional deliveries on both the Blue Dolphin System and the GA 350 Pipeline. The Blue Dolphin System has gained production from three shippers in 2006 and one shipper in 2005. The Blue Dolphin System is currently transporting approximately 26 MMcf per day, or approximately 16% of capacity. The GA 350 Pipeline gained production from one shipper in December 2006 and is currently transporting approximately 20 MMcf per day, or approximately 31% of capacity.

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Our working interests in High Island Block 37 and High Island Block A-7 continue to generate revenues for us. However, the amount of revenues is declining as the rate of production from these properties declines as reserves are depleted. The rate of production from High Island Block 37 declined by approximately 65% during 2006. The rate of production from High Island Block A-7 has declined by approximately 60% since the end of 2006. High Island Block 37 is currently producing an aggregate of approximately 8 MMcf per day from two wells and High Island Block A-7 is currently producing approximately 2 MMcf per day from a single well. These wells could experience production difficulties, which could significantly lower production levels or cause production to cease. Recent production data for the High Island Block A-7 well has provided evidence that this well is reaching the end of its production life. Further production declines or cessations of production from these wells could have a material adverse effect on our cash flows and liquidity if the resulting revenue declines are not offset by revenues from other sources. Despite the recent throughput gains, our pipeline assets remain significantly under-utilized. In addition, due to our small size, geographically concentrated asset base and limited capital resources, any negative event has the potential to significantly impact our financial condition. We are continuing our efforts to increase the utilization of our existing assets and acquire additional assets that will alleviate and diversify the risks to our cash flows and be accretive to earnings.

Liquidity and Capital Resources

We ended 2006 with working capital of approximately $6.7 million and notes payable have been reduced to zero. At the end of 2005, our working capital was approximately $2.1 million and our short-term and long-term notes payable totaled $950,000. The increase in working capital from year-end 2005 was primarily the result of proceeds received from two private placements that were completed in the first half of 2006, significant revenues from oil and gas sales and increased revenues from our pipeline operations.

The following table summarizes our financial position for the years indicated (in thousands):

	Years Ended December 31,			
	2006		2005	
	Amount	%	Amount	%
Working capital	$ 6,652	57	$ 2,053	29
Property and equipment, net	4,912	43	4,980	71
Other noncurrent assets	22		11	
Total	$ 11,586	100	$ 7,044	100
Long-term liabilities	$ 2,014	17	$ 2,256	32
Stockholders equity	9,572	83	4,788	68
Total	$ 11,586	100	$ 7,044	100

Even though our pipeline assets remain under-utilized, throughput on the Blue Dolphin System and the GA 350 Pipeline increased significantly during 2006. The Blue Dolphin System is currently transporting approximately 26 MMcf per day and the GA 350 Pipeline is currently transporting approximately 20 MMcf per day. All five of the shippers we have contracted with since 2005 have commenced deliveries of production into our pipelines. Four of these shippers are delivering production into the Blue Dolphin System and one of the new shippers is delivering production into the GA 350 Pipeline. One of the shippers began deliveries into the Blue Dolphin System in August 2005. In 2006, one shipper began

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deliveries into the Blue Dolphin System in each of May, June and November. A shipper began deliveries into the GA 350 Pipeline in December 2006. Also, in July 2006, a shipper that has delivered production into the Blue Dolphin System for a number of years, successfully recompleted an existing well, resulting in an increase of daily production. The average rate of throughput on the Blue Dolphin System during 2006 increased 228% to 17.3 MMcf per day as compared to 7.6 MMcf per day during 2005 as a result of the four new shippers added to the Blue Dolphin System. Since the new shipper on the GA 350 Pipeline did not commence deliveries until December 2006, the average rate of throughput on the GA 350 Pipeline declined during 2006 to 9.0 MMcf per day from 11.6 MMcf per day during 2005. Revenues from all pipeline operations increased to $1,939,834 in 2006 as compared to $1,375,173 in 2005 due to new volumes. The increase in gas transportation rates negotiated in 2004 with the shippers transporting their production on the Blue Dolphin System at that time also had a positive effect on our revenues, but to a lesser extent since the revenues from the new shippers now exceeds that of the pre-2005 shippers, as the levels of production from the pre-2005 shippers naturally decline. The gas transportation rates charged to the pre-2005 shippers could decline back to the rates in effect prior to the renegotiation if the operating results of the Blue Dolphin System continue to improve. Due to the low utilization of our pipeline assets, we have significant available capacity on the Blue Dolphin System, the Galveston Block 350 Pipeline and the inactive Omega Pipeline. The 26 MMcf of throughput currently being transported per day on the Blue Dolphin System represents approximately 16% of system capacity. The 20 MMcf of throughput currently being transported per day on the GA 350 Pipeline represents approximately 31% of capacity. We believe that the pipelines are in geographic market areas that are experiencing an increased level of interest by oil and gas operators. This assessment is based on recent leasing, drilling activity and discoveries in the lease blocks surrounding the pipelines, as well as information obtained directly from the operators of properties near our pipelines. There have been nine new discoveries near the Blue Dolphin System and the Galveston Block 350 Pipeline during the period from 2005 through early-2007. We have entered into contracts for transportation and handling services with operators of five of the nine discoveries and are in negotiations with the operators of the other four discoveries. Drilling activity around our pipelines continues to be impeded by a shortage of drilling equipment and service providers in the Gulf of Mexico due to increased demand caused by higher drilling activity levels resulting from higher commodity prices, and to a lesser extent, by continued infrastructure repairs following Hurricanes Katrina and Rita. Ultimately, the future utilization of our pipelines and related facilities will depend upon the success of drilling programs around our pipelines, as well as attraction and retention of producers/shippers to the pipeline systems. If we are successful in our efforts to attract additional discoveries to our pipelines, we would gain additional throughput on the pipelines resulting in additional revenues. Our financial condition continues to be adversely affected by the low utilization of our pipeline assets.

The revenues from our working interests in High Island Block 37 and High Island Block A-7 are declining as the rate of production declines. The rate of production from High Island Block 37 declined by approximately 65% during 2006. The rate of production from High Island Block A-7 has declined by approximately 60% since the end of 2006. Recent production data from High Island Block A-7 has provided evidence that the producing well is reaching the end of its productive life. We currently believe that the High Island Block A-7 well could cease production before mid 2007. We believe that production from one of the two producing High Island Block 37 wells could continue to produce into early 2008 and the other well could produce until mid 2008. However, the wells could deplete faster than anticipated or could develop production problems resulting in the cessation of production. Without the revenues and resulting cash inflows we receive from oil and gas sales, we may not be able to generate sufficient cash from operations to cover our operating and general and administrative expenses.

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We recognized gross oil and gas sales revenues of $889,682 and $2,413,512 for the twelve months ended December 31, 2006 and 2005, respectively, associated with our 2.8% contractual working interest in two wells in High Island Block 37. The High Island Block 37 wells are currently producing at a combined rate of approximately 8 MMcf per day. We recognized gross oil and gas sales revenues of $1,469,132 and $722,498 for the twelve months ended December 31, 2006 and 2005, respectively, associated with our approximate 8.9% working interest in the High Island Block A-7 wells. The active High Island Block A-7 well is currently producing at a rate of approximately 2 MMcf per day.

In early-2005, we entered into an amendment to our purchase agreement with MCNIC to acquire MCNIC s one-third interest in the Blue Dolphin System and the inactive Omega Pipeline. Pursuant to the terms of the amendment, we issued a new promissory note in the principal amount of $250,000 and either (i) MCNIC could have received a contingent payment of up to $500,000 from 50% of the net profits, if any, realized from the one-third interest through December 31, 2006, or (ii) the principal amount of the new promissory note could have been increased by up to $500,000 if 50% or more of our 83% interest in the assets was sold before December 31, 2006. A contingent payment from 50% of the net profits was not triggered nor did we sell the assets. As a result, the $500,000 contingent portion of the promissory note was extinguished effective December 31, 2006.

In April 2005, the holders of $450,000 of the $750,000 aggregate principal amount of promissory notes sold in September 2004, agreed to extend the maturity date of their promissory notes to June 30, 2006, and to defer the payment of all unpaid and future interest on their promissory notes until maturity. The first $300,000 aggregate principal amount of promissory notes was retired at maturity on September 8, 2005. The promissory notes were originally sold on September 8, 2004 pursuant to the Note and Warrant Purchase Agreement we entered into with certain accredited investors and certain of our directors. The remaining $450,000 aggregate principal amount of promissory notes was retired on June 30, 2006 along with interest payments of $88,123 for a total cash payment of $538,123.

The following table summarizes certain of our contractual obligations and other commercial commitments at December 31, 2006 (in thousands):

CONTRACTUAL OBLIGATIONS AND OTHER COMMERCIAL COMMITMENTS

	Payments Due by Period				
	Total	1 Year or Less	1-3 Years	3-5 Years	5 Years or More
Operating leases	$ 430	$ 71	$ 211	$ 148	$
Asset retirement obligations	2,014		403		1,611
Total contractual obligations and other commercial commitments	$ 2,444	$ 71	$ 614	$ 148	$ 1,611

In March 2006, we completed a private placement with certain accredited investors of 1,171,432 shares of our common stock. The net proceeds from the offering after the payment of commissions and expenses were approximately $2.0 million and we issued warrants to purchase an aggregate of 8,572 shares of common stock. The exercise price per share of the warrants varied. All warrants associated with this offering were exercised in 2006 at an exercise price of $1.93 per share.

In April 2006, we completed a second private placement with an accredited institutional investor of 400,000 shares of our common stock. Net proceeds from the offering were approximately $1.8 million. We incurred commissions and expenses of approximately $160,000 associated with the offering, and issued warrants to purchase an aggregate of 24,000 shares of common stock. These warrants were immediately exercisable upon issuance and 7,560 of the warrants were exercised in 2006 at an exercise

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price of $5.39 per share. The exercise price varies based on the following conditions: (i) until the later of the registration of the warrants or one year from the issue date, 110% of the purchase price of $4.90 per share; (ii) from the later of (x) the registration of the warrants and (y) one year, until two years from the issue date, 120% of the purchase price of $4.90 per share; and (iii) after the expiration of two years from the issue date of the warrants, 130% of the purchase price of $4.90 per share.

The net proceeds from these offerings are being used for general corporate and working capital purposes, and may also be used for possible acquisitions and planned expansions of our facilities. In addition to providing funds immediately available for specific uses, the net proceeds of the private placements also provided additional working capital, which assists in our ability to withstand events that could have a material adverse affect on our operations. During the twelve months ended December 31, 2006, we incurred capital expenditures of $15,700 for the further development of our proved reserves.

