TRANSMONTAIGNE INC
Form 10-K
September 27, 2002
Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

x **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended June 30, 2002

OR

¨ **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the transition period ____________________ to ____________________

Commission File Number 001-11763

TRANSMONTAIGNE INC.

Delaware **(State or other jurisdiction of incorporation or organization)**	**06-1052062** **(I.R.S. Employer Identification No.)**

2750 Republic Plaza, 370 Seventeenth Street
Denver, Colorado 80202
(Address, including zip code, of principal executive offices)

(303) 626-8200
(Telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock; $.01 par value	**American Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act:

NONE

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such report), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

The aggregate market value of the voting stock held by non-affiliates of the Registrant was $138,360,557. The aggregate market value was computed by reference to the last sale price ($5.11 per share) of the Registrant s Common Stock on the American Stock Exchange on August 30, 2002.

The number of shares of the registrant s Common Stock outstanding on August 30, 2002 was 39,934,767.

Table of Contents

TABLE OF CONTENTS

Table of Contents

PART I

This Annual Report contains certain forward-looking statements and information relating to TransMontaigne Inc. that are based on beliefs and assumptions made by us as well as information currently available to us. When used in this document, the words anticipate, believe, estimate, expect, and similar expressions, are intended to identify forward-looking statements. Such statements reflect our current views with respect to future events and are subject to certain risks, uncertainties, and assumptions. Should one or mores of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may vary materially from those described herein as anticipated, believed, estimated or expected. We do not intend to update these forward-looking statements except as required by law.

ITEM 1. BUSINESS

General

TransMontaigne Inc., a Delaware corporation (TransMontaigne), was formed in 1995 to create an independent petroleum products merchant based in Denver, Colorado. We are a holding company that conducts our commercial activities primarily in the Mid-Continent, Gulf Coast, Southeast, Mid-Atlantic and Northeast regions of the United States. Our commercial activities currently are divided into two main areas: (i) Product supply, distribution, and marketing services, and (ii) Terminal and pipeline operations.

We are seeking to expand our terminal and pipeline operations by acquiring strategically-located terminal and pipeline assets. We are evaluating opportunities to expand our terminal and pipeline infrastructure in the United States, including entering into operating agreements with major energy companies to operate their terminal facilities. Growth by acquisition will be complemented by construction of new projects and expansion of existing facilities in specific locations to increase our present operating capabilities. We also are seeking to expand the spectrum of commodities that we handle and markets that we serve to increase the utilization of our Products supply, distribution and marketing operations. In addition, we are aggressively pursuing additional industrial/commercial end-users to grow our energy-related supply chain management services. Capital to finance acquisitions and expand our commercial operations may be provided by borrowings under existing credit facilities, the issuance of debt in the capital markets, the sale of additional common stock, and cash flow from operating activities.

Commercial Activities

We provide a broad range of integrated supply, distribution, transportation, storage, and marketing services to refiners, distributors, marketers, and industrial/commercial end-users of refined petroleum products (e.g., gasoline, diesel fuel and heating oil), chemicals, crude oil and other bulk liquids (collectively referred to as Product).

We purchase Product primarily from refineries in Texas and Louisiana and schedule transportation of the Product to our and third-party terminals on common carrier pipelines. Simultaneously, we enter into risk management contracts, principally futures contacts on the New York Mercantile Exchange (NYMEX) to sell Product at a specified future date, to reduce our exposure to changes in commodity prices. Upon sale and delivery of the physical inventory of Product to a third party, we enter into a second risk management contract that offsets the original contract in both timing and amount and, effectively, cancels our original NYMEX position.

We seek to maintain a balanced position of forward sale commitments against our discretionary inventories and forward purchase commitments, thereby minimizing or eliminating exposure to commodity price

Table of Contents

fluctuations. We evaluate our exposure to commodity price risk from an overall portfolio basis that considers the continuous movement of discretionary inventory volumes and the open positions in energy services and risk management contracts. However, there are certain risks that we do not attempt to hedge or eliminate. For example, differences in commodity prices exist between delivery locations that are not attributable to the cost of transportation. We refer to these differences in commodity prices between delivery locations as basis (geographical location) differentials. We attempt to exploit the basis (geographical location) differentials by transporting the Product to the delivery location that maximizes the value of the Product to us. We move the Product to the desired delivery location by rerouting the transportation of the Product using our pipelines and terminals, as well as third-party pipelines, barges, vessels, rail cars, and over-the-road tractor trailers. These differentials create opportunities for increased operating margins when we predict the most beneficial location (highest value location) for sales of our discretionary inventories of Products. However, the margins created from exploiting these market inefficiencies do not occur ratably over our reporting periods.

It is our policy not to acquire Products, futures contracts or other derivative products for the sole purpose of speculating on commodity prices. Risk management policies have been established by our risk management committee to monitor and control price risks. Our risk management committee is comprised of senior executives of TransMontaigne.

Product Supply, Distribution, and Marketing Services

Overview. Our Product supply, distribution and marketing operations attempt to maximize utilization of our terminal and pipeline infrastructure to market and trade various Products. Our Product supply, distribution, and marketing margins are generated from bulk sales, exchanges of Products with major and large independent energy companies; wholesale distribution and sales of Products to jobbers and retailers (referred to as rack sales); distribution and sales of Products to regional and national industrial/commercial end-users; and tailored fuel and risk management logistical services arrangements to wholesale, retail and industrial/commercial end-users. Our storage capacity and forward sales transactions enable us to purchase Product inventories; store inventory utilizing owned and leased tank space, as well as line space controlled by us in major common carrier pipelines; arbitrage basis (geographical location) differentials and transportation costs; and, depending upon market conditions, realize margins through sales in the future cash market or by using NYMEX contracts. In addition, we provide risk management products and logistical services to gasoline and distillate customers that minimize the customer s exposure to both commodity price movements and basis (geographical location) differentials. We provide these services to customers for periods as short as one month to terms that span up to three years. The type and length of contracts provided by us will vary based upon market conditions, customer needs, and the risk management practices of the individual customer. The margins created from the risk-management contracts that we enter into with our customers do not occur ratably over our reporting periods and can cause operating results to fluctuate from one period to the next.

Generally, as we purchase discretionary inventory at prevailing prices from refiners and producers at production points and common trading locations, we simultaneously attempt to establish or lock-in a margin by selling the Product for physical delivery to third party users or by entering into a future delivery obligation, such as a futures contract on the NYMEX. We seek to maintain a balanced position of forward sale commitments against our discretionary inventories and forward purchase commitments, thereby minimizing exposure to commodity price fluctuations occurring after the initial transactions. However, certain risks (e.g., basis (geographical location) differentials, types of Product or delivery periods) cannot be completely hedged or eliminated.

Our discretionary inventories of Product are shipped via our pipelines or third party-owned barges, vessels, and pipelines to our terminals or to third-party terminal locations. From these terminal locations, the Products are made available to our customers through daily-priced rack sales, exchange agreements, and contract sales.

Table of Contents

Rack Sales. We manage the physical quantity of our discretionary inventories of Product through daily-priced rack sales. On a daily basis we establish the selling price for each Product for each of our delivery locations/terminals. We announce or post those selling prices to independent local jobbers via facsimile, website, email, and telephone communications. Our selling price of a particular Product on a particular day is a function of our supply at that delivery location/terminal and our estimate of the costs to replenish the Product at that delivery location. The demand for a particular Product is sensitive to changes in pricing. If our objective is to increase demand for a particular Product at a specific delivery location, we would post the selling price of that Product at the low end of the range of prices being offered in that location to increase our local demand. If our objective is to decrease demand for a particular Product at a specified delivery location, we would post the selling price at the high end of the range of prices being offered in that location to reduce our local demand. For the years ended June 30, 2002 and 2001, we averaged approximately 110,000 and 64,000 barrels per day, respectively, of delivered volumes under daily-priced rack sales.

Exchanges. Exchange agreements are entered into with major oil companies and independent refiners. These agreements provide for the exchange of Product at one delivery location for Product at a different location. We generally receive a fee based on the volume of the Product exchanged. That fee takes into account the cost of transportation from the receipt location to the exchange delivery location. For the years ended June 30, 2002 and 2001, we averaged approximately 110,000 and 170,000 barrels per day, respectively, of delivered volumes under exchange agreements.

Bulk and Cycle Sales. Bulk and cycle sales of Products are entered into with major oil companies and independent refiners. These transactions involve the sale of Products in large quantities in liquid bulk markets (Pasadena, TX, New York Harbor, Chicago, IL, Tulsa, OK refining area, and Los Angeles, CA). These transactions also involve the sale of Products in large quantities prior to scheduled delivery to us by producers and refiners for transportation by pipelines, barges, vessels, or rail cars to our terminals. These transactions may occur while the Products are in transit prior to reaching our terminals. For the years ended June 30, 2002 and 2001, we averaged approximately 340,000 and 260,000 barrels per day, respectively, of delivered volumes under bulk and cycle sales.

Contract Sales. Contract sales of Products are conducted from our and third-party terminal, storage, and delivery locations with independent local jobbers, industrial/commercial end users, and governmental agencies. Contract sales provide these customers with a specified volume of Product over a specified term at a specified price. The terms of these contracts range from as short as one month to terms that span up to three years. At the customer s option, the pricing of the Product delivered under a contract sale may be fixed at a stipulated price per gallon, or it may vary based on changes in published indices (e.g., OPIS and Platts). For the years ended June 30, 2002 and 2001, we averaged approximately 80,000 and 60,000 barrels per day, respectively, of delivered volumes under contract sales.

Energy Services. We provide supply chain management services to our industrial/commercial end-users downstream of the truck loading rack location. Fuel and risk management logistical services provide our large and small volume customers an assured, cost effective delivered source of Products supply through our pipelines and terminals, as well as through third-party pipeline, terminal, truck, rail and barge distribution channels. Customers of our supply chain management services receive the benefits of our web-based technology systems enabling the customers to minimize their total Product costs while meeting their volumetric needs. As a result of this service, a customer can reduce the processing time associated with dispatching Product to its physical locations, processing payments associated with Product purchases at both bulk and retail locations, and obtain other costs savings associated with procuring Product. By aggregating the demands of various customers, we are able to leverage the demand and build relationships with other companies along the supply and distribution chain that benefit all the parties through reductions in the back office processing costs associated with buying and selling Products. We generally receive a fee based on the volume of the Products we originate for the customer.

Dedicated Capacity. Using our dedicated pipeline capacity, we averaged in the aggregate approximately 220,000 and 230,000 barrels per day of transported volumes on the Colonial, Plantation, Explorer, and Teppco pipeline systems for the years ended June 30, 2002 and 2001, respectively. We also transport Product to our terminals by barges, vessels, and rail cars.

Terminals and Pipelines

Overview. Our Product supply, distribution and marketing operations generally utilize our terminal and pipeline infrastructure to market and trade various Products and provide specialized supply, logistical, and risk management services to our customers. We own and operate an extensive terminal infrastructure that handles Products with transportation connections via pipelines, barges, rail cars and trucks to our facilities, or to third-party facilities. As of June 30, 2002, we owned and operated the following facilities: 30 delivery locations/terminals with approximately 9.9 million barrels of tank space capacity along the Colonial and Plantation pipeline systems; 3 delivery locations/terminals with approximately 500,000 barrels of tank space capacity along the Williams pipeline system; 3 delivery locations/terminals with approximately 1.0 million barrels of tank capacity along the Florida coast; 1 delivery location/terminal with approximately 2.2 million barrels of tank capacity in Brownsville, Texas; and 12 delivery locations/terminals with approximately 2.9 million barrels of tank capacity along the Mississippi and Ohio rivers.

We own an interstate Products pipeline operating from Mt. Vernon, Missouri to Rogers, Arkansas (the Razorback Pipeline), together with associated terminal facilities at Mt. Vernon and Rogers. The Razorback Pipeline is the only Products pipeline providing transportation services to northwest Arkansas. Effective June 30, 2002, we acquired for cash consideration of approximately $7.2 million the remaining 40% interest in the Razorback Pipeline that we did not previously own. We also own and operate a small intrastate crude oil gathering pipeline system, located in east Texas (the CETEX pipeline).

The success of our terminal and pipeline operations depends in large part on the level of demand for Products by end users in the geographic locations served by such facilities and the ability and willingness of our customers to supply such demand by utilizing our terminals and pipelines as opposed to the terminals and pipelines of other companies. At our terminals and pipelines, we provide throughput, storage, and transportation related services to distributors, marketers and industrial/commercial end-users of Products.

Throughput Revenues. Terminal throughput fees are based on the volume of Products handled at the facility s truck loading racks, generally at a standard rate per gallon. For the years ended June 30, 2002 and 2001, we averaged approximately 520,000 and 620,000 barrels per day, respectively, of throughput volumes at our terminals.

Storage Revenues. Terminal storage fees generally are based on a per barrel rate or tank space capacity committed and will vary with the duration of the arrangement, the Product stored and special handling requirements, particularly when certain types of chemicals and other bulk liquids are involved.

Transportation Revenues. Pipeline transportation fees are based on the volume of Products transported and the distance from the origin point to the delivery point. For the years ended June 30, 2002 and 2001, we averaged approximately 24,000 and 74,000 barrels, respectively, of transported volumes through our pipelines.

Sale of NORCO, Little Rock and Bear Paw

We owned and operated an interstate Products pipeline from Ft. Madison, Iowa through Chicago, Illinois to Toledo, Ohio (the NORCO Pipeline) and associated storage facilities located at Hartsdale, East Chicago and Indianapolis, Indiana and Toledo, Ohio and related product distribution facilities located at South Bend, Indiana; Peoria, Illinois; and Bryan, Ohio. On July 31, 2001, we completed the sale of the NORCO Pipeline system and related terminals (NORCO) to Buckeye Partners L.P. for cash consideration of approximately $62.0 million.

On June 30, 2001, we completed the sale of the Little Rock terminal to Williams Energy Partners L.P. for cash consideration of approximately $29.0 million. On July 3, 2001, we received the cash proceeds from Williams Energy Partners L.P.

We previously provided selected natural gas services including the gathering, processing, fractionating and marketing of natural gas liquids (NGL) and natural gas, through Bear Paw Energy Inc., a wholly-owned subsidiary. On December 31, 1999, we sold Bear Paw Energy Inc. to BPE Acquisition LLC for cash consideration of approximately $131.2 million.

See Note 2 of Notes to Consolidated Financial Statements.

Investments in Petroleum Related Assets

We own 18.04% of the common stock of Lion Oil Company (Lion), a refinery located in Arkansas. At June 30, 2002 and 2001, our investment in Lion, carried at cost, was approximately $10.1 million.

On July 27, 2001, we sold 861 shares of the common stock of West Shore Pipeline Company (West Shore), thereby reducing our ownership interest to 18.50%. The West Shore common stock was sold to Midwest Pipeline Company, LLC for cash consideration of approximately $2.9 million. We sold our remaining 18.50% interest on October 29, 2001 to Buckeye Partners L.P. for cash consideration of approximately $23.1 million.

On May 30, 2002, our 30.02% equity interest in ST Oil Company was reacquired by ST Oil Company for cash consideration of approximately $3.0 million.

See Note 8 of Notes to Consolidated Financial Statements.

Tariff Regulations

The Razorback Pipeline, which runs between Mt. Vernon, Missouri and Rogers, Arkansas, is an interstate Products pipeline and is subject to regulation by the Federal Energy Regulatory Commission (FERC) under the Interstate Commerce Act, the Energy Policy Act of 1992 and rules and orders promulgated pursuant thereto. FERC regulation requires that interstate oil pipeline rates be posted publicly and that these rates be just and reasonable and nondiscriminatory. Rates of interstate oil pipeline companies are currently regulated by the FERC primarily through an index methodology, whereby a pipeline is allowed to change its rates based on the change from year to year in the Producer Price Index for finished goods, less 1% (PPI Index). In the alternative, interstate oil pipeline companies may elect to support rate filings by using a cost-of-service methodology, competitive market showings or actual agreements between shippers and the oil pipeline company.

The CETEX Pipeline, our intrastate crude oil pipeline located in east Texas, is subject to regulation by the Texas Railroad Commission. Texas regulations require that intrastate tariffs be filed with the Texas Railroad Commission and allows shippers to challenge such tariffs.

Environmental Matters

Our operations are subject to extensive federal, state and local laws and regulations covering the discharge of materials into the environment, or otherwise relating to the protection of the environment, and which require expenditures for remediation at various operating facilities, as well as expenditures in connection with the construction of new facilities. We believe that our operations and facilities are in material compliance with applicable environmental regulations. Environmental laws and regulations have changed substantially and rapidly over the last 20 years, and we anticipate that there will be continuing changes. The trend in environmental regulation is to place more restrictions and limitations on activities that may impact the environment, such as

Table of Contents

emissions of pollutants, generation and disposal of wastes and use and handling of chemical substances. Increasingly strict environmental restrictions and limitations have resulted in increased operating costs for us and other businesses throughout the United States, and it is possible that the costs of compliance with environmental laws and regulations will continue to increase. We will attempt to anticipate future regulatory requirements that might be imposed and to plan accordingly in order to remain in compliance with changing environmental laws and regulations and to minimize the costs of such compliance. It is not anticipated that we will be required in the near future to expend amounts that are material in relation to our total capital expenditures program to comply with environmental laws and regulations, but inasmuch as such laws and regulations are frequently changed, we are unable to predict the ultimate costs and liabilities of compliance.

Water

The Federal Water Pollution Control Act of 1972, as renamed and amended as the Clean Water Act (CWA), imposes strict controls against the discharge of oil and its derivates into navigable waters. The CWA provides penalties for any discharges of petroleum products in reportable quantities and imposes substantial potential liability for the costs of removing an oil or hazardous substance spill. State laws for the control of water pollution also provide varying civil and criminal penalties and liabilities in the case of a release of petroleum or its derivatives in surface waters or into the groundwater. Spill prevention control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum tank spill, rupture or leak.

Contamination resulting from spills or release of refined petroleum products is an inherent risk within the petroleum terminal and pipeline industry. To the extent that groundwater contamination requiring remediation exists around the assets we own as a result of past operations, we believe any such contamination can be controlled or remedied without having a material adverse effect on our financial condition. However, such costs are site specific and, therefore, there can be no assurance that the effect will not be material in the aggregate.

