BLUE DOLPHIN ENERGY CO
Form 10KSB/A
August 19, 2005

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-KSB/A

AMENDMENT NO. 2

[X] Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2004

or

[ ] Transition Report Pursuant to 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, 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: NONE

Securities registered pursuant to Section 12(g) of the Exchange Act:
COMMON STOCK, $.01 PAR VALUE
(Title of Class)

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 [X] No [ ]

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.[ ]

The issuer's revenues for the year ended December 31, 2004 were $1,435,646.

The aggregate market value of the common stock, par value $.01 per share, held by non-affiliates of the registrant as of June 27, 2005, was approximately $18,500,000.

As of August 18, 2005, there were outstanding 9,157,917 shares of common stock, par value $.01 per share, of the issuer.

DOCUMENTS INCORPORATED BY REFERENCE

Certain sections of the registrant's definitive proxy statement for the 2005 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, 2004, are incorporated by reference in Part III of this report.

Transitional Small Business Disclosure Format. Yes [ ] No [X]

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EXPLANATORY NOTE

This Amendment No. 2 to our Form 10-KSB filed with the Securities and Exchange Commission (the "SEC") on March 25, 2005 is being filed solely in response to comments received from the staff of the SEC. This filing revises disclosure in Items 1, 7 and 8A of the Form 10-KSB. None of these revisions change our previously reported results, loss from operations, net loss, loss per share or cash flows for the periods included, nor result in a restatement to our financial position or results of operations. Except for such revisions, this amendment does not update any other disclosures contained in the Form 10-KSB filed on March 25, 2005 to reflect developments since the date of such filing.

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;
- gas and oil price volatility;
- uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of development expenditures;
- 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 is a holding company that conducts substantially all of its operations through its subsidiaries. We conduct our business activities in two primary business segments: (i) pipeline operations, and (ii) oil and gas exploration and production. Substantially all of our assets consist of equity interests in our subsidiaries. Our subsidiaries and affiliates are:

- Blue Dolphin Pipe Line Company, a Delaware corporation;
- Blue Dolphin Petroleum Company, a Delaware corporation;
- Blue Dolphin Exploration Company, a Delaware corporation;
- Blue Dolphin Services Co., a Texas corporation;

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- Petroport, Inc., a Delaware corporation; and
- Drillmar, Inc., a Delaware corporation in which we own a 12.8% interest.

Our principal executive office is located at 801 Travis, 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 7 full-time employees. Our common stock is traded on the National Association of Securities Dealers, Inc. Automated Quotation System ("NASDAQ") Small Cap Market under the trading symbol "BDCO". Our home page address on the world wide web 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" on pages 16 to 18 of this Form 10-KSB.

RECENT DEVELOPMENTS

In September 2004, we entered into a Note and Warrant Purchase Agreement (the "Purchase Agreement") with certain accredited investors and certain of our directors for the purchase and sale of promissory notes in an aggregate principal amount of $750,000 (the "Promissory Notes") and warrants to purchase 2,800,000 shares of common stock at a purchase price of $0.003 per warrant (the "Warrants"). The sale of the Promissory Notes and the first tranche of 1,250,000 Warrants (the "Initial Warrants") closed on September 8, 2004, and the closing of the sale of the second tranche of 1,550,000 Warrants (the "Additional Warrants") closed on November 30, 2004, after we received stockholder approval at our November 11, 2004 special stockholders' meeting. We received net proceeds of $758,400 from the sale of the Promissory Notes and the Warrants. The Promissory Notes mature on September 8, 2005, and accrue interest at a rate of 12.0% per annum, of which 4% is payable monthly and 8% is payable at maturity. The Promissory Notes are secured by a second lien on our Blue Dolphin System (as defined in "Pipeline Operations and Activities-Blue Dolphin Pipeline System"). The Warrants are immediately exercisable and will expire five years after their date of issuance. Each Warrant is exercisable to acquire one share of common stock at an exercise price of $0.25 per share. The Warrants contain standard antidilution provisions, as well as provisions that will result in adjustments to the exercise price of the Warrants if we issue common stock at a price below $0.25 per share, subject to certain exceptions.

In October 2004, we sold our 25% equity interest in New Avoca Gas Storage LLC ("New Avoca") to SemGas LP. Pursuant to the terms of the Purchase and Sale Agreement, we received approximately $930,000 for our interest in New Avoca, and may receive an additional payment of up to approximately $375,000, subject to the commencement of commercial operations at the New Avoca natural gas storage facility prior to October 29, 2011.

On February 28, 2005 (effective as of January 1, 2005), we entered into an amendment (the "Amendment") to our Asset Purchase Agreement dated February 1, 2002 (the "Purchase Agreement") with MCNIC Offshore Pipeline and Processing Company ("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 promissory note that we originally issued to MCNIC in the principal amount of $750,000 due December 31, 2006 (the "Original Promissory Note") was exchanged for a new non-interest bearing promissory note in the principal amount of $250,000 (the "New Promissory Note"), and all accrued interest on the Original Promissory Note, $132,368 at December 31, 2004, was forgiven. In addition to the New Promissory Note, MCNIC can 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 will make monthly principal payments of $10,000 through its maturity date of December 31, 2006. The principal amount of the New Promissory Note may be increased by up to $500,000 if 50% or more of our 83% interest in the Blue Dolphin System is sold before December 31, 2006.

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 is solely dependent upon the amounts of gas and condensate gathered and transported through our pipeline systems. 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 provision of such services with third party producer/shippers may be for specified time periods, there can be no assurance that current or future producer/shippers will not subsequently tie-in to alternative transportation systems or that current rates charged will be maintained in the future. We actively market gathering and transportation services to prospective third party producer/shippers 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 producer/shippers to the systems.

