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 var 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 17.1º 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 Discounted at:			In Thousands of U.S. Dollars Discounted at:		
	Oil (Mbbl)	Gas (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		