The primary federal law for oil spill liability is the Oil Pollution Act of 1990 (OPA), which addresses three principal areas of oil pollution prevention, containment and cleanup, and liability. It applies to vessels, offshore platforms, and onshore facilities, including terminals, pipelines and transfer facilities. In order to handle, store or transport oil, shore facilities are required to file oil spill response plans with the United States Coast Guard, the United States Department of Transportation Office of Pipeline Safety (OPS) or the Environmental Protection Agency (EPA). Numerous states have enacted laws similar to OPA. Under OPA and similar state laws, responsible parties for a regulated facility from which oil is discharged may be liable for removal costs and natural resources damages. We believe that we are in material compliance with regulations pursuant to OPA and similar state laws.

The EPA has adopted regulations that require us to have permits in order to discharge certain storm water run-off. Storm water discharge permits may also be required by certain states in which we operate. Such permits may require us to monitor and sample the effluent. We believe that we are in material compliance with effluent limitations at existing facilities.

Air Emissions

Our operations are subject to the federal Clean Air Act and comparable state and local statutes. The Clean Air Act Amendments of 1990 (the Clean Air Act) require most industrial operations in the United States to incur capital expenditures in order to meet the air emission control standards that are developed and implemented by the EPA and state environmental agencies. Pursuant to the Clean Air Act, any of our facilities that emit volatile organic compounds or nitrogen oxides and are located in ozone non-attainment areas face increasingly stringent regulations, including requirements that certain sources install the reasonably available control technology. Some of our facilities have been included within the categories of hazardous air pollutant sources, and we are in compliance with the currently applicable standards. The Clean Air Act regulations are still being implemented by the EPA and state agencies, and we do not anticipate that implementation of the regulations will have a material adverse effect on us.

Safety Regulation

We are subject to regulation by the United States Department of Transportation under the Accountable Pipeline and Safety Partnership Act of 1996, sometimes referred to as the Hazardous Liquid Pipeline Safety Act (HLPSA), and comparable state statutes relating to the design, installation, testing, construction, operation, replacement and management of our pipeline facilities. HLPSA covers petroleum and petroleum products and requires any entity that owns or operates pipeline facilities to comply with such regulations, to permit access to and copying of records and to make certain reports and provide information as required by the Secretary of Transportation.

We are subject to OPS regulation requiring qualification of pipeline personnel. The regulation requires pipeline operators to develop and maintain a written qualification program for individuals performing covered tasks on pipeline facilities. The intent of this regulation is to ensure a qualified work force and to reduce the probability and consequence of incidents caused by human error. The regulation establishes qualification requirements for individuals performing covered tasks, and amends certain training requirements in existing regulations.

We are also subject to OPS regulation for High Consequence Areas (HCA) for Category 2 pipeline systems (companies operating less than 500 miles of jurisdictional pipeline). This regulation specifies how to assess, evaluate, repair and validate the integrity of pipeline segments that could impact populated areas, areas unusually sensitive to environmental damage and commercially navigable waterways, in the event of a release. The pipeline segments that could impact HCAs must be identified by November 18, 2002. The regulation requires an integrity management program that utilizes internal pipeline inspection, pressure testing, or other equally effective means to assess the integrity of pipeline segments in HCAs. An integrity management program must be completed by February 18, 2003. The program requires periodic review of pipeline segments in HCAs to ensure adequate preventative and mitigative measures exist. Through this program, we are to evaluate a range of threats to each pipeline segment s integrity by analyzing available information about the pipeline segment and consequences of a failure in a HCA. The regulation requires prompt action to address integrity issues raised by the assessment and analysis. The complete baseline assessment of all segments must be performed by February 17, 2009, with intermediate compliance deadlines prior to that. Our assets that are subject to these requirements are: (1) the Pinebelt Pipeline (the pipeline connecting the Collins and Purvis, Mississippi complexes); (2) the Razorback Pipeline; (3) the Bellemeade Pipeline (pipeline connecting the Richmond Terminal to the nearby Virginia Power plant); and (4) the Birmingham Terminal pipeline connection to Plantation Pipeline.

We are also subject to the requirements of the federal Occupational Safety and Health Act (OSHA) and comparable state statutes. We believe that we are in material compliance with OSHA and state requirements, including general industry standards, record keeping requirements and monitoring of occupational exposures.

The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act, and comparable state statutes require us to organize and disclose information about the hazardous materials used in our operations. Certain parts of this information must be reported to employees, state and local governmental authorities, and local citizens upon request. In general, we expect to increase our expenditures during the next decade to comply with higher industry and regulatory safety standards such as those described above. Such expenditures cannot be accurately estimated at this time, although we do not believe that they will have a material adverse impact.

We are subject to OSHA Process Safety Management (PSM) regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above the specified thresholds; or any process which involves a flammable liquid or gas, as defined in the regulations, stored on-site in one location, in a quantity of 10,000 pounds or more. We believe that we are in material compliance with the PSM regulations.

Employees

We had 440 employees at August 30, 2002. No employees are subject to representation by unions for collective bargaining purposes.

Table of Contents

ITEM 2. PROPERTIES

Our executive offices are located at 2750 Republic Plaza, 370 Seventeenth Street, Denver, Colorado 80202; telephone number (303) 626-8200 and facsimile number (303) 626-8228. In addition, we have an operations office located at 200 Mansell Court East, Suite 600, Roswell, Georgia 30076; telephone number (770) 518-3500 and facsimile number (770) 518-3567.

On or about March 1, 2003, our executive offices will be located at 1670 Broadway, Suite 3100, Denver, Colorado 80202.

Our pipelines, approximate miles of pipeline, and geographical locations are as follows:

Pipeline Name	Approximate Miles of Pipeline	Geographical Location
Razorback	67	Mt. Vernon, Missouri south to Rogers, Arkansas
CETEX	220	East Texas area north of Tyler, Texas
NORCO(1)	480	Fort Madison, Iowa east to Toledo, Ohio

(1) This pipeline was sold on July 31, 2001. See Note 2 of Notes to Consolidated Financial Statements.

Table of Contents

At June 30, 2002, our terminal locations and approximate useable storage capacity were as follows:

Locations	Approximate Useable Storage Capacity (in barrels)
Colonial/Plantation Facilities:	
Albany, GA	181,000
Americus, GA	83,000
Athens, GA	165,000
Atlanta, GA	370,000
Bainbridge, GA	188,000
Belton, SC	204,000
Belton, SC Piedmont	258,000
Birmingham, AL	533,000
Charlotte, NC	400,000
Charlotte, NC Piedmont	290,000
Collins, MS	170,000
Collins, MS (Pipeline Injection Facility)	1,263,000
Doraville, GA Piedmont	394,000
Greensboro, NC	422,000
Greensboro, NC Piedmont	368,000
Griffin, GA	93,000
Lookout Mountain, GA	195,000
Macon, GA	164,000
Meridian, MS	120,000
Montgomery, AL	124,000
Montvale, VA	443,000
Norfolk, VA	360,000
Purvis, MS	938,000
Purvis, MS Piedmont	124,000
Rensselaer, NY	503,000
Richmond, VA	414,000
Rome, GA	132,000
Selma, NC Piedmont	468,000
Spartanburg, SC	286,000
Spartanburg, SC Piedmont	260,000
	9,913,000
Midwest Facilities:	
Mount Vernon, MO	198,000
Rogers, AR	172,000
Chippewa Falls, WI	113,000
	483,000
Upper River Facilities:	
Evansville, IN	214,000
Greater Cincinnati, KY (Covington)	183,000
Henderson, KY	261,000
New Albany, IN	177,000
Louisville, KY	172,000

Cape Girardeau, MO	131,000
East Liverpool, OH	206,000
Owensboro, KY	147,000
Paducah, KY Complex	297,000
	1,788,000

Locations	Approximate Useable Storage Capacity (in barrels)
Lower River Facilities:	
Baton Rouge, LA - Dock facility	
Arkansas City, AR	633,000
Greenville, MS Complex	502,000
	1,135,000
Brownsville Facilities:	
Brownsville, TX Complex	2,200,000
Florida Facilities:	
Pensacola, FL	147,000
Port Everglades, FL	422,000
Tampa, FL	454,000
	1,023,000
Total Terminal Useable Storage Capacity	16,542,000

Table of Contents

Locations	Approximate Useable Storage Capacity (in barrels)
NORCO Facilities(1):	
Bryan, OH	67,000
East Chicago, IN	1,148,000
Hartsdale, IN	918,000
Indianapolis, IN	192,000
Peoria, IL	169,000
South Bend, IN	136,000
Toledo, OH	483,000
	3,113,000

(1) These facilities were sold on July 31, 2001. See Note 2 of Notes to Consolidated Financial Statements.

ITEM 3. LEGAL PROCEEDINGS

We have been named as a defendant in various lawsuits and a party to various other legal proceedings, in the ordinary course of business, some of which are covered in whole or in part by insurance. We believe that the outcome of such lawsuits and other proceedings will not individually or in the aggregate have a material adverse effect on our consolidated financial condition, results of operations, or cash flows.

ITEM 4. VOTE OF SECURITY HOLDERS

No matter was submitted to a vote of security holders, through the solicitation of proxies or otherwise, during the three months ended June 30, 2002.

Table of Contents

PART II

ITEM 5. MARKET FOR COMMON STOCK

Our common stock is traded on the American Stock Exchange under the symbol TMG . The following table sets forth, for the periods indicated, the range of high and low per share sale prices for our common stock as reported on the American Stock Exchange.

	Low	High
July 1, 2000 through September 30, 2000	$ 4.25	$ 6.50
October 1, 2000 through December 31, 2000	$ 2.38	$ 5.50
January 1, 2001 through March 31, 2001	$ 2.75	$ 4.50
April 1, 2001 through June 30, 2001	$ 3.50	$ 6.10
July 1, 2001 through September 30, 2001	$ 4.00	$ 6.75
October 1, 2001 through December 31, 2001	$ 4.35	$ 6.30
January 1, 2002 through March 31, 2002	$ 5.10	$ 6.00
April 1, 2002 through June 30, 2002	$ 4.20	$ 6.05

On August 30, 2002, the last reported sale price for our common stock on the American Stock Exchange was $5.11 per share. As of August 30, 2002, there were 443 stockholders of record of our common stock. This number does not include stockholders whose shares are held in trust by other entities. The actual number of stockholders is greater than the number of stockholders of record. Based on the number of annual reports requested by brokers, we estimate that we have approximately 2,200 beneficial owners of our common stock as of August 30, 2002.

On June 28, 2002, we issued 72,890 shares of Series B Redeemable Convertible Preferred Stock in a transaction exempt from registration pursuant to Regulation D of the Securities Act of 1933 (see Note 14 of Notes to Consolidated Financial Statements).

No dividends were declared or paid on our common stock during the periods reported in the table above. We intend to retain future cash flow for use in our business and have no current intention of paying dividends to our common stockholders in the foreseeable future. Any payment of future dividends to our common stockholders and the amounts thereof will depend upon our earnings, financial condition, capital requirements and other factors deemed relevant by our Board of Directors. Our bank credit facility and certificate of designations of our preferred stock contain restrictions on the payment of dividends on our common stock. Under the terms and conditions of our bank credit facility, we are precluded from paying a dividend on our common stock without the express consent of the lenders (see Note 12 of Notes to Consolidated Financial Statements). Our preferred stock certificate of designations restricts the payment of cash dividends on our common stock unless the holders of our preferred stock have received a cash dividend for their immediately preceding dividend payment date. Additionally, we are precluded from paying dividends on our common stock in excess of $10 million during any 12-month period without the express consent of holders of two-thirds of the then outstanding shares of preferred stock.

Table of Contents

ITEM 6. SELECTED FINANCIAL DATA

The following selected financial data for the years ended June 30, 2002, 2001, 2000 and 1999; the two months ended June 30, 1998; and the year ended April 30, 1998 has been derived from our consolidated financial statements. This selected financial data should be read in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations, Item 7, and the consolidated financial statements and notes thereto included in Item 8, Financial Statements and Supplementary Data.

TRANSMONTAIGNE INC.

Selected Financial Data
(thousands of dollars)

	Years ended June 30,				Two months ended June 30,	Year ended April 30,
	2002	**2001**	**2000**	**1999**	**1998**	**1998**
STATEMENT OF OPERATIONS DATA:						
Net operating margins(1)	$ 91,502	73,890	73,597	64,944	1,125	35,889
Impairment of long lived assets			(50,136)			
Corporate relocation and transition	(6,316)					
Operating income (loss)	33,419	20,308	(40,563)	30,179	(2,586)	19,234
Interest expense and other financing costs	(21,432)	(30,424)	(35,480)	(30,454)	(1,769)	(8,164)
Gain (loss) on disposition of assets, net	(13)	22,146	13,930			
Net earnings (loss)	8,558	11,338	(37,937)	1,939	(2,663)	7,638
Net earnings (loss) attributable to common stockholders	(2,793)	2,375	(46,443)	(335)	(2,663)	7,638
OTHER FINANCIAL DATA:						
EBITDA(2)	51,425	42,878	33,507	48,703	(524)	29,510
Adjusted EBITDA(3)	64,388	61,196	33,507	48,703	(524)	29,510
Capital expenditures	15,809	11,542	61,264	137,556	6,455	66,634
STATEMENT OF CASH FLOWS DATA:						
Net cash provided by (used in):						
Operating activities	(89,127)	35,507	267,526	(68,861)	3,673	(4,570)
Investing activities	106,822	(18,969)	77,902	(467,040)	(6,277)	(66,131)
Financing activities	3,811	(61,130)	(305,417)	522,613	12	64,124
BALANCE SHEET DATA:						
Working capital	162,216	33,872	134,807	356,602	86,467	94,393
Long-term debt	187,000	130,000	202,625	495,672	128,971	128,970
Preferred stock	105,360	174,825	170,115	170,115		
Common stockholders equity	205,350	167,550	161,983	205,936	145,266	147,804

(1) Net operating margins represents net revenues, less direct operating costs and expenses.

(2) EBITDA is defined as total net operating margins, less selling, general and administrative expenses, less corporate relocation and transition costs, plus dividend income from petroleum related investments. We believe that, in addition to cash flow from operating activities and net earnings (loss), EBITDA is a useful financial performance measurement for assessing operating performance since it provides an additional basis to evaluate our ability to incur and service debt and to fund capital expenditures. In evaluating EBITDA, we believe that consideration should be given, among other things, to the amount by which EBITDA exceeds interest costs for the period; how EBITDA compares to principal repayments on debt for

the period; and how EBITDA compares to capital expenditures for the period. To evaluate EBITDA, the components of EBITDA such as net revenue and direct operating expenses and the variability of such components over time, also should be considered. EBITDA should not be construed, however, as an alternative to operating income (loss) (as determined in accordance with generally accepted accounting principles (GAAP)) as an indicator of our operating performance, or to cash flows from operating activities (as determined in accordance with GAAP) as a measure of liquidity. Our method of calculating EBITDA may differ from methods used by other companies and, as a result, EBITDA measures disclosed herein might not be comparable to other similarly titled measures used by other companies.

(3) Adjusted EBITDA is defined as EBITDA, plus lower or cost or market write-downs on our inventories minimum volumes (see Note 7 of Notes to Consolidated Financial Statements). We believe that Adjusted EBITDA is the most useful measure in evaluating our performance because it eliminates the impact on our operating results from the impairment of our inventories minimum volumes.

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

This Annual Report contains certain forward-looking statements and information relating to TransMontaigne Inc. that are based on beliefs and assumptions made by us as well as information currently available to us. When used in this document, the words anticipate, believe, estimate, expect, and similar expressions, are intended to identify forward-looking statements. Such statements reflect our current views with respect to future events and are subject to certain risks, uncertainties, and assumptions. Should one or mores of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may vary materially from those described herein as anticipated, believed, estimated or expected. The Company does not intend to update these forward-looking statements except as required by law.

GENERAL

The following discussion and analysis of the results of operations and financial condition should be read in conjunction with the consolidated financial statements. Material period-to-period variances in the consolidated statements of operations are discussed under Results of Operations. The Liquidity and Capital Resources section analyzes cash flows and financial position.

TransMontaigne Inc. (TransMontaigne) was formed in 1995 to create an independent refined petroleum products merchant based in Denver, Colorado. We are a holding company that conducts our commercial activities primarily in the Mid-Continent, Gulf Coast, Southeast, Mid-Atlantic and Northeast regions of the United States. We supply, distribute, transport, store, and market refined petroleum products, chemicals, crude oil, and other bulk liquids (collectively referred to as Products) to refiners, distributors, marketers, and industrial/commercial end-users.

Our commercial activities currently are divided into two main areas: (i) Product supply, distribution, and marketing services, and (ii) Terminal and pipeline operations. Our Product supply, distribution and marketing operations generally utilize our terminal and pipeline infrastructure to market and trade various Products and provide specialized supply, logistical, and risk management services to our customers.

Product Supply, Distribution, and Marketing Operations

We seek to maintain a balanced position of forward sale commitments against our discretionary inventories and forward purchase commitments, thereby minimizing or eliminating exposure to commodity price fluctuations. We evaluate our exposure to commodity price risk from an overall portfolio basis that considers the continuous movement of discretionary inventory volumes and the open positions in energy services and risk management contracts. However, there are certain risks that we do not attempt to hedge or eliminate. For example, we attempt to exploit the price relationships between various delivery locations (referred to as basis (geographical location) differentials). These differentials create opportunities for increased operating margins when we predict the most beneficial location (highest value location) for sales of our discretionary inventories of refined products. However, the margins created from exploiting these market inefficiencies do not occur ratably over our reporting periods.

Our Product supply, distribution, and marketing operations typically purchase Products at prevailing prices from refiners and producers at production points and common trading locations. When we purchase Products, we simultaneously sell the Products for physical delivery to third party users or by entering into future delivery obligations, such as, futures contracts on the NYMEX. These futures contracts minimize or eliminate our exposure to fluctuations in the quoted price of the commodity, but do not minimize exposure to basis (geographical location) differentials. These Products are then shipped via barge, pipelines we own, or third party- owned pipelines to terminals we own or to third-party terminal locations. From these terminal locations, the Products are made available to our customers either through contract sales, exchange agreements or daily-priced rack sales.