Blue Dolphin Pipeline System. The Blue Dolphin 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 in 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. The offshore segment transports both gas and liquids (crude oil and condensate) and is comprised of approximately 34 miles of 20-inch pipeline from a platform in Galveston Area Block 288 to shore. The offshore segment includes a platform 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 shore facility at Freeport, Texas. The onshore segment consists of 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. The Buccaneer Pipeline, an 8-inch liquids pipeline, transports crude oil and condensate from the storage tanks to our barge-loading terminal on the Intracoastal Waterway near Freeport, Texas for sale to third parties.

Various fees are charged to producer/shippers for provision of transportation and shore facility services. Our current aggregate capacity is 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 4% and 6% of capacity during 2004 and 2003, respectively. All gas and liquids volumes transported in 2004 and 2003 were attributable to production from third party producer/shippers. See Note 12 to the Consolidated Financial Statements included in Item 7.

During late 2004, due to operating losses incurred by us from the Blue Dolphin System, we renegotiated our gas transportation rates with our shippers, effective October 1, 2004. As a result, fourth quarter 2004 gas transportation revenues from the Blue Dolphin System totaled $318,000. Without the increase in rates, gas transportation revenues for the fourth quarter of 2004 would have been $107,000.

Galveston Area Block 350 Pipeline. We own an 83% ownership interest in an 8-inch, 12.78 mile pipeline extending from Galveston Area Block 350 to an interconnect to a transmission pipeline in Galveston Area Block 391 (the "GA 350 Pipeline"), approximately 14 miles south of the Blue Dolphin Pipeline. Current system capacity on the GA 350 Pipeline is 65 MMcf per day of gas. Gas throughput for the GA 350 Pipeline averaged approximately 26% and 17% of capacity during 2004 and 2003, respectively. The pipeline currently

transports approximately 22 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 the currently inactive Omega Pipeline. The Omega Pipeline originates in West Cameron Block 342 and extends to High Island Area, East Addition Block A-173, where it was previously connected to the High Island Offshore System ("HIOS"). The line could either be reconnected to HIOS, or a lateral pipeline could be constructed connecting into the Black Marlin Pipeline, approximately 14 miles to the west. Reactivation of the Omega Pipeline will be dependent upon future drilling activity in the vicinity and successfully attracting reserves to the system.

New Avoca Gas Storage Project

We formed New Avoca with WBI Holdings, Inc. ("WBI"), and together held assets to develop a natural gas storage project in Avoca, New York. We held a 25% equity interest and were the manager of New Avoca. Our investment in New Avoca was recorded by using the equity method of accounting. In October 2004, we sold our 25% interest in New Avoca. See "Recent Developments."

OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES

our oil and gas assets are held by Blue Dolphin Petroleum and Blue Dolphin Exploration. Our oil and gas exploration and production activities 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 and central Gulf of Mexico. We currently own seismic and other data 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.

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 A-7. High Island Block A-7 is located 33 miles offshore Texas in an average water depth of 39 feet. We own an 8.9% working interest in this lease that covers approximately 5,760 acres. The lease contains one producing well which is operated by Spinnaker Exploration Company. During the years ended December 31, 2004 and 2003, we recorded revenues from oil and gas sales of approximately $332,000 and $1,447,000, respectively, from this field.

Unproved Leasehold Interests. Our leased prospect inventory, which we continue to market, consists of a prospect on the offshore lease for West Cameron Area Block 212. We have after payout reversionary working interests in the following offshore leases.

- Galveston Area Block 297
- Galveston Area Block 287
- Galveston Area Block 271
- Galveston Area Block 284

In December 2004, we placed our interest in Galveston Area Blocks 287 and 297 in the Gulf of Mexico with third parties. These blocks are part of a prospect we generated that includes Galveston Area Block 298. A well is currently being drilled in Galveston Area Block 297. As a result of the placement of our working interest in Galveston Area Blocks 287 and 297, we expect to receive proceeds of approximately $160,000, and a 7.5% after payout reversionary working interest.

Abandonment of Buccaneer Field. We owned a 100% working interest in the Buccaneer Field. In November 2000, we elected to abandon the Buccaneer Field due to adverse developments in the field. In August 2001, we reached an agreement with Tetra Applied Technologies, Inc. ("Tetra") to remove the Buccaneer Field platforms for a cost of approximately $2.6 million on extended payment terms. To provide security for the extended payment terms, we provided Tetra with a first lien on a 50% interest in the Blue Dolphin System. Operations to remove the platforms commenced in August 2001 and were completed in August 2003. Before the removal operations were completed we commenced discussions with the Texas Parks and Wildlife Department ("TPW"), and were granted permission to leave the underwater portion of the platforms in place as artificial reefs. As a result of TPW's approval, the scope of the work to be performed by Tetra was changed to include reefing, instead of complete removal. Pursuant to the Deeds of Donation with TPW, we agreed to pay TPW $390,000, of which $350,000 represented half of the site clearance work that was eliminated (which payment the TPW required) and $40,000 represented the cost of buoys to mark the reef sites. While the scope of work with Tetra was changed, the contract price and payment terms remained unchanged. Our payments to Tetra began in September 2003. In August 2004, we negotiated an extension of the payment terms of our remaining indebtedness to Tetra in the amount of $668,000 originally due in September and October 2004. Under the new terms we agreed to pay the outstanding balance to Tetra in twelve monthly installments of $55,667 beginning September 1, 2004, plus interest on the outstanding balance at the rate of 6% per annum. We reduced our provision for the Buccaneer Field abandonment costs resulting in a gain of approximately $.5 million for the year ended December 31, 2003. At December 31, 2004, accounts payable includes approximately $450,000 due Tetra, payable as described above.

Sale of Oil and Gas Properties. During 2002, we sold all of our producing oil and gas properties. From October 2002 to late April 2003, we had no interest in any producing oil and gas properties.

In June 2004, we sold our working interest in the High Island Block 34 field for approximately $34,000 to Fidelity Exploration and Production Company. Production from this field accounted for 4% and 2% of our total revenues for the years ended December 31, 2004 and 2003, respectively.

