IVANHOE ENERGY INC
Form 10-K
March 10, 2005

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

FORM 10-K

(Mark One)

þ **Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. For the fiscal year ended December 31, 2004.**

or

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

Commission file number 000-30586

IVANHOE ENERGY INC.
(Exact name of registrant as specified in its charter)

Yukon, Canada
(State or other jurisdiction of incorporation or organization)

98- 0372413
(I.R.S. Employer Identification No.)

654 999 Canada Place
Vancouver, British Columbia, Canada
V6C 3E1
(Address of principal executive offices)

(604) 688-8323
(Registrant s telephone number, including area code)

Securities to be registered pursuant to Section 12(b) of the Act: None

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

Title of each class	**Name of each exchange on which registered**
Common Shares, no par value	Toronto Stock Exchange NASDAQ SmallCap Market

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) 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 reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes þ No o

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. þ

Indicate by check mark whether the registrant is an accelerated filer as defined in Rule 12b-2 of the Act.

Yes þ No o

As at February 25, 2005, 169,892,413 common shares of the Registrant were issued and outstanding. The aggregate market value of the voting stock held by non-affiliates of the Registrant on June 30, 2004 based on the closing price on the NASDAQ SmallCap Market on that date, was $369,335,406.

Documents incorporated by reference: None

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CURRENCY AND EXCHANGE RATES

Unless otherwise specified, all reference to **dollars** or to **$** are to U.S. dollars and all references to **Cdn.$** are to Canadian dollars. The closing, low, high and average noon buying rates in New York for cable transfers for the conversion of Canadian dollars into U.S. dollars for each of the five years ended December 31 as reported by the Federal Reserve Bank of New York were as follows:

	2004	2003	2002	2001	2000
Closing	$ 0.83	$ 0.77	$ 0.63	$ 0.63	$ 0.67
Low	$ 0.72	$ 0.63	$ 0.62	$ 0.62	$ 0.64
High	$ 0.85	$ 0.77	$ 0.66	$ 0.67	$ 0.70
Average Noon	$ 0.77	$ 0.71	$ 0.63	$ 0.65	$ 0.67

The average noon rate of exchange reported by the Federal Reserve Bank of New York for conversion of U.S. dollars into Canadian dollars on February 25, 2005 was $ 0.81 ($1.00 = Cdn.$1.24).

ABBREVIATIONS

As generally used in the oil and gas business and in this Annual Report on Form 10-K, the following terms have the following meanings:

Boe	= barrel of oil equivalent
Bbl	= barrel
MBbl	= thousand barrels
MMBbl	= million barrels
Bopd	= barrels of oil per day
Bbls/d	= barrels per day
Boe/d	= barrels of oil equivalent per day
Mboe/d	= thousands of barrels of oil equivalent per day
MBbls/d	= thousand barrels per day
MMBls/d	= million barrels per day
MMBtu	= million British thermal units
Mcf	= thousand cubic feet
MMcf	= million cubic feet
Mcf/d	= thousand cubic feet per day
MMcf/d	= million cubic feet per day

When we refer to oil in **equivalents** , we are doing so to compare quantities of oil with quantities of gas or to express these different commodities in a common unit. In calculating Bbl equivalents, we use a generally recognized industry standard in which one Bbl is equal to six Mcf. Boes may be misleading, particularly if used in isolation. The conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this document are forward-looking statements within the meaning of the United States Private Securities Litigation Reform Act of 1995, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. Such forward-looking statements involve known and unknown risks, uncertainties and other factors which may cause our actual results, performance or achievements, or other future events, to be materially different from any future results, performance or achievements or other events expressly or implicitly predicted by such forward-looking statements. Such risks, uncertainties and other factors include, but are not limited to, our short history of limited revenue, losses and negative cash flow from our current exploration and development operations in the U.S. and China; our limited cash resources and consequent need for additional financing; our ability to raise additional financing; future benefits to be derived from the proposed acquisition of Ensyn Group, Inc. (**Ensyn**); conditions to completing the Ensyn acquisition and timetable for completion and other matters; uncertainties regarding the potential success of our oil and gas exploration and development properties in the U.S. and China; uncertainties regarding the potential success of heavy-to light oil upgrading and gas-to-liquids technologies; oil price volatility; oil and gas industry operational hazards and environmental concerns; government regulation and requirements for permits and licenses, particularly in the foreign jurisdictions in which we carry on business; title matters; risks associated with carrying on business in foreign jurisdictions; conflicts of interests; competition for a limited number of promising oil and gas exploration properties from larger more well financed oil and gas companies; and other statements contained herein regarding matters that are not historical facts. Forward-looking statements can often be identified by the use of forward-looking terminology such as may , will , expect , intend , estimate , anticipate , believe or continue or the negative thereof or va or similar terminology. We believe that any forward-looking statements made are reasonable based on information available to us on the date such statements were made. However, no assurance can be given as to future results, levels of activity and achievements. We undertake no obligation to update publicly or revise any forward-looking statements contained in this report. All subsequent forward-looking statements, whether written or oral, attributable to us, or persons acting on our behalf, are expressly qualified in their entirety by these cautionary statements.

ENFORCEABILITY OF CIVIL LIABILITIES

We were organized under the laws of Canada and our executive offices are located in British Columbia, Canada. Some of our directors, controlling persons and officers and representatives of the experts named in this Annual Report on Form 10-K reside outside the U.S. and a substantial portion of their assets and our assets are located outside the U.S. As a result, it may be difficult for you to effect service of process within the U.S. upon the directors, controlling persons, officers and representatives of experts who are not residents of the U.S. or to enforce against them judgments obtained in the courts of the U.S. based upon the civil liability provisions of the federal securities laws or other laws of the U.S. There is doubt as to the enforceability in Canada against us or against any of our directors, controlling persons, officers or experts who are not residents of the U.S., in original actions or in actions for enforcement of judgments of U.S. courts, of liabilities based solely upon civil liability provisions of the U.S. federal securities laws. Therefore, it may not be possible to enforce those actions against us, our directors, officers, controlling persons or experts named in this Annual Report on Form 10-K.

AVAILABLE INFORMATION

Copies of our annual reports on Form 10-K, our quarterly reports on Form 10-Q, our current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available free of charge on or through our website at http://www.ivanhoe-energy.com/or through the Securities and Exchange Commission s website at http://www.sec.gov/.

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

CORPORATE OVERVIEW

We are an international energy company engaged in the exploration for and production of oil and gas, enhanced oil recovery and natural gas projects and the application of heavy-to-light (**HTL**) oil upgrading and gas-to-liquids (**GTL**) technologies. Our core operations are in the United States and China, with business development opportunities worldwide.

We were incorporated pursuant to the laws of the Yukon, Canada, on February 21, 1995 under the name 888 China Holdings Limited. On June 3, 1996, we changed our name to Black Sea Energy Ltd., and on June 24, 1999, we changed our name to Ivanhoe Energy Inc.

Our authorized capital consists of an unlimited number of common shares without par value and an unlimited number of preferred shares without par value.

Our principal executive office is located at Suite 654 999 Canada Place, Vancouver, British Columbia, V6C 3E1, and our registered and records office is located at 300-204 Black Street, Whitehorse, Yukon, Y1A 2M9. Our headquarters for operations is located at Suite 400 5060 California Avenue, Bakersfield, California, 93309.

HISTORICAL OVERVIEW

We were incorporated in 1995 and, in 1996, established a series of joint ventures in Russia with local partners to enhance oil recovery from certain Russian oil and gas properties on which past field development practices had not maximized reserve recoveries. However, after successfully increasing oil production and reserves at the Kalchinskoye field in western Siberia, a dispute with our partner arose in 1998, which effectively prevented us from continuing to participate in the project. Although the dispute was settled in 2000, our management had already decided to terminate our business activities in Russia and implement a diversification program aimed at expanding the geographical scope of our business.

During 1998, we accumulated working interests and royalty interests in the San Joaquin Basin of California, primarily through an exploration agreement with Aera Energy LLC (**Aera**). This agreement entitled us to joint exploration rights with Aera in return for analyzing and identifying oil and gas prospects on properties owned by Aera in the San Joaquin Basin of southern California.

In June 1999, we expanded the geographical scope of our business by acquiring Sunwing Energy Ltd. (**Sunwing**), an oil and gas company with operations in China. As a result of our acquisition of Sunwing, we acquired two production-sharing contracts with China National Petroleum Corporation (**CNPC**) to develop and operate the Kongnan oilfield in Dagang, located in Hebei Province and the Zhaozhou oilfield in Daqing located in Heilongjiang Province. We subsequently disposed of our interest in the Daqing field but retained a royalty. In April 2003, we received approval of our Overall Development Program (**ODP**) for the Dagang field and in September 2003 we commenced drilling. We signed a farm-out agreement with China International Trust & Investment Corporation (**CITIC**) for 40% of the Dagang field. This farm-out agreement provides that the parties will jointly develop the field, with Sunwing as the operator.

In April 2000, we acquired a limited volume license and, subsequently, a master license from Syntroleum Corporation (**Syntroleum**) to use its proprietary GTL technology to convert natural gas into synthetic fuels. The master license allows us to use Syntroleum s proprietary process in an unlimited number of GTL projects throughout the world to convert natural gas into an unlimited volume of ultra clean transportation fuels and other synthetic petroleum products (**Site License**). We plan to use the technology in areas with large natural gas deposits, which would otherwise be uneconomic to develop. Our master license expires on the latter of April 2015 or five years from the effective date of the last Site License issued to us by Syntroleum.

During 2000 and 2001, we expanded into Texas by earning working interests in oil and gas exploration properties in the Spraberry Trend of the West Texas Permian Basin and leasing mineral rights in the East Texas Basin. In 2001, we entered into a joint venture agreement with a subsidiary of Unocal Corp. (**Unocal**) to explore and develop prospects in the Bossier Trend of the East Texas Basin. We subsequently farmed-out our interests in three wells drilled by Unocal and currently have mineral rights in approximately 7,400 gross acres.

In February 2001, we extended our China interests. We entered into two memoranda of understanding with PetroChina Corporation (**PetroChina**), a subsidiary of CNPC, which gave us the exclusive right to negotiate production-sharing contracts for the development of oil and gas reserves in three blocks in the Sichuan Basin. In September 2002, we signed a 30-year production-sharing contract with CNPC for two of these blocks covering approximately 900,000 acres, which were combined into one Zitong block. In October 2003, we initiated the first phase of the exploration program in the Zitong block. We have the right to negotiate a production-sharing contract for the third block, the one-million-acre Yudong Block, located on the eastern edge of the Sichuan Basin.

In December 2002, we formed a wholly owned subsidiary, GTL Japan Corporation (**GTLJ**) to facilitate the participation of Japanese companies in GTL projects and in November 2004 changed the name to Energy Resources Development Japan Corporation (**ERDJ**) and expanded the charter of the company to include participation of multi-national companies in enhanced oil recovery (**EOR**) projects, including those involving HTL oil upgrading.

In January 2004, we finalized an agreement with Derek Resources (USA), Inc. (**Derek**) to jointly develop the LAK Ranch field, a steam assisted gravity drainage (**SAGD**) project covering approximately 7,300 gross acres in the Powder River basin in Weston County, Wyoming.

In January 2004, we entered into a stock purchase and shareholders agreement with Ensyn and its subsidiary, Ensyn Petroleum International Limited (**EPIL**) pursuant to which we acquired a 10% equity interest in EPIL for $2.0 million and certain rights to use their proprietary rapid thermal processing technology (**RTP Technology**). We subsequently increased our equity interest in EPIL to 15% in consideration of a cash payment to EPIL of $1.0 million.

In December 2004, we signed a definitive merger agreement to acquire Ensyn for $85 million. We agreed to pay $10 million in cash and to issue common shares valued at $75 million based on a weighted, 10-day average of our closing share price on the NASDAQ SmallCap Market determined prior to the closing of the acquisition (subject to a minimum issuance of 30 million shares), in exchange for all of the issued and outstanding shares of Ensyn common shares and the rights of holders of purchase warrants to acquire shares of Ensyn common shares that remain unexercised immediately after the effective time of the merger. We currently expect the merger with Ensyn to be completed early in the second quarter of 2005. Prior to the closing of the transaction, Ensyn will be required to satisfy our defined performance criteria for their California Commercial Demonstration Facility (**CDF**).

In December 2004, we purchased the remaining working interest in seven wells, either producing or capable of producing, that we did not already own in the Knights Landing field in the Sacramento Gas Basin of northern California and an 80% working interest in four additional producing wells in which we did not previously hold an interest. The purchase includes mineral leases on 13,000 gross acres surrounding the producing wells. We originally farmed into this field in February 2004 for a 50% working interest after pay out.

CORPORATE STRATEGY

Our objective is to create shareholder value by finding and developing oil and gas reserves through the implementation of three main strategies: (1) conventional exploration and production (**E&P**) of oil and gas, primarily in the U.S. and China, (2) EOR development projects, and (3) monetization of stranded oil and gas reserves through the application of the Ensyn RTP™ Technology and the technology licensed from Syntroleum. In pursuing these three business development areas, we are focused on achieving a balance in our short, medium and long-term goals. In the short term, we are focused on E&P and EOR projects that can be implemented and achieve early production and cash flow. Our medium term strategy is to continue exploration and development of our significant mineral interest holdings in California, Wyoming and China and develop opportunities for the Ensyn RTP ™ Technology in the oil sector. Our long-term priority is on GTL production of ultra clean fuels and specialty petroleum products. We have advanced each of these objectives during the past year and our projects continue to mature.

Our short-term objective is to focus on exploiting our existing mineral interest holdings and identifying new opportunities where production can be achieved quickly and efficiently to create cash flow to fund our operations and allow us to pursue our medium and long-term objectives. To date, we have established oil and natural gas production in the South Midway and Citrus properties in the San Joaquin Basin, in the Knights Landing field in the Sacramento Gas Basin, in the Spraberry Trend of the West Texas Permian Basin and at the Dagang field in China. Over the next twelve months, we plan to drill more than thirty development wells on our current producing properties, six exploration wells in East Texas and non-Aera properties in California and also initiate a completion and testing program of our Northwest Lost Hills # 1-22 well, which is our deep gas play in the San Joaquin Basin.

One of the key elements of our medium-term strategy is continued exploration and development in the San Joaquin Basin. In 1998, we acquired exploration rights through an agreement with Aera, California s largest producer. This agreement gave us access to Aera s inventory of exploration, seismic and technical data for the purpose of identifying drillable prospects, primarily beneath or adjacent to existing oil fields in the San Joaquin Basin. Nine identified drillable prospects, in which Aera has agreed to participate, have yet to be explored. The LAK Ranch field is also a key element of our medium-term strategy. After completion of an ultra-high resolution 3-D seismic survey and interpretation in the first half of 2005, we plan to drill additional delineation wells to prove up oil-in-place reserves and commerciality of a full steam injection SAGD project.

Our exploration activities in China also have the potential to contribute to our medium-term growth. In September 2002, we entered into a 30-year production-sharing contract with CNPC in the western portion of the Sichuan Basin. Under the terms of the agreement, we will explore for and develop natural gas deposits on the 900,000-acre Zitong block**.** We plan to commence the drilling of our first exploration well on this block in the first quarter of 2005.

One of the most significant elements of our medium-term strategy is the acquisition of Ensyn. Current test results from over 90 test runs on heavy oil at Ensyn s pilot plant in Ontario show that Ensyn s RTP Technology offers a means of improving the value of heavy, sour crude oils in a manner that is comparable to established coking technologies but at significantly lower operating and capital costs. In addition, these test results evidence that the RTP Technology reduces or eliminates the need for an external energy source (usually natural gas, for steam production used in the recovery process), reduces the viscosity of the heavy oil and also permits the use of the processed oil to be used as a blending agent to facilitate the transportation of heavy oil by pipeline.

We believe that the innovative characteristics of Ensyn s RTP Technology offer the means to technologically and economically improve the production and marketing of heavy oil in the petroleum industry, which will provide us with an opportunity to significantly increase our base of oil reserves worldwide through joint venture and production sharing arrangements. As a result, the acquisition is expected to represent a major advance in the implementation of our corporate strategy because it will offer significant potential for broadening our access to project opportunities that might not otherwise be available to us.

Our long-term objective is to become a leader in the development and operation of GTL projects. We foresee rapidly increasing future demand for clean energy as environmental regulations become more stringent and the world s crude oil becomes more sour and heavy. We believe that Syntroleum s proprietary GTL technology holds significant potential for the economic production of synthetic fuels and other specialty petroleum products from stranded natural gas deposits throughout the world, which would otherwise be uneconomic to exploit. Although there are several competing GTL technologies under development, we believe that the Syntroleum technology offers several key advantages. Plant construction is less expensive and we believe the plant is safer to operate because, unlike competing technologies, the conversion process utilizes compressed air rather than pure oxygen.

OIL AND GAS PROPERTIES

Our primary oil and gas properties are located in California s San Joaquin Basin and Sacramento Gas Basin, the West Texas Permian and East Texas Basins, the Powder River Basin in Wyoming and the Hebei and Sichuan Provinces in China. Set forth below is a description of our material oil and gas properties.

California

Over the past seven years, we acquired interests in a number of properties in and around the San Joaquin Basin. In 2004, we acquired properties in the Knights Landing field in the Sacramento Gas Basin and established production in the Citrus field in the San Joaquin Basin. To date, our South Midway, Citrus and Knights Landing properties contain proved reserves and have wells on production. We cannot assure you that any of our other prospects in California will result in the development of commercially viable production.

Aera Exploration Agreement

The Aera exploration agreement, originally covering an area of more than 250,000 acres in the San Joaquin Basin, gave us access to all of Aera s exploration, seismic and technical data in the region for the purpose of identifying drillable exploration prospects. To date, we have identified 13 prospects within 11 areas of mutual interest (**AMIs**) covering approximately 72,400 gross acres. Of the 13 prospects submitted, Aera has elected to take a working interest in 10 prospects, resulting in us retaining working interests ranging from 12.5% to 50%. We have a 100% working interest in three prospects in which Aera elected not to participate. We will continue to hold exploration rights to the lands within previously designated and accepted prospect AMIs until an exploration well is drilled on that prospect. There is no time deadline for drilling to occur if Aera elects to participate in the drilling of a prospect. If Aera elects not to participate we have an additional two years to drill the prospect on our own or with other parties. This two-year period will be extended as long as we continue to drill or have established production.

South Midway

We currently have 55 producing wells in South Midway and are the operator, with a working interest of 100% and a 93% net revenue interest. In 2004, we drilled seven new wells on the South Midway properties, consisting of six step-out development locations and one exploratory well. Four of the six development wells were completed as producers. The exploratory well was unsuccessful and will be held for a future disposal well.

In the southern expansion area, we have supplemented the cyclic steam project with a pilot to test continuous steam injection into two wells. The project began in October 2004 and by year-end 2004 it was beginning to yield increased production in the surrounding wells. If successful, continuous steam injection could increase recovery of the oil in place by an estimated 50-70%, similar to recovery in other fields in the area, and add a significant amount of probable reserves to our proved undeveloped reserves. Current production from the southern expansion area is approximately 165 Bopd and total South Midway production is approximately 585 Bopd.

Citrus

We are the operator of the Citrus field, located in the southern extension of the currently producing Lost Hills field, which is unrelated to our deep-gas prospect at Northwest Lost Hills, 15 miles to the north. We have leased mineral interests ranging from 83% to 100% in approximately 3,400 gross acres offsetting the Lost Hills field, where there has been development drilling.

One horizontal and two vertical development wells were drilled and completed on this southern extension area of the Lost Hills field in 2004. Production is currently approximately 120 Bopd and 450 Mcf/d of gas with all three wells on rod pump. We are evaluating drilling another horizontal leg on Citrus #1 by the second quarter of 2005. The target upper Antelope zone, located a few hundred feet above the existing horizontal well, should yield improved oil rates and reduced water from the lease. Development drilling may resume during the last half of 2005, following this test.

Northwest Lost Hills

The Northwest Lost Hills #1-22 well, operated by Aera, began drilling in August 2001. The well was designed to fully evaluate the natural gas and condensate reserve potential of the deep Temblor formation and reach a depth of approximately 20,000 feet. This drilling objective was achieved in August 2002 after substantial delays and cost overruns resulting from difficult drilling conditions. While drilling the well, we encountered several high-pressure intervals, which indicated the presence of natural gas, and decided to set casing in preparation for testing. In 2003, the well was temporarily abandoned pending the identification of one or more partners to share the costs of the testing program. Progress has been made towards finding investment partners to complete and test the Temblor formation and resolution of the Northwest Lost Hills #1-22 well is expected in 2005. Until it is tested, the well s commercial potential, if any, cannot be determined. Of the approximately 8,000 gross acres encompassing the Northwest Lost Hills prospect, we hold, on average, a 39% working interest. We have a 42% working interest in the Northwest Lost Hills #1-22 well. If, as and when we identify a partner to fund a test of the well s commercial potential, our working interest is expected to decrease by up to 50% under a new arrangement.

Belgian Anticline

We drilled the first well in this prospect in 2001 and found non-commercial gas shows. A second well in this prospect, originally contemplated for 2004, has been delayed and may be drilled in 2005. We have a 40% working interest in this prospect and Aera is the operator.

Other California Prospects

Knights Landing

In February 2004, we farmed into the Knights Landing field, which is a 13,000-acre block located in the Sutter and Yolo counties, in northern California. Under this exploration and development farm-in agreement, we purchased, for $1.0 million, a 50% working interest in four previous discoveries in the contract area and agreed to fund, for $0.6 million, gas gathering, surface treatment facilities and meters to connect the four wells to an existing pipeline system. We drilled nine new exploratory wells under this agreement in order to earn a 50% working interest after payout in any new discoveries. Our 2004 drilling resulted in three successful completions and six dry holes. The three new discovery wells are expected to be connected in the first quarter of 2005. The primary objective of this development and exploration program is the Starkey Sand formation, which is an established producing reservoir in the region that lies between depths of 2,000 to 3,500 feet.

In December 2004, we reached an agreement with the operator of the field to purchase its interest, increasing our working interests in the field and existing producing gas wells to between 80% and 100%. We plan to use 3-D seismic to identify additional prospects and development well locations as well as reduce the dry hole risk in this gas producing area. Gross production is currently 1,520 Mcf/d from six producing wells. Well workovers are planned to increase gas rates and reduce operating costs.

North South Forty

In 1999, we entered into agreements with two other companies to pool certain of our acreage positions and jointly conduct a 3-D seismic survey in the southern San Joaquin Basin in order to identify new prospects. Although these agreements expired in 2003, we identified four drillable prospects covering approximately 13,400 gross acres, in which we have working interests ranging from 17.5% to 50%.

We participated with a 50% working interest in drilling two exploration prospects in the North South Forty area during 2004 but both wells were plugged and abandoned.

In December 2004, we participated in drilling a well with a carried 50% working interest in the third of the four prospects we developed from the 3-D seismic data in the North South Forty area. The Peach #1 well is located just west of the North Antelope Hills field. The well was drilled to a depth of 4,500 feet and initial evaluation was encouraging at test rates of 800Mcf/d on a 9/16-inch choke. During the test, the well produced natural gas and condensate with no water production. We will follow up testing with an estimate of commerciality, the drilling of an appraisal well and discussions with gas buyers. Gas gathering facilities and natural gas markets exist in close proximity to the discovery.

Sledge Hamar

In November 2003, we farmed into the Sledge Hamar prospect, which is located in a 900-acre block at the southern extension of the South Belridge field. The first well, Sledge Hamar 1-7, began producing in January 2004 at 30 Bopd from the Stevens sands at 4,950 feet. However, the follow up well drilled in April 2004 encountered the Stevens sands below the oil/water contact and tested only water. After evaluating the production results and other potential hydrocarbon intervals, we concluded that the future economic potential was unfavorable and, in December 2004, sold our working interest.

McCloud Ranch / North Salt Creek

In mid-2004, we farmed into the McCloud River Prospect near the Cymric field in the San Joaquin Basin with a 24% working interest. The initial well resulted in a dry hole. As a result of follow up work in the area, a second prospect was developed on the acreage called the North Salt Creek prospect. It is anticipated that we will participate with a 24% working interest and serve as operator for drilling this prospect in the first quarter of 2005. We have an interest in 1,140 gross acres over this prospect.

Texas

Spraberry

This producing property is located on 2,500 gross acres in the Spraberry Trend of the West Texas Permian Basin in Midland County, Texas, which we acquired in 2000 through a farm-in. After selling a portion of our working interests in 2002 for approximately $3 million, we retain working interests ranging from of 31% to 48% in 25 wells, which are currently producing approximately 80 net Boe/d.

East Texas

We currently own mineral rights in approximately 7,400 gross acres in East Texas but do not plan to renew leases as they expire except in the Creslenn Ranch, Catfish Creek and Malakoff prospects, which combined contain approximately 4,300 gross acres.

We spud the first well in the Malakoff prospect in the first quarter of 2005 where we will have a 25% carried working interest. The well is located in Henderson County, Texas and will be drilled to 8,200 feet to test the Rodessa and Travis Peak sands in the prospect. We have an interest in approximately 1,300 gross acres in the prospect.

In November 2003, we farmed out our interest in the Catfish Creek prospect for an 11,000-foot well to test the Rodessa and Pettit formations. We will retain a 25% working interest after payout in this prospect and surrounding acreage. We plan to spud this well after drilling the first well in the Malakoff prospect.

In 2003, we farmed out our interests in two wells we drilled in the Creslenn Ranch prospect to test the shallower zones in the wells. A successful gas recompletion was made in the first well in July 2003 from the Pettit limestone and is currently on production. The second well was plugged and abandoned after determination was made that it was not economic. We retain a 30% working interest after payout in the producing well and a 50% working interest in the remaining acreage.

Wyoming

LAK Ranch

In January 2004, we signed farm-in and joint operating agreements with Derek for the joint development of the LAK Ranch field, a thermal recovery/horizontal well oil project in Weston County, Wyoming. The LAK Ranch field covers approximately 7,500 acres in Wyoming s Powder River basin.

Under the terms of the joint operating agreement, we will be the operator of the project and will earn an initial 30% working interest by financing the capital cost of the pilot phase. Following the pilot phase, we will have the option to increase our working interest to 60% by providing additional capital toward the initial development phase for a total of $5.0 million, including the amounts spent on the pilot phase. Thereafter, all future capital expenditures are to be shared on a working-interest basis. Should we elect not to proceed beyond the pilot phase our working interest will be reduced to 15% and Derek will become the operator.

Prior to the farm-in agreement, Derek completed a SAGD horizontal well pair to a depth of 1,000 feet and 1,800 feet into the Newcastle Sand formation. Surface steam-injection and oil-recovery equipment were installed. Extensive testing indicates that because of the viscosity of the oil, production can be expected to respond favorably to the application of continuous heat through steam injection. Facility modifications for the pilot phase were completed in the second quarter of 2004 to enable steam injection in the producing horizontal well. Two cycle steam stimulation treatments were performed during the year. The second cycle of steam injection was completed in September 2004 with over 13,000 barrels of steam injected into the horizontal well. Production following the second steaming increased from the first steam cycle. The well is currently producing minimal amounts of oil and may be stimulated with a third steam cycle in the first quarter of 2005, pending results of seismic interpretation and recent drilling data.

The ultra-high resolution 3-D seismic survey needed to better define the optimum reservoir development locations began in November and was completed in December 2004. We expect evaluation results during the second quarter of 2005. In addition, one vertical well was drilled in the first quarter of 2005 for data collection purposes. After completion of the 3-D seismic survey we plan to use the data to plan and drill injection wells and test the potential of continuous steam injection.

Following completion of the pilot phase, the development phase is scheduled to include additional horizontal production wells, new steam-injection and extension of surface facilities. We estimate that, at the low end of the initial development phase the program could grow to more than 20 producing wells. During the pilot phase, our working interest has increased from an initial 30% to 39% by year-end 2004. Should we decide to enter into the next two phases of the contract, our working interest will increase to a maximum of 60%. Should we elect not to proceed beyond the pilot phase, our working interest would be reduced to 15% and we would no longer be the operator.

China

Dagang

Our producing property in China is a 30-year production-sharing contract with CNPC, covering an area of 22,400 gross acres divided into six blocks in the Kongnan oilfield in Dagang, Hebei Province, China (the **Dagang field**). Under the contract as operator, we fund 100% of the development costs to earn 82% of the net revenue from oil production until cost recovery, at which time our entitlement reverts to 49%. In January 2004, we negotiated farm-out and joint operating agreements with Richfirst Holdings Limited (**Richfirst**), a wholly owned subsidiary of CITIC whereby Richfirst paid $20.0 million to acquire a 40% working interest in the field after Chinese regulatory approvals, which were finalized in June 2004. Richfirst will have the right to exchange its working interest in the Dagang field for common shares in Sunwing, should we obtain a public listing for Sunwing, or for common shares in Ivanhoe. Richfirst s right to exchange its working interest for Ivanhoe common shares expires in December 2005. CITIC also has committed to assist in arranging non-recourse project financing for the remainder of the Dagang development program.

The production-sharing contract stipulates that we have the right to market our oil domestically or export it, sell our product in U.S. dollars and receive world market prices for our product. We are currently selling our crude oil to CNPC at a three-month rolling average price of Cinta crude oil, which historically has averaged approximately $2.00 per barrel less than the West Texas Intermediate

(**WTI**) price. Cinta is an Indonesian crude that is traded daily on the international oil market.

All petroleum producers in China pay a value added tax of 5% on oil production. We pay no royalty until annual gross production of crude oil from a particular block within the Dagang field exceeds 500,000 tonnes per annum. Royalties then become payable at a rate of 2% and increase incrementally as the rate of production increases to a maximum of 12.5% once annual gross production on a block exceeds four million tonnes. Our entire interest in the Dagang field will revert to CNPC at the end of the 20-year production phase of the contract or if we abandon the field earlier.

During 2001, we completed the pilot phase and in 2002 submitted the final draft of our ODP to the Chinese regulatory authorities for approval. Final government approval was obtained in April 2003, after which the development phase commenced in late 2003. In 2004, we drilled 19 development wells of which 16 were completed and placed on production. The year-end 2004 gross production rate was 1,655 Bopd. To complete the ODP over the next three years, we expect to drill 90 new wells and rework an additional 28 of the 82 existing wells at an estimated cost to Ivanhoe of $113 million.