Rack Sales. We manage the physical quantity of our discretionary inventories of Product through daily-priced rack sales. On a daily basis we establish the selling price for each Product for each of our delivery locations/terminals. We announce or post those selling prices to independent local jobbers via facsimile, website, email, and telephone communications. Our selling price of a particular Product on a particular day is a function of our supply at that delivery location/terminal and our estimate of the costs to replenish the Product at that delivery location. The demand for a particular Product is sensitive to changes in pricing. If our objective is to increase demand for a particular Product at a specific delivery location, we would post the selling price of that Product at the low end of the range of prices being offered in that location to increase our local demand. If our objective is to decrease demand for a particular Product at a specified delivery location, we would post a selling price at the high end of the range of prices being offered in that location to reduce our local demand. For the years ended June 30, 2002 and 2001, we averaged approximately 110,000 and 64,000 barrels per day, respectively, of delivered volumes under daily-priced rack sales.

Exchanges. Exchange agreements are entered into with major oil companies and independent refiners. These agreements provide for the exchange of Product at one delivery location for Product at a different location. We generally receive a fee based on the volume of the Product exchanged. That fee takes into account the cost of transportation from the receipt location to the exchange delivery location. For the years ended June 30, 2002 and 2001, we averaged approximately 110,000 and 170,000 barrels per day, respectively, of delivered volumes under exchange agreements.

Bulk and Cycle Sales. Bulk and cycle sales of Products are entered into with major oil companies and independent refiners. These transactions involve the sale of Products in large quantities in liquid bulk markets (Pasadena, TX, New York Harbor, Chicago, IL, Tulsa, OK refining area, and Los Angeles, CA). These transactions also involve the sale of Products in large quantities prior to scheduled delivery to us by producers and refiners for transportation by pipelines, barges, vessels, or rail cars to our terminals. These transactions may occur while the Products are in transit prior to reaching our terminals. For the years ended June 30, 2002 and 2001, we averaged approximately 340,000 and 260,000 barrels per day, respectively, of delivered volumes under bulk and cycle sales.

Contract Sales. Contract sales of Products are conducted from our own and third-party terminal, storage, and delivery locations with independent local jobbers, industrial/commercial end users, and governmental agencies. Contract sales provide these customers with a specified volume of Product over a specified term at a specified price. The terms of these contracts range from as short as one month to terms that span up to three years. The pricing of the Product delivered under a contract sale may be fixed at a stipulated price per gallon or it may vary based on changes in published indices (e.g., OPIS and Platts). For the years ended June 30, 2002 and 2001, we averaged approximately 80,000 and 60,000 barrels per day, respectively, of delivered volumes under contract sales.

Energy Services. We provide supply chain management services to our industrial/commercial end-users downstream of the truck loading rack location. Fuel and risk management logistical services provide our large and small volume customers an assured, cost effective delivered source of Products supply through our pipelines and terminals, as well as through third-party pipeline, terminal, truck, rail and barge distribution channels. Customers of our supply chain management services receive the benefits of our web-based technology systems enabling the customers to minimize their total Product costs while meeting their volumetric needs. We generally receive a fee based on the volume of the Products we originate for the customer in exchange for providing our supply chain management services.

Our Product supply, distribution, and marketing operations include energy trading and risk management activities as defined by Emerging Issues Task Force Issue No. 98-10 (EITF 98-10), *Accounting for Contracts Involved in Energy Trading and Risk Management Activities*. In accordance with EITF 98-10, our energy trading and risk management activities are marked to market (i.e., recorded at fair value in the accompanying consolidated balance sheet). The mark-to-market method of accounting requires that the effect of changes in the fair value of our energy trading and risk management activities be recognized as assets and liabilities and included in net revenues attributable to Product supply, distribution, and marketing in the period of the change in value.

The consensus on EITF 98-10 previously permitted revenues from energy trading and risk management activities to be presented on the face of the statement of operations on either a gross or net basis. We previously elected to present revenues from our Product supply, distribution, and marketing operations on a gross basis with a separate line item entitled Product costs in the costs and expenses section of the accompanying consolidated statements of operations. Product costs represent the cost of the Products sold, settlement of risk management contracts, transportation, storage, terminaling costs, and commissions. At its June 2002 meeting, the EITF amended its consensus on EITF 98-10 to require that revenues from energy trading and risk management activities be reported on a net basis (i.e., product costs are required to be netted directly against gross revenues to arrive at net revenues). That amended guidance is effective for financial statements issued for periods ending after July 15, 2002. Nevertheless, we have chosen to adopt early that amended guidance for all periods presented. Therefore, for the year ended June 30, 2002 and all prior periods, we have presented revenues from our Product supply, distribution and marketing operation on a net basis in the accompanying consolidated statements of operations. Net earnings (loss) have not been affected by this change in presentation. Net revenues attributable to our Product supply, distribution, and marketing operations are as follows (in thousands):

	Years ended June 30,		
	2002	2001	2000
Gross revenues	$ 5,967,508	5,140,833	4,953,707
Less cost of revenues	(5,898,761)	(5,094,515)	(4,934,854)
Net revenues	$ 68,747	46,318	18,853

Our energy trading and risk management activities include our inventories discretionary volumes, energy services contracts, and risk management contracts. Our inventories discretionary volumes are held for sale or exchange in the ordinary course of business and consist of refined petroleum products, primarily gasoline and distillates. Our energy services contracts require us to deliver physical quantities of Products over specified terms at specified prices. Our risk management contracts (e.g., forward sales contracts, forward purchase contracts, and swaps) minimize our exposure to changes in commodity prices. We enter into risk management contracts with the objective of offsetting the changes in the values of our inventories discretionary volumes and energy services contracts. It is our policy not to acquire Products, futures contracts or other derivative products for the purpose of speculating on the flat price associated with the underlying commodity. Risk management policies have been established by our Risk Management Committee to monitor and control these price risks. Our Risk Management Committee is comprised of our senior executives.

Our inventories discretionary volumes are carried at fair value in the accompanying consolidated financial statements. Our energy services and risk management contracts also are carried at fair value in the accompanying consolidated financial statements. The fair value of our energy services and risk management contracts are presented as Unrealized gains or losses on energy services and risk management contracts in the accompanying consolidated balance sheet.

Terminals and Pipelines

We own and operate a terminal infrastructure that handles Products with transportation connections via pipelines, barges, rail cars and trucks to our facilities and to third-party facilities. As of June 30, 2002, we owned and operated the following facilities: 30 delivery locations/terminals with approximately 9.9 million barrels of tank space capacity along the Colonial and Plantation pipeline systems; 3 delivery locations/terminals with

Table of Contents

approximately 500,000 barrels of tank space capacity along the Explorer/Williams pipeline systems; 3 delivery locations/terminals with approximately 1.0 million barrels of tank capacity along the Florida coast; 1 delivery location/terminal with approximately 2.2 million barrels of tank capacity in Brownsville, Texas; and 12 delivery locations/terminals with approximately 2.9 million barrels of tank capacity along the Mississippi and Ohio rivers.

We own an interstate Products pipeline operating from Mt. Vernon, Missouri to Rogers, Arkansas (the Razorback Pipeline), together with associated terminal facilities at Mt. Vernon and Rogers. The Razorback Pipeline is the only Products pipeline providing transportation services to northwest Arkansas. Effective June 30, 2002, we acquired for cash consideration of approximately $7.2 million the remaining 40% interest in the Razorback Pipeline system that we did not previously own. We also own and operate a small intrastate crude oil gathering pipeline system, located in east Texas (the CETEX pipeline).

The success of our terminal and pipeline operations depends in large part on the level of demand for Products by end users in the geographic locations served by such facilities and the ability and willingness of our customers to supply such demand by utilizing our terminals and pipelines as opposed to the terminals and pipelines of other companies. At our terminals and pipelines, we provide throughput, storage, and transportation related services to distributors, marketers and industrial/commercial end-users of Products.

Throughput Revenues. Terminal throughput fees are based on the volume of Products handled at the facility s truck loading racks, generally at a standard rate per gallon. For the years ended June 30, 2002 and 2001, we averaged approximately 520,000 and 620,000 barrels per day, respectively, of throughput volumes at our terminals.

Storage Revenues. Terminal storage fees generally are based on a per barrel rate or tank space capacity committed and will vary with the duration of the arrangement, the Product stored and special handling requirements, particularly when certain types of chemicals and other bulk liquids are involved.

Transportation Revenues. Pipeline transportation fees are based on the volume of Products transported and the distance from the origin point to the delivery point. For the years ended June 30, 2002 and 2001, we averaged approximately 24,000 and 74,000 barrels per day, respectively, of transported volumes through our pipelines.

The direct operating costs and expenses of the terminals and pipelines operations include the directly related wages and employee benefits, utilities, communications, maintenance and repairs, property taxes, rent, vehicle expenses, environmental compliance costs, materials and supplies. We cannot predict the impact of future fuel conservation measures, alternate fuel requirements, governmental regulation, technological advances in fuel economy, demographic changes, weather conditions, crop prices, and energy-generation devices, all of which could reduce the demand for Products in the areas we serve.

Natural Gas Services

We previously provided selected natural gas services including the gathering, processing, fractionating, and marketing of natural gas liquids and natural gas. We discontinued this activity when we sold it effective December 31, 1999 (see Note 2 of Notes to Consolidated Financial Statements).

Natural gas gathering and processing revenues were based on the inlet volume of natural gas purchased from producers under both percentage-of-proceeds and fee-based arrangements. Natural gas was gathered and processed into NGL products, principally propane, butane and natural gasoline and residue natural gas. These products were transported by truck or pipeline to storage facilities from which they were further transported and marketed to wholesalers and end-users. Residue natural gas was delivered to and marketed through connections with third-party interstate natural gas pipelines. Operating expenses of the natural gas processing activity include the directly related wages and employee benefits, utilities, maintenance and repairs, property taxes, rent, insurance, vehicle expenses, environmental compliance costs, materials and supplies.

CRITICAL ACCOUNTING ESTIMATES

A summary of the significant accounting policies that we have adopted and followed in the preparation of our consolidated financial statements is detailed in Note 1 of Notes to the Consolidated Financial Statements. Certain of these accounting policies require the use of estimates. We have identified the following estimates that, in our opinion, are subjective in nature, require the exercise of judgment, and involve complex analysis. These estimates are based on our knowledge and understanding of current conditions and actions we may take in the future. Changes in these estimates will occur as a result of the passage of time and the occurrence of future events. Subsequent changes in these estimates may have a significant impact on our financial condition and results of operations.

Allowance for Doubtful Accounts. At June 30, 2002, our allowance for doubtful accounts was $1.25 million. Our allowance for doubtful accounts represents the amount of trade receivables that we do not expect to collect. The valuation of our allowance for doubtful accounts is based on our analysis of specific individual customer balances that are past due and, from that analysis we estimate the amount of the receivable balance that we do not expect to collect. That estimate is based on various factors, including our experience in collecting past due amounts from the customer being evaluated, customer s current financial condition, the current economic environment and the economic outlook for the future.

Inventories Discretionary Volumes. At June 30, 2002, we held Products for sale or exchange in the ordinary course of business with a value of $175.2 million. Our inventories discretionary volumes are carried at fair value in the accompanying consolidated balance sheets. The valuation of our inventories discretionary volumes is based on quoted prices, when available. However, quoted prices are not available from brokers for all future periods and delivery locations in which we are committed to do business. When quoted prices are not available, we estimate the values based on historical relationships between current and future prices and delivery locations.

Energy Services Contracts. At June 30, 2002, we were a party to energy services contracts that require us to deliver physical quantities of refined petroleum products over a specified term at a specified price. Our energy services contracts are carried at fair value in the accompanying consolidated balance sheets. At June 30, 2002, our net unrealized gains on energy services contracts were approximately $13.9 million. The valuation of our energy services contracts is based on quoted prices, when available. However, quoted prices are not available from brokers for all future periods and delivery locations in which we are committed to do business. When quoted prices are not available, we estimate the values based on historical relationships between current and future prices and delivery locations.

Accrued Lease Abandonment. At June 30, 2002, we have an accrued liability of $3.1 million as our estimate of the future payments we expect to pay, net of sublease payments we expect to receive from subleasing our to-be-vacated office space in Denver, Colorado and Atlanta, Georgia. The valuation of our accrued lease abandonment is based on the timing and amount of sublease payments we expect to receive from subleasing our to-be-vacated office space. Our estimate of the timing and amount of sublease payments is based on information received from real estate brokers.

Accrued Transportation and Deficiency Agreements. At June 30, 2002, we have an accrued liability of $2.8 million as our estimate of the future payments we expect to pay for the estimated shortfall in volumes for the remainder of the terms of our transportation and deficiency agreements. The valuation of our accrued transportation and deficiency agreements is based on our estimate of the future volumes we expect to supply and ship with the counterparties to these agreements. We estimate the future volumes based on our historical volumes supplied and shipped with the counterparties. Our accrued liability would be adjusted if our current projections of future volumes to be supplied and shipped with the counterparties indicated a significant increase or decrease in expected volumes due to changes in the scope and breadth of our Product supply, distribution, and marketing operations.

Accrued Environmental Obligations. At June 30, 2002, we have an accrued liability of $2.3 million as our estimate of the future payments we expect to pay for environmental costs to remediate existing conditions attributable to past operations. The valuation of our accrued environmental obligations is based on our estimate of the remediation costs to be incurred in the future. We estimate the future remediation costs based on specific site studies using enacted laws and regulations. Estimates of our environmental obligations are subject to change due to a number of factors and judgments involved in the estimation process, including the early stage of investigation at certain sites, the lengthy time frames required to complete remediation, technology changes affecting remediation methods, alternative remediation methods and strategies, and changes in environmental laws and regulations.

Series B Redeemable Convertible Preferred Stock. At June 30, 2002, the carrying amount of the Series B Redeemable Convertible Preferred Stock was $80.9 million. The carrying amount is based on our estimate of the fair value of the Series B Redeemable Preferred Stock at the date of issuance (June 28, 2002). We estimated the value of the Series B Redeemable Preferred Stock by adding together (i) the present value of the expected dividend payments and mandatory redemption value discounted at a risk-adjusted rate and (ii) the value of the embedded conversion option using an option pricing model.

SIGNIFICANT DEVELOPMENTS

During the year ended June 30, 2002, we amended and restated our bank credit facility (New Facility) to provide us with financing to expand our petroleum products marketing and terminaling network, support our working capital requirements and general corporate needs, recapitalize our preferred stock, and repurchase shares of our common stock. The New Facility provides us with a revolving line of credit and the ability to issue letters of credit to support our Product supply, distribution, and marketing operations.

We also announced our decision to relocate our Product supply, distribution, and marketing operations from Roswell, Georgia to Denver, Colorado to join our corporate headquarters.

Extension of Bank Credit Facility

On June 28, 2002, we entered into the New Facility with a syndication of banks. The New Facility provides for a maximum borrowing under the revolving line of credit that is the lesser of (i) $300 million and (ii) the borrowing base. The borrowing base is a function of our accounts receivable, inventory, exchanges, margin deposits, open positions of energy services and risk management contracts, outstanding letters of credit, and outstanding indebtedness as defined in the New Facility. Borrowings under the New Facility bear interest (at our option) based on the lender s base rate plus a specified margin, or LIBOR plus a specified margin; the specified margins are a function of our leverage ratio as defined in the New Facility. Borrowings under the New Facility are secured by substantially all of our assets. The New Facility matures on June 27, 2005. The terms of the New Facility include financial covenants relating to fixed charge coverage, current ratio, maximum leverage ratio, consolidated tangible net worth, capital expenditures, cash distributions and open inventory positions that are tested on a quarterly and annual basis. At June 30, 2002, we were in compliance with all covenants included in the New Facility.

Preferred Stock Recapitalization

On June 28, 2002, we entered into an agreement with the holders of the Series A Convertible Preferred Stock (the Preferred Stock Recapitalization Agreement) to redeem a portion of the outstanding Series A Convertible Preferred Stock and warrants in exchange for cash, shares of common stock, and shares of a newly created and designated preferred stock (Series B Redeemable Convertible Preferred Stock).

The Preferred Stock Recapitalization Agreement resulted in the redemption of 157,715 shares of Series A Convertible Preferred Stock and warrants to purchase 9,841,493 shares of common stock in exchange for the (i) issuance of 72,890 shares of Series B Redeemable Convertible Preferred Stock with a fair value of approximately

$80.9 million, (ii) issuance of 11,902,705 shares of common stock with a fair value of approximately $59.5 million, and (iii) a cash payment of approximately $21.3 million. The fair value of the consideration paid to the holders of the Series A Convertible Preferred Stock was in excess of the financial statement carrying amount of the Series A Convertible Preferred Stock that was redeemed. That excess of approximately $1.5 million has been treated in a manner similar to preferred stock dividends in the accompanying consolidated financial statements. At June 30, 2002, there were 24,421 shares of Series A Convertible Preferred Stock that remain outstanding.

In connection with the Preferred Stock Recapitalization Agreement, we also agreed to repurchase approximately 4.1 million shares of our common stock from an institutional holder of the Series A Convertible Preferred Stock for cash consideration of approximately $20.4 million.

We borrowed approximately $41.7 million under the New Facility to finance the redemption of the Series A Convertible Preferred Stock and the reacquisition of the common stock.

Corporate Relocation and Transition

During the year ended June 30, 2002, we announced to our employees that our Product supply, distribution, and marketing operations in Atlanta, Georgia would be relocated to Denver, Colorado. On March 19, 2002, we offered approximately 72 employees the opportunity to relocate to Denver, Colorado and we informed approximately 25 employees that they would not be offered the opportunity to relocate to Denver, Colorado. Ultimately, 36 employees chose to relocate to Denver, Colorado. Those employees are entitled to receive a transition bonus and a relocation package payable upon transfer to the Denver office. The transition bonus is being accrued over the period from date of acceptance by the employee to the expected date of arrival in Denver, Colorado. The relocation costs are being accrued as incurred/earned by the employee. Ultimately, 36 employees chose not to relocate and those employees are entitled to receive termination benefits on their termination date as determined by us. The special termination benefits were accrued upon receipt of the notification from the employee that they did not intend to accept the offer to relocate to Denver, Colorado. For the year ended June 30, 2002, we accrued approximately $2.1 million of benefits due to employees, of which approximately $2.0 million remains unpaid as of June 30, 2002. We expect to pay the accrued liability of approximately $2.0 million during the year ending June 30, 2003.