Results of Operations

For the year ended December 31, 2006 (2006), we reported net income of $912,864, compared to net income of $541,386 for the year ended December 31, 2005 (2005).

2006 Compared to 2005

Revenue from Pipeline Operations. Revenues from pipeline operations increased by $564,721, or 41.1%, in 2006 to $1,939,894. Revenues in 2006 from the Blue Dolphin System totaled approximately $1,755,000 compared to approximately $1,154,000 in 2005, primarily as a result of production from three new shippers who began deliveries during 2006.

The increased revenues on the Blue Dolphin System were partially offset by decreased revenues on the GA 350 Pipeline of approximately $98,000, primarily due to a decrease in average daily gas volumes transported to approximately 9 MMcf per day in 2006 from approximately 12 MMcf per day in 2005.

Revenue from Oil and Gas Sales. Revenues from oil and gas sales decreased by $777,196 to $2,358,814 in 2006. Revenues were approximately $890,000 for High Island Block 37 and $1,469,000 for High Island Block A-7 in 2006, compared to approximately $2,414,000 for High Island Block 37 and $722,000 for High Island Block A-7 in 2005. Production in 2006 from High Island Block A-7 averaged 5.6 MMcf per day. In 2005, a single well produced at an average rate of less than 1 MMcf per day for the first half of the year. Two wells were successfully recompleted during the third quarter of 2005 and produced at a higher rate through the end of the year. The $2,414,000 in revenues recognized for High Island Block 37 in 2005 represents our interest in production from the estimated payout date of July 1, 2004 through December 2005. The sales mix by product in 2006 was 90% gas and 10% condensate and natural gas liquids. Our average realized gas price per Mcf in 2006 was $7.56, compared to $8.11 in 2005. Our average realized price per barrel of condensate was $62.60 in 2006, compared to $51.83 in 2005.

Pipeline Operating Expenses. Pipeline operating expenses in 2006 increased by $44,976 to $1,126,539 primarily due to an increase of approximately $157,000 in insurance costs because of higher property and liability insurance premiums. The lower insurance costs in 2005 were partially a result of a refund received in 2005 for having no claims in the previous policy period. Increased insurance costs in 2006 were offset by a decrease in legal costs of approximately $121,000. The higher legal costs in 2005 were associated with an action filed against us, the outcome of which we do not believe will have a material impact on our financial condition. However, as this litigation continues, we will continue to incur legal expenses which could have a material adverse affect on our financial condition. Also, repairs and maintenance expense increased approximately $27,000 in 2006 as compared to 2005.

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Lease Operating Expenses. Lease operating expenses increased by $302,138 in 2006. The increase was primarily due to increased activity associated with High Island Block A-7, which accounted for $420,067 in lease operating costs in 2006 as compared to $125,497 in 2005. In 2005, lease operating costs increased in the third and fourth quarters following the recompletion of two wells on High Island Block A-7 and the recognition of the expense associated with our interest in High Island Block 37. Both blocks produced for twelve full months in 2006.

Depletion, Depreciation and Amortization. Depletion, depreciation and amortization expense increased by $98,841 in 2006 to $502,058. In 2006 we recorded depletion expense of approximately $103,200 associated with our oil and gas properties, compared to approximately $52,100 in 2005. The increase in depletion expense was a result of there being limited remaining unamortized oil and gas costs in 2005 and new oil and gas costs added to the depletion pool in late 2005 and 2006. Estimated dismantlement costs increased approximately $14,500 due to an increase in asset retirement obligations.

General and Administrative. General and administrative expenses decreased by $835,409 to $1,773,102 in 2006. The decrease was due to recognition in 2005 of $774,369 of non-cash compensation expense associated with cashless exercises of 289,321 stock options by certain of our directors and employees during the period. Also contributing to the decrease were lower legal expenses of approximately $77,000 and lower directors and officers insurance costs of approximately $28,000.

Interest and Other Expense. Interest and other expense decreased $82,070 in 2006 to $42,224. Interest expense in 2006 decreased by approximately $50,200 due to a decrease in the amount of our outstanding debt. Other expense in 2005 included approximately $38,000 for the amortization of debt issuance costs.

Interest and Other Income. Interest and other income decreased by $238,307 in 2006. Interest income in 2006 totaled $137,659. Other income in 2005 included a gain on the elimination of accrued interest pursuant to the restructuring of the MCNIC promissory note of approximately $132,000, a gain of approximately $178,000 associated with the collection of a related-party receivable and accounts receivable of $45,000 that were both previously written off.

Gain on Sale of Assets. We recorded a gain in 2005 on the placement of our interests in the Galveston Area Block 287/297 leases of approximately $140,000.

Gain on Extinguishment of Debt. In 2006, we recognized a gain of $500,000 on the extinguishment of the contingent portion of the promissory note payable to MCNIC. The contingent portion of the promissory note was extinguished effective December 31, 2006.

Critical Accounting Policies

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules, and the use of judgment, to the specific set of circumstances existing in our business. We make every effort to properly comply with all applicable rules at or before their adoption, and believe the proper implementation and consistent application of the accounting rules is critical. However, not all situations are specifically addressed in the accounting literature. In these cases, we must use our best judgment to adopt a policy for accounting for these situations. We accomplish this by comparatively analyzing similar situations and reviewing the accounting guidance governing them, and may consult with our independent accountants about the appropriate interpretation and application of these policies. Our most critical accounting policies currently relate to the accounting for the impairment of long-lived assets, which include primarily our pipeline assets, as of December 31, 2006 and the accounting for future asset retirement costs.

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In accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, we initiate a review for impairment of our long-lived assets whenever events or changes in circumstances indicate that the carrying amount of a long-lived asset may not be recoverable. Recoverability of an asset is measured by comparison of its carrying amount to the expected future undiscounted cash flows expected to result from the use and eventual disposition of that asset, excluding future interest costs that would be recognized as an expense when incurred. Any impairment to be recognized is measured by the amount by which the carrying amount of the asset exceeds its fair market value. Significant management judgment is required in the forecasting of future operating results which are used in the preparation of projected cash flows and, should different conditions prevail or judgments be made, material impairment charges could be necessary. Currently, our pipeline assets are significantly under utilized and such underutilization is an indicator of possible impairment at December 31, 2006. Accordingly, we developed future cash flows as of December 31, 2006 expected to be generated from our pipeline assets based on certain assumptions. The most significant assumption made in connection with the preparation of expected future cash flows is the assumption that pipeline throughput volumes will increase over the next few years due to increasing current leasing and drilling activities, and prospective drilling activity surrounding our pipelines. Based on the results of the impairment test, which indicates expected future undiscounted cash flows are in excess of the pipeline assets net carrying value, no impairment has been recorded as of December 31, 2006.

The accounting for future abandonment costs changed on January 1, 2003 with the adoption of SFAS No. 143. This new standard requires that a liability for the discounted fair value of an asset retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted towards its future value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. Future asset retirement costs include costs to dismantle and relocate or dispose of our offshore platforms, pipeline systems and related onshore facilities and restoration costs of land and seabed. We develop estimates of these costs for each of our assets based upon the type of platform structure, depth of water, reservoir characteristics, depth of the reservoir, market demand for equipment, currently available procedures and consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. We review our assumptions and estimates of future abandonment costs on a quarterly basis.

Recently Issued Accounting Pronouncements and Accounting Developments

In February 2007, FASB issued FASB Statement No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115* (SFAS 159). This standard permits an entity to choose to measure many financial instruments and certain other items at fair value. This option is available to all entities, including not-for-profit organizations. Most of the provisions in SFAS 159 are elective; however, the amendment to FASB Statement No. 115, *Accounting for Certain Investments in Debt and Equity Securities*, applies to all entities with available-for-sale and trading securities. Some requirements apply differently to entities that do not report net income. The FASB s stated objective in issuing this standard is as follows: to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions.

The fair value option established by SFAS 159 permits all entities to choose to measure eligible items at fair value at specified election dates. A business entity will report unrealized gains and losses on items for which the fair value option has been elected in earnings (or another performance indicator if the business entity does not report earnings) at each subsequent reporting date. A not-for-profit organization will report unrealized gains and losses in its statement of activities or similar statement. The fair value option: (i) may be applied instrument by instrument, with a few exceptions, such as investments otherwise accounted

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for by the equity method; (ii) is irrevocable (unless a new election date occurs); and (iii) is applied only to instruments and not to portions of instruments.

SFAS 159 is effective as of the beginning of an entity s first fiscal year that begins after November 15, 2007. Early adoption is permitted as of the beginning of the previous fiscal year provided that the entity makes that choice in the first 120 days of that fiscal year and also elects to apply the provisions of FASB Statement No. 157, *Fair Value Measurements* (SFAS 157). We are currently assessing the impact of SFAS 159 on our consolidated financial statements.

In September 2006, SFAS 157 was issued by the FASB. This new standard provides guidance for using fair value to measure assets and liabilities. The FASB believes the standard also responds to investors requests for expanded information about the extent to which companies measure assets and liabilities at fair value, the information used to measure fair value and the effect of fair value measurements on earnings. SFAS 157 applies whenever other standards require (or permit) assets or liabilities to be measured at fair value but does not expand the use of fair value in any new circumstances.

Currently, over 40 accounting standards within GAAP require (or permit) entities to measure assets and liabilities at fair value. Prior to SFAS 157, the methods for measuring fair value were diverse and inconsistent, especially for items that are not actively traded. The standard clarifies that for items that are not actively traded, such as certain kinds of derivatives, fair value should reflect the price in a transaction with a market participant, including an adjustment for risk, not just the company s mark-to-model value. SFAS 157 also requires expanded disclosure of the effect on earnings for items measured using unobservable data.

Under SFAS 157, fair value refers to the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the market in which the reporting entity transacts. In this standard, FASB clarifies the principle that fair value should be based on the assumptions market participants would use when pricing the asset or liability. In support of this principle, SFAS 157 establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. The fair value hierarchy gives the highest priority to quoted prices in active markets and the lowest priority to unobservable data, for example, the reporting entity s own data. Under the standard, fair value measurements would be separately disclosed by level within the fair value hierarchy.

The provisions of SFAS 157 are effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. Earlier application is encouraged, provided that the reporting entity has not yet issued financial statements for that fiscal year, including any financial statements for an interim period within that fiscal year. We are currently assessing the impact of SFAS 157 on our financial statements.

In July 2006, FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes-An Interpretation of FASB Statement No. 109* (FIN 48), was issued. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes*. FIN 48 also prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The new FASB standard also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition.