Sichuan Basin

In February 2001, we signed two memoranda of understanding with PetroChina. These memoranda gave us the exclusive right to negotiate production-sharing contracts for the Zitong and Yudong land blocks in Sichuan Province, which cover an area of approximately 2.2 million acres. We agreed with PetroChina to carry out joint feasibility studies on the blocks located in the Sichuan Basin, approximately 930 miles southwest of Beijing. In September 2002, we signed a production-sharing contract (the **Zitong Contract**), with CNPC. The Zitong Contract received final Chinese regulatory approval in November 2002.

Under the Zitong Contract, we agreed to conduct an exploration program on the Zitong block consisting of two phases, each three years in length. The parties will jointly participate in the development and production of any commercially viable deposits, with production rights limited to a maximum of the lesser of 30 years following the date of the Zitong Contract or 20 years of continuous production.

During the first phase of exploration, we must complete a minimum work program consisting of reprocessing approximately 1,250 miles of seismic data, completing approximately 300 additional miles of new seismic lines and drilling and completing two wells totaling at least 23,000 feet, with estimated minimum expenditures for the program of $18 million. Upon completion of the first phase, we must relinquish up to 30% of the Zitong block. During 2003 and 2004, we reprocessed approximately 1,550 miles of existing seismic data and acquired approximately 540 miles of a 700-mile seismic acquisition program. Following processing and interpretation of the seismic data, we selected the location of our first exploration well and expect to spud the well in the first quarter of 2005.

If we elect to participate in phase two, we must complete a minimum work program consisting of new seismic lines totaling approximately 200 miles and drill and complete two additional wells totaling approximately 23,000 feet, with estimated minimum expenditures for the program of $16 million. Following the completion of phase two, we must relinquish all of the property except any areas identified for development and production.

We can elect to commence the development of commercially viable deposits at any time following the submission of an ODP. Once we complete phase one of the exploration project, we can also elect not to proceed with phase two of the exploration project. However, once we commence a phase of the exploration project we must complete the minimum work program or we will be obligated to pay, to CNPC, the cash equivalent of the deficiency in the work program for that exploration phase.

If we identify a field for development and/or production, the parties will divide the participating interest in the project, with CNPC entitled to fund and take up to 51% of the participating interest.

Once commercial production commences, we will recover annual exploration, development and operating costs from up to 60% of gross oil production and 70% of gross natural gas production. After annual cost recovery, we are entitled to production equaling our participating interest, subject to certain additional rights of the Chinese government. Assuming we hold a 49% participating interest, we will be entitled to approximately 75% of production initially, declining to approximately 45% after full exploration and development cost recovery.

CNPC retains the rights to production from six existing wells located on the Zitong block. We can drill new wells on the same structure as those tapped by the existing wells, but our wells must be no closer than 3,280 feet from the existing wells.

In 2003, we established an office in Chengdu, the capital of Sichuan. We have also completed our feasibility study obligations for the Yudong block and submitted a report to PetroChina in April 2002. In September 2002, we submitted a letter of intent to negotiate a production-sharing contract and our work plan for the Yudong block, and are currently awaiting PetroChina s reply.

CITIC Alliance

In October 2002, we entered into an agreement with CITIC Energy Ltd. (**CITIC Energy**) to form a strategic alliance to seek out and develop oil and gas projects in China and around the world. CITIC Energy is a subsidiary of CITIC, a major Chinese state-owned enterprise that holds interests in a wide range of industries.

Under the terms of the agreement, CITIC Energy will assist Sunwing in raising its profile in Asian capital markets and gaining access to future financing opportunities. CITIC Energy will also support Sunwing in its plan to obtain a listing for its shares on the Stock Exchange of Hong Kong.

We are expected to assist CITIC Energy in identifying and acquiring interests in international oil and gas development projects and in introducing GTL and other advanced energy-sector technologies to China s domestic oil and gas industry. We hold a master license to Syntroleum s proprietary GTL process, the geographical scope of which includes China.

CITIC Energy has also agreed to assist us in our efforts to negotiate a production-sharing contract with PetroChina covering the Yudong block in the Sichuan Basin. Should a production-sharing contract for the Yudong block be obtained, Sunwing and CITIC Energy will jointly participate in the development of the project on a 70/30 basis. Within 180 days thereafter, either party can elect to convert CITIC Energy s 30% participating interest in the project into a 20% equity interest in Sunwing. CITIC Energy has the right to appoint a representative to Sunwing s Board of Directors and will be entitled to appoint a second representative if, as and when it acquires a 20% equity interest in Sunwing.

In April 2003, we entered into a further agreement with CITIC Energy that enables both companies to form a global strategic alliance to investigate, explore and develop oil, natural gas, metallurgical coal, liquefied natural gas and GTL projects in China and around the world, to help supply China s future energy requirements. The new agreement builds upon the initial partnership formed between the two companies in October 2002 and follows discussions both between the two companies and with asset owners of potential projects in China and in other parts of the world.

ENHANCED OIL RECOVERY AND HEAVY-TO-LIGHT OIL PROJECTS

Ensyn

The Ensyn RTP™ Technology, patented in the U.S., Canada and other countries, upgrades the quality of heavy oil by producing lighter, more valuable crude oil. Ensyn reports that this process dramatically improves the economics in heavy-oil projects. The heaviest hydrocarbon fraction is consumed as fuel to generate the steam used to enhance recovery of heavy crude. This lowers costs by reducing or eliminating the need to purchase high-priced natural gas for steam generation and improves revenue since the higher quality light-crude fraction can be sold at higher prices. The lighter crude has improved viscosity that permits more efficient pumping through pipeline networks and significantly reduces transportation costs to marketing points. The Ensyn RTP™ Technology uses readily available plant and process components.

The RTP™ Technology already has been successfully applied to continuous wood/biomass processing, in six commercial plants in operation in Canada and the U.S. A seventh biomass plant is under construction in Canada. The technology has recently been applied to petroleum processing and an Ensyn pilot plant in Ontario, Canada has completed more than 90 test runs on heavy oil. In addition, Ensyn s 1,000-barrel-per-day CDF, located in the Belridge heavy oil field near Bakersfield, California, successfully started up in December 2004. Ensyn currently plans to use the facility to process local heavy oil, as well as to test a range of heavy crudes from around the world.

During 2004, we acquired, for $3.0 million, a 15% equity interest in EPIL and exclusive rights to use the proprietary Ensyn RTP™ Technology in key international markets in China, Mongolia, Iraq, Oman and all countries in South America except Venezuela. In these countries, we have exclusive rights to use the Ensyn RTP Technology for an initial term of five years until January 2009, subject to extension if and when commercial plants are constructed. For each project we develop using the Ensyn RTP™ Technology in our exclusive territories, Ensyn could elect to receive an equity participation in the project for the same proportionate cost we paid. The participation that may be obtained by Ensyn could be no more than 10%, except for each such project that we develop in South America, other than in Peru, where Ensyn could elect to receive an equity interest equal to 25% of our interest. Ensyn s equity position would offset and eliminate the payment of license fees for use of the Ensyn RTP™ Technology in the project.

On December 11, 2004, Ivanhoe, Ivanhoe Merger Sub, Inc. (**Merger Sub**), a Delaware corporation and our wholly-owned subsidiary, and Ensyn entered into an Agreement and Plan of Merger (the **Merger Agreement**), pursuant to which Merger Sub will be merged with and into Ensyn and Ensyn will become our wholly owned subsidiary (the **Merger**) and all of the issued and outstanding shares of Ensyn common stock will be converted into the right to receive cash and common shares of Ivanhoe.

We have agreed to pay $10 million in cash and issue Ivanhoe common shares (**Merger Shares**) in exchange for all of the issued and outstanding Ensyn common shares and all unissued Ensyn common shares issuable upon the future exercise of any purchase warrants that remain unexercised when the Merger takes effect. The number of Merger Shares to be issued will be the greater of: (i) 30,000,000 or (ii) the quotient obtained by dividing $75 million by the weighted average of the closing prices of Ivanhoe common shares on the NASDAQ SmallCap Market over a period of ten consecutive trading days determined five business days prior to the scheduled date of a special meeting of the shareholders of Ensyn at which their approval of the Merger will be sought.

One-third of the total number of Merger Shares issued will be deposited and held in an escrow fund (the **Indemnity Escrow Fund**) to secure certain obligations on the part of the Ensyn shareholders and to indemnify us for damages arising from breaches of warranties and covenants under, and other circumstances more particularly described in, the Merger Agreement. Subject to any prior claims by us for indemnification, one-half of the Merger Shares in the Indemnity Escrow Fund will be released to the Ensyn shareholders no later than 20 days from (i) the date that we, Ensyn or any of our respective controlled affiliates enters into a definitive agreement with an unaffiliated third party for the construction or use of a processing plant equipped with the RTP Technology and having a minimum daily input processing capacity of 10,000 barrels of oil per day (an **RTP Plant**) or (ii) the second anniversary of the closing date of the Merger, whichever is earlier. The balance of the Merger Shares in the Indemnity Escrow Fund will be released, subject to any prior claims by us for indemnification, as of (i) the second anniversary of the date that we, Ensyn or any of our respective controlled affiliates enters into a definitive agreement with an unaffiliated third party for the construction or use of an RTP Plant, (ii) the second anniversary of the date that we or any of our controlled affiliates commences construction of an RTP Plant, (iii) the date that we, Ensyn or any of our respective controlled affiliates enters into a second definitive agreement with an unaffiliated third party for the construction or use of an RTP Plant, (iv) the date that we or any of our controlled affiliates commences construction of a second RTP Plant, and (v) the third anniversary of the closing date of the Merger, whichever is earliest but, in any event, no earlier than the first anniversary of the closing date of the Merger.

Ensyn currently uses the RTP Technology in two ways: a biomass process that transforms wood and other organic material into bio-fuels, resins and other products (the **Renewables Business**) and a petroleum process that upgrades heavy oil and bitumen, into lighter, less viscous petroleum products (the **Petroleum Business**). The Merger Agreement provides that Ensyn will use commercially reasonable efforts to distribute to its shareholders, by way of a dividend prior to the Merger taking effect, all of the issued and outstanding shares of a newly formed wholly owned subsidiary that, prior to such distribution, will indirectly own and operate the Renewables Business. Ensyn will retain the Petroleum Business when it becomes our wholly owned subsidiary pursuant to the Merger. Upon the Merger taking effect, we will thereafter share the intellectual property rights in the RTP Technology with Ensyn through a series of cross-licensing and non-competition arrangements.

Upon the implementation of the Merger, two individuals designated by Ensyn will be appointed to our Board of Directors. We have agreed to use our reasonable best efforts to nominate Ensyn s designees for re-election to our Board of Directors annually for at least five years.

The respective obligations of the parties to consummate the Merger are subject to a number of conditions precedent customary in similar transactions. These conditions include the adoption of the Merger Agreement and the approval of the Merger by a majority of the votes cast by the Ensyn shareholders at a special meeting to be convened for that purpose and, if the number of Merger Shares to be issued, together with any other common shares of Ivanhoe issued or issuable pursuant to any private placement equity financing transactions undertaken by us in connection with the Merger, exceeds the maximum number of common shares that we would be permitted to issue without shareholder approval under the applicable rules of the Toronto Stock Exchange, approval of the issuance of such Ivanhoe common shares by a majority of the votes cast by our shareholders at a special meeting to be convened for that purpose.

Our obligation to effect the Merger is also subject to Ensyn s RTP Technology-equipped commercial demonstration facility in California having satisfied certain technical performance requirements and criteria provided for in the Merger Agreement. This condition will be satisfied when we receive reports from certain third party technical consultants confirming that the facility has met the requisite requirements and criteria.

The transactions contemplated by the Merger Agreement are expected to close early in the second quarter of 2005. Either we, or Ensyn, may elect to terminate the Merger Agreement if the Merger has not been consummated by May 15, 2005, subject to an extension of up to sixty days in certain circumstances more particularly described in the Merger Agreement. There can be no assurance that the transactions contemplated by the Merger Agreement will be consummated.

The Boards of Directors of both Ivanhoe and Ensyn have approved the merger transaction. In reaching its decision to approve the merger transaction, our Board of Directors considered a variety of factors, a number of which are summarized below:

Acquiring innovative petroleum production technology is a key aspect of our corporate strategy. A key aspect of our corporate strategy is to grow our business by expanding our oil and gas reserve base. Although part of this strategy involves conventional exploration and production, our management recognizes that we lack the size and the significant financial resources necessary to pursue the conventional exploration and production growth strategies historically undertaken by large, integrated oil companies. The core of our corporate strategy is to accelerate the development of our business by leveraging the experience, expertise and existing business relationships of our senior management personnel. We seek projects requiring relatively low initial capital outlays to which we can apply innovative technology and enhanced recovery techniques in developing them. Our Board of Directors believes that the acquisition of Ensyn s RTP Technology will represent a major advance in the implementation of our corporate strategy in that it offers significant potential for broadening our access to project opportunities that might not otherwise be available to us.

Ensyn s RTP Technology represents a unique approach to heavy oil upgrading. The innovative characteristics of Ensyn s RTP Technology offer the means to technologically and economically improve the production and marketing of heavy oil in the petroleum industry. Current test results from over 90 test runs on heavy oil at Ensyn s pilot plant in Ontario show that the RTP Technology offers a means of improving the value of heavy, sour crude oils in a manner that is comparable to established coking technologies but at significantly lower operating and capital costs. In addition, these test results evidence that the RTP Technology reduces or eliminates the need for an external energy source (usually natural gas, for steam production used in the recovery process), reduces the viscosity of the heavy oil and also permits the use of the processed oil to be used as a blending agent to facilitate the transportation of heavy oil by pipeline.

Heavy oil represents a vast untapped resource. Heavy oil deposits throughout the world represent a potentially massive resource, holding quantities of heavy oil more than double the existing global reserves of light or conventional oil. Heavy oil extraction and transportation presents a number of technological challenges and typically requires extensive and cost-intensive infrastructure. Higher viscosity makes the transportation of heavy oil through conventional pipelines difficult or impossible unless it is first blended with lighter, lower viscosity oil or expensive diluents. As a result, less than 1% of the world s heavy oil deposits are currently under active development. Our Board of Directors believes that Ensyn s RTP Technology offers us the unique opportunity to accumulate reserves by acquiring interests in stranded heavy oil deposits that would otherwise be uneconomic to develop through conventional means and developing them on an incremental, cost-efficient basis using Ensyn s RTP Technology.

Application of Ensyn s RTP Technology to heavy oil deposits offers potentially significant economic benefits. Our Board of Directors believes that, if the Ensyn RTP Technology can be deployed on a commercial scale, it will offer a number of potential cost saving and revenue-enhancement benefits. The reduction or elimination of the need for an external energy source, usually natural gas, for steam production used in the heavy oil recovery process, often a substantial added cost to conventional producers, could significantly reduce the operating cost of extracting the heavy oil. The RTP Technology upgraded oil is likely to command a higher market price, reducing what would otherwise be a significant price differential between heavy and light oil. The price paid to producers for heavy oil is lower than the price paid for light oil as the heavy oil requires additional refining. Unlike conventional heavy oil extraction facilities, which usually must be constructed on a large scale in order to be economical and therefore require a significant up-front capital investment, we expect to be able to deploy the RTP Technology on a relatively small scale and independent of refineries, which should allow us to develop smaller heavy oil fields that would otherwise be uneconomic to exploit using conventional technologies. The scalability of RTP Technology-equipped facilities offers the potential to develop heavy oil deposits on an incremental basis financed by cash flow. Given their limited infrastructure requirements, RTP Technology-equipped facilities can be located in relatively remote areas where constructing conventional facilities would not be feasible.

Exclusive control of Ensyn s RTP Technology in its application to petroleum processing gives us an important strategic advantage. Although we already hold exclusive licensing rights to deploy Ensyn s RTP Technology in petroleum processing projects in a number of countries, including China, Mongolia, Iraq, Oman and most of South America and non-exclusive rights to use the technology elsewhere in the world, exclusive control of the technology throughout the world increases our leverage in the pursuit of our strategic plans and objectives. We believe that the value of the technology can be maximized by using it to create opportunities to acquire interests, and actively participate, in heavy oil development projects rather than licensing the technology to third parties and collecting passive licensing payments. The acquisition of Ensyn will advance this strategy by giving us the exclusive right, subject to limited pre-existing licensing rights, to deploy the RTP Technology anywhere in the world, including in the key North American markets. At the same time, the acquisition will effectively result in us re-acquiring from Ensyn the future project participation rights (between 10% and 25%) we granted to Ensyn when we first acquired exclusive licensing rights in the technology and will minimize our obligations to pay licensing fees in respect of those projects we develop using the technology.

Combining the technical expertise of Ensyn s personnel with the international petroleum industry experience and expertise of our personnel will benefit us. Our Board of Directors believes that aligning the interests of Ensyn s shareholders with those of our shareholders ensures that we will continue to enjoy access to the benefits of the scientific and technological expertise possessed by Ensyn s personnel. Our management team has been working closely with key members of Ensyn s management team, including Ensyn s co-founders, for nearly two years. The acquisition of Ensyn should create synergies between the technical expertise of Ensyn s personnel and the international petroleum industry experience and expertise of our personnel and result in a more integrated Ivanhoe/Ensyn management team for the deployment of the RTP Technology, as the former Ensyn shareholders will become significant shareholders in our company and two members of Ensyn s management will join our Board of Directors.

Iraq

In October 2004, we signed a memorandum of understanding (**MOU**) with the Ministry of Oil of the Government of Iraq to study and evaluate the shallow Qaiyarah oil field in Iraq. The field s reservoirs contain a large proven accumulation of 17.1° API heavy oil at a depth of about 1,000 feet.

We will evaluate the potential response of the Qaiyarah oil field to the latest in EOR techniques, along with the potential value that could be added using the Ensyn RTP™ Technology to produce higher quality, more valuable crude oil. The work will include an assessment of the oil-in-place in the reservoirs, and the optimum EOR/HTL methods to establish economically recoverable volumes at the Qaiyarah oil field.

If the evaluation studies indicate development of the field is economically viable, we will present a development plan and offer a commercial proposal to implement an EOR program for the Qaiyarah oil field. The Iraqi Ministry of Oil is under no obligation to execute the project or to enter into formal commercial negotiations at the completion of our study.

Colombia

In December 2004, we signed an MOU with Ecopetrol S.A. (**Ecopetrol**) for a study of the heavy crudes from the large Castilla and Chichimene oil fields in Colombia. The two oil fields are about 75 miles southeast of Bogotá in the Central Llanos Basin. This region is an active oil producing area and the Castilla and Chichimene fields have successfully been producing oil since the 1970 s.

In the initial phase, we will run tests on the two heavy crudes to determine the value that could be added to these fields using the Ensyn RTP™ Technology.

Ecopetrol S.A., formerly Empresa Colombiana de Petroleos, is a public company with 100% of its shares currently owned by the Republic of Colombia. Ecopetrol is exclusively devoted to searching for, producing, transporting, storing, refining and marketing hydrocarbons and is the fourth largest national oil company in Latin America. Gross oil production in 2003, by Ecopetrol and its associates, was 541,000 Bopd, and year-end reserves were over 1.5 billion barrels.

GAS-TO-LIQUIDS PROJECTS

Syntroleum License

We hold a non-exclusive master license entitling us to use Syntroleum s proprietary GTL process in an unlimited number of projects with no limit on production volume. In June 2003, we gave up our rights for license fee credits for the $10.0 million we paid for the master license and $2.0 million we invested in Syntroleum s Sweetwater project. In consideration, Syntroleum removed certain territorial restrictions to our master license, which will enable us to pursue GTL project opportunities worldwide, particularly in China. Syntroleum has also agreed that, in respect of GTL projects in which both companies participate, no additional license fees or royalties will be payable and that Syntroleum will also contribute to any such project the right to manufacture specialty and lubricant products. Both companies have the right to pursue GTL projects independently, but we would be required to pay Syntroleum the normal license fees and royalties in such projects.

Syntroleum Process

Syntroleum s proprietary GTL process is designed to catalytically convert natural gas into synthetic liquid hydrocarbons. This patented process uses compressed air, steam and natural gas as initial components to the catalyst process. As a result, this process (the **Syntroleum Process**) substantially reduces the capital and operating costs and the minimum economic size of a GTL plant as compared to the other oxygen-based GTL technologies.

Syntroleum developed its GTL technology based on a process developed in Germany in the 1920s for the gasification of coal into oil, called the Fischer-Tropsch reaction. Syntroleum has applied its principles to the conversion of natural gas to synthetic liquid hydrocarbons. Syntroleum believes that it holds a competitive advantage over other GTL technologies because the Syntroleum Process uses air when converting natural gas into synthetic hydrocarbons. Competitor GTL processes use either steam reforming or a combination of steam reforming and partial oxidation with pure oxygen. A steam reformer and an air separation plant necessary for oxidation are expensive and considered hazardous and increase operating costs.

From our perspective, the attraction of the Syntroleum Process lies in the commercialization of stranded natural gas. Such gas exists in discovered and known reservoirs, but requires innovative gas processing to produce products that can be marketed on an economic basis. Operators consider natural gas to be stranded based on the relative size of the fields and their remoteness from comparable sized markets.

GTL Projects

We have performed detailed project feasibility studies for the construction, operation and cost of GTL plants in both Qatar and Egypt. In May 2003, advanced negotiations with Qatar Petroleum and the Qatari government to construct and operate such a facility terminated without an agreement being reached. In the quarter ended June 30, 2003, we wrote down $3.3 million of our GTL investments for expenditures incurred in connection with these negotiations. In the second quarter of 2004, we wrote down our $0.3 million investment in the Oman GTL project as our opportunity to build a 45,000-barrels per day GTL fuels plant in Oman failed to materialize due to a lack of sufficient uncommitted gas volumes.

We have conducted marketing and transportation feasibility studies for both European and Asia Pacific regions in which we identified potential markets and estimated premiums for GTL diesel and GTL naphtha. Based on our ongoing commercialization studies and the growing demand for cleaner sources of energy in Japan, we incorporated GTLJ to facilitate the potential future participation by Japanese companies in GTL projects. In November 2004, we changed the name of GTLJ to ERDJ and expanded the charter of the company to include participation of multi-national companies in EOR projects, including those involving HTL oil upgrading. Should we be successful in obtaining the rights to develop such projects, we intend to assign a certain percentage of our interest in the project to ERDJ. We would then invite multi-national companies from the refining and distribution, exploration and production, and trading and manufacturing industry sectors to invest in ERDJ. The proceeds raised would be used to fund a portion of the total project capital costs, including front-end engineering and design.

In 2004, we initiated a feasibility study to convert coal to synthesis gas (**CTL**) as a feedstock for the Syntroleum Fischer-Tropsch process. The objective of the study is to explore opportunities for converting coal into clean burning CTL fuels in parts of the world where there is a relatively cheap supply of sizeable coal deposits. China in particular, has large coal deposits and a rapidly growing need for clean energy.

Egypt

The feasibility studies we have undertaken for Egypt contemplate the natural gas feedstock being purchased, rather than developed. A preliminary feasibility study for a 45,000 barrels per day fuels, specialty products and lubricants GTL plant in Egypt was completed and presented to the government of Egypt and its agencies responsible for the development and monetization of its natural gas reserves. The Egyptian governmental agencies are now making economic comparisons of the three alternative methods for gas monetization that they have available to them: (1) pipeline exports to Syria and Jordan, (2) liquefied natural gas exports to Europe and (3) GTL. This is an ongoing analysis and we believe our GTL proposal remains a viable alternative for Egypt. Discussions continue with Egyptian officials to promote the GTL alternative. Accordingly, we have recently initiated a new detailed GTL fuels plant engineering feasibility and product price study that takes full advantage of the latest advancements in the Syntroleum technology.

Bolivia

In July 2003, we signed a participation agreement with Repsol-YPF Bolivia S.A. (**Repsol**) and Syntroleum for a commercialization study to build a 90,000-barrel-per-day GTL plant in southern Bolivia. The commercialization study includes an analysis of alternative plant sites, transportation logistics and screening economics conducted by representatives from Ivanhoe, Repsol and Syntroleum. The initial phase of the commercialization study was completed in 2004 and we determined that under Bolivia s current hydrocarbon tax regulations a 90,000-barrel-per-day GTL plant could be commercially viable. However, due to the passing of a referendum to overhaul Bolivia s tax regulations in the third quarter of 2004 we elected to postpone any further work on the commercialization study. The participation agreement with Repsol and Syntroleum expired at the end of 2004 and we elected not to renew the participation agreement. We continue to pursue other opportunities in Bolivia for monetization of the country s vast natural gas deposits into GTL fuels.

RISK FACTORS

We are subject to a number of risks due to the nature of the industry in which we operate, our reliance on strategies which include technologies that have not been proved on a commercial scale, the present state of development of our business and the foreign jurisdictions in which we carry on business. The following factors contain certain forward-looking statements involving risks and uncertainties. Our actual results may differ materially from the results anticipated in these forward-looking statements.

We cannot guarantee the successful commercialization of our exploration activities.

We have exploration and development projects in the U.S. and China. Our projects are at various stages and, like all exploration companies in the oil and gas industry, we are exposed to the significant risk that our exploration activities will not necessarily result in a discovery of economically recoverable volumes.

We have a history of losses and must generate greater revenue to achieve profitability.

We commenced operations in 1997 and have been involved in three start-up situations in Russia, China and the U.S. Like most start-up companies we have incurred losses during our start-up activities. Our current cash flows alone are insufficient to fund our medium and long-term business plans, necessitating further growth and funding for implementation. We may be unable to achieve the needed growth to obtain profitability and may fail to obtain the funding that we need when it is required.

We are not able to guarantee the successful commercial development of our licensed GTL technology.

To date, no commercial-scale GTL plants have been constructed using the proprietary GTL process we license from Syntroleum and, therefore, the process has not been proven on a commercial scale. Other developers of GTL technology have significantly more financial resources than we do and may be able to use this to obtain a competitive advantage.

We may not be able to conclude a GTL development and production-sharing contract.

We were unsuccessful in concluding a GTL development and production-sharing contract in Qatar and we can give no assurances as to when or if we will be able to conclude such contracts in Egypt, Bolivia or other countries where we are now, or will be, exploring GTL project opportunities.

We are not able to guarantee the successful commercial development of Ensyn s RTP™ Technology.

To date, no commercial-scale HTL plants have been constructed using the Ensyn RTP™ Technology and, therefore, the process has not been proven to be financially viable on a commercial scale. Other developers of competing HTL technologies may have significantly more financial resources than we do and may be able to use this to obtain a competitive advantage.

We may not be able to conclude HTL joint venture or production-sharing contracts using the RTP ™ Technology.

We have signed memoranda of understanding in Iraq and Colombia to study the economic feasibility of an RTP Technology HTL oil processing facility for specified oil fields in those countries but we can give no assurances as to when or if we will be able to conclude a joint venture or production-sharing contract with the governments in those countries or any other countries where we are now, or will be, seeking HTL project opportunities.

Commercialization of our GTL or HTL projects may give rise to claims of infringement upon the patents or proprietary rights of others.

We own licenses to employ Syntroleum s GTL and Ensyn s RTP™ Technology processes but we may not become aware of claims of infringement upon the patents or rights of others in these respective technologies until after we have made a substantial investment in the development and commercialization of projects utilizing these licensed technologies. Third parties may claim that the technologies we license have infringed upon past, present or future patented technologies. Legal actions could be brought against the licensor and us claiming damages and seeking an injunction that would prevent us from testing or commercializing the affected technologies. If an infringement action were successful, in addition to potential liability for damages, we and our licensors could be required to obtain a claiming party s license in order to continue to test or commercialize the affected technologies. Any required license might not be made available or, if available, might not be available on acceptable terms, and we could be prevented entirely from testing or commercializing the affected licensed technology. We may have to expend substantial resources in litigation defending against the infringement claims of others. Many possible claimants, such as the major energy companies that have or may be developing proprietary GTL or HTL technologies competitive with the Syntroleum and RTP™ Technology processes that we license, may have significantly more resources to spend on litigation.

Ensyn has a history of operating losses and may continue to incur losses in the future.

Since its inception, Ensyn has invested a significant amount of time and money in the research and development of new products. Its development expense, including development of licensing fees, was $0.9 million and $0.6 million for the years ended September 30, 2004 and 2003, respectively. Its total operating expense, including development costs, was $1.8 million and $1.0 million for the years ended September 30, 2004 and 2003, respectively, compared to total revenue of $0.3 million and $0.7 million, respectively, for such periods. Ensyn had net losses of $1.2 million and $0.6 million for the years ended September 30, 2004 and 2003, respectively. Ensyn s accumulated deficit as of September 30, 2004 was $14.4 million. If we incur losses in our application of the RTP™ Technology after completion of the Ensyn acquisition, this may have an adverse impact on our operating results, which could cause the market price of our shares to decline.

Technological advances could significantly decrease the cost of upgrading petroleum, and if we are unable to adopt or incorporate technological advances into our operations, the RTP™ Technology could become uncompetitive or obsolete.

We expect that technological advances in the processes and procedures for upgrading heavy oil and bitumen into lighter, less viscous products will continue to occur. It is possible that those advances could make the processes and procedures that are presently being utilized by Ensyn (and which we intend to utilize after the acquisition) less efficient or cause the upgraded product currently being produced by Ensyn to be of a lesser quality. These advances could also allow competitors to produce upgraded products at a lower cost than that at which Ensyn is currently able to produce such products. If we are unable to adopt or incorporate technological advances, our production methods and processes could be less efficient than those of our competitors, which could cause RTP™ Technology plants to become uncompetitive.

In addition, alternative sources of energy are continually under development. Alternative energy sources that can reduce reliance on oil and bitumen may be developed, which may decrease the demand for RTP™ Technology upgraded product. It is also possible that technological advances in engine design and performance could reduce the use of oil and bitumen, which would lower the demand for such products.

Conflict in the Middle East may hamper our GTL, EOR and HTL project objectives.

Ongoing tensions and conflict in the Middle East could harm our business in the short to medium term by making it difficult or impossible to continue our pursuit of GTL, EOR and HTL projects in the region or to obtain financing for projects we do succeed in obtaining. It is impossible to predict the occurrence of such events, how long they will last, the economic consequences of the conflict for the energy industry, regionally and globally, and how our business might be affected over the longer term.

Crude oil and natural gas prices are volatile.

Fluctuations in the prices of oil and natural gas will affect many aspects of our business, including our revenues, cash flows and earnings; our ability to attract capital to finance our operations; our cost of capital; the amount we are able to borrow and the value of our oil and natural gas properties.

