BLUE DOLPHIN ENERGY CO
Form 10KSB
March 21, 2003

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

FORM 10-KSB

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

For the fiscal year ended December 31, 2002

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. [X]

The issuer's revenues for the year ended December 31, 2002 were $2,910,277.

The aggregate market value of the voting stock held by non-affiliates of the registrant as of March 13, 2003, was approximately $1,923,264.

As of March 13, 2003, there were outstanding 6,606,585 shares of common stock, par value $.01 per share, of the issuer.

Documents Incorporated By Reference

The registrant's definitive proxy statement for the 2003 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"), to be filed with the Securities and Exchange Commission pursuant to Regulation 14A, is incorporated by reference in Part III of this report.

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PART I

Item 1. Business

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" or the "Company") cautions readers that any such 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 risks associated with exploration;
- 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;
- availability and cost of capital;
- actions or inactions of third party operators for properties where the Company has an interest;
- 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. The Company undertakes no duty to update these forward-looking statements. Readers are urged to carefully review and consider the various disclosures made by the Company which attempt to advise interested parties of the additional factors which may affect the Company's business, including the disclosures made under the caption "Management's Discussion and Analysis of Financial Condition and Results of Operations" in this report.

THE COMPANY

The Company conducts its business activities in two primary business segments: (i) oil and gas exploration and production, and (ii) pipeline operations, which includes developmental projects. The Company is a holding company that conducts substantially all of its operations through its subsidiaries. Substantially all of the Company's assets consist of equity in its subsidiaries. The Company's subsidiaries and affiliates are as follows:

- American Resources Offshore, Inc., a Delaware corporation;
- Blue Dolphin Petroleum Company, a Delaware corporation;
- Blue Dolphin Exploration Company, a Delaware corporation;

- Blue Dolphin Pipe Line Company, a Delaware corporation;
- Blue Dolphin Services Co., a Texas corporation;
- Petroport, Inc., a Delaware corporation;
- New Avoca Gas Storage, LLC, a Texas limited liability company in which the Company owns a 25% interest; and
- Drillmar, Inc., a Delaware corporation in which the Company owns a 12.8% interest.

Effective January 1, 2002, two wholly owned subsidiaries, Mission Energy, Inc. and Buccaneer Pipe Line Co. were merged into Blue Dolphin Pipe Line Company.

The principal executive office of the Company is located at 801 Travis, Suite 2100, Houston, Texas, 77002, telephone number (713) 227-7660. Shore based facilities are maintained in Freeport, Texas serving Gulf of Mexico operations. The Company has 11 full-time employees. The Company's common stock is traded on the National Association of Securities Dealers, Inc. Automated Quotation System ("NASDAQ") Small Cap Market under the trading symbol "BDCO". The Company's home page address on the world wide web is http://www.blue-dolphin.com.

Recent Developments

Sale of Oil and Gas Properties. During 2002, American Resources sold all of its interests in its oil and gas properties in two separate transactions described below. These properties represented over 99% of the Company's proved oil and gas reserves. The Company's remaining oil and gas properties consist of working interests in several exploratory lease blocks located offshore Louisiana in the Gulf of Mexico and reversionary working interests in certain exploratory and producing lease blocks located offshore Texas in the Gulf of Mexico.

In July 2002, American Resources sold its working interest in the South Timbalier Block 148 property for $2.3 million to Newfield Exploration Company. Production from this field accounted for 15% and 19% of the Company's oil and gas sales revenues and 9% and 16% of the Company's total revenues for the years ended December 31, 2002 and 2001, respectively. In November 2002, American Resources sold its working interest in all of its remaining proved oil and gas properties for $2.7 million to Fidelity Exploration & Production Company. Production from these fields accounted for 85% and 81% of the Company's oil and gas sales revenues and 52% and 67% of the Company's total revenues for the years ended December 31, 2002 and 2001, respectively. As a result of these transactions, the Company will be primarily dependent on revenues generated from its pipeline operations and reversionary interest in oil and gas properties.

Abandonment of Buccaneer Field. The Company owned a 100% working interest in the Buccaneer Field. The Company conducted traditional oil and gas production operations for itself, and operated and maintained oil and gas production facilities at the Buccaneer Field for third party producers who utilized the Blue Dolphin Pipeline System for gathering and transportation of their production. In November 2000 the Company decided to abandon and not reestablish production from the Buccaneer Field. As a result of this decision, the leases in this field terminated in January 2001 pursuant to their terms, and the Company's third party operation and maintenance services contract was terminated in December 2000.

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As a result of the termination of the Company's leases in or around the Buccaneer Field, the Company must plug and abandon all remaining wells and remove platform facilities. Blue Dolphin Exploration provided the U.S. Minerals Management Service ("MMS") surety bonds in the amount of $4.2 million for its abandonment obligations. The rules and regulations of the MMS require that the Company complete the plugging and abandonment within one year after termination of the leases.

During removal of the platform complexes in October 2001, the Company initiated discussions with the Texas Parks and Wildlife Department ("TPW") in an effort to leave certain underwater portions of the platform complexes in place as artificial reefs. In December 2001, operations to remove the platform complexes were suspended while the Company continued its discussions with the TPW. By leaving the platform complexes in place as artificial reefs, certain site clearance costs will be eliminated. On January 3, 2003, the Company and TPW executed deeds of donation for both of the Company's platform complexes in the Buccaneer Field, whereby the Company will leave certain of the underwater portions of the platforms in place as artificial reefs and donate them to the TPW. The Company requested and has received an extension from the MMS until April 1, 2003 to complete the abandonment operations needed to convert the platform complexes into artificial reefs. Remaining abandonment operations include mechanically severing the upper section of the platform jackets and well casings at a minimum of minus 50 feet from the water's surface, cutting the severed pieces into sections that meet the clearance requirement, and placing those sections on the seafloor near the base of the platform jackets. The work to complete the abandonment/reefing is expected to begin and be completed during the second quarter 2003. The Company will seek a further extension from the MMS.

Until abandonment operations were suspended in December 2001, significant progress was made. Both platform complexes consisted of production platform with a bridge connected quarters platform. At the complex located in GA Block 288, the decks on both the production and quarters platforms and the bridge have been removed. At the complex located in GA Block 296, the deck on the quarters platform, a portion of the deck on the production platform and the bridge have been removed.

Pipeline Operations and Activities

The Company's pipeline assets are held and operations conducted by Blue Dolphin Pipe Line Company. Effective January 1, 2002, Mission Energy and Buccaneer Pipe Line, which held pipeline assets, were merged into Blue Dolphin Pipe Line Company, where all of the Company's pipeline assets are now held.

The economic return to the Company on its pipeline system investments is solely dependent upon the amounts of gas and condensate gathered and transported through the pipeline systems. Competition for provision of gathering and transportation services, similar to those provided by the Company, is intense in the market areas served by the Company. See Competition below. Since contracts for provision of such services between the Company and third party producer/shippers are generally for a specified time period, 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 by the

Company will be maintained in the future. The Company actively markets gathering and transportation services to prospective third party producer/shippers in the vicinity of its pipeline systems. Future utilization of the pipelines and related facilities will depend upon the success of drilling programs around the pipelines, and attraction, and retention, of producer/shippers to the systems.

Blue Dolphin Pipeline System. The Company owns an 83% undivided interest in the Blue Dolphin Pipeline System (the "Blue Dolphin System"). The Blue Dolphin System includes the Blue Dolphin Pipeline, Buccaneer Pipeline, onshore

facilities for condensate and gas separation and dehydration, 85,000 Bbls of above-ground tankage for storage of 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 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 Buccaneer Pipeline, an 8" condensate pipeline, transports condensate from the storage tanks to the Company's barge loading terminal on the Intracoastal Waterway near Freeport, Texas for sale to third parties.

The Blue Dolphin Pipeline consists of two segments. The offshore segment transports both gas and condensate and is comprised of approximately 34 miles of 20-inch pipeline from a platform in GA Block 288 to shore. An additional 4 miles of 20 inch pipeline connect the offshore segment to the shore facility at Freeport, Texas. In 2001, Blue Dolphin Pipe Line Company installed a platform in GA Block 288 to operate and maintain the Blue Dolphin Pipeline System as a result of the Company's decision to abandon and remove the Buccaneer Field platforms in GA Blocks 288 and 296, which were previously used to operate and maintain the Blue Dolphin System. The installation of the platform and its connection to the Blue Dolphin System cost approximately $1.7 million net to the Company's interest. Additionally, the offshore segment includes 5 field gathering lines totaling approximately 27 miles, connected to the main 20-inch line. This system's 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.

Various fees are charged to producer/shippers for provision of transportation and shore facility services. Blue Dolphin System gas throughput averaged approximately 9% and 16% of capacity during 2002 and 2001, respectively. Current system capacity is approximately 160 MMcf per day of gas and 7,000 Bbls per day of condensate. During 2002, 100% of gas and condensate volumes transported were attributable to production from third party producer/shippers. See Note 11 to Consolidated Financial Statements included in Item 7.

In February 2002, the Company's interest in the Blue Dolphin System was increased from 50% to 83% by acquiring a 1/3 interest in the Blue Dolphin System and the inactive Omega Pipeline from MCNIC Pipeline and Processing Company ("MCNIC").

Black Marlin Pipeline System. In January 2001, the Company and its partners, MCNIC and WBI Holdings, Inc. ("WBI") sold the Black Marlin Pipeline System and the High Island Block A-5 pipeline to Williams Field Services for $9.3 million. The Company through wholly-owned subsidiaries owned a 50% interest in these assets and received $4.6 million for its interest. The Black Marlin Pipeline System included the Black Marlin Pipeline, onshore facilities for condensate and gas separation and dehydration, 3,000 Bbls of above ground tankage for storage of condensate, a truck loading facility for oil and condensate, and five acres of land in Galveston County, Texas where the Black Marlin Pipeline comes ashore and on which are located the pipeline system's shore facilities. See Note 13 to Consolidated Financial Statements included in Item 7.

In July 2000, the Company reached an agreement to provide transportation services for Vastar Resources, Inc. in High Island Area Block A-5, offshore Texas in the Gulf of Mexico. To accommodate this production, the Company constructed a 3.4 mile 12" diameter pipeline from the production platform in

High Island Area Block A-5 to the Black Marlin Pipeline. The cost to construct the pipeline was approximately $1.9 million, $.9 million net to the Company's 50% interest in the pipeline. The pipeline was completed in September 2000. See Note 13 to Consolidated Financial Statements included in Item 7.

Galveston Area Block 350 Pipeline. In July 2000, the Company acquired 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 GA Block 391 (the "GA350 Pipeline"), approximately 14 miles south of the Company's Blue Dolphin Pipeline for $224,000. The pipeline currently transports approximately 8,000 Mcf of gas per day.

Other. The Company also holds 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.

Oil and Gas Exploration and Production Activities

The Company's oil and gas assets are held by Blue Dolphin Petroleum and Blue Dolphin Exploration. The Company's oil and gas exploration and production activities include the exploration, acquisition, development, operation and, when appropriate, disposition of oil and gas properties. The Company focuses its oil and gas acquisitions and exploration activities in the western and central Gulf of Mexico, and onshore Texas and Louisiana. The leasehold interests in properties held by the Company are subject to royalty, overriding royalty and interests of others. In the future, the Company's 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.

Certain terms that are commonly used in the oil and gas industry, including terms that define the Company's rights and obligations with respect to each of its properties, are defined in the "Glossary of Certain Oil and Gas Terms" on pages 22, 23 and 24 of this Form 10-KSB.

The following is a description of the Company's oil and gas exploration and production assets and activities:

Offshore Oil and Gas Prospect Generation Activities. Effective, December 31, 2000 the Company suspended its prospect generation program as a result of the withdrawal of its partner. The program developed oil and gas exploration prospects in the Gulf of Mexico for sale to third parties. In addition to recovering prospect development costs, the Company sought to retain a reversionary working interest in each drillable prospect it sold through this program. As a result of the withdrawal of the Company's partner from its prospect generation program, effective December 31, 2000 this program was suspended. Although the program is suspended the Company has seismic and other data to evaluate and develop prospects, including a non-exclusive license to 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.

In January 2001, the Company entered into a consulting agreement with Cheyenne Petroleum Co., whereby the Company's remaining prospect generation staff provided technical consulting services to Cheyenne in the evaluation of prospects for the March 2001 central Gulf of Mexico federal lease sale. In

exchange, Cheyenne reimbursed the Company for personnel costs and allowed the Company to participate in prospects generated with a 5% working interest in four undeveloped offshore blocks. This agreement terminated April 30, 2001.

Unproved Leasehold Interests. The Company's leased prospect inventory, which it continues to market, consists of prospects on the following offshore leases:

- East Cameron Area Block 90
- East Cameron Area Block 94
- West Cameron Area Block 212
- Mustang Island Area Block 817
- Mustang Island Area Block 839

The Company has reversionary working interests in several offshore leases after payout. These leases are:

- Galveston Area Block 297
- Galveston Area Block 271
- Galveston Area Block 284
- Galveston Area Block 285
- Matagorda Island Area Block 710
- Matagorda Island Area Block 713

Other. In connection with Blue Dolphin Exploration's acquisition of a controlling interest in American Resources in December 1999, Fidelity Oil acquired an 80% interest in American Resources oil and gas assets located in the Gulf of Mexico for approximately $24.2 million and agreed to assign Blue Dolphin Exploration 10% of its working interest in the proved properties of American Resources after it recovered its investment in these properties. In addition, Fidelity Oil agreed to assign Blue Dolphin Exploration 15% of its working interest in each exploratory property after Fidelity recovered its investment in these exploratory properties on a property by property basis.