	Special charge	Amounts paid	Accrued liability at June 30, 2002
Accrued severance payable to employees not relocating to Denver, Colorado	$ 1,512	(84)	1,428
Accrued transition benefits payable to employees relocating to Denver, Colorado	501		501
Relocation costs incurred during the period	100		100
Other	25	(25)	
	$ 2,138	(109)	2,029

In connection with our corporate relocation and transition, we entered into an operating lease for new office space in Denver, Colorado. The new lease was executed on April 19, 2002. Prior to June 30, 2002, we engaged commercial real estate agents to solicit prospective tenants to sublease our existing office space in Denver, Colorado and the vacated space in Roswell, Georgia. We expect to vacate our existing office space in Denver, Colorado during February 2003 and the space in Roswell, Georgia during September 2002. The accrual for the abandonment of the office leases represents the excess of the remaining lease payments subsequent to vacancy of the space by us over the estimated sublease rentals to be received based on current market conditions. The abandonment of leasehold improvements represents the carrying amount of those assets that are expected to be abandoned in connection with the abandonment of the office leases. For the year ended June 30, 2002, we charged to income approximately $4.2 million for abandonment of office leases and leasehold improvements.

	Special charge	Amounts paid or written-off	Accrued liability at June 30, 2002
Abandonment of office leases:			
Denver, Colorado	$ 1,150		1,150
Atlanta, Georgia	1,960		1,960
Abandonment of leasehold improvements:			
Denver, Colorado	550	(550)	
Atlanta, Georgia	518	(518)	
	$ 4,178	(1,068)	3,110

We expect to pay the accrued liability of approximately $3.1 million, net of estimated sublease rentals, as follows:

Years ending June 30:	Lease payments	Estimated sublease rentals	Accrued liability at June 30, 2002
2003	$ 745	(97)	648
2004	991	(562)	429
2005	1,020	(565)	455
2006	1,045	(569)	476
2007	948	(508)	440
Thereafter	1,243	(581)	662
	$ 5,992	(2,882)	3,110

DISPOSITIONS

On May 31, 2002, our 30.02% interest in ST Oil Company was reacquired by ST Oil Company for cash consideration of approximately $3.0 million and we recognized a net gain of approximately $1.4 million on the sale. The proceeds from the sale were used for general corporate purposes.

On July 31, 2001, we sold the NORCO Pipeline system and related terminals (NORCO) to Buckeye Partners L.P. for cash consideration of approximately $62.0 million and recognized a net gain of approximately $8.6 million on the sale. The proceeds from the sale were used to repay long-term debt and for general corporate purposes.

On July 27, 2001, we sold 861 shares of the common stock of West Shore Pipeline Company (West Shore), thereby reducing our ownership interest to 18.50%. The West Shore common stock was sold to Midwest Pipeline Company, LLC for cash consideration of approximately $2.9 million. We recognized a loss of approximately $1.1 million on this sale. As a result of this transaction, we also recognized a loss on our remaining investment in West Shore of approximately $8.8 million. We sold our remaining 18.50% interest on October 29, 2001 to Buckeye Partners L.P. for cash consideration of approximately $23.1 million, which approximated our adjusted book value. The cash proceeds from both sales were used to repay long-term debt and for general corporate purposes.

Effective June 30, 2001, we sold two petroleum distribution facilities in Little Rock, Arkansas to Williams Energy Partners L.P. for $29.0 million. The cash proceeds from the sales transactions were received on July 3,

Table of Contents

2001. We recognized a net gain in June 2001 of approximately $22.1 million on the sale. The proceeds from the sale were used to repay long-term debt and for general corporate purposes.

Effective December 31, 1999, we sold our natural gas gathering subsidiary, Bear Paw Energy Inc., (BPEI), to BPE Acquisition LLC, a special purpose entity formed by Bear Paw s management in association with Thomas J. Edelman and Chase Capital Partners. The sale of BPEI was for cash consideration of $107.5 million, plus $23.7 million for reimbursement of the capital expenditures we made on BPEI s newly constructed Powder River coal seam gathering system from July 1, 1999 to December 31, 1999. This disposition resulted in an approximate $16.6 million gain. The sale proceeds were used to reduce long-term debt and for general corporate purposes.

ACQUISITIONS

Effective June 30, 2002, we acquired for cash consideration of approximately $7.2 million the remaining 40% interest that we previously did not own in the Razorback Pipeline system, a 67 mile Products pipeline between Mount Vernon, Missouri and Rogers, Arkansas with approximately .4 million barrels of storage capacity.

On May 31, 2000, we acquired two Products terminals located in Richmond and Montvale, Virginia for approximately $3.2 million. These facilities are interconnected to the Colonial and Plantation pipeline systems and include approximately .5 million barrels of storage capacity.

SUBSEQUENT EVENTS

On August 23, 2002, we announced the signing of a long-term terminaling agreement with P.M.I. Trading Limited to provide Products terminaling services and a related pipeline construction assistance agreement with P.M.I. Services North America, Inc., both affiliates of Petroleos Mexicanos, for the construction of a new 17-mile U.S. Products pipeline from the U.S./Mexican border to our terminaling facility located at the port of Brownsville, Texas.

We also announced that on July 31, 2002, we closed on the purchase of a 25,000-barrel terminal in Brownsville, Texas. The terminal provides us with additional storage and rail car handling facilities and operating synergies with our main facility in Brownsville, Texas.

Table of Contents

RESULTS OF OPERATIONS

Selected annual results of operations data are summarized below (in thousands):

	Years ended June 30,		
	2002	**2001**	**2000**
Product supply, distribution and marketing:			
Revenues, net	$ 68,747	46,318	18,853
Lower of cost or market write-downs on minimum inventory volumes (1)	(12,963)	(18,318)	
Net operating margins (2)	55,784	28,000	18,853
Terminals and pipelines:			
Revenues	63,386	82,305	78,522
Direct operating costs and expenses	(27,668)	(36,415)	(34,268)
Net operating margins	35,718	45,890	44,254
Natural gas services (3):			
Revenues			18,249
Direct operating costs and expenses			(7,759)
Net operating margins			10,490
Total net operating margins	91,502	73,890	73,597
Selling, general and administrative expenses	(35,211)	(34,072)	(41,680)
Depreciation and amortization	(16,556)	(19,510)	(22,344)
Impairment of long-lived assets			(50,136)
Corporate relocation and transition	(6,316)		
Operating income (loss)	33,419	20,308	(40,563)
Dividend income from and equity in earnings of petroleum related investments	1,450	3,060	1,590
Interest income	599	2,914	3,419
Interest expense and other financing costs	(21,432)	(30,424)	(35,480)
Gain (loss) on disposition of assets, net	(13)	22,146	13,930
Earnings (loss) before income taxes	14,023	18,004	(57,104)
Income tax (expense) benefit	(5,465)	(6,666)	19,167
Net earnings (loss)	8,558	11,338	(37,937)
Preferred stock dividends	(11,351)	(8,963)	(8,506)
Net earnings (loss) attributable to common stockholders	$ (2,793)	2,375	(46,443)

(1) We did not measure lower of cost or market write-downs related to minimum inventory during the year ended June 30, 2000, as we did not separately account for our minimum inventory prior to July 1, 2000.

(2) Net operating margins represent net revenues, less direct operating costs and expenses.

(3) Our natural gas services activities were divested as of December 31, 1999.

Table of Contents

The following table summarizes our cash flows, EBITDA, and adjusted EBITDA (in thousands):

	Years ended June 30, 2002	2001	2000
Net cash provided (used) by operating activities	$ (89,127)	35,507	267,526
Net cash provided (used) by investing activities	$ 106,822	(18,969)	77,902
Net cash provided (used) by financing activities	$ 3,811	(61,130)	(305,417)
Calculation of EBITDA and Adjusted EBITDA:			
Total net operating margins	$ 91,502	73,890	73,597
Selling, general, and administrative	(35,211)	(34,072)	(41,680)
Corporate relocation and transition	(6,316)		
Dividend income from petroleum related investments	1,450	3,060	1,590
EBITDA (1)	51,425	42,878	33,507
Lower of cost or market write-downs on minimum inventory volumes	12,963	18,318	
Adjusted EBITDA (2)	$ 64,388	61,196	33,507

(1) EBITDA is defined as total net operating margins, less selling, general and administrative expenses, less corporate relocation and transition costs, plus dividend income from petroleum related investments. We believe that, in addition to cash flow from operating activities and net earnings (loss), EBITDA is a useful financial performance measurement for assessing operating performance since it provides an additional basis to evaluate our ability to incur and service debt and to fund capital expenditures. In evaluating EBITDA, we believe that consideration should be given, among other things, to the amount by which EBITDA exceeds interest costs for the period; how EBITDA compares to principal repayments on debt for the period; and how EBITDA compares to capital expenditures for the period. To evaluate EBITDA, the components of EBITDA, such as net revenue and direct operating expenses, and the variability of such components over time, also should be considered. EBITDA should not be construed, however, as an alternative to operating income (loss) (as determined in accordance with GAAP) as an indicator of our operating performance, or to cash flows from operating activities (as determined in accordance with GAAP) as a measure of liquidity. Our method of calculating EBITDA may differ from methods used by other companies and, as a result, EBITDA measures disclosed herein might not be comparable to other similarly titled measures used by other companies.

(2) Adjusted EBITDA is defined as EBITDA plus lower of cost or market write-downs on our inventories minimum volumes. We believe that Adjusted EBITDA is the most useful measure in evaluating our performance because it eliminates the impact on operating results from the impairment of our inventories minimum volumes.

Table of Contents

Selected quarterly results of operations data are summarized below (in thousands, except volume and per unit margin data):

	Three months ended				Year ended
	September 30, 2001	December 31, 2001	March 31, 2002	June 30, 2002	June 30, 2002
Product supply, distribution and marketing:					
Revenues, net	$ 27,599	13,729	20,106	7,313	68,747
Lower of cost or market write-downs on minimum inventory volumes	(849)	(12,114)			(12,963)
Net operating margins	26,750	1,615	20,106	7,313	55,784
Terminals and pipelines:					
Revenues	15,516	15,175	15,764	16,931	63,386
Direct operating costs and expenses	(7,175)	(6,662)	(6,168)	(7,663)	(27,668)
Net operating margins	8,341	8,513	9,596	9,268	35,718
Total net operating margins	35,091	10,128	29,702	16,581	91,502
Selling, general, and administrative	(8,465)	(8,185)	(8,955)	(9,606)	(35,211)
Depreciation and amortization	(4,282)	(4,024)	(4,143)	(4,107)	(16,556)
Corporate relocation and transition			(315)	(6,001)	(6,316)
Operating income (loss)	22,344	(2,081)	16,289	(3,133)	33,419
Other income (expense), net	(6,811)	(2,660)	(2,200)	(7,725)	(19,396)
Income tax (expense) benefit	(5,902)	1,801	(5,354)	3,990	(5,465)
Net earnings (loss)	$ 9,631	(2,940)	8,735	(6,868)	8,558
Calculation of EBITDA and Adjusted EBITDA:					
Total net operating margins	$ 35,091	10,128	29,702	16,581	91,502
Selling, general, and administrative	(8,465)	(8,185)	(8,955)	(9,606)	(35,211)
Corporate relocation and transition			(315)	(6,001)	(6,316)
Dividend income from petroleum related investments	1,349	108	(7)		1,450
EBITDA	27,975	2,051	20,425	974	51,425
Lower of cost or market write-downs on minimum inventory volumes	849	12,114			12,963
Adjusted EBITDA	$ 28,824	14,165	20,425	974	64,388
Terminal Volumes bbls/day	515,035	499,955	509,005	546,670	517,666
Terminals Net Operating Margin per bbl	$ 0.162	0.169	0.189	0.169	0.170
Pipeline Volumes bbls/day	32,674	17,226	22,961	23,552	24,103
Pipelines Net Operating Margin per bbl	$ 0.288	0.585	0.451	0.458	0.415

27

Table of Contents

	Three months ended				Year ended
	September 30, 2000	December 31, 2000	March 31, 2001	June 30, 2001	June 30, 2001
Product supply, distribution and marketing:					
Revenues, net	$ 8,310	10,865	14,640	12,503	46,318
Lower of cost or market write-downs on minimum inventory volumes	(4,528)	(2,353)	(1,940)	(9,497)	(18,318)
Net operating margins	3,782	8,512	12,700	3,006	28,000
Terminals and pipelines:					
Revenues	20,753	20,527	20,164	20,861	82,305
Direct operating costs and expenses	(8,401)	(8,496)	(9,944)	(9,574)	(36,415)
Net operating margins	12,352	12,031	10,220	11,287	45,890
Total net operating margins	16,134	20,543	22,920	14,293	73,890
Selling, general, and administrative	(7,237)	(8,157)	(9,102)	(9,576)	(34,072)
Depreciation and amortization	(4,847)	(4,821)	(4,927)	(4,915)	(19,510)
Operating income (loss)	4,050	7,565	8,891	(198)	20,308
Other income (expense), net	(3,616)	(4,754)	(8,143)	14,209	(2,304)
Income tax (expense) benefit	(165)	(1,068)	(284)	(5,149)	(6,666)
Net earnings (loss)	$ 269	1,743	464	8,862	11,338
Calculation of EBITDA and Adjusted EBITDA:					
Total net operating margins	$ 16,134	20,543	22,920	14,293	73,890
Selling, general, and administrative	(7,237)	(8,157)	(9,102)	(9,576)	(34,072)
Dividend income from petroleum related investments	919	820	766	555	3,060
EBITDA	9,816	13,206	14,584	5,272	42,878
Lower of cost or market write-downs on minimum inventory volumes	4,528	2,353	1,940	9,497	18,318
Adjusted EBITDA	$ 14,344	15,559	16,524	14,769	61,196
Terminal Volumes bbls/day	618,987	601,985	610,929	630,063	615,491
Terminals Net Operating Margin per bbl	$ 0.188	0.188	0.171	0.170	0.179
Pipeline Volumes bbls/day	74,771	71,218	74,487	76,717	74,298
Pipelines Net Operating Margin per bbl	$ 0.240	0.245	0.120	0.222	0.207

Table of Contents

YEAR ENDED JUNE 30, 2002 COMPARED TO YEAR ENDED JUNE 30, 2001

We reported net earnings of $8.6 million for the year ended June 30, 2002, compared to net earnings of $11.3 million for the year ended June 30, 2001. After preferred stock dividends, the net earnings (loss) attributable to common stockholders was $(2.8) million for the year ended June 30, 2002, compared to net earnings of $2.4 million for the year ended June 30, 2001. Basic and diluted loss per common share for the year ended June 30, 2002 was $(0.09) based on 31.3 million weighted average common shares outstanding. Basic and diluted earnings per share for the year ended June 30, 2001 was $0.08 per share based upon 30.9 million weighted average common shares outstanding and 31.0 million weighted average diluted shares outstanding.

Product Supply, Distribution and Marketing

Our Product supply, distribution, and marketing operations include energy trading and risk management activities as defined by Emerging Issues Task Force Issue No. 98-10 (EITF 98-10), *Accounting for Contracts Involved in Energy Trading and Risk Management Activities*. In accordance with EITF 98-10, our energy trading and risk management activities are marked to market (i.e., recorded at fair value in the accompanying consolidated balance sheet). The mark-to-market method of accounting requires that the effect of changes in the fair value of our energy trading and risk management activities be recognized as assets and liabilities and included in net revenues attributable to Product supply, distribution, and marketing in the period of the change in value.

We seek to maintain a balanced position of forward sale commitments against our discretionary inventories and forward purchase commitments, thereby minimizing or eliminating exposure to commodity price fluctuations. We evaluate our exposure to commodity price risk from an overall portfolio basis that considers the continuous movement of discretionary inventory volumes and the open positions in energy services and risk management contracts. However, there are certain risks that we do not attempt to hedge or eliminate. For example, we attempt to exploit the price relationships between various delivery locations (referred to as basis (geographical location) differentials). These differentials create opportunities for increased operating margins when we predict the most beneficial location (highest value location) for sales of our discretionary inventories of refined products. However, the margins created from exploiting these market inefficiencies do not occur ratably over our reporting periods.

During a contango or carry market structure, we utilize our and third-party terminals to store Products to capture commodity price differentials between current and future months. Mark-to-market accounting will create volatility in our net operating margins due to either the widening or narrowing of these pricing spreads from the original spread relationship. If the spreads widen (narrow), marking these storage volumes and the related forward contracts to market will produce unrealized losses (gains) in interim reporting periods. These negative (positive) results will reverse and the originally anticipated spread will be recognized during the future periods when the physical Product inventory is delivered against the short future position. At June 30, 2002, we held approximately 3.0 million barrels of distillates in our terminals for future delivery.

The net operating margins reported for the Product supply, distribution and marketing operations include amounts realized on Product sales, exchanges and arbitrage. The net revenues from our Product supply, distribution, and marketing operations for the year ended June 30, 2002 was $68.7 million compared to $46.3 million for the year ended June 30, 2001. The increase of $22.4 million in net revenues is due principally to taking advantage of market opportunities that were caused by volatility in basis (geographical location) differentials. During the quarter ended September 30, 2001, a disruption at a Chicago refinery resulted in increased volatility in basis (geographical location) differentials. This disruption increased the basis (geographical location) differentials for both gasoline and distillates between the Gulf Coast, Chicago and Group (Mid-Continent) regions, which created significant margin opportunities in arbitraging the basis (geographical location) differentials between those markets. During the quarter ended March 31, 2002, we were able to increase our net operating margins by taking advantage of the price volatility in the gasoline market in the Gulf Coast region. That volatility also created significant arbitrage opportunities associated with basis (geographical

Table of Contents

location) differentials. In addition, during the quarter ended March 31, 2002, we renegotiated and extended for an additional year, a fixed-price supply contract with a large industrial/commercial end-user. We recognized approximately $3.0 million in net revenues associated with this contract extension and we deferred approximately $1.7 million for the value of the supply chain management services that we are committed to provide over the term of the supply contract. During the quarter ended June 30, 2002, we experienced a reduction in volatility in basis (geographical location) differentials combined with an unfavorable relationship between crude oil and refined product prices.

During the years ended June 30, 2002 and 2001, we recognized impairment losses of approximately $13.0 million and $18.3 million, respectively, due to lower of cost or market write-downs on the minimum inventory volumes. These write-downs are included in net operating margins attributable to our Product supply, distribution, and marketing operations.

Terminals and Pipelines

The net operating margins from our terminal and pipeline operations for the year ended June 30, 2002 were $35.7 million compared to $45.9 million for the year ended June 30, 2001. The decrease of $10.2 million in net operating margins was due principally to the sale of our Little Rock facilities on June 30, 2001 and the NORCO system on July 31, 2001. For the year ended June 30, 2001, the net operating margins from the Little Rock facilities and the NORCO system were $9.1 million.