Both oil and natural gas prices are extremely volatile. Oil prices are determined by international supply and demand. Political developments, compliance or non-compliance with self-imposed quotas, or agreements between members of the OPEC can affect world oil supply and prices. Any material decline in prices could result in a reduction of our net production revenue and overall value. The economics of producing from some wells could change as a result of lower prices. As a result, we could elect not to produce from certain wells. Any material decline in prices could also result in a reduction in our oil and natural gas acquisition and development activities.

In addition, a material decline in oil and natural gas prices from historical average prices could adversely affect our ability to borrow and to obtain additional capital on attractive terms.

Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploration projects.

Government regulations in foreign countries may limit our activities and harm our business operations.

In addition to our interest in our China projects, we may enter into contractual arrangements to acquire oil and gas properties in other foreign jurisdictions with governments, governmental agencies or government-owned entities. The foreign legal framework for these agreements, particularly in developing countries, is often based on recent political and economic reforms and newly enacted legislation, which may not be consistent with long-standing local conventions and customs. As a result, there may be ambiguities, inconsistencies and anomalies in the agreements or the legislation upon which they are based which are atypical of more developed legal systems and which may affect the interpretation and enforcement of our rights and obligations and those of our foreign partners. Local institutions and bureaucracies responsible for administering foreign laws may lack a proper understanding of the laws or the experience necessary to apply them in a modern business context. Foreign laws may be applied in an inconsistent, arbitrary and unfair manner and legal remedies may be uncertain, delayed or unavailable.

We may not be successful in negotiating additional production-sharing contracts in China.

We hold our interests in China through two production-sharing contracts with CNPC for the Dagang and Zitong blocks. We also have an MOU with PetroChina indicating a mutual intention to negotiate an additional production-sharing contract in the Sichuan basin. We cannot assure you, based on our existing MOU with PetroChina, that we will successfully negotiate additional production-sharing contracts. It is possible that disputes between us could arise in the future, which must be resolved under foreign law. We cannot be sure that we can enforce our legal rights in foreign countries or that an effective legal remedy will be available to us in any dispute governed by foreign law.

We might not be successful in acquiring and developing new prospects and our exploration and development properties may not contain any significant proved reserves.

Our future exploration and development success depends upon our ability to find, develop and acquire additional economically recoverable oil and natural gas reserves. The successful acquisition and development of oil and gas properties requires proper forecasting of recoverable reserves, oil and gas prices and operating costs, potential environmental and other liabilities and productivity of new wells drilled.

Estimates of cost to explore, develop and produce are assessments and are inexact. As a result, we might not recover the purchase price of a property from the sale of production from the property, or might not recognize an acceptable return from properties we acquire. Our estimates of exploration, development and production costs can be affected by such factors as permitting regulations and requirements, weather, environmental factors, unforeseen technical difficulties and unusual or unexpected formations, pressures and work interruptions.

Exploration and development involves significant risks. Few wells, which are drilled, are developed into commercially producing fields. Substantial expenditures may be required to establish the existence of proved reserves, and we cannot assure you commercial quantities of oil and gas deposits will be discovered sufficient to enable us to recover our exploration and development costs or be sufficient to sustain our business.

Expansion of our operations will require significant capital expenditures for which we may be unable to provide sufficient financing. Our need for additional capital may harm our financial condition.

We will be required to make substantial capital expenditures far beyond our existing capital resources to develop a GTL, EOR or HTL project, to exploit our existing reserves and to discover new oil and gas reserves. Historically, we have relied, and continue to rely, on external sources of financing to meet our capital requirements to continue acquiring, exploring and developing oil and gas properties and to otherwise implement our corporate development and investment strategies. We have, in the past, relied upon equity capital as our principal source of funding. We plan to obtain the future funding we will need through debt and equity markets, but we cannot assure you that we will be able to obtain additional funding when it is required and whether it will be available on commercially acceptable terms. We also make offers to acquire oil and gas properties in the ordinary course of our business. If these offers are accepted, our capital needs may increase substantially. If we fail to obtain the funding that we need when it is required, we may have to forego or delay potentially valuable opportunities to acquire new oil and gas properties or default on existing funding commitments to third parties and forfeit or dilute our rights in existing oil and gas property interests. Our limited operating history may make it difficult to obtain future financing.

You should not unduly rely on reserve information because reserve information represents estimates.

Reserve estimates involve a great deal of uncertainty, because they depend in large part upon the reliability of available geologic and engineering data, which is inherently imprecise. Geologic and engineering data are used to determine the probability that a reservoir of oil and natural gas exists at a particular location, and whether oil and natural gas are recoverable from a reservoir. Recoverability is ultimately subject to the accuracy of data including, but not limited to geological characteristics of the reservoir structure, reservoir fluid properties, the size and boundaries of the drainage area and reservoir pressure and the anticipated rate of pressure depletion.

The evaluation of these and other factors is based upon available seismic data, computer modeling, well tests and information obtained from production of oil and natural gas from adjacent or similar properties, but the probability of the existence and recoverability of reserves is less than 100% and actual recoveries of proved reserves usually differ from estimates.

Reserve estimates also require numerous assumptions relating to operating conditions and economic factors including, among others, the price at which recovered oil and natural gas can be sold, the costs of recovery, prevailing environmental conditions associated with drilling and production sites, availability of enhanced recovery techniques, ability to transport oil and natural gas to markets and governmental and other regulatory factors, such as taxes and environmental laws.

A negative change in any one or more of these factors could result in quantities of oil and natural gas previously estimated as proved reserves becoming uneconomic. For example, a decline in the market price of oil or natural gas to an amount that is less than the cost of recovery of such oil and natural gas in a particular location could make production thereof commercially impracticable. The risk that a decline in price could have that effect is magnified in the case of reserves requiring sophisticated or expensive production enhancement technology and equipment, such as some types of heavy oil. Each of these factors, by having an impact on the cost of recovery and the rate of production, will also affect the present value of future net cash flows from estimated reserves.

In addition, estimates of reserves and future net cash flows expected from them prepared by different independent engineers, or by the same engineers at different times, may vary substantially.

Information in this document regarding our future plans reflects our current intent and is subject to change.

We describe our current exploration and development plans in this document. Whether we ultimately implement our plans will depend on availability and cost of capital; receipt of additional seismic data or reprocessed existing data; current and projected oil or gas prices; costs and availability of drilling rigs and other equipment, supplies and personnel; success or failure of activities in similar areas; changes in estimates of project completion costs; our ability to attract other industry partners to acquire a portion of the working interest to reduce costs and exposure to risks and decisions of our joint working interest owners.

We will continue to gather data about our projects and it is possible that additional information will cause us to alter our schedule or determine that a project should not be pursued at all. You should understand that our plans regarding our projects might change.

Our business may be harmed if we are unable to retain our licenses, leases and working interests in licenses and leases.

Some of our properties are held under licenses and leases and working interests in licenses and leases. If we, or the holder of the license or lease, fail to meet the specific requirements of each license or lease, the license or lease may terminate or expire. We cannot assure you that any of the obligations required to maintain each license or lease will be met. The termination or expiration of our licenses or leases or our working interest relating to a license or lease may harm our business. Some of our property interests will terminate unless we fulfill certain obligations under the terms of our agreements related to such properties. If we are unable to satisfy these conditions on a timely basis, we may lose our rights in these properties. The termination of our interests in these properties may harm our business.

Complying with environmental and other government regulations could be costly and could negatively impact our production.

Our operations are governed by numerous laws and regulations at various levels of government in the countries in which we operate. These laws and regulations govern the operation and maintenance of our facilities, the discharge of materials into the environment and other environmental protection issues. The laws and regulations may, among other potential consequences, require that we acquire permits before commencing drilling; restrict the substances that can be released into the environment with drilling and production activities; limit or prohibit drilling activities on protected areas such as wetlands or wilderness areas; require that reclamation measures be taken to prevent pollution from former operations; require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells and remediating contaminated soil and groundwater and require remedial measures be taken with respect to property designated as a contaminated site, for which we are a responsible person.

Under these laws and regulations, we could be liable for personal injury, clean-up costs and other environmental and property damages, as well as administrative, civil and criminal penalties. We maintain limited insurance coverage for sudden and accidental environmental damages as well as environmental damage that occurs over time. However, we do not believe that insurance coverage for the full potential liability of environmental damages is available at a reasonable cost. Accordingly, we could be liable, or could be required to cease production on properties, if environmental damage occurs.

The costs of complying with environmental laws and regulations in the future may harm our business. Furthermore, future changes in environmental laws and regulations could occur that result in stricter standards and enforcement, larger fines and liability, and increased capital expenditures and operating costs, any of which could have a material adverse effect on our financial condition or results of operations.

We compete for oil and gas properties with many other exploration and development companies throughout the world who have access to greater resources.

We operate in a highly competitive environment in which we compete with other exploration and development companies to acquire a limited number of prospective oil and gas properties. Many of our competitors are much larger than we are and, as a result, may enjoy a competitive advantage in accessing financial, technical and human resources. They may be able to pay more for productive oil and gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial, technical and human resources permit.

Our share ownership is highly concentrated and, as a result, our principal shareholder effectively controls our business.

As at the date of this annual report, our largest shareholder, Robert M. Friedland, owned approximately 27% of our common shares. As a result, he effectively controls our Board of Directors and determines our policies, business and affairs and the outcome of any corporate transaction or other matter, including mergers, consolidations and the sale of all, or substantially all, of our assets.

In addition, the concentration of our ownership may have the effect of delaying, deterring or preventing a change in control that otherwise could result in a premium in the price of our common shares.

If we lose our key management and technical personnel, our business may suffer.

We rely upon a relatively small group of key management and technical personnel. Messrs. David Martin and E. Leon Daniel, in particular, have extensive experience in oil and gas operations throughout the world. We do not maintain any key man insurance. We do not have employment agreements with certain of our key management and technical personnel and we cannot assure you that these individuals will remain with us in the future. An unexpected partial or total loss of their services would harm our business.

COMPETITION

The oil and gas industry is highly competitive. Our position in the oil and gas industry, which includes the search for and development of new sources of supply, is particularly competitive. Our competitors include major, intermediate and junior oil and natural gas companies and other individual producers and operators, many of which have substantially greater financial and human resources and more developed and extensive infrastructure than we do. Our larger competitors, by reason of their size and relative financial strength, can more easily access capital markets than we can and may enjoy a competitive advantage in the recruitment of qualified personnel. They may be able to absorb the burden of any changes in laws and regulations in the jurisdictions in which we do business more easily than we can, adversely affecting our competitive position. Our competitors may be able to pay more for productive oil and natural gas properties and may be able to define, evaluate, bid for, and purchase a greater number of properties and prospects than we can. Further, these companies may enjoy technological advantages and may be able to implement new technologies more rapidly than we can. Our ability to acquire additional properties in the future will depend upon our ability to conduct efficient operations, to evaluate and select suitable properties, implement advanced technologies, and to consummate transactions in a highly competitive environment. The oil and gas industry also competes with other industries in supplying energy, fuel and other needs of consumers. See Risk Factors .

ENVIRONMENTAL REGULATIONS

Our conventional oil and gas, EOR, HTL and GTL operations are subject to various levels of government laws and regulations relating to the protection of the environment in the countries in which they operate. See Risk Factors . We believe that our operations comply in all material respects with applicable environmental laws.

In the U.S., environmental laws and regulations, implemented principally by the Environmental Protection Agency, Department of Transportation and the Department of the Interior and comparable state agencies, govern the management of hazardous waste, the discharge of pollutants into the air and into surface and underground waters and the construction of new discharge sources, the manufacture, sale and disposal of chemical substances, and surface and underground mining. These laws and regulations generally provide for civil and criminal penalties and fines, as well as injunctive and remedial relief.

In China, environmental regulation does not exist on a national level. Individual projects are monitored by the state and the standard of environmental regulation depends on each case.

ENVIRONMENTAL PROVISIONS

As at December 31, 2004, a $0.7 million provision has been made for future site restoration and plugging and abandonment of wells in the U.S., which are currently estimated at $1.4 million. We do not make such a provision for our oil and gas operations in China as the remaining life of our Dagang production sharing contract is less than the remaining economic life of the field and there is no obligation on our part to contribute to the future cost to abandon the field and restore the site. During 2004, we recorded a further provision for future site restoration and plugging and abandonment of wells of $0.2 million.

GOVERNMENT REGULATIONS

Our business is subject to certain U.S. and Chinese federal, state and local laws and regulations relating to the exploration for, and development, production and marketing of, crude oil and natural gas, as well as environmental and safety matters. In addition, the Chinese government regulates various aspects of foreign company operations in China. Such laws and regulations have generally become more stringent in recent years in the U.S., often imposing greater liability on a larger number of potentially responsible parties. It is not unreasonable to expect that the same trend will be encountered in China. Because the requirements imposed by such laws and regulations are frequently changed, we are not able to predict the ultimate cost of compliance.

EMPLOYEES

As at December 31, 2004 we had 137 employees. None of our employees are unionized.

Information on our executive officers is presented in Item 10 of this Annual Report on Form 10-K.

RESERVES, PRODUCTION AND RELATED INFORMATION

See the Supplementary Disclosures About Oil and Gas Production Activities which follows the notes to our financial statements set forth in Item 8 in this Annual Report on Form 10-K for information with respect to our oil and gas producing activities. We have not filed with nor included in reports to any other U.S. federal authority or agency, any estimates of total proved crude oil or natural gas reserves since the beginning of the last fiscal year.

The following tables set forth, for each of the last three fiscal years, our average sales prices and average operating costs per unit of production based on our net interest after royalties. Average operating costs are for lifting costs only and exclude production taxes, allocated engineering support costs, depletion and depreciation income taxes, interest, selling and administrative expenses.

	Average Sales Price			**Average Operating Costs**		
	2004	**2003**	**2002**	**2004**	**2003**	**2002**
Crude Oil and Natural Gas ($/Boe)						
U.S	$ 34.66	$ 25.69	$ 22.43	$ 8.94	$ 7.65	$ 6.76
China	$ 36.11	$ 28.41	$ 22.30	$ 6.04	$ 9.31	$ 6.49

The following table sets forth the number of commercially productive wells (both producing wells and wells capable of production) in which we held a working interest at the end of each of the last three fiscal years:

	2004		**2003**		**2002**	
	Gross(1)	**Net(2)**	**Gross(1)**	**Net(2)**	**Gross(1)**	**Net(2)**
U.S.	97(5)	78.9(5)	77	60.4	60(3)	43.9(3)
China	21	10.3(6)	9	7.4	9(4)	7.4(4)

(1) Gross wells are the total number of wells in which an interest is owned.

(2) Net wells are the sum of fractional interests owned in gross wells.

(3) After the sale of 4.4 net (7 gross) Spraberry wells in August 2002 and a 50% working interest, or 6.9 net wells, in our remaining Spraberry wells in October 2002.

(4) After the sale of 3.4 net (4 gross) Daqing wells in January 2002.

(5) After the sale of 0.8 net (2 gross) Sledge Hamar wells in December 2004 and the purchase of 8.2 net (9 gross) Knight s Landing wells partially in April of 2004 and the remainder (including an increase in the working interest of the existing wells) in December of 2004.

(6) After giving effect to the 40% farm-in of CITIC to Dagang field.

The following two tables set forth, for each of the last three fiscal years, our participation in the completed drilling of net oil and gas wells:

Exploratory

		Productive	
	2004	**2003**	**2002**
U.S.	3.4		
China			
Total	3.4	0	0

		Dry	
	2004	**2003**	**2002**
U.S.	5.4		1.7(1)
China			
Total	5.4	0	1.7

(1) Includes 1.5 (3 gross) net exploratory wells drilled in Kentucky during 2001, which were determined to be dry in 2002.

Development

	Productive		
	2004	**2003**	**2002**
U.S.	7.3(1)	17.0	8.8
China	7.9		
Total	15.2	17.0	8.8

	Dry		
	2004	**2003**	**2002**
U.S.	2.0	2.0	
China			
Total	2.0	2.0	0

(1) Includes 0.3 (1 gross) net producing wells acquired as a result of the farm-in to LAK Ranch.

Wells in Progress

At the end of 2004, 2003 and 2002 we had 2.9 (6 gross), 2.8 (5 gross) and 2.3 (5 gross) net wells, respectively, which were either in the process of drilling or suspended.

The following table sets forth our holdings of developed and undeveloped oil and gas acreage as at December 31, 2004:

	Developed		**Undeveloped**	
	Gross Acres(1)	**Net Acres(2)**	**Gross Acres(1)**	**Net Acres(2)**
U.S.	16,224	8,649	100,315	38,288
China (3)	2,289	1,126	899,760	889,567

(1) Gross acres include the interests of others.

(2) Net acres exclude the interests of others.

(3) The number of developed acres disclosed in respect of our China properties relates only to those portions of the field covered by our producing operations and does not include the remaining portions of the field previously developed by CNPC.

The following table sets out estimates of our share of proved reserves in respect of our U.S. and China operations and calculations of cash flows, before tax and after tax, undiscounted and discounted at 10% and 15%, based on costs and prices as at December 31, 2004. Estimates for our U.S. and China operations were prepared by independent petroleum consultants Netherland, Sewell & Associates Inc. and Gilbert Laustsen Jung Associates Ltd., respectively.

	Our Share of Before Tax Cash Flows	**Our Share of After Tax Cash Flows**

	Our Share		In Thousands of U.S. Dollars			In Thousands of U.S. Dollars		
	Oil	Gas	Discounted at:			Discounted at:		
	(Mbbl)	(MMcf)	0%	10%	15%	0%	10%	15%
Net Proved Reserves (1)								
U.S.	1,430	2,683	$ 33,427	$ 22,189	$ 19,375	$ 33,427	$ 22,189	$ 19,375
China	7,908		184,311	114,637	93,534	139,603	88,829	73,254
	9,338	2,683	$ 217,738	$ 136,826	$ 112,909	$ 173,030	$ 111,018	$ 92,629

(1) "**Net Proved Reserves** are our share of the estimated quantities of crude oil which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic conditions. See the Supplementary Disclosures about Oil and Gas Production Activities , which follow the notes to our financial statements set forth in Item 8 of this Annual Report on Form 10-K.

Special Note to Canadian Investors

Ivanhoe is a United States Securities and Exchange Commission (**SEC**) registrant and files annual reports on Form 10-K. Accordingly, our reserves estimates and securities regulatory disclosures are prepared based on U.S. disclosure standards. In 2003, certain Canadian securities regulatory authorities adopted *National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities* (**NI 51-101**) which prescribes certain standards that Canadian companies are required to follow in the preparation and disclosure of reserves and related information. We applied for, and have been granted, exemptions from certain NI 51-101 disclosure requirements. These exemptions permit us to substitute disclosures based on U.S. standards for much of the annual disclosure required by NI 51-101 and to prepare our reserves estimates and related disclosures in accordance with U.S. disclosure requirements, generally accepted industry practices in the U.S. as promulgated by the Society of Petroleum Engineers, and the standards of the Canadian Oil and Gas Evaluation Handbook (the **COGE Handbook**) modified to reflect U.S. disclosure requirements.

The reserves quantities disclosed in this Annual Report on Form 10-K represent net proved reserves calculated on a constant price basis using the standards contained in SEC Regulation S-X and FAS 69. Such information differs from the corresponding information prepared in accordance with Canadian disclosure standards under NI 51-101. The primary differences between the U.S. requirements and the NI 51-101 requirements are as follows:

SEC registrants apply SEC reserves definitions and prepare their reserves estimates in accordance with SEC requirements and generally accepted industry practices in the U.S. whereas NI 51-101 requires adherence to the definitions and standards promulgated by the COGE Handbook;

the SEC mandates disclosure of proved reserves calculated using year-end constant prices and costs only whereas NI 51-101 also requires disclosure of reserves and related future net revenues using forecasted prices;

the SEC mandates disclosure of proved and proved producing reserves by country only whereas NI 51-101 requires disclosure of more reserve categories and product types;

the SEC does not require separate disclosure of proved undeveloped reserves or related future development costs whereas NI 51-101 requires disclosure of more information regarding proved undeveloped reserves, related development plans and future development costs; and

the SEC leaves the engagement of independent qualified reserves evaluators to the discretion of a company s board of directors whereas NI 51-101 requires issuers to engage such evaluators and to file their reports.

The foregoing is a general and non-exhaustive description of the principal differences between U.S. disclosure standards and NI 51-101 requirements.

ITEM 3. LEGAL PROCEEDINGS

We are not currently a party to any material legal proceedings.

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

No matter was submitted to a vote of security holders during the fourth quarter of 2004.

PART II

ITEM 5. MARKET FOR REGISTRANT S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Market Information

Our common shares trade on the NASDAQ SmallCap Market and the Toronto Stock Exchange. The high and low sale prices of our common shares as reported on the NASDAQ and Toronto Stock Exchange for each quarter during the past two years are as follows:

NASDAQ MARKET (IVAN)
(U.S.$)

	2004	**2003**

	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr
High	3.20	2.33	3.06	4.28	7.55	3.07	1.18	.60
Low	2.03	1.22	2.08	1.96	2.52	.79	.42	.50

TORONTO STOCK EXCHANGE (IE)
(CDN$)

	2004				2003			
	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr
High	3.90	3.00	4.15	5.49	10.40	4.15	1.60	.88
Low	2.56	1.62	2.88	2.63	3.30	1.10	.53	.77

On December 31, 2004, the closing prices for our common shares were $2.52 on the NASDAQ SmallCap Market and Cdn. $3.04 on the Toronto Stock Exchange.

Exemptions from Certain NASDAQ Marketplace Rules

NASDAQ may provide exemptions from certain of its Marketplace Rules to foreign issuers when those rules are contrary to a law, rule or regulation of any public authority exercising jurisdiction over such issuer or contrary to generally accepted business practices in the issuer s country of domicile.

We have received from NASDAQ an exemption from NASDAQ s requirement that a majority of our Board of Directors be comprised of independent directors. Existing Toronto Stock Exchange guidelines recommend, but do not require, that a majority of the directors of a corporation be unrelated directors. An unrelated director is a director who is independent of management and is free from any interest and any business or other relationship which could, or could reasonably be perceived to, materially interfere with the director s ability to act with a view to the best interests of the corporation, other than interests and relationships arising from shareholding. Three of the eight directors on our board are unrelated for the purposes of the Toronto Stock Exchange guidelines.

We have also received from NASDAQ an exemption from NASDAQ s requirement that our shareholders approve the issuance of more than 20% of our total outstanding common shares in connection with our proposed acquisition of Ensyn and any related private placement transactions, provided that we comply with the rules and policies of the Toronto Stock Exchange. The rules and policies of the Toronto Stock Exchange require us to obtain shareholder approval for the issuance of common shares in connection with the Ensyn transaction and any related private placements if the aggregate number of common shares to be issued exceeds 25% of the common shares outstanding immediately prior to the transaction.

Holders of Common Shares

As at December 31, 2004, a total of 169,664,911 of our common shares were issued and outstanding and held by 180 holders of record with an estimated 45,500 additional shareholders whose shares were held for them in street name or nominee accounts.

Dividends

We have not paid any dividends on our outstanding common shares since we were incorporated and we do not anticipate that we will do so in the foreseeable future. The declaration of dividends on our common shares is, subject to certain statutory restrictions described below, within the discretion of our Board of Directors based on their assessment of, among other factors, our earnings or lack thereof, our capital and operating expenditure requirements and our overall financial condition. Under the *Yukon Business Corporations Act*, our Board of Directors has no discretion to declare or pay a dividend on our common shares if they have reasonable grounds for believing that we are, or after payment of the dividend would be, unable to pay our liabilities as they become due or that the realizable value of our assets would, as a result of the dividend, be less than the aggregate sum of our liabilities and the stated capital of our common shares.

Exchange Controls and Taxation

There is no law or governmental decree or regulation in Canada that restricts the export or import of capital, or affects the remittance of dividends, interest or other payments to a non-resident holder of our common shares, other than withholding tax requirements.

There is no limitation imposed by the laws of Canada, the laws of the Yukon, or our constating documents on the right of a non-resident to hold or vote our common shares, other than as provided in the *Investment Canada Act* (Canada) (the **Investment Act**), which generally prohibits a reviewable investment by an entity that is not a **Canadian** , as defined, unless after review, the minister responsible for the Investment Act is satisfied that the investment is likely to be of net benefit to Canada. An investment in our common shares by a non-Canadian who is not a **WTO investor** (which includes governments of, or individuals who are nationals of, member states of the World Trade Organization and corporations and other entities which are controlled by them), at a time when we were not already controlled by a WTO investor, would be reviewable under the Investment Act under two circumstances. First, if it was an investment to acquire control (within the meaning of the Investment Act) and the value of our assets, as determined under Investment Act regulations, was Cdn. $5 million or more. Second, the investment would also be reviewable if an order for review was made by the federal cabinet of the Canadian government on the grounds that the investment related to Canada s cultural heritage or national identity (as prescribed under the Investment Act), regardless of asset value. An investment in our common shares by a WTO investor, or by a non-Canadian at a time when we were already controlled by a WTO investor, would be reviewable under the Investment Act if it was an investment to acquire control and the value of our assets, as determined under Investment Act regulations, was not less than a specified amount, which for 2005 is Cdn.$250 million. The Investment Act provides detailed rules to determine if there has been an acquisition of control. For example, a non-Canadian would acquire control of us for the purposes of the Investment Act if the non-Canadian acquired a majority of our outstanding common shares. The acquisition of less than a majority, but one-third or more, of our common shares would be presumed to be an acquisition of control of us unless it could be established that, on the acquisition, we were not controlled in fact by the acquirer. An acquisition of control for the purposes of the Investment Act could also occur as a result of the acquisition by a non-Canadian of all or substantially all of our assets.

Amounts that we may, in the future, pay or credit, or be deemed to have paid or credited, to you as dividends in respect of the common shares you hold at a time when you are not a resident of Canada within the meaning of the *Income Tax Act* (Canada) will generally be subject to Canadian non-resident withholding tax of 25% of the amount paid or credited, which may be reduced under the Canada-U.S. Income Tax Convention (1980) (the **Convention**). Currently, under the Convention, the rate of Canadian non-resident withholding tax on the gross amount of dividends paid or credited to a U.S. resident is generally 15%. However, if the beneficial owner of such dividends is a U.S. resident corporation, which owns 10% or more of our voting stock, the withholding rate is reduced to 5%. In the case of certain tax-exempt entities, which are residents of the U.S. for the purpose of the Convention, the withholding tax on dividends may be reduced to 0%.

Sales of Unregistered Securities

During the year ended December 31, 2004, we issued securities, which were not registered under the Securities Act of 1933 (the **Act**), as follows:

in February 2004, we issued 5,448,276 special warrants at a price of $2.90 per special warrant to two institutional investors in a transaction exempt from registration under Rule 903 of the Act. Each special warrant was exercisable to acquire, for no additional consideration, one common share and one share purchase warrant following the issuance of a receipt for a prospectus by applicable Canadian securities regulatory authorities, which occurred in March 2004. Two common share purchase warrants are exercisable to purchase an additional common share at $3.00 at any time on or prior to the first anniversary date following the special warrant date of issue and at $3.20 thereafter until the second anniversary date of the special warrant date of issue; and

in March 2004, we issued 1,724,138 special warrants at a price of $2.90 per special warrant to an institutional investor in a transaction exempt from registration under Rule 903 of the Act. Each special warrant was exercisable to acquire, for no additional consideration, one common share and one share purchase warrant following the issuance of a receipt for a prospectus by applicable Canadian securities regulatory authorities, which occurred in March 2004. Two common share purchase warrants are exercisable to purchase an additional common share at $3.00 at any time on or prior to the first anniversary date following the special warrant date of issue and at $3.20 thereafter until the second anniversary date of the special warrant date of issue.

ITEM 6. FIVE YEAR SUMMARY OF SELECTED FINANCIAL DATA

The selected financial data set forth below are derived from the accompanying financial statements, which form part of this Annual Report on Form 10-K. The financial statements have been prepared in accordance with generally accepted accounting principles (**GAAP**) applicable in Canada, which are not materially different from GAAP in the U.S. except as noted immediately below in Reconciliation to U.S. GAAP . See also Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations .

The following table shows selected financial information for the years indicated:

	December 31, (stated in thousands of U.S. dollars, except per share amounts)				
	2004	**2003**	**2002**	**2001**	**2000**
Financial Position					
Total assets	118,486	106,574	107,088	104,003	99,800
Long-term debt	2,639	833	Nil	Nil	Nil

Shareholders equity	103,586	100,537	100,548	96,897	95,838
Common shares outstanding (in thousands)	169,665	161,359	144,466	139,267	126,874
Capital investments	46,454	15,391	18,828	40,504	40,827
Results of Operations					
Revenues	17,997	9,659	8,437	9,722	14,063(1)
Net income (loss)	(20,725)(2)	(30,179)(2)(3)	(7,130)(2)(3)	(21,122)(2)	5,429
Net income (loss) per share basic	(0.12)	(0.20)	(0.05)	(0.16)	0.05
Net income (loss) per share diluted	(0.12)	(0.20)	(0.05)	(0.16)	0.04

(1) Includes $12.2 million gain on sale of our Russian project. See Note 9 to our financial statements under Item 8 in our 2001 Annual Report on Form 10-K.

(2) Includes asset write-downs and provisions for impairment of $16.6 million, $23.3 million, $2.4 million and $14.0 million for 2004, 2003, 2002 and 2001, respectively. See Notes 4 and 13 to our financial statements under Item 8 in this Annual Report on Form 10-K.

(3) Restated by $0.5 million and $0.3 million in 2003 and 2002, respectively, for a change in accounting policy to recognize compensation costs using the fair value based method of accounting for stock options granted to employees and directors after January 1, 2002. See Notes 2 and 9 to our financial statements under Item 8 of this Annual Report on Form 10-K.

Reconciliation to U.S. GAAP

Our financial statements have been prepared in accordance with GAAP applicable in Canada, which differ in certain respects from those principles that we would have followed had our financial statements been prepared in accordance with GAAP in the U.S. The only material differences between Canadian and U.S. GAAP, which affect our financial statements are as follows:

- adjustment for the reduction in stated capital in 1999,
- increase in the ascribed value of shares issued for the acquisition of U.S. royalty interests in 1999 and 2000,
- additional impairment provision for our China oil and gas properties in 2001, net of depletion expense,
- reduction in impairment provision for our U.S. oil and gas properties in 2004, net of depletion expense,
- net additional expense from 2001 to 2004 in connection with development costs for our GTL and EOR projects, and
- reduction in the net losses from 2002 to 2004 for stock based compensation accounted for under the intrinsic value method for U.S. GAAP.