The evaluation of a tax position in accordance with FIN 48 is a two-step process. The first step is a recognition process whereby the enterprise determines whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. In evaluating whether a tax position has met the more-likely-than-not recognition threshold, the enterprise should presume that the position will be examined by the appropriate taxing authority that has full knowledge of all relevant information. The second step is a measurement process whereby a tax position that meets the more-likely-than-not recognition threshold is

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calculated to determine the amount of benefit to recognize in the financial statements. The tax position is measured at the largest amount of benefit that is greater than 50% likely of being realized upon ultimate settlement.

The provisions of FIN 48 are effective for fiscal years beginning after December 15, 2006. Earlier application is permitted as long as the enterprise has not yet issued financial statements, including interim financial statements, in the period of adoption. The provisions of FIN 48 are to be applied to all tax positions upon initial adoption of this standard. Only tax positions that meet the more-likely-than-not recognition threshold at the effective date may be recognized or continue to be recognized upon adoption of FIN 48. The cumulative effect of applying the provisions of FIN 48 should be reported as an adjustment to the opening balance of retained earnings (or other appropriate components of equity or net assets in the statement of financial position) for that fiscal year. We are currently assessing the impact on our consolidated financial statements of FIN 48.

On September 13, 2006, the SEC staff issued Staff Accounting Bulletin No. 108, which adds Section N to Topic 1, Financial Statements *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements* (SAB 108). The SEC staff provides guidance on how prior year misstatements should be taken into consideration when quantifying misstatements in current year financial statements for the purposes of determining whether the current year s financial statements are materially misstated. In providing this guidance, the SEC staff references both the iron curtain and rollover approaches to quantifying a current year misstatement for purposes of determining its materiality. The iron curtain approach focuses on how the current year s balance sheet would be affected in correcting a misstatement without considering the year(s) in which the misstatement originated. The rollover approach focuses on the amount of the misstatement that originated in the current year s income statement. The SEC staff indicates in SAB 108 that registrants must quantify the impact of correcting all misstatements, including both the carryover and reversing effects of prior year misstatements, on the current year financial statements. In other words, both the iron curtain approach and rollover approach should be used in assessing the materiality of a current year misstatement. SAB 108 provides that once a current year misstatement has been quantified, the guidance in Staff Accounting Bulletin No. 99, Section M, Topic 1, Financial Statements *Materiality* (SAB 99), should be applied to determine whether the misstatement is material and should result in an adjustment to the financial statements.

If correcting a misstatement in the current year would materially misstate the current year s income statement, the SEC staff indicates that the prior year financial statements should be adjusted. In addition, adjusting for one misstatement in the current year may alter the amount of the misstatement attributable to prior years that exists in the current year s financial statements. If adjusting for the resultant misstatement is material to the current year s financial statements, the SEC staff again indicates that the prior year financial statements should be adjusted. These adjustments to prior year financial statements are necessary even though such adjustments were appropriately viewed as immaterial in the prior year. In making these adjustments, previously filed reports do not need to be amended. Instead, the adjustments should be reflected the next time the registrant would otherwise be filing those prior year financial statements. It should be noted that if, in the current year, a registrant identifies a misstatement in the prior year financial statements and determines that the misstatement is material to those prior year financial statements, the registrant would be required to restate for the material misstatement in accordance with FASB Statement No. 154, *Accounting Changes and Error Corrections* (SFAS 154).

If a registrant has historically been using either the iron curtain approach or the rollover approach and, upon application of the guidance of SAB 108, determines that there is a material misstatement in its financial statements, the SEC staff will not require the registrant to restate its prior year financial statements provided that: (a) management properly applied the approach it previously used as its accounting policy and (b) management considered all relevant qualitative factors in its materiality assessment. If the registrant does not elect to restate its financial statements for the material misstatements

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that arise in connection with application of the guidance in SAB 108, then for fiscal years ending after November 15, 2006, it must recognize the cumulative effect of applying SAB 108 in the current year beginning balances of the affected assets and liabilities with a corresponding adjustment to the current year opening balance in retained earnings. Certain disclosures are required in this situation. SAB 108 provides additional transition guidance if it is adopted early in an interim period. The adoption of SAB 108 did not have a material effect on our consolidated financial statements.

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Item 7. Financial Statements

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Report of Independent Registered Public Accounting Firm

The Board of Directors and
Stockholders of Blue Dolphin Energy Company

We have audited the accompanying consolidated balance sheet of Blue Dolphin Energy Company and subsidiaries (the Company) as of December 31, 2006, and the related consolidated statements of income, stockholders equity and cash flows for each of the years in the two-year period ended December 31, 2006. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated 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 audits 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 consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Blue Dolphin Energy Company and subsidiaries as of December 31, 2006, and the consolidated results of their operations and their cash flows for each of the years in the two-year period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America.

/s/ UHY, LLP
Houston, Texas
March 20, 2007

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Consolidated Balance Sheet

	December 31, 2006
ASSETS	
Current assets:	
Cash and cash equivalents	$ 5,499,147
Accounts receivable	1,174,319
Prepaid expenses and other assets	337,167
Total current assets	7,010,633
Property and equipment, at cost:	
Oil and gas properties (full-cost method)	715,970
Pipelines	4,575,295
Onshore separation and handling facilities	1,919,402
Land	860,275
Other property and equipment	269,192
	8,340,134
Less:	
Accumulated depletion, depreciation, amortization and impairment	3,428,268
	4,911,866
Other assets	21,999
TOTAL ASSETS	$ 11,944,498
LIABILITIES AND STOCKHOLDERS EQUITY	
Current liabilities:	
Accounts payable	$ 264,684
Accrued expenses and other liabilities	93,661
Total current liabilities	358,345
Long-term liabilities:	
Asset retirement obligations	2,014,408
Total long-term liabilities	2,014,408
Stockholders equity:	
	115,555

Common stock, ($.01 par value, 25,000,000 shares authorized, 11,555,452 shares issued and outstanding	
Additional paid-in capital	31,835,137
Accumulated deficit	(22,378,947)
	9,571,745
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 11,944,498

See accompanying notes to consolidated financial statements.

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Consolidated Statements of Income

	Years Ended December 31, 2006	2005
Revenue from operations:		
Pipeline operations	$ 1,939,894	$ 1,375,173
Oil and gas sales	2,358,814	3,136,010
Total revenue from operations	4,298,708	4,511,183
Cost of operations:		
Pipeline operating expenses	1,126,539	1,081,563
Lease operating expenses	457,312	155,174
Depletion, depreciation and amortizaton	502,058	403,217
General and administrative expenses	1,773,102	2,608,511
Accretion expense	107,589	100,308
Total cost of operations	3,966,600	4,348,773
Income from operations	332,108	162,410
Other income (expense):		
Interest and other expense	(42,224)	(124,294)
Interest and other income	137,659	375,966
Gain on extinguishment of debt	500,000	
Gain on sale of assets		140,409
Income before income taxes	927,543	554,491
Income tax expense	(14,679)	(13,105)
Net income	$ 912,864	$ 541,386
Income per common share:		
Basic	$ 0.08	$ 0.06
Diluted	$ 0.08	$ 0.06
Weighted average number of common shares outstanding:		
Basic	11,202,951	8,763,475
Diluted	11,306,662	8,874,117

See accompanying notes to consolidated financial statements.

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Consolidated Statements of Stockholders Equity

	Common Stock Shares	Common Stock	Additional Paid-In Capital	Accumulated Deficit	Total Stockholders Equity
Balance at December 31, 2004	6,863,689	$ 68,637	$ 27,129,162	$ (23,833,197)	$ 3,364,602
Exercise of stock options	201,899	2,019	772,350		774,369
Common stock issued for services	53,345	533	107,167		107,700
Exercise of warrants	2,820,369	28,204	(28,204)		
Net income				541,386	541,386
Balance at December 31, 2005	9,939,302	99,393	27,980,475	(23,291,811)	4,788,057
Sale of common stock	1,571,432	15,714	3,825,110		3,840,824
Common stock issued for services	39,960	400	29,600		30,000
Exercise of warrants	4,758	48	(48)		
Net income				912,864	912,864
Balance at December 31, 2006	11,555,452	$ 115,555	$ 31,835,137	$ (22,378,947)	$ 9,571,745

See accompanying notes to consolidated financial statements.

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Consolidated Statements of Cash Flows

	Years Ended December 31, 2006	2005
OPERATING ACTIVITIES		
Net income	$ 912,864	$ 541,386
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion, depreciation and amortization	502,058	403,217
Amortization of debt issue costs		54,630
Gain on sale of assets		(140,409)
Accretion of asset retirement obligations	107,589	100,308
Gain on modification of note payable		(132,368)
Gain on extinguishment of debt	(500,000)	
Compensation from exercise of stock options		774,369
Common stock issued for services	30,000	94,800
Changes in operating assets and liabilities:		
Accounts receivable	427,977	(1,285,932)
Prepaid expenses and other assets	(164,053)	(68,095)
Accounts payable, accrued expenses and other liabilities	(100,876)	(292,274)
Net cash provided by operating activities	1,215,559	49,632
INVESTING ACTIVITIES		
Exploration and development costs	(15,700)	(72,501)
Property, equipment and other assets	(267,447)	(35,849)
Proceeds from sale of assets		214,632
Investment in unconsolidated affiliates	(1,177)	
Net cash provided by (used in) investing activities	(284,324)	106,282
FINANCING ACTIVITIES		
Proceeds from the sale of common stock, net of offering costs	3,840,824	
Payments on borrowings	(570,000)	(430,000)
Financing costs incurred		(2,275)
Proceeds from exercise of stock options		12,900
Net cash provided by (used in) financing activities	3,270,824	(419,375)
Increase (decrease) in cash and cash equivalents	4,202,059	(263,461)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	1,297,088	1,560,549
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 5,499,147	$ 1,297,088

Supplementary cash flow information:

Interest paid	$ 88,334	$ 46,422

See accompanying notes to consolidated financial statements.

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements
(1) Organization and Significant Accounting Policies

Organization

Blue Dolphin Energy Company was incorporated in Delaware in January 1986 to engage in oil and gas exploration, production and acquisition activities and oil and gas transportation and marketing. We were formed pursuant to a reorganization effective June 9, 1986.

Principles of Consolidation

Our consolidated financial statements include the accounts of our wholly-owned subsidiaries. All significant intercompany balances and transactions have been eliminated in consolidation.

Accounting Estimates

We have made a number of estimates and assumptions relating to the reporting of assets and liabilities and to the disclosure of contingent assets and liabilities, including reserve information, which affects the depletion calculation as well as the computation of the full cost ceiling limitation to prepare these consolidated financial statements in conformity with accounting principles generally accepted in the United States of America. While we believe current estimates are reasonable and appropriate, actual results could differ from those estimated.