In the fourth quarter 2001, Fidelity Oil recovered its investment in the proved properties. However, instead of assigning 10% of its interest in the proved properties, Fidelity paid Blue Dolphin $1.4 million in December 2001, for the property interest owed to Blue Dolphin.

At December 31, 2002, there was one such exploratory property remaining located in High Island Area Block 34. A successful well was drilled on this property in late 2002, with further drilling expected in 2003. If payout occurs, the Company would receive an approximate 1.8% working interest.

High Island Block A-7. The Company previously announced a gas discovery in High Island Area Block A-7, in the Gulf of Mexico. The Company owns an 8.9% reversionary working interest in this field and it will begin to receive revenues from its reversionary interest after "payout" occurs. Payout occurs after all of the other working interest owners have recovered their costs and expenses associated with developing the field from sales of gas and oil production from the field. In late 2002, two wells from this field were successfully recompleted. As a result of the two recompleted wells and based on current levels of production and commodity prices, the Company now believes that it could begin to receive revenues from its reversionary working interest in this field in mid 2003.

Proved Oil and Gas Reserves. Estimates of proved reserves, future net revenues, and discounted present value of future net revenues to the net interest of the Company have been prepared as of December 31, 2002, by the Company.

The quantities of proved gas and oil reserves presented below include only those amounts which the Company reasonably expects 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 the Company's 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 the Company's Proved Reserves, changes in Proved Reserves, estimated future net revenues and costs incurred in the Company's oil and gas activities and the discounted present value of estimated future net revenues from the Company's Proved Reserves, see Note 12 - 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 the net interest of the Company in oil and gas properties as of December 31, 2002. The discounted present value of future net revenues and future net revenues are calculated using the SEC Method (defined above) and are not intended to represent the current market value of the oil and gas reserves the Company owns.

PROVED RESERVES
As of December 31, 2002 (1) (3)

	Net Oil Reserves (Mbbls)	Net Gas Reserves (Mmcf)	Future Net Revenues (in thousands)	Discounted Present Value of Future Net Revenues (2) (in thousands)
Total Proved Reserves	1.4	280	757	$ 748
Total Proved Developed Reserves	1.4	280	757	$ 748

(1) As of December 31, 2002, all of the Company's proved reserves are from its 8.9% reversionary interest in the High Island Block A-7 field.

(2) The estimated discounted present value of future net revenues before deductions for income taxes from the Company's Proved Reserves have been determined by using prices of $32.36 per barrel of oil and $4.83 per Mcf of gas, representing the December 31, 2002 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").

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(3) As of December 31, 2002, the Company reported no proved undeveloped reserves.

Capital Expenditures for Proved Reserves. The following table presents information regarding the costs the Company expects to incur in development activities associated with its proved reserves. These expenditures include recompletion costs, workover costs and the cost of drilling additional wells required to recover proved reserves. The information regarding proved reserves summarized in the preceding table assumes the following estimated capital expenditures in the years indicated.

Estimated Capital Expenditures To Develop Proved Reserves
For the years ending December 31,
(in thousands)

	2003	2004	2005	2006	2007
High Island Block A-7	0	$150	0	$192	0

Management will continue to evaluate its capital expenditure program based on, among other things, demand and prices obtainable for the Company's production. The availability of capital resources and the willingness of other working interest owners to participate in development operations may affect the Company's 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 the interest of the Company for each of the periods indicated.

NET PRODUCTION, PRICE AND COST DATA

	Year Ended December 31,		
	2002 (1)	2001	2000
Gas:			
Production (Mcf)	418,895	815,184	911,671
Revenue	$ 1,221,168	$ 3,607,910	$ 3,674,192
Average Production (Mcf) per day	1,147.7	2,233.4	2,490.9
Average Sales Price Per Mcf	$ 2.92	$ 4.43	$ 4.03
Oil:			
Production (Bbls)	28,230	40,769	64,707
Revenue	$ 560,790	$ 1,086,292	$ 1,844,948
Average Production (Bbls) per day	77.3	111.7	176.8
Average Sales Price Per Bbl	$ 19.87	$ 26.65	$ 28.51
Production Costs (2):			
Per Mcfe:	$ 0.88	$ 1.06	$ 1.05

(1) See "Recent Developments."

(2) 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 2002 there was no drilling activity. The following table shows the Company's drilling activity for 2001. "Gross" as it applies to wells refers to the number of wells in which a working interest is owned, while "net" applies to the sum of the fractional working interests in gross wells.

	Exploratory Wells Drilled				Developmental Wells		
	Productive		Dry		Productive		D
	Gross	Net	Gross	Net	Gross	Net	Gross
2001							
American Resources	--	--	1	0.06	1	0.1	--
Other	--	--	--	--	--	--	--

The Company maintains professional staff and consultants capable of supervising and coordinating the operation and administration of its 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.

Development Projects

Avoca Gas Storage Project

In November 1999, the Company and WBI formed New Avoca Gas Storage, LLC ("New Avoca"), and acquired the assets of Avoca Gas Storage, Inc. from Northeastern Gas Caverns ("Northeastern"). The Company has a 25% equity interest and is the manager of New Avoca. The Company records its investment in New Avoca by using the equity method of accounting. The existing New Avoca assets include:

- Approximately 900 acres of land located south of Rochester near the town of Avoca, New York
- Pumps and pipeline for fresh water
- Pump house containing 12 pumps (6,400 HP) for the solution mining operation
- 7 cavern wells - 4,000 feet deep
- 6 brine disposal wells - 9,000 feet to 11,000 feet deep
- Storage building with valves, fittings, and miscellaneous parts
- Electrical switch gear
- Solution mining equipment
- Compressor foundations

The Avoca salt cavern gas storage project was conceived as a 5 Bcf working gas storage facility located south of Rochester near the town of Avoca, New York. Its design provides for 250 Mmcf per day injection and 500 Mmcf per day withdrawal capacities, with deliveries into the Tennessee Gas Pipeline HC400 24" line and other area transmission lines.

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To create the gas storage facility salt caverns must be created. To create the salt caverns, fresh water is injected from the surface to dissolve the salt formations below. The brine solution produced by this process must be continuously brought to the surface and then injected into underground disposal wells or disposed of in some other manner. The disposal wells must have sufficient porosity and permeability to accept the injected brine at a rate at least consistent with the rate at which brine is being produced during the creation of the salt caverns. The original owners of the Avoca gas storage assets conducted tests to determine the rate that the disposal wells would accept brine. New Avoca believes that the testing procedures used by the original owners of the project to analyze the rate at which the disposal wells could accept brine may have been flawed as a result of the accelerated pace at which the tests were conducted, and therefore yielded test results that were uncertain and did not conclusively support an acceptable rate of brine disposal. The original owners of the Avoca gas storage assets encountered technical and other difficulties as a result of the uncertainty of their test results. New Avoca is reviewing additional brine disposal options that could be used to accelerate the creation of the salt caverns.

During 2000, New Avoca completed an analysis of the project. Based on this analysis and recent technological advances, New Avoca believes the disposal wells will be capable of handling the more moderate rates of brine injection expected to be produced under its proposed construction schedule. From October 2000 through February 2001, New Avoca tested the disposal wells to determine the rate that these wells will accept brine. In February 2001, as a result of mild seismic activity in the area surrounding Avoca, the New York State Department of Environmental Conservation requested that New Avoca stop testing the disposal wells. New Avoca stopped testing the wells, and does not plan on further testing at this time. As a viable solution for the brine disposal, New Avoca has studied the construction of a brine pipeline to deliver brine to a salt plant. New Avoca believes that a combination of the use of disposal wells and brine deliveries by pipeline appears to be the most feasible means of brine disposal, and believes that it can negotiate an agreement with area salt plants to take the brine. In 2002 the Company and WBI began marketing their ownership interest in New Avoca. If the Company and WBI do not sell their interest in New Avoca, the Company would need to secure financing in order to proceed with the project. New Avoca estimates that it will take between 9 months to 15 months for approval of its permit, and between 21 months to 2 years after approval of its permit to contract and begin operations at partial capacity, with another 2 years needed to complete construction and reach the full 5 BCF capacity. There can be no assurance that the Company and WBI will be able to sell their interest in New Avoca on acceptable terms or that the Company will be able to secure financing necessary to proceed with the project.

Offshore Crude Oil Terminalling

Previously, the Company began the development of offshore crude oil terminals. The Company's efforts focused on two prospective market areas for locating such a facility: the Greater Houston area, including the Freeport, Texas and Houston Ship Channel market (the "Petroport" project); and the Beaumont - Port Arthur, Texas and Westlake - Lake Charles, Louisiana market (the "Sabine Seaport" project).

The Company elected to discontinue its efforts to develop an offshore crude oil terminal effective December 31, 2001, due to the lack of market support for the projects, the Company recorded a full impairment of $1.9 million of its investment in both the Petroport and Sabine Seaport projects. The Company will continue market surveillance activities and seek prospective partners to jointly develop an offshore terminal project, if market conditions warrant such development in the future.

Drillmar Project

In 2000, the Company, together with other partners, formed Drillmar, Inc., to develop mooring solutions which will allow a semi-submersible tender unit to

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be placed next to a deepwater floating production platform to assist in the drilling and completion of oil and gas wells. Drillmar has developed a proprietary mooring system and has patents and patents pending to protect this technology.

In 2000, Drillmar acquired a 1% general partner interest in Zephyr Drilling, Ltd., a Texas limited partnership ("Zephyr"). Zephyr owned a semi-submersible drilling rig. At December 31, 2000, the Company's investment in Drillmar and the partnership consisted of $25,000 cash and the contribution of management and administrative services of $50,000.

In May 2001, the Company increased its ownership in Drillmar from 37.5% to 64%. Consideration paid by the Company included cash of approximately $131,000, and contribution of services in the amount of $434,000.

Effective January 2001, the Company entered into an agreement with Drillmar whereby it agreed to provide office space and certain management and administrative services to Drillmar for approximately $40,000 per month. The Company used the payments it was entitled to receive under this agreement to fund its investment in Drillmar. The funding of the Company's investment in Drillmar was completed in October 2001.

In September 2001, Zephyr merged into Drillmar. As a result of the merger, the Company's interest in Drillmar decreased from 64% to 12.8%.

Ivar Siem, Chairman of the Company, Harris A. Kaffie and James M. Trimble, Directors of the Company, were limited partners of Zephyr. After the merger between Drillmar and Zephyr, Messers. Siem, Kaffie and Trimble were owners of 30.3%, 30.6% and 6.6%, respectively, of Drillmar's common stock. Messrs. Siem and Kaffie are both Directors, and Mr. Siem is Chairman and President of Drillmar. Messrs. Siem and Kaffie provided funding to Drillmar in 2002 of $116,000 and $100,000, respectively, and in 2001 of $300,000 and $425,000, respectively, and were issued unsecured promissory notes from Drillmar. The promissory notes were due June 30, 2002 and bore interest at the rate of 10% per annum. Along with the promissory notes, Drillmar issued detachable warrants to Messrs. Siem and Kaffie to purchase 41,500 and 42,500 shares of Drillmar common stock, respectively. The promissory notes issued by Drillmar are nonrecourse to the Company.

In January 2003, Drillmar stockholders approved a restructuring plan whereby Drillmar will issue up to $3.0 million of convertible notes that will convert into common stock representing over 99% of Drillmar's outstanding shares. As a result, the Company's ownership in Drillmar will be reduced to less than 1%. Messrs. Siem and Kaffie are expected to exchange their promissory notes and accrued interest into Drillmar new convertible notes, which were outstanding at December 31, 2002.

In May 2002, the Company terminated its agreement with Drillmar effective as of May 1, 2002, whereby it provided office space and certain management and administrative services to Drillmar for approximately $40,000 per month and entered into a new agreement effective as of May 1, 2002, whereby the Company provided office space and minimal accounting and administrative services to Drillmar for $2,000 per month. This agreement was terminated and a new agreement was entered into effective as of February 1, 2003, whereby the Company will provide office space to Drillmar for $1,500 per month. The Company will also provide professional, accounting and administrative services to Drillmar billed on agreed hourly rates. The agreement can be terminated upon 30 days notice or by the mutual agreement of the parties.

Effective March 31, 2002, the Company recorded a full impairment of its investment in Drillmar of approximately $340,000 and a full reserve for the accounts receivable amount owed from Drillmar of approximately $200,000 due to Drillmar's working capital deficiency and delays in securing capital funding.

Customers

The Company generated revenues from both of its primary business segments. Revenues from major customers exceeding 10% of revenues were as follows for 2002 and 2001.

	Oil and gas sales	Pipeline operations	Total
Year ended December 31, 2002:			

Houston Exploration and Production Company	$	--	290,223	290,223
Apache Corporation	$	--	282,215	282,215
Year ended December 31, 2001:				
Houston Exploration and Production Company	$	--	639,975	639,975

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 producing properties and the marketing of oil and gas production. There is also competition for the acquisition of oil and gas leases suitable for exploration and for the hiring of experienced personnel to manage and operate the Company's assets. Several highly competitive alternative transportation and delivery options exist for current and potential customers of the Company's traditional gas and oil gathering and transportation business. Gas storage customers who would use the proposed Avoca Gas Storage system have alternatives, including depleted reservoir and other salt cavern storage systems. Competition also exists with other industries in supplying the energy and fuel needs of consumers.

Markets

The availability of a ready market for gas and oil, and the prices of such gas and oil, depends upon a number of factors, which are beyond the control of the Company. 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, and 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 the Company provides.