For the U.S. GAAP reconciliations, see Note 19 to our financial statements in this Annual Report on Form 10-K.

Had we followed U.S. GAAP, certain selected financial information reported above, in accordance with Canadian GAAP, would have been reported as follows:

	Year ended December 31, (stated in thousands of U.S. dollars, except per share amounts)				
	2004	**2003**	**2002**	**2001**	**2000**
Financial Position					
Total assets	105,791	94,024	91,921	90,219	101,158
Shareholders equity	90,892	87,987	85,279	83,113	97,196
Results of Operations					
Net income (loss)	(19,696)	(27,086)	(8,202)	(36,264)	5,429
Net income (loss) per share basic	(0.12)	(0.18)	(0.06)	(0.28)	0.05
Net income (loss) per share diluted	(0.12)	(0.18)	(0.06)	(0.28)	0.05

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

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THE FOLLOWING SHOULD BE READ IN CONJUNCTION WITH THE CONSOLIDATED FINANCIAL STATEMENTS INCLUDED IN THIS ANNUAL REPORT ON FORM 10-K. THE CONSOLIDATED FINANCIAL STATEMENTS HAVE BEEN PREPARED IN ACCORDANCE WITH GAAP IN CANADA. THE IMPACT OF SIGNIFICANT DIFFERENCES BETWEEN CANADIAN AND U.S. GAAP ON THE FINANCIAL STATEMENTS IS DISCLOSED IN NOTE 19 TO THE CONSOLIDATED FINANCIAL STATEMENTS.

OUR DISCUSSION AND ANALYSIS OF OUR OIL AND GAS ACTIVITIES WITH RESPECT TO OIL AND GAS VOLUMES, RESERVES AND RELATED PERFORMANCE MEASURES IS PRESENTED ON OUR WORKING INTEREST BASIS AFTER ROYALTIES.

NOTE: CANADIAN INVESTORS SHOULD READ THE SPECIAL NOTE TO CANADIAN INVESTORS ON PAGE 22 WHICH HIGHLIGHTS DIFFERENCES

BETWEEN OUR RESERVE ESTIMATES AND RELATED DISCLOSURES THAT ARE OTHERWISE REQUIRED BY CANADIAN REGULATORY AUTHORITIES.

Executive Overview of 2004 Results

Although our 2004 results improved over those achieved a year ago, we were not profitable in 2004. Revenue for 2004 increased by 86% to $18.0 million on the strength of an increase in production as well as higher oil and gas prices. However, this improvement was offset by increased costs related to our significant business development activities, a $16.3 million impairment of a number of our unproved and proved U.S. oil and gas properties and professional fees related to our assessment of the effectiveness of the design and operation of our internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002. Despite cost increases, we achieved positive cash flow from operations of $4.0 million for the year ended December 31, 2004 compared to deficits of $1.5 million and $2.1 million for the comparable periods in 2003 and 2002, respectively.

Our single goal continues to be to build our oil and gas reserve base and production. Our strategy is to do this through the application of technologically innovative methods for oil and gas recovery. Our most significant activity in this regard, during 2004, is related to our December 2004 agreement to acquire Ensyn and its proprietary RTP Technology. We believe that the deployment of this RTP Technology can launch us into the forefront of heavy oil production around the world.

The following table sets forth certain selected consolidated data for the past three years:

	Year ended December 31, (stated in thousands of U.S. dollars, except share amounts)		
	2004	**2003**	**2002**
Net loss	20,725	30,179	7,130
Net loss per share	0.12	0.20	0.05
Average annual production (Mboe/d)	1,376	979	1,020
Capital investments	46,454	15,391	18,828
Cash flow (deficit) from operating activities	4,032	(1,522)	(2,120)

Financial Results - Year to Year Change in Net Loss

The following provides an analysis of our changes in net losses for the year ended December 31, 2004 when compared to the same period for 2003 and for the year ended December 31, 2003 when compared to the same period for 2002:

	2004 vs. 2003	**2003 vs 2002**
	(stated in thousands of U.S. Dollars)	
Net Losses for 2003 and 2002, as restated	$ 30,179	$ 7,130

Favorable (unfavorable) variances:		
Cash Items:		
Net Operating Revenues:		
Production volumes	4,534	(416)
Oil and gas prices	3,442	1,899
Hedge loss	250	(243)
Less: Operating costs	(780)	(452)
	7,446	788
General and administrative	(177)	(2,091)
Net interest	(36)	(179)
Total Cash Variances	7,233	(1,482)
Non-Cash Items:		
Depletion and depreciation	(3,653)	(517)
Stock based compensation	(800)	(165)
Write downs of GTL investments	3,071	(885)
Impairment of U.S. oil and gas properties	3,650	(20,000)
Other	(47)	
Total Non-Cash Variances	2,221	(21,567)
Net Losses for 2004 and 2003	$ 20,725	$ 30,179

Our net loss for 2004 was $20.7 million ($0.12 per share) compared to our net loss in 2003 of $30.2 million ($0.20 per share) after restatement of 2003 for a retroactive change in accounting policy for stock based compensation (See Notes 2 and 9). The decrease in our net loss from 2003 to 2004 of $9.5 million is due mainly to a $3.7 million reduction in impairment of our U.S. oil and gas properties, $3.1 million decrease in write-downs of our GTL investments and a $7.4 million increase in net operating revenues. This is partially offset by a $3.7 million increase in depletion and depreciation expense and a $1.0 million increase in general administrative expenses including stock based compensation.

The $23.0 million increase in our restated net losses from 2002 to 2003 is due mainly to a $20.0 million impairment of our U.S. oil and gas properties, a $0.9 million increase in write-downs of our GTL investments, a $0.5 million increase in depletion and depreciation expense and a $2.3 million increase in general and administrative costs including stock based compensation. This is partially offset by an increase in net operating revenues of $0.8 million, including a $0.2 million hedge loss for 2003.

Significant variances in our net losses are explained in the sections that follow.

Net Operating Revenues

Production Volumes 2004 vs. 2003

Net production volumes in 2004 increased 41% from 2003 due to 63% and 26% increases in production volumes in our China and U.S. properties, respectively, resulting in increased revenues of $4.5 million.

Net production volumes at the Dagang field increased 46% in 2004 despite the farm-out of 40% of our interest to Richfirst in June 2004. We commenced development of the Dagang field in late 2003 and by the end of 2004 we drilled 19 wells of which 16 were completed and placed on production. The year-end 2004 gross production rate was 1,655 Bopd (774 net Bopd) compared to 505 Bopd at the end of 2003 (236 net Bopd adjusting for a 40% Richfirst farm-in for comparability to 2004). At year-end 2004, a total of 22 wells were producing at our Dagang field. Additionally, we continue to benefit from the expanded Daqing development program and the royalty interest we retained after the sale of our working interest in this field in 2002 as our royalty share of production increased 224% from 2003.

Net production volumes in the U.S. increased 26% mainly from the Citrus and Knights Landing fields, both of which started production in 2004, and our continuing development program at South Midway. We farmed into the Knights Landing gas field in northern California in February 2004 with a 50% working interest in 4 producing natural gas wells and in December 2004 improved the potential of our California properties by increasing our working interest to between 80% and 100% in 12 Knights Landing natural gas wells capable of production and selling our interest in the Sledge Hamar field. We are the operator of the Citrus field and currently have a 100% working interest before payout in three Citrus wells, which were completed and placed on production in 2004. We continue to see increased production rates from our successful drilling and steaming operations at our South Midway field where we have drilled 19 producing wells over the last two years. At year end 2004, we were producing from 95 wells in the South Midway, Spraberry, Citrus, and Knights Landing fields at gross rates of production of approximately 1,320 Boe/d (920 net Boe/d).

The following is a comparison of changes in production volumes for the year ended December 31, 2004 when compared to the same period in 2003:

	Average Net Boe's		Percentage
	2004	**2003**	**Change**
China:			
Dagang	190,309	130,651	46%

Daqing	44,626	13,771	224%
	234,935	144,422	63%
U.S.:			
South Midway	183,875	169,858	8%
Citrus	31,008		100%
Knights Landing	14,786		100%
Others	38,945	42,962	-9%
	268,614	212,820	26%
	503,549	357,242	41%

Production Volumes 2003 vs. 2002

Net production volumes in 2003 declined 4% from 2002 due mainly to the sale of our interests in certain wells in the Spraberry field in the last half of 2002 and in Dagang due to a combination of factors which occurred during 2003 including well workovers, natural declines and the suspension of one pilot phase well pending conversion to water injection service. Production from South Midway increased 24% in 2003 primarily due to drilling 15 new wells in the southern expansion in 2003 and initiation of full-scale cyclic steam enhancement program in May 2002 in the primary area of South Midway and cyclic steaming of the southern expansion wells in the fourth quarter of 2003.

At year-end 2003, we were producing from seven pilot phase wells in the Dagang field at gross rates of 505 Bopd (236 net Bopd adjusting for a 40% Richfirst farm-in for comparability to 2004) compared to 599 Bopd at the end of 2002 (280 net Bopd adjusting for a 40% Richfirst farm-in for comparability to 2004) and 76 wells from the South Midway and Spraberry fields at gross rates of production of approximately 911 Boe/d (611 net Boe/d).

The following is a comparison of changes in production volumes for the year ended December 31, 2003 when compared to the same period in 2002:

	Average Net Boe's		**Percentage**
	2003	**2002**	**Change**
China:			
Dagang	130,651	141,257	-8%
Daqing	13,771	3,591	283%
	144,422	144,848	0%
U.S.:			
South Midway	169,858	136,705	24%
Spraberry	40,695	88,598	-54%
Others	2,266	1,998	13%
	212,820	227,301	-6%
	357,242	372,149	-4%

Oil and Gas Prices 2004 vs. 2003

Oil and gas prices increased 32% per Boe in 2004 generating $3.4 million in additional revenue as compared to 2003. We realized an average of $36.11/Boe from our operations in China during 2004, which is an increase of $7.70/Boe from 2003 prices and accounts for $1.7 million of our increase in revenues. From the U.S. operations, we realized an average of $34.66/Boe during 2004, which is an increase of $8.97/Boe and accounts for $1.7 million of our increased revenues.

We entered into costless collar derivatives to hedge our cash flow from the sale of 500 barrels of oil production per day over two six-month periods starting October 2002 and June 2003. We realized losses of $0.3 million on these derivative transactions in 2003 but had no derivative contracts in place during 2004.

Oil and Gas Prices 2003 vs. 2002

Oil and gas prices increased 20% per Boe in 2003 generating $1.9 million in additional revenue as compared to 2002. We realized an average of $28.41/Boe from our operations in China during 2003, which is an increase of $6.11/Boe from 2002 prices and accounts for $0.9 million of our increase in revenues. From the U.S. operations, we realized an average of $25.69/Boe during 2003, which is an increase of $3.26/Boe and accounts for $1.0 million of our increased revenues.

As discussed above, we realized losses of $0.3 million on derivative transactions in 2003 compared to the insignificant losses realized on such transactions during 2002.

Operating Costs 2004 vs. 2003

Operating costs for 2004 increased $0.8 million in absolute terms from 2003 but decreased $1.96 on a per barrel of oil equivalent basis.

Operating costs in China, including engineering support, decreased 41% or $5.57 per Boe for 2004 due mainly to an increase in production from the Dagang field in relation to the level of fixed field operating costs and engineering support required to operate the field and reduced well workover and power costs during 2004.

Operating costs in the U.S., including engineering support and production taxes, increased 8% or $0.89 per Boe for 2004. Field operating costs increased $1.29/Boe due mainly to an increase in fuel costs incurred for the cyclic steam operations in the southern expansion of South Midway, increased costs to treat hydrogen sulfide levels in the gas produced from the South Midway field and the start up of production operations at our Citrus, Knights Landing, and Sledge Hamar fields. This is partially offset by a reduction in workover costs at our South Midway and Spraberry fields from 2003. Engineering support increased $0.19/Boe due mainly to the start up of production operations at Citrus, where we are the operator, and also at Knights Landing where we became the operator in December 2004. Production taxes are down $0.59/Boe due mainly to a retroactive reassessment of property values at South Midway, which led to a refund of prior ad valorem taxes paid and a reduction in current assessed values.

Operating Costs 2003 vs. 2002

Operating costs for 2003 increased $0.5 million in absolute terms from 2002 and $1.70 on a per barrel of oil equivalent basis.

Operating costs in China, including engineering support, increased 33% or $3.42 per Boe in 2003 mainly due to increased well workover and manpower costs in preparation for the full field development which started in the fourth quarter of 2003.

Operating costs in the U.S., including engineering support and production taxes, increased 5% or $0.52 per Boe in 2003 due mainly to an increase in fuel costs incurred for the cyclic steam operations in the southern expansion of South Midway partially offset by a reduction in field operating costs at the Spraberry field as the wells mature.

Production and operating information including oil and gas revenue, operating costs and depletion, on a per Boe basis, from 2002 to 2004 are detailed below:

	Year ended December 31,								
		2004			2003			2002	
	U.S.	China	Total	U.S.	China	Total	U.S.	China	Total
Net Production:									
Boe	268,614	234,935	503,549	212,820	144,422	357,242	227,301	144,848	372,149
Boe/day for the year	734	642	1,376	583	396	979	623	397	1,020
		Per Boe			Per Boe			Per Boe	
Oil and gas revenue	$ 34.66	$ 36.11	$ 35.34	$ 25.69	$ 28.41	$ 26.79	$ 22.43	$ 22.30	$ 22.38
Operating costs	8.94	6.04	7.59	7.65	9.31	8.52	6.76	6.49	6.66
Production taxes	0.44		0.23	1.03		0.62	1.21		0.74
Engineering support	2.38	2.10	2.25	2.19	4.40	2.89	2.38	3.80	2.93
	11.76	8.14	10.07	10.87	13.71	12.03	10.35	10.29	10.33
Net operating revenue	22.90	27.97	25.27	14.82	14.70	14.76	12.08	12.01	12.05
Depletion	16.80	12.18	14.64	10.58	10.23	10.44	8.39	8.30	8.35
	$ 6.10	$ 15.79	$ 10.63	$ 4.24	$ 4.47	$ 4.32	$ 3.69	$ 3.71	$ 3.70

General and Administration

Our changes in general and administrative expenses for the year ended December 31, 2004 when compared to the same period for 2003 and for the year ended December 31, 2003 when compared to the same period for 2002 were as follows:

	2004 vs. 2003	2003 vs 2002
Favorable (unfavorable) variances:		
General and administrative	$ (177)	$ (2,091)
Stock based compensation	(800)	(165)
	$ (977)	$ (2,256)

As discussed below in this Item 7 in Critical Accounting Principles and Estimates Write-down of Non-Oil and Gas Properties , we incur various costs in the pursuit of GTL and EOR projects. Such costs incurred prior to signing an MOU, or similar agreement, are considered to be business development or project identification, are expensed as incurred and are reflected in the following table as GTL or EOR general and administrative expenses. Additionally, we capitalize a portion of our general and administrative costs that can be directly related to, and is necessary to, our capital investment activities. For the years ended December 31, 2004, 2003 and 2002, general and administrative expenses related directly to oil and gas acquisition, exploration and development activities, and investments in GTL and EOR projects of $3.8 million, $1.8 million and $2.6 million, respectively, were capitalized and thus are not included in the following table of changes in general administrative expenses (including stock based compensation) by segment:

	2004 vs. 2003	2003 vs 2002
Favorable (unfavorable) variances:		
Oil and Gas Activities:		
U.S.	$ 1,119	$ (931)
China	216	(271)
GTL	(140)	(656)
EOR	(442)	
Corporate	(1,730)	(398)
	$ (977)	$ (2,256)

General and Administrative 2004 vs. 2003

General and administrative expenses related to U.S. operations, before allocations to capital and operating costs, increased $0.8 million for 2004 primarily due to increased labor costs, including non-cash stock based compensation. This is offset by increased allocations of general and administrative to capital investments and operating costs of $1.5 million and $0.4 million, respectively, as a result of increased levels of exploration and development activities in the U.S during 2004 and the start up of production operations at Citrus, where we are the operator, and also at Knights Landing where we became the operator in December 2004.

General and administrative expenses related to the China operations, before allocations of costs to capital and operating costs, increased $0.4 million primarily due to increased labor costs and ramp up of administrative offices required to support the development and exploration activities initiated at the end of 2003. This is offset by increased allocations of general and administrative costs to capital investments and operating costs of $0.5 million and $0.1 million, respectively, primarily as a result of the development program and increased operations at our Dagang field.

We incurred a higher level of business development costs during 2004 related to identification of new opportunities for our GTL and HTL technologies particularly in the Middle East and China resulting in increased general and administrative costs of $0.6 million.

Corporate general and administrative expenses increased $1.7 million mainly due to $0.8 million incurred during 2004 to comply with the provisions of Section 404 of the Sarbanes-Oxley Act of 2002, a $0.8 million increase in non-cash stock based compensation related to the issuance of stock options and other net increases such as higher costs for directors and officers liability insurance.

General and Administrative 2003 vs. 2002

General and administrative costs, including stock based compensation costs, increased $2.3 million in 2003 from 2002.

General and administrative expenses related to U.S. operations increased $0.9 million compared to 2002. General and administrative expenses before allocations of costs to capital investments and operating costs increased $0.3 million for 2003 primarily due to increased labor costs including non-cash stock based compensation. Additionally, allocations of general and administrative costs to capital investments decreased $0.6 million as a result of decreased levels of exploration and development activities in the U.S during 2003.

General and administrative expenses related to the China operations, before allocations of costs to capital investments and operating costs, increased $0.3 million primarily due to costs incurred to explore the possibility of a public listing for Sunwing.

We incurred a higher level of business development costs for our GTL initiatives during 2003 primarily related to pursuing new sources of project financing resulting in increased general and administrative costs of $0.7 million.

Corporate general and administrative expenses increased $0.4 million during 2003 mainly due to fees incurred for the filing of a $100 million Canadian base shelf prospectus and corresponding U.S. shelf registration statement and increase in insurance costs.

Depletion and Depreciation

The primary expense in this classification is depletion of the carrying values of our oil and gas properties in our U.S. and China cost centers over the life of their proved oil and gas reserves as determined by independent reserve evaluators. For more information on how we calculate depletion and determine our proved reserves see Critical Accounting Principles and Estimates Oil and Gas Reserves and Depletion in this Item 7.

Depletion and Depreciation 2004 vs. 2003

Depletion and depreciation increased $3.7 million in 2004, which was due to the increase in depletion rates to $14.64 per Boe in 2004 compared to $10.44 per Boe in 2003.

The U.S. depletion rate for 2004 was $16.80 per Boe, a 59% increase from 2003. Despite a $16.3 million impairment of our U.S. oil and gas properties in 2004, our depletion rate increased in 2004 primarily as a result of significant costs of finding and acquiring proved reserves at our Knights Landing and Citrus fields as measured as at December 31, 2004. We believe we can continue to develop these fields over the coming year in order to economically increase our reserve base and improve our operating results.

The China depletion rate for 2004 was $12.18 per Boe, a 19% increase from 2003, due mainly to a downward revision of our share of proved reserves at Dagang as a result of continued increases in oil prices from 2003 and additional anticipated increases in future development costs. During periods of increasing oil prices our share of proved oil reserves decreases, as fewer barrels of oil are required to recover our costs under our production-sharing contract with CNPC.

Depletion and Depreciation 2003 vs. 2002

Depletion and depreciation increased $0.5 million in 2003, which was primarily due to the increase in depletion rates to $10.44 per Boe in 2003 compared to $8.35 per Boe in 2002.

The U.S. depletion rate for 2003 was $10.58 per Boe, a 26% increase from 2002, due mainly to an increase in the carrying value of our evaluated U.S. oil and gas properties primarily in Northwest Lost Hills, East Texas and North South Forty in the fourth quarter of 2003.

The China depletion rate for 2003 was $10.23 per Boe, a 23% increase from 2002, as a result of a downward revision of our share of proved reserves at Dagang due to increased oil prices in 2003 and anticipated increases in Dagang future development costs.

Write-Down of GTL Investments

As discussed below in this Item 7 in Critical Accounting Principles and Estimates Write-down of Non-Oil and Gas Properties , for Canadian GAAP we capitalize technical and commercial feasibility costs incurred for GTL or EOR projects, including studies for the marketability of the projects products, subsequent to executing an MOU. If no definitive agreement is reached, then the capitalized costs, which are deemed to have no future value, are written down to our results of operations with a corresponding reduction in our investments in GTL and EOR assets. For U.S. GAAP, all such costs are expensed as incurred.

Write-Down of GTL Investments 2004 vs. 2003

In the second quarter of 2004, we wrote down our $0.3 million investment in the Oman GTL project as our opportunity to build a 45,000-barrels per day GTL fuels plant in Oman failed to materialize due to a lack of sufficient uncommitted gas volumes. This compares to the $3.3 million write-down of our GTL investments in connection with negotiation costs incurred to construct and operate a GTL production facility in Qatar, which was terminated in 2003 without reaching a definitive agreement.

Write-Down of GTL Investments 2003 vs. 2002

We wrote-down $3.3 million of our GTL investments in 2003 as a result of the termination of our contract negotiation for a GTL development and production contract in Qatar compared to a write-down of $2.4 million in 2002 related to our investment in Syntroleum s Sweetwater GTL project.

Impairment of U.S. Oil and Gas Properties

As discussed below in this Item 7 in Critical Accounting Principles and Estimates Impairment of Proved Oil and Gas Properties , we evaluate each of our cost center s proved oil and gas properties for impairment on a quarterly basis. If as a result of this evaluation, a cost center s carrying value exceeds its expected future net cash flows from its proved and probable reserves then a provision for impairment must be recognized in the results of operations.

Impairment of U.S. Oil and Gas Properties 2004 vs. 2003

We impaired our U.S. oil and gas properties by $16.3 million in 2004, compared to an impairment of $20.0 million in 2003. The impairment for 2004 is due to an evaluation of a number of our proved properties at the Knights Landing, Citrus and South Midway fields, and a further impairment of our unproved properties, primarily Northwest Lost Hills.

At the Knights Landing gas field, our 2004 drilling resulted in three successful completions and six dry holes. We plan to use 3-D seismic to improve the discovery rate in this field and well workovers are planned to increase gas rates and reduce operating costs. At our Citrus field we are evaluating drilling another horizontal leg in our horizontal well by the second quarter of 2005 to target the upper Antelope zone located a few hundred feet above the existing horizontal well. In the southern expansion area at South Midway, we have supplemented the cyclic steam project with a pilot to test continuous steam injection into two wells. The project began in October 2004 and by year-end 2004 was beginning to yield increased production in the surrounding wells. The further impairment of our Northwest Lost Hills prospect reflects the potential farm-out of a portion of our working interest to one or more partners to fund a test of the well.

Impairment of U.S. Oil and Gas Properties 2003 vs. 2002

The $20.0 million impairment for 2003 was due to an increase in the carrying value of our proved U.S. oil and gas properties primarily in Northwest Lost Hills, East Texas and North South Forty when compared to the expected future cash flows of our U.S. proved reserves at year end 2003. Such carrying values increased as a result of our decision, in the fourth quarter of 2003, to potentially farm-out up to 50% of our working interest to one or more partners to fund a test of Northwest Lost Hills # 1-22. Additionally during 2003, we completed our evaluation of significant portions of our acreage positions in East Texas and North South Forty and either relinquished or plan to relinquish our interests, thus adding to the carrying value of our proved U.S. oil and gas properties.

Capital Investments - 2004

Our investments in capital activities in each of the three most recently completed financial years were as follows:

	Year ended December 31,		
	2004	**2003**	**2002**
Oil and Gas Activities:			
U.S.	$ 17,428	$ 8,386	$ 13,305
China	26,965	6,213	3,626
GTL	95	792	1,897
EOR	1,966		
	$ 46,454	$ 15,391	$ 18,828

Oil and Gas Activities - U.S.

We completed the drilling of the first Citrus well, which was spud in December 2003, and drilled two additional Citrus wells and completed production facilities during 2004 for $5.5 million.

We spent $7.1 million on our Knights Landing field during 2004. We farmed-in to the Knights Landing field in February 2004 by purchasing a 50% working interest in four previous discoveries in the contract area and funding gas gathering, surface treatment facilities and meters to connect the four wells to an existing pipeline system. Additionally, we drilled nine new exploratory wells to earn a 50% working interest after payout in any new discoveries, which resulted in three successful completions and six dry holes. In December 2004, we reached an agreement with the operator of the field to purchase its interest in the field, increasing our working interests in the field and 11 existing producing natural gas wells to between 80% and 100%.

We invested $2.1 million during 2004 to extend the SAGD pilot program at LAK Ranch including modifications to the existing facilities for cyclic steaming operations to enable steam injection in the producing horizontal well, installation of fiber optic temperature recording and artificial lift equipment on the producing horizontal well and acquisition of ultra high resolution 3-D seismic needed to better define the optimum reservoir development locations.

In 2004, we drilled seven new wells on the South Midway properties for $1.1 million, consisting of six step-out development locations and one exploratory well. Four of the six development wells were completed as producers. The exploratory well was unsuccessful and will be held for a future disposal well.

We completed the drilling of the first Sledge Hamar well, which was spud in December 2003, and drilled one follow up well for $0.4 million. However, the follow up well drilled in April 2004 encountered the Stevens sands below the oil/water contact and tested only water. After evaluating the production results and other potential hydrocarbon intervals, we concluded that the future economic potential was unfavorable and, in December 2004, sold our working interest for $0.5 million.

We drilled one well at the McCloud River prospect during 2004 for $0.3 million, including prospect acquisition costs. The initial well resulted in a dry hole.

We incurred $0.9 million of lease acquisition costs, including lease rentals, geological and geophysical and seismic on various prospects primarily in California during 2004, which were capitalized under the full cost method of accounting. See Critical Accounting Principles and Estimates Full Cost Accounting in this Item 7.

Oil and Gas Activities China

We incurred $20.0 million in capital investments during 2004 to further our overall development program at Dagang. We drilled and completed 16 development wells and converted 1 existing well to water injection service. Three new wells were awaiting completion at the end of 2004 and we commenced the drilling of 1 well in late December 2004.

We incurred $7.0 million during 2004 to complete the acquisition, processing and interpretation of approximately 540 miles of a 700-mile seismic acquisition program on the Zitong block. We selected the location of our first exploration well and signed a drilling contract to commence drilling of the well in the first quarter of 2005. The drilling of a second well, expected in late 2005, will follow completion of the remaining portion of our seismic acquisition program.

EOR Activities

Capital investments in EOR related activities for 2004 was $2.0 million, primarily related to Iraqi EOR project activities.

In October 2004, we signed an MOU with the Ministry of Oil of the Government of Iraq to study and evaluate the shallow Qaiyarah oil field in Iraq. The field s reservoirs contain a large proven accumulation of 17.9 API heavy oil at a depth of about 1,000 feet. We will evaluate the potential response of the Qaiyarah oil field to the latest in EOR techniques, along with the potential value that could be added using the Ensyn RTP Technology to produce higher quality, more valuable crude oil. The work will include an assessment of the oil-in-place in the reservoirs, and the optimum EOR/HTL methods to establish economically recoverable volumes at the Qaiyarah oil field. If the evaluation studies indicate development of the field is economically viable, we will present a development plan and offer a commercial proposal to implement an EOR program for the Qaiyarah oil field. The Iraqi Ministry of Oil is under no obligation to execute the project or to enter into formal commercial negotiations at the completion of our study.

GTL Activities

There was minimal capital investment in GTL projects for 2004. There were no significant changes in the status of our active GTL projects in Egypt and Bolivia and we continue to pursue definitive agreements for the construction and operation of GTL facilities in those countries.

Liquidity and Capital Resources

Sources and Uses of Cash

Our net cash and cash equivalents decreased by $5.2 million in 2004. Our 2004 operating activities provided $4.0 million in cash due to a 41% increase in our production volumes, primarily from China, and a 32% increase in oil and gas prices from 2003. We raised a net of $22.2 million from two special warrant financings in the first quarter of 2004 and from the exercise of options during the year. We raised $14.0 million of cash during 2004 from the farm-out of a 40% working interest in the Dagang field and the sale of our working interest in the Sledge Hamar field. We completed the drawdown of our non-revolving line of credit for the development of the South Midway field by borrowing $4.0 million and we made note payments of $0.7 million during 2004. This was offset by capital investments, after changes in non-cash working capital, of $43.2 million, as discussed in this Item 7 Capital

Investments 2004 , and $2.5 million to acquire a 15% equity interest in EPIL plus merger expenses of $2.5 million incurred during 2004 to acquire 100% of Ensyn.

Our net cash and cash equivalents increased by $10.5 million in 2003 compared to a decrease of $5.7 million in 2002. We raised $17.9 million more in 2003 than in 2002 through private placements and the exercise of warrants and incentive stock options and we invested $3.4 million less in 2003 than in 2002 on exploration, development and GTL activities. This was partially offset by a reduction in cash generated from asset sales as we sold non-core assets in China and Texas for $5.4 million in 2002.

	Year ended December 31,		
	2004	2003	2002
Cash flow (deficit) from operating activities	$ 4,032	$ (1,522)	$ (2,120)
Investing Activities			
Capital investments, after changes in non-cash working capital	(43,190)	(15,928)	(19,466)
Proceeds from sale of assets	13,958		5,351
Investment in Ensyn	(5,016)	(500)	
Other	(410)	(37)	(65)
	(34,658)	(16,465)	(14,180)
Financing Activities			
Private placements, net of share issue costs	20,428	24,070	9,964
Proceeds from exercise of options and warrants	1,723	3,928	119
Net debt financing	3,306	500	500
	25,457	28,498	10,583
Net Sources (Uses) of Cash	$ (5,169)	$ 10,511	$ (5,717)

Outlook for 2005

Our capital investment budget for 2005 is $79.0 million. Of the total 2005 investment program, $54.2 million, or 69%, is for continued development of our producing fields at Dagang, South Midway, Knights Landing and Citrus. Approximately $22.5 million, or 29% of the budget, is for exploration programs in the U.S., principally in California, and for our exploration commitment in the Zitong block. The balance of our 2005 budget, or approximately $2.3 million, is for the continued development of EOR and GTL initiatives around the world. Additionally, we have agreed to pay $10.0 million in cash and $75 million in stock to acquire Ensyn and expect to incur approximately $1.5 million in Merger related expenses during 2005 in order to close the transaction. We plan to seek financing on an as needed basis, from equity markets, project lenders, joint ventures or other potential financing sources to complete this capital program and acquisition of Ensyn, to pursue acquisitions of proven and probable reserves and to deploy our HTL and GTL technologies. In addition, we, together with our 40% partner in the Dagang project, are in active discussions with European and Chinese lending banks to provide funding for the development of the Dagang field.