Our pipeline net operating margins per barrel of transported volumes were approximately $0.42 and $0.21 for the years ended June 30, 2002 and 2001, respectively. The increase in net operating margins per barrel is due principally to the higher unit tariff being realized on one of our joint tariffs, as compared to the lower unit tariff associated with our NORCO system which was disposed of in July 2001.

Selling, General, and Administrative

Selling, general and administrative expenses for the year ended June 30, 2002 were $35.2 million, compared to $34.1 million for the year ended June 30, 2001. The increase of $1.1 million was due principally to increased compensation and travel expenses related to our corporate relocation and transition during the year ended June 30, 2002.

Depreciation and amortization for the year ended June 30, 2002 was $16.6 million, compared to $19.5 million for the year ended June 30, 2001. The decrease of $2.9 million in depreciation and amortization was due primarily to the disposition of the NORCO system and Little Rock facilities.

We recognized special charges of $6.3 million during the year ended June 30, 2002 related to the corporate relocation and transition. We expect to recognize an additional special charge of $2.1 million during the year ended June 30, 2003 to complete the corporate relocation and transition. The additional special charges will consist of $1.7 million in moving costs for employees relocating to Denver, Colorado, transition benefits of $0.3 million payable to employees relocating to Denver, Colorado, and moving costs of $0.1 million related to the relocation of the corporate headquarters.

Other Income and Expenses

Dividend income and equity in earnings from petroleum related investments for the year ended June 30, 2002 was $1.5 million, compared to $3.1 million for the year ended June 30, 2001. The decrease of $1.6 million in dividend income was due principally to the decline in dividends received from West Shore. We sold our investment in West Shore on October 29, 2001.

Interest income for the year ended June 30, 2002 was $0.6 million, compared to $2.9 million for the year ended June 30, 2001. The decrease of $2.3 million in interest income was due primarily to a decrease in interest bearing cash balances and lower interest rates during the year ended June 30, 2002. Pursuant to our cash management practices, excess cash balances are used to pay down our outstanding borrowings under our bank credit facility and commodity margin loan.

Interest expense for the year ended June 30, 2002 was $12.4 million, compared to $18.1 million during the year ended June 30, 2001. For the year ended June 30, 2002, our interest expense resulted from $7.0 million for outstanding borrowings under our bank credit facility and Senior Notes, $0.3 million for outstanding letters of credit, $0.5 million for outstanding borrowings under our commodity margin loan, and $4.6 million in net payments for the interest rate swap. The decrease of $5.7 million in interest expense was primarily attributable to a reduction in the amount of debt outstanding during the current year. We used a portion of the proceeds from the sale of the Little Rock facilities, NORCO system, and West Shore to repay our outstanding borrowings under our bank credit facility and commodity margin loan. We also benefited from lower interest rates during the year ended June 30, 2002, as the average interest rate under our bank credit facility was 5.13% and 6.6% for the years ended June 30, 2002 and 2001, respectively.

Other financing costs for the year ended June 30, 2002 were $9.0 million, compared to $12.3 million for the year ended June 30, 2001. The decrease of $3.3 million in other financing costs was due principally to a reduction in the amortization of deferred financing costs of $1.7 million and a lower unrealized loss on the interest rate swap of $1.3 million. The unrealized loss on the interest rate swap was $2.3 million and $3.6 million during the years ended June 30, 2002 and 2001, respectively. The swap agreement provides that we pay a fixed interest rate of 5.48% on the notional amount of $150 million in exchange for receiving a variable rate based on LIBOR so long as the one-month LIBOR interest rate does not rise above 6.75%. If the one-month LIBOR rate rises above 6.75%, the swap knocks out and we will receive no payments under the agreement until such time as the one-month LIBOR rate declines below 6.75%. At June 30, 2002 and 2001, the one-month LIBOR rate was 1.84% and 4.08%, respectively. This swap agreement expires in August 2003.

Gain (loss) on the disposition of assets for the year ended June 30, 2002 consists of $(9.9) loss on the sale of West Shore, $8.6 million gain on the sale of the NORCO system, $1.4 million gain on the sale of our investment in ST Oil Company, and $(0.1) loss on the sale of other assets. Gain on the disposition of assets was $22.1 million for the year ended June 30, 2001 due to the sale of the Little Rock facilities.

Income Taxes

Income tax expense was $5.5 million for the year ended June 30, 2002, which represents an effective combined federal and state income tax rate of 39.0%. Income tax expense was $6.7 million for the year ended June 30, 2001, which represents an effective combined federal and state income tax rate of 37.0%.

Preferred Stock Dividends

Preferred stock dividends on the Series A Convertible Preferred Stock were $9.8 million and $9.0 million for the years ended June 30, 2002 and 2001, respectively. The increase in the current year dividend resulted from our election to pay the preferred dividends in-kind by issuing additional shares of Series A Convertible Preferred Stock.

The fair value of the consideration paid to the holders of the Series A Convertible Preferred Stock to affect the Preferred Stock Recapitalization was in excess of the financial statement carrying amount of the Series A Convertible Preferred Stock that was redeemed. That excess of approximately $1.5 million has been treated in a manner similar to preferred stock dividends in the accompanying consolidated financial statements.

Table of Contents

YEAR ENDED JUNE 30, 2001 COMPARED TO YEAR ENDED JUNE 30, 2000

We reported net earnings of $11.3 million for the year ended June 30, 2001, compared to a net loss of $(37.9) million for the year ended June 30, 2000. After preferred stock dividends, the net earnings attributable to common stockholders was $2.4 million for the year ended June 30, 2001, compared to a net loss of $(46.4) million for the year ended June 30, 2000. Basic and diluted earnings per common share for the year ended June 30, 2001 were $0.08 based on 30.9 million weighted average common shares outstanding and 31.0 million weighted average diluted shares outstanding. Basic and diluted loss per share for the year ended June 30, 2000 were $(1.52) based on 30.5 million weighted average common shares outstanding.

The increase in net earnings resulted primarily from the absence of an impairment charge in the year ended June 30, 2001, compared to a pre-tax $50.1 million impairment charge in fiscal 2000; increased net operating margins from the Product supply, distribution and marketing operations, offset by the net operating margins from the natural gas services activities which were sold; decreased selling, general and administrative expenses; decreased depreciation and amortization expenses attributable to the sale of the natural gas services activities; and decreased interest expense, attributable to a decrease in average interest rates for the current year, a reduction in the amount of outstanding debt resulting from the sale of the natural gas services activities, and a reduction in the amount of discretionary inventory being carried by us during the current year.

Product Supply, Distribution and Marketing

The net revenues reported for the Product supply, distribution and marketing operations include amounts realized on Product sales, exchanges and arbitrage transactions. During the year ended June 30, 2001, we benefited from the following items: increased supply disruptions in the gasoline and distillate markets; concerns regarding the availability of distillate for the Northeastern region of the United States; the completion of our Baton Rouge dock facility which allowed us to arbitrage basis (geographical location) differentials between Colonial pipeline supplied barrels and Mississippi River based barrels; and an overall increase in the demand for Products from customers supplied by us. In the prior year, we experienced losses from liquidating a portion of our discretionary inventory position and an unfavorable impact from an abnormal price movement between crude oil and distillates. Subsequently, we amended our risk management policies to reduce the potential exposure from future abnormal commodity price movements of this nature by establishing daily reporting of our cumulative profit and loss positions to various levels of management, each of which has predetermined limits that escalate with the applicable level of authority.

Our Products inventory consists primarily of gasoline and distillates, the majority of which is held for sale or exchange in the ordinary course of business. A portion of this inventory, based on line fill and tank bottoms, is required to be held for operating balances in the conduct of our daily Product supply, distribution and marketing operations, and is maintained both in tanks and pipelines owned by us and pipelines owned by third parties. During the quarter ended June 30, 2000, we embarked upon a thorough review of our inventory management strategies and customer contracts. As a result, we lowered our required minimum inventory from over 3.8 million barrels to the current level of 2.0 million barrels. We also changed our strategy regarding the risk management associated with this minimum inventory. Previously, we were hedging the minimum inventory in the futures market and we were renewing the hedges forward at the end of each month as the prior month s hedging contracts expired. In connection with our new risk management strategy, we removed the hedging contracts on our minimum inventory, thereby eliminating any future cash receipts or payments associated with rolling the hedging contracts on the inventory that was not being sold.

During the year ended June 30, 2000, we experienced a cash loss of $12.4 million associated with rolling the hedges into a backwardated market (a market in which the current month commodity price is higher than the future price in succeeding periods) with respect to the minimum inventory. No loss of this type was realized in the year ended June 30, 2001 due to the change in the strategy associated with hedging the minimum inventory. The new policy has resulted in recording the minimum inventories at the lower of cost or market with the resulting non-cash write-downs recognized in net operating margins. We recognized a lower of cost or market write-down of $18.3 million during the year ended June 30, 2001 relating to our minimum inventories.

Table of Contents

Terminals and Pipelines

The net operating margins from our terminal and pipeline operations for the year ended June 30, 2001 was $45.9 million, compared to $44.3 million for the year ended June 30, 2000. The increase of $1.6 million in net operating margins is mostly attributable to increased utilization of our terminals during the current year which was offset somewhat by lower utilization of our pipeline systems. The total revenues recognized by our terminal and pipeline operations increased by approximately $3.8 million during the year ended 2001. The increase in net operating margins resulting from the increases in revenues was offset by an increase of approximately $2.3 million in operating expenses during the year ended June 30, 2001. In the year ended June 30, 2000, we recognized a loss of approximately $0.8 million for the write-off of a few small terminal customers receivable balances.

Natural Gas Services

Our natural gas services activities were divested effective December 31, 1999.

Selling, General, and Administrative

Selling, general and administrative expenses for the year ended June 30, 2001 were $34.1 million, compared to $41.7 million for the year ended June 30, 2000. The decrease of $7.6 million in selling, general, and administrative expenses is due principally to lease contract cancellation costs, additional personnel related costs related to separation and release agreements, non-cash stock compensation costs, and other personnel costs related to a corporate staff reduction and relocation plan, all of which amounted to approximately $5.0 million during the year ended June 30, 2000 that were not incurred during the current year. The sale of our natural gas services activities resulted in a reduction of approximately $0.5 million of employee costs in the current year. During the year ended June 30, 2001, travel and entertainment expenses decreased by approximately $0.6 million, and employee wage and benefit expenses decreased by approximately $1.5 million.

Depreciation and amortization for the year ended June 30, 2001 was $19.5 million, compared to $22.3 million for the year ended June 30, 2000. The decrease was due primarily to the disposition of our natural gas services activities.

Non-cash impairment charges on long-lived assets for the fiscal year ended June 30, 2000 totaled $50.1 million, before income taxes. The charges include $31.9 million relating to certain of our Product terminals acquired in the 1998 acquisition of Louis Dreyfus Energy Corp. and $18.2 million relating to certain intangible assets recorded as a result of the same acquisition. The impairment charges resulted from the change in the planned use of certain terminals and the abandonment of a pipeline that supplied one terminal, thereby significantly impacting the economic viability of the terminals. Each of these events significantly reduced or eliminated future cash flows related to these assets. The $31.9 million impairment charge for the terminals reduced the book value of the assets to their estimated fair value. The additional $18.2 million impairment charge for the intangible assets represented the unamortized balance of the intangible assets. Our review of the market location differentials associated with those assets showed that we received little or no value from those assets in the period ended June 30, 2000. There were no impairment charges on long-lived assets for the year ended June 30, 2001.

Other Income and Expenses

Dividend income and equity in earnings from petroleum related investments for the year ended June 30, 2001 were $3.1 million, compared to $1.6 million for the year ended June 30, 2000. The increase of $1.5 million in dividend income was due principally to dividends being received from West Shore and Lion Oil in the year ended June 30, 2001, compared to the prior year in which dividends were received only from West Shore. Additionally, we recorded $0.1 million of equity earnings in the year ended June 30, 2001 from our investment in ST Oil Company.

Table of Contents

Interest income for the year ended June 30, 2001 was $2.9 million, compared to $3.4 million for the year ended June 30, 2000. The decrease of $0.5 million in interest income was due primarily to a decrease in interest bearing cash balances and lower interest rates during the year ended June 30, 2001.

Interest expense for the year ended June 30, 2001 was $18.1 million, compared to $28.5 million for the year ended June 30, 2000. The decrease of $10.4 million in interest expense was primarily attributable to a reduction in the amount of debt outstanding during the current year resulting from the sale of our natural gas services activities and the liquidation of our discretionary inventory in the prior year. We also benefited by an overall reduction in our borrowing rate under our bank credit facility due to declining LIBOR rates.

Other financing costs for the year ended June 30, 2001 were $12.3 million, compared to $6.9 million for the year ended June 30, 2000. The unrealized loss on the interest rate swap was $3.6 million for the year ended June 30, 2001. In the year ended June 30, 2000, the unrealized gain on the interest rate swap was $1.6 million. The unrealized loss on the interest rate swap was due to a decline in the one-month LIBOR rates during the year ended June 30, 2001.

Gain on the disposition of assets was $22.1 for the year ended June 30, 2001, primarily due to the sale of the Little Rock facilities. Gain on the disposition of assets was $13.9 million for the year ended June 30, 2000 and was primarily due to the sale of our natural gas services activities, partially offset by losses on the disposition and retirement of other assets no longer used in our operations.

Income Taxes

Income tax expense was $6.7 million for the year ended June 30, 2001, which represents an effective combined federal and state income tax rate of 37.0%. Income tax benefit was $19.2 million for the year ended June 30, 2000, which represents an effective combined federal and state income tax rate of 33.6%. The effective tax rate for the year ended June 30, 2000 was lower than the effective tax rate for the year ended June 30, 2001 due to an adjustment in cumulative temporary differences recognized in the fiscal year ended June 30, 2000.

Preferred Stock Dividends

Preferred stock dividends on the Series A Convertible Preferred Stock were $9.0 million and $8.5 million for the years ended June 30, 2001 and 2000, respectively. The increase in the current year dividend resulted from our election to pay the preferred dividends for the quarters ended March 31 and June 30, 2001 in-kind by issuing additional shares of Series A Convertible Preferred Stock.

Table of Contents

FINANCIAL POSITION

At June 30, 2002, our current assets exceeded our current liabilities by $162.2 million, compared to $33.9 million at June 30, 2001. The increase of $128.3 in working capital is due principally to increases in accounts receivable of $94.7 million and inventories discretionary volumes of $138.0 million, net of amounts due under exchange agreements, being offset by decreases in the current portion of net unrealized gains on energy trading and risk management contracts of $18.3 million and increases in accounts payable of $31.1 million and excise taxes payable of $40.0 million.

The increase in accounts receivable of $94.7 million is due principally to an increase in the volume of daily-priced rack sales, which are billed on a gross basis, compared to exchange transactions, which are billed on a net basis, and an increase in Product supply, distribution, and marketing volumes coupled with a corresponding increase in the price of gasoline. Our gross revenues for the Product supply, distribution, and marketing operations were approximately $564.8 million for the month ended June 30, 2002, compared to approximately $391.6 million for the month ended June 30, 2001.

Our inventories discretionary volumes are held for sale or exchange in the ordinary course of business and consist of Products, primarily gasolines and distillates. Our inventories discretionary volumes are presented in the accompanying consolidated balance sheet as current assets and are carried at fair value. Inventories discretionary volumes are as follows (in thousands):

	June 30, 2002		June 30, 2001	
	Amount	**Bbls**	**Amount**	**Bbls**
Products held for sale or exchange	$ 158,261	5,224	$ 20,234	468
Products due to others under exchange agreements, net	16,908	525	76,754	2,778
Inventories discretionary volumes	$ 175,169	5,749	$ 96,988	3,246

During the last six months of the year ended June 30, 2002, we increased our discretionary inventory of distillates to capitalize on the carry or contango market structure. During a contango market, we utilize our and third-party terminals to store Products to capture commodity price differentials between current and future months. At June 30, 2002, we held approximately 3.0 million barrels of distillates in our terminals for future delivery.

Our inventories discretionary volumes are an integral component of our overall energy trading and risk management activities. We evaluate the level of inventories discretionary volumes in combination with energy trading and risk management disciplines, (including certain hedging strategies, forward purchases and sales, swaps and other financial instruments) to manage market exposure, primarily commodity price risk. We evaluate the market exposure from an overall portfolio basis that considers both continuous movement of physical inventory balances and related open positions in energy trading and risk management contracts.

Our inventories minimum volumes are required to be held for operating balances in the conduct of our overall operating activities. We do not intend to sell or exchange these inventories in the ordinary course of business and, therefore, we do not hedge the market risks associated with this minimum inventory. Our inventories minimum volumes are presented in the accompanying consolidated balance sheet as non-current assets and are carried at the lower of cost or market. Inventories minimum volumes are as follows (in thousands):

	June 30, 2002		June 30, 2001	
	Amount	**Bbls**	**Amount**	**Bbls**
Gasolines	$ 27,855	1,200	$ 33,831	1,200
Distillates	17,443	800	24,430	800
Inventories minimum volumes	$ 45,298	2,000	$ 58,261	2,000

Table of Contents

During the years ended June 30, 2002 and 2001, we recognized impairment losses of approximately $13.0 million and $18.3 million, respectively, due to lower of cost or market write-downs on this minimum inventory. These write-downs are included in net operating margins attributable to our Product supply, distribution, and marketing operations. At June 30, 2002 and 2001, the weighted average adjusted cost basis of our inventories minimum volumes was $0.54 and $0.69 per gallon, respectively.

During the three months ended June 30, 2000, we conducted a thorough review of our inventory management strategies and customer contracts. Effective July 1, 2000, we designated 2.0 million barrels of refined petroleum products as inventories minimum volumes and we changed our risk management strategy associated with this minimum inventory. In accordance with our revised risk management strategy, we removed the hedging contracts on the minimum inventory volumes prior to July 1, 2002.

Relative month-end commodity prices from June 30, 2001 to June 30, 2002 (NYMEX close on the last day of the month) are as follows:

	Crude	Heating oil	Gasoline
6/30/01	$ 26.25	.709	.721
7/31/01	26.35	.697	.732
8/31/01	27.20	.766	.806
9/30/01	23.43	.664	.680
10/31/01	21.18	.598	.552
11/30/01	19.44	.532	.534
12/31/01	19.84	.551	.573
1/31/02	19.48	.523	.559
2/28/02	21.74	.563	.581
3/31/02	26.31	.669	.825
4/30/02	27.29	.689	.823
5/31/02	25.31	.630	.738
6/30/02	26.86	.680	.794

The following table indicates the maturities of our energy services and risk management contracts, including the credit quality of our counter parties to those contracts with unrealized gains at June 30, 2002.