Governmental Regulation

The production, processing, marketing, and transportation of oil and gas, and the development of terminalling and storage of crude oil and gas by the Company are subject to federal, state and local regulations which can have a significant impact upon the Company's 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, the Natural Gas Policy Act and the rules and regulations promulgated by 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 price and terms for access to pipeline transportation is subject to extensive federal regulation. In April 1992, the FERC issued Order No. 636, beginning a series of related orders, which required interstate pipelines to provide open-access transportation on a basis that is equal for all gas suppliers. The FERC has stated that it intends Order No. 636 to foster increased competition within all phases of the gas industry. Order No. 636 affects how buyers and sellers gain access to the necessary transportation facilities and how gas is sold in the marketplace. In 2000, the FERC issued Order No. 637 which, among other things, will permit pipelines to file for peak/off-peak and term differentiated rate structures and changed existing regulations relating to scheduling procedures, capacity segmentation, pipeline imbalance processes and penalties, and pipeline reporting requirements.

The Company cannot predict whether the FERC's actions will achieve the goal of increasing competition in the gas markets or how these, or future regulations will affect its operations or competitive position. However, the Company does not believe that any action taken will affect it in any way that materially differs from the way that such action affects the Company's competitors.

Of the gas pipelines owned by the Company in 2001, only the Black Marlin Pipeline (sold in January 2001) was subject to rules and regulations of the Natural Gas Act. As a result, its gas transportation service and pricing service were subject to the regulatory jurisdiction of the FERC.

All of the Company's pipelines located offshore in federal waters are subject to the requirements of the Outer Continental Shelf Lands Act ("OCSLA"). 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 will transport for non-owner shippers in a nondiscriminatory manner and will be operated in accordance with certain pro-competitive principles. More recently, the FERC has undertaken several investigations into the nature and extent of its regulatory powers on the Outer Continental Shelf. It issued a policy statement on Outer Continental Shelf pipelines reaffirming the requirement that all pipelines provide nondiscriminatory service. In 2000, FERC issued Order 639, formally imposing new OCSLA regulations on offshore pipelines not otherwise subject to its Natural Gas Act jurisdiction. Order 639's requirements, which largely entail reporting and disclosure obligations to FERC, contain certain exemptions for, among other things, an offshore pipeline system that "feeds into a facility where gas is first collected or a facility where gas is first separated, dehydrated, or otherwise processed." Among the FERC's stated purposes in issuing such rules was the desire to provide shippers on the OCS with greater assurance of open-access services on pipelines located on the OCS and non-discriminatory rates and conditions of service on such pipelines. A federal district court recently determined that FERC has exceeded its statutory authority in promulgating Order nos. 639 and 639-A, and the court permanently enjoined FERC from enforcing the orders. FERC has appealed the district court's decision.

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 the Companies' offshore pipelines fall within the exemption for feeder facilities and already operate on the basis required under OCSLA, the Company does not anticipate significant changes directly resulting from requirements concerning nondiscriminatory open access transportation. Moreover, if an offshore pipeline's throughput increases to the extent that the pipeline's capacity is completely utilized, under OCSLA, the FERC may be petitioned to direct capacity allocation on the pipeline. Accordingly, the Company cannot predict how application of the OCSLA to its pipelines may ultimately affect Company operations.

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. The Company's operation of the Buccaneer Pipeline is subject to a variety of regulations promulgated by the FERC and imposed on all oil pipelines pursuant to federal law. In particular, the rates chargeable by the Company are subject to prior approval by the FERC, as are operating conditions and related matters contained in the Company's transportation tariffs which are on file with the FERC. In 1993, the FERC issued Order No. 561, which was intended to simplify oil pipeline ratemaking, largely through use of a ceiling based on an indexing system. At the end of 2000, the Commission issued an order based on a five-year review of the indexing system, affirming this approach to oil pipeline ratemaking. Because Buccaneer Pipeline has not taken action to become subject to Order No. 561 or Order No. 572 concerning market-based rates for oil pipelines, the Company cannot predict whether or how an indexed or market-based rate system will affect the Buccaneer Pipeline's rates.

Safety and Operational Regulations. The operations of the Company are generally subject to safety and operational regulations administered primarily by the 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 Outer Continental Shelf vessels, rigs, platforms, vehicles 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, the Company believes that it is in material compliance with the various safety and operational regulations that it is subject to. However, as safety and operational regulations are frequently changed, the Company is unable to predict the future effect changes in these regulations will have on its operations, if any.

Federal Oil and Gas Leases. All of the Company's exploration and production operations are located on federal oil and gas leases in the OCS, which are administered by the Minerals Management Service ("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. The MMS also has regulations restricting the flaring or venting of natural gas, and has proposed to amend such regulations to prohibit the flaring of liquid hydrocarbons and oil without prior authorization. Similarly, the MMS has promulgated other regulations governing the plugging and abandonment of wells located offshore and the installation and removal of all production facilities. 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. The Company is currently in compliance with the bonding requirements of the MMS. Under some circumstances, the MMS may require any of the Company's operations on federal leases to be suspended or terminated. Any such suspension or termination could materially adversely affect the Company's financial condition and results of operations.

The Company's leases in the OCS provide for royalty payments on gas production calculated at some fraction of the value of the gas produced. OCS lessees have challenged the Department of Interior's rules and regulations which prohibit the natural gas producer from subtracting downstream marketing costs from royalties owed to the Federal government. The U.S. Court of Appeals for the District of Columbia on February 8, 2002 reversed the U.S. District Court for the District of Columbia and upheld the Department of Interior's rule that producers may not deduct costs such as downstream marketing costs, including aggregator/marketing fees or intra-hub transfer fees charged by pipelines to track paper transactions at a pipeline junction (not for physical transfers).

With respect to any Company 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 Company 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. The Company's 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 crude oil, natural gas and natural gas liquids 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 the Company believes 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 the Company's operations, could result in substantial costs and liabilities. It is not anticipated that, in response to such regulation, the Company will be required in the near future to expend amounts that are material relative to its 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, the Company is unable to predict the ultimate cost of compliance.

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 owner or operator of a site where the release occurred 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 the Company's operations. At this time, neither the Company nor any of its predecessors has 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 the Company's oil and gas operations are currently exempt from regulation as a 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.

The Company currently owns or leases, or has in the past owned or leased, numerous properties used for the exploration and production of oil and gas or used to store and maintain equipment regularly used in these operations. Although the Company's 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 the Company's control. These properties and any waste disposed thereon may be subject to CERCLA, RCRA, and state laws which could require the Company 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. In August 1995, the DOT issued a Rulemaking under OPA providing that the Secretary of Transportation can set the liability limit and associated Certificate of Financial Responsibility requirement for Deepwater Ports from between $350 million and $50 million concurrent with the overall processing of the DWPA license application. Development of the liability limit would be based upon engineering and environmental analysis provided during the licensing process. 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. The Company believes it has established adequate financial responsibility. While the financial responsibility requirements under OPA may be amended to impose additional costs on the Company, the impact of such a change is not expected to be any more burdensome on the Company 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. The Company 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 the Company does 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 the Company's operations, it is 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. The Company believes it is 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 the Company.

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, other than Deepwater Ports. 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. The Company currently maintains 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 the operations of the Company.

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 the Company's 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, the Company will be required in the near future to expend amounts that are material relative to its 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, the Company is unable to predict the ultimate cost of compliance.

RISK FACTORS

The Company will be primarily dependent on revenues from its pipeline systems.

As a result of the Company's sale of substantially all of its proved oil and gas reserves, the Company's future revenues will be primarily dependent on the level of use of its pipeline systems. Various factors will influence the level of use of the Company's pipeline system including the amount of oil and

gas production near the Company's pipelines and the Company's ability to attract new users. There are various competing pipelines in and around the Company's pipeline systems that the Company vigorously competes with to attract new users to its pipeline systems. There can be no assurance that the Company's marketing activities will result in attracting new oil and gas reserves to its pipeline systems.

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 the Company.

The Company's revenues, profitability, operating cash flow and its 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 the Company's control. These factors include: o 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 the Company, including the following:

- reducing the exploration and development of oil and gas reserves held by third party companies around the Company's pipeline systems;
- increasing the Company's dependence on external sources of capital to meet its cash needs; and
- impairing the Company's ability to obtain needed equity.

Volatile oil and gas prices also make it difficult to estimate the value of producing properties the Company may acquire and also make it difficult for the Company to budget for and project the return on acquisitions and development and exploitation projects.

The Company faces strong competition from larger companies that may negatively affect its ability to carry on operations.

The Company operates in a highly competitive industry. The Company's 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 the Company. The Company's ability to successfully compete in the marketplace is affected by many factors.

- Most of the Company's competitors have greater financial resources than it does, which gives them better access to sources of capital to acquire and develop oil and gas properties.

- Most of the Company's competitors have longer operating histories and have more data generally available to them, including information relating to oil and gas properties.

- The Company often establishes a higher standard for the minimum projected rate of return on an investment than some of its competitors since it cannot afford to absorb certain risks. The Company believes this puts it at a competitive disadvantage in acquiring oil and gas properties.

The Company's future success depends, in part, upon its ability to find, develop and acquire new oil and gas reserves.

The Company sold substantially all of its proved reserves in 2002, and is currently attempting to find and acquire properties containing proved reserves. Until the Company acquires additional proved reserves, substantially all of the Company's revenues will be from its pipeline systems and reversionary interest in oil and gas properties. There can be no assurance that the Company will be able to acquire proved reserves.

The Company cannot control the activities on properties it does not operate.

Currently, other companies operate all of the oil and gas properties in which the Company has an interest. As a result, the Company will depend on the operator of the wells 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 the Company, including the amount and timing of revenues, if any, it receives from its interest.

The Company has and generally anticipates that it will typically own substantially less than a 50% working interest in its prospects and will therefore engage in joint operations with other working interest owners. In instances in which the Company owns or controls 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 the Company is unwilling or unable to participate in the costs of operations approved by a majority of the working interests in a well, the Company's 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 the Company's interest in the well or a relinquishment of the Company's 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 the Company if it had elected to participate, which often ranges from 400% to 600% of such costs.

The Company has pursued, and intends to continue to pursue, acquisitions. The Company's business may be adversely affected if it cannot effectively integrate acquired operations.

One of the Company's business strategies has been to acquire operations and assets that are complementary to its 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 the Company 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.

Any future acquisitions would likely result in an increase in expenses. In addition, competition from other potential buyers could cause the Company to pay a higher price than it otherwise might have to pay and reduce its acquisition opportunities. The Company is often out-bid by larger, better capitalized companies for acquisition opportunities it pursues. Moreover, the Company's past success in making acquisitions and in integrating acquired businesses does not necessarily mean it will be successful in making acquisitions and integrating businesses in the future.

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

The Company's 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 the Company from injury and loss of life, damage to and destruction of property and equipment, pollution and other environmental damage and suspension of operations. The Company's 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 the Company's financial condition and operations.

The Company maintains several types of insurance to cover its 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. The Company also maintains 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.

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The Company may not be able to maintain adequate insurance in the future at rates it considers reasonable or losses may exceed the maximum limits under the Company's insurance policies. If a significant event that is not fully insured or indemnified occurs, it could materially and adversely affect the Company's financial condition and results of operations.

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

The Company's 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 drilling commences;
- 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 the Company's 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 the Company's operating costs, as well as on the oil and gas industry in general.

The Company's 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. The Company 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 the Company's financial condition and results of operations. The Company maintains insurance coverage for its operations, including limited coverage for sudden and accidental environmental damages, but the Company does 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, the Company may be subject to liability or may lose the privilege to continue exploration or production activities upon substantial portions of its 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 the Company.

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 tract where the owner is not the operator of the tract.

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. Properties

Information appearing in Item 1 describing the Company's oil and gas properties under the caption "Business" is incorporated herein by reference.

The Company leases its executive offices in Houston, Texas, under an operating lease expiring December 31, 2006. The Company's aggregate annual lease payment obligation under this lease is approximately $195,000.

In March 2003, the Company entered into a sublease agreement expiring December 31, 2006 for certain of its office space to Tri-Union Development Corporation. The Company's annual receipts from this sublease will be $81,630. Mr. James M. Trimble, director of the Company is the Chairman and Chief Executive Officer of Tri-Union.

Item 3. Legal Proceedings

In May 2002, the Company, American Resources and members of prior management of American Resources, including its former chief financial officer, entered into a settlement agreement with H&N Gas, Limited Partnership ("H&N"), whereby American Resources paid approximately $0.3 million in settlement of this litigation and additionally released funds of approximately $0.7 million it was holding that were due to H&N. The settlement agreement and the payments made thereunder were made in compromise of disputed claims and are not an admission of wrongdoing or of liability of any kind.

Neither the Company nor any of its property is subject to any material pending legal proceedings.

PART II

Item 5. Market for Registrant's Common Stock and Related Stockholder Matters

The Company's common stock trades in the over-the-counter market and is quoted on the NASDAQ Small Cap Market under the symbol "BDCO". As of March 13, 2003, there were an estimated 600 stockholders of record and the Company estimates there are more than 1,000 beneficial owners of its 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, 2001	$ 5.19	$ 3.25
Quarter Ended June 30, 2001	$ 4.95	$ 3.80
Quarter Ended September 30, 2001.............	$ 4.31	$ 2.81
Quarter Ended December 31, 2001	$ 3.40	$ 1.60
Quarter Ended March 31, 2002	$ 1.86	$ 1.52
Quarter Ended June 30, 2002	$ 1.70	$ 0.60
Quarter Ended September 30, 2002.............	$ 0.79	$ 0.28
Quarter Ended December 31, 2002	$ 0.81	$ 0.22

The Company has not declared or paid any dividends on the Common Stock since its incorporation. The Company currently intends to retain earnings for its capital needs and expansion of its business and does not anticipate paying cash dividends on the Common Stock in the foreseeable future. Previously, the Company was restricted, pursuant to a loan agreement from paying dividends on the Common Stock if there was an outstanding balance under the loan agreement.