In October 2003, we filed a base shelf prospectus with Canadian securities regulatory authorities and a shelf registration statement with the U.S. Securities and Exchange Commission to qualify for potential future sale in Canada and the U.S. up to $100 million of various types of securities, including common shares, preferred shares, warrants and debt securities. These shelf filings are expected to give us greater flexibility to fund our expansion and capital programs and will allow us to take advantage of a broader range of financing opportunities on a timelier basis. A combination of such equity financing, as well as convertible debenture, debt and mezzanine financing and joint venture partner participation, will be required to complete our future capital programs. We cannot assure you that we will be successful in raising the additional funds necessary or securing joint venture partners to complete our capital programs. If we are unsuccessful, we will have to prioritize our capital programs, which may result in delaying and potentially losing some valuable business opportunities.

Contractual Obligations and Commitments

The table below summarizes and cross-references the contractual obligations and commitments that are reflected in our Consolidated
Balance Sheets and/or disclosed in the accompanying Notes:

	Payments Due by Year (stated in thousands of U.S. dollars)					
	Total	**2005**	**2006**	**2007**	**2008**	**After 2008**
Purchase Agreement:	$ 200	$ 100	$ 100	$	$	$
Consolidated Balance Sheets:						
Note payable current portion *(Note 8)*	1,667	1,667				
Long term debt *(Note 8)*	2,639		1,667	972		
Other Commitments:						
Interest payable (1)	302	186	99	17		
Lease commitments *(Note 17)*	2,123	616	543	342	287	335
Zitong exploration commitment *(Note 17)*	12,400	12,400				
Total	$ 19,331	$ 14,969	$ 2,409	$ 1,331	$ 287	$ 335

(1) This is the estimated future interest payments on our note payable and long term debt using the rate of interest in effect as at December 31, 2004, which is 5.25%.
We have excluded our normal purchase arrangements as they are discretionary and/or being performed under contracts which are cancelable immediately or with a 30-day notification period.

Critical Accounting Principles and Estimates

Our accounting principles are described in Note 2 to Notes to the Consolidated Financial Statements in Item 8 of this Annual Report on Form 10-K. We prepare our Consolidated Financial Statements in conformity with GAAP in Canada, which conform in all material respects to U.S. GAAP except for those items disclosed in Note 19 to Notes to the Consolidated Financial Statements in Item 8 of this Annual Report on Form 10-K. For U.S. readers, we have detailed the differences and have also provided a reconciliation of the differences between U.S. and Canadian GAAP in Note 19 to Notes to the Consolidated Financial Statements.

The preparation of our financial statements requires us to make estimates and judgments that affect our reported amounts of assets, liabilities, revenue and expenses. On an ongoing basis we evaluate our estimates, including those related to asset impairment, revenue recognition, allowance for doubtful accounts and contingencies and litigation. These estimates are based on information that is currently available to us and on various other assumptions that we believe to be reasonable under the circumstances. Actual results could vary from those estimates under different assumptions and conditions.

We have identified the following critical accounting policies that affect the more significant judgments and estimates used in preparation of our consolidated financial statements.

Full Cost Accounting We follow the full cost method of accounting for our oil and gas properties. Under the full cost method, all exploration and development costs associated with lease and royalty interest acquisition, geological and geophysical activities, carrying charges for unproved properties, drilling both successful and unsuccessful wells, gathering and production facilities and equipment, financing, administrative costs directly related to capital projects and asset retirement costs are capitalized on a country-by-country cost center basis. As at December 31, 2004, the carrying values of our U.S. and China cost centers were $40.8 million and $39.7 million, respectively.

The other generally accepted method of accounting for costs incurred for oil and gas properties is the successful efforts method. Under this method, costs associated with land acquisition and geological and geophysical activities are expensed in the year incurred and the costs of drilling unsuccessful wells are expensed upon abandonment.

As a consequence of following the full cost method of accounting, we may be more exposed to potential impairments if the carrying value of a cost center s oil and gas properties exceeds its estimated future net cash flows than if we followed the successful efforts method of accounting. An impairment may occur if a cost center s recoverable reserve estimates decrease, oil and natural gas prices decline or capital, operating and income taxes increase to levels that would significantly affect its estimated future net cash flows. See Impairment of Proved Oil and Gas Properties below.

Oil and Gas Reserves The process of estimating quantities of reserves is inherently uncertain and complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. Our reserve estimates are based on current production forecasts, prices and economic conditions. The reserve numbers and values included in this Annual Report on Form 10-K are only estimates and you should not assume that the present value of our future net cash flows from these estimates is the current market value of our estimated proved oil and gas reserves. (See Risk Factors)

Reserve estimates are critical to many accounting estimates and financial decisions including:

determining whether or not an exploratory well has found economically producible reserves. Such determinations involve the commitment of additional capital to develop the field based on current estimates of production forecasts, prices and other economic conditions.

calculating our unit-of-production depletion rates. Proved reserves are used to determine rates that are applied to each unit-of-production in calculating our depletion expense. In 2004, oil and gas depletion of $7.4 million was recorded in depletion and depreciation expense. If our reserve estimates changed by 10%, our depletion and depreciation expense for 2004 would have changed by approximately $0.7 million assuming no other changes to our reserve profile. See Depletion below.

assessing our proved oil and gas properties for impairment on a quarterly basis. Estimated future net cash flows used to assess impairment of our oil and gas properties are determined using proved and probable reserves [(1)]. See Impairment of Proved Oil and Gas Properties below.

Management is responsible for estimating the quantities of proved oil and natural gas reserves and preparing related disclosures. Estimates and related disclosures are prepared in accordance with SEC requirements, generally accepted industry practices in the U.S.

as promulgated by the Society of Petroleum Engineers, and the standards of the COGE Handbook modified to reflect SEC requirements.

Independent qualified reserves evaluators prepare reserve estimates for each property at least annually and issue a report thereon. The reserve estimates are reviewed by our engineers familiar with the property and by our operational management. Our CEO and CFO meet with our operational personnel to review the current reserve estimates and related disclosures in this Annual Report on Form 10-K and upon their review and approval present the independent qualified reserves evaluators reserve reports to our Board of Directors with a recommendation for approval. Our Board of Directors has approved the reserve estimates and related disclosures in this Annual Report on Form 10-K.

The estimated discounted future net cash flows from estimated proved reserves included in the Supplementary Financial Information in this Annual Report on Form 10-K are based on prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower. Actual future net cash flows will also be affected by factors such as actual production levels and timing, and changes in governmental regulation or taxation, and may differ materially from estimated cash flows.

(1) **Proved** oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate and natural gas liquids that geological and engineering data demonstrate with reasonable certainty can be recoverable in future years from known reservoirs under existing economic and operating conditions. Reservoirs are considered proved if economic producability is supported by either actual production or a conclusive formation test. **Probable** reserves are those additional reserves that are less likely to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of estimated proved plus probable reserves.

Depletion As indicated previously our estimate of proved reserves are critical to calculating our unit-of-production depletion rates.

Another critical factor affecting our depletion rate is our determination that an impairment of unproved oil and gas properties has occurred. Costs incurred on an unproved oil and gas property are excluded from the depletion rate calculation until it is determined whether proved reserves are attributable to an unproved oil and gas property or upon determination that an unproved oil and gas property has been impaired. An unproved oil and gas property would likely be impaired if, for example, a dry hole has been drilled and there are no firm plans to continue drilling on the property. Also, the likelihood of partial or total impairment of a property increases as the expiration of the lease term approaches and there are no plans to drill on the property or to extend the term of the lease. We assess each of our unproved oil and gas properties for impairment on a quarterly basis. If we determined that an unproved oil and gas property has been totally or partially impaired we respectively include all or a portion of the accumulated costs incurred for that unproved oil and gas property in the calculation of our unit-of production depletion rate. As at December 31, 2004, we had $20.4 million and $10.6 million of costs incurred on unproved oil and gas properties in the U.S. and China, respectively.

Our depletion rate is also affected by our estimates of future costs to develop the proved reserves. We estimate future development costs using quoted prices, historical costs and trends. It is difficult to predict prices for materials and services required to develop a field particularly over a period of years with rising oil and gas prices during which there is generally increased competition for a limited number of suppliers. We update our estimates of future costs to develop our proved reserves on a quarterly basis.

Impairment of Proved Oil and Gas Properties We evaluate each of our cost center s proved oil and gas properties for impairment on a quarterly basis. The basis for calculating the amount of impairment is different for U.S. and Canadian GAAP purposes.

Effective January 2004, Accounting Guideline 16 Oil and Gas Accounting Full Cost (**AcG 16**) requires recognition and measurement processes to assess impairment of oil and gas properties (**ceiling test**). In the recognition of an impairment, the carrying value [(1)] of a cost center is compared to the undiscounted future net cash flows of that cost center s proved reserves using estimates of future oil and gas prices and costs plus the cost of unproved properties that have been excluded from the depletion calculation. If the carrying value is greater than the value of the undiscounted future net cash flows of the proved reserves plus the cost of unproved properties excluded from the depletion calculation, then the amount of the cost center s potential impairment must be measured. A cost center s impairment loss is measured by the amount its carrying value exceeds the discounted future net cash flows of its proved and probable reserves using estimates of future oil and gas prices and costs plus the cost of unproved properties that have been excluded from the depletion calculation and which contain no probable reserves. The net cash flows of a cost center s proved and probable reserves are discounted using a risk-free interest rate. The amount of the impairment loss is recognized as a charge to the results of operations and a reduction in the net carrying amount of a cost center s oil and gas properties. We provided for $16.3 million and $20.0 million in ceiling test impairments for our U.S. cost center for the years ended December 31, 2004 and 2003, respectively. No ceiling test impairments were provided for in the year ended December 31, 2002.

For U.S. GAAP, we follow the requirements of the SEC s Regulation S-X Article 4-10(c)4 for determining the limitation of capitalized costs. Accordingly, the carrying value [(1)] of a cost center s oil and gas properties cannot exceed the discounted future net cash flows of its proved reserves using period-end oil and gas prices and costs plus (i) the cost of properties that have been excluded from the depletion calculation and (ii) the lower of cost or estimated fair value of unproved properties included in the depletion calculation less income tax effects related to differences between the book and tax basis of the properties. The net cash flows of a cost center s proved reserves are discounted using ten percent. The amount of the impairment loss is recognized as a charge to the results of operations and a reduction in the net carrying amount of a cost center s oil and gas properties. We provided for $15.0 million and $20.0 million in ceiling test impairments for our U.S. cost center for the years ended December 31, 2004 and 2003, respectively. No ceiling test impairments were provided for in the year ended December 31, 2002.

(1) For Canadian GAAP, the carrying value includes all capitalized costs for each cost center, including costs associated with asset retirement net of estimated salvage values, unproved properties and major development projects, less accumulated depletion and ceiling test impairments. This is essentially the same definition according to Regulation S-X, except that carrying value of assets should be net of deferred income taxes and costs of major development projects are to be considered separately for purposes of the ceiling test calculation.

Write-down of Non-Oil and Gas Properties We incur various costs in the pursuit of GTL and EOR projects throughout the world. For Canadian GAAP, such costs incurred prior to signing an MOU, or similar agreements, are considered to be business development or project identification and are expensed as incurred. Upon executing an memorandum of understanding to determine the technical and commercial feasibility of a project, including studies for the marketability of the projects products, we assume the feasibility and related costs incurred have potential future value, are probable of leading to a definitive agreement for the exploitation of proved reserves and should be capitalized. If no definitive agreement is reached, then the capitalized costs, which are deemed to have no future value, are written down to our results of operations with a corresponding reduction in our investments in GTL and EOR assets. For the years ended December 31, 2004, 2003 and 2002, we wrote down $0.3 million, $3.3 million and $2.4 million, respectively, of capitalized negotiation and feasibility costs associated with our GTL projects which did not result in definitive agreements.

For U.S. GAAP, feasibility, marketing and related costs incurred prior to executing a GTL or EOR definitive agreement are considered to be research and development and are expensed as incurred. For the years ended December 31, 2004, 2003 and 2002, we expensed $2.1 million, $0.8 million and $1.9 million, respectively, of feasibility, marketing and related costs incurred prior to executing definitive agreements.

Impact of New and Pending Canadian GAAP Accounting Standards

In December 2002, the Canadian Institute of Chartered Accountants (**CICA**) approved Section 3110, Asset Retirement Obligations (**S.3110**). S.3110 requires liability recognition for retirement obligations associated with property, plant and equipment. These obligations are initially measured at fair value, which is the discounted future value of the liabilities. This fair value is capitalized as part of the cost of the related assets and amortized to expense over their useful life. The liabilities accrete until expected settlement of the retirement obligations. S.3110 is effective for fiscal years beginning on or after January 1, 2004. We elected early implementation of this accounting policy. Accordingly, effective January 1, 2003, we changed our accounting policy to capitalize asset retirement costs as part of the carrying value of our oil and gas properties and adjusted the amount of our site restoration liability to the present value of the liability for the corresponding asset retirement obligation as of this date. We have adopted the policy without retroactive adjustment of prior years because implementation of this change had an immaterial effect on our financial position and results of operations in prior years and in the current period.

In September 2003, the CICA issued AcG 16. AcG 16 is to be applied no later than January 1, 2004 and provides a new methodology for determining impairment of oil and gas properties, provides linkage to the new standards for determination of reserves and related disclosures under National Instrument 51-101 and revises certain other aspects of accounting for oil and gas operations under the full cost method.

Prior to January 2004, we applied hedge accounting to all derivative instruments used to manage price fluctuations in oil and natural gas prices. Effective January 1, 2004, we adopted CICA Accounting Guideline 13 (**AcG 13**), Hedging Relationships . This guideline sets out the criteria that must be met in order to apply hedge accounting for derivatives. The guideline provides detailed guidance on the identification, designation, documentation and effectiveness of hedging relationships for purposes of applying hedge accounting, and the discontinuance of hedge accounting. Gains and losses on derivative instruments designated and qualifying as hedges under this guideline are recognized in earnings in the same period as the related hedged item. Ineffective hedging relationships and hedges not designated in a hedging relationship are carried at fair value in the statement of financial position, and subsequent changes in their fair value are recorded in the results of operations. The adoption of this accounting guideline did not have a material impact on the consolidated financial statements.

In July 2002, the CICA approved Section 3870, Stock Based Compensation and Other Stock Based Payments (**S.3870**). S.3870 applies to all stock based awards entered into during fiscal years beginning on or after January 1, 2002. For awards entered into with non-employees on or after January 1, 2002, S.3870 requires compensation costs to be recognized in the financial statements over the periods in which the stock options vest using the fair value based method of accounting. Although earlier implementation was encouraged, S.3870 did not require compensation costs to be recognized in the financial statements for stock based awards to employees and directors entered into during fiscal years beginning on or after January 1, 2002 until January 1, 2004. If earlier implementation was not elected, S.3870 requires a retroactive application of the change in accounting for such stock based awards entered into between January 1, 2002 and December 31, 2003 with an option to restate the financial statements of prior periods. We implemented S.3870, as it relates to stock based awards to employees and directors, effective January 1, 2004 with a restatement of the financial statements of prior periods.

In January 2005, the CICA approved Section 1530 Comprehensive Income (**S.1530**), Section 3855 Financial Instruments Recognition and Measurement (**S.3855**) and Section 3865 Hedges (**S.3865**) to harmonize financial instrument and hedge accounting with U.S. GAAP and introduce the concept of comprehensive income. S.1530 requires presentation of certain gains and losses outside of net income, such as unrealized gains and losses related to hedges or other derivative instruments. S.3855 establishes standards for recognizing and measuring financial assets and financial liabilities and non-financial derivatives as required to be disclosed under Section 3861 Financial Instruments Disclosure and Presentation . S.3865 establishes standards for how and when hedge accounting may be applied. We apply SFAS No. 133 Accounting for Derivative Instruments and Hedging Activities for U.S. GAAP purposes and will implement S.3865 for Canadian GAAP for hedging activities. These sections apply to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006 and are not expected to have a material impact on our financial statements.

In January 2005, the CICA approved Section 3251 Equity which establishes standards for the presentation of equity and changes in equity during a reporting period. This section applies to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006 and is not expected to have a material impact on our financial statements.

The following standards issued by the CICA do not impact us at this time:

Section 3861, Financial Instruments Disclosure and Presentation , effective for fiscal years beginning on or after November 1, 2004.

Accounting Guideline 15, Consolidation of Variable Interest Entities , effective for annual and interim periods beginning on or after January 1, 2004.

Impact of New and Pending U.S. GAAP Accounting Standards

In June 2004, the Financial Accounting Standards Board (**FASB**) issued an exposure draft of a proposed statement, Fair Value Measurements to provide guidance on how to measure the fair value of financial and non-financial assets and liabilities when required by other authoritative accounting pronouncements. The proposed statement attempts to address concerns about the ability to develop reliable estimates of fair value and inconsistencies in fair value guidance provided by current U.S. GAAP, by creating a framework that clarifies the fair value objective and its application in U.S. GAAP. In addition, the proposal expands disclosures required about the use of fair value to re-measure assets and liabilities. The standard would be effective for financial statements issued for fiscal years beginning after June 15, 2005.

In September of 2004, the SEC released Staff Accounting Bulletin No. 106, which provides guidance regarding the interaction of Statement of Financial Accounting Standard No. 143, Accounting for Asset Retirement Obligations (**SFAS 143**) with the full cost accounting rules in Article 4-10 of Regulation S-X. This bulletin clarifies the treatment of assets and liabilities resulting from the implementation of SFAS 143 on the full cost ceiling test and the calculation of depletion, depreciation and amortization. We are in compliance with the provisions of Staff Accounting Bulletin No. 106.

In December 2004, the FASB issued a revision to SFAS No. 123, Accounting for Stock Based Compensation , which supersedes APB No. 25, Accounting for Stock Issued to Employees . This Statement requires measurement of the cost of employee services received in exchange for an award of equity instruments based on the fair value of the award on the date of the grant and recognition of the cost in the results of operations over the period during which an employee is required to provide service in exchange for the award. No compensation cost is recognized for equity instruments for which employees do not render the requisite service. We apply APB Opinion No. 25, as interpreted by FASB Interpretation No. 44, in accounting for awards issued from our stock option plan and do not recognize compensation costs in our financial statements for stock options issued to our employees and directors. This statement is effective for the first interim or annual reporting period that begins after June 15, 2005 and may be implemented on a modified prospective or retrospective basis. We have elected to implement this statement on a modified prospective basis starting in the third quarter of 2005. Under the modified prospective basis we would recognize stock based compensation in our U.S. GAAP results of operations for the unvested portion of awards outstanding as of July 1, 2005 and for all awards granted after July 1, 2005.

The following standards issued by the FASB do not impact us at this time:

SFAS No. 151, Inventory Costs an amendment of ARB No. 43, Chapter 4 effective for inventory costs incurred during fiscal years beginning after June 15, 2005.

SFAS No. 153, Exchanges of Nonmonetary Assets an amendment of APB Opinion No. 29 effective for nonmonetary asset exchanges occurring in fiscal years beginning after June 15, 2005.

Off Balance Sheet Arrangements

At December 31, 2004 and 2003, we did not have any relationships with unconsolidated entities or financial partnerships, such as structured finance or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. In addition, we do not engage in trading activities involving non-exchange traded contracts. As such, we are not materially exposed to any financing, liquidity, market or credit risk that could arise if we had engaged in such relationships. We do not have relationships and transactions with persons or entities that derive benefits from their non-independent relationship with us, or our related parties, except as disclosed herein.

Related Party Transactions

We have entered into agreements with a number of entities, some of which are related through common directors or shareholders, to share administrative personnel, aircraft, office space and facilities on a cost recovery basis. The agreement for the usage of aircraft was terminated in 2003. The costs incurred in the normal course of business with respect to the above arrangements amounted to $0.9 million each for 2004 and 2003 and $1.2 million for 2002. In addition, a company controlled by a director provides us with consulting services. Consulting services and out of pocket expenses paid to this company were $0.7 million for 2004 and $0.4 million each for 2003 and 2002. At year-end, amounts included in accounts payable under these arrangements totaled $0.1 million in 2004 and 2003 and $0.8 million in 2002.

In 2003, we borrowed $1.25 million from a related company controlled by one of our directors. The loan, plus accrued interest, was repaid in September 2003.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Equity Market Risks

We currently have limited production in the U.S and China, which have not generated sufficient cash from operations to fund our exploration and development activities. Historically, we have relied on the equity markets as the primary source of capital to fund our expansion and growth opportunities. We estimate that we will need approximately $40 million from the equity markets to fund our capital investment programs for 2005.

We can give no assurance that we will be successful in obtaining financing from equity markets as and when needed. Factors beyond our control may make it difficult or impossible for us to obtain equity financing on favorable terms or at all. Failure to obtain any required equity financing on a timely basis may cause us to postpone our development plans, forfeit rights in some or all of our projects or reduce or terminate some or all of our operations.

Commodity Price Risk

Commodity price risk related to crude oil prices is one of our most significant market risk exposures. Crude oil prices and quality differentials are influenced by worldwide factors such as OPEC actions, political events and supply and demand fundamentals. To a lesser extent we are also exposed to natural gas price movements. Natural gas prices are generally influenced by oil prices, North American supply and demand and local market conditions. We estimate that our net income and cash from operations for 2005 would change $1.0 million and $0.9 million for every $1.00/Bbl change in WTI prices and $0.50/Mcf in natural gas prices, respectively.

We periodically engage in the use of derivatives to hedge our cash flow from operations but have no hedge contracts in place as at December 31, 2004. See Note 12 to the Consolidated Financial Statements in Item 8.

Decreases in oil and natural gas prices would negatively impact our results of operations as a direct result of a reduction in revenues but may also do so in the ceiling test calculation for the impairment of our oil and gas properties. On a quarterly basis, we compare the value of our proved and probable reserves, using estimated future oil and gas prices [(1)], to the carrying value of our oil and gas properties. The ceiling test calculation is sensitive to oil and gas prices and in a period of declining prices could result in a charge to our results of operations as we experienced in 2001 when we recorded a $14.0 million provision for impairment for Canadian GAAP and an additional $10.0 million for U.S. GAAP mainly due to a decline in oil and gas prices. Decreases in oil and gas prices from those used in our ceiling test calculation as at December 31, 2004 as discussed above in Critical Accounting Principles and Estimates Impairment of Proved Oil and Gas Properties may result in additional impairment provisions on our U.S. oil and gas properties.

(1) The recoverable value of probable reserves is included only for the measurement of the impairment of the carrying value of oil and gas properties as required under

Canadian GAAP but not for U.S. GAAP. Additionally, U.S. GAAP requires the use of period end oil and gas prices to measure the amount of the impairment rather than estimated future oil and gas prices as required by Canadian GAAP. See Critical Accounting Principles and Estimates in Item 7 in this Annual Report on Form 10-K for the difference between Canadian and U.S. GAAP in calculating the impairment provision for oil and gas properties.

Foreign Currency Rate Risk

In the international petroleum industry, most production is bought and sold in U.S. dollars or with reference to the U.S. dollar. Accordingly, we do not expect to face foreign exchange risks associated with our production revenues.

Most of our business transactions, in the countries in which we operate, are conducted in U.S. dollars or currencies, such as Chinese renminbi, which are pegged to the U.S. dollar. As a result, we incurred insignificant foreign currency exchange gains or losses during the three years ended December 31, 2004.

Interest Rate Risk

We currently have minimal debt obligations and, therefore, we do not believe that we face any undue financial risk from interest rate fluctuations.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Financial Statements and Related Information

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Shareholders of
Ivanhoe Energy Inc.:

We have audited the consolidated balance sheets of Ivanhoe Energy Inc. as at December 31, 2004 and 2003 and the consolidated statements of loss and shareholders equity and cash flow for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). These standards require that we plan and perform an audit to obtain reasonable assurance 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, these consolidated financial statements present fairly, in all material respects, the financial position of Ivanhoe Energy Inc. as at December 31, 2004 and 2003 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004 in accordance with Canadian generally accepted accounting principles.

(signed) Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Alberta, Canada

February 11, 2005

COMMENTS BY AUDITORS FOR U.S. READERS ON CANADA U.S. REPORTING DIFFERENCES

The standards of the Public Company Accounting Oversight Board (United States) require the addition of an explanatory paragraph (following the opinion paragraph) when there are changes in accounting principles that have a material effect on the comparability of the Company s financial statements and changes in accounting principles that have been implemented in the financial statements. As discussed in Note 2 to the consolidated financial statements, the Company changed its method of accounting for asset retirement obligations (Canadian Institute of Chartered Accountants (CICA) Handbook Section 3110), stock-based compensation (CICA Handbook Section 3870), and the full cost method of accounting (CICA Accounting Guideline 16). Our report to the shareholders dated February 11, 2005 is expressed in accordance with Canadian reporting standards, which do not require a reference to such changes in accounting principles in the auditors report when the changes are properly accounted for and adequately disclosed in the financial statements.

(signed) Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Alberta, Canada

February 11, 2005

IVANHOE ENERGY INC.

Consolidated Balance Sheets
(stated in thousands of U.S. Dollars, except share amounts)

	As at December 31, 2004	2003 (restated Notes 2 and 9)
Assets		
Current Assets		
Cash and cash equivalents	$ 9,322	$ 14,491
Accounts receivable *(Note 3)*	5,377	2,720
Prepaid and other current assets	812	409
	15,511	17,620
Long term assets *(Note 5)*	6,424	998
Oil and gas properties and investments, net *(Note 4)*	96,551	87,956
	$ 118,486	$ 106,574
Liabilities and Shareholders Equity		
Current Liabilities		
Accounts payable and accrued liabilities	$ 9,845	$ 4,516
Note payable current portion *(Note 6)*	1,667	167
	11,512	4,683
Long term debt *(Note 6)*	2,639	833
Asset retirement obligations *(Note 7)*	749	521
Commitments and contingencies *(Note 17)*		
Shareholders Equity		
Share capital, issued and outstanding 169,664,911 common shares; December 31, 2003 161,359,339 common shares *(Note 8)*	183,617	161,075
Contributed surplus	1,748	516
Accumulated deficit	(81,779)	(61,054)
	103,586	100,537
	$ 118,486	$ 106,574

(See accompanying Notes to Consolidated Financial Statements)

Approved by the Board:

(signed) David R. Martin Director	(signed) E. Leon Daniel Director

IVANHOE ENERGY INC.

Consolidated Statements of Loss
(stated in thousands of U.S. Dollars, except share amounts)

	Year ended December 31,		
	2004	**2003**	**2002**
		(restated Notes 2 and 9)	
Revenue			
Oil and gas revenue	$ 17,795	$ 9,569	$ 8,329
Interest income	202	90	108
	17,997	9,659	8,437
Expenses			
Operating costs	5,073	4,293	3,841
General and administrative	9,188	8,211	5,955
Depletion and depreciation	7,482	3,829	3,312
Interest expense	379	184	23
Write-downs and provision for impairment *(Notes 4 and 13)*	16,600	23,321	2,436
	38,722	39,838	15,567
Net Loss	$ 20,725	$ 30,179	$ 7,130
Net Loss per share Basic and Diluted ***(Note 15)***	$ 0.12	$ 0.20	$ 0.05
Weighted Average Number of Shares (in thousands) ***(Note 15)***	167,612	150,154	142,314

(See accompanying Notes to Consolidated Financial Statements)

IVANHOE ENERGY INC.

Consolidated Statements of Shareholders Equity
(stated in thousands of U.S. Dollars, except share amounts)

	Share Capital		**Contributed**	**Accumulated**	
	Shares	**Amount**	**Surplus**	**Deficit**	**Total**
Balance December 31, 2001	139,267	$ 120,392	$	$ (23,495)	$ 96,897
Net loss, as previously reported				(6,819)	(6,819)
Retroactive application of change in accounting policy for stock based compensation (Notes 2 and 9)			311	(311)	
Net loss, as restated				(7,130)	
Shares issued on private placements, net of share issue costs	5,000	9,964			9,964
Shares issued on exercise of options	163	119			119
Shares issued for services	201	387			387
Elimination of employee loans *(Note 8)*		409			409
Retirement of shares	(165)	(159)		(250)	(409)
Balance December 31, 2002 (as restated)	144,466	131,112	311	(30,875)	100,548
Net loss, as previously reported				(29,703)	(29,703)
Retroactive application of change in accounting policy for stock based compensation (Notes 2 and 9)			476	(476)	
Net loss, as restated				(30,179)	
Shares issued on private placements, net of share issue costs	12,654	24,070			24,070
Shares issued on conversion of debenture (Note 8)	2,000	1,000			1,000
Shares issued on exercise of warrants	250	425			425
Shares issued on exercise of options (as restated)	1,363	3,773	(271)		3,502
Shares issued for services	626	695			695
Balance December 31, 2003, (as restated)	161,359	161,075	516	(61,054)	100,537
Net loss				(20,725)	(20,725)
Shares issued on private placements, net of share issue costs	7,173	20,428			20,428
Shares issued on exercise of options	975	1,767	(44)		1,723
Shares issued for services	158	347			347
Stock based compensation			1,276		1,276

Balance December 31, 2004	169,665	$ 183,617	$ 1,748	$ (81,779)	$ 103,586

(See accompanying Notes to Consolidated Financial Statements)

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IVANHOE ENERGY INC.

