IVANHOE ENERGY INC
Form 10-K
March 16, 2007

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-K

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2006

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	**98-0372413**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
654-999 Canada Place Vancouver, British Columbia, Canada	**V6C 3E1**
(Address of principal executive offices)	(Zip Code)

(604) 688-8323
(Registrant s telephone number, including area code)
Securities registered pursuant to Section 12(b) of the Act:
None
Securities 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 Capital Market

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes o No þ

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.

Yes o No þ

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 (§ 229.405 of this chapter) 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 a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act (Check one).

Large accelerated filer o Accelerated filer þ Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o No þ

As of June 30, 2006, the aggregate market value of the registrant s common stock held by non-affiliates of the registrant was $590,875,805 based on the average bid and asked price as reported on the National Association of Securities Dealers Automated Quotation System National Market System.

Indicate the number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date.

Class	Outstanding at March 8, 2007
Common Shares, no par value	241,254,394 shares

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:

	2006	**2005**	**2004**	**2003**	**2002**
Closing	$0.86	$0.86	$0.83	$0.77	$0.63
Low	$0.85	$0.79	$0.72	$0.63	$0.62
High	$0.91	$0.87	$0.85	$0.77	$0.66
Average Noon	$0.88	$0.83	$0.77	$0.71	$0.63

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 28, 2007 was $ 0.85 ($1.00 = Cdn.$1.17).

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
Mboe	= thousands of barrels of oil equivalent
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 activities in the U.S. and China; our limited cash resources and consequent need for additional financing; our ability to raise additional financing; uncertainties regarding the potential success of heavy-to-light oil upgrading and gas-to-liquids technologies; uncertainties regarding the potential success of our oil and gas exploration and development properties in the U.S. and China; 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 what appear to be 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 , expect , intend , estimate , anticipate , believe continue or the negative thereof or variations thereon 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.

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 United States Securities and Exchange Commission s website at http://www.sec.gov/.

ITEMS 1 AND 2 BUSINESS AND PROPERTIES

GENERAL

Ivanhoe Energy is an independent international heavy oil development and production company focused on pursuing long-term growth in its reserve base and production.

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

We were incorporated pursuant to the laws of the Yukon Territory of 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 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 are located at Suite 400 5060 California Avenue, Bakersfield, California, 93309.

CORPORATE STRATEGY

Importance of the Heavy Oil Segment of the Oil and Gas Industry

The global oil and gas industry is operating near capacity, driven by sharp increases in demand from developing economies and the declining availability of replacement low cost reserves. This has resulted in a significant increase in the relative price of oil and marked shifts in the demand and supply landscape. These shifts include demand moving toward China and India, while supply has shifted towards the need to develop higher cost/lower value resources, including heavy oil and bitumen.

Heavy oil developments can be segregated into two types: conventional heavy oil which flows to the surface without steam enhancement and non-conventional heavy oil and bitumen. While we focus on the heavier non-conventional heavy oil, both are playing an important role in creating opportunities for Ivanhoe.

Production of conventional heavy oil has been steadily increasing worldwide, led by Canada and Latin America but with significant contributions from most oil basins, including the Middle East and the Far East, as producers struggle to replace declines in light oil reserves. Even without the impact of the large non-conventional heavy oil projects in Canada and Venezuela, world oil production has been getting heavier. Refineries, on the other hand, have not been able to keep up with the need for deep conversion capacity, and heavy-light price differentials have widened significantly.

With regard to non-conventional heavy oil and bitumen, the dramatic increase in interest and activity has been fueled by higher prices, in addition to various key advances in technology, including improved remote sensing, horizontal drilling, and new thermal techniques. This has enabled producers to much more effectively access the extensive, heavy oil resources around the world.

These newer technologies, together with firm oil prices, have generated increased access to heavy oil resources, although for profitable exploitation, key challenges remain, with varied weightings, project by project: 1) the requirement for steam and electricity to help extract heavy oil, 2) the need for diluent to move the oil once it is at the surface, and 3) the wide heavy-light price differentials that the producer is faced with when the product gets to market. These challenges can lead to distressed assets, where economics are poor, or to stranded assets, where the resource cannot be economically produced and lies fallow.

Ivanhoe s Value Proposition

Ivanhoe s application of the patented rapid thermal processing process (**RTP Process**) for heavy oil upgrading (**HTL Technology** or **HTL**) seeks to address the three key heavy oil development challenges outlined above, and can do so at a relatively small scale.