Any loan agreements which the Company may enter into in the future will likely contain restrictions on the payment of dividends on its' Common Stock. Future policy with respect to dividends will be determined by the Board of Directors based upon the Company's earnings and financial condition, capital requirements and other considerations. The Company is a holding company that conducts substantially all of its operations through its' subsidiaries. As a result, the Company's ability to pay dividends on the Common Stock is dependent on the cash flow of its subsidiaries.

On July 15, 2002, the Company received a notice from the NASDAQ, that because the Company's Common Stock traded below the minimum bid requirement of $1.00 for 30 consecutive trading days the Common Stock would be delisted if its bid price does not close above $1.00 for 10 consecutive trading days by January

13, 2003. On January 14, 2003, the Company received notice from NASDAQ that the initial deadline was extended until July 14, 2003. As of March 13, 2003, the bid price for the Company's Common Stock had not closed above $1.00. If the Company's Common Stock is delisted from NASDAQ it would then trade on the OTC Bulletin Board or "pink sheets". This could materially decrease the liquidity of the Company's Common Stock and further limit the Company's ability to raise capital.

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

During 2002, the Company sold substantially all of its interests in its oil and gas properties for approximately $5.0 million. The properties sold represented over 99% of the Company's proved oil and gas reserves. As a result of the sale of the Company's proved oil and gas properties, the amount of future oil and gas sales revenues, lease operating expenses, depletion and capital expenditures associated with oil and gas production activities will be dependent upon the success of the Company's exploratory properties, reversionary working interests and future acquisitions of oil and gas properties. The following is a review of certain aspects of the financial condition and results of operations of the Company and should be read in conjunction with the Consolidated Financial Statements included in Item 7. and Item 1. Business.

LIQUIDITY AND CAPITAL RESOURCES

Historically, the Company has 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 its operations. At December 31, 2002, the Company's working capital was approximately $2.2 million. During the third and fourth quarters of 2002, the Company received approximately $5.0 million from the sale of substantially all of its proved oil and gas properties. In addition to using the sales proceeds to satisfy its working capital needs the Company may also use the sale proceeds to finance future asset acquisitions, which may include other oil and gas properties. However, there can be no assurance that the Company will be able to acquire and develop additional oil and gas reserves that are economically recoverable.

The following table summarizes certain of the Company's contractual obligations and other commercial commitments at December 31, 2002 (amounts in thousands).

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Contractual Obligations	Total	Payments Due by Period Less than 1 year	2-3 years	4-5 years	After 5 years
Long-Term Debt	$ 750	--	--	750	--
Operating Leases	487	136	237	114	--
Abandonment - Costs	2,700	1,440	1,260	--	--
Total Contractual Obligations	$ 3,937	1,576	1,497	864	--

Other Commercial Commitments	Total	Amount of Commitment Expiration Per Period Less than 1 year	2-3 years	4-5 years	After 5 years
Abandonment - Costs	$ 1,100	1,100	--	--	--
Total Commercial Obligations	$ 1,100	1,100	--	--	--

The following table summarizes the Company's financial position for the periods indicated:

December 31,
(amounts in thousands)

	2002		2001	
	Amount	%	Amount	%
Working Capital	$ 2,243	29	$ --	--
Property and equipment, net	4,687	60	5,980	85
Other noncurrent assets	845	11	1,043	15
Total	$ 7,775	100	$ 7,023	100
Working Capital	$ --	--	$ 1,197	17
Long-term Liabilities	2,010	26	--	--
Minority Interest	--	--	1,065	15
Stockholders' equity	5,765	74	4,761	68
Total	$ 7,775	100	$ 7,023	100

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The change in the Company's financial position from December 31, 2001 to December 31, 2002, was primarily due to the sale of its South Timbalier Block 148 oil and gas property in July 2002 and the sale of substantially all of its remaining oil and gas properties in November 2002. See Item 1. Business - Recent Developments.

The Company's future cash flows are subject to a number of variables, including receipt of revenues from leases in which the Company holds reversionary interests utilization of its pipeline systems, utilization of its services by third parties and commodity prices among others. The Company believes that it has sufficient liquidity at December 31, 2002 to meet its obligations and operating needs for the year ending December 31, 2003. However, there can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of expenditures. The net cash provided by or used in operating, investing and financing activities is summarized below:

	Years Ended December 31 (amounts in thousands)	
	2002	2001
Net cash provided by (used in):		
Operating activities	$ (2,836)	$ 1,447
Investing activities	3,898	2,412
Financing activities	--	(2,587)
Net increase in cash	$ 1,062	$ 1,272

The Company's cash flow from operating activities decreased by $4.3 million in 2002 from 2001, due primarily to a decrease in cash generated from 2002 operations of approximately $2.1 million and a reduction in current liabilities of approximately $2.3 million.

Cash flow provided by investing activities during 2002 included the proceeds from the sale of the American Resources oil and gas properties of approximately $5.0 million. Cash flow used in investing activities included exploration and development costs associated with oil and gas properties owned by American Resources of approximately $0.5 million, the purchase of American Resources minority stockholders interests of approximately $0.3 million, and other capital expenditures of approximately $0.2 million.

The Company previously announced a gas discovery in High Island Area Block A-7, in the Gulf of Mexico. The Company owns an 8.9% reversionary working interest in this field and it will begin to receive revenues from its reversionary interest after "payout" occurs. Payout occurs after all of the other working interest owners have recovered their costs and expenses associated with developing the field from sales of gas and oil production from the field. In late 2002, two wells from this field were successfully recompleted. As a result of the recompleted wells and based on current levels of production and commodity prices, the Company now believes that it could begin to receive revenues from its reversionary working interest in this field in the second or third quarter 2003.

In November 2000, the Company elected to abandon the Buccaneer Field due to adverse developments in the field. The Company reached an agreement with Tetra Applied Technologies, Inc. ("Tetra"), to plug and abandon the wells located in the Buccaneer Field. The work was completed in the first quarter of 2001 for approximately $1.4 million. In addition, Maritech Resources, Inc. ("Maritech"), an affiliate of Tetra, purchased an adjacent lease from Apache Corporation for which the Company provided production operating services. In connection with this lease purchase, Maritech also assumed the operating agreement. In December

2000, as a result of the Company's plans to abandon the Buccaneer Field platform facilities, the Company and Maritech terminated the operating agreement. The Company installed a new platform in 2001 at a cost of $1.7 million net to its interest, to operate and maintain the Blue Dolphin Pipeline System as well as handle the production from Maritech's lease. The Blue Dolphin System was previously tied into and operated from the Buccaneer Field platforms.

In August 2001, the Company reached an agreement with Tetra to remove the Buccaneer Field platforms for a cost of approximately $2.6 million. Pursuant to the agreement, Tetra and the Company agreed to extended payment terms, whereby the Company will pay 20% upon completion and 5% per month for twelve months, with the remaining balance due in the thirteenth month. To provide security for the extended payment terms, the Company provided Tetra with a first lien on the 50% interest it then owned in the Blue Dolphin Pipeline System. Operations to remove the platforms commenced in August 2001 and were suspended in December 2001, while the Company continued discussions with and was awaiting a decision from the Texas Parks and Wildlife Department ("TPW") to leave the underwater portion of the platforms in place as artificial reefs. The scope of work with Tetra has changed due to the reefing rather than complete removal originally contemplated. The contract price and the payment terms remain unchanged. The Company requested and has received an extension from the Minerals Management Service until April 1, 2003 to complete abandonment operations needed to convert the platform complexes into artificial reefs. Tetra is expected to resume its operations during the second quarter 2003. The Company is also obligated to pay $390,000 to TPW, of which $350,000 represents half of the site clearance work that will be eliminated and $40,000 represents the cost of buoys to mark the reef sites. As a result of the reefing agreement with TPW, the Company has reduced its provision for abandonment costs by $310,000 due to the elimination of site clearance costs, and by approximately $373,000 due to lowering its contingency associated with the abandonment work. The Company will request and expects the MMS to grant additional time to complete the reefing activities. The Company believes that its provision for abandonment costs of $3.8 million at December 31, 2002 is adequate.

In January 2001, the Company and its partners sold the Black Marlin Pipeline System for $7.3 million and the High Island Block A-5 pipeline for $2.0 million to Williams Field Services. The Company's portion of the proceeds were $3.6 million and $1.0 million, respectively.

During 2002, the Company incurred capital expenditures of approximately $512,000 for development of its proved reserves. As a result of the sales of its proved reserves during 2002, future capital expenditures associated with the Company's oil and gas properties will be dependent upon the success of the Company's exploratory properties, reversionary working interests and future acquisitions of proved oil and gas reserves. The reserves and future net revenues presented in Item 1 "Business" reflect capital expenditures totaling $150,000 and $192,000 in the years ending December 31, 2004 and 2006, respectively.

On December 2, 1999, the Company, through Blue Dolphin Exploration, acquired a 75% ownership interest in American Resources by purchasing approximately 39.5 million shares of American Resources common stock for approximately $4.5 million. On February 19, 2002, the Company completed its acquisition of American Resources, pursuant to the Amended and Restated Agreement and Plan of Merger dated as of December 19, 2001 (the "Merger Agreement"). Pursuant to the Merger Agreement, American Resources became a wholly owned subsidiary of the Company. As a result of elections made by American Resources' stockholders, the Company issued 277,330 shares of Common Stock and paid approximately $255,000 in cash.

In connection with the Company's initial investment in American Resources Den norske Bank sold American Resources senior secured debt to the Company for the right to receive a possible future payment. The payment due to Den norske was determined to be approximately $0.8 million net to American Resources; however, in June 2002, Den norske agreed to accept $0.6 million as full payment, which American Resources paid in June 2002.

In May 2002, the Company, American Resources and members of prior management of American Resources, including its former chief financial officer, entered into a litigation settlement agreement with H&N Gas. American Resources paid approximately $0.3 million in settlement of the litigation and additionally released funds of approximately $0.7 million it was holding that were due to H&N. The settlement agreement and the payments made thereunder were made in compromise of disputed claims and are not an admission of wrongdoing or of liability of any kind.

In February 2002, the Company acquired an additional 1/3 interest in the Blue Dolphin Pipeline System and the inactive Omega Pipeline from MCNIC. Pursuant to the terms of the purchase and sales agreement, Blue Dolphin Pipeline issued MCNIC a $750,000 promissory note due December 31, 2006, with required monthly payments to be made out of 90% of the net revenues of the interest acquired. The note bears interest at the rate of 6% per annum and is secured by the interest acquired. Additionally, contingent payments of up to $750,000 will be made, if the promissory note is retired before its maturity date, payable annually after the promissory note is retired until December 31, 2006, out of 50% of the net revenues from the interest acquired. The maturity date, December 31, 2006, will be extended by one additional year, up to a maximum of two years, for years in which non-recurring, extraordinary expenditures, attributable to the interest acquired, exceeds $200,000, in the aggregate, during any year. As of December 31, 2002, the amount owed MCNIC is $750,000 plus accrued interest of $42,245. During the year ended December 31, 2002 the Company paid MCNIC interest of $2,755.

RESULTS OF OPERATIONS

For the year ended December 31, 2002 ("2002"), the Company reported net income of $482,054, compared to a net loss of $2,649,142 for the year ended December 31, 2001 ("2001"). The improvement in results in 2002 was due to a gain on sale of assets of approximately $2.2 million in 2002 offset by the 2001 gain on sale of assets of approximately $1.4 million, and 2001 recordings of an impairment for the Company's Petroport and Sabine Seaport projects of $1.9 million and a $1.0 million increase in the Company's impairment of the Buccaneer Field.

2002 compared to 2001

Revenue from oil and gas sales. Revenues from oil and gas sales decreased by $2,912,294 in 2002, from those of 2001. The decrease was primarily due to a 45% reduction in oil and gas production volumes due to the sale of the Company's proved reserves during 2002 resulting in a decrease in revenues of $2.0 million (see Item 1. Business) and normal production declines, and a reduction in gas prices of 34% and oil prices of 25% in 2002, resulting in a $0.9 million reduction in revenues.

Revenue from pipeline operations. Revenues from pipeline operations increased by $136,496 or 14% in 2002 to $1,128,319. The increase was due primarily to the Company's acquisition of an additional 1/3 interest in the Blue Dolphin Pipeline System effective January 1, 2002, increasing the Company's interest from 50% to 83%, resulting in additional revenues of approximately $.47 million, offset in part by a decrease in transportation volumes of 26 % resulting in decreased revenues of approximately $.33 million.

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Lease operating expenses. Lease operating expenses for 2002 decreased by $636,629, or 55% from 2001. The decrease resulted primarily from the sale of the Company's proved oil and gas reserves during 2002.

Pipeline operating expenses. Pipeline operating expenses in 2002 increased by $321,553 from $517,054 in 2001. The increase was primarily due to the acquisition of the 1/3 interest in the Blue Dolphin Pipeline System effective January 1, 2002 increasing the company's interest from 50% to 83%.

Depletion, depreciation and amortization expense. Depletion, depreciation and amortization expenses decreased by $999,128 from 2001. Depletion expense decreased in the 2002 due to a 45% decrease in production volumes resulting in decreased depletion of $0.5 million and a lower depletion rate used in 2002 compared to 2001 resulting in decreased depletion of approximately $0.4 million.

Impairment of assets. Impairment of assets decreased in 2002 by $2,600,480. In 2002 the Company recorded an impairment of its investment in Drillmar of $0.3 million (see Item 1. Business - Drillmar). In 2001, the Company recorded an impairment of its investment in the Petroport and Sabine Seaport projects of approximately $1.9 million, and increased the impairment of the Buccaneer Field by $1.0 million due to revised plugging and abandonment estimates.