Consolidated Statements of Cash Flow
(stated in thousands of U.S. Dollars)

	Year ended December 31,		
	2004	**2003**	**2002**
		(restated Notes 2 and 9)	
Operating Activities			
Net loss	$ (20,725)	$ (30,179)	$ (7,130)
Items not requiring use of cash:			
Depletion and depreciation	7,482	3,829	3,312
Write-downs and provision for impairment *(Notes 4 and 13)*	16,600	23,321	2,436
Stock based compensation *(Note 2 and 9)*	1,276	476	311
Other	47		
Changes in non-cash working capital items	(648)	1,031	(1,049)
	4,032	(1,522)	(2,120)
Investing Activities			
Capital investments	(46,454)	(15,391)	(18,828)
Proceeds from sale of assets *(Note 4)*	13,958		5,351
Equity investment and other related costs *(Note 5)*	(5,016)	(500)	
Other	(410)	(37)	(65)
Changes in non-cash working capital items	3,264	(537)	(638)
	(34,658)	(16,465)	(14,180)
Financing Activities			
Shares issued on private placements, net of share issue costs	20,428	24,070	9,964
Shares issued on exercise of options and warrants	1,723	3,928	119
Proceeds from notes and advances *(Note 6)*	14,000	1,750	500
Payments of note payable *(Note 6)*	(694)	(1,250)	
Redemption of advance payable *(Note 6)*	(10,000)		
	25,457	28,498	10,583
Increase (decrease) in cash and cash equivalents, for the year	(5,169)	10,511	(5,717)
Cash and cash equivalents, beginning of year	14,491	3,980	9,697
Cash and cash equivalents, end of year	$ 9,322	$ 14,491	$ 3,980
Supplementary Information			
Regarding Non-Cash Transactions			
Financing activities, non-cash			
Shares issued on conversion of debenture *(Note 8)*	$	$ 1,000	$

Included in the above are the following:			
Taxes paid (refunded)	$ 3	$ 6	$ (27)
Interest paid	$ 317	$ 96	$ 74
Changes in non-cash working capital items Operating Activities:			
Accounts receivable	$ (1,949)	$ (201)	$ 38
Other current assets	(403)	282	(316)
Accounts payable and accrued liabilities	1,704	950	(771)
	(648)	1,031	(1,049)
Investing Activities			
Accounts receivable	(708)		(619)
Accounts payable and accrued liabilities	3,972	(537)	(19)
	3,264	(537)	(638)
	$ 2,616	$ 494	$ (1,687)

(See accompanying Notes to Consolidated Financial Statements)

IVANHOE ENERGY INC.

Notes to the Consolidated Financial Statements

(all tabular amounts are expressed in thousands of U.S. Dollars, except share amounts)

1. NATURE OF OPERATIONS

Ivanhoe Energy Inc., a Canadian company, and its subsidiaries are focused internationally on three major strategies: 1) conventional exploration and production of oil and gas 2) enhanced oil recovery (**EOR**) development projects including the application of heavy-to-light oil (**HTL**) upgrading technology and 3) the monetization of stranded gas reserves through a licensed gas-to-liquids (**GTL**) technology. Conventional oil and gas operations are currently carried out in the U.S. and China and GTL, EOR and HTL projects for a number of countries are in various stages.

2. SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements have been prepared in accordance with generally accepted accounting principles (**GAAP**) in Canada. The impact of material differences between Canadian and U.S. GAAP on the consolidated financial statements is disclosed in Note 19.

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts and other disclosures in these consolidated financial statements. Actual results may differ from those estimates.

Certain items in the 2003 and 2002 financial statements have been reclassified for comparison to the 2004 presentation.

Changes in Accounting Policies

Asset Retirement Costs

Prior to January 2003, the Company had estimated its future site restoration and abandonment costs associated with its oil and gas properties and amortized this estimate to operations using the unit-of-production method based upon estimated proved reserves. The provision was included with depletion and depreciation expense.

The Canadian Institute of Chartered Accountants (**CICA**) approved Section 3110, Asset Retirement Obligations which requires, for fiscal years beginning after January 1, 2004, asset retirement costs and liabilities associated with site restoration and abandonment of tangible long-lived assets be initially measured at a fair value which approximates the cost a third party would incur in performing the tasks necessary to retire such assets. The fair value is recognized in the financial statements at the present value of expected future cash outflows to satisfy the obligation. Subsequent to the initial measurement, the effect of the passage of time on the liability for the asset retirement obligation (accretion expense) and the amortization of the asset retirement cost are recognized in the results of operations.

The Company elected early implementation of this accounting policy. Accordingly, effective January 1, 2003, the Company changed its accounting policy to capitalize asset retirement costs as part of the carrying value of its oil and gas properties and adjusted the amount of its site restoration liability to the present value of the liability for the corresponding asset retirement obligation as of this date. The Company has adopted the policy without retroactive adjustment of prior years because implementation of this change had an immaterial effect on the Company s financial position and results of operations in prior years (See Notes 4 and 7).

Stock Based Compensation

Prior to January 1, 2004, the Company accounted for share options granted to employees and directors using the intrinsic-value of the stock options. Under this method, compensation costs were not recognized in the financial statements for stock options granted at market value but rather disclosure was required, on a pro forma basis, of the impact on net income of using the fair value at the stock option grant date. The Company recognizes compensation costs in its financial statements for stock options granted to non-employees after January 1, 2002 based on the fair value of the stock options at the date granted.

The CICA approved Section 3870, Stock Based Compensation and Other Stock Based Payments which requires, for fiscal years beginning on or after January 1, 2004, compensation costs to be recognized in the financial statements using the fair value based method of accounting for all stock options granted after January 1, 2002. Implementation of this change in accounting policy requires retroactive application with the option of restating financial statements of prior periods.

Accordingly, effective January 1, 2004, the Company changed its accounting policy, for Canadian GAAP purposes, to recognize compensation costs using the fair value based method of accounting for stock options granted to employees and directors after January 1, 2002. This change has been adopted retroactively and the Company has elected to restate the financial statements of prior periods (See Note 9). The Company uses the Black-Scholes option-pricing model for determining the fair value of all stock options issued at grant date.

Principles of Consolidation

These consolidated financial statements include the accounts of Ivanhoe Energy Inc. and its subsidiaries, all of which are wholly owned. The Company conducts most exploration, development and production activities in its oil and gas business jointly with others and our accounts reflect only the Company s proportionate interest.

All inter-company transactions and balances have been eliminated for the purposes of these consolidated financial statements.

Foreign Currency Translation

The Company uses the U.S. Dollar as its functional currency since it is the currency in which the worldwide petroleum business denominates its business. Monetary assets and liabilities denominated in foreign currencies are converted to the U.S. Dollar at the exchange rate in effect at the balance sheet date and non-monetary assets and liabilities at the exchange rates in effect at the time of acquisition or issue. Revenues and expenses are converted to the U.S. Dollar at rates approximating exchange rates in effect at the time of the transactions. Exchange gains or losses resulting from the period-end translation of monetary assets and liabilities denominated in foreign currencies are reflected in the results of operations.

Cash and Cash Equivalents

Cash and cash equivalents include short-term money market instruments with terms to maturity, at the date of issue, not exceeding 90 days.

Financial Instruments

The fair value of the Company s cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, note payable and long term debt approximates the carrying values due to the immediate or short-term maturity of these financial instruments.

Oil and Gas Properties

Full Cost Accounting

The Company follows the full cost method of accounting for oil and gas operations whereby all exploration and development expenditures are capitalized on a country-by-country (cost center) basis. Such expenditures include lease and royalty interest acquisition costs, geological and geophysical expenses, carrying charges for unproved properties, costs of drilling both successful and unsuccessful wells, gathering and production facilities and equipment, financing, administrative costs related to capital projects and asset retirement costs. The Company periodically evaluates its unproved properties for exploration and exploitation opportunities. If the Company determines that the exploration or exploitation potential of an unproved property has diminished, all, or a portion, of the costs incurred on such property is impaired and transferred to the carrying value of proved oil and gas properties. Proceeds from sales of oil and gas properties are recorded as reductions in the carrying value of proved oil and gas properties, unless such amounts would significantly alter the rate of depreciation and depletion, whereupon gains or losses would be recognized in income. Maintenance and repair costs are expensed as incurred, while improvements and major renovations are capitalized.

Depletion

The Company s share of costs for proved oil and gas properties accumulated within each cost center, including a provision for future development costs, are depleted using the unit-of-production method over the life of the Company s share of estimated remaining proved oil and gas reserves. Significant development projects and expenditures on unproved properties are excluded from the depletion calculation until evaluated. Natural gas reserves and production are converted to a barrels of oil equivalent using a generally recognized industry standard in which six thousand cubic feet of gas is equal to one barrel of oil. Barrels of oil equivalent may be misleading, particularly if used in isolation. The conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Impairment of Proved Oil and Gas Properties

Prior to January 2004, impairment of oil and gas properties was based on the amount by which a cost center s carrying value exceeded its undiscounted future net cash flows from proved reserves using period-end, non-escalated prices and costs, less an estimate for future general and administrative expenses, financing costs and income taxes (**ceiling test**).

Effective January 2004, Accounting Guideline 16 Oil and Gas Accounting Full Cost requires recognition and measurement processes to assess impairment of oil and gas properties. In the recognition of an impairment, the carrying value of a cost center is compared to the undiscounted future net cash flows of that cost center s proved reserves using estimates of future oil and gas prices and costs plus the cost of unproved properties that have been excluded from the depletion calculation. If the carrying value is greater than the value of the undiscounted future net cash flows of the proved reserves plus the cost of unproved properties excluded from the depletion calculation, then the amount of the cost center s potential impairment must be measured. A cost center s impairment loss is measured by the amount its carrying value exceeds the discounted future net cash flows of its proved and probable reserves using estimates of future oil and gas prices and costs plus the cost of unproved properties that have been excluded from the depletion calculation and which contain no probable reserves. The net cash flows of a cost center s proved and probable reserves are discounted using a risk-free interest rate. The amount of the impairment loss is recognized as a charge to the results of operations and a reduction in the net carrying amount of a cost center s oil and gas properties.

Asset Retirement Costs

The Company measures the expected costs required to retire its producing U.S. oil and gas properties at a fair value which approximates the cost a third party would incur in performing the tasks necessary to abandon the field and restore the site. The fair value is recognized in the financial statements at the present value of expected future cash outflows to satisfy the obligation. The Company does not make such a provision for its oil and gas operations in China as the remaining life of its Dagang production sharing contract is less than the remaining economic life of the field and there is no obligation on the Company s part to contribute to the future cost to abandon the field and restore the site.

Asset retirement costs are being depleted using the unit of production method based on estimated proved reserves and are included with depletion and depreciation expense. The accretion of the liability for the asset retirement obligation is included with interest expense.

Investments in GTL and EOR Projects

The Company incurs various costs in the pursuit of GTL and EOR projects throughout the world. Such costs incurred prior to signing a memorandum of understanding (**MOU**), or similar agreements, are considered to be business development or project identification and are expensed as incurred. Upon executing an MOU to determine the technical and commercial feasibility of a project, including studies for the marketability for the projects products, the Company assumes the feasibility and related costs incurred have potential future value, are probable of leading to a definitive agreement for the exploitation of proved reserves and should be capitalized. If no definitive agreement is reached, then the project s capitalized costs, which are deemed to have no future value, are written down to the results of operations with a corresponding reduction in the investments in GTL and EOR assets.

Furniture and Fixtures

Furniture and fixtures are stated at cost. Depreciation is provided on a straight-line basis over the estimated useful life of the respective assets, at rates ranging from three to ten years.

Oil and Gas Revenue

Sales of crude oil and natural gas are recognized in the period in which the product is delivered to the customer. Oil and gas revenue represents the Company s share and is recorded net of royalty payments to governments and other mineral interest owners.

In China, the Company conducts operations jointly with the government of China in accordance with a production-sharing contract. Under this contract, the Company pays both its share and the government s share of operating and capital costs. The Company recovers the government s share of these costs from future revenues or production over the life of the production-sharing contract. The government s share of operating costs is recorded in operating expense when incurred and capital costs are recorded in oil and gas properties and expensed to depletion and depreciation in the year recovered. All recoveries of the government s share of costs are recorded as oil and gas revenue in the year of recovery.

Earnings or Loss Per Share

Basic earnings or loss per share is calculated by dividing the net earnings or loss to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings per share reflects the potential dilution that would occur if stock options and warrants were exercised. The treasury stock method is used in calculating diluted earnings per share, which assumes that any proceeds received from the exercise of in-the-money stock options and warrants would be used to purchase common shares at the average market price for the period (See Note 15). The Company does not report diluted loss per share amounts, as the effect would be antidilutive to the common shareholders.

Income Taxes

The Company follows the liability method of accounting for future income taxes. Under the liability method, future income taxes are recognized to reflect the expected future tax consequences arising from tax loss carry-forwards and temporary differences between the carrying value and the tax basis of the Company s assets and liabilities.

Stock Based Compensation

The Company has an Employees and Directors Equity Incentive Plan consisting of stock option, bonus and an employee share purchase plan (See Note 9). The Company accounts for equity-based compensation under this plan using the fair value based method of accounting for all stock options granted after January 1, 2002. Compensation costs are recognized in the results of operations over the periods in which the stock options vest for all stock options granted based on the fair value of the stock options at the date granted. The Company uses the Black-Scholes option-pricing model for determining the fair value of stock options issued at grant date. As of the date stock options are granted, the Company estimates a percentage of stock options issued to employees and directors it expects to be forfeited. Compensation costs are not recognized for stock option awards forfeited due to a failure to satisfy the service requirement for vesting. Compensation costs are adjusted for the actual amount of forfeitures in the period in which the stock options expire.

Upon the exercise of stock options, share capital is credited for the fair value of the stock options at the date granted with a charge to contributed surplus. Consideration paid upon the exercise of the stock options is also credited to share capital.

Compensation expenses are recognized when shares are issued from the stock bonus plan. The employee share purchase portion of the plan has not yet been activated.

Derivative Activities

Prior to January 2004, the Company applied hedge accounting to all derivative instruments used to manage price fluctuations in oil and natural gas prices.

Effective January 1, 2004, the Company adopted CICA Accounting Guideline 13 (AcG 13), Hedging Relationships . This guideline sets out the criteria that must be met in order to apply hedge accounting for derivatives. The guideline provides detailed guidance on the identification, designation, documentation and effectiveness of hedging relationships for purposes of applying hedge accounting, and the discontinuance of hedge accounting. Gains and losses on derivative instruments designated and qualifying as hedges under this guideline are recognized in earnings in the same period as the related hedged item. Ineffective hedging relationships and hedges not designated in a hedging relationship are carried at fair value in the statement of financial position, and subsequent changes in their fair value are recorded in the results of operations. The adoption of this accounting guideline did not have a material impact on the consolidated financial statements (See Note 12).

Impact of New and Pending Canadian GAAP Accounting Standards

In January 2005, the CICA approved Section 1530 Comprehensive Income (**S.1530**), Section 3855 Financial Instruments Recognition and Measurement (**S.3855**) and Section 3865 Hedges (**S.3865**) to harmonize financial instrument and hedge accounting with U.S. GAAP and introduce the concept of comprehensive income. S.1530 requires presentation of certain gains and losses outside of net income, such as unrealized gains and losses related to hedges or other derivative instruments. S.3855 establishes standards for recognizing and measuring financial assets and financial liabilities and non-financial derivatives as required to be disclosed under Section 3861 Financial Instruments Disclosure and Presentation . S.3865 establishes standards for how and when hedge accounting may be applied. The Company applies SFAS No. 133 Accounting for Derivative Instruments and Hedging Activities for U.S. GAAP purposes and will implement S.3865 for Canadian GAAP for hedging activities. These sections apply to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006 and are not expected to have a material impact on the Company s financial statements.

In January 2005, the CICA approved Section 3251 Equity which establishes standards for the presentation of equity and changes in equity during a reporting period. This section applies to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006 and is not expected to have a material impact on the Company s financial statements.

The following standards issued by the CICA do not impact the Company at this time:

Section 3861, Financial Instruments Disclosure and Presentation , effective for fiscal years beginning on or after November 1, 2004.

Accounting Guideline 15, Consolidation of Variable Interest Entities , effective for annual and interim periods beginning on or after November 1, 2004.

3. CONCENTRATION OF CREDIT RISKS

The Company sells oil and natural gas products to pipelines, refineries, major oil companies and foreign national petroleum companies. Where possible, credit is extended based on an evaluation of the customer s financial condition and historical payment record.

The following summarizes the accounts receivable balances and revenues from significant customers:

	Accounts Receivable as at December 31,		Oil and Gas Revenues for the Year Ended December 31,		
	2004	2003	2004	2003	2002
U.S. Customers					
A	$ 542	$ 407	$ 6,140	$ 4,392	$ 2,916
B	398		1,202		
C	193	175	1,040	986	1,764
D	229		441		
E	71	60	300	273	390
All others	20	15	188	65	29
	1,453	657	9,311	5,716	5,099
China Customer					
A	1,982	950	8,484	4,103	3,230
	3,435	1,607	17,795	9,819	8,329
Receivables from partners	1,652	947			
Other receivables	290	166			
	$ 5,377	$ 2,720	$ 17,795	$ 9,819	$ 8,329

Oil and gas revenues for the year ended December 31, 2003 in the table above do not include $0.3 million of oil hedge losses from derivative activities.

Accounts receivable as at December 31, 2004 and 2003 in the table above include $1.7 million and $0.9 million, respectively, of costs billed to joint venture partners and advances to partners for joint operations where the Company is not the operator.

4. OIL AND GAS PROPERTIES AND INVESTMENTS

Capital assets categorized by segment are as follows:

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	As at December 31, 2004				
	Oil and Gas				
	U.S.	China	GTL	EOR	Total
Oil and Gas Properties:					
Proved	$ 81,648	$ 35,771	$	$	$ 117,419
Unproved	20,447	10,581			31,028
	102,095	46,352			148,447
Accumulated depletion	(10,956)	(6,663)			(17,619)
Accumulated provision for impairment	(50,350)				(50,350)
	40,789	39,689			80,478
GTL and EOR Investments:					
GTL master license			10,000		10,000
Feasibility studies and other deferred costs			3,793	2,091	5,884
			13,793	2,091	15,884
Furniture and equipment	417	84		11	512
Accumulated depreciation	(300)	(22)		(1)	(323)
	117	62		10	189
	$ 40,906	$ 39,751	$ 13,793	$ 2,101	$ 96,551

	As at December 31, 2003				
	Oil and Gas				
	U.S.	China	GTL	EOR	Total
Oil and Gas Properties:					
Proved	$ 57,545	$ 29,201	$	$	$ 86,746
Unproved	27,534	3,639			31,173
	85,079	32,840			117,919
Accumulated depletion	(6,442)	(3,804)			(10,246)
Accumulated provision for impairment	(34,000)				(34,000)
	44,637	29,036			73,673
GTL and EOR Investments:					
GTL master license			10,000		10,000
Feasibility studies and other deferred costs			4,072		4,072
			14,072		14,072
Furniture and equipment	433	31			464
Accumulated depreciation	(253)				(253)

	180	31			211
	$ 44,817	$ 29,067	$ 14,072	$	$ 87,956

Effective January 1, 2003, the Company capitalized $0.3 million as a result of implementation of a new accounting policy on asset retirement obligations. For the years ended December 31, 2004 and 2003, $0.2 million and $0.1 million, respectively, of future asset retirement costs were capitalized (See Note 2).

Costs as at December 31, 2004 and 2003 of $31.0 million and $31.2 million, respectively, related to unproved oil and gas properties were excluded from the depletable cost centers.

For the years ended December 31, 2004 and 2003, general and administrative expenses related directly to oil and gas acquisition, exploration and development activities, and investments in GTL and EOR projects of $3.8 million and $1.8 million, respectively, were capitalized.

United States

The Company s U.S. oil and gas operations are primarily conducted through joint operations with other oil and gas companies in California, Texas and Wyoming. Costs capitalized in the U.S. cost center under the full cost method of accounting are as follows:

	As at December 31,	
	2004	**2003**
California	$ 74,155	$ 59,386
Texas	24,239	24,046
Wyoming	2,054	
Other	1,647	1,647
	$ 102,095	$ 85,079

Included in the carrying value for the Company s California properties are $9.2 million of costs incurred to acquire overriding royalties in various exploration prospects and producing properties.

During 2004, the Company sold its working interest in one of its California producing properties for $0.5 million. The sale proceeds were credited to the U.S. cost center as the sale did not significantly alter the depletion rate for the U.S. cost center.

The provision for impairment calculated for U.S. oil and gas properties was $16.3 million and $20.0 million for 2004 and 2003, respectively. No provision for impairment of U.S. oil and gas properties was required for 2002 (See Note 13).

China

The Company currently holds a production-sharing contract with China National Petroleum Corporation (**CNPC**) to develop existing oil properties in the Dagang region. In January 2004, the Company signed farm-out and joint operating agreements with Richfirst Holdings Limited (Richfirst), a wholly-owned subsidiary of China International Trust and Development Corporation, to acquire a forty percent working interest in the Dagang field for an up-front payment of $20.0 million following receipt of Chinese regulatory approvals in June 2004. Richfirst will have the right to exchange its working interest in the Dagang field for common shares in the Company s wholly owned subsidiary, Sunwing Energy Ltd. (**Sunwing**), should the Company obtain a public listing for Sunwing, or for the Company s common shares. Richfirst s right to exchange its working interest for the Company s common shares expires in December 2005. The Company and Richfirst incur 100% of the costs to earn 82% of the production, before recovery of costs incurred, reverting to a 49% share post recovery. The carrying value of the Company s China oil and gas properties was reduced by $13.5 million for the amount of the proceeds associated with the farm-in of Richfirst to the Dagang field. The reduction in the carrying value did not significantly alter the depletion rate of the China cost center.

The Company held a production-sharing contract to develop existing oil fields in the Daqing region until the sale of its interest in the field in January 2002. The Company retains an overriding royalty on future production.

The Company also holds a production-sharing contract with CNPC in a contract area, known as the Zitong block located in the northwestern portion of the Sichuan Basin. Under the terms of the production-sharing contract, the Company will develop natural gas deposits within the block and in return will receive approximately 75% of the revenue until costs are recovered and approximately 45% thereafter. CNPC has the option, at the end of appraisal activities, to participate with the Company in any proposed field developments, with up to a 51% working interest.

Costs capitalized in the China cost center under the full cost method of accounting are as follows:

As at December 31,

	2004	2003
Dagang Project	$ 32,061	$ 25,357
Sichuan Basin	10,581	3,639
Daqing Project	3,710	3,844
	$ 46,352	$ 32,840

Gas-to-Liquids

The Company owns a master license from Syntroleum Corporation (**Syntroleum**) permitting the Company to use their proprietary GTL process in an unlimited number of projects around the world. The Syntroleum GTL process converts natural gas into synthetic liquid hydrocarbons that can be utilized to develop, among other things, clean-burning diesel fuel. In July 2003, the master license was amended in respect of GTL projects in which both the Company and Syntroleum participate such that no additional license fees or royalties will be payable by the Company and that Syntroleum will contribute, to any such project, the right to manufacture specialty and lubricant products. Both companies have the right to pursue GTL projects independently, but the Company would be required to pay the normal license fees and royalties in such projects.

Since 2000, the Company has undertaken detailed project feasibility studies for the construction, operation and cost of GTL plants in Qatar, Egypt, Oman and Bolivia. In addition, the Company has conducted marketing, commercialization and transportation feasibility studies. Marketing studies were conducted for both European and the Asia Pacific regions for GTL diesel and specialty fuels.

For the years ended December 31, 2004, 2003 and 2002, the Company wrote down $0.3 million, $3.3 million and $2.4 million, respectively, of capitalized negotiation and feasibility costs associated with our GTL projects which did not result in definitive agreements. Other costs associated with feasibility studies and related costs, which are deemed to have future value, remain capitalized. Recovery of the GTL costs capitalized is dependent upon finalizing contracts to access natural gas reserves in the respective countries and the successful completion of GTL processing plants.

Enhanced Oil Recovery

In the fourth quarter of 2004, the Company signed memoranda of understanding with the Ministry of Oil of the Government of Iraq to study and evaluate the shallow Qaiyarah oil field in Iraq and with Ecopetrol S.A., a public company wholly owned by the Republic of Colombia, for a study of the heavy crude oil from the Castilla and Chichimene oil fields in Colombia. The $2.1 million of EOR investments, as at December 31, 2004, include feasibility studies and related costs associated with these memoranda of understanding and other project activities in these regions.

5. LONG TERM ASSETS

During 2004, the Company acquired a 15% equity interest in Ensyn Petroleum International Ltd. (**EPIL**) and exclusive rights to use the proprietary Ensyn RTP™ Technology in key international markets in China, Mongolia, Iraq, Oman and all countries in South America except Venezuela. In these countries, the Company s rights were to be exclusive for an initial term of five years until January 2009, subject to extension if and when commercial plants are constructed. For each project the Company develops using the Ensyn RTP™ Technology in its exclusive territories, Ensyn could elect to receive an equity participation in the project for the same proportionate cost the Company paid. The participation that may be obtained by Ensyn could be no more than 10%, except for each such project that the Company develops in South America, other than in Peru, where Ensyn could elect to receive an equity interest equal to 25% of the Company s interest. Ensyn s equity position would offset and eliminate the payment of license fees for use of the Ensyn RTP™ Technology in the project.

In December 2004, the Company and Ensyn Group Inc. (**Ensyn**), the parent company of EPIL, announced the signing of a merger agreement (**Merger Agreement**) in which Ensyn will be merged with the Company (**Merger**) and Ensyn will become a wholly owned subsidiary of the Company. With this Merger, the Company will gain full ownership of EPIL and its advanced upgrading technology for the development of heavy oil reserves around the world. Ensyn will spin-off its existing biomass processing business to its shareholders prior to the closing of this transaction.

Under the Merger Agreement, the Company will acquire all of the outstanding shares of Ensyn and all of the unissued shares of Ensyn common stock issuable upon the future exercise of any purchase warrants that remain unexercised when the Merger takes effect in exchange for $10 million in cash and the issuance of Company common shares. The number of Company common shares to be issued will be based on the weighted, 10-day average of the Company s closing share price on the NASDAQ SmallCap market prior to the approval of the transaction by Ensyn shareholders. A minimum of 30 million Company common shares will be issued (See Note 17).

The Boards of Directors of both Ivanhoe and Ensyn have approved the Merger. The Merger will require the approval of Ensyn shareholders and may require the approval of the Company s shareholders, depending on the number of Company common shares required to be issued. The Merger is also subject to applicable regulatory approvals and other closing conditions customary in transactions of this nature.

As at December 31, 2004, the costs to acquire the 15% equity interest in EPIL of $3.0 million plus $2.5 million of costs incurred by the Company associated with the Merger are included in long term assets.

6. NOTES AND ADVANCE PAYABLE

In February 2003, the Company obtained a bank facility for up to $5.0 million to develop the southern expansion of its South Midway field. The note is repayable over three years starting August 2004 with interest at 0.5% above the bank s prime rate or 3.0% over the London Inter-Bank Offered rate (**LIBOR**), at the option of the Company. The note is secured by all the Company s rights and interests in the South Midway properties. The note balance, as at December 31, 2004 and 2003, was $4.3 million and $1.0 million, respectively, with a six-month fixed LIBOR rate of 5.25% as at December 31, 2004.

The scheduled maturities of the bank note payable as at December 31, 2004 were as follows:

2005	$ 1,667
2006	1,667
2007	972
	4,306
Less: current portion	1,667
	$ 2,639

In March 2004, the Company received a $10.0 million advance as part of the $20.0 million up-front payment due from Richfirst for their farm-in to the Dagang field (See Note 4). Upon finalization of the farm-in agreement in June 2004, Richfirst elected to apply $10.0 million of the up-front payment due to the Company against the advance.

The Company borrowed $1.25 million from a related party at U.S. prime plus 3%. The unsecured loan was repaid with accrued interest in September 2003. The Company negotiated a revolving credit facility of $1.25 million to re-establish or extend that loan in the future as needs arise.

The Company has a stand-by loan facility for $6.0 million payable with interest at 8% per annum upon the earliest of i.) five days following receipt of proceeds from a private placement or public offering of Company common shares ii.) ninety days following written demand for repayment from lender or iii.) August 23, 2005. As at December 31, 2004, the Company had not made a drawdown under the loan (See Note 18).

7. ASSET RETIREMENT OBLIGATION

Effective January 2003, the Company changed its policy on accounting for liabilities associated with site restoration and abandonment of its oil and gas properties. The undiscounted amount of expected cash flows required to settle the asset retirement obligations as at December 31, 2004 was estimated at $1.4 million to be settled over a twelve-year period starting in 2010. The liability for the expected cash flows, as reflected in the financial statements, has been discounted from 5% to 7%. Implementation of the policy resulted in an additional provision for asset retirement of $0.2 million. For the years ended December 31, 2004 and 2003, $0.2 million and $0.1 million, respectively, were added to the carrying amount of the asset retirement obligations related to the restoration and abandonment of the Company s U.S. oil and gas properties as follows:

Balance as at December 31, 2002	$ 243
Cumulative effect of change in accounting policy	155
Accretion of liability	31
Additions	92
Balance as at December 31, 2003	521
Accretion of liability	48
Additions	180
Balance as at December 31, 2004	$ 749

8. SHARE CAPITAL

The authorized capital of the Company consists of an unlimited number of common shares without par value and an unlimited number of preferred shares without par value.

Private Placements and Share Purchase Warrants

Under a private placement in 2002, the Company issued 5.0 million common shares at $2.00, for net proceeds of $10.0 million.

In 2004 and 2003, the Company closed six special warrant financings for net proceeds of $20.4 million and $24.1 million, respectively, to advance its worldwide exploration and production, EOR and GTL activities, to pay down or restructure certain business indebtedness and for general working capital purposes. The financings consisted of 17,951,826 special warrants from $1.00 to $4.00 per special warrant. Each special warrant entitles the holder to acquire one common share and one common-share purchase warrant, at no additional cost. The net proceeds from the special warrant financings have been apportioned to the common shares. No amounts have been apportioned to the purchase warrants. The purchase warrants are exercisable to purchase additional common shares through the anniversary dates of the special warrant financing at the price per share as indicated in the following table:

Year of Special Warrant Financing	Price per Special Warrant (U.S.$)	Number of Purchase Warrants Issued	Remaining Number of Purchase Warrants (thousands)	Number of Equivalent Common Shares	First Anniversary Date	First Anniversary Price per Share (U.S.$)	Second Anniversary Date	Second Anniversary Price per Share (U.S.$)
2003	$ 1.00	3,000	3,000	1,500			July 3, 2005	$ 1.10
2003	$ 1.00	3,000	3,000	1,500			August 18, 2005	$ 1.10
2003	$ 1.70	3,529	3,029	1,515			August 21, 2005	$ 1.87
2003	$ 4.00	1,250	1,250	1,250			October 31, 2005	$ 4.30
2004	$ 2.90	5,449	5,449	2,725	February 18, 2005	$ 3.00	February 18, 2006	$ 3.20
2004	$ 2.90	1,724	1,724	862	March 5, 2005	$ 3.00	March 5, 2006	$ 3.20
		17,952	17,452	9,352				

In November 2003, 500 thousand purchase warrants for $1.70 per share were exercised for the purchase of 250 thousand common shares.