Cash Equivalents

Cash equivalents include liquid investments with an original maturity of three months or less. Cash balances are maintained in depository and overnight investment accounts with financial institutions which at times, exceed insured limits. We monitor the financial condition of the financial institutions and have experienced no losses associated with these accounts.

Oil and Gas Properties

Oil and gas properties are accounted for using the full-cost method of accounting, whereby all costs associated with acquisition, exploration, and development of oil and gas properties, including directly related internal costs, are capitalized on a country-by-country cost center basis. We utilize one cost center for all of our properties. Amortization of such costs and estimated future development costs is determined using the unit-of-production method. Costs directly associated with the acquisition and evaluation of unproved properties are excluded from the amortization computation until it is determined whether or not proved reserves can be assigned to the properties or impairment has occurred.

Estimated proved oil and gas reserves are based upon reports prepared internally by us. The net carrying value of oil and gas properties, less related deferred income taxes, is limited to the lower of unamortized cost or the cost center ceiling, defined as the sum of the present value (10% discount rate applied) of estimated future net revenues from proved reserves, after giving effect to income taxes, and the lower of cost or estimated fair value of unproved properties. Disposition of oil and gas properties are recorded as adjustments to capitalized costs, with no gain or loss recognized unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves.

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

We capitalize interest on expenditures made in connection with significant exploration and development projects that are not subject to current amortization. Interest is capitalized only for the period that activities are in progress to bring these projects to their intended use. No interest has been capitalized for the years reflected herein.

Pipelines and Facilities

Pipelines and facilities are recorded at cost. Depreciation is computed using the straight-line method over estimated useful lives ranging from 10 to 22 years.

Other Property and Equipment

Depreciation of furniture, fixtures and other equipment, including assets held under capital leases, is computed using the straight-line method over estimated useful lives ranging from 3 to 10 years.

In accordance with Statements of Financial Accounting Standards (SFAS) No. 144, *Accounting for the Impairment or Disposal of Long-lived Assets*, assets are grouped and evaluated for impairment based on the ability to identify separate cash flows generated therefrom.

Asset Retirement Obligations

In August 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143, *Accounting for Asset Retirement Obligations*, as amended, which addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. The standard applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset.

SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset and this additional carrying amount is depreciated over the life of the asset. If the obligation is settled for other than the carrying amount of the liability, a gain or loss on settlement is recognized.

We have asset retirement obligations associated with the future abandonment of pipelines and related facilities and offshore oil and gas properties. The following table summarizes our asset retirement obligation transactions during the years ended December 31, 2006 and 2005 (in thousands).

	Years Ended December 31,	
	2006	2005
Beginning asset retirement obligations	$ 1,756	$ 1,622
Liabilities incurred		40
Liabilities settled		
Gain from adjustment to estimated obligations		(6)
Accretion expense	108	100
Revisions in estimated cash flows	150	
Ending asset retirement obligations	$ 2,014	$ 1,756

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

Stock-Based Compensation

Effective January 1, 2006, we adopted Statement of Financial Accounting Standards No. 123 (Revised), *Share-Based Payments* (SFAS 123(R)) utilizing the modified prospective approach. Prior to the adoption of SFAS 123(R) we accounted for stock option grants in accordance with APB Opinion No. 25, *Accounting for Stock Issued to Employees* (the intrinsic value method), and accordingly, recognized no compensation expense when stock options were granted with an exercise price equal to the grant date fair market value of a share of our common stock.

Under the modified prospective approach, SFAS 123(R) applies to new awards and to awards that were outstanding on January 1, 2006 that are subsequently modified, repurchased, or cancelled. Under the modified prospective approach, had there been any awards granted during 2006, compensation expense recognized in the periods would have included compensation cost for all share-based payments granted prior to, but not yet vested, based on the grant date fair value estimated in accordance with the original provisions of Statement of Financial Accounting Standards No. 123, *Accounting for Stock-Based Compensation*, and compensation cost for all share-based payments granted subsequent to January 1, 2006, based on the grant date fair value estimated in accordance with the provisions of SFAS 123(R). Prior periods were not restated to reflect the impact of adopting the new standard.

Recognition of Oil and Gas Revenue

Sales from producing wells are recognized on the entitlement method of accounting which defers recognition of sales when, and to the extent that, deliveries to customers exceed our net revenue interest in production. Similarly, when deliveries are below our net revenue interest in production, sales are recorded to reflect the full net revenue interest. Our imbalance liability at December 31, 2006 was not material.

Recognition of Pipeline Transportation Revenue

Revenues from our pipelines are derived from fee-based contracts and are typically based on transportation fees per unit of volume transported multiplied by the volume delivered. Revenue is recognized when volumes have been physically delivered for the customer through the pipeline.

Income Taxes

We provide for income taxes using the asset and liability method pursuant to SFAS No. 109, *Accounting for Income Taxes*. Under the asset and liability method of SFAS No. 109, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

Earnings Per Share

We apply the provisions of Statement of Financial Accounting Standards No. 128, *Earnings per Share* (SFAS 128). SFAS 128 requires the presentation of basic earnings per share (EPS) which excludes dilution and is computed by dividing net income (loss) available to common stockholders by the weighted-average number of shares of common stock outstanding for the period. SFAS 128 requires dual presentation of basic EPS and diluted EPS on the face of the income statement and requires a reconciliation of the numerators and denominators of basic EPS and diluted EPS. Diluted EPS is computed by dividing net income (loss) available to common shareholders by the diluted weighted average number of common shares outstanding, which includes the potential dilution that could occur if securities or other contracts to issue common stock were converted to common stock that then shared in the earnings of the entity.

The following table provides reconciliation between basic and diluted earnings per share:

	Net Income	Weighted-Average Number of Common Shares Outstanding and Potential Dilutive Common Shares	Per Share Amount
Year ended December 31, 2006:			
Basic income per share	$ 912,864	11,202,951	$ 0.08
Effect of dilutive stock options		103,711	
Diluted income per share	$ 912,864	11,306,662	$ 0.08
Year ended December 31, 2005:			
Basic income per share	$ 541,386	8,763,475	$ 0.06
Effect of dilutive stock options		110,642	
Diluted income per share	$ 541,386	8,874,117	$ 0.06

Environmental

We are subject to extensive federal, state and local environmental laws and regulations. These laws, which are constantly changing, regulate the discharge of materials into the environment and may require us to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a noncapital nature are recorded when environmental assessment and/or remediation is probable, and the costs can be reasonably estimated. Such liabilities are generally recorded at their undiscounted amounts unless the amounts and timing of payments is fixed or reliably determinable.

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

Recently Issued Accounting Pronouncements

In February 2007, FASB issued FASB Statement No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115* (SFAS 159). This standard permits an entity to choose to measure many financial instruments and certain other items at fair value. This option is available to all entities, including not-for-profit organizations. Most of the provisions in SFAS 159 are elective; however, the amendment to FASB Statement No. 115, *Accounting for Certain Investments in Debt and Equity Securities*, applies to all entities with available-for-sale and trading securities. Some requirements apply differently to entities that do not report net income. The FASB s stated objective in issuing this standard is as follows: to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions.

The fair value option established by SFAS 159 permits all entities to choose to measure eligible items at fair value at specified election dates. A business entity will report unrealized gains and losses on items for which the fair value option has been elected in earnings (or another performance indicator if the business entity does not report earnings) at each subsequent reporting date. A not-for-profit organization will report unrealized gains and losses in its statement of activities or similar statement. The fair value option: (i) may be applied instrument by instrument, with a few exceptions, such as investments otherwise accounted for by the equity method; (ii) is irrevocable (unless a new election date occurs); and (iii) is applied only to instruments and not to portions of instruments.

SFAS 159 is effective as of the beginning of an entity s first fiscal year that begins after November 15, 2007. Early adoption is permitted as of the beginning of the previous fiscal year provided that the entity makes that choice in the first 120 days of that fiscal year and also elects to apply the provisions of FASB Statement No. 157, *Fair Value Measurements* (SFAS 157). We are currently assessing the impact of SFAS 159 on our consolidated financial statements.

In September 2006, SFAS 157 was issued by the FASB. This new standard provides guidance for using fair value to measure assets and liabilities. The FASB believes the standard also responds to investors requests for expanded information about the extent to which companies measure assets and liabilities at fair value, the information used to measure fair value and the effect of fair value measurements on earnings. SFAS 157 applies whenever other standards require (or permit) assets or liabilities to be measured at fair value but does not expand the use of fair value in any new circumstances.

Currently, over 40 accounting standards within GAAP require (or permit) entities to measure assets and liabilities at fair value. Prior to SFAS 157, the methods for measuring fair value were diverse and inconsistent, especially for items that are not actively traded. The standard clarifies that for items that are not actively traded, such as certain kinds of derivatives, fair value should reflect the price in a transaction with a market participant, including an adjustment for risk, not just the company s mark-to-model value. SFAS 157 also requires expanded disclosure of the effect on earnings for items measured using unobservable data.

Under SFAS 157, fair value refers to the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the market in which the reporting entity transacts. In this standard, FASB clarifies the principle that fair value should be based on the assumptions market participants would use when pricing the asset or liability. In support of this principle, SFAS 157 establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. The fair value hierarchy gives the

highest priority

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

to quoted prices in active markets and the lowest priority to unobservable data, for example, the reporting entity s own data. Under the standard, fair value measurements would be separately disclosed by level within the fair value hierarchy.

The provisions of SFAS 157 are effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. Earlier application is encouraged, provided that the reporting entity has not yet issued financial statements for that fiscal year, including any financial statements for an interim period within that fiscal year. We are currently assessing the impact of SFAS 157 on our financial statements.

In July 2006, FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes-An Interpretation of FASB Statement No. 109* (FIN 48), was issued. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes*. FIN 48 also prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The new FASB standard also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition.

The evaluation of a tax position in accordance with FIN 48 is a two-step process. The first step is a recognition process whereby the enterprise determines whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. In evaluating whether a tax position has met the more-likely-than-not recognition threshold, the enterprise should presume that the position will be examined by the appropriate taxing authority that has full knowledge of all relevant information. The second step is a measurement process whereby a tax position that meets the more-likely-than-not recognition threshold is calculated to determine the amount of benefit to recognize in the financial statements. The tax position is measured at the largest amount of benefit that is greater than 50% likely of being realized upon ultimate settlement.