General and administrative expenses. General and administrative expenses for 2002 decreased $337,744 from 2001. The decrease is primarily due to the Company's cost reduction plan implemented in 2002 that resulted in a reduction in staff and other costs of approximately $0.6 million, the acquisition of the American Resources minority shareholders interest and the closing of American Resource's New Orleans office of approximately $0.2 million and lower legal expenses of approximately $0.1 million as a result of the settlement of the H&N lawsuit in 2002. These cost reductions were offset in part by the elimination of approximately $0.6 million of management fees generated by the Company that were recorded as a reduction to general and administrative expenses during 2001, of which $0.3 million were recorded from Drillmar, and $0.3 million were recorded from the 1/3 interest in the Blue Dolphin Pipeline System acquired by the Company effective January 1, 2002.

Interest and other expense. Interest and other expense decreased by $23,990 in 2002. In 2002, the Company recorded an expense associated with the settlement of litigation with H&N of approximately $0.3 million and costs associated with unsuccessful acquisitions and other expenses of approximately $0.1 million, offset in part by a reduction of the payment to Den norske Bank of approximately $0.2 million. In 2001 other expenses included a $0.2 million increase in the provision for the contingent payment to Den norske Bank.

Gain on sale of assets. Current period gain on sale of assets increased by $802,923 from 2001. In 2002, the Company recorded gains on the sale of its proved oil and gas reserves of $2.2 million. In 2001, the Company recorded a gain on the sale of the Black Marlin Pipeline System of $1.4 million.

Bad debt expense. The Company recorded bad debt expense of $197,500 in 2002 from accounts receivable owed by Drillmar and other accounts receivable of $24,250.

Equity losses of affiliates. In 2001, the Company recorded losses from its equity interests in Drillmar and New Avoca of $245,201.

Interest and other income. Interest and other income increased $644,285 in 2002. The increase is primarily due to the Company's $0.7 million reduction in its provision for the Buccaneer Field abandonment costs.

Critical Accounting Policies

The selection and application of accounting policies is an important process that has developed as Blue Dolphin's 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 the Company's business. The Company makes every effort to properly comply with all applicable rules on or before their adoption, and believes 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, the Company must use its best judgment to adopt a policy for accounting for these situations. Blue Dolphin accomplishes this by analogizing to similar situations and the accounting guidance governing them, and often consults with its independent accountants about the appropriate interpretation and application of these policies.

Given that the Company has sold substantially all of its oil and gas exploration and production assets as of December 31, 2002, its most critical accounting policy currently relates to the accounting for the impairment of long lived assets, which include primarily the pipeline assets, as of December 31, 2002.

In accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets", Blue Dolphin initiates its review 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, the Company's pipeline assets are significantly under utilized and therefore is an indicator of possible impairment at December 31, 2002. Accordingly, management developed future cash flows as of December 31, 2002 expected to be generated from its 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 the current leasing and drilling activity surrounding the Company's pipeline. Based on the results of the impairment test, which indicates expected future undiscounted cash flows are in excess of the pipeline assets net carrying value, no impairment has been recorded as of December 31, 2002.

Recently Issued Accounting Pronouncements

In August 2001, the Financial Accounting Standards Board ("FASB") issued Statement No. 143 ("SFAS 143"), "Accounting for Asset Retirement Obligations," which addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. The standard applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset. SFAS 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset and this additional carrying amount is depreciated over the life of the asset. If the obligation is settled for other than the carrying amount of the liability, the Company will recognize a gain or loss on settlement.

The Company is required and will adopt the provisions of SFAS 143 for the quarter ending March 31, 2003. The Company currently estimates that the adoption of SFAS 143 will result in the recording of an asset retirement obligation of $1.6 million.

In May 2002, the FASB issued Statement of Financial Accounting Standards No. 145 ("SFAS 145"), "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections". This Statement rescinds FASB Statements No. 4, Reporting Gains and Losses from Extinguishment of Debt, and an amendment of Statement No. 4 and FASB Statement No. 64, Extinguishments of Debt Made to Satisfy Sinking-Fund Requirements. This Statement also rescinds FASB Statement No. 44, Accounting for Intangible Assets of Motor Carriers. This Statement amends FASB Statement No. 13, Accounting for Leases, to eliminate an inconsistency between the required accounting for sale-leaseback transactions and the required accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. SFAS 145 is effective for fiscal years beginning after May 15, 2002. The Company's management does not expect the adoption of SFAS 145 to have a material effect on the Company's financial condition and results of operations.

In June 2002, the FASB issued Statement of Financial Accounting Standards No. 146 ("SFAS 146"), "Accounting for Costs Associated with Exit or Disposal Activities". This Statement addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Issues Task Force Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)". SFAS 146 is effective for exit or disposal activities initiated after December 31, 2002. The Company's management does not expect the adoption of SFAS 146 to have a material effect on the Company's financial condition and results of operations.

In December 2002, the FASB issued Statement of Financial Accounting Standards ("SFAS") No. 148, "Accounting for Stock-Based Compensation, Transition and Disclosure." SFAS No. 148 provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. SFAS No. 148 also requires that disclosures of the pro forma effect of using the fair value method of accounting for stock-based employee compensation be displayed more prominently and in a tabular format. Additionally, SFAS No. 148 requires disclosure of the pro forma effect in interim financial statements. The transition and annual disclosure requirements of SFAS No. 148 are effective for fiscal years ending after December 15, 2002. The interim disclosure requirements are effective for interim periods beginning after December 15, 2002. The Company does not expect that the adoption of SFAS 148 will have a material effect on its financial position or results of operations.

Item 7. Financial Statements and Supplementary Data

Index to Financial Statements:

Independent Auditors' Report

The Board of Directors
Blue Dolphin Energy Company

We have audited the accompanying consolidated balance sheet of Blue Dolphin Energy Company and subsidiaries as of December 31, 2002, 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, 2002. 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 auditing standards generally accepted in the 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, 2002, and the consolidated results of their operations and their cash flows for each of the years in the two-year period ended December 31, 2002 in conformity with accounting principles generally accepted in the United States.

/s/ Mann Frankfort Stein & Lipp CPAs, LLP

Houston, Texas
February 28, 2003

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Consolidated Balance Sheet

December 31, 2002

Assets

Current assets:	
Cash and cash equivalents	$ 4,405,676
Trade accounts receivable	515,292
Prepaid expenses and other assets	294,192
Total current assets	5,215,160
Property and equipment, at cost:	
Oil and gas properties, including $140,233 of unproved leasehold cost (full-cost method)	21,920,491
Pipelines	3,670,510
Onshore separation and handling facilities	1,664,128
Land	860,275
Other property and equipment	272,508
	28,387,912
Less accumulated depletion, depreciation, amortization and impairment	23,700,652
	4,687,260
Deferred federal income tax	244,444
Investment in New Avoca	585,629
Other assets	15,415
	$10,747,908

See accompanying notes to consolidated financial statements.

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Consolidated Balance Sheet, continued

December 31, 2002

Liabilities and Stockholders' Equity

Current liabilities:	
Trade accounts payable	$ 366,304
Asset retirement obligations - current portion	2,540,000
Accrued expenses and other liabilities	66,245
Total current liabilities	2,972,549
Long-term liabilities:	
Note payable	750,000
Asset retirement obligations, net of current portion	1,260,000
Total long-term liabilities	2,010,000
Stockholders' equity:	
Common stock, $.01 par value, 10,000,000 shares authorized and 6,606,585 shares issued and outstanding	66,066
Additional paid-in capital	26,239,098
Accumulated deficit	(20,539,805)
Total stockholders' equity	5,765,359
	$ 10,747,908

See accompanying notes to consolidated financial statements.

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Consolidated Statements of Operations

Years ended December 31, 2002 and 2001

	2002	2001
Revenue from operations:		
Oil and gas sales	$ 1,781,958	4,694,202
Pipeline operations	1,128,319	991,823
Revenue from operations	2,910,277	5,686,025
Cost of operations:		
Lease operating expenses	518,920	1,155,549
Pipeline operating expenses	838,607	517,054
Depletion, depreciation and amortization	818,642	1,817,770
Impairment of assets	339,984	2,940,464
General and administrative expenses	2,507,716	2,845,459
Cost of operations	5,023,869	9,276,296
Loss from operations	(2,113,592)	(3,590,271)
Other income (expense):		
Interest and other expense	(219,601)	(243,591)
Gain on sale of assets	2,220,549	1,417,626
Interest and other income	760,702	116,417
Bad debt expense	(221,750)	--
Equity in losses of affiliates	--	(245,201)
Income (loss) before minority interest and income taxes	426,308	(2,545,020)
Minority interest	55,746	(104,122)
Income tax expense	--	--
Net income (loss)	$ 482,054	(2,649,142)
Income (loss) per common share-basic	$ 0.08	(0.44)
Income (loss) per common share- diluted	$ 0.08	(0.44)
Weighted average number of common shares outstanding - basic	6,343,834	6,004,019
Weighted average number of common shares outstanding - diluted	6,359,072	6,004,019

See accompanying notes to consolidated financial statements.

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Consolidated Statements of Stockholders' Equity

Years ended December 31, 2002 and 2001

	Common stock	Additional paid-in capital	Accumulated deficit	s
Balance at December 31, 2000	60,167	25,775,417	(18,372,717)	
Exercise of 3,333 stock options	33	12,715	--	
Issuance of shares to 401K plan	500	79,500	--	
Stock registration costs and other	215	(145,572)	--	
Net loss			(2,649,142)	
Balance at December 31, 2001	$ 60,915	25,722,060	(21,021,859)	
Acquire minority interest of subsidiary	2,773	360,173	--	
Common stock issued for services	--	159,243	2,378	
Net income			482,054	
Balance at December 31, 2002	$ 66,066	26,239,098	(20,539,805)	

See accompanying notes to consolidated financial statements.

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Consolidated Statements of Cash Flows

Years ended December 31, 2002 and 2001

	2002	2001
Operating activities:		
Net income (loss)	$ 482,054	(2,649,142)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Depletion, depreciation and amortization	818,642	1,817,770
Minority interest	(55,746)	104,122
Gain on sale of assets	(2,220,549)	(1,417,626)
Impairment of assets - investments	339,984	2,940,464
Change in Abandonment costs	(410,816)	--
Increase in other liabilities	--	250,000
Equity in income (losses) of affiliate	(60,158)	245,201
Bad debt expense	221,750	--
Common stock issued for services	159,243	80,000
Changes in operating assets and liabilities:		
Trade accounts receivable	521,197	1,148,512
Prepaid expenses and other assets	(130,367)	(35,912)
Abandonment costs incurred	(194,592)	(442,984)
Other assets	--	28,389
Trade accounts payable, accrued expenses and other liabilities	(2,307,021)	(622,292)
Net cash provided by (used in) operating activities	(2,836,379)	1,446,502
Investing activities:		
Exploration and development costs	(512,393)	(1,022,843)
Purchases of property and equipment	(180,600)	(1,764,245)
Net proceeds from sale of assets	5,030,000	5,985,000
Development costs - Petroport	--	(59,305)
Development costs - New Avoca	(82,000)	(234,140)
Acquisition and development costs - Drillmar	--	(492,460)
Purchase of minority interest in subsidiary	(356,512)	--
Net cash provided by investing activities	3,898,495	2,412,007

See accompanying notes to consolidated financial statements.

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Consolidated Statements of Cash Flows, Continued

Years ended December 31, 2002 and 2001

	2002	2001
Financing activities:		
Payments on borrowings, preferred stockholders	--	(218,412)
Payments on borrowings, related parties	--	(2,000,000)
Payments of offering costs and other	--	(145,357)
Dividends paid by subsidiary	--	(235,610)
Net proceeds from the exercise of stock options	--	12,748
Net cash provided by (used in) financing activities	--	(2,586,631)
Increase in cash and cash equivalents	1,062,116	1,271,878
Cash and cash equivalents at beginning of year	3,343,560	2,071,682
Cash and cash equivalents at end of year	$ 4,405,676	3,343,560
Supplementary cash flow information:		
Interest paid	$ 2,755	98,500
Taxes paid	$ --	6,530
Non cash investing and financing activities		
Purchase of property and equipment financed with debt	750,000	--

See accompanying notes to consolidated financial statements.

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements

December 31, 2002 and 2001

(1) Organization and Significant Accounting Policies

Organization

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

Principles of Consolidation

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

Accounting Estimates

Management has made a number of estimates and assumptions relating to the reporting of assets and liabilities and to the disclosure of contingent assets and liabilities including reserve information which affects the depletion calculation as well as the computation of the full cost ceiling limitation to prepare these financial statements in conformity with accounting principles generally accepted in the United States. Actual results could differ from those estimated.

Cash Equivalents

Cash equivalents include liquid investments with an original maturity of three months or less. Cash balances are maintained in depository and overnight investment accounts with a financial institution which at times, exceed insured limits. The Company monitors the financial condition of the financial institution and has experienced no losses associated with these accounts.

Oil and Gas Properties

Oil and gas properties are accounted for using the full-cost method of accounting, whereby all costs associated with acquisition, exploration, and development of oil and gas properties, including directly related internal costs, are capitalized on a country-by-country cost center basis. The Company utilizes one cost center for all of its properties. Amortization of such costs and estimated future development costs are determined using the unit-of-production method. Provision for the estimated costs of offshore platform and well abandonment, net of salvage value, is computed on the units of production method and is included in depletion, depreciation and amortization. Costs directly associated with the acquisition and evaluation of unproved properties are excluded from the amortization computation until it is determined whether or not proved reserves can be assigned to the properties or impairment has occurred. Estimated proved oil and gas reserves are based upon reports of independent petroleum engineers or prepared internally by the Company. The net carrying value of oil and gas

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

The following table reflects the depletion expense incurred from oil and gas properties during the periods indicated:

	Year Ended December 31, 2002	Year Ended December 31, 2001
Depletion expense per Mcf equivalent produced	$ 1.05	$ 1.53

At December 31, 2002, oil and gas properties included $140,233 of unproved leasehold costs that are not being amortized. These costs will begin to be amortized when they are evaluated and proved reserves are discovered, impairment is indicated or when the lease term expires. Unproved leasehold costs consist of interests in state and federal leases located in the Gulf of Mexico with expiration dates ranging from October 2003 to November 2005. In order to retain the leases after the primary term, they must be producing or development operations must be in progress. The leases have primary terms of 5 years. Development of these leases is dependent upon the other owners of the leases to initiate a plan of development.