	Fair value of contracts (in thousands)				
	Maturity less than 1 year	Maturity 1-3 years	Maturity 4-5 years	Maturity in excess of 5 years	Total
Unrealized gain position asset					
Energy services contracts:					
Investment grade	$ 3,651				3,651
Non-investment grade	4,123	7,979			12,102
No external rating	6,751	113			6,864
	14,525	8,092			22,617
Risk management contracts					
NYMEX futures contracts	11,809	5,877			17,686
	$ 26,334	13,969			40,303
Unrealized loss position liability					
Energy services contracts	$ (8,522)	(209)			(8,731)
Risk management contracts					
NYMEX futures contracts	(13,641)				(13,641)
	$ (22,163)	(209)			(22,732)

Net unrealized gain position asset	$ 4,171	13,760			17,931

36

Table of Contents

At June 30, 2002, the unrealized gain on our energy services contracts with non-investment grade counterparties was approximately $12.1 million. A single industrial/commercial end-user represented approximately $11.5 million of that unrealized gain. At June 30, 2002, we also had energy services contracts with that end-user that were in an unrealized loss position of approximately $0.5 million. Therefore, the fair value of our energy services contracts with that industrial/commercial end-user was approximately $11.0 million at June 30, 2002. The following table includes information about the changes in the fair value of our energy services contracts with that industrial/commercial end-user for the year ended June 30, 2002 (in thousands):

Fair value at June 30, 2001	$	11,401
Amounts realized or otherwise settled during the year		(3,461)
Fair value of additional contracts entered into during the year(1)		4,689
Change in fair value attributable to change in commodity prices		(2,002)
Other changes in fair value		414
Fair value at June 30, 2002	$	11,041

(1) Approximately $3.0 million was included in net revenues attributable to the Product supply, distribution and marketing activities and approximately $1.7 million was deferred for supply chain management services to be provided over the term of the contract (see Note 11 of Notes to Consolidated Financial Statements).

We do not acquire or sell Products, futures contracts, or other financial instruments solely for the purpose of speculating on changes in commodity prices. Our Risk Management Committee reviews the discretionary inventory and related open positions in energy services and risk management contracts on a regular basis in order to ensure compliance with our inventory and risk management policies. We have adopted policies under which changes to our net risk position, which is subject to commodity price risk, requires the prior approval of our Audit Committee of the Board of Directors.

Our inventories discretionary volumes, energy services contracts, and risk management contracts are the integral components of our overall energy trading and risk management activities. We evaluate our market risk exposure from an overall portfolio basis that considers changes in physical inventories discretionary volumes, open positions in energy services contracts, and open positions in risk management contracts. We have established risk management policies and procedures to monitor and control our market risk exposure. Our overall risk management objective is to minimize our exposure to changes in commodity prices. We accomplish this objective by entering into risk management contracts that offset the changes in the values of our inventories discretionary volumes and energy services contracts when there are changes in commodity prices. At June 30, 2002, our open positions in risk management contracts include forward contracts (purchases and sales), swaps, and other financial instruments to manage market exposure, primarily commodity price risk.

We principally utilize exchange-traded risk management contracts to manage our commodity price risk. These contracts require us to maintain initial and variation margin deposits with a third party financial intermediary. At June 30, 2002, we had $8.6 million on deposit to cover our margin requirements on open risk management contracts, which consisted solely of an initial margin deposit. At June 30, 2002, a $0.05 per gallon unfavorable change in commodity prices would have required us to deposit approximately $1.6 million in variation margin. Conversely, a $0.05 per gallon favorable change in commodity prices would have permitted us to reduce the deposit in our margin account by approximately $1.6 million. We have the contractual right to request that the counterparties to our energy services contracts post additional letters of credit or make additional cash deposits with us to assist us in meeting our obligations to cover our margin requirements.

Capital expenditures for the year ended June 30, 2002 were $15.8 million for terminal and pipeline facilities and assets to support these facilities. Future capital expenditures will depend on numerous factors, including the availability, economics and cost of appropriate acquisitions which we identify and evaluate; the economics, cost and required regulatory approvals with respect to the expansion and enhancement of existing systems and facilities; customer demand for the services we provide; local, state and federal governmental regulations;

environmental compliance requirements; and the availability of debt financing and equity capital on acceptable terms.

On June 28, 2002, we executed the New Facility with a syndication of banks. The New Facility provides for a maximum borrowing line of credit that is the lesser of (i) $300 million and (ii) the borrowing base. The borrowing base is a function of our accounts receivable, inventory, exchanges, margin deposits, open positions of energy services and risk management contracts, outstanding letters of credit, and outstanding indebtedness as defined in the New Facility. Borrowings under the New Facility are secured by substantially all of our assets. The New Facility matures on June 27, 2005. The terms of the New Facility include financial covenants relating to fixed charge coverage, current ratio, maximum leverage ratio, consolidated tangible net worth, capital expenditures, cash distributions and open inventory positions that are tested on a quarterly and annual basis. As of June 30, 2002, we were in compliance with all covenants included in the New Facility. At June 30, 2002, we had borrowings of $187.0 million outstanding under the New Facility. We also had the ability to borrow an additional $113.0 million under the New Facility based on the borrowing base computation at June 30, 2002.

We have contractual obligations that are required to be settled in cash. The amounts of our contractual obligations are as follows (in thousands):

	Years ending June 30,					
	2003	**2004**	**2005**	**2006**	**2007**	**Thereafter**
Debt	$ 11,312		187,000			
Preferred stock						72,890
Transportation and deficiency agreements	779	786	786	489		
Operating leases:						
New corporate headquarters		524	968	968	1,015	5,788
Existing corporate headquarters (excluding estimated sublease rentals)	1,888	1,398	1,435	1,468	1,380	2,591
Property and equipment	1,304	1,294	1,141	324	162	
Total contractual obligations to be settled in cash	$ 15,283	4,002	191,330	3,249	2,557	81,269

See Notes 11, 12, 14 and 19 of Notes to Consolidated Financial Statements.

We have outstanding letters of credit with third parties in the amount of $11.5 million which expire within one year.

We believe that our current working capital position; future cash expected to be provided by operating activities; available borrowing capacity under our New Facility and commodity margin loan; and our relationship with institutional lenders and equity investors should enable us to meet our planned capital and liquidity requirements.

CASH FLOWS

Net cash used by operating activities of $89.1 million for the fiscal year ended June 30, 2002 was due principally to increases in accounts receivable and inventories   discretionary volumes. The net cash provided by operating activities of $35.5 million for the year ended June 30, 2001 was due principally to decreases in accounts receivable and inventories   discretionary volumes, offset by an increase in net assets from price risk management activities and a decrease in trade accounts payable and inventory due under exchange agreements. The net cash provided by operating activities of $269.1 million for the year ended June 30, 2000 was due principally to a reduction in our physical inventory, an increase in the amount of inventory due under exchanges and a reduction of trade accounts receivable, offset by a reduction in trade accounts payable.

Table of Contents

Net cash provided by investing activities of $106.8 million for the year ended June 30, 2002 was due principally to proceeds received from the sale of assets of $120.5 million offset by capital expended for construction and improvements to existing operating facilities and acquisitions of $15.8 million. Net cash used by investing activities of $19.0 million during the year ended June 30, 2001 was due principally to capital expended for construction and improvements to existing operating facilities of $11.5 million and additional restricted cash of $8.0 million to cover required margin deposits on risk management contracts. Net cash provided by investing activities of $76.3 million during the year ended June 30, 2000 was due principally to proceeds from the sale of our natural gas services activities of $137.4 million offset by capital expended for construction and improvements to existing operating facilities and acquisitions of $61.3 million.

Net cash provided by financing activities of $3.8 million for the year ended June 30, 2002 was due principally to proceeds from additional borrowings under our bank credit facility of $57.0 million offset by payments to retire common stock of $20.4 million, payments to retire preferred stock of $21.3 million, payments on our commodity margin loan of $8.7 million, and additional deferred debt issuance costs of $2.8 million. Net cash used by financing activities of $61.1 million for the year ended June 30, 2001 was due principally to repayments of borrowings under our bank credit facility and master shelf facility of $77.0 million and payments of preferred stock dividends of $4.3 million offset by borrowings under our commodity margin loan of $20.0 million. Net cash used by financing activities of $305.4 million for the year ended June 30, 2000 was due principally to repayments of borrowings under our bank credit facility and master shelf facility of $290.7 million and payments of preferred stock dividends of $8.5 million and additional deferred debt issuance costs of $6.4 million.

NEW ACCOUNTING STANDARDS

In June 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 141, *Business Combinations*, and SFAS No. 142, *Goodwill and Other Intangible Assets*. SFAS No. 141 requires that the purchase method of accounting be used for all business combinations initiated after June 30, 2001. SFAS No. 141 also specifies criteria intangible assets acquired in a purchase method business combination must meet to be recognized and reported apart from goodwill, and establishes that any purchase price allocable to an assembled workforce may not be accounted for separately. SFAS No. 142 requires that goodwill and intangible assets with indefinite useful lives no longer be amortized, but instead tested for impairment at least annually in accordance with the provisions of SFAS No. 142. SFAS No. 142 also requires that intangible assets with definite useful lives be amortized over their respective estimated useful lives to their estimated residual values, and reviewed for impairment in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. We have adopted the provisions of SFAS No. 141 and we will adopt SFAS No. 142 effective July 1, 2002. The adoption of SFAS No. 141 did not have any impact on our financial statements, and we do not expect the adoption of SFAS No. 142 to have an impact on our financial statements.

In June 2001, the FASB issued SFAS No. 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 No. 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset and this additional carrying amount is depreciated over the life of the asset. The liability is accreted at the end of each period through charges to operating expense. If the obligation is settled for other than the carrying amount of the liability, a gain or loss is recognized on settlement. We are required to adopt the provisions of SFAS No. 143 effective July 1, 2002. To accomplish this, we must identify all legal obligations for asset retirement obligations, if any, and determine the fair value of these obligations on the date of adoption. The determination of fair value is complex and will require us to gather market information and develop cash flow models. Additionally, we will be required to develop processes to track and monitor these obligations. We currently are in the process of assessing the impact, if any, on our financial position, results of operations, and cash flows of adopting SFAS No. 143. However, we are unable to estimate the impact of adopting this statement at the date of this report.

Table of Contents

In August 2001, the FASB issued SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, which is effective for fiscal years beginning after December 15, 2001. SFAS No. 144 establishes one accounting model to be used for long-lived assets to be disposed of by sale and broadens the presentation of discontinued operations to include more disposal transactions. SFAS No. 144 also provides guidance that will eliminate inconsistencies in accounting for the impairment or disposal of long-lived assets under existing accounting pronouncements. The new rule retains many of the fundamental recognition and measurement provisions provided for in SFAS No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of*, but significantly changes the criteria for classifying an asset as held for sale. We do not expect the adoption of SFAS No. 144 to have an impact on our financial statements.

The FASB issued Statement No. 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections,* on April 30, 2002. Statement No. 145 rescinds Statement No. 4, which required all gains and losses from extinguishments of debt to be aggregated and, if material, classified as an extraordinary item, net of related income tax effect. Upon adoption of Statement No. 145, companies will be required to apply the criteria in APB Opinion No. 30, *Reporting the Results of Operations reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions* in determining the classification of gains and losses resulting from the extinguishments of debt. Statement No. 145 is effective for fiscal years beginning after May 15, 2002. We have adopted SFAS No. 145 as of July 1, 2001 (see Note 11 of Notes to Consolidated Financial Statements).

In June 2002 the FASB issued SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*, which addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Issues Task Force (EITF) 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 No. 146 applies to costs associated with an exit activity that does not involve an entity newly acquired in a business combination or with a disposal activity covered by SFAS No. 144. A liability for a cost associated with an exit or disposal activity generally shall be recognized and measured initially at its fair value in the period in which the liability is incurred. In periods subsequent to initial measurement, changes to the liability shall be measured using the credit-adjusted risk-free rate that was used to measure the liability initially. We are required to adopt the provisions of SFAS No. 146 for exit or disposal activities initiated after December 31, 2002. In connection with our corporate relocation and transition, we accrued our expected lease abandonment costs and severance costs. It would appear that SFAS No. 146 would not permit the accrual of those expected costs in advance of those costs being incurred. Had SFAS No. 146 been in effect for the year ended June 30, 2002, we believe that approximately $3.1 million of accrued lease abandonment costs and approximately $0.7 million of accrued severance benefits would not have been recognized at June 30, 2002.

ITEM 7A. QUALITATIVE AND QUANTITATIVE DISCLOSURES ABOUT MARKET RISK

Risk Policies

We are exposed to market risk through changes in commodity prices and interest rates as discussed below. We have no foreign currency exchange risks. Risk management policies have been established by our Risk Management Committee (RMC) to monitor and control these market risks. Our RMC is comprised primarily of senior executives. Our RMC has responsibility for oversight with respect to all product risk management policies and our Audit Committee approves the financial exposure limits.

Commodity Risk

Our earnings, cash flow and liquidity may be affected by a variety of factors beyond our control, including the supply of, and demand for Products. Demand for Products depends on, among other factors, changes in domestic and foreign economies, weather conditions, domestic and foreign political affairs, production levels, the availability of imports, the marketing of competitive fuels and the extent of government regulation. As a result, Products experience price volatility, which directly impacts our revenues and net operating margins. Our net operating margins are not impacted as much by the absolute price of the commodities as they are by the impact that the absolute price has upon supply and demand and the related movement of Products.

We have developed risk management strategies to mitigate the risk associated with price volatility on our Product inventories. We believe these strategies are integral to our risk policies since Product inventories are required to effectively operate our Product supply, distribution and marketing operations and such inventories are expected to be purchased, sold and carried over extended periods of time in the ordinary course of business.

We mitigate exposure to commodity price fluctuations by maintaining a balanced position of future commitments for Product purchases and sales, either in the physical commodity market or the derivative commodity markets. Our strategies are intended to minimize the impact of Product prices volatility on profitability and generally involve the purchase and sale of exchange-traded, energy futures and options. To a lesser extent, we enter into energy swap agreements, such as crack spreads, when they better match specific price movements in our markets. These strategies are designed to minimize, on a short-term basis, our exposure to the risk of fluctuations in Product margins. The barrels of Products covered by such contracts vary and are closely managed and subject to internally established risk guidelines.

In connection with our Products supply, distribution and marketing operations, we engage in price risk management activities. Our price risk management activities are energy trading activities as defined by EITF 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities*. As such, the financial instruments utilized are marked to market in accordance with the guidance set forth in EITF 98-10. Under the mark-to-market method of accounting, forwards, swaps, options and other financial instruments with third parties are reflected at market value, net of future physical delivery related costs, and are shown as Unrealized gain or loss on energy services and risk management contracts in the accompanying consolidated balance sheets. Unrealized gains and losses from newly originated contracts, contract restructurings and the impact of price movements are included in net revenues. Changes in the assets and liabilities from price risk management activities result primarily from changes in the valuation of the portfolio of contracts, newly initiated transactions and the timing of settlement relative to the receipt of cash for certain contracts. The market prices used to value these transactions reflect management s best estimate considering various factors, including closing exchange and over-the-counter quotations, time value and volatility factors underlying the commitments. The values are adjusted to reflect the potential impact of liquidating our position in an orderly manner over a reasonable period of time under present market conditions.

For certain of our energy services contracts and contract locations, calculating fair value relies on a degree of estimation in calculating the basis (geographical location) differentials for deferred trading months and locations without an actively traded forward cash market. For these markets (in which we cannot secure a

Table of Contents

forward traded basis (geographical location) differential quote from a broker), our mark-to-market model estimates the basis (geographical location) differentials based on a rolling historical average. Currently, it is not practicable for us to estimate the effects on our financial condition, results of operations, or cash flows from an unfavorable change in basis (geographical location) differentials.

Contractual commitments are subject to risks relating to market value fluctuations, as well as counterparty credit and liquidity risk. We have established procedures to continually monitor these contracts in order to minimize credit risk, including the establishment and review of credit limits, margin requirements, master net out arrangements, letters of credit and other guarantees.

Interest Rate Risk

At June 30, 2002, we had outstanding $187.0 million under the New Facility. We are exposed to risk resulting from changes in interest rates as a result of the variable-rate debt associated with the New Facility. The interest rate is based on the lender s alternate base rate plus a spread, or LIBOR plus a spread, in effect at the time of the borrowings and is adjusted monthly, bi-monthly, quarterly or semi-annually. Based on the outstanding balance of our variable interest rate debt at June 30, 2002, our interest rate swap, and assuming market interest rates increase or decrease 100 basis points, the potential annual increase or decrease in interest expense is approximately $0.4 million.

In August 1999, we entered into two periodic knock-out swap agreements with money center banks to offset the exposure of an increase in variable interest rates on our debt. Each swap was for a notional value of $150 million and was for a term expiring in August 2003. The swaps settle monthly, contain a knockout level on the one-month LIBOR at or above 6.75%, and have a fixed interest rate of 5.48%. The swaps provide that we pay a fixed interest rate of 5.48% on $300 million notional amount in exchange for a variable rate based on LIBOR so long as the one-month LIBOR interest rate does not rise above 6.75%. If the one-month LIBOR rate rises above 6.75%, the swap knocks out and no payments are due under the agreements until such time as the one-month LIBOR rate declines below 6.75%. Prior to June 30, 2000, proceeds from the swap agreements were recorded as a reduction in interest expense, as the swaps were designated as hedges against the changes in interest rates.

As a result of the significant reduction in the variable rate debt during the fiscal year ended June 30, 2000 and with the adoption of SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*, and SFAS No. 138, *Accounting for Derivative Instruments and Certain Hedging Activities, an amendment of FASB Statement No. 133*, on June 30, 2000, the swaps were no longer designated as hedges. Any changes in the fair value of the interest rate swap are recognized immediately in earnings. As a result, at June 30, 2000, we recorded the fair value of the two swap agreements at $1.6 million in other assets, and a corresponding unrealized gain of $1.6 million. In August 2000, we settled one of the swap agreements, recognizing no gain or loss on the settlement. As of June 30, 2002, the fair market value of the remaining swap agreement is a liability of $5.4 million, which is recorded in accrued liabilities. For the years ended June 30, 2002 and 2001, we recorded an unrealized (non-cash) loss on the interest rate swap of $2.3 million and $3.6 million, respectively. For the years ended June 30, 2002, 2001 and 2000, we made (received) net payments of $4.6 million, $(0.7) million, and $(1.0) million, respectively, on the interest rate swap that are included in interest expense (income).