The provisions of FIN 48 are effective for fiscal years beginning after December 15, 2006. Earlier application is permitted as long as the enterprise has not yet issued financial statements, including interim financial statements, in the period of adoption. The provisions of FIN 48 are to be applied to all tax positions upon initial adoption of this standard. Only tax positions that meet the more-likely-than-not recognition threshold at the effective date may be recognized or continue to be recognized upon adoption of FIN 48. The cumulative effect of applying the provisions of FIN 48 should be reported as an adjustment to the opening balance of retained earnings (or other appropriate components of equity or net assets in the statement of financial position) for that fiscal year. We are currently assessing the impact on our consolidated financial statements of FIN 48.

On September 13, 2006, the SEC staff issued Staff Accounting Bulletin No. 108, which adds Section N to Topic 1, Financial Statements *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements* (SAB 108). The SEC staff provides guidance on how prior year misstatements should be taken into consideration when quantifying misstatements in current year financial statements for the purposes of determining whether the current year s financial statements are materially misstated. In providing this guidance, the SEC staff references both the iron curtain and rollover approaches to quantifying a current year misstatement for purposes of determining its materiality. The iron curtain approach focuses on how the current year s balance sheet would be affected in correcting a misstatement without considering the year(s) in which the misstatement originated. The rollover approach focuses on the amount of the misstatement that originated in the current year s income statement. The SEC staff indicates in SAB 108 that

registrants must quantify the impact of

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

correcting all misstatements, including both the carryover and reversing effects of prior year misstatements, on the current year financial statements. In other words, both the iron curtain approach and rollover approach should be used in assessing the materiality of a current year misstatement. SAB 108 provides that once a current year misstatement has been quantified, the guidance in Staff Accounting Bulletin No. 99, Section M, Topic 1, Financial Statements *Materiality* (SAB 99), should be applied to determine whether the misstatement is material and should result in an adjustment to the financial statements.

If correcting a misstatement in the current year would materially misstate the current year s income statement, the SEC staff indicates that the prior year financial statements should be adjusted. In addition, adjusting for one misstatement in the current year may alter the amount of the misstatement attributable to prior years that exists in the current year s financial statements. If adjusting for the resultant misstatement is material to the current year s financial statements, the SEC staff again indicates that the prior year financial statements should be adjusted. These adjustments to prior year financial statements are necessary even though such adjustments were appropriately viewed as immaterial in the prior year. In making these adjustments, previously filed reports do not need to be amended. Instead, the adjustments should be reflected the next time the registrant would otherwise be filing those prior year financial statements. It should be noted that if, in the current year, a registrant identifies a misstatement in the prior year financial statements and determines that the misstatement is material to those prior year financial statements, the registrant would be required to restate for the material misstatement in accordance with FASB Statement No. 154, *Accounting Changes and Error Corrections* (SFAS 154).

If a registrant has historically been using either the iron curtain approach or the rollover approach and, upon application of the guidance of SAB 108, determines that there is a material misstatement in its financial statements, the SEC staff will not require the registrant to restate its prior year financial statements provided that: (a) management properly applied the approach it previously used as its accounting policy and (b) management considered all relevant qualitative factors in its materiality assessment. If the registrant does not elect to restate its financial statements for the material misstatements that arise in connection with application of the guidance in SAB 108, then for fiscal years ending after November 15, 2006, it must recognize the cumulative effect of applying SAB 108 in the current year beginning balances of the affected assets and liabilities with a corresponding adjustment to the current year opening balance in retained earnings. Certain disclosures are required in this situation. SAB 108 provides additional transition guidance if it is adopted early in an interim period. The adoption of SAB 108 did not have a material effect on our consolidated financial statements.

(2) Liquidity

We ended 2006 with working capital of approximately $6.7 million and notes payable have been reduced to zero. At the end of 2005, our working capital was approximately $2.1 million and our short-term and long-term notes payable totaled $950,000. The increase in working capital from year-end 2005 was primarily the result of proceeds received from two private placements that were completed in the first half of 2006, significant revenues from oil and gas sales and increased revenues from our pipeline operations.

Throughput on the Blue Dolphin System and the GA 350 Pipeline increased significantly during 2006. The Blue Dolphin System is currently transporting approximately 26 MMcf per day and the GA 350 Pipeline is currently transporting approximately 20 MMcf per day. All five of the new shippers we have contracted with since 2005 have commenced deliveries. Four of the new shippers are delivering production into the Blue Dolphin System and one of the new shippers is delivering production into the GA 350 Pipeline. One of the five new shippers began deliveries into the Blue Dolphin System in August 2005. In 2006, one new shipper began deliveries

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

into the Blue Dolphin System in each of May, June and November. A new shipper began deliveries into the GA 350 Pipeline in December 2006. Also, in July 2006, a shipper that has delivered production into the Blue Dolphin System for a number of years, successfully recompleted an existing well, resulting in an increase of daily production.

Revenues from our working interests in High Island Block 37 and High Island Block A-7 are declining as the rate of production declines. Production from High Island Block 37 is currently 8 MMcf per day and High Island Block A-7 is currently 2 MMcf per day. Recent production data has provided evidence that the well in High Island Block A-7 is reaching the end of its production life. We currently believe that the High Island Block A-7 well could cease production before mid 2007. We believe that production from one of the High Island Block 37 wells could continue into early 2008 at a declining rate. However, the wells could deplete faster than anticipated or could develop production problems resulting in the cessation of production. Without the revenues and resulting cash inflows we receive from oil and gas sales, we may not be able to generate sufficient cash from operations to cover our operating and general and administrative expenses.

In March 2006, we entered into a stock purchase agreement with certain accredited investors for the private placement of 1,171,432 shares of our common stock at a price of $1.75 per share. The net proceeds from this offering after commissions and expenses were approximately $2,025,000. The net proceeds from this offering are being used for general corporate and working capital purposes. We may also use these proceeds for possible acquisitions and planned expansions of our existing facilities.

In April 2006, we entered into a second stock purchase agreement with an accredited institutional investor for the private placement of 400,000 shares of our common stock at a purchase price of $4.90 per share. Net proceeds from the offering were approximately $1.8 million. We incurred commissions and expenses of approximately $160,000 associated with the offering, and issued warrants to purchase an aggregate of 24,000 shares of common stock. The net proceeds from the offering are also being used for general corporate and working capital purposes, but may be used for possible acquisitions and planned expansions of our facilities. We believe we have sufficient liquidity to satisfy our working capital requirements through December 31, 2007.

The net cash provided by or used in operating, investing and financing activities is summarized below (in thousands):

	Years Ended December 31,	
	2006	2005
Net cash provided by (used in):		
Operating activities	$ 1,215	$ 50
Investing activities	(284)	106
Financing activites	3,271	(419)
Net decrease in cash	$ 4,202	$ (263)

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

(3) Fair Value of Financial Instruments

The carrying values of cash and cash equivalents, accounts receivable and accounts payable approximate fair value due to the short-term maturities of these instruments.

(4) Income Taxes

Income tax expense consisted of current federal expense of $14,679 and $13,105 for 2006 and 2005, respectively.

The income tax effects of temporary differences that give rise to significant portions of deferred tax assets and deferred tax liabilities at December 31, 2006 are presented below:

Deferred tax assets:	
Net operating loss and capital loss carryforwards	$ 5,157,648
AMT credit carryforward	16,687
Basis differences in property and equipment	48,022
Total deferred tax assets	5,222,357
Less: valuation allowance	(5,222,357)
Deferred tax assets, net	$

In assessing the reliability of deferred tax assets, we apply SFAS No. 109 to determine whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. As a result, a full valuation allowance against our deferred tax asset was recognized at December 31, 2006 due to our uncertainty as to the utilization of the deferred tax assets in the foreseeable future.

Our effective tax rate applicable to continuing operations in 2006 and 2005 is as follows:

	Years Ended December 31,	
	2006	2005
Expected tax rate	34%	34%
Change in valuation allowance recognized in earnings	(32.42%)	(31.65%)
	1.58%	2.35%

For federal tax purposes, we have net operating loss carryforwards (NOLs) of approximately $15.2 million at December 31, 2006. These NOLs must be utilized prior to their expiration, which is between 2007 and 2024.

(5) Long-term Debt and Notes Payable

On February 28, 2005 (effective as of January 1, 2005), we entered into the Amendment to our Purchase Agreement with MCNIC. Under the terms of the original Purchase Agreement, we acquired MCNIC s one-third interests in both the Blue Dolphin System and the inactive Omega Pipeline. Pursuant to the terms of the

Amendment, the Original Promissory Note was exchanged

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

for the New Promissory Note, and all accrued interest on the Original Promissory Note, $132,368 at December 31, 2004, was forgiven and included in other income for the year ended December 31, 2005. In addition to the New Promissory Note, MCNIC could receive additional payments of up to $500,000 from 50% of the net profits, if any, realized from the one-third interest in the Blue Dolphin System through December 31, 2006. We made a principal payment on the New Promissory Note of $30,000 upon the execution of the Amendment. Under the terms of the New Promissory Note we made monthly principal payments of $10,000 through its maturity date of December 31, 2006. The principal amount of the New Promissory Note also could have been increased by up to $500,000 if 50% or more of our 83% interest in the Blue Dolphin System was sold before December 31, 2006. We were not required to make any contingent payments on the New Promissory Note and extinguished the $500,000 contingent portion of the New Promissory Note effective December 31, 2006.

In April 2005, the holders of $450,000 of the $750,000 aggregate principal amount of promissory notes sold in September 2004, agreed to extend the maturity date of their promissory notes to June 30, 2006, and to defer the payment of all unpaid and future interest on their promissory notes until maturity. The promissory notes were originally sold on September 8, 2004 pursuant to the Note and Warrant Purchase Agreement we entered into with certain accredited investors and certain of our directors. The $300,000 aggregate principal amount of promissory notes was retired at maturity on September 8, 2005. The remaining $450,000 aggregate principal amount of promissory notes was retired on June 30, 2006.

Total interest expense was approximately $32,000 and $82,000 for 2006 and 2005, respectively.

(6) Exercise of Warrants

On December 21, 2006, 4,286 outstanding warrants were exercised by warrant holders. The exercises were accomplished via a net exercise, whereby holders surrender their right to receive a portion of the shares of common stock. The rights to receive 2,618 shares of common stock were surrendered and we issued 1,668 shares of common stock upon exercise. The Company did not receive any proceeds from the net exercise of these warrants.

On August 8, 2006, 11,417 outstanding warrants were exercised by warrant holders. The exercises were also accomplished via a net exercise, whereby holders surrender their right to receive a portion of the shares of common stock. The rights to receive 8,622 shares of common stock were surrendered and we issued 2,795 shares of common stock upon exercise. The Company did not receive any proceeds from the net exercise of these warrants.