The following table reflects the periods when costs were incurred for unproved leasehold costs:

	Total	December 31, 2002	December 31, 2001	Prior Years
Property acquisition costs	$ 101,097	(76,421)	(102,920)	280,438
Exploration costs	39,136	(5,178)	(106,030)	150,344

$ 140,233	(81,599)	(208,950)	430,782
=========	=========	=========	=========

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

Pipelines and Facilities

Pipelines and facilities are recorded at cost. Depreciation is computed using the straight-line method over estimated useful lives of 10-22 years. Provision for the estimated cost of pipeline and facilities abandonment, net of salvage value, is computed on a straight line basis over the estimated useful life of such assets and is included in Depletion, Depreciation and Amortization.

Other Property and Equipment

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

In accordance with Statement of Financial Accounting Standards ("SFAS") No. 144, Accounting for the Impairment or Disposal of Long-lived Assets, assets are grouped and evaluated for impairment based on the ability to identify separate cash flows generated therefrom. For the year ended December 31, 2001, the Company recorded a full impairment of $1.9 million of its investment in both the Petroport and Sabine Seaport projects and for the year ended December 31, 2002, the Company recorded a full impairment of approximately $.4 million of its investment in Drillmar, Inc.

Abandonment

A provision for the abandonment, dismantlement and site clearance of offshore production platforms and existing wells is made using the unit-of-production method applied to estimates based on current costs. A provision for pipeline and pipeline facilities abandonment costs is also provided using the straight-line method over the estimated useful lives of the pipeline and pipeline facilities. Aggregate abandonment liability, all of which is for the Buccaneer Field is estimated to be approximately $3.8 million at December 31, 2002. Based on timing of the reefing and related payment plan $2.5 million is reflected as "Asset retirement obligations - current portion" and $1.3 million is reflected as a long-term liability, due to the extended payment terms arranged by the Company.

New Avoca and Drillmar

The Company records its investment in New Avoca (25% owned and managed by the Company) and Drillmar using the equity method of accounting. Under the equity method, investments are recorded at cost plus the Company's equity in undistributed earnings and losses after acquisition.

Stock-Based Compensation

The Company applies SFAS No. 123, Accounting for Stock-Based Compensation, which allows a company to adopt a fair value based method of accounting for a stock-based employee compensation plan or to continue to use the intrinsic value based method of accounting prescribed by Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees. The Company accounts for stock-based compensation under the intrinsic value method and provides the pro forma effects of the fair value method as required.

Recognition of Oil and Gas Revenue

Sales from producing wells are recognized on the entitlement method of accounting which defers recognition of sales when, and to the extent that, deliveries to customers exceed the Company's net revenue interest in production. Similarly, when deliveries are below the Company's net revenue interest in production, sales are recorded to reflect the full net revenue interest. The Company's imbalance liability at December 31, 2002 and 2001 was not material.

Recognition of Pipeline Transportation Revenue

Revenue from the transportation of gas, condensate and crude oil is recognized on the accrual basis as products are transported.

Income Taxes

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

Earnings Per Share

The Company follows SFAS No. 128 ("Statement 128"), "Earnings per Share", for computing and presenting earnings per share and requires, among other things, dual presentation of basic and diluted earnings per share on the face of the statement of operations.

The employee stock options at December 31, 2001, were not included in the computation of diluted earnings per share because the effect of their assumed exercise and conversion would have an antidilutive effect on the computation of diluted loss per share. In 2002 there was one employee stock option that was used in the computation of diluted earnings per share.

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

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (continued)

	Net Income (Loss)	Weighted-Average Number of Common Shares Outstanding and Potential Dilutive Common Shares	Per Share Amount
Year ended December 31, 2002			
Basic earnings per share	$ 482,054	6,343,834	$ 0.08
Effect of dilutive stock options		15,238	
Diluted earnings per share	$ 482,054	6,359,072	$ 0.08
Year ended December 31, 2001			
Basic and diluted earnings per share	$ (2,649,142)	6,004,019	$ 0.44

Environmental

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

Recently Issued Accounting Pronouncements

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

SFAS 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset and this additional carrying amount is depreciated over the life of the asset. If the obligation is settled for other than the carrying amount of the liability, the Company will recognize a gain or loss on settlement.

The Company is required and plans to adopt the provisions of SFAS 143 for the quarter ending March 31, 2003. To accomplish this, the Company must identify all legal obligations for asset retirement obligations and determine the fair value of these obligations on the date of adoption. The determination of fair value is complex and requires the Company to gather market information and develop cash flow models. Additionally, the Company is required to develop processes to track and monitor these obligations. The Company currently estimates that the adoption of SFAS 143 will result in the recording of an asset retirement obligation of $1.6 million.

In May 2002, the FASB issued Statement of Financial Accounting Standards No. 145 ("SFAS 145"), "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections". This Statement rescinds FASB Statements No. 4, Reporting Gains and Losses from Extinguishment of Debt, and an amendment of Statement No. 4 and FASB Statement No. 64, Extinguishments of Debt Made to Satisfy Sinking-Fund Requirements. This Statement also rescinds FASB Statement No. 44, Accounting for Intangible Assets of Motor Carriers. This Statement amends FASB Statement No. 13, Accounting for Leases, to eliminate an inconsistency between the required accounting for sale-leaseback transactions and the required accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. SFAS 145 is effective for fiscal years beginning after May 15, 2002. The Company does not expect the adoption of SFAS 145 to have a material effect on the Company's financial condition and results of operations.

In June 2002, the FASB issued Statement of Financial Accounting Standards No. 146 ("SFAS 146"), "Accounting for Costs Associated with Exit or Disposal Activities". This Statement addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Issues Task Force Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)". SFAS 146 is effective for exit or disposal activities initiated after December 31, 2002. The Company does not expect the adoption of SFAS 146 to have a material effect on the Company's financial condition and results of operations.

In December 2002, the FASB issued Statement of Financial Accounting

Standards ("SFAS") No. 148, "Accounting for Stock-Based Compensation, Transition and Disclosure." SFAS No. 148 provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. SFAS No. 148 also requires that disclosures of the pro forma effect of using the fair value method of accounting for stock-based employee compensation be displayed more prominently and in a tabular format. Additionally, SFAS No. 148 requires disclosure of the pro forma effect in interim financial statements. The transition and annual disclosure requirements of SFAS No. 148 are effective for fiscal years ending after December 15, 2002. The interim disclosure requirements are effective for interim periods beginning after December 15, 2002. The Company does not expect that the adoption of SFAS 148 will have a material effect on its financial position or results of operations.

(2) Liquidity

At December 31, 2002, the Company's working capital was approximately $2.2 million. During the third and fourth quarters of 2002, the Company received approximately $5.0 million from the sale of proved oil and gas properties from two separate transactions. As a result, the Company believes that it has sufficient cash to meet its working capital and capital expenditure requirements through 2003. Historically, the Company has 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 its operations.

(3) Fair Value of Financial Instruments

The carrying values of cash and cash equivalents, receivables and accounts payable approximate fair value due to the short-term maturities of these instruments. The carrying value of the Note Payable approximates the fair value due to its interest rate approximating current borrowing rates.

(4) Income Taxes

Income tax expense for both 2002 and 2001 was $0.

The income tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2002 are presented below:

Deferred tax assets:	
Net operating loss and capital loss carryforwards	$ 11,753,227
Alternative minimum tax credit	388,336
Basis differences in property and equipment	731,629
Total gross deferred tax asset	12,873,192
Net deferred tax asset	12,873,192
Less valuation allowance	(12,628,748)

Deferred tax asset	$ 244,444

In 1999, the Company acquired a 75% interest in American Resources, which had deferred tax assets of approximately $8.5 million made up of basis differences in oil and gas properties and net operating losses. A full valuation allowance was recorded to reduce the corresponding deferred assets, since it is more likely than not that they will not be realized, due to the limitation of the use of the net operating loss carryforwards resulting from the ownership change in December 1999.

In assessing the realizability of deferred tax assets, the Company applies SFAS No. 109 to determine whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. As a result, the Company's valuation allowance at December 31, 2002 reduces the deferred tax assets to $244,444.

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (continued)

The Company's effective tax rate applicable to continuing operations in 2002 and 2001 is as follows:

	2002	2001
Expected tax rate	(34%)	(34%)
State taxes, net of federal benefit	--	--
Expenses not deductible for tax purposes	--	--
Increase in valuation allowance recognized in earnings	34%	34%
Other	--	--
	0%	0%

For federal tax purposes, the Company had a net operating loss carryforward ("NOL") of approximately $32.0 million and $31.1 million for the years ended December 31, 2002 and 2001, respectively. These NOLs must be utilized prior to their expiration, which is between 2003 and 2022. Of the $32.0 million of NOLs as of December 31, 2002, $17.2 million relate to American Resources.

The Company has alternative minimum tax credit carry forwards of $388,336 that do not expire and may be applied to reduce regular tax to an amount not less than the alternative minimum tax payable in any one year.

(5) Long-term Debt

In February 2002, the Company acquired a 1/3 interest in the Blue Dolphin Pipeline System and the inactive Omega Pipeline from MCNIC Pipeline and Processing Company ("MCNIC") effective January 1, 2002. Pursuant to the terms of the purchase and sales agreement, Blue Dolphin issued MCNIC a $750,000 promissory note due December 31, 2006, with required monthly payments to be made out of 90% of the net revenues of the interest acquired. As of December 31, 2002, net revenues attributable to the acquired interest were insufficient to provide any principal payments, however the note continues to accrue interest at 6% per annum. Additionally, an aggregate contingent payment of up to $750,000 will be made, if the promissory note is retired before its maturity date. The contingent payments will be payable annually after the promissory note is retired until December 31, 2006 out of 50% of the net revenues from the interest acquired. The termination date, December 31, 2006, will be extended by one additional year, up to a maximum of two years, for years in which non-recurring, extraordinary expenditures attributable to the interest acquired, exceeds $200,000, in the aggregate, during any year. Currently, the Company does not believe that net revenues from the 1/3 interest in the Blue Dolphin Pipeline System will be sufficient enough to provide any principal payments to MCNIC in the year ending December 31, 2003.

Long-term debt at December 31, 2002 is as follows:

Note payable, interest at 6% per annum payable out of 90% of the net revenues from the 1/3 interest acquired in the Blue Dolphin Pipeline System, secured by the 1/3 interest acquired, all remaining principal due December 31, 2006.	$ 750,000
Less current maturities	--
	$ 750,000

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (continued)

(6) Stockholders' Equity

On December 2, 1999, the Company, through Blue Dolphin Exploration, acquired a 75% ownership interest in American Resources by purchasing approximately 39.5 million shares of American Resources common stock. On February 19, 2002, the Company completed its acquisition of American Resources, pursuant to the Amended and Restated Agreement and Plan of Merger dated as of December 19, 2001 (the "Merger Agreement"). Pursuant to the Merger Agreement, American Resources became a wholly owned subsidiary of the Company and each outstanding share of (i) American Resources common stock, par value $.00001 per share, was converted into the right to receive, at the option of the holder, either $.06 per share in cash or .0362 of a share of the Company's Common Stock, par value $.01 per share (the "Common Stock"), and (ii) American Resources Series 1993 Preferred Stock, par value $12.00 per share, was converted into the right to receive, at the option of the holder, either $.07 in cash or .0301 of a share of Common Stock.

As a result of elections made by American Resources' stockholders, the Company issued 277,330 shares of Common Stock and paid $255,000 in cash.

The Company incurred costs totaling $101,128 and $185,943 in 2002 and 2001, respectively, associated with the registration of shares of its Common Stock that were issued to American Resources stockholders. In addition, the

Company issued 62,603 and 17,867 shares of its Common Stock in 2002 and 2001, respectively, as a severance payment to former employees and recorded compensation expense of $70,740 and $28,586 in 2002 and 2001, respectively. The Company also issued 25,060 and 2,824 shares in 2002 and 2001, respectively, to the board of directors and recorded an expense of $21,000 and $12,000 in 2002 and 2001, respectively.

(7) Stock Options

Effective April 14, 2000, the Company adopted, after approval by stockholders, a stock incentive plan (the "2000 Plan"). The stock subject to the options and other provisions of the 2000 Plan are shares of the Company's Common Stock $.01 par value (the "Stock"). No more than 500,000 shares of Stock will be available for incentive stock options ("ISOs"). The 2000 Plan is administered by the Compensation Committee of the Board of Directors. Options granted must be exercised within 10 years from their grant date. The exercise price of ISOs cannot be less than 100% of the fair market value of a share of Stock. The 2000 Plan also provides for the granting of other incentive awards, however only ISOs and non-statutory stock options have been issued under the 2000 Plan.