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The following consolidated financial statements should be read in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations.

Table of Contents

Independent Auditors Report

The Board of Directors and Stockholders
TransMontaigne Inc.:

We have audited the accompanying consolidated balance sheets of TransMontaigne Inc. and subsidiaries as of June 30, 2002 and 2001, and the related consolidated statements of operations, preferred stock and common stockholders equity, and cash flows for each of the years in the three-year period ended June 30, 2002. These consolidated financial statements are the responsibility of TransMontaigne 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 of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of TransMontaigne Inc. and subsidiaries as of June 30, 2002 and 2001, and the results of their operations and their cash flows for each of the years in the three-year period ended June 30, 2002, in conformity with accounting principles generally accepted in the United States of America.

Denver, Colorado
September 13, 2002

Table of Contents

TRANSMONTAIGNE INC. AND SUBSIDIARIES

Consolidated Balance Sheets
(In thousands, except share amounts)

	June 30, 2002	June 30, 2001
Assets		
Current assets:		
Cash and cash equivalents	$ 30,852	9,346
Restricted cash held by commodity broker	4,577	7,984
Trade accounts receivable, net	173,736	79,050
Inventories discretionary volumes	175,169	96,988
Unrealized gains on energy services and risk management contracts	26,334	55,282
Receivable from sale of assets		29,033
Prepaid expenses and other	2,598	4,130
	413,266	281,813
Property, plant and equipment, net	251,431	304,232
Inventories minimum volumes	45,298	58,261
Unrealized gains on energy services and risk management contracts	13,969	9,875
Investments in petroleum related assets	10,131	47,760
Deferred tax assets	7,882	12,944
Deferred debt issuance costs, net	2,729	4,667
Other assets	4,263	2,977
	$ 748,969	722,529
Liabilities, Preferred Stock, and Common Stockholders Equity		
Current liabilities:		
Commodity margin loan	$ 11,312	20,000
Trade accounts payable	103,314	72,170
Unrealized losses on energy services and risk management contracts	22,163	32,822
Inventory due under exchange agreements, net	16,908	76,754
Excise taxes payable	72,045	32,025
Other accrued liabilities	25,308	14,170
	251,050	247,941
Other liabilities:		
Long-term debt	187,000	130,000
Unrealized losses on energy services and risk management contracts	209	2,213
Total liabilities	438,259	380,154
Preferred stock:		
Series A Convertible Preferred stock	24,421	174,825
Series B Redeemable Convertible Preferred stock	80,939	
	105,360	174,825
Common stockholders equity:		

Common stock	399	318
Capital in excess of par value	245,844	205,256
Deferred stock-based compensation	(2,540)	(2,465)
Accumulated deficit	(38,353)	(35,559)
	205,350	167,550
	$ 748,969	722,529

See accompanying notes to consolidated financial statements.

Table of Contents

TRANSMONTAIGNE INC. AND SUBSIDIARIES

Consolidated Statements of Operations
(In thousands, except per share amounts)

	Year ended June 30, 2002	Year ended June 30, 2001	Year ended June 30, 2000
Revenues:			
Product supply, distribution, and marketing, net	$ 68,747	46,318	18,853
Terminal and pipelines	63,386	82,305	78,522
Natural gas services			18,249
	132,133	128,623	115,624
Direct operating costs and expenses:			
Lower of cost or market write-downs on minimum inventory volumes	(12,963)	(18,318)	
Terminal and pipelines	(27,668)	(36,415)	(34,268)
Natural gas services			(7,759)
	(40,631)	(54,733)	(42,027)
Net operating margins	91,502	73,890	73,597
Costs and expenses:			
Selling, general and administrative	(35,211)	(34,072)	(41,680)
Depreciation and amortization	(16,556)	(19,510)	(22,344)
Impairment of long-lived assets			(50,136)
Corporate relocation and transition:			
Severance, transition, and relocation benefits	(2,138)		
Abandonment of office leases and leasehold improvements	(4,178)		
	(58,083)	(53,582)	(114,160)
Operating income (loss)	33,419	20,308	(40,563)
Other income (expenses):			
Dividend income from and equity in earnings of petroleum related investments	1,450	3,060	1,590
Interest income	599	2,914	3,419
Interest expense	(12,436)	(18,129)	(28,540)
Other financing costs:			
Early payment penalty on senior notes	(1,943)	(1,277)	(875)
Amortization of debt issuance costs	(1,744)	(3,499)	(3,770)
Write-off of debt issuance costs related to bank credit facility and senior notes	(2,987)	(3,885)	(3,855)
Unrealized gain (loss) on interest rate swap	(2,322)	(3,634)	1,560
Gain (loss) on disposition of assets, net	(13)	22,146	13,930
	(19,396)	(2,304)	(16,541)
Earnings (loss) before income taxes	14,023	18,004	(57,104)
Income tax benefit (expense)	(5,465)	(6,666)	19,167

Net earnings (loss)	$ 8,558	11,338	(37,937)

See accompanying notes to consolidated financial statements.

Table of Contents

TRANSMONTAIGNE INC. AND SUBSIDIARIES

Consolidated Statements of Operations (continued)
(In thousands, except per share amounts)

	Year ended June 30, 2002	Year ended June 30, 2001	Year ended June 30, 2000
Computation of earnings (loss) per share:			
Net earnings (loss)	$ 8,558	11,338	(37,937)
Preferred stock dividends	(11,351)	(8,963)	(8,506)
Net earnings (loss) attributable to common stockholders	$ (2,793)	2,375	(46,443)
Earnings (loss) per common share			
Basic	$ (0.09)	0.08	(1.52)
Diluted	$ (0.09)	0.08	(1.52)
Weighted average common shares outstanding:			
Basic	31,267	30,879	30,491
Diluted	31,267	31,003	30,491

See accompanying notes to consolidated financial statements.

47

Table of Contents

TRANSMONTAIGNE INC. AND SUBSIDIARIES

Consolidated Statements of Preferred Stock and Common Stockholders Equity
Years Ended June 30, 2002, 2001 and 2000
(In thousands)

	Preferred stock						
	Series A	Series B	Common stock	Capital in excess of par value	Deferred stock-based compensation	Retained earnings (accumulated deficit)	Total common stockholders equity
Balance at June 30, 1999	$ 170,115		$ 305	197,122		8,509	205,936
Common stock issued for options exercised				136			136
Net tax effect arising from stock-based compensation				(68)			(68)
Deferred compensation related to restricted stock awards			2	1,863	(1,865)		
Amortization of deferred stock-based compensation					400		400
Compensation expense related to extension of exercise period of options				2,022			2,022
Preferred stock dividends						(8,506)	(8,506)
Net loss						(37,937)	(37,937)
Balance at June 30, 2000	$ 170,115		$ 307	201,075	(1,465)	(37,934)	161,983
Common stock issued for options and warrants exercised			6	1,891			1,897
Net tax effect arising from stock-based compensation				(5)			(5)
Forfeiture of restricted stock awards prior to vesting				(135)	135		
Deferred compensation related to restricted stock awards			5	2,430	(2,435)		
Amortization of deferred stock-based compensation					1,300		1,300
Preferred stock dividends, including $4,710 paid-in-kind	4,710					(8,963)	(8,963)
Net earnings						11,338	11,338
Balance at June 30, 2001	$ 174,825		$ 318	205,256	(2,465)	(35,559)	167,550
Common stock issued for options exercised				151			151
Common stock repurchased from employees for withholding taxes				(112)			(112)
Net tax effect arising from stock-based compensation				(24)			(24)
Forfeiture of restricted stock awards prior to vesting			(1)	(501)	502		
Deferred compensation related to restricted stock awards			4	2,085	(2,089)		
Amortization of deferred stock-based compensation					1,512		1,512
Preferred stock dividends paid-in-kind	9,816					(9,816)	(9,816)
Recapitalization of Series A Convertible Preferred stock	(160,220)	80,939	119	59,394		(1,536)	57,977
Common stock repurchased and retired			(41)	(20,405)			(20,446)
Net earnings						8,558	8,558
Balance at June 30, 2002	$ 24,421	80,939	$ 399	245,844	(2,540)	(38,353)	205,350

See accompanying notes to consolidated financial statements.

Table of Contents

TRANSMONTAIGNE INC. AND SUBSIDIARIES

Consolidated Statements of Cash Flows
(In thousands)

	Year ended June 30, 2002	Year ended June 30, 2001	Year ended June 30, 2000
Cash flows from operating activities:			
Net earnings (loss)	$ 8,558	11,338	(37,937)
Adjustments to reconcile net earnings (loss) to net cash provided (used) by operating activities:			
Depreciation and amortization	16,556	19,510	22,344
Equity in earnings of petroleum related investments		93	
Deferred tax expense (benefit)	5,062	6,224	(19,948)
Net tax effect arising from stock-based compensation	(24)	(5)	(68)
Loss (gain) on disposition of assets, net	13	(22,146)	(13,930)
Impairment of long-lived assets			50,136
Abandonment of office leases	3,110		
Abandonment of leasehold improvements	1,068		
Amortization of deferred stock-based compensation	1,512	1,300	400
Amortization of debt issuance costs	1,744	3,499	3,770
Write-off of debt issuance costs	2,987	3,885	3,855
Unrealized loss (gain) on interest rate swap	2,322	3,634	(1,560)
Net change in unrealized (gains)/losses on long-term energy services and risk management contracts	(6,098)	(7,663)	
Lower of cost or market write-downs on minimum inventory volumes	12,963	18,318	
Compensation expense related to extension of exercise period on options			2,022
Other	538		316
Changes in operating assets and liabilities, net of non-cash activities:			
Trade accounts receivable, net	(94,686)	38,689	56,383
Inventories discretionary volumes	(78,182)	67,302	127,891
Prepaid expenses and other	1,533	1,944	(1,719)
Trade accounts payable	31,144	(34,507)	(58,795)
Unrealized (gain)/loss on energy services and risk management contracts	18,289	(36,797)	32,783
Inventory due under exchange agreements, net	(59,845)	(48,504)	99,467
Excise taxes payable and other accrued liabilities	42,309	9,393	2,116
Net cash provided (used) by operating activities	(89,127)	35,507	267,526
Cash flows from investing activities:			
Purchases of property, plant and equipment	(15,809)	(11,542)	(61,264)
Proceeds from sale of assets	120,510	1,439	137,357
Decrease (increase) in restricted cash held by commodity broker	3,407	(7,984)	
Decrease (increase) in other assets	(1,286)	(882)	1,809
Net cash provided (used) by investing activities	106,822	(18,969)	77,902
Cash flows from financing activities:			
Net borrowings (repayments) of long-term debt	57,000	(76,995)	(290,677)
Net borrowings (repayments) of commodity margin loan	(8,688)	20,000	
Deferred debt issuance costs	(2,791)	(1,779)	(6,370)
Common stock issued for options and warrants exercised	151	1,897	136
Common stock repurchased from employees for withholding taxes	(112)		
Common stock repurchased and retired	(20,446)		
Cash paid to recapitalize preferred stock	(21,303)		
Preferred stock dividends paid in cash		(4,253)	(8,506)

Net cash provided (used) by financing activities	3,811	(61,130)	(305,417)
Increase (decrease) in cash and cash equivalents	21,506	(44,592)	40,011
Cash and cash equivalents at beginning of year	9,346	53,938	13,927
Cash and cash equivalents at end of year	$ 30,852	9,346	53,938

See accompanying notes to consolidated financial statements.

Table of Contents

TRANSMONTAIGNE INC. AND SUBSIDIARIES

Consolidated Statements of Cash Flows (continued)
(In thousands)

	Year ended June 30, 2002	Year ended June 30, 2001	Year ended June 30, 2000
Supplemental disclosures of cash flow information:			
Cash paid for income taxes	$ 600	700	200
Cash paid for interest expense	$ 12,240	19,731	26,542
Sale of Bear Paw on December 31, 1999:			
Assets disposed	$		(114,313)
Liabilities recorded			(250)
Interest income			(78)
Gain on disposition			(16,587)
Cash received from sale	$		131,228
Sale of Little Rock facilities on June 30, 2001:			
Proceeds receivable	$	29,033	
Assets disposed		(6,162)	
Liabilities recorded:			
Accrued environmental obligations		(700)	
Other		(25)	
Gain on disposition		(22,146)	
Cash received from sale	$ 29,033		
Sale of West Shore shares on July 27, 2001 and October 29, 2001:			
Investment in West Shore	$ (35,952)		
Loss on disposition	9,896		
Cash received from sale	$ 26,056		
Sale of NORCO system on July 31, 2001:			
Assets disposed	$ (49,733)		
Liabilities recorded upon sale:			
Accrued environmental obligations	(2,000)		
Accrued indemnities	(1,300)		
Other	(116)		
Gain on disposition	(8,601)		
Cash received from sale	$ 61,750		
Sale of ST Oil Company on May 31, 2002:			
Investment in ST Oil Company	$ (1,677)		
Gain on disposition	(1,363)		

Cash received from sale	$ 3,040		
Other cash sales cash received from sales of other assets	$ 631	1,439	6,129
Total cash received from sales of assets	$ 120,510	1,439	137,357

See accompanying notes to consolidated financial statements.

Table of Contents

TRANSMONTAIGNE INC. AND SUBSIDIARIES

Notes to Consolidated Financial Statements
Years ended June 30, 2002, 2001 and 2000

(1) Summary of Significant Accounting Policies

Principles of Consolidation and Use of Estimates

Our accounting and financial reporting policies conform to accounting principles and practices generally accepted in the United States of America. The accompanying consolidated financial statements include the accounts of TransMontaigne Inc. and its majority-owned subsidiaries. All significant intercompany accounts and transactions have been eliminated in consolidation.

The preparation of financial statements in conformity with generally accepted accounting principles requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Changes in these estimates and assumptions will occur as a result of the passage of time and the occurrence of future events. Actual results could differ from these estimates.

Nature of Business and Basis of Presentation

TransMontaigne Inc., a Delaware corporation (TransMontaigne), was formed in 1995 to create an independent petroleum products merchant based in Denver, Colorado. We are a holding company that conducts operations primarily in the Mid-Continent, Gulf Coast, Southeast, Mid-Atlantic and Northeast regions of the United States. We provide a broad range of integrated supply, distribution, marketing, terminal storage, and transportation services to refiners, distributors, marketers, and industrial/commercial end-users of refined petroleum products (e.g., gasoline, diesel fuel, and heating oil), chemicals, crude oil and other bulk liquids (collectively referred to as Product).

Our commercial operations currently are divided into two main areas: (i) Product supply, distribution, and marketing, and (ii) terminals and pipelines.

Accounting for Product Supply, Distribution, and Marketing Operations

Our Product supply, distribution, and marketing operations include energy trading and risk management activities. Our energy trading and risk management activities are marked to market (i.e., recorded at fair value in the accompanying consolidated balance sheet) in accordance with Emerging Issues Task Force Issue No. 98-10 (EITF 98-10), *Accounting for Contracts Involved in Energy Trading and Risk Management Activities*. The mark-to-market method of accounting requires that the effect of changes in the fair value of our energy trading and risk management activities be recognized as assets and liabilities and included in net revenues attributable to Product supply, distribution, and marketing in the period of the change in value.

The consensus on EITF 98-10 previously permitted revenues from energy trading and risk management activities to be presented on the face of the statement of operations on either a gross or net basis. We previously elected to present revenues from our Product supply, distribution, and marketing operations on a gross basis with a separate line item entitled Product costs in the costs and expenses section of the accompanying consolidated statements of operations. Product costs represent the cost of the Products sold, settlement of risk management contracts, transportation, storage, terminaling costs, and commissions. At its June 2002 meeting, the EITF amended its consensus on EITF 98-10 to require that revenues from energy trading and risk management activities be reported on a net basis (i.e., product costs are required to be netted directly against gross revenues to arrive at net revenues). That amended guidance is effective for

Table of Contents

TRANSMONTAIGNE INC. AND SUBSIDIARIES

Notes To Consolidated Financial Statements (Continued)
Years ended June 30, 2002, 2001 and 2000

financial statements issued for periods ending after July 15, 2002. Nevertheless, we have chosen to adopt early that amended guidance for all periods presented. Therefore, for the year ended June 30, 2002 and all prior periods, we have presented revenues from our Product supply, distribution and marketing operation on a net basis in the accompanying consolidated statements of operations. Net earnings (loss) have not been affected by this change in presentation. Net revenues attributable to our Product supply, distribution, and marketing operations are as follows (in thousands):

	Years ended June 30,		
	2002	2001	2000
Gross revenues	$ 5,967,508	5,140,833	4,953,707
Less cost of revenues	(5,898,761)	(5,094,515)	(4,934,854)
Net revenues	$ 68,747	46,318	18,853

The cash flow impact of these energy trading and risk management activities is reflected in cash flows from operating activities in the accompanying consolidated statements of cash flows.

We evaluate our market exposure, primarily commodity price risk, from an overall portfolio basis that considers both continuous movement of discretionary inventory volumes and related open positions in energy services and risk management contracts. Our inventories discretionary volumes are an integral component of our overall energy trading and risk management activities.

Energy Services Contracts. We enter into energy services contracts that require us to deliver physical quantities of Product over a specified term at a specified price. The pricing of the Product delivered under energy services contracts may be fixed at a stipulated price per gallon, or it may vary based on changes in published indices (e.g., Platt s Bulk and OPIS Wholesale).

Our energy services contracts are carried at fair value in the accompanying consolidated financial statements. The fair value of our energy services contracts is included in Unrealized gains or losses on energy services and risk management contracts in the accompanying consolidated balance sheet. Changes in the fair value of our energy services contracts are included in net revenues attributable to our Product supply, distribution and marketing operations.

The fair value of an energy services contract is based on a combination of published daily market prices and estimates based on historical market conditions. For market locations in which we have access to Product via our terminals, dedicated pipeline capacity, and/or a throughput/exchange arrangement, fair value is determined by adding the quoted near month New York Mercantile Exchange (NYMEX) futures quote to the appropriate basis (geographical location) differential and the transportation cost to deliver the Product from the bulk trading location to the contract s specified delivery location. We estimate the basis (geographical location) differentials for certain deferred trading months and city-specific locations because we cannot secure a forward traded basis (geographical location) differential quote from a broker. In those situations, our mark-to-market model estimates the basis (geographical locations) differentials based on a rolling historical average, which is updated quarterly.