On April 17, 2006, 429 outstanding warrants were exercised by warrant holders. The exercises were accomplished via a net exercise, whereby holders surrendered their right to receive a portion of the shares of common stock. The rights to receive 134 shares of common stock were surrendered and the Company issued 295 shares of common stock upon exercise.

These securities were issued in reliance upon the exemption from registration pursuant to Section 4(2) under the Securities Act of 1933, as amended.

At January 1, 2005, there were 3,100,000 warrants outstanding that were issued pursuant to our Note and Warrant Purchase Agreement dated September 8, 2004. During the twelve months ended December 31, 2005, all 3,100,000 warrants were exercised.

The exercise of the warrants was accomplished via net exercises, whereby holders surrendered their right to purchase a portion of the shares of common stock, resulting in 279,631 shares of

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

common stock being surrendered to us for payment of the warrant exercise price and 2,820,369 shares issued to warrant holders.

A summary of warrant activity for 2006 and 2005 is as follows:

	Number of Warrants	Weighted-Average Exercise Price	Warrants Exercisable	Weighted-Average Exercise Price
Outstanding, December 31, 2004	3,100,000	$0.25	3,100,000	$0.25
Granted				
Exercised	(3,100,000)	$0.25		
Outstanding, December 31, 2005				
Granted	32,572	$4.48		
Exercised	(16,132)	$3.55		
Outstanding, December 31, 2006	16,440	$5.39	16,440	$5.39

At December 31, 2006, the range of warrant prices for shares under warrants and the weighted-average remaining contractual life was as follows:

	Warrants Outstanding, Fully Vested and Exercisable at December 31, 2006		
Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life in Years	Weighted Average Exercise Price
$5.00 to $5.50	16,440	2.2	$ 5.39

(7) Stockholders Equity

In March 2006, we entered into a stock purchase agreement with certain accredited investors for the private placement of 1,171,432 shares of our common stock. Net proceeds from the offering after payment of commissions and expenses were approximately $2.0 million. In April 2006, we entered into a second stock purchase agreement with an accredited institutional investor for the private placement of 400,000 shares of our common stock. Net proceeds from the offering after payment of commissions and expenses were approximately $1.8 million. Warrants to purchase 32,572 shares of common stock were issued associated with these offerings and 16,132 of the warrants were exercised in 2006 via a net exercise resulting in the issuance of 4,758 shares of common stock.

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

In January 2006, we issued 30,000 shares of common stock into our Blue Dolphin Services Co. 401K Plan as a 2005 contribution. We recorded compensation expense of $64,800 associated with this contribution in 2005.

In 2005, 319,321 stock options were exercised in a cashless manner, resulting in the issuance of 201,899 shares of common stock and recognition of approximately $774,000 of non-cash compensation expense. Also in 2005, 3,100,000 warrants outstanding were exercised in a cashless manner, whereby holders surrendered a portion of the shares obtained to pay for the exercise price of the warrants, resulting in 279,631 shares of common stock being surrendered and 2,820,369 shares of common stock issued to the warrant holders.

(8) Stock Options

Effective April 14, 2000, we adopted, after approval by our stockholders, the 2000 Stock Incentive Plan (the 2000 Plan). Under the 2000 Plan, we are able to make incentive stock awards. We amended the 2000 Plan effective March 19, 2003, after approval by our stockholders on May 21, 2003, increasing the number of shares of common stock available for incentive stock options (ISOs) and other stock incentive awards from 500,000 to 650,000 shares. The 2000 Plan is administered by the Compensation Committee of our Board of Directors. Options granted must be exercised within 10 years from their date of grant. The exercise price of ISOs cannot be less than 100% of the grant date fair market value of a share of our common stock. All ISO awards granted in previous years vested immediately. Although the 2000 Plan provides for the granting of other incentive awards, only ISOs and non-statutory stock options have been issued under the 2000 Plan.

Effective January 1, 2006, we adopted Statement of Financial Accounting Standards No. 123 (Revised), *Share-Based Payments* (SFAS 123(R)) utilizing the modified prospective approach. Prior to the adoption of SFAS 123(R) we accounted for stock option grants in accordance with APB Opinion No. 25, *Accounting for Stock Issued to Employees* (the intrinsic value method), and accordingly, recognized no compensation expense when stock options were granted with an exercise price equal to the grant date fair market value of a share of our common stock.

Under the modified prospective approach, SFAS 123(R) applies to new awards and to awards that were outstanding on January 1, 2006 that are subsequently modified, repurchased, or cancelled. Under the modified prospective approach, had there been any awards granted during 2006, and had there been awards granted prior to January 1, 2006 which were not yet fully vested, compensation expense recognized in 2006 would have included compensation cost for all share-based payments granted prior to, but not yet vested, based on the grant date fair value estimated in accordance with the original provisions of Statement of Financial Accounting Standards No. 123, *Accounting for Stock-Based Compensation*, and compensation cost for all share-based payments granted subsequent to January 1, 2006, based on the grant date fair value estimated in accordance with the provisions of SFAS 123(R). Prior periods were not restated to reflect the impact of adopting the new standard.

As a result of adopting SFAS 123(R) on January 1, 2006, our income before taxes, net income and basic and diluted earnings per share for the twelve months ended December 31, 2006 was unchanged compared to if we had continued to account for stock-based compensation under APB Opinion No. 25 for our stock option grants.

Stock-based compensation expense of $774,369 was recognized in the twelve months ended December 31, 2005. Prior to adoption of SFAS 123(R), recognition of non-cash compensation expense was required by Financial Accounting Standards Board Interpretation No. 44, *Accounting*

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

for Certain Transactions involving Stock Compensation An Interpretation of APB Opinion No. 25 (FIN 44). Pursuant to FIN 44, stock options exercised in a cashless manner by surrendering a portion of the option shares issued to pay the option exercise price, trigger variable accounting treatment, requiring the measurement of compensation expense at a period beyond the date of grant.

SFAS 123(R) states that a tax deduction is permitted for stock options exercised during the period, generally for the excess of the price at which the options are sold over the exercise price of the options. Tax benefits are to be shown on the Statement of Cash Flows as financing cash inflows. Any tax deductions we receive from the exercise of stock options for the foreseeable future will be applied to the valuation allowance in determining our net operating loss carryforward.

Additionally, we utilized the alternate transition method (simplified method) for calculating the beginning balance in the pool of excess tax benefits in accordance with FASB Staff Position FAS123(R)-3, *Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards*.

The fair market value of each option granted, pursuant to SFAS No. 123(R), is estimated on the date of grant using the Black-Scholes-Merton option-pricing model, which uses assumptions noted in the following table:

	Years Ended December 31,	
	2006	2005
Stock options granted		90,376
Risk-free interest rate (on date of grant)	N/A	3.72%
Expected term, in years	N/A	10.00
Expected volatility	N/A	104.6%
Dividend yield	0.00%	0.00%

Expected volatility is based on implied volatility of our common stock. Historical data is used to estimate option exercises and employee terminations used in the model. The data shows that of the 117,142 shares exercised in 2004 and 289,321 exercised in 2005, the average length of time between grant date and exercise date was approximately 2.05 years. Also, of the option grants that have been outstanding for two or more years, approximately 14% of the total number of shares granted are forfeited within the first two years after the grant date. The expected term of options granted used in the model represents the period of time that options granted are expected to be outstanding. This is the simplified method as allowed under the provisions of the Securities and Exchange Commission s Staff Accounting Bulletin No. 107. This number is calculated by taking the average of the vesting period (zero) and the original contract term (10 years). The risk-free interest rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the date of the grant. As we have not declared dividends on our common stock since we became a public entity, no dividend yield was used. Actual value realized, if any, is dependent on the future performance of our common stock and overall stock market conditions. There is no assurance that the value realized by an optionee will be at or near the value estimated by the Black-Scholes-Merton option-pricing model.

Had compensation cost for our stock options been determined based on the fair market value at the grant dates for awards made in 2005, our net income and earnings per share would have been

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

adjusted to the pro forma amounts indicated below. For purposes of this pro forma disclosure, the value of the options is estimated using the Black-Scholes-Merton option-pricing model.

	Year Ended December 31, 2005
Net income as reported	$ 541,386
Add: total stock-based employee compensation expense included in net income, net of related tax effects	774,369
Deduct: total stock-based employee compensation expense determined under fair value based method for all awards, net of tax related effects	(66,420)
Pro forma net income	$ 1,249,335
Basic income per share:	
As reported	$ 0.06
Pro forma	$ 0.14
Diluted income per share:	
As reported	$ 0.06
Pro forma	$ 0.14

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

At December 31, 2006 we reserved a total of 143,997 shares of common stock for issuance under the above mentioned stock option plans. A summary of the status of our stock options granted to key employees, officers and directors, for the purchase of shares of common stock, was as follows:

	Years Ended December 31,			
	2006		2005	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Options outstanding at the beginning of the year	143,997	$ 1.56	346,942	$ 1.09
Options granted		$ 0.00	90,376	$ 0.80
Options exercised		$ 0.00	(289,321)	$ 0.71
Options expired or cancelled		$ 0.00	(4,000)	$ 4.89
Options outstanding at the end of the year	143,997		143,997	
Weighted average exercise price of options outstanding	$ 1.56		$ 1.56	
Weighted average fair value of options granted during the period	$ 0.00		$ 0.73	
Weighted average remaining contractual life of options outstanding	6.0 years		7.1 years	

At December 31, 2006, options for 143,997 shares of common stock were vested and immediately exercisable. There were no options granted during 2006, and 90,376 options granted during 2005, all of which occurred in the first quarter of 2005. Pursuant to the requirements of SFAS No. 123(R), the weighted average fair market value of options granted during 2005 was $0.73 per share. The weighted average exercise price for outstanding options at December 31, 2006 and 2005 was $1.56 and $1.56 per share, respectively. Outstanding options at December 31, 2006 expire between May 17, 2010 and February 3, 2015.

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

	Options Outstanding, Fully Vested and Exercisable at December 31, 2006		
Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life In Years	Weighted Average Exercise Price
$0.35 to $0.80	98,768	6.8	$ 0.54
$1.55 to $1.90	23,429	5.1	$ 1.71
$6.00	21,800	3.4	$ 6.00
	143,997		

(9) Related Party Transactions

Related party transactions which are not disclosed elsewhere in these consolidated financial statements are discussed in the following paragraphs:

We own 0.07% of the common stock of Drillmar, Inc. (Drillmar). Our Chairman, Ivar Siem, and one of our Directors, Harris A. Kaffie, beneficially own 26.6%, and 22.1%, respectively, of Drillmar Inc. s common stock and 34.5% and 10.1%, respectively, of Drillmar Energy, Inc. s common stock. Messrs. Siem and Kaffie are both Directors of Drillmar, and Mr. Siem is Chairman and President of Drillmar.