The Company adopted a stock option plan in 1996 (the "1996 Plan"). The stock subject to the options and other provisions of the 1996 Plan are shares of the Company's Common Stock. The total amount of the Common Stock with respect to which options may be granted shall not exceed in the aggregate 10% of the number of issued and outstanding shares of Common Stock of the Company. The stock options become exercisable from time to time in part or as a whole, as the Compensation Committee, appointed by the

Board of Directors, or the Board of Directors in their discretion may provide. However, the Committee shall not grant options which may become exercisable in any one calendar year to purchase more than one-third of the maximum amount granted. All options expire five years after the date of grant. The price of options granted may not be less than eighty-five percent of the fair market value of the Common Stock on the date the option is granted. Optionees must continue their association with the Company for six months after exercising the options, or the underlying stock reverts to the Company.

At December 31, 2002 the Company has reserved a total of 416,321 shares of Common Stock for issuance under the above mentioned stock option plans. The outstanding stock options granted to key employees, officers and directors, for the purchase of shares of the Company's Common Stock, are as follows:

		Exercise price per share	
	Shares	From	To
Balance, December 31, 2000	151,236	2.78	6.000

Granted	42,104	1.90	1.900
Expired	(36,834)	3.12	6.000
Exercised	(3,333)	3.82	3.825
Balance, December 31, 2001	153,173	1.90	6.000
Granted	340,277	0.33	1.550
Expired	(77,129)	1.55	6.000
Balance, December 31, 2002	416,321	0.33	6.000

The weighted average exercise price per share was $3.825 in 2001.

As of December 31, 2002, options for 400,988 shares of Common Stock were immediately exercisable. There were 340,277 and 42,104 options granted in 2002 and 2001, respectively. Pursuant to the requirements of FASB No. 123, the weighted average fair market value of options granted during 2002 and 2001 was $0.94 per share and $0.24 per share, respectively. The weighted average closing bid prices for the Company's stock at the date the options were granted during 2002 and 2001 were $1.01 per share and $1.90 per share, respectively. The fair market value pursuant to FASB No. 123 of each option granted is estimated on the date of grant using the Black-Scholes options-pricing model. The model assumed expected volatility of 88% and 29%, risk-free interest rate of 1.45% and 2.22% for grants in 2002 and 2001, respectively, and an expected life of 1 year. As the Company has not declared dividends on its Common Stock since it became a public entity, no dividend yield was used. Actual value realized, if any, is dependent on the future performance of the Company's Common Stock and overall stock market conditions. There is no assurance the value realized by an optionee will be at or near the value estimated by the Black-Scholes model. No compensation expense was recorded in 2002 and 2001 for stock options granted. Had compensation cost for the Company's stock option plans been determined based on the fair market value at the grant dates for awards made, the Company's net income (loss) and income (loss) per share would have been adjusted to the pro forma amounts indicated below:

	Year ended December 31,	
	2002	2001
Net income (loss) as reported	$ 482,054	$(2,649,142)
Less total stock based employer compensation expense determined under fair value based method for all awards, net of tax related effects	(250,234)	(110,294)

Pro Forma	$ 231,820	$(2,759,436)
	===========	===========
Basic and diluted (loss)		
Per share as reported	$ 0.08	$ (0.44)
Pro Forma	$ 0.04	$ (0.46)

Outstanding options at December 31, 2002 expire between December 25, 2003 and November 13, 2012.

(8) Related Party Transactions

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

In September 2001, Drillmar, Inc. a 64% owned affiliate of the Company, entered into a merger agreement and merged with Zephyr Drilling Ltd. ("Zephyr"). Prior to the merger, Zephyr was a limited partnership in which Drillmar was the general partner. Zephyr owned a semi-submersible drilling rig that has been prepared for reconfiguration into a semi-tender. As a result of the merger, the Company's interest in Drillmar decreased from 64% to 12.8%.

Ivar Siem, Chairman of the Company, Harris A. Kaffie and James M. Trimble, Directors of the Company, were limited partners of Zephyr. After the merger between Drillmar and Zephyr, Messers. Siem and Kaffie were owners of 30.3% and 30.6%, respectively, of Drillmar's common stock. Messrs. Siem and Kaffie are both Directors, and Mr. Siem is Chairman and President of Drillmar. Messrs. Siem and Kaffie provided funding to Drillmar in 2002 of $116,000 and $100,000, respectively, and in 2001 of $300,000 and $425,000, respectively, and were issued unsecured promissory notes from Drillmar. The promissory notes were due June 30, 2002 and bore interest at the rate of 10% per annum. Along with the promissory notes, Drillmar issued detachable warrants to Messrs. Siem and Kaffie of 41,500 and 42,500, respectively. The promissory notes issued by Drillmar are nonrecourse to the Company.

Effective March 31, 2002, the Company recorded a full impairment of its investment in Drillmar of approximately $340,000 and a full reserve for the accounts receivable amount owed from Drillmar of approximately $200,000 due to Drillmar's working capital deficiency and delays in securing capital funding.

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (continued)

In May 2002, the Company and Drillmar entered into a new agreement effective as of May 1, 2002, whereby the Company will provide office space and minimal accounting and administrative services to Drillmar for $2,000 per month. If Drillmar is able to secure financing to implement its business plan, the fee will increase to $20,000 per month retroactive to May 1, 2002. The agreement can be terminated upon 30 days notice or by the mutual agreement of the parties.

In January 2003, Drillmar stockholders approved a restructuring plan whereby Drillmar will issue up to $3.0 million of convertible notes that will convert into common stock representing over 99% of Drillmar's outstanding shares. As a result, the Company's ownership in Drillmar will be reduced to less than 1%. Messrs. Siem and Kaffie are expected to exchange their promissory notes and accrued interest into Drillmar new convertible notes.

In February 2003, the Company and Drillmar entered into a new agreement effective as of February 1, 2003, whereby the Company will provide office space to Drillmar for $1,500 per month. The Company will also provide professional, accounting and administrative services to Drillmar based on hourly rates based on the Company cost. The agreement can be terminated upon 30 days notice or by the mutual agreement of the parties.

(9) Leases

The Company has various noncancelable operating leases which continue through 2006. In March 2003, the Company entered into a sublease agreement expiring December 31, 2006 for certain of its office space with Tri-Union Development Corporation. The Company's annual receipts from this sublease will be $81,630. Mr. James M. Trimble, Director of the Company is the Chairman and Chief Executive Officer of Tri-Union.

The following is a schedule of future minimum lease payments required under noncancelable operating leases at December 31, 2002:

Year ending December 31,	Future minimum lease payments	Future sublease payments	Future minimum lease payments, net
2003	$ 203,826	$ 67,943	$ 135,883
2004	201,432	81,630	119,802
2005	198,153	81,630	116,523
2006	195,618	81,630	113,988
	$ 799,029	$ 312,833	$ 486,196

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

Year ended December 31,	
2002	$ 186,498
2001	198,548

(10) Commitments and Contingencies

As a result of the decision to cease operating activities in the Buccaneer Field, the Company's leases in or on the Buccaneer Field terminated in January 2001. The Company must plug and abandon all remaining wells and remove platform facilities within one year from the termination of the leases. In 2001, the Company plugged its remaining wells at a cost of approximately $1.4 million. During the operations of removing the Buccaneer Field platform complexes in 2001, discussions were initiated with the Texas Parks and Wildlife Department ("TPW") in an effort to leave certain of the underwater portions of the platform complexes in place as artificial reefs. By leaving the platform complexes in place as an artificial reef, certain site clearance costs will be eliminated. On January 3, 2003, the Company and TPW executed deeds of donation for both of the Company's platform complexes in the Buccaneer Field, whereby the Company will leave certain of the underwater portions of the platforms in place as artificial reefs and donate them to the TPW, along with cash of $390,000, of which $350,000 represents half of the site clearance work that will be eliminated and $40,000 represents the cost of buoys to mark the reef sites. In addition, the Company has reduced its provision for abandonment costs by $310,000, due to the elimination of site clearance and by $373,000 due to lowering its contingency associated with the abandonment work. The Company requested and has received an extension from the MMS until April 1, 2003 to complete the abandonment operations needed to convert the platform complexes into artificial reefs. The work to complete the abandonment/reefing is expected to begin and be completed during the second quarter 2003. The Company will seek a further extension from the MMS. The Company believes that its provision for abandonment costs of $3.8 million at December 31, 2002 is adequate.

In May 2002, the Company, American Resources and members of prior management of American Resources, including its former chief financial officer, entered into a settlement agreement with H&N Gas. American Resources paid approximately $0.3 million in settlement of this litigation and additionally released funds of approximately $0.7 million it was holding that were due to H&N. The settlement agreement and the payments made thereunder were made in compromise of disputed claims and are not an admission of wrongdoing or of liability of any kind.

The Company is involved in various other claims and legal actions arising in the ordinary course of business. In the opinion of management, the ultimate disposition of these matters will not have a material effect on the Company's financial position, results of operations or cash flows.

(11) Business Segment Information

The Company's income producing operations are conducted in two principal business segments: oil and gas exploration and production, which includes upstream projects, and pipeline operations, which includes mid-stream projects. Intersegment revenues consist of transportation, general processing and storage fees charged by one subsidiary to another for gas and crude oil transported through the Blue Dolphin Pipeline System. The intercompany revenues and expenses are eliminated in consolidation. Information concerning these segments for the years ended December 31, 2002 and 2001 is as follows:

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (continued)

	Revenues	Operating income (loss)(1)	Identifiable assets
Year ended December 31, 2002:			
Oil and gas exploration and production	$ 1,781,958	(256,252)	4,720,424
Pipeline operations	1,128,319	(465,358)	4,990,027
Other	--	(1,391,982)	1,037,457
Consolidated	2,910,277	(2,113,592)	10,747,908
Other income		2,539,900	
Income before income taxes		426,308	
Year ended December 31, 2001:			
Oil and gas exploration and production and operating fees	$ 4,694,202	(616,124)	5,125,652
Pipeline operations	991,823	(11,756)	4,433,200
Other	--	(3,189,867)	2,230,160
Consolidated	5,686,025	(3,817,747)	11,789,012
Other income		1,272,727	
Loss before income taxes		(2,545,020)	

1. Consolidated income (loss) from operations includes $1,030,897 and $1,223,117 in unallocated general and administrative expenses, and unallocated depletion, depreciation, amortization and impairment of $361,084 and $1,966,750 for the years ended December 31, 2002 and 2001, respectively.

2. Pipeline depletion, depreciation and amortization includes a provision for pipeline abandonment of $32,901 and $19,740 for the years ended December 31, 2002 and 2001, respectively. Oil and gas depletion, depreciation and amortization includes a provision for abandonment costs of platforms and wells of $0 and $13,793 for the years ended December 31, 2002 and 2001, respectively. In addition, the Company recorded an expense of approximately $1.0 million for the year ended December 31, 2001, as a result of a change in the estimated costs associated with the Buccaneer Field abandonment.

3. See the supplemental disclosures for oil and gas producing activities for discussion of capitalized costs incurred for oil and gas production operations. Capital expenditures of $180,600 and $1,737,331 were incurred for pipeline operations for the years ended December 31, 2002 and 2001, respectively. Capitalized expenditures of $0 and $59,305 were incurred for mid-stream projects for the years ended

December 31, 2002 and 2001, respectively.

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (continued)

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

	operating fees	Oil and gas sales and operations	Pipeline Total
Year ended December 31, 2002:			
Houston Exploration and Production Company	$ --	290,223	290,223
Apache Corporation	$ --	282,215	282,215
Year ended December 31, 2001:			
Houston Exploration and Production Company	$ --	639,975	639,975

(12) Supplemental Oil and Gas Information - Unaudited

The following supplemental information regarding the oil and gas activities of the Company is presented pursuant to the disclosure requirements promulgated by the Securities and Exchange Commission ("SEC") and SFAS No. 69, Disclosures About Oil and Gas Producing Activities (`Statement 69").

In July 2002, American Resources sold its working interest in the South Timbalier Block 148 property to Newfield Exploration Company for $2.3 million and recorded a gain of $1.4 million. Production from this field accounted for 15% and 19% of the Company's oil and gas sales revenues for the years ended December 31, 2002 and 2001, respectively, and 9% and 16% of the Company's total revenues for these periods.

In November 2002, American Resources sold its working interest in all of its remaining proved oil and gas properties to Fidelity Exploration & Production Company for $2.7 million and recorded a gain of $0.8 million. Production from these fields accounted for 85% and 81% of the Company's oil and gas sales revenues for the years ended December 31, 2002 and 2001, respectively, and 52% and 67% of the Company's total revenues for these periods.

Estimated Quantities of Proved Oil and Gas Reserves

Set forth below is a summary of the changes in the estimated quantities of the Company's crude oil and condensate, and gas reserves for the periods indicated, as estimated by the Company as of December 31, 2002 and by Ryder Scott Company as of December 31, 2001. All of the Company's reserves are located within the United States. Proved reserves cannot be measured exactly because the estimation of reserves involves numerous judgmental determinations. Accordingly, reserve estimates must be continually revised as a result of new information obtained from drilling and production history, new geological and geophysical data and changes in economic conditions.