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, 2004.

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 to Consolidated Financial Statements included in Item 7.

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 before income taxes to our net interest in oil and gas properties as of December

31, 2004. 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, 2004 (1)(2)

	Net Oil Reserves (Mbbls)	Net Gas Reserves (Mmcf)	Present Value of Future Net Cash Outflows After Income Taxes (1) (in thousands)
Total Proved Reserves High Island Block A-7	.4	35.3	$ (12)
Total Proved Developed High Island Block A-7	.4	35.3	$ (12)

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(1) The estimated present value of future net cash outflows after income taxes from our Proved Reserves have been determined by using prices of $43.22 per barrel of oil and $7.22 per Mcf of gas, representing the December 31, 2004 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"). At December 31, 2004, the value of our reserves is negative as a result of asset retirement obligations exceeding future revenues.

(2) As of December 31, 2004, we reported no proved undeveloped reserves.

Capital Expenditures for Proved Reserves. The following table presents information regarding the costs we expect to incur in development activities associated with our proved reserves. These expenditures include recompletion costs, workover costs and the cost of drilling additional wells required to recover proved reserves and 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.

	Estimated Undiscounted Capital Expenditures To Develop Proved Reserves For the years ending December 31, (in thousands)				
	2005	2006	2007	2008	2009
High Island Block A-7	$ 13	-	$203	-	-

We will continue to evaluate our capital expenditure program based on, among other things, demand and prices obtainable for our production. The availability of capital resources and the willingness of other working interest owners to participate in development operations may affect our timing for further development, and there can be no assurance that the timing of the development of such reserves will be as currently planned.

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

	Year Ended December 31,		
	2004	2003	200
Gas:			
Production (Mcf)	66,491	274,268	41
Revenue	$ 367,611	$ 1,513,182	$ 1,22
Average Production (Mcf) per day (*)	182.20	751.40	1,1
Average Sales Price			
Per Mcf	$ 5.53	$ 5.52	$
Oil:			
Production (Bbls)	810	2,271	2
Revenue	$ 28,089	$ 68,872	$ 56
Average Production (Bbls) per day (*)	2.20	6.20	
Average Sales Price			
Per Bbl	$ 34.68	$ 30.33	$
Production Costs (**):			
Per Mcfe:	$ 1.88	$ 0.65	$

(*) Average production is based on a 365 day year. However, we only had production for 255 days and 304 days in 2003 and 2002, respectively.

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

Drilling Activity. During fiscal years 2004 and 2003 there was no drilling activity.

EMPLOYEES

We maintain a professional staff of 7 full-time employees and consultants 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.

CUSTOMERS

We generated revenues from both of our primary business segments. Revenues from major customers exceeding 10% of revenues were as follows for 2004 and 2003:

	Oil and gas Sales	Pipeline Operations	Tota
Year ended December 31, 2004:			
Spinnaker Exploration Company	$ 331,858	-	$ 331
Houston Exploration	-	$ 239,444	$ 239
Apache Corporation	-	$ 229,265	$ 229
Kerr McGee Oil & Gas	-	$ 152,487	$ 152
Year ended December 31, 2003:			
Spinnaker Exploration Company	$ 1,446,622	-	$1,446

COMPETITION

The oil and gas industry is highly competitive in all segments. Increasingly vigorous competition occurs among oil, gas and other energy sources, and between producers, transporters, and distributors of oil and gas. Competition is particularly intense with respect to the acquisition of desirable mid-stream assets, producing oil and gas properties and the marketing of oil and gas production. 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 gas, and the prices of such oil and gas, depends 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 and transshipment and other means of transportation
- the availability and marketing of other competitive fuels
- fluctuating and seasonal demand for oil, gas and refined products
- 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, gas and refined petroleum products, it is not possible to predict accurately the prices or marketability of the gas and oil 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, and the development of storage of gas by us are subject to federal, state and local regulations which can have a significant impact upon our overall 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. Congress could, however, 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.

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 nonjurisdictional 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.

Further FERC initiatives concerning possibly diminished Natural Gas Act regulation of pipelines on the OCS and/or broader regulation under the OCSLA remain possible and could cause increased regulatory compliance costs. 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 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 that we are subject to. 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 standardize 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 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 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 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 Nation's coastal zone 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.

RISK FACTORS

We need to raise additional capital to meet our obligations during 2005. Our capital requirements raise substantial doubt about our ability to continue as a going concern.

During 2005, we have various debt obligations to satisfy along with continued losses from operations that are currently expected to exceed our available cash. These obligations include approximately $450,000 due to Tetra during January through August 2005, $130,000 due to MCNIC during February through December 2005, and, our promissory notes in the principal amount of $750,000, along with accrued interest of approximately $60,000 due and payable in September 2005.

In order to satisfy our debt and other working capital and capital expenditure requirements for the year ending December 31, 2005, we believe that we will need to raise approximately $500,000 of capital. In the absence of an improvement in our operating results, we will need to either extend the payment terms of our promissory notes, arrange external financing and/or sell assets to raise the necessary capital.

Historically, we have relied on the proceeds from the sale of assets and capital raised from the issuance of debt and equity securities to individual investors and related parties to sustain our operations. There can be no assurance that we will be able to obtain financing or sell assets on commercially acceptable terms to meet our capital requirements. Our inability to raise capital will have a material adverse effect on our financial condition, ability to meet our obligations and operating needs, and results of operations.

We are primarily dependent on revenues from our pipeline systems.

As a result of our sale of substantially all of our proved oil and gas reserves in 2002 and the limited remaining reserves that were added in 2003, our future revenues are 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 amount of oil and gas production near our pipelines and our ability to attract new users. There are various competing pipelines in and around our pipeline systems that we vigorously compete with to attract new users to our pipeline

systems. There can be no assurance that our marketing activities will result in attracting new oil and gas reserves to our pipeline systems.