On March 31, 2006, we purchased 334 shares of common stock in Drillmar Energy, Inc. for $334 in a private placement offering by Drillmar, Inc. to its shareholders on a proportionate basis to their current ownership percentage in Drillmar, Inc. This investment represented 0.07% of the total offering, which is approximately equal to our current ownership in Drillmar, Inc.

On May 25, 2006, we purchased 2 shares of common stock in Drillmar, Inc. (an affiliate of Drillmar Energy, Inc.) for $563 in a private placement offering by Drillmar, Inc. to its shareholders on a proportionate basis to their current ownership percentage in Drillmar, Inc. This investment represented 0.07% of the total offering.

On September 25, 2006, we participated in an issuance of callable notes by Drillmar, Inc. in proportion to our 0.07% interest in Drillmar, Inc. We were issued a note in the amount of $280. The note is callable by Drillmar, Inc. at any time on or after three months from the date of issuance and accrues interest at 3% per annum, which is due and payable at maturity. The note matures on January 1, 2009.

In 2002, we recorded a full impairment of our investment in Drillmar and a full reserve for the accounts receivable amount owed to us by Drillmar of approximately $200,000 due to Drillmar s working capital deficiency and delays in securing capital funding. During 2004, we collected $165,000 of the accounts receivable from Drillmar and we collected the remaining balance of approximately $45,000 in 2005.

In January 2003, Drillmar stockholders approved a restructuring plan whereby Drillmar was able to issue up to $3.0 million of convertible notes that will convert into common stock representing over 99% of Drillmar s

outstanding shares. As a result, our ownership in Drillmar has been reduced to less than 1%. In November 2003, we converted a contingent obligation due from Drillmar for providing office space, accounting and administrative services from May 2002

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

through January 2003 totaling $162,000 (9 months at $18,000 per month) into a convertible note. In December 2005, we collected $178,555 from Drillmar for this convertible note, including interest at 6% per annum.

We entered into an agreement with Drillmar effective as of February 1, 2003, whereby we provided and charged for office space. This agreement terminated December 31, 2006. We also provided professional, accounting and administrative services to Drillmar at hourly rates based upon our cost. Since our implementation of staff reductions in mid 2004, no such services have been provided.

(10) Leases

We have various operating leases that extend through April 2017. Certain of these operating leases are non-cancelable through May 2010. In March 2003, we entered into a sublease agreement expiring December 31, 2006 for certain of our office space with TexCal Energy (GP) LLC, formerly Tri-Union Development Corporation. Our annual receipts from this sublease were approximately $78,000.

The following is a schedule of future minimum lease payments required under noncancelable operating leases at December 31, 2006:

Years Ending December 31,	Future Minimum Lease Payments
2007	$ 70,821
2008	103,266
2009	107,592
2010	148,713
2011	
Thereafter	
	$430,392

Rental expense on operating leases, net of sublease income and other rental reimbursements, for the years indicated are as follows:

Years Ended December 31,	Rent Expense
2006	$78,815
2005	$46,287

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

(11) Commitments and Contingencies

We are involved in various claims and legal actions arising in the ordinary course of business. In our opinion, the ultimate disposition of these matters will not have a material effect on our consolidated financial position, results of operations or cash flows.

(12) Business Segment Information

Our income producing operations are conducted in two principal business segments: (i) pipeline transportation services and (ii) oil and gas exploration and production. Intercompany revenue and expenses are eliminated in consolidation. Information concerning these segments for the years ended December 31, 2006 and 2005 is as follows:

	Revenues	Operating Income (Loss) [1]	Identifiable Assets [2]	Depletion, Depreciation, Amortization and Impairment [3]
Year Ended December 31, 2006:				
Pipeline transportation	$ 1,939,894	(228,460)	6,360,814	353,472
Oil and gas exploration and production	2,358,814	1,032,681	851,668	139,643
Other		(472,113)	4,732,016	8,943
Consolidated	4,298,708	332,108	11,944,498	502,058
Other income		595,435		
Income before income taxes		927,543		
Year Ended December 31, 2005:				
Pipeline transportation	$ 1,375,173	(467,484)	5,645,179	319,686
Oil and gas exploration and production	3,136,010	2,025,255	1,358,484	73,940
Other		(1,395,361)	1,069,884	9,591
Consolidated	4,511,183	162,410	8,073,547	403,217
Other income		392,081		
Loss before income taxes		554,491		

(1) Consolidated income (loss) from operations includes $463,170 and $1,385,768 in unallocated general and

administrative expenses, and unallocated depletion, depreciation, amortization and impairment of $8,943 and $9,591 for the years ended December 31, 2006 and 2005, respectively. All unallocated amounts are included in Other .

(2) See the supplemental disclosures for oil and gas producing activities for discussion of capitalized costs incurred for oil and gas production operations. Capital expenditures of $262,684 and $25,179 were recorded for pipeline operations for the years ended December 31, 2006 and 2005, respectively.

(3) Pipeline depletion, depreciation and amortization includes a provision for pipeline abandonment of $48,595 for the

years ended December 31, 2006 and 2005. Oil and gas depletion, depreciation, amortization and impairment includes a provision for abandonment costs of platforms and wells of $34,694 and $20,169 for the years ended December 31, 2006 and 2005, respectively.

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

Our primary market area is the Texas and Louisiana Gulf Coast region of the United States. We have a concentration of credit risk with customers in the energy industry. Our customers may be similarly affected by changes in economic, regulatory or other factors. Trade receivables are generally not collateralized; however, our customers historical and future credit positions are thoroughly analyzed prior to extending credit. Revenues from major customers exceeding 10% of revenues were as follows for the period indicated:

	Oil and Gas Sales	Pipeline Operations	Total
Year Ended December 31, 2006:			
Hydro Gulf, LLC (formerly Spinnaker Exploration Company)	$1,469,132	$	$1,469,132
Fidelity Exploration and Production Company	$ 889,682	$	$ 889,682
Year Ended December 31, 2005:			
Hydro Gulf, LLC (formerly Spinnaker Exploration Company)	$ 722,499	$	$ 722,499
Fidelity Exploration and Production Company	$2,413,511	$	$2,413,511

(13) Supplemental Oil and Gas Information Unaudited

The following supplemental information regarding our oil and gas activities are presented pursuant to the disclosure requirements promulgated by the Securities and Exchange Commission and SFAS No. 69, *Disclosures about Oil and Gas Producing Activities*.

Associated with our non-operating interest in High Island Block A-7, we recognized gross gas and oil sales revenues of approximately $1.5 million and $722,000 in 2006 and 2005, respectively, and lease operating expenses of approximately $430,000 and $139,000 in 2006 and 2005. Our working interest is approximately 8.9%. In September 2005, the two wells in High Island Block A-7 were successfully recompleted and resumed production at significantly higher rates compared to the single well that produced through the first and second quarters of 2005. One of the wells produced throughout 2006. The second well ceased production in February 2006. We non-consented to a recompletion of the second well.

Associated with our non-operating interest in High Island Block 37, we recognized gross gas and oil sales revenues of approximately $0.9 million and $2.4 million in 2006 and 2005, respectively, and lease operating expenses of approximately $27,000 and $16,000 in 2006 and 2005, respectively. We have a working interest of approximately 2.8% in two producing wells in the block. The wells are currently producing an aggregate of approximately 8 MMcf per day.

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

Estimated Quantities of Proved Oil and Gas Reserves

Set forth below is a summary of the changes in the estimated quantities of our crude oil and condensate, and gas reserves for the periods indicated, as estimated by us at December 31, 2006 and 2005. All of our reserves are located within the United States of America. Proved reserves cannot be measured exactly because the estimation of reserves involves numerous judgmental determinations. Accordingly, reserve estimates must be continually revised as a result of new information obtained from drilling and production history, new geological and geophysical data and changes in economic conditions.

Proved reserves are estimated quantities of gas, crude oil, and condensate which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Quantity of Oil and Gas Reserves	Oil (Bbls)	Gas (Mcf)
Total proved reserves at December 31, 2004:	365	35,264
Revisions to previous estimates		
Extensions, discoveries, improved recovery and other additions	1,303	685,080
Purchase of reserves in place		
Sales of reserves in place		
Production	(781)	(378,791)
Total proved reserves at December 31, 2005	887	341,553
Total proved reserves at December 31, 2005:	887	341,553
Revisions to previous estimates	1,089	78,640
Extensions, discoveries, improved recovery and other additions		
Purchase of reserves in place		
Sales of reserves in place		
Production	(1,823)	(312,146)
Total proved reserves at December 31, 2006	153	108,047
Proved developed reserves:		
December 31, 2006	153	108,047
December 31, 2005	887	341,553
Total proved reserves:		
December 31, 2006	153	108,047
December 31, 2005	887	341,553

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

Capitalized Costs of Oil and Gas Producing Activities

The following table sets forth the aggregate amounts of capitalized costs relating to our oil and gas producing activities and the aggregate amount of related accumulated depletion, depreciation, amortization and impairment as of:

	December 31, 2006	2005
Unproved properties and prospect generation costs not being amortized	$	$ 5,343
Proved properties being amortized	715,970	544,377
Total capitalized costs	715,970	549,720
Accumulated depreciation, depletion and amortization	(541,915)	(403,982)
Net capitalized costs	$ 174,055	$ 145,738

Costs Incurred in Oil and Gas Producing Activities

The following table reflects the costs incurred in oil and gas property acquisition, disposition, exploration and development activities during the periods indicated:

	Years Ended December 31, 2006	2005
Costs incurred:		
Acquisition of proved properties	$	$
Acquisition of unproved properties		
Exploration costs		
Development costs	15,700	72,501
Total costs incurred	$ 15,700	$ 72,501

We did not acquire any oil and gas properties in 2006 or 2005.

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

Results of Operations for Oil and Gas Producing Activities

The results of operations from oil and gas producing activities below exclude non-oil and gas revenues, general and administrative expenses, interest expense and interest income.