Convertible Debenture

In June 2003, the $1.0 million unsecured convertible debenture was converted into two million of the Company s common shares at $0.50 per share. All accrued interest on the debenture was paid as of the conversion date .

Share Purchase Loans

In 1999 and 2001, the Company loaned $0.4 million to an employee and two directors to facilitate their exercise of stock options and warrants to purchase 165 thousand common shares of the Company. The Company held the shares as collateral for the loans. The loan balances were previously netted against the share capital balances. In December 2002, the Company determined the loans would not be renewed when they became due in December 2002 and January 2003. Each of the borrowers authorized the Company to acquire the shares held as collateral in full payment of their loan amounts and accrued interest, thereon. Subsequently, the Company eliminated the loans and retired the 165 thousand common shares at the average price of all common shares then issued and outstanding ($0.96 per share) and recorded a $0.25 million loss to retained earnings.

9. STOCK BASED COMPENSATION

The Company has an Employees and Directors Equity Incentive Plan under which it can grant stock options to directors and employees to purchase common shares, issue common shares to directors and employees for bonus awards and issue shares under a share purchase plan for employees.

Stock options are issued at not less than the quoted market value on the date of the grant and are conditional on continuing employment. Expiration and vesting periods are set at the discretion of the Board of Directors. Stock options granted prior to March 1, 1999 vested over a two-year period and expire ten years from date of issue. Stock options granted after March 1, 1999 vest over four years and expire five to ten years from the date of issue.

Following is a summary of the stock option portion of the Company s Equity Incentive Plan, including changes during the years ended:

	December 31, 2004		**December 31, 2003**		**December 31, 2002**	
	Number of Stock Options (thousands)	**Weighted-Average Exercise Price (Cdn.$)**	**Number of Stock Options (thousands)**	**Weighted-Average Exercise Price (Cdn.$)**	**Number of Stock Options (thousands)**	**Weighted-Average Exercise Price (Cdn.$)**
Outstanding at beginning of year	8,949	$ 2.64	10,265	$ 2.69	8,635	$ 2.66
Granted	608	$ 2.52	840	$ 4.95	2,095	$ 2.86
Exercised	(975)	$ 2.43	(1,363)	$ 3.39	(164)	$ 1.57
Cancelled/forfeited	(336)	$ 2.96	(793)	$ 4.42	(301)	$ 3.48
Outstanding at end of year	8,246	$ 2.65	8,949	$ 2.64	10,265	$ 2.69
Options exercisable at end of year	6,698	$ 2.44	6,974	$ 2.20	7,122	$ 2.13

The Company accounts for all stock options granted using the fair value based method of accounting. This method was adopted retroactively effective January 1, 2004 for stock options granted to employees and directors after January 1, 2002. Under this method, compensation costs are recognized in the financial statements over the stock options vesting period using an option-pricing model for determining the fair value of the stock options at the grant date. The Company estimates a 20% forfeiture rate for stock options for purposes of calculating the fair value on the date stock options are granted. Revisions in forfeiture estimates are reflected as a change in accounting estimate in the period in which the revision occurs.

The effect of the accounting change on the net loss, as previously reported, for the years ended December 31, 2003 and 2002, was an increase of $0.5 million and $0.3 million, respectively. There is negligible effect on the net loss per share for the periods as previously reported. The accumulated deficit, as previously reported, as at the beginning of each of the years ended December 31, 2004 and 2003 has increased $0.8 million and $0.3 million, respectively, to reflect the retroactive adoption of the fair value based method of accounting for stock options granted to employees and directors after January 1, 2002. Additionally, 0.3 million stock options granted to employees and directors after January 1, 2002 were exercised during 2003 resulting in a $0.3 million increase in share capital as at December 31, 2003, as previously reported, with a corresponding reduction in contributed surplus. For the year ended December 31, 2004, the Company expensed $1.3 million for stock based compensation, which is included in the results of operations.

The foregoing is calculated in accordance with Black-Scholes options pricing model. The weighted average grant-date fair value of stock options granted during 2004, 2003 and 2002 was Cdn.$1.95, Cdn.$3.99 and Cdn.$1.65, respectively. The fair value of the stock options granted is estimated with the following weighted average assumptions for the years presented:

	2004	**2003**	**2002**
Assumptions used:			
Risk-free interest rate	4.0%	4.1%	4.4%
Dividend yield	0.0%	0.0%	0.0%
Volatility factor	107.6%	99.4%	72.0%
Expected life (years)	4.0	4.0	4.0

The following table summarizes information respecting stock options outstanding and exercisable as at December 31, 2004:

	Stock Options Outstanding			**Stock Options Exercisable**	
Range of Exercise Prices (Cdn.$)	**Number Outstanding (thousands)**	**Weighted-Average Remaining Contractual Life (Years)**	**Weighted-Average Exercise Price (Cdn.$)**	**Number Exercisable (thousands)**	**Weighted-Average Exercise Price (Cdn.$)**
$0.50 to $2.00	4,347	3.7	$ 0.65	4,031	$ 0.56
$2.60 to $3.60	1,651	3.0	$ 3.09	860	$ 3.14
$5.35 to $7.60	2,248	1.7	$ 6.17	1,807	$ 6.28
$0.50 to $7.60	8,246	3.0	$ 2.65	6,698	$ 2.44

10. RETIREMENT PLAN

In 2001, the Company adopted a defined contribution retirement or thrift plan (**401(k) Plan**) to assist U.S. employees in providing for retirement or other future financial needs. Employees contributions (up to the maximum allowed by U.S. tax laws) are matched 50% by the Company in 2001 and increasing 10% per year thereafter to a maximum of 100%. The Company s matching contributions to the 401(k) Plan were $0.2 million for each of the years ended December 31, 2004 and 2003 and $0.1 million for the year ended December 31, 2002.

11. SEGMENT INFORMATION

The Company has three reportable business segments: Oil and Gas, GTL and EOR.

Oil and Gas

The Company explores for, develops and produces crude oil and natural gas in the U.S. and in China. In the U.S., the Company s exploration, development and production activities are primarily conducted in California and Texas. In China, the Company s development and production activities are conducted at the Dagang oil field located in Hebei Province and exploration activities in the Zitong block located in Sichuan Province.

GTL

The Company holds a master license from Syntroleum to use its proprietary GTL technology to convert natural gas into synthetic fuels. The master license allows the Company to use Syntroleum s proprietary process in an unlimited number of GTL projects throughout the world to convert natural gas into an unlimited volume of ultra clean transportation fuels and other synthetic petroleum products. The Company does not currently own or operate any GTL projects but has entered into agreements to study the feasibility of GTL plants in Egypt and Bolivia.

EOR

The Company seeks projects requiring relatively low initial capital outlays to which it can apply innovative technology and enhanced recovery techniques in developing them. The Company has exclusive rights to use the proprietary Ensyn RTP™ Technology in key international markets in China, Mongolia, Iraq, Oman and all countries in South America except Venezuela. In 2004, the Company entered into memoranda of understanding to evaluate the potential response of specific fields in Iraq and Colombia to the latest in EOR techniques and to determine the value that could be added to these fields using the Ensyn RTP™ Technology.

The Company maintains a corporate office in Canada with its operational office in the U.S. For this note, any amounts for the corporate office in Canada are included in Corporate**.** The accounting policies of the segments are the same as those disclosed in Note 2.

	Year ended December 31, 2004					
	Oil and Gas					
	U.S.	**China**	**GTL**	**EOR**	**Corporate**	**Total**
Oil and gas revenue	$ 9,311	$ 8,484	$	$	$	$ 17,795
Interest income	10	16			176	202
	9,321	8,500			176	17,997
Operating costs	3,159	1,914				5,073
General and administrative	990	960	1,471	442	5,325	9,188
Depletion and depreciation	4,594	2,864	16	4	4	7,482
Interest expense	195				184	379
Write-downs and provision for impairment	16,350		250			16,600
	25,288	5,738	1,737	446	5,513	38,722
Net (Income) Loss	$ 15,967	$ (2,762)	$ 1,737	$ 446	$ 5,337	$ 20,725
Capital Investments	$ 17,428	$ 26,965	$ 95	$ 1,966	$	$ 46,454
Identifiable Assets (As at December 31, 2004)	$ 49,465	$ 44,960	$ 13,867	$ 2,441	$ 7,753	$ 118,486

Year ended December 31, 2003 (as restated, see Notes 2 and 9)

	Oil and Gas U.S.	China	GTL	EOR	Corporate	Total
Oil and gas revenue	$ 5,466	$ 4,103	$	$	$	$ 9,569
Interest income	19				71	90
	5,485	4,103			71	9,659
Operating costs	2,313	1,980				4,293
General and administrative	2,109	1,176	1,331		3,595	8,211
Depletion and depreciation	2,321	1,484	20		4	3,829
Interest expense	115	27			42	184
Write-down and provision for impairment	20,000		3,321			23,321
	26,858	4,667	4,672		3,641	39,838
Net Loss	$ 21,373	$ 564	$ 4,672	$	$ 3,570	$ 30,179
Capital Investments	$ 8,386	$ 6,213	$ 792	$	$	$ 15,391
Identifiable Assets (As at December 31, 2003)	$ 47,650	$ 30,766	$ 14,181	$	$ 13,977	$ 106,574

	Year ended December 31, 2002 (as restated, see Notes 2 and 9)					
	Oil and Gas					
	U.S.	China	GTL	EOR	Corporate	Total
Oil and gas revenue	$ 5,099	$ 3,230	$	$	$	$ 8,329
Interest income	6	1			101	108
	5,105	3,231			101	8,437
Operating costs	2,351	1,490				3,841
General and administrative	1,178	905	675		3,197	5,955
Depletion and depreciation	2,090	1,206	13		3	3,312
Interest expense	2	21				23
Write-down and provision for impairment			2,436			2,436
	5,621	3,622	3,124		3,200	15,567
Net Loss	$ 516	$ 391	$ 3,124	$	$ 3,099	$ 7,130
Capital Investments	$ 13,305	$ 3,626	$ 1,897	$	$	$ 18,828
Identifiable Assets (As at December 31, 2002)	$ 62,922	$ 25,620	$ 17,111	$	$ 1,435	$ 107,088

12. DERIVATIVE ACTIVITIES

The Company s results of operations are sensitive mainly to fluctuations in oil and natural gas prices. The Company may periodically use different types of derivative instruments to manage its exposure to price volatility, thus mitigating fluctuations in commodity-related cash flows.

The Company entered into costless collar derivatives to hedge its cash flow from the sale of 500 barrels of oil production per day over two six-month periods starting October 2002 and June 2003. The derivatives had ceiling prices of $30.45 and $28.95 per barrel for the June 2003 and October 2002 contracts, respectively, and a floor price of $24.00 per barrel using WTI as the index traded on the NYMEX. Gains and losses on derivatives were recognized in the results of operations as realized. For the year ended December 31, 2003, the Company had realized losses of $0.3 million on derivative transactions. The Company had insignificant realized derivative losses for the year ended December 31, 2002. The derivative losses are included in oil and gas revenue.

For the year ended December 31, 2004 the Company had no hedging activity. There were no hedge contracts outstanding as at December 31, 2004 and 2003.

13. PROVISION FOR IMPAIRMENT

The Company impaired its U.S. oil and gas properties $16.3 million in 2004 due to the evaluation of a number of its unproved properties, primarily in California, plus the impairment of its producing fields at Knights Landing, Citrus and the southern expansion at South Midway as costs incurred to add new reserves exceeded the expected future cash flows from those properties. Prices used in calculating the expected future cash flows were based on the following benchmark prices adjusted for gravity, transportation and other factors as required by sales agreements:

	As at December 31. 2004	
	West Texas Intermediate (per Bbl)	**Henry Hub** (per Mcf)
2005	$ 42.00	$ 6.20
2006	$ 40.00	$ 6.00
2007	$ 38.00	$ 5.75
2008	$ 36.00	$ 5.50
2009	$ 34.00	$ 5.50
2010 to 2015	$ 33.00 to $34.50	$ 5.50 to $5.75
Thereafter	2% per year	2% per year

The $20.0 million provision for impairment for 2003 is due mainly to an increase in the carrying costs of the Company s evaluated U.S. oil and gas properties primarily in East Texas, Northwest Lost Hills and other California prospects when compared to the estimated recoverable value of its U.S. proved reserves as at December 31, 2003. Such carrying costs increased as a result of the decision, in the fourth quarter of 2003, to potentially farm-out up to 50% of the Company s working interest to one or more partners to fund a test of Northwest Lost Hills # 1-22. Additionally, evaluation of significant portions of the Company s acreage positions in East Texas and the southern San Joaquin Basin in California was completed in 2003 and either have been, or will be, relinquished, thus adding to the carrying value of the Company s evaluated U.S. oil and gas properties. Prices used in calculating the expected future cash flows were based on the following benchmark prices adjusted for gravity, transportation and other factors as required by sales agreements:

	As at December 31, 2003	
	West Texas Intermediate	Henry Hub
	(per Bbl)	(per Mcf)
2004	$ 29.00	$ 5.10
2005	$ 26.00	$ 4.50
2006	$ 25.00	$ 4.35
2007	$ 25.00	$ 4.35
2008	$ 25.00	$ 4.35
2009 to 2014	$ 25.00	$ 4.35
Thereafter	1.5% per year	1.5% per year

14. INCOME TAXES

The Company and its subsidiaries are required to individually file tax returns in each of the jurisdictions in which they operate. The provision for income taxes differs from the amount computed by applying the statutory income tax rate to the net losses before income taxes. The statutory rate as at December 31, 2004 was 33.6% and 43.2% as at December 31, 2003 and 2002. The sources and tax effects for the differences were as follows**:**

	As at December 31,		
	2004	**2003**	**2002**
Tax benefit computed at the combined Canadian federal and provincial statutory income tax rates	$ (6,968)	$ (12,832)	$ (2,946)
Effect of change in effected income tax rates on future tax assets	(488)		
Foreign net losses affected at lower income tax rates	(246)	3,251	1,411
Expiry of tax loss carry-forwards	977	569	125
Effect of change in foreign exchange rates	(3,433)	(522)	
Stock-based compensation not deductible for income tax purposes	375		
Tax credit carry-forward	(1,094)		
Change in prior year estimate of tax loss carry-forwards	1,756	(239)	(3,090)
Permanent differences related to U.S. royalty interests acquired	1,250	710	
Other	(5)	170	(25)
	(7,876)	(8,893)	(4,525)
Valuation allowance	7,876	8,893	4,525
	$	$	$

Significant components of the Company s future net income tax assets as at December 31 were as follows:

	2004 Future Income Tax		2003 Future Income Tax	
	Assets	Liabilities	Assets	Liabilities
Oil and gas properties and investments	$	$ (11,560)	$	$ (8,393)
Tax loss carry-forwards	58,842		48,893	
Tax credit carry-forward	1,094			
Valuation allowance	(48,376)		(40,500)	
	$ 11,560	$ (11,560)	$ 8,393	$ (8,393)

Due to the uncertainty of utilizing these net income tax assets, the Company has made a valuation allowance of an equal amount against the potential recoverable amounts.

The tax loss carry-forwards in Canada are Cdn. $43.2 million and in the U.S. $73.5 million. The tax loss carry-forwards in Canada expire between 2005 and 2011 and in the U.S. between 2018 and 2024. In China, the Company has available for carry-forward against future Chinese income $49.2 million of cost basis. The loss of approximately Cdn. $55.3 million from the Russian operations in 2000, being the aggregate investment, not including accounting write-downs, less proceeds received on settlement is a capital loss for Canadian income tax purposes, available for carry-forward against future Canadian capital gains indefinitely and is not included in the future income tax assets above.

15. NET LOSS PER SHARE

Had the Company generated net earnings during the years presented, the earnings per share calculations for the years presented would have included the following weighted average items:

	Year ended December 31, (thousands of shares)		
	2004	**2003**	**2002**
Warrants	2,107	556	
Convertible debenture		499	1,299
Stock options	3,796	3,535	2,986
	5,903	4,590	4,285

Additionally, the earnings per share calculations would not have included the following weighted average items because the exercise prices exceeded the average market prices of the common shares:

	Year ended December 31, (thousands of shares)		
	2004	**2003**	**2002**
Warrants	4,082	140	
Convertible debenture		306	
Stock options	3,669	3,802	5,359
	7,751	4,248	5,359

16. RELATED PARTY TRANSACTIONS

The Company has entered into agreements with a number of entities, some of which are related through common directors or shareholders, to share administrative personnel, aircraft, office space and facilities. The agreement for the usage of aircraft was terminated in 2003. The Company is billed on a cost recovery basis. The costs incurred in the normal course of business with respect to the above arrangements amounted to $0.9 million for each of the years ended December 31, 2004 and 2003 and $1.2 million for the year ended December 31, 2002. In addition, a company controlled by a director provides consulting services to the Company. Consulting services and out of pocket expenses paid to this company were $0.7 million for the year ended December 31, 2004 and $0.4 million for each of the years ended December 31, 2003 and 2002. As at December 31, 2004 and 2003, amounts included in accounts payable under these arrangements were $0.1 million.

The Company borrowed $1.25 million from a related company controlled by a director of the Company. The loan, plus accrued interest, was repaid in September 2003 (See Note 6).

17. COMMITMENTS AND CONTINGENCIES

Zitong Exploration Commitment

With the signing of the production-sharing contract in September 2002 for the Zitong block, the Company is obligated to conduct a minimum exploration program during the first three years, which will include acquiring seismic data, reprocessing existing seismic and drilling two exploration wells. At the end of the three-year period, if the Company does not complete the minimum exploration program, and elects not to continue, it will be obligated to pay, to CNPC within 30 days, a cash equivalent of the deficiency in the work program. The remaining cost of the minimum exploration program was estimated to be at least $12.4 million as at December 31, 2004.

Northwest Lost Hills Abandonment Contingency

The Company has temporarily abandoned Northwest Lost Hills #1-22 pending the identification of one or more partners to share the costs of the testing program. If the well were permanently abandoned, the Company would be obligated for its share of the costs to plug and abandon the well, which is estimated to be $1.1 million. There is no provision in the balance sheet for this contingent obligation.

Ensyn Acquisition

Under the Merger Agreement, the Company will pay $10 million in cash and issue Company common shares to acquire all the issued and outstanding common shares of Ensyn and all of the unissued shares of Ensyn common stock issuable upon the future exercise of any purchase warrants that remain unexercised when the Merger takes effect. The number of Company common shares to be issued will be the greater of (i) 30 million or (ii) the quotient obtained by dividing $75 million by the weighted average of the closing prices of the Company common shares on the NASDAQ SmallCap Market over a period of ten consecutive trading days determined five business days prior to the meeting at which Ensyn s shareholders will be asked to approve the Merger. If the number of Company common shares to be issued exceeds 42.4 million Company common shares, then the Company shall be required to hold a meeting at which its shareholders will be asked to approve the issuance of the Company common shares. The Company may be required to pay Ensyn a termination fee of $2.75 million if it is required to hold a shareholders meeting to approve the issuance of the Company common shares and decides not to or holds a required shareholders meeting and the Company s shareholders do not approve such share issuance. Additionally, the Merger Agreement provides that the Company may be obligated, under certain circumstances, to reimburse up to $1.0 million of Ensyn s expenses related to the Merger.

Other Commitments

The Company may provide indemnifications, in the course of normal operations, that are often standard contractual terms to counterparties in certain transactions such as purchase and sale agreements. The terms of these indemnifications will vary based upon the contract, the nature of which prevents the Company from making a reasonable estimate of the maximum potential amounts that may be required to be paid. The Company s management is of the opinion that any resulting settlements relating to potential litigation matters or indemnifications would not materially affect the financial position of the Company.

Lease Commitments

For the years ended December 31, 2004, 2003 and 2002, the Company expended $0.5 million, $0.5 million and $0.6 million, respectively, on operating leases relating to the rental of office space, which expire between April 2005 and March 2010. Such leases frequently provide for renewal options and require the Company to pay for utilities, taxes, insurance and maintenance expenses. As at December 31, 2004, future net minimum lease payments for operating leases (excluding oil and gas and other mineral leases) were the following:

2005	$ 616
2006	543
2007	342
2008	287
2009	287
Thereafter	48
	$ 2,123

18. SUBSEQUENT EVENTS

In February 2005, the Company borrowed $6.0 million of the stand-by loan facility and amended the loan agreement to provide the lender the right to convert, at the lender s election, unpaid principal and interest during the loan term to the Company s common shares at $2.25 per share (See Note 6).

19. ADDITIONAL DISCLOSURES REQUIRED UNDER U.S. GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Company s consolidated financial statements have been prepared in accordance with GAAP as applied in Canada. In the case of the Company, Canadian GAAP conforms in all material respects with U.S. GAAP except for certain matters, the details of which are as follows:

Consolidated Balance Sheets

The application of U.S. GAAP has the following effects on balance sheet items as reported under Canadian GAAP:

Shareholders   Equity and Oil and Gas Properties and Investments

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	As at December 31, 2004				
	Oil and Gas Properties and Investments	Shareholders Equity			
		Share Capital	Contributed Surplus	Accumulated Deficit	Total
Canadian GAAP	$ 96,551	$ 183,617	$ 1,748	$ (81,779)	$ 103,586
Adjustment for reduction in stated capital		74,455		(74,455)	
Adjustment to ascribed value of shares issued for U.S. royalty interests, net	1,358	1,358			1,358
Provision for impairment	(8,650)			(8,650)	(8,650)
Depletion adjustments due to differences in provision for impairment	482			482	482
GTL and EOR development costs expensed	(5,884)			(5,884)	(5,884)
Adjustment for change in accounting for stock based compensation		(300)	(1,660)	1,960	
U.S. GAAP	$ 83,857	$ 259,130	$ 88	$ (168,326)	$ 90,892

	As at December 31, 2003				
	Oil and Gas Properties and Investments	Shareholders Equity			
		Share Capital	Contributed Surplus	Accumulated Deficit	Total
Canadian GAAP	$ 87,956	$ 161,075	$ 516	$ (61,054)	$ 100,537
Adjustment for reduction in stated capital		74,455		(74,455)	
Adjustment to ascribed value of shares issued for U.S. royalty interests, net	1,358	1,358			1,358
Provision for impairment	(10,000)			(10,000)	(10,000)
Depletion adjustments due to differences in provision for impairment	166			166	166
GTL and EOR development costs expensed	(4,074)			(4,074)	(4,074)
Adjustment for change in accounting for stock based compensation		(271)	(516)	787	
U.S. GAAP	$ 75,406	$ 236,617	$	$ (148,630)	$ 87,987

Share Capital and Accumulated Deficit

In June 1999, the shareholders approved a reduction of stated capital in respect of the common shares by an amount of $74.4 million being equal to the accumulated deficit as at December 31, 1998. Under U.S. GAAP, a reduction of the accumulated deficit such as this is not recognized except in the case of a quasi reorganization. The effect of this is that under U.S. GAAP, share capital and accumulated deficit are increased by $74.4 million as at December 31, 2004 and 2003.

Oil and Gas Properties and Investments

Prior to January 2004, there were certain differences between the full cost method of accounting for oil and gas properties as applied in Canada and as applied in the U.S. The principal difference was in the method of performing ceiling test evaluations under the full cost method of accounting rules. Under Canadian GAAP prior to January 2004, impairment of oil and gas properties was based on the amount by which a cost center s carrying value exceeded its undiscounted future net cash flows from proved reserves using period-end, non-escalated prices and costs, less an estimate for future general and administrative expenses, financing costs and income taxes. As more fully described in Note 2 Oil and Gas Properties , effective January 2004, Canadian GAAP requires recognition and measurement processes to assess impairment of oil and gas properties using estimates of future oil and gas prices and costs plus the cost of unproved properties that have been excluded from the depletion calculation. In the measurement of the impairment, the future net cash flows of a cost center s proved and probable reserves are discounted using a risk-free interest rate.

For U.S. GAAP purposes, future net cash flows from proved reserves using period-end, non-escalated prices and costs, are discounted to present value at 10% per annum and compared to the carrying value of oil and gas properties. The Company performed the ceiling test in accordance with U.S. GAAP and determined that for 2004 an impairment provision of $15.0 was required on its U.S. oil and gas properties compared to a $16.3 million impairment provision under Canadian GAAP. For 2001, a $10.0 million provision for impairment was required, for U.S. GAAP purposes, in connection with the Company s China oil and gas properties resulting in accumulated net additional impairment provisions of $8.7 million for U.S. GAAP purposes as at December 31, 2004. There was no difference in the impairment provisions for 2003 and no impairment provision was required for 2002 under Canadian or U.S. GAAP.

The differences in the amount of impairment provisions between Canadian and U.S. GAAP resulted in a reduction in accumulated depletion of $0.5 million and $0.2 million as at December 31, 2004 and 2003, respectively.

As more fully described under Investments in EOR and GTL Projects in Note 2, for Canadian GAAP the Company capitalizes certain costs incurred for GTL and EOR projects subsequent to executing an MOU to determine the technical and commercial feasibility of a project, including studies for the marketability for the projects products. If no definitive agreement is reached, then the project s capitalized costs, which are deemed to have no future value, are written down and charged to operations with a corresponding reduction in the investments in GTL and EOR assets.

For U.S. GAAP, feasibility, marketing and related costs incurred prior to executing a GTL or EOR definitive agreement are considered to be research and development and are expensed as incurred. As at December 31, 2004 and 2003, the Company capitalized $5.9 million and $4.1 million, respectively, for Canadian GAAP, which was expensed for U.S. GAAP purposes.

For U.S. GAAP purposes, the aggregate value attributed to the acquisition of U.S. royalty rights during 1999 and 2000 was $1.4 million higher, due to the difference between Canadian and U.S. GAAP in the value ascribed to the shares issued, primarily resulting from differences in the recognition of effective dates of the transactions. For the year ended December 31, 2004, a ceiling test impairment of $1.0 million of the U.S. GAAP difference related to royalty rights was recognized in the results of operations.

Consolidated Statements of Loss

The application of U.S. GAAP had the following effects on net loss and net loss per share as reported under Canadian GAAP:

	Year ended December 31,					
	2004		**2003**		**2002**	
	Net Loss	**Net Loss Per Share**	**Net Loss**	**Net Loss Per Share**	**Net Loss**	**Net Loss Per Share**
Canadian GAAP (as restated for 2003 and 2002 see *Notes 2 and 9*)	$ 20,725	$ 0.12	$ 30,179	$ 0.20	$ 7,130	$ 0.05
Stock based compensation expense	(1,173)	(0.01)	(476)		(311)	
Provision for impairment	(1,350)	(0.01)				
Depletion adjustments due to differences in provision for impairment	(316)		(88)		(78)	
GTL and EOR development costs expensed, net	1,810	0.02	(2,529)	(0.02)	1,461	0.01
U.S. GAAP	$ 19,696	0.12	$ 27,086	$ 0.18	$ 8,202	$ 0.06
Weighted Average Number of Shares under U.S. GAAP (in thousands)		167,612		150,154		142,314

As discussed under Oil and Gas Properties and Investments in this note, there is a difference in performing the ceiling test evaluation under the full cost method of accounting between U.S. and Canadian GAAP. Application of the ceiling test evaluation under U.S. GAAP for 2004, resulted in a lower impairment provision on the Company s U.S. oil and gas properties by $1.3 million and for 2001 required an additional $10.0 million provision for impairment with respect to the Company s China oil and gas properties. The net increase in impairment provisions resulted in lower depletion rates for U.S. GAAP purposes and a reduction of $0.3 million in the net loss for the year ended December 31, 2004 and $0.1 million reductions in the net losses for each of the years ended December 31, 2003 and 2002.

As more fully discussed under Stock Based Compensation in Notes 2 and 9, as of January 1, 2004 the Company changed its accounting policy, for Canadian GAAP, to recognize compensation costs using the fair value based method of accounting for stock options granted to employees and directors after January 1, 2002. For U.S. GAAP, the Company continues to apply APB Opinion No. 25, as interpreted by FASB Interpretation No. 44, in accounting for its stock option plan and does not recognize compensation costs in its financial statements for stock options issued to employees and directors. This resulted in a reduction of $1.2 million, $0.5 million and $0.3 million in the net losses for the years ended December 31, 2004, 2003 and 2002, respectively.

As more fully described under Oil and Gas Properties and Investments in this note, for Canadian GAAP, feasibility, marketing and related costs incurred prior to executing a GTL or EOR definitive agreement are capitalized and are subsequently written down upon determination that a project s future value has been impaired. For U.S. GAAP, such costs are considered to be research and development and are expensed as incurred. For the years ended December 31, 2004 and 2002, the Company expensed $1.8 million and $1.5 million, respectively, in excess of the Canadian GAAP write-downs during those corresponding years. For the year ended December 31, 2003, the Company expensed $2.5 million less for U.S. GAAP than the write-down recognized for Canadian GAAP.

Stock Based Compensation

Had stock based compensation expense been determined based on fair value at the stock option grant date, consistent with the method of SFAS No. 123, Accounting for Stock Based Compensation , the Company s net loss and net loss per share would have been increased to the pro forma amounts indicated below:

	Year ended December 31,		
	2004	2003	2002
Net loss under U.S. GAAP	$ 19,696	$ 27,086	$ 8,202
Stock-based compensation expense determined under the fair value based method for employee and director awards	1,869	1,682	1,885
Pro forma net loss under U.S. GAAP	$ 21,565	$ 28,768	$ 10,087
Basic and diluted loss per common share under U.S. GAAP:			
As reported	$ 0.12	$ 0.18	$ 0.06
Pro forma	$ 0.13	$ 0.19	$ 0.07
Weighted Average Number of Shares under U.S. GAAP (in thousands)	167,612	150,154	142,314
Stock options granted during the period (thousands)	458	690	1,870
Weighted average exercise price	$ 1.88	$ 4.00	$ 1.92
Weighted average fair value of options granted during the year	$ 1.40	$ 2.83	$ 1.07

Stock based compensation for U.S. GAAP was calculated in accordance with the Black Scholes option-pricing model using the same assumptions as used for Canadian GAAP.