Our future success depends, in part, upon our ability to acquire mid-stream (pipeline) assets and oil and gas reserves.

We are currently attempting to find and acquire mid-stream assets. Until we acquire additional mid-stream assets, substantially all of our revenues will be from our existing pipeline systems and reversionary interests in oil and gas properties. There can be no assurance that we will be able to acquire additional assets.

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.

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

- We often establish a higher standard for the minimum projected rate of return on an investment 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, the 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 gas prices. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply and demand for oil and 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 gas;
- the price of foreign imports; and
- the availability of alternate fuel sources.

In addition, low or declining oil and 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.

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

Currently, other companies operate or control all 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, could adversely affect us, including the amount and timing of revenues, if any, we receive from our interests.

We have and generally anticipate that we will typically 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 more than 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.

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 risks inherent in the oil and gas industry, such as:

- 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.

These risks could result in substantial losses to us 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 with maximum limits of $50 million. We also maintain operator's extra expense coverage, which covers the control of drilled or producing wells as well as redrilling 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, as a result of our operating losses, we cancelled the property insurance coverage on our pipelines, however we do continue to carry property insurance coverage on our shore facilities and our offshore platforms. 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.

Compliance with environmental and other government regulations could be costly and could negatively impact pipeline and production 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 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 exploration or production activities upon 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.

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.

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.

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 December 31, 2006. Our aggregate annual lease payment obligation under this lease is approximately $200,000.

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 are approximately $78,500. One of our Directors, Mr. James M. Trimble, was the Chairman and Chief Executive Officer of TexCal Energy (GP) LLC until November

2004.

We have month to month contracts with several companies, including Drillmar, Inc. (see Note 9 in Item 7 of the Consolidated Financial Statements) to use our extra office space. Monthly proceeds from these contracts is approximately $6,000.

ITEM 3. LEGAL PROCEEDINGS

Neither we nor any of our property is subject to any material pending legal proceedings.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

A special meeting of stockholders was held on November 11, 2004. The matters that were voted on at the meeting, and the number of votes cast for, against or withheld, as well as the number of abstentions and broker non-votes, as to such matter, where applicable, are set forth below.

	Votes For	Votes Against	Votes Withheld	Abstentions	Broker Non-Votes
1) Election of Directors					
Ivar Siem	4,586,747	17,914	23,178	-	1,389,523
Laurence N. Benz	4,603,472	1,189	23,178	-	1,389,523
Michael S. Chadwick	4,603,472	1,189	23,178	-	1,389,523
Harris A. Kaffie	4,603,400	1,261	23,178	-	1,389,523
F. Gardner Parker	4,603,472	1,189	23,178	-	1,389,523
James M. Trimble	4,602,272	2,389	23,178	-	1,389,523
2) To issue warrants to purchase up to 1,550,000 shares of common stock pursuant to that certain Note and Warrant Purchase Agreement:	3,666,698	52,670	3,444	-	1,389,523

	Votes For	Votes Against	Votes Withheld	Abstentions	Broker Non-Votes
3) To amend and restate the certificate of Incorporation to increase the number of authorized shares of common stock to 25,000,000 shares:	4,564,929	59,137	3,773	-	1,389,523
4) To amend and restate the certificate of incorporation to (a) incorporate the other amendments to the					

	Certificate that have been, or will be, approved by the stockholders and (b) to eliminate the authorized Series A preferred stock:	3,666,652	53,945	2,215	-	1,389,523
5)	To issue warrants to purchase up to 100,000 shares of common stock to Laurence N. Benz, Michael S. Chadwick and F. Gardner Parker:	3,666,404	55,167	1,241	-	1,389,523

ITEM 5. MARKET FOR COMMON STOCK AND RELATED STOCKHOLDER MATTERS

MARKET PRICE FOR COMMON STOCK

Our common stock is quoted on the NASDAQ Small Cap Market under the symbol "BDCO". As of March 14, 2005, there were an estimated 600 stockholders of record and we estimate 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 bid price for the common stock as reported by the NASDAQ.

	High	Low
Quarter Ended March 31, 2003.................	$ 0.63	$ 0.41
Quarter Ended June 30, 2003..................	$ 1.85	$ 0.38
Quarter Ended September 30, 2003.............	$ 4.00	$ 0.75
Quarter Ended December 31, 2003..............	$ 3.20	$ 1.65
Quarter Ended March 31, 2004.................	$ 2.60	$ 1.26
Quarter Ended June 30, 2004..................	$ 1.37	$ 1.00
Quarter Ended September 30, 2004.............	$ 1.66	$ 0.90
Quarter Ended December 31, 2004..............	$ 1.98	$ 0.97

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 have 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. Previously, our loan agreement restricted us from paying dividends on our common stock if there was an outstanding balance under the loan agreement. Any loan agreements which we may 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 is dependent on the cash flow of our subsidiaries.

RECENT SALES OF UNREGISTERED SECURITIES

In September 2004, we sold Promissory Notes in an aggregate principal amount of $750,000 and 1,250,000 Warrants, and in November 2004 we sold 1,550,000 Warrants. These securities are more fully described in Item 6 Management's Discussion and Analysis of Financial Condition and Results of Operations.

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 Consolidated Financial Statements included in Item 7 and the description of our business in Item 1-Description of Business.

EXECUTIVE SUMMARY

We are engaged in two lines of business: (i) pipeline operations and (ii) oil and gas exploration and production. We conduct our operations through our subsidiaries. We provide pipeline transportation services to producer/shippers, and sell oil and gas from a producing property. Our assets are located offshore and onshore in the Texas Gulf coast area. In addition to satisfying our liquidity and capital needs, our focus in 2005 is to increase utilization of existing assets, strategic acquisitions and cost management. Our long-term goal is to create greater value for our stockholders through the addition of assets. Our focus on acquisitions has centered on pipelines, however, producing oil and gas properties are also being considered.