	Years Ended December 31,	
	2006	2005
Revenues from oil and gas producing activities	$ 2,358,814	$ 3,136,010
Production costs	(457,312)	(155,174)
Depreciation, depletion, and amortization	(139,643)	(73,940)
Pretax income from producing activities	1,761,859	2,906,896
Income tax expense/estimated loss carryforward benefit	(27,883)	(123,698)
Results of oil and gas producing activities (excluding corporate overhead and interest costs)	$ 1,733,976	$ 2,783,198

Standardized Measure of Discounted Future Net Cash Flows

The following table reflects the Standardized Measure of Discounted Future Net Cash Flows relating to our interest in proved oil and gas reserves for:

	Years Ended December 31,	
	2006	2005
Future cash inflows	$ 605,000	$ 3,807,000
Future development and dismantlement costs	(432,000)	(268,000)
Future production costs	(126,000)	(162,000)
Future income taxes	(15,980)	(1,148,180)
10% discount factor	27,720	(123,420)
Standardized measure of discounted future net cash inflows (outflows)	$ 58,740	$ 2,105,400

Future net cash flows at each year end, as reported in the above schedule, were determined by summing the estimated annual net cash flows computed

by: (1) multiplying estimated quantities of proved reserves to be produced during each year by year-end prices and (2) deducting estimated expenditures to be incurred during each year to develop and produce the proved reserves (based on year-end costs).

Income taxes were computed by applying year-end statutory rates to pretax net cash flows, reduced by the tax basis of the properties and available net operating loss carryforwards. The annual future net cash flows were discounted, using a prescribed 10% rate, and summed to determine the standardized measure of discounted future net cash flow.

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

We caution readers that the standardized measure information which places a value on proved reserves is not indicative of either fair market value or present value of future cash flows. Other logical assumptions could have been used for this computation which would likely have resulted in significantly different amounts. Such information is disclosed solely in accordance with Statement 69 and the requirements promulgated by the Securities Exchange Commission to provide readers with a common base for use in preparing their own estimates of future cash flows and for comparing reserves among companies. We do not rely on these computations when making investment and operating decisions. Principal changes in the *Standardized Measure of Discounted Future Net Cash Flows* attributable to our proved oil and gas reserves for the periods indicated are as follows:

	Years Ended December 31,	
	2006	2005
Sales and transfers, net of production costs	$ (1,901,502)	$ (2,980,836)
Net change in sales and transfer prices, net of production costs	(959,002)	(54,000)
Extension, discoveries and improved recovery, net of future production and development costs		6,170,836
Changes in estimated future development cost	(310,553)	204,039
Revisions of quantity estimates	(235,475)	
Accretion of discount	319,000	(1,800)
Net change in income taxes	1,054,340	(1,090,720)
Change in production rates (timing) and other	(13,468)	(130,239)
Net change	$ (2,046,660)	$ 2,117,280

Item 8. Changes in and Disagreements with Accountants on Accounting and Financial Disclosures

None.

Item 8A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of the end of the year covered by this report, we carried out an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer and Principal Accounting and Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act. Based upon this evaluation, as of December 31, 2006, the Chief Executive Officer and Principal Accounting and Financial Officer concluded that our disclosure controls and procedures were effective to ensure that information required to be disclosed by us in reports that we file or submit under the Exchange Act, are recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms and that such information is accumulated and communicated to our management, including the Chief Executive Officer and Principal Accounting and Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)
Changes in Internal Controls over Financial Reporting

There have been no changes made in our internal control over financial reporting that materially affected, or is reasonably likely to materially affect, the internal control over financial reporting, during the period covered by this report.

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PART III

Item 9. Directors, Executive Officers, Promoters, Control Persons and Corporate Governance; Compliance with Section 16(a) of the Exchange Act

The information required by Item 9 is incorporated by reference to our definitive proxy statement relating to our 2007 annual meeting of stockholders, which proxy statement will be filed pursuant to Regulation 14A within 120 days after the end of the last fiscal year.

Item 10. Executive Compensation

The information required by Item 10 is incorporated by reference to our definitive proxy statement relating to our 2007 annual meeting of stockholders, which proxy statement will be filed pursuant to Regulation 14A within 120 days after the end of the last fiscal year.

Item 11. Security Ownership of Certain Beneficial Owners and Management

The information required by Item 11 is incorporated by reference to our definitive proxy statement relating to our 2007 annual meeting of stockholders, which proxy statement will be filed pursuant to Regulation 14A within 120 days after the end of the last fiscal year.

Item 12. Certain Relationships and Related Transactions, and Director Independence

The information required by Item 12 is incorporated by reference to our definitive proxy statement relating to our 2007 annual meeting of stockholders, which proxy statement will be filed pursuant to Regulation 14A within 120 days after the end of the last fiscal year.

Item 13. Exhibits

(a) 1. Exhibits

No.	Description
3.1 (1)	Amended and Restated Certificate of Incorporation of the Company.
3.2 (8)	Amended and Restated Bylaws of the Company.
4.1 (2)	Specimen Certificate of our Company common stock.
4.2 (6)	Form of Promissory Note issued pursuant to the Note and Warrant Purchase Agreement dated September 8, 2004.
* 10.1 (3)	Blue Dolphin Energy Company 2000 Stock Incentive Plan.
* 10.2 (4)	Amendment to the Blue Dolphin Energy Company 2000 Stock Incentive Plan.
10.3 (5)	Purchase and Sale Agreement by and between Blue Dolphin Pipeline Company and MCNIC, dated February 1, 2002.

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No.	Description
10.4 (6)	Sale of American Resources Offshore , Inc. Common Stock Agreement between Blue Dolphin Exploration Co. and Ivar Siem, dated September 8, 2004.
10.7 (7)	Purchase and Sale Agreement by and between Blue Dolphin Energy Company, WBI Pipeline & Storage Group, Inc. and SemGas LP, dated October 29, 2004.
10.8 (9)	Amendment to the Asset Purchase Agreement by and among MCNIC Offshore Pipeline and Processing Company and Blue Dolphin Pipe Line Company dated February 28, 2005.
10.9 (11)	Placement Agency Agreement by and between Blue Dolphin Energy Company and Starlight Investments, LLC dated May 27, 2005.
10.10 (12)	Form of Stock Purchase Agreement between Blue Dolphin Energy Company and Osler Holdings Limited, Gilbo Invest AS, Spencer Energy AS, Spencer Finance Corp., Hudson Bay Fund, LP, Don Fogel and SIBEX Capital Fund, Inc. dated March 8, 2006.
14.1 (10)	Code of Ethics applicable to the Chairman, Chief Executive Officer and Senior Financial Officer.
** 21.1	List of Subsidiaries of the Company.
** 23.1	Consent of UHY, LLP.
** 31.1	Ivar Siem Certification Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to section 302 of the Sarbanes-Oxley Act of 2002.
** 31.2	Gregory W. Starks Certification Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to section 302 of the Sarbanes-Oxley Act of 2002.
** 32.1	Ivar Siem Certification Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002.
** 32.2	Gregory W. Starks Certification Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002.

* Management Compensation Plan.

** Filed herewith.

(1) Incorporated herein by reference to Exhibits filed in connection with the definitive

Proxy Statement of Blue Dolphin Energy Company under the Securities and Exchange Act of 1934, dated October 13, 2004 (Commission File No. 000-15905).

(2) Incorporated herein by reference to Exhibits filed in connection with Form 10-K of Blue Dolphin Energy Company for the year ended December 31, 1989 under the Securities and Exchange Act of 1934, dated March 30, 1990 (Commission File No. 000-15905).

(3) Incorporated herein by reference to Exhibits filed in connection with the Proxy Statement of Blue Dolphin Energy Company under the Securities and Exchange Act of 1934, dated May 18, 2000 (Commission File No. 000-15905).

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(4) Incorporated herein by reference to Exhibits filed in connection with the definitive Proxy Statement of Blue Dolphin Energy Company under the Securities and Exchange Act of 1934, dated April 16, 2003 (Commission File No. 000-15905).

(5) Incorporated herein by reference to Exhibits filed in connection with Form 10-KSB of Blue Dolphin Energy Company under the Securities and Exchange Act of 1934, dated July 23, 2002 (Commission File No. 000-15905).

(6) Incorporated herein by reference to Exhibits filed in connection with Form 8-K of Blue Dolphin Energy Company under the Securities and Exchange Act of 1934,

dated September 14, 2004 (Commission File No. 000-15905).

(7) Incorporated herein by reference to Exhibits filed in connection with Form 8-K of Blue Dolphin Energy Company under the Securities and Exchange Act of 1934, dated December 6, 2004 (Commission File No. 000-15905).

(8) Incorporated herein by reference to Exhibits filed in connection with Form 10-QSB of Blue Dolphin Energy Company for the quarter ended June 30, 2004 under the Securities and Exchange Act of 1934, dated August 20, 2004 (Commission File No. 000-15905).

(9) Incorporated herein by reference to Exhibits filed in connection with

Form 8-K of Blue Dolphin Energy Company under the Securities and Exchange Act of 1934, dated March 2, 2005 (Commission File No. 000-15905).

(10) Incorporated herein by reference to Exhibit 14.1 filed in connection with Form 10-KSB of Blue Dolphin Energy Company for the year ended December 31, 2004 under the Securities Exchange Act of 1934, dated March 25, 2005 (Commission File No. 000-15905).

(11) Incorporated herein by reference to Exhibit 10.9 filed in connection with Form 10-KSB of Blue Dolphin Energy Company for the year ended December 31, 2005 under the Securities Exchange Act of 1934, dated March 30, 2006

(Commission File No. 000-15905).

(12) Incorporated herein by reference to Exhibit 10.10 filed in connection with Form 10-KSB of Blue Dolphin Energy Company for the year ended December 31, 2005 under the Securities Exchange Act of 1934, dated March 30, 2006 (Commission File No. 000-15905).

Item 14. Principal Accountant Fees and Services

The information required by Item 14 is incorporated by reference to our definitive proxy statement relating to our 2007 annual meeting of stockholders, which proxy statement will be filed pursuant to Regulation 14A within 120 days after the end of the last fiscal year.

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SIGNATURES

In accordance with Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

BLUE DOLPHIN ENERGY COMPANY
(Registrant)

By: /s/ Ivar Siem
Ivar Siem
(Chairman and CEO)

Date: March 30, 2007

In accordance with the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Ivar Siem Ivar Siem	Chairman and CEO (Principal Executive Officer)	March 30, 2007
/s/ Gregory W. Starks Gregory W. Starks	Treasurer (Principal Accounting and Financial Officer)	March 30, 2007
/s/ Laurence N. Benz Laurence N. Benz	Director	March 30, 2007
/s/ Michael S. Chadwick Michael S. Chadwick	Director	March 30, 2007
/s/ John N. Goodpasture John N. Goodpasture	Director	March 30, 2007
/s/ Harris A. Kaffie Harris A. Kaffie	Director	March 30, 2007
/s/ Erik Ostbye Erik Ostbye	Director	March 30, 2007

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