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

Quantity of Oil and Gas Reserves	Oil (Bbls)	Gas (Mcf)
Total proved reserves at December 31, 2000	185,135	4,667,000
Revisions to previous estimates	(13,476)	(841,816)
Production	(40,769)	(815,184)
Total proved reserves at December 31, 2001	130,890	3,010,000
Production	(28,230)	(418,895)
Reserves sold	(101,213)	(2,311,105)
Total proved reserves at December 31, 2002	1,447	280,000
Proved developed reserves:		
December 31, 2002	1,447	280,000
December 31, 2001	128,783	2,613,000

Capitalized Costs of Oil and Gas Producing Activities

The following table sets forth the aggregate amounts of capitalized costs relating to the Company's oil and gas producing activities and the aggregate amount of related accumulated depletion, depreciation and amortization as of December 31, 2002:

Unproved properties and prospect generation

costs not being amortized	$ 140,233
Proved properties being amortized	21,780,258
Less accumulated depletion, depreciation, amortization and impairment	(21,780,258)
Net capitalized costs	$ 140,233

Costs Incurred in Oil and
Gas Producing Activities

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

	Year Ended December 31,	
	2002	2001
Exploration costs	$ --	249,728
Development costs	512,393	773,115
	$ 512,393	1,022,843

Standardized Measure of Discounted
Future Net Cash Flows

Due to the sale of substantially all of the reserves during 2002, there are no Future Net Cash Flows as of December 31, 2002. The following table reflects the Standardized Measure of Discounted Future Net Cash Flows relating to the Company's interest in proved oil and gas reserves as of:

	December 31,	
	2002	2001
Future cash inflows	$ 1,183,824	$ 10,374,365
Future development costs	(342,210)	(1,190,585)
Future production costs	(84,930)	(1,761,074)
Future net cash inflows before income taxes	756,684	7,422,706
Future income taxes	(257,273)	10,473,236

Future net cash flows	499,411	17,895,942
10% discount factor	(6,017)	(920,497)
Standardized measure of discounted future net cash inflow	$ 493,394	16,975,445

Future net cash flows at each year end, as reported in the above schedule, were determined by summing the estimated annual net cash flows computed by: (1) multiplying estimated quantities of proved reserves to be produced during each year by current prices and (2) deducting estimated expenditures to be incurred during each year to develop and produce the proved reserves (based on current costs).

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

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements (continued)

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

	December 31,	
	2002	2001
Sales and transfers, net of production costs	$ (1,263,038)	(3,538,653)
Acquisition of reserves	--	--
Net change in estimated future development costs	--	980,063
Sales of minerals in place	(4,454,581)	--
Revisions in previous quantity estimates	162,782	(1,663,095)
Net changes is sales and transfer prices, net of production costs	(161,868)	(27,307,388)
Accretion of discount	602,801	3,688,897
Net change in income taxes	3,236,489	13,719,714
Change in production rates (timing) and other	(14,604,636)	(5,551,671)

Net change	$(16,482,051)	(19,672,133)

(13) Sales of Assets

On January 22, 2001, the Company sold its 50% interest in the Black Marlin Pipeline System to affiliates of the Williams Companies, Inc. for approximately $4.6 million. The Black Marlin Pipeline System includes a 75-mile gas and condensate gathering line with related shore facilities servicing the High Island Area, offshore Texas (the "Black Marlin Pipeline") and a 3-mile lateral pipeline extending from High Island Block A-5 to an interconnection to the Black Marlin Pipeline in High Island Block A-6 (the "A-5 Lateral").

This disposition was consummated, in part, through a sale of all of the outstanding capital stock of Black Marlin Pipeline Company (formerly an indirect wholly owned subsidiary of the Company) the owner of a 50% interest in the Black Marlin Pipeline, pursuant to a Purchase and Sale Agreement dated January 12, 2001 (the "Stock Purchase Agreement") among Black Marlin Energy Company, a wholly owned subsidiary of the Company, MCNIC Pipeline & Processing Company ("MCNIC"), WBI Southern, Inc. ("WBI") and Williams Field Services Group, Inc. The Company received $3.6 million for the outstanding capital stock of Black Marlin Pipeline Company for a gain of $1,305,534.

The remaining part of this disposition was consummated through the sale of the A-5 Lateral owned 50% by Blue Dolphin Pipe Line Company, a wholly owned subsidiary of the Company ("BDPL"), pursuant to a Purchase and Sale Agreement dated January 12, 2001, among BDPL, MCNIC, WBI and Williams Field Services - Gulf Coast Company, L.P. The Company received $1.0 million for its interest in the A-5 Lateral, for a gain of $112,092.

In connection with Blue Dolphin Exploration's acquisition of American Resources in December 1999, Blue Dolphin Exploration arranged for Fidelity Oil to acquire an 80% interest in American Resources oil and gas assets located in the Gulf of Mexico for approximately $24.2 million. For the right to participate in the acquisition of these assets, Fidelity Oil agreed to assign Blue Dolphin Exploration 10% of its working interest in the proved properties acquired from American Resources after it has recovered its investment in these properties. In the fourth quarter 2001, Fidelity Oil had recovered its investment in the proved properties. However, instead of assigning 10% of its interest in the proved properties, Fidelity Oil paid Blue Dolphin $1.4 million in cash in December 2001. The proceeds were accounted for as a reduction to capitalized costs of oil and gas properties.

See footnote (12) Supplemental Oil and Gas Information - Unaudited for disclosure of oil and gas properties sold in 2002.

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

None.

Item 9. Directors and Executive Officers of the Registrant

The information required by Item 9 is incorporated by reference to the Company's definitive proxy statement relating to its 2003 annual meeting of stockholders, which proxy statement will be filed pursuant to Regulation 14A within 120 days after the end of the last fiscal year.

Item 10. Executive Compensation

The information required by Item 10 is incorporated by reference to the Company's definitive proxy statement relating to its 2003 annual meeting of stockholders, which proxy statement will be filed pursuant to Regulation 14A within 120 days after the end of the last fiscal year.

Item 11. Security Ownership of Certain Beneficial Owners and Management and Related Stockholders Matters

The information required by Item 11 is incorporated by reference to the Company's definitive proxy statement relating to its 2003 annual meeting of stockholders, which proxy statement will be filed pursuant to Regulation 14A within 120 days after the end of the last fiscal year.

Item 12. Certain Relationships and Related Transactions

The information required by Item 12 is incorporated by reference to the Company's definitive proxy statement relating to its 2003 annual meeting of stockholders, which proxy statement will be filed pursuant to Regulation 14A within 120 days after the end of the last fiscal year.

PART III

Item 13. Exhibits and Reports on Form 8-K

(a) 1. Exhibits

	No.	Description
	3.1 (1)	Certificate of Incorporation of the Company.
	3.2 (2)	Certificate of Correction to the Certificate of Incorporation of the Company dated June 30, 1987.
	3.3 (2)	Certificate of Amendment to the Certificate of Incorporation of the Company dated June 30, 1987.
	3.4 (2)	Certificate of Amendment to the Certificate of Incorporation of the Company dated December 11, 1989.
	3.5 (2)	Certificate of Amendment to the Certificate of Incorporation of the Company dated December 14, 1989.
	3.6 (2)	Bylaws of the Company.
	3.7 (4)	Certificate of Amendment to the Certificate of Incorporation of the Company dated December 8, 1997.
	4.1 (2)	Specimen Certificate of Blue Dolphin Energy Company Common Stock.
*	10.1 (3)	Blue Dolphin Energy Company 1996 Employee Stock Option Plan.
*	10.2 (6)	Blue Dolphin Energy Company 2000 Stock Incentive Plan
	10.11(5)	Investment Agreement, as amended, by and between American Resources Offshore, Inc. and Blue Dolphin Exploration Company.
	10.12(7)	Purchase and Sale Agreement by and between Williams Field Services Group, Inc. and Black Marlin Energy Company
	10.13(7)	Purchase and Sale Agreement by and between Williams Field Services - Gulf Coast Company, L.P. and Blue Dolphin Pipeline Company
	10.14(8)	Amended and Restated Agreement and Plan of Merger dated as of December 19, 2001 (the "Merger Agreement") among Blue Dolphin Energy Company, American Resources Offshore, Inc. and BDCO Merger Sub, Inc.
	10.15(10)	Amended and Restated Agreement and Plan of Merger, as amended, among American Resources Offshore, Inc., Blue Dolphin Energy Company and BDCO Merger Sub, Inc.
	10.16(9)	Letter agreement between Blue Dolphin Exploration Company and Fidelity Exploration & Production Company.
	10.17(9)	Amendment No.1 to the Amended and Restated Agreement and Plan of Merger.
	10.18(11)	Purchase and Sale Agreement by and between Blue Dolphin Energy Company and Newfield Exploration Company.

10.19(12) Purchase and Sale Agreement by and between Blue Dolphin Energy Company and Fidelity Exploration and Production Company.

** 10.20 Purchase and Sale Agreement by and between Blue Dolphin Pipeline Company and MCNIC.

** 21.1 List of subsidiaries of the Company.

** 23.1 Consent of Mann Frankfort Stien & Lipp CPAs, LLP.

** 99.1 Michael J. Jacobson Certification Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002.

** 99.2 G. Brian Lloyd Certification Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002.

(1) Incorporated herein by reference to Exhibits filed in connection with Registration Statement on Form S-4 of ZIM Energy Corp. filed under the Securities Act of 1933 (Commission File No. 33-5559).

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

(3) Incorporated herein by reference to Exhibits filed in connection with Form 10-K of Blue Dolphin Energy Company for the year ended December 31, 1995 under the Securities and Exchange Act of 1934, dated March 29, 1996 (Commission File No. 000-15905).

(4) Incorporated herein by reference to Exhibits filed in connection with the definitive Information Statement on Schedule 14C of Blue Dolphin Energy Company under the Securities and Exchange Act of 1934, dated November 18, 1997 (Commission File No. 000-15905).

(5) Incorporated herein by reference to Exhibits filed in connection with Schedule 13D of Blue Dolphin Energy Company under the Securities and Exchange Act of 1934, dated October 22, 1999 (Commission File No. 000-15905).

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

(7) Incorporated herein by reference to Exhibits filed in connection with Form 8-K of Blue Dolphin Energy Company under the Securities and Exchange Act of 1934, dated January 22, 2001 (Commission File No. 000-15905).

(8) Incorporated herein by reference to Exhibits filed in connection with Form S-4 of Blue Dolphin Energy Company under the Securities Act of 1933 (Commission File No. 333-82186).

(9) Incorporated herein by reference to Exhibits filed in connection with Form 8-K of Blue Dolphin Energy Company under the Securities and Exchange Act of 1934, dated February 25, 2002 (Commission File No. 000-15905).

(10) Incorporated herein by reference to Exhibits filed in connection with Form 8-K of Blue Dolphin Energy Company under the Securities and Exchange Act of 1934, dated July 23, 2002 (Commission File No. 000-15905).

(11) Incorporated herein by reference to Exhibits filed in connection with Form 8-K of Blue Dolphin Energy Company under the Securities and Exchange Act of 1934, dated November 4, 2002 (Commission File No. 000-15905).

* Management Compensation Plan.
** Filed herewith.

(b) Reports on Form 8-K

None

ITEM 14. DISCLOSURE CONTROLS AND PROCEDURES

Within the 90 days prior to the date of this Annual Report, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer and Primary Financial Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rules 13a - 14(c) and 15d - 14 (c) under Securities Exchange Act of 1934, as amended). Based upon the evaluation, the Chief Executive Officer and Primary Financial Officer concluded that the Company's disclosure controls and procedures are effective to ensure that information required to be disclosed by the Company in reports that it files or submits under the Securities Exchange Act of 1934, as amended is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms. There were no significant changes in the Company's internal controls or in other factors that could significantly affect these controls subsequent to the date of their evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

SIGNATURES

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

BLUE DOLPHIN ENERGY COMPANY
(Registrant)

By: /s/ Michael J. Jacobson
Michael J. Jacobson, President
(principal executive officer)

Date: March 21, 2003

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

Signature	Title	Date
/s/ Michael J. Jacobson Michael J. Jacobson	President (principal executive officer)	March 21, 2003
/s/ G. Brian Lloyd G. Brian Lloyd	Vice President, Treasurer (principal accounting and financial officer)	March 21, 2003
/s/ Ivar Siem Ivar Siem	Chairman	March 21, 2003
/s/ Harris A. Kaffie Harris A. Kaffie	Director	March 21, 2003
/s/ Michael S. Chadwick Michael S. Chadwick	Director	March 21, 2003
/s/ Robert D. Wagner, Jr. Robert D. Wagner, Jr.	Director	March 21, 2003
/s/ James M. Trimble James M. Trimble	Director	March 21, 2003

CERTIFICATION BY MICHAEL J. JACOBSON PURSUANT TO SECURITIES EXCHANGE ACT RULE 13a-14

I, Michael J. Jacobson, certify that:

I have reviewed this annual report on Form 10-KSB of Blue Dolphin Energy Company (the "Registrant").

1. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such

statements were made, not misleading with respect to the period covered by this annual report

2. Based on my knowledge, the financial statements and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this annual report;

3. The Registrants other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the Registrant and we have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) evaluated the effectiveness of the Registrants disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the Evaluation Date); and

   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

4. The Registrants other certifying officer and I have disclosed, based on our most recent evaluation, to the Registrants auditors and the audit committee of Registrants board of directors (or persons performing the equivalent function):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrants ability to record, process, summarize and report financial data and have identified for the registrants auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrants internal controls; and

5. The Registrants other certifying officer and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weakness.

Date: March 21, 2003

/s/ Michael J. Jacobson

Michael J. Jacobson
President and Chief Executive Officer

CERTIFICATION BY G. BRIAN LLOYD PURSUANT TO SECURITIES EXCHANGE ACT RULE 13a-14

I, G. Brian Lloyd, certify that:

I have reviewed this annual report on Form 10-KSB of Blue Dolphin Energy Company (the "Registrant")

1. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;

2. Based on my knowledge, the financial statements and other financial information included in this Annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this annual report;

3. The Registrants other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the Registrant and we have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) evaluated the effectiveness of the Registrants disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the Evaluation Date); and

   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

4. The Registrants other certifying officer and I have disclosed, based on our most recent evaluation, to the Registrants auditors and the audit committee of Registrants board of directors (or persons performing the equivalent function):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrants ability to record, process, summarize and report financial data and have identified for the registrants auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrants internal controls; and

5. The Registrants other certifying officer and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weakness.

Date: March 21, 2003

/s/ G. Brian Lloyd

G. Brian Lloyd
Vice President, Treasurer (Principal Accounting Officer)