At the beginning of 2004 we faced a significant liquidity shortage. We estimated that we would need to raise approximately $1,500,000 to satisfy our liquidity and working capital requirements through 2004. In an effort to address our current liquidity shortage we:

- Implemented cost savings measures in mid 2004 that included, among other things, reducing the number of employees and contract personnel, resulting in expected annual cost savings of approximately $360,000. As a result of these measures, our primary focus was shifted to our pipeline business,

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- Extended the payment terms of $668,000 of indebtedness that was due in August and September 2004, to now be payable over a twelve month period from September 2004 through August 2005,

- Received borrowings of $750,000 through the issuance of Promissory Notes,

- Sold our interest in New Avoca Gas Storage, LLC for approximately $930,000 in October 2004. New Avoca was a development project that required significant additional capital to develop which we planned to suspend if not sold by the end of 2004, and

- Negotiated an increase in gas transportation rates on the Blue Dolphin System effective October 2004, that provided additional revenues of approximately $210,000 in the fourth quarter 2004.

In 2004, we engaged Sanders Morris Harris Group, Inc. and Amerifund Capital Group, LLC as financial advisors to assist us in raising capital and seeking strategic acquisitions. So far in 2005, we have renegotiated the terms of a $750,000 promissory note due December 31, 2006 to MCNIC, originally bearing interest at 6% per annum, whereby under the new terms the note is non-interest bearing, in the principal amount of $250,000. In addition, all accrued interest on this promissory note was forgiven. Principal payments to be made in 2005 total $130,000.

As a result of these and other actions taken in 2004, we ended 2004 with working capital of approximately $400,000. However, due to our continuing losses from operations and debt service and other contractual obligations due in 2005, of approximately $1,465,000, we estimate that we will need to raise additional capital of approximately $500,000 to satisfy our obligations in 2005. Our inability to raise capital may have a material adverse effect on our financial condition, ability to meet our obligations and operating needs, and results of operations. As a result of our ongoing liquidity problems, our auditors UHY Mann Frankfort Stein & Lipp CPAs, LLP added an explanatory paragraph in their opinion on our consolidated financial statements as of the year ended December 31, 2004, indicating that substantial doubt exists about our ability to continue as a going concern. See Note 2 in Item 7 of the Consolidated Financial Statements.

LIQUIDITY AND CAPITAL RESOURCES

Although we were able to implement certain cost savings measures and restructure the terms of some of our indebtedness we were not able to generate sufficient cash from operations to cover operating and general and administrative expenses. Furthermore, our financial condition has been significantly and negatively affected by the poor performance of our businesses and our significant indebtedness. For the year ended December 31, 2004, we generated total revenues of approximately $1.4 million while operating costs and general administrative costs, excluding certain non-cash compensation expense, totaled approximately $2.8 million.

In August 2004, we extended the remaining payments totaling $668,000 due in September and October 2004 to Tetra for the abandonment/reefing of the Buccaneer Field. Under the revised terms, we will pay Tetra the outstanding balance in twelve monthly installments of $55,667 beginning September 1, 2004, plus interest on the outstanding balance at the rate of six percent per annum. As of December 31, 2004, the remaining balance due Tetra was approximately $450,000.

On September 8, 2004, we entered into the Purchase Agreement with certain accredited investors and certain of our directors for the purchase and sale of Promissory Notes in an aggregate principal amount of $750,000 and 2,800,000 Warrants to purchase shares of our common stock at a purchase price of $0.003 per Warrant. The sale of the Promissory Notes and the first tranche of 1,250,000 Initial Warrants closed on September 8, 2004, and the closing of the sale of the second tranche of 1,550,000 Additional Warrants closed on November 30, 2004 after we received stockholder approval of the issuance of the Additional Warrants at our November 11, 2004 special stockholders meeting. We received proceeds of $758,400 from the issuance of the Promissory Notes and the Warrants. The Promissory Notes mature on September 8, 2005, and accrue interest at

a rate of 12.0% per annum, of which 4% is payable monthly and 8% is payable at maturity. The Warrants have an exercise price of twenty five cents per share and a term of five years.

In October 2004, we sold our 25% equity interest in New Avoca. Pursuant to the terms of a Purchase and Sale Agreement, we received approximately $930,000 for our interest in New Avoca, and may receive an additional payment of up to approximately $375,000, subject to the commencement of commercial operations at the New Avoca natural gas storage facility prior to October 29, 2011. The proceeds from the sale of our interest in New Avoca will be used for general corporate purposes.

The current poor performance of our existing assets combined with the capital requirements inherent in our business raise substantial doubt about our ability to continue as a going concern. Our long-term viability as a going concern is dependent upon the following factors:

- our ability to raise capital to meet current commitments and obligations, and fund the continuation of our business operations; and

- our ability to ultimately achieve profitability and cash flows from operations in amounts that will sustain our operations through our existing assets and acquisition of other assets.

The following table summarizes our contractual obligations and other commercial commitments at December 31, 2004 (amounts in thousands):

	Payments Due by Period				
Contractual Obligations	Total	1 year or less	1-3 years	3-5 years	After 5 years
Accounts Payable - Tetra	$ 445	445	-	-	-
Notes Payable and Long-Term Debt	1,651	900	751	-	-
Operating Leases, net of sublease	237	120	117	-	-
Total Contractual Obligations	$ 2,333	1,465	868	-	-

	Amount of Commitment Expiration Per Period				
Other Commercial Commitments	Total	1 year or less	1-3 years	3-5 years	After 5 years
Abandonment - Costs	$ 1,622	-	188	-	1,434
Total Commercial Obligations	$ 1,622	-	188	-	1,434

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The following table summarizes our financial position for the periods indicated:

	December 31, (amounts in thousands)			
	2004		2003	
	Amount	%	Amount	%
Working Capital	$ 404	7	$ 680	9
Property and equipment, net	5,324	93	5,775	79
Other noncurrent assets	11	0	848	12
Total	$ 5,739	100	$ 7,303	100
Long-term Liabilities	$ 2,374	41	$ 2,302	32
Stockholders' equity	3,365	59	5,001	68
Total	$ 5,739	100	$ 7,303	100

The change in our financial position from December 31, 2003 to December 31, 2004, was primarily due to our net loss from operations for the year ended December 31, 2004 of approximately $2,500,000, the issuance of $750,000 in promissory notes and the sale of New Avoca for approximately $930,000.