Consolidated Statements of Cash Flow

As a result of the write-down of GTL and EOR development costs required under U.S. GAAP, the statement of cash flow as reported would result in a cash surplus from operating activities of $2.0 million for the year ended December 31, 2004 and cash deficiencies from operating activities of $2.3 million and $4.0 million for the years ended December 31, 2003 and 2002, respectively. Additionally, capital investments reported under investing activities would be $44.4 million, $14.6 million and $16.9 million for the same periods ended, respectively.

Additional U.S. GAAP Disclosures

Oil and Gas Properties and Investments

The categories of costs included in Oil and Gas Properties and Investments , including the U.S. GAAP adjustments discussed in this note were as follows:

	As at December 31, 2004				As at December 31, 2003			
	U.S.	China	GTL	Total	U.S.	China	GTL	Total
Property acquisition costs	$ 22,295	$ 2,418	$	$ 24,713	$ 17,518	$ 2,418	$	$ 19,936
Royalty rights acquired	10,582			10,582	10,582			10,582

Exploration costs	35,120	8,594		43,714	31,269	1,669		32,938
Development costs	35,456	35,105		70,561	27,068	28,587		55,655
GTL master license			10,000	10,000			10,000	10,000
Support equipment and general property	480	270		750	433	196		629
	103,933	46,387	10,000	160,320	86,870	32,870	10,000	129,740
Accumulated depletion and depreciation	(11,197)	(6,266)		(17,463)	(6,696)	(3,638)		(10,334)
Provision for impairment	(49,000)	(10,000)		(59,000)	(34,000)	(10,000)		(44,000)
	$ 43,736	$ 30,120	$ 10,000	$ 83,857	$ 46,174	$ 19,232	$ 10,000	$ 75,406

U.S. development costs as at December 31, 2004 and 2003 include $0.6 million and $0.4 million, respectively, of asset retirement costs.

As at December 31, 2004, the costs of unproved properties included in oil and gas properties were as follows:

		Incurred in			
	Total	2004	2003	2002	Prior to 2002
Property Acquisition	$ 8,973	$ 893	$ 673	$ 2,055	$ 5,352
Royalty rights	6,851				6,851
Exploration	15,592	8,949	1,877		4,766
	$ 31,416	$ 9,842	$ 2,550	$ 2,055	$ 16,969

The difference from Canadian GAAP in unproved oil and gas properties as at December 31, 2004 was $0.4 million related to the $1.4 million of aggregate value attributed to the acquisition of U.S. royalty rights during 1999 and 2000 less a $1.0 million ceiling test impairment associated with these royalty rights recognized for U.S. GAAP during the year ended December 31, 2004.

Accounts Payable and Accrued Liabilities

The following was the breakdown of accounts payable and accrued liabilities:

	As at December 31,	
	2004	2003
Accounts payable and accruals	$ 8,745	$ 3,626
Accrued salaries and related expenses	929	858
Accrued interest	11	2
Other accruals	160	30
	$ 9,845	$ 4,516

Impact of New and Pending U.S. GAAP Accounting Standards

In June 2004, the Financial Accounting Standards Board (**FASB**) issued an exposure draft of a proposed statement, Fair Value Measurements to provide guidance on how to measure the fair value of financial and non-financial assets and liabilities when required by other authoritative accounting pronouncements. The proposed statement attempts to address concerns about the ability to develop reliable estimates of fair value and inconsistencies in fair value guidance provided by current U.S. GAAP, by creating a framework that clarifies the fair value objective and its application in GAAP. In addition, the proposal expands disclosures required about the use of fair value to re-measure assets and liabilities. The standard would be effective for financial statements issued for fiscal years beginning after June 15, 2005.

In September of 2004, the SEC released Staff Accounting Bulletin No. 106, which provides guidance regarding the interaction of Statement of Financial Accounting Standard No. 143, Accounting for Asset Retirement Obligations (**SFAS 143**) with the full cost accounting rules in Article 4-10 of Regulation S-X. This bulletin clarifies the treatment of assets and liabilities resulting from the implementation of SFAS 143 on the full cost ceiling test and the calculation of depletion, depreciation and amortization. The Company is in compliance with the provisions of Staff Accounting Bulletin No. 106.

In December 2004, the FASB issued a revision to SFAS No, 123, Accounting for Stock Based Compensation which supersedes APB No. 25, Accounting for Stock Issued to Employees . This Statement requires measurement of the cost of employee services received in exchange for an award of equity instruments based on the fair value of the award on the date of the grant and recognition of the cost in the results of operations over the period during which an employee is required to provide service in exchange for the award. No compensation cost is recognized for equity instruments for which employees do not render the requisite service. The Company applies APB Opinion No. 25, as interpreted by FASB Interpretation No. 44, in accounting for awards issued from our stock option plan and do not recognize compensation costs in our U.S. GAAP financial statements for stock options issued to its employees and directors. This statement is effective for the first interim or annual reporting that begins after June 15, 2005 and maybe implemented on a modified prospective or retrospective basis. The Company has elected to implement this statement on a modified prospective basis starting in the third quarter of 2005. Under the modified prospective basis the Company would recognize stock based compensation in its U.S. GAAP results of operations for the unvested portion of awards outstanding as of July 1, 2005 and for all awards granted after July 1, 2005.

The following standards issued by the FASB do not impact the Company at this time:

SFAS No. 151, Inventory Costs an amendment of ARB No. 43, Chapter 4 effective for inventory costs incurred during fiscal years beginning after June 15, 2005.

SFAS No. 153, Exchanges of Nonmonetary Assets an amendment of APB Opinion No. 29 effective for nonmonetary asset exchanges occurring in fiscal years beginning after June 15, 2005.

QUARTERLY FINANCIAL DATA IN ACCORDANCE WITH CANADIAN AND U.S. GAAP (UNAUDITED)

	QUARTER ENDED							
	2004				2003			
	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr
Total revenue	$ 6,212	$ 4,932	$ 3,521	$ 3,332	$ 2,330	$ 2,423	$ 2,338	$ 2,568
Net loss - Canadian GAAP	$ 17,184	$ 951	$ 1,298	$ 1,292	$ 23,154	$ 1,330	$ 4,587	$ 1,108
Net loss - U.S. GAAP	$ 15,736	$ 980	$ 1,510	$ 1,470	$ 23,270	$ 1,306	$ 1,325	$ 1,185
Net loss per share - Canadian GAAP	$ 0.09	$ 0.01	$ 0.01	$ 0.01	$ 0.15	$ 0.01	$ 0.03	$ 0.01
Net loss per share - U.S. GAAP	$ 0.09	$ 0.01	$ 0.01	$ 0.01	$ 0.15	$ 0.01	$ 0.01	$ 0.01

The 2003 quarterly earnings for Canadian GAAP have been restated to give effect to the retroactive application of CICA Section 3870   Stock Based Compensation and Other Stock Based Payments , which is more fully described in Note 2 under Stock Based Compensation . The net losses in the fourth quarter of 2004, for Canadian and U.S. GAAP, were primarily due to impairment provisions of $16.3 million and $15.0 million, respectively, for U.S. oil and gas properties. The net losses in the fourth quarter of 2003, for both Canadian and U.S. GAAP, were primarily due to an impairment provision of $20.0 million for U.S. oil and gas properties. The net loss under Canadian GAAP for the second quarter of 2003 included a $3.3 million write-down of costs associated with the unsuccessful negotiations of a GTL contract in Qatar. For U.S. GAAP, these costs are expensed as they are incurred.

SUPPLEMENTARY DISCLOSURES ABOUT OIL AND GAS PRODUCTION ACTIVITIES (UNAUDITED)

The following information about the Company s oil and gas producing activities is presented in accordance with U.S. Statement of Financial Accounting Standards No. 69, Disclosures About Oil and Gas Producing Activities .

Oil and Gas Reserves

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic conditions.

Proved developed oil and gas reserves are reserves, which can be expected to be recovered from existing wells with existing equipment and operating methods.

Estimates of oil and gas reserves are subject to uncertainty and will change as additional information regarding the producing fields and technology becomes available and as future economic conditions change.

Reserves presented in this section represent the Company s share of reserves, excluding royalty interests of others. The reserves for 2004 and 2003 in the U.S. were based on the estimates by the independent petroleum engineering firm of Netherland, Sewell & Associates, Inc. The reserves for 2002 in the U.S. were based on estimates by the independent petroleum engineering firms of Joe C. Neal & Associates and Allan Spivak Engineering. In China, the reserves were based on estimates by the independent petroleum engineering firm of Gilbert Laustsen Jung Associates Ltd.

The Company s net proved and net proved developed oil and gas reserves were as follows:

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	Oil (MBbl) U.S.	Oil (MBbl) China	Oil (MBbl) Total	Gas (MMcf) U.S.
Net proved reserves, December 31, 2001	2,003	21,795	23,798	1,631
Extensions and discoveries	710		710	63
Production	(208)	(142)	(350)	(103)
Revisions to previous estimates	(280)	(2,601)	(2,881)	(101)
Sales of reserves	(441)	(3,448)	(3,889)	(671)
Net proved reserves, December 31, 2002	1,784	15,604	17,388	819
Extensions and discoveries	480		480	22
Production	(202)	(144)	(346)	(50)
Revisions to previous estimates	(499)	239	(260)	(96)
Net proved reserves, December 31, 2003	1,563	15,699	17,262	695
Extensions and discoveries	240		240	1,289
Purchases of reserves in place				819
Production	(234)	(235)	(469)	(207)
Revisions to previous estimates	(121)	(1,360)	(1,481)	87
Sale of reserves	(18)	(6,196)	(6,214)	
Net proved reserves, December 31, 2004	1,430	7,908	9,338	2,683
Net proved developed reserves:				
December 31, 2002	1,131	48	1,179	819
December 31, 2003	1,225	209	1,434	695
December 31, 2004	1,187	1,142	2,329	2,365

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Gas Reserves

The following standardized measure of discounted future net cash flows from proved oil and gas reserves was computed using period end statutory tax rates, costs and prices of $40.25, $30.31 and $29.04 per barrel of oil in 2004, 2003 and 2002, respectively, and $5.94, $6.13 and $5.30 per Mcf of gas in 2004, 2003 and 2002, respectively. A discount rate of 10% was applied in determining the standardized measure of discounted future net cash flows.

The Company does not believe that this information reflects the fair market value of its oil and gas properties. Actual future net cash flows will differ from the presented estimated future net cash flows in that:

- future production from proved reserves will differ from estimated production;
- future production will also include production from probable and potential reserves;
- future, rather than year end, prices and costs will apply; and
- existing economic, operating and regulatory conditions are subject to change.

The standardized measure of discounted future net cash flows as at December 31 in each of the three most recently completed financial years were as follows:

	2004		
	U.S.	**China**	**Total**
Future cash inflows	$ 64,357	$ 327,481	$ 391,838
Future development and restoration costs	3,063	84,682	87,745
Future production costs	27,867	58,488	86,355
Future income taxes		44,708	44,708
Future net cash flows	33,427	139,603	173,030
10% annual discount	11,238	50,774	62,012
Standardized measure	$ 22,189	$ 88,829	$ 111,018

	2003		
	U.S.	**China**	**Total**
Future cash inflows	$ 48,751	$ 478,748	$ 527,499
Future development and restoration costs	2,138	154,245	156,383
Future production costs	22,037	91,912	113,949
Future income taxes		61,647	61,647
Future net cash flows	24,576	170,944	195,520
10% annual discount	7,466	89,180	96,646
Standardized measure	$ 17,110	$ 81,764	$ 98,874

	2002		
	U.S.	**China**	**Total**
Future cash inflows	$ 52,057	$ 461,256	$ 513,313
Future development and restoration costs	4,597	129,855	134,452
Future production costs	16,288	134,540	150,828
Future income taxes		52,656	52,656
Future net cash flows	31,172	144,205	175,377
10% annual discount	9,687	84,423	94,110
Standardized measure	$ 21,485	$ 59,782	$ 81,267

Changes in standardized measure of discounted future net cash flows as at December 31 in each of the three most recently completed financial years were as follows:

	2004		
	U.S.	**China**	**Total**
Sale of oil & gas net of production costs	$ (6,152)	$ (6,570)	$ (12,722)
Net changes in pricing and production costs	1,015	56,329	57,344
Sale of reserves	(108)	(21,646)	(21,754)
Discoveries and extensions	6,779		6,779
Purchases of reserves in place	3,050		3,050
Revisions of previous estimates	(1,401)	(22,847)	(24,248)
Net change in income taxes		(9,107)	(9,107)
Net change in future development costs	(1,700)	(14,424)	(16,124)
Accretion of discount	3,596	25,330	28,926
Increase (decrease)	5,079	7,065	12,144
Standardized measure, beginning of year	17,110	81,764	98,874
Standardized measure, end of year	$ 22,189	$ 88,829	$ 111,018

	2003		
	U.S.	**China**	**Total**

Sale of oil & gas net of production costs	$ (3,153)	$ (2,123)	$ (5,276)
Net changes in pricing and production costs	(4,034)	47,960	43,926
Discoveries and extensions	5,712	(636)	5,076
Revisions of previous estimates	(8,957)	1,604	(7,353)
Net change in income taxes		(9,435)	(9,435)
Net change in future development costs	2,337	(14,626)	(12,289)
Accretion of discount	3,720	(762)	2,958
Increase (decrease)	(4,375)	21,982	17,607
Standardized measure, beginning of year	21,485	59,782	81,267
Standardized measure, end of year	$ 17,110	$ 81,764	$ 98,874

	2002		
	U.S.	China	Total
Sale of oil & gas net of production costs	$ (2,748)	$ (1,740)	$ (4,488)
Net changes in pricing and production costs	13,700	150,510	164,210
Sale of reserves	(4,192)	(43,493)	(47,685)
Discoveries and extensions	10,135	(550)	9,585
Revisions of previous estimates	(7,661)	(34,600)	(42,261)
Net change in income taxes		(21,206)	(21,206)
Net change in future development costs	3,539	(309)	3,230
Accretion of discount	(1,531)	3,124	1,593
Increase (decrease)	11,242	51,736	62,978
Standardized measure, beginning of year	10,243	8,046	18,289
Standardized measure, end of year	$ 21,485	$ 59,782	$ 81,267

Costs incurred in oil and gas property acquisition, exploration, and development activities were as follows:

	As at December 31,		
	2004	2003	2002
Property acquisition			
Proved	$ 3,204	$	$
Unproved	1,572	650	913
Exploration	11,276	3,148	10,841
Development	28,364	11,181	5,178
	$ 44,416	$ 14,979	$ 16,932

Development cost additions for the years ended December 31, 2004 and 2003 included $0.2 million and $0.4 million of asset retirement costs, respectively.

Depletion, per unit of net production, before provision for impairment were as follows:

U.S.	
Year ended December 31, 2004	$ 16.80
Year ended December 31, 2003	$ 10.58
Year ended December 31, 2002	$ 8.39
China	
Year ended December 31, 2004	$ 12.18
Year ended December 31, 2003	$ 10.23
Year ended December 31, 2002	$ 8.30

The results of operations from producing activities were as follows:

	2004			2003			2002		
	U.S.	China	Total	U.S.	China	Total	U.S.	China	Total
Oil and gas revenue	$ 9,311	$ 8,484	$ 17,795	$ 5,466	$ 4,103	$ 9,569	$ 5,099	$ 3,230	$ 8,329
Operating costs	3,159	1,914	5,073	2,313	1,980	4,293	2,351	1,490	3,841
Depletion (including provision for impairment)	19,428	2,630	22,058	22,253	1,477	23,730	1,906	1,202	3,108
Results of operations from producing activities	$ (13,276)	$ 3,940	$ (9,336)	$ (19,100)	$ 646	$ (18,454)	$ 842	$ 538	$ 1,380

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

We carried out an evaluation, under the supervision of and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our internal control over financial reporting pursuant to the requirements of the Securities Exchange Act of 1934. Based upon that evaluation, our management, including the Chief Executive Officer and Chief Financial Officer, concluded that, as at December 31, 2004, because of the issues referenced below, our internal control over financial reporting was not effective at a reasonable assurance level. Our management, including our Chief

Executive Officer and Chief Financial Officer believe, however, that when fully implemented, remediation measures will address the internal control deficiencies described below and will allow us to conclude that our internal control over financial reporting is effective at a reasonable level of assurance at future filing dates.

There were several significant changes in our internal control over financial reporting both during the year ended December 31, 2004 and since that date. These changes were in direct response to management s formal assessment of the effectiveness of the design and operation of our internal control over financial reporting. The Securities Exchange Act of 1934 requires an annual management report on the effectiveness of our internal control over financial reporting. Our independent registered chartered accountants must attest to this report. Although we would ordinarily include such information in our Annual Report on Form 10-K, we meet the eligibility requirements for a 45-day extension for the provision of this report and attestation, as detailed in an exemptive order by the U.S. Securities and Exchange Commission in November 2004. Because we have elected to use this extension, this Annual Report on Form 10-K does not include either the management report or the independent registered chartered accountants attestation. These will instead be included in an amended Annual Report on Form 10-K that we expect to file in April 2005.

Our review to date of our internal control over financial reporting has brought to our attention two material weaknesses that are discussed below.

1. Information and Communication

Information systems produce reports, containing operational, financial and compliance-related information, that make it possible to run and control the business. Pertinent information must be identified, captured, and communicated in an effective manner to enable employees to carry out their responsibilities. These information systems deal not only with internally generated data, but also with the information about external events necessary to informed business decision-making and external reporting, such as industry, economic, and regulatory information. Effective communication also must occur in a broader sense, flowing down, across, and up the organization.

Our review of our information and communication procedures identified certain deficiencies. Taken together, the following deficiencies are considered to constitute a material weakness in internal control over financial reporting.

a weakness in the procedure for the receipt of complaints regarding accounting, internal accounting controls, or auditing matters.

- Section 301 of the Sarbanes-Oxley Act of 2002 requires our Audit Committee to establish procedures for the confidential, anonymous submission by employees . . . regarding questionable accounting or auditing matters. Our current complaint procedure, applicable to both employees and third parties, directs complaints to our Corporate Secretary, who then advises the appropriate board committee or management member. We do not believe this procedure provides the requisite anonymity to a reporting employee or third party. As a result, we have adopted corrective measures that will be in place by March 31, 2005. An independent firm will handle all complaints, whether from employees or third parties. In addition, anyone wishing to raise concerns regarding accounting or auditing matters will be able to do so by means of a secure website.

a lack of a formal process to ensure active ongoing communication of employees roles and responsibilities related to internal control over financial reporting across the organization.

- Although the importance of the safeguarding of our assets and the honest and accurate recording of information are key parts of our Code of Business Conduct, we do not formally review these processes with our employees on a regular basis. We will be formally communicating the roles and responsibilities related to internal control over financial reporting to all employees as part of our new complaint process noted above.

a lack of a formal self-assessment process to monitor and detect control deficiencies related to internal control over financial reporting.

- As part of our responsibilities under Section 404 of the Sarbanes-Oxley Act of 2002, there will be an annual and extensive formal review to monitor and detect control deficiencies related to internal control over financial reporting.

our present fraud or misconduct response plans and policies are informal and do not provide a written and clear process for employees and external third parties to follow if they wish to report an issue, including inappropriate management overrides.

- We will be formally communicating such plans and policies as part of our new complaint process noted above.

2. Financial Reporting Process

Our review of our financial reporting process identified several deficiencies, principally related to the lack of formal processes, division of duties and procedures for documentation of various approvals and reviews. Taken together, these deficiencies are considered to constitute a material weakness in internal control over financial reporting. Management believes that these procedures and reviews were properly carried out and that the deficiencies identified during the review process relate principally to the lack of written evidence that procedures and reviews were properly completed. Prior to December 31, 2004 and since that date, we have changed many of our policies and procedures for the documentation of these reviews and procedures and have designed appropriate document retention policies to provide written evidence of our reviews and procedures.

As noted above, upon completion of our assessment of our internal control over financial reporting we currently expect to conclude that the above described two material weaknesses in our internal control over financial reporting existed as at December 31, 2004. However, we have not yet completed our assessment and so there may be other material weaknesses identified.

Accordingly, management expects to conclude that our internal control over financial reporting as at December 31, 2004 is ineffective, and Deloitte & Touche LLP has advised us that they expect their report on management s assessment of internal control over financial reporting will also indicate that internal control over financial reporting was ineffective as at December 31, 2004.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The following table provides the names of all of our directors and executive officers, their positions, terms of office and their principal occupations during the past five years. Each director is elected for a one-year term or until his successor has been duly elected or appointed. Officers serve at the pleasure of the Board of Directors.

Name, Age and Municipality of Residence	Position with the Registrant	Present Occupation and Principal Occupation for the Past Five Years
DAVID R. MARTIN, age 73 Santa Barbara, California	Chairman of the Board and Director (since August, 1998)	Chairman of the Board of Ivanhoe Energy Inc. (August 1998 present); President, Cathedral Mountain Corporation (1997 present); President and Chief Executive Officer, Occidental Oil and Gas Corporation (1986-1996); Executive Vice President and Director, Occidental Petroleum Corporation (1986-1996)
ROBERT M. FRIEDLAND, age 54 Hong Kong	Deputy Chairman (since June, 1999) and Director (since February, 1995)	Chairman and President, Ivanhoe Capital Corporation, a Singapore based venture capital company principally involved in establishing and financing international mining and exploration companies; Chairman and Director, Ivanhoe Mines Ltd. (March 1994 present)
E. LEON DANIEL, age 68 Park City, Utah	President, Chief Executive Officer (since June, 1999) and Director (since August, 1998)	President and Chief Executive Officer of Ivanhoe Energy Inc. (June, 1999 present); Executive Vice President, Worldwide Business Development, Occidental Oil and Gas Corporation (1996-1998); Vice President Engineering, Drilling and Production, Occidental Petroleum Corporation (1997-1998)
JOHN A. CARVER, age 72 Bakersfield, California	Director (since August, 1998)	Retired (1998); Senior Vice President, Worldwide Exploration, Occidental Petroleum Corporation (1997-1998)
R. EDWARD FLOOD, age 59 Reno, Nevada	Director (since June, 1999)	Deputy Chairman and Director, Ivanhoe Mines Ltd. (May 1999 present); Mining Analyst, Haywood Securities (May, 1999 September 2001); President, Ivanhoe Mines Ltd. (1995-1999)
SHUN-ICHI SHIMIZU, age 64 Tokyo, Japan	Director (since July, 1999)	Managing Director of C.U.E. Management Consulting Ltd. (1994 present)
HOWARD R. BALLOCH, age 53 Beijing, China	Director (since January, 2002)	President, The Balloch Group (July 2001 present); President, Canada China Business Council (July 2001 present); Canadian Ambassador to China, Mongolia and Democratic Republic of Korea (April 1996 July 2001); Director, Methanex Corporation (December 2004 present); Director, Zi Corporation (August 2001 present); Director, Magic Lantern Corporation (December 2003

		present)
J. STEVEN RHODES, age 53 Los Angeles, California	Director (since December, 2003)	Chairman and Chief Executive Officer. Claiborne- Rhodes, Inc. (2001 present); Senior Vice President, First Southwest Company (1999 2001); White House, Chief Domestic Advisor to Vice President George Bush (1981 1985)
W. GORDON LANCASTER, C.A. age 61 Vancouver, British Columbia	Chief Financial Officer (Since January, 2004)	Vice President Finance and Chief Financial Officer of Xantrex Technology Inc., (July 2003 December 2003); Vice President Finance and Chief Financial Officer of Power Measurement, Inc., (August 2000 June 2003); Senior President Finance and Chief Financial Officer of Lions Gate Entertainment Corp., (1998 2000)
PATRICK CHUA, age 49 Hong Kong, China	Executive Vice-President (since June, 1999)	Executive Vice-President of Ivanhoe Energy Inc. (June, 1999 present); President and Director of Sunwing Energy Ltd. (Bermuda) (March 2000 present): Co-Chairman and Director of Sunwing Energy Ltd. (June, 1996 June, 1999)
GERALD MOENCH, age 56 Lethbridge, Alberta	Executive Vice-President (since June, 1999)	Executive Vice-President of Ivanhoe Energy Inc. (June, 1999 present); President and Director, Sunwing Energy Ltd. (July, 1997 June, 1999)

Each of our directors was elected at our last annual general meeting of shareholders held on April 29, 2004. The term of office of each director concludes at our next annual general meeting of shareholders, unless the director s office is earlier vacated in accordance with our by-laws. There are no family relationships among any of our directors, officers or key employees.

As required under the *Business Corporations Act* (Yukon), our Board of Directors has an Audit Committee. We also have a Compensation Committee. The members of the Audit Committee are Messrs. Edward Flood, Howard Balloch and Steven Rhodes. Mr.

Rhodes replaced Mr. Shun-ichi Shimizu effective March 2, 2004. Mr. Flood, one of our independent directors, has been determined by the Board of Directors to be an Audit Committee financial expert. We believe that Mr. Flood s prior experience as the chief executive officer of a public traded mining company, as a member of the management of a U.S. investment fund and as a mining analyst for a Canadian brokerage firm provides a sufficient basis for considering him to be an Audit Committee financial expert. The members of the Compensation Committee are Messrs. Edward Flood, Howard Balloch and Steven Rhodes. Mr. Rhodes was appointed to the Compensation Committee on March 2, 2004.

Management is responsible for our financial reporting process including our system of internal controls over financial reporting and for the preparation of consolidated financial statements in accordance with generally accepted accounting principles in Canada. Our independent registered chartered accountants are responsible for auditing those financial statements. The members of the Audit Committee are not our employees, and are not professional accountants or auditors. The Audit Committee s primary purpose is to assist the Board of Directors in fulfilling its oversight responsibilities by reviewing the financial information provided to shareholders and others, and the systems of internal controls which management has established to preserve our assets and the audit process. It is not the Audit Committee s duty or responsibility to conduct auditing or accounting reviews or procedures or to determine that our financial statements are complete and accurate and in accordance with generally accepted accounting principles in Canada. In giving its recommendation to the Board of Directors, the Audit Committee has relied on management s representations that the financial statements have been prepared with integrity and objectivity and in conformity with generally accepted accounting principles in Canada and on the opinion of the independent registered chartered accountants included in their report on our financial statements.

Based solely on a review of the reports furnished to us, we believe that during 2004 all of our directors, executive officers and 10% shareholders complied with the applicable Canadian requirements for reporting initial ownership and changes in ownership of our common shares.

Code of Business Conduct and Ethics

We have a Code of Business Conduct and Ethics applicable to all employees, consultants, officers and directors regardless of their position in our organization, at all times and everywhere we do business. The Code of Business Conduct and Ethics provides that our employees, consultants, officers and directors will uphold our commitment to a culture of honesty, integrity and accountability and that we require the highest standards of professional and ethical conduct from our employees, consultants, officers and directors. Our Code of Business Conduct and Ethics has been filed as Exhibit 14.1 to our 2004 Annual Report on Form 10-K. A copy of our Code of Business Conduct and Ethics may be obtained, without charge, by request to Ivanhoe Energy Inc., 654-999 Canada Place, Vancouver, British Colombia, Canada V6C 3E1, Attention: Investor Relations or by phone to 604-688-8323.

ITEM 11. EXECUTIVE COMPENSATION

In accordance with the requirements of applicable securities legislation in Canada, the following executive compensation disclosure is provided in respect of the our Chief Executive Officer and Chief Financial Officer as at December 31, 2004, and each of our three most highly compensated executive officers whose annual compensation exceeded Cdn.$150,000 in the year ended December 31, 2004 (collectively, the **Named Executive Officers**). During the year ended December 31, 2004, the aggregate compensation paid to all of our executive officers whose annual compensation exceeded Cdn.$40,000 was U.S.$1,285,834.

Summary Compensation Table

The following table sets forth a summary of all compensation paid during the years ending December 31, 2004, 2003 and 2002 to each of the Named Executive Officers.

SUMMARY COMPENSATION TABLE ($U.S.)

		Annual Compensation			Long Term Compensation			
					Awards		Payouts	
Name and Principal Position	**Year**	**Salary**	**Bonus**[(6)]	**Other Annual Compen-sation**	**Securities Under Options/ SARs Granted (#)**	**Restricted Shares or Restricted Share Units**	**LTIP Payouts**	**All Other Compen-sation**[(7)]
E. Leon Daniel	2004	300,000	90,000					12,792
President & Chief Executive	2003	332,610	81,123					9,792
Officer[(1)]	2002	266,500						5,415
David R. Martin	2004	200,000	60,000		-			12,792
Chairman[(2)]	2003	205,562	54,082					9,792
	2002	253,167						7,200
Patrick Chua	2004	144,000						
Executive Vice President[(3)]	2003	144,000	32,449					
	2002	182,970			60,000			
Gerald Moench	2004	165,000	41,250					
Executive Vice President[(4)]	2003	150,000	33,801					
	2002	152,475			50,000			
W. Gordon Lancaster Chief Financial Officer [(5)]	2004	200,000	60,000		250,000			

(1) Mr. Daniel was appointed President and Chief Executive Officer in June 1999, and has been one of our directors since August 1998.

(2) Mr. Martin has been Chairman and one of our directors since August 1998.

(3) Mr. Chua was appointed as an Executive Vice President in June 1999.

(4) Mr. Moench was appointed an Executive Vice President in June 1999.

(5) Mr. Lancaster was appointed Chief Financial Officer effective January 2004.

(6) Bonuses earned are payable in cash and common shares from our Employees and Directors Equity Incentive Plan at fair market value on the date of approval by the Compensation Committee.

(7) Our matching contribution to the 401(k) plan, a U.S. defined contribution retirement plan available to U.S. employees.

Long Term Incentive Plan

We do not presently have a long-term incentive plan for any of our executive officers, including our Named Executive Officers.

Options and Stock Appreciation Rights (SARs)

During the year ended December 31, 2004, Mr. Lancaster received an incentive stock option to acquire 250,000 common shares, which vest over 4 years and expire on the 5th anniversary of the date of grant. Although this option was granted during the fourth quarter of 2003 in anticipation of Mr. Lancaster s appointment as Chief Financial Officer, it did not become exercisable by Mr. Lancaster until January 1, 2004, the date upon which his appointment as Chief Financial Officer took effect. No other stock options or SARs were granted to our Named Executive Officers in the year ended December 31, 2004.

	Securities, Under	Percent of Total Options/ SARs	Market Value of Securities