For market locations in which we do not have access to Product via our terminals, dedicated pipeline capacity, and/or a throughput/exchange arrangement, we purchase Product on a spot basis from approved vendors to satisfy our contractual obligations. In these contracts, we are exposed to the differential between

Table of Contents

TRANSMONTAIGNE INC. AND SUBSIDIARIES

Notes To Consolidated Financial Statements (Continued)
Years ended June 30, 2002, 2001 and 2000

the bulk trading locations and the city-specific wholesale markets, as we do not control the pipeline and terminal capacity to facilitate shipment of the physical Product. Our mark-to-market model incorporates this basis (geographical location) differential to each city-specific location.

Risk Management Contracts. We enter into risk management contracts to minimize our exposure to changes in commodity prices. We evaluate our market risk exposure from an overall portfolio basis that considers changes in physical inventories discretionary volumes, open positions in energy services contracts, and open positions in risk management contracts. We enter into risk management contracts that offset the changes in the values of our inventories discretionary volumes and energy services contracts. At June 30, 2002, our open positions in risk management contracts include forward contracts (purchases and sales), swaps, and other financial instruments to manage market exposure, primarily commodity price risk.

Our risk management contracts are carried at fair value in the accompanying consolidated financial statements. The fair value of our risk management contracts is included in Unrealized gains or losses on energy services and risk management contracts in the accompanying consolidated balance sheet. Changes in the fair value of our risk management contracts are included in net revenues attributable to our Product supply, distribution and marketing operations. The fair value of our risk management contracts is based on quoted market prices. Forward contracts (purchases and sales) are valued using NYMEX quoted market prices.

We also enter into various swap agreements with our trading partners and price risk management customers that settle against a wide variety of wholesale and retail pricing indices. We utilize a combination of futures contracts and over-the-counter forward contracts to manage the commodity price risk associated with these contracts. Our methodology used to calculate a forward replacement cost for these instruments is consistent with the methodology used to value our forward physical cash commitments. We use a rolling historical average difference between the pricing index that the swap contract utilizes (e.g., Department of Energy National and OPIS-Wholesale indices) and the related NYMEX futures contract utilized to manage the commodity price risk associated with the commitment.

Inventories Discretionary Volumes. Our inventories discretionary volumes are held for sale or exchange in the ordinary course of business and consist of refined petroleum products, primarily gasoline and distillates. Our inventories discretionary volumes are carried at fair value in the accompanying consolidated financial statements. Changes in the fair value of our inventories discretionary volumes are included in net revenues attributable to our Product supply, distribution and marketing operations.

We maintain and hold for sale or exchange discretionary inventory that has different quality grades but is interchangeable within these grades (e.g., premium, mid-grade, and regular unleaded gasoline). Our refined petroleum products inventories are traded in futures markets, large fungible bulk markets (Pasadena, TX, New York Harbor, Chicago, IL, Tulsa, OK refining area, and Los Angeles, CA); and in city-specific wholesale markets. Quoted market prices (e.g., NYMEX, Platt s-Bulk, and OPIS-Wholesale) are readily available for these markets. The valuation of our inventories discretionary volumes is based on the nearest quoted market price, plus quoted basis (geographical location) differentials to the various bulk market areas, plus Federal Energy Regulatory Commission regulated transportation costs and industry recognized handling charges to city-specific wholesale markets. Near-term basis (geographical location) differentials are quoted and traded in the over-the-counter petroleum markets and are verified by the various cash brokers that facilitate trading. We estimate the basis (geographical location) differentials for certain deferred trading months and city-specific locations because we cannot secure a forward traded basis (geographical location) differential quote from a broker. In those situations, our mark-to-market model estimates the basis (geographical locations) differentials based on a rolling historical average, which is updated quarterly.

Table of Contents

TRANSMONTAIGNE INC. AND SUBSIDIARIES

Notes To Consolidated Financial Statements (Continued)
Years ended June 30, 2002, 2001 and 2000

We utilize this valuation methodology for all inventories discretionary volumes held by us in storage, along with any valuation of a related exchange imbalance with a trading partner. This methodology provides us a consistent means of valuing discretionary inventory volumes at a spot liquidation value and utilizes pricing components that are based on market prices and regulated pipeline tariffs.

Inventories Minimum Volumes. Our inventories minimum volumes are required to be held for operating balances in the conduct of our overall operating activities. We do not consider our inventories minimum volumes to be a component of our energy trading and risk management activities. We do not intend to sell or exchange these inventories in the ordinary course of business and, therefore, we do not hedge the market risks associated with this minimum inventory.

Our inventories minimum volumes are presented in the accompanying consolidated balance sheet as non-current assets and are carried at the lower of cost or market (replacement cost). The replacement cost of our inventories minimum volumes is based on the nearest quoted market price, plus quoted basis (geographical location) differentials to the various bulk market areas, plus Federal Energy Regulatory Commission regulated transportation costs and industry recognized handling charges to city-specific wholesale markets. Near-term basis (geographical location) differentials are quoted and traded in the over-the-counter petroleum markets and are easily verified by the various cash brokers that facilitate trading.

Prior to July 1, 2000, we carried our inventories minimum volumes at fair value because they were a component of our energy trading and risk management activities. Effective July 1, 2000, upon completion of a review of our inventory management strategies and customer contracts, we designated 2.0 million barrels of refined petroleum products as inventories minimum volumes and we changed our risk management strategy associated with this minimum inventory. In accordance with our revised risk management strategy, we removed the hedging contracts on the inventories minimum volumes prior to July 1, 2000.

Accounting for Terminal and Pipeline Activities

In connection with our terminal and pipeline operations, we utilize the accrual method of accounting for revenue and expenses. At our terminals and pipelines, we provide throughput, storage, and transportation related services to distributors, marketers, and industrial/commercial end-users of Products. Throughput revenue is recognized when the Product is delivered to the customer; storage revenue is recognized ratably over the term of the storage contract; transportation revenue is recognized when the Product has been delivered to the customer at the specified delivery location.

Cash and Cash Equivalents

We consider all short-term investments with a remaining maturity of three months or less at the date of purchase to be cash equivalents.

Restricted cash represents cash deposits held by our commodity broker to cover initial and variation margin requirements related to open NYMEX futures contracts.

Property, Plant and Equipment

Depreciation is computed using the straight-line and double-declining balance methods. Estimated useful lives are 20 to 25 years for plant, which includes buildings, storage tanks, and pipelines, and 3 to 20 years for equipment. All items of property, plant and equipment are carried at cost. Expenditures that

Table of Contents

TRANSMONTAIGNE INC. AND SUBSIDIARIES

Notes To Consolidated Financial Statements (Continued)
Years ended June 30, 2002, 2001 and 2000

increase capacity, or extend useful lives are capitalized. Routine repairs and maintenance are expensed. For the years ended June 30, 2002, 2001 and 2000, we incurred repairs and maintenance costs of approximately $7.7 million, $8.7 million, and $7.3 million, respectively. Computer software costs are capitalized and amortized over their useful lives, generally not to exceed 5 years. The costs of installing certain enterprise wide information systems are amortized over periods not exceeding 10 years.

We evaluate long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable based on expected undiscounted cash flows attributable to that asset. If an asset is impaired, the impairment loss to be recognized is the excess of the carrying amount of the asset over its estimated fair value (see Note 9 of Notes to Consolidated Financial Statements).

Deferred Debt Issuance Costs

Deferred debt issuance costs are amortized using the interest method over the term of the underlying debt instrument.

Environmental Obligations

We accrue for environmental costs that relate to existing conditions caused by past operations when estimable. Environmental costs include initial site surveys and environmental studies of potentially contaminated sites, costs for remediation and restoration of sites determined to be contaminated and ongoing monitoring costs, as well as fines, damages and other costs, including direct internal and legal costs. Liabilities for environmental costs at a specific site are initially recorded when it is probable that we will be liable for such costs, and a reasonable estimate of the associated costs can be made based on available information. Such an estimate includes our share of the liability for each specific site and the sharing of the amounts related to each site that will not be paid by other potentially responsible parties, based on enacted laws and adopted/regulations and policies. Adjustments to initial estimates are recorded, from time to time, to reflect changing circumstances and estimates based upon additional information developed in subsequent periods. Estimates of our ultimate liabilities associated with environmental costs are particularly difficult to make with certainty due to the number of variables involved, including the early stage of investigation at certain sites, the lengthy time frames required to complete remediation, technology changes, alternatives available and the evolving nature of environmental laws and regulations. At June 30, 2002 and 2001, we had accrued environmental reserves of approximately $2.3 million and $0.7 million, respectively, representing our best estimate of our remediation obligations (see Note 11 of Notes to Consolidated Financial Statements). During the year ended June 30, 2002, we made payments of approximately $0.4 million towards our remediation obligations.

Income Taxes

We utilize the asset and liability method of accounting for income taxes. Under this method, 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. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply in the years in which these temporary differences are expected to be recovered or settled. Changes in tax rates are recognized in income in the period that includes the enactment date.

Equity-Based Compensation Plans

We account for our employee stock option plans and restricted stock awards using the intrinsic value method pursuant to APB Opinion No. 25. We recognize deferred compensation on the date of grant if the

TRANSMONTAIGNE INC. AND SUBSIDIARIES

Notes To Consolidated Financial Statements (Continued)
Years ended June 30, 2002, 2001 and 2000

quoted market price of the underlying common stock exceeds the exercise price (zero exercise price in the case of an award of restricted common stock). Deferred compensation is amortized to income over the related vesting period on an accelerated basis pursuant to FASB Interpretation No. 28.

Earnings (Loss) Per Common Share

Basic earnings (loss) per common share is calculated based on the weighted average number of common shares outstanding during the period, excluding restricted common stock subject to continuing vesting requirements. Diluted earnings (loss) per share is calculated based on the weighted average number of common shares outstanding during the period and, when dilutive, potential common shares from the exercise of stock options and warrants to purchase common stock and restricted common stock subject to continuing vesting requirements pursuant to the treasury stock method. Diluted earnings (loss) per share also gives effect, when dilutive, to the conversion of the preferred stock pursuant to the if-converted method.

Reclassifications

Certain amounts in the prior years have been reclassified to conform to the current year s presentation. We have classified inventories minimum volumes as a non-current asset in the accompanying consolidated balance sheet (see Note 7 of Notes to Consolidated Financial Statements). We also have presented separately the current and non-current unrealized gains/losses on open energy services and risk management contracts in the accompanying consolidated balance sheet (see Note 5 of Notes to Consolidated Financial Statements). At June 30, 2001, we presented our commodity margin loan (see Note 12 of Notes to Consolidated Financial Statements) as an offset to cash and cash equivalents and we presented our preferred stock as a component of stockholders equity (see Note 14 of Notes to Consolidated Financial Statements) in the accompanying consolidated balance sheet. Net earnings (loss) have not been affected by these reclassifications.

(2) Dispositions of Terminals and Pipelines

On July 31, 2001, we sold the NORCO Pipeline system and related terminals (NORCO) for cash consideration of approximately $62.0 million and recognized a net gain of approximately $8.6 million on the sale. For the year ended June 30, 2001, we recognized net revenues of approximately $8.6 million, direct operating costs and expenses of approximately $3.3 million, and depreciation and amortization expense of approximately $3.0 million related to the operations of the NORCO system.

Effective June 30, 2001, we sold two petroleum distribution facilities in Little Rock, Arkansas for $29.0 million. The cash proceeds from the sales transactions were received on July 3, 2001. We recognized a net gain in June 2001 of approximately $22.1 million on the sale. For the year ended June 30, 2001, we recognized net revenues of approximately $4.7 million, direct operating costs and expenses of approximately $0.9 million, and depreciation and amortization expense of approximately $0.4 million.

Effective December 31, 1999, we sold our natural gas gathering subsidiary, Bear Paw Energy Inc. (BPEI), for cash consideration of $131.2 million and recognized a net gain of approximately $16.6 million on the sale.

(3) Acquisitions of Terminals and Pipelines

Effective June 30, 2002, we acquired for cash consideration of approximately $7.2 million the remaining 40% interest that we previously did not own in the Razorback Pipeline system (Razorback), a

Table of Contents

TRANSMONTAIGNE INC. AND SUBSIDIARIES

Notes To Consolidated Financial Statements (Continued)
Years ended June 30, 2002, 2001 and 2000

67 mile petroleum products pipeline between Mount Vernon, Missouri and Rogers, Arkansas with approximately .4 million barrels of storage capacity.

On May 31, 2000, we acquired two Products terminals located in Richmond and Montvale, Virginia for cash consideration of approximately $3.2 million. These facilities are interconnected to the Colonial and Plantation pipeline systems and include approximately 0.5 million barrels of storage capacity.

We accounted for these acquisitions using the purchase method of accounting as of the effective date of each transaction. Accordingly, the purchase price of each transaction was allocated to the assets and liabilities acquired based upon the estimated fair value of those assets and liabilities as of the acquisition date. The purchase price was allocated as follows (in thousands):

	Razorback	Virginia terminals
Prepaid expenses and other current assets	$ 2	
Property, plant and equipment	7,188	3,234
Other accrued liabilities assumed	(75)	
Cash paid, net of cash acquired of $85 and $0, respectively	$ 7,115	3,234

The proforma combined results of operations including Razorback as if the acquisition of Razorback had occurred on July 1, 2001 would not have been materially different from the results of operations reported in the accompanying consolidated statements of operations.

(4) Inventories Discretionary Volumes

Inventories discretionary volumes are as follows (in thousands):

	June 30, 2002	June 30, 2001
Products held for sale or exchange	$ 158,261	20,234
Products due under exchange agreements, net	16,908	76,754
Inventories discretionary volumes	$ 175,169	96,988

Our inventories discretionary volumes are held for sale or exchange in the ordinary course of business and consist of Products, primarily gasolines and distillates. Our inventories discretionary volumes are presented in the accompanying consolidated balance sheet as current assets and are carried at fair value. Changes in the fair value of our inventories discretionary volumes are included in net revenues attributable to our Product supply, distribution and marketing segment. Products due under exchange agreements represent physical Products in our possession that we owe to counterparties pursuant to an exchange agreement in which we exchange Product in a specified delivery location for Product in a different delivery location.

Our inventories discretionary volumes are an integral component of our overall energy trading and risk management activities. We manage inventories discretionary volumes in combination with energy services and risk management contracts by utilizing risk and portfolio management disciplines, including certain hedging strategies, forward purchases and sales, swaps and other financial instruments to manage market exposure, primarily commodity price risk (see Note 5 of Notes to Consolidated Financial

Table of Contents

TRANSMONTAIGNE INC. AND SUBSIDIARIES

Notes To Consolidated Financial Statements (Continued)
Years ended June 30, 2002, 2001 and 2000

Statements). At June 30, 2002 and 2001, we held for sale or exchange approximately 5.2 million and .5 million barrels of discretionary inventory, net of .5 million and 2.8 million barrels due under exchange agreements, at a weighted average value of approximately $0.72 and $1.03 per gallon, respectively.

(5) Unrealized Gains/Losses on Energy Services and Risk Management Contracts, Net

Unrealized gains and losses on energy services and risk management contracts are as follows (in thousands):

	June 30, 2002	June 30, 2001
Unrealized gains current	$ 26,334	55,282
Unrealized gains long-term	13,969	9,875
Unrealized gains asset	40,303	65,157
Unrealized losses current	(22,163)	(32,822)
Unrealized losses long-term	(209)	(2,213)
Unrealized losses liability	(22,372)	(35,035)
Net asset position	$ 17,931	30,122

Our energy services contracts are primarily sales commitments to industrial/commercial end users, logistical service contracts, and basis (geographical) differentials versus published indices (referred to as swaps). These commitments provide our customers both price risk management and real time inventory management solutions via our web-based information systems.

Our risk management contracts include forward purchases and sales, swaps, and other financial instruments to offset market exposure, primarily commodity price risk, on our energy trading contracts and inventories discretionary volumes. In managing market risks on these contracts and inventories, we evaluate the market exposure from an overall portfolio basis that considers both the open position in the energy services contracts and the related movement of certain physical inventory balances (see Note 4 of Notes to Consolidated Financial Statements).

(6) Property, Plant and Equipment, net

Property, plant and equipment, net is as follows (in thousands):

	June 30, 2002	June 30, 2001
Land	$ 14,125	15,181
Terminals, pipelines, and equipment	277,393	320,127
Technology and equipment	12,658	12,654
Furniture, fixtures, and equipment	5,732	6,703
Construction in progress	2,444	3,592
	312,352	358,257
Less accumulated depreciation	(60,921)	(54,025)
	$ 251,431	304,232

58

Table of Contents

(7) Inventories Minimum Volumes

Inventories minimum volumes are as follows (in thousands):

	June 30, 2002	June 30, 2001
Products:		
At original cost basis	$ 76,579	76,579
Adjustment for write-downs to lower of cost or market	(31,281)	(18,318)
Inventories minimum volumes	$ 45,298	58,261

Our inventories minimum volumes are required to be held for operating balances in the conduct of our overall operating activities. We do not consider our inventories minimum volumes to be a component of our energy trading and risk management activities. We do not intend to sell or exchange these inventories in the ordinary course of business and, therefore, we do not hedge the market risks associated with this minimum inventory. Our inventories minimum volumes are presented in the accompanying consolidated balance sheet as non-current assets and are carried at the lower of cost or market. During the year ended June 30, 2002 and 2001, we recognized impairment losses of approximately $13.0 million and $18.3 million, respectively, due to lower of cost or market write-downs on this minimum inventory. These write-downs are included in net revenues attributable to our Product supply, distribution, and marketing operations. At June 30, 2002 and 2001, the weighted average adjusted cost basis of our inventories minimum volumes was $0.54 and $0.69 per gallon, respectively.

Prior to July 1, 2000, we carried our inventories minimum volumes at fair value because they were a component of our energy trading and risk management activities. Effective July 1, 2000, upon completion of a review of our inventory management strategies and customer contracts, we designated 2.0 million barrels of Products as inventories minimum volumes and we changed our risk management strategy associated with this minimum inventory. In accordance with our revised risk management strategy, we removed the hedging contracts on the inventories minimum volumes prior to July 1, 2000.

(8) Investments in Petroleum Related Assets

Investments in petroleum related assets are as follows (in thousands):

	June 30, 2002	June 30, 2001
Lion Oil Company	$ 10,131	10,131
ST Oil Company		