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

	Years Ended December 31 (amounts in thousands)	
	2004	2003
Net cash provided by (used in):		
Operating activities	$ (2,603)	$ (1,365)
Investing activities	875	(338)
Financing activities	586	-
Net decrease in cash	$ (1,142)	$ (1,703)

For the year ended December 31, 2003, we generated $1.4 million of revenue from the sale of oil and gas production from the High Island Block A-7 field, representing approximately 57% of our revenues for that period. Oil and gas production from the High Island Block A-7 field declined significantly for the year ended December 31, 2004. Our revenues from the sale of oil and gas production from the High Island Block A-7 field decreased approximately 76% in 2004 to $332,000, which accounted for approximately 23% of our revenues for that period. As a result of the decline in production from this field, we expect that a significant portion of our revenues in 2005 will continue to be derived from utilization of our pipeline systems. To increase operating results, we must increase our pipeline revenues and/or acquire additional income generating assets.

From October 2002 to late April 2003, we had no interest in any producing oil and gas properties. In late April 2003, we began to receive revenue from our 8.9% reversionary working interest in the High Island Block A-7 field, in the Gulf of Mexico. See "Sale of Oil and Gas Properties" and "High Island Block A-7" in Item 1. This field currently produces at a gross rate of 0.8 MMcf/day.

During 2004, we incurred no capital expenditures for the development of our proved reserves. The reserves and future net revenues presented in Item 1 "Description of Business" reflect projected capital expenditures totaling $13,000 and $203,000 in the years ending December 31, 2005 and 2007, respectively. Capital expenditures in 2005 represent workover costs, net to our interest for the producing well in the High Island Block A-7 field and in 2007 the abandonment costs of our High Island Block A-7 field, net to our interest.

We have significant available capacity in our Blue Dolphin System in a market area that we believe is experiencing an increased level of interest by oil and gas operators. Natural gas transportation throughput on our Blue Dolphin System is currently 7 MMBtu per day representing 4% of system capacity. Effective October 1, 2004, we renegotiated the gas transportation rates on the Blue Dolphin System due to losses incurred from operating the system. As a result, fourth quarter 2004 gas transportation revenues from the Blue Dolphin System totaled approximately $318,000. Without the increased gas transportation rates, revenues would have been approximately $107,000, for this same period. Future utilization of our pipelines and related facilities will depend upon the success of drilling programs around our pipeline systems, and attraction and retention of producer/shippers to the systems. As a result of current and anticipated drilling activity around the Blue Dolphin System, we expect that utilization of the Blue Dolphin System will increase in late 2005.

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 for the New Promissory Note, and all accrued interest on the Original Promissory Note, $132,368 at December 31, 2004, was forgiven. In addition to the New Promissory Note, MCNIC can 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 will make monthly principal payments of $10,000 through its maturity date of December 31, 2006. The principal amount of the New Promissory Note may be increased by up to $500,000 if 50% or more of our 83% interest in the Blue Dolphin System is sold before December 31, 2006.

RESULTS OF OPERATIONS

For the year ended December 31, 2004 ("2004"), we reported a net loss of $2.5 million, compared to a net loss of $793,050 for the year ended December 31, 2003 ("2003").

2004 compared to 2003

Revenue from pipeline operations. Revenues from pipeline operations increased by $79,377 or 8% in 2004 to $1,014,137. The increase is due to increased volumes from new wells tied into our GA 350 Pipeline in mid 2004. Average daily gross gas volumes transported on the GA 350 Pipeline increased from 10.7 Mmcf per day in 2003 to 16.5 Mmcf per day in 2004, resulting in an increase in revenues from $257,000 in 2003 to $351,000 in 2004. The increase in pipeline revenues from the GA 350 Pipeline was offset in part by a 34% decrease in volumes transported on the Blue Dolphin System in 2004 from those of 2003. Revenues in 2004 from the Blue Dolphin System totaled $663,000 compared to $678,000 in 2003. As a result of net operating losses incurred from the operation of the Blue Dolphin System, we negotiated an increase in our average gas transportation rates on the Blue Dolphin System effective October 2004. The increased rates will decrease as our net operating results from the Blue Dolphin System improve, but in any case, the rates will be no lower than the rates that were in effect prior to October 2004. If the increased gas transportation rates would have been in effect on January 1, 2004, pipeline transportation revenues would have increased by approximately $640,000. However, there can be no assurance that volumes transported in 2005 will be at the same level as in 2004.

Revenue from oil and gas sales. Revenues from oil and gas sales decreased by $1,186,354 in 2004 from $1,582,054 in 2003, primarily due to a significant production decline in the High Island Block A-7 field. The High Island Block A-7 field provided revenues from oil and gas sales of approximately $332,000 in 2004 compared to approximately $1.4 million in 2003. We expect that production from the reservoir currently producing will cease in mid 2005, however there is an additional reservoir in which a recompletion in the existing well is possible. Oil and gas sales from this additional reservoir are not expected to significantly increase our total revenues in 2005. Oil and gas sales in 2004 include approximately $64,000 from our interest in the High Island Block 34 field, which we sold in June 2004, compared to $61,000 recorded in 2003.

Gain on sale of oil and gas property. In June 2004 we recorded a gain on sale of oil and gas property representing a gain of $25,809 recognized from the sale of our interest in the High Island Block 34 field.

Pipeline operating expenses. Pipeline operating expenses in 2004 decreased by $120,064 from $1,198,729 in 2003. Cost reductions implemented during 2003 resulted in lower expenses in 2004 of approximately $104,000. Insurance costs in 2004 decreased by $67,000 due to the elimination of property insurance coverage on our pipelines, offset in part by higher costs associated with our other insurance. Our elimination of property insurance coverage is consistent with trends in the pipeline industry. Since the elimination of the property insurance occurred in mid 2004, we expect that pipeline operating expenses will decrease in 2005 as a result of lower insurance costs for 2005 to be lower. The above cost reductions were offset in part by an increase in repair and maintenance costs of $75,000 in 2004. Legal costs incurred in 2004 associated with an action filed against us, the outcome of which we do not believe will have a material impact, decreased by $24,000. However, as this litigation continues we incur significant legal expenses, which could have a material adverse effect on our financial condition.

Lease operating expenses. Lease operating expenses for 2004 decreased by $52,343 from $186,656 in 2003 primarily due to a well that stopped producing in the High Island Block A-7 field in early 2004.

Depletion, depreciation and amortization expense. Depletion, depreciation and amortization expense decreased by $55,286 in 2004 from $488,052 in 2003. In 2004, we recorded depletion of approximately $88,000 associated with our oil and gas properties compared to depletion of approximately $146,000 recorded in 2003. The decrease in depletion was a result of there being no significant remaining unamortized oil and gas costs as of mid 2004.

Impairment of assets. In 2004 there were no impairment of assets recorded. In 2003, we recorded a partial impairment of our oil and gas properties of approximately $89,000, due to the decline in proved reserves from our interest in the High Island Block A-7 field.

General and administrative. General and administrative expenses increased by $701,908 from $1,685,693 in 2003. The increase was due to a one time, non-cash compensation expense recorded in 2004 of $818,000 of which $694,000 is associated with the issuance of Warrants to certain of our directors and $124,000 is associated with the issuance of shares of common stock to our 401k plan. The increase was partially offset by lower personnel and other costs as a result of our cost reduction plans in 2003 and 2004. The 2004 cost reductions included the termination of certain employees in mid 2004. The annual cost savings associated with measures taken is expected to be approximately $360,000. As a result, 2005 general and administrative expenses are expected to be lower. However, if our business activities expand, we will need to hire additional employees and personnel and associated costs may increase.

Interest and other expense. Interest and other expense increased $291,926 in 2004. Interest and other expenses in 2004 includes legal and other fees of approximately $200,000 associated with a proposed financing transaction that was not consummated, the amortization of costs associated with the Purchase Agreement of approximately $120,000 and interest expense on our Promissory Notes and other debt of $85,000. Other expense in 2003 includes costs associated with capital funding activities of $65,000 and interest expense on a promissory note of $45,000. In 2005, the previously recorded interest expense associated with the MCNIC promissory note

has been eliminated, however this decrease will be offset by the increase in interest expense associated with the issuance of $750,000 aggregate principal amount of Promissory Notes issued in September 2004.

Gain on sale of assets. In 2004, we recorded a gain of approximately $344,000 associated with the sale of our 25% interest in New Avoca and a gain of $27,000 associated with the sale of our 5% interest in two exploratory leases, East Cameron Blocks 90 and 94.

Interest and other income. Interest and other income decreased $339,115 in 2004 from 2003. Other income in 2004 includes the collection of accounts receivable that were previously written off of $165,000, and consulting services provided by us, associated with the evaluation of oil and gas properties, of $110,000. Other income in 2003 included a $500,000 gain resulting from a reduction in our provision for the Buccaneer Field abandonment costs, and consulting services we provided, associated with the evaluation of oil and gas properties, of approximately $104,000. We do not expect to receive revenues from consulting services in 2005, as we did in 2004 and 2003. However, in March, 2005 we received the remaining balance of the accounts receivable that were previously written off of approximately $45,000 from Drillmar.

Cumulative effect of a change in accounting principle. In 2003, as a result of our adoption of Statement of Financial Accounting Standards (SFAS) No. 143, we recorded a cumulative effect adjustment at January 1, 2003 of a change in accounting principle for asset retirement obligations of $40,455 (see Note 1 in Item 7 of the Consolidated Financial Statements). There was no adjustment for changes in accounting principals recorded in 2004.

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, 2004 and the accounting for future abandonment costs.

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, 2004. Accordingly, we developed future cash flows as of December 31, 2004 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

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future undiscounted cash flows are in excess of the pipeline assets net carrying value, no impairment has been recorded as of December 31, 2004.

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 July 2003, an issue was brought before the FASB regarding whether or not contract-based oil and gas mineral rights held by lease or contract ("mineral rights") should be recorded or disclosed as intangible assets. The issue presents a view that these mineral rights are intangible assets as defined in SFAS No. 141, "Business Combinations," and, therefore, should be classified separately on the balance sheet as intangible assets. SFAS No. 141 and SFAS No. 142, "Goodwill and Other Intangible Assets," became effective for transactions subsequent to June 30, 2001, with the disclosure requirements of SFAS No. 142 required as of January 1, 2002. SFAS No. 141 requires that all business combinations initiated after June 30, 2001 be accounted for using the purchase method and that intangible assets be disaggregated and reported separately from goodwill. SFAS No. 142 established new accounting guidelines for both finite lived intangible assets and indefinite lived intangible assets. Under the statements, intangible assets should be separately reported on the face of the balance sheet and accompanied by disclosure in the notes to financial statements. SFAS No. 142 does not apply to accounting utilized by the oil and gas industry as prescribed by SFAS No. 19, and is silent about whether or not its disclosure provisions apply to oil and gas companies.

In September 2004, the FASB posted FASB staff position ("FSP") SFAS 142-2, "Application of SFAS 142 to Oil and Gas Producing Entities." The FSP clarifies that the exception in paragraph 8(b) of SFAS No. 142, "Goodwill and Other Intangible Assets," includes the balance sheet classification and disclosures for drilling and mineral rights of oil and gas producing entities. Accordingly, the FASB staff believes that the scope exception extends to the disclosure provisions of SFAS No. 142 for drilling and mineral rights of oil and gas producing entities. SFAS 142-2 is effective for the first reporting period after September 2, 2004. The FSP had no impact on our financial position, results of operations or cash flows.

In December, 2004, the FASB issued SFAS No. 123R, "Share-Based Payment," that addresses the accounting for share-based payment transactions in which a company receives employee services in exchange for equity instruments of the company, such as stock options and restricted stock. SFAS No. 123R eliminates the ability to account for share-based compensation transactions using APB Opinion No. 25 and requires instead that such transactions be accounted for using a fair value-based method. We currently account for stock-based compensation using the intrinsic method pursuant to APB Opinion No. 25. SFAS No. 123R requires that all stock-based payments to employees, including grants of employee stock options and restricted stock, be recognized as compensation expense in the financial statements based on their fair values. Public entities that file as small business issuers will be required to apply Statement 123R in the first interim or annual reporting period that begins after December 15, 2005. Accordingly, we will be required to apply SFAS No. 123R beginning in the fiscal quarter ending March 31, 2006. We are currently assessing the provisions of SFAS No. 123R and its impact on our consolidated financial statements.

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, 2004, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the years in the two-year period ended December 31, 2004. 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, 2004, and the consolidated results of their operations and their cash flows for each of the years in the two-year period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America.

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 2 to the consolidated financial statements, the Company has incurred net losses and negative cash flows from operations in recent years and has projected a cash deficit for 2005. Those conditions raise substantial doubt about the Company's ability to continue as a going concern. Management's plans in regard to those matters are described in Note 2. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

As discussed in Note 1, the Company adopted the provisions of SFAS No. 143, "Accounting for Asset Retirement Obligations," as of January 1, 2003.

/s/ UHY Mann Frankfort Stein & Lipp CPAs, LLP
Houston, Texas
March 9, 2005

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

December 31, 2004

Assets

Current assets:	
Cash and cash equivalents	$ 1,560,549
Accounts receivable	314,759
Related party receivable	1,605
Prepaid expenses and other assets	191,394
Total current assets	2,068,307
Property and equipment, at cost:	
Oil and gas properties, including $177,589 of unproved leasehold cost (full-cost method)	517,210
Pipelines	4,547,362
Onshore separation and handling facilities	1,664,128
Land	860,275
Other property and equipment	253,758
	7,842,733
Less accumulated depletion, depreciation, amortization, and impairment	2,518,932
	5,323,801
Other assets	11,359
	$ 7,403,467

See accompanying notes to consolidated financial statements.

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET, CONTINUED

December 31, 2004

Liabilities and Stockholders' Equity

Current liabilities:	
Accounts payable	$ 740,907
Notes payable	750,000
Current portion of long-term debt	130,000
Accrued expenses and other liabilities	43,861
Total current liabilities	1,664,768
Long-term liabilities:	
Long-term debt	620,000
Interest payable	132,368
Asset retirement obligations	1,621,729
Total long-term liabilities	2,374,097
Stockholders' equity:	
Common stock, $.01 par value, 10,000,000 shares authorized and 6,863,689 shares issued and outstanding	68,637
Additional paid-in capital	27,129,162
Accumulated deficit	(23,833,197
Total stockholders' equity	3,364,602
	$ 7,403,467

See accompanying notes to consolidated financial statements.

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

Years ended December 31, 2004 and 2003

	2004	2003
Revenue from operations:		
Pipeline operations	$ 1,014,137	$ 934,7
Oil and gas sales	395,700	1,582,0
Gain on sale of oil and gas property	25,809	
Revenue from operations	1,435,646	2,516,8
Cost of operations:		
Pipeline operating expenses	1,078,665	1,198,7
Lease operating expenses	134,313	186,6

Depletion, depreciation and amortization	432,766	488,0
Impairment of assets	-	88,8
General and administrative expenses	2,387,601	1,685,6
Accretion expense	96,542	80,4
Cost of operations	4,129,887	3,728,3
Loss from operations	(2,694,241)	(1,211,5
Other income (expense):		
Interest and other expense	(426,973)	(135,0
Gain on sale of assets	371,340	
Interest and other income	345,656	684,7
Equity in losses of affiliate	(96,116)	(90,7
Loss before income taxes	(2,500,334)	(752,6
Income tax expense	-	
Loss before cumulative effect of change in accounting principle	(2,500,334)	(752,6
Cumulative effect of a change in accounting principle for asset retirement obligations	-	(40,4
Net loss	$ (2,500,334)	$ (793,0
Loss per common share-basic		
Loss before accounting change	$ (0.37)	$ (0.
Cumulative effect of a change in accounting principle	$ -	$ (0.
Net loss	$ (0.37)	$ (0.
Loss per common share-diluted		
Loss before accounting change	$ (0.37)	$ (0.
Cumulative effect of a change in accounting principle	$ -	$ (0.
Net loss	$ (0.37)	$ (0.
Weighted average number of common shares		
- basic	6,734,395	6,640,2
- diluted	6,734,395	6,640,2

See accompanying notes to consolidated financial statements.

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

Years ended December 31, 2004 and 2003

	Common	Additional

	stock shares	Common stock	paid-in capital	Accumulate deficit
Balance at December 31, 2002	6,606,578	$ 66,066	26,239,098	(20,539,8
Common stock issued for services	51,267	512	28,210	
Net loss				(793,0
Balance at December 31, 2003	6,657,845	$ 66,578	26,267,308	(21,332,8
Exercise of stock options	93,688	937	19,063	