In addition to improving oil quality, an HTL facility can yield surplus energy for production of the steam and electricity used in heavy oil production. The thermal energy generated by the HTL process can provide heavy oil producers with an alternative to increasingly volatile prices for natural gas that now is widely used to generate steam. Test yields of the low-viscosity, upgraded product are greater than 85% by volume, and high conversion of the heavy residual fraction is achieved. In addition to the liquid upgraded oil product, a small amount of valuable by-product gas is produced, and usable excess heat is generated from the by-product coke.

Ivanhoe s HTL process offers three potential advantages in that it can virtually eliminate cost exposure to natural gas and diluent, solve the transport challenge, and capture the majority of the heavy to light oil price differential for oil producers. Testing indicates that Ivanhoe s HTL process can accomplish this at a much smaller scale and at lower per barrel capital cost compared with established competing technologies, using readily available plant and process components. Since HTL facilities will be designed for installation near the wellhead, they are expected to eliminate the need for diluent and may make large, dedicated upgrading facilities unnecessary.

The business opportunities available to Ivanhoe correspond to the challenges each potential heavy oil project faces. In Canada, California, Iraq, Oman and Kazakhstan, all three of the HTL advantages identified above come into play. In others, including certain identified opportunities in Colombia, Ecuador and Libya, the heavy oil naturally flows to the surface, but transport is the key problem.

The economics of a project are effectively dictated by the advantages that HTL can bring to a particular opportunity. The more stranded the resource and the fewer monetization alternatives that the resource owner has, the greater the opportunity the Company will have to establish the Ivanhoe value proposition.

Implementation Strategies

In order to capture the value that our HTL Technology provides, the Company is pursuing the following strategies:

1. ***Build a portfolio of major HTL projects***. We will continue to deploy our personnel and our financial resources in support of our goal to capture opportunities for development projects utilizing our HTL technology.

2. ***Advance the technology***. Additional development work will continue as we advance the technology through the first commercial application and beyond.

3. ***Enhance our financial position in anticipation of major projects***. Implementation of large projects requires significant capital outlays. We are refining our financing plans and establishing the relationships required for the development activities that we see ahead.

4. ***Build internal capabilities in advance of major projects.*** The HTL technical team, which includes our own staff, specialized consultants including the inventors of the technology, and our enhanced oil recovery (**EOR**) team will be supplemented and expanded to add additional expertise in areas such as project management.

5. ***Build the relationships that we will need for the future.*** Commercialization of our technologies demands close alignment with partners, suppliers, host governments and financiers.

6. ***Capture value from other company assets as we complete the transition to a heavy oil focused company.*** Revenue from existing operations in California and China will be utilized to fund growth of the business. Non-heavy oil related investment opportunities in our portfolio will be leveraged to capture value and provide maximum return for the company.

HEAVY TO LIGHT OIL UPGRADING TECHNOLOGY

RTP™ License and Patents

In April 2005, we acquired all the issued and outstanding common shares of Ensyn Group, Inc. (**Ensyn**) whereby we acquired an exclusive, irrevocable license to Ensyn s RTP™ Process for all applications other than biomass. In January 2007 the Company received a Notice of Allowance from the U.S. Patent Office for the first of a family of additional petroleum upgrading patent applications. Since Ivanhoe acquired the patented heavy oil upgrading technology it has been working to expand patent coverage to protect innovations to the HTL Technology as they are developed. This allowance is the first patent protection that has been granted directly to Ivanhoe Energy, and significantly broadens the Company s portfolio of HTL intellectual property for petroleum upgrading and opens up additional HTL patenting opportunities for Ivanhoe Energy.

Commercial Demonstration Facility

In 2004, Ensyn constructed a Commercial Demonstration Facility (**CDF**) to confirm earlier pilot test results on a larger scale and to test certain processing options. This facility, that the Company acquired as part of the Ensyn merger was built in the Belridge field, a large heavy oil field owned by Aera Energy LLC, a company owned by affiliates of ExxonMobil and Shell. In March 2005, initial performance testing of the CDF was completed successfully and the results of the test were verified by two large independent engineering consulting firms. The CDF demonstrated an overall processing capacity of approximately 1,000 barrels-per-day of raw, heavy oil and a hot section capacity of 300 barrels-per-day.

The CDF test runs to date have successfully demonstrated that product upgraded by the CDF compares favorably to test runs carried out at Ensyn s pilot facility. We will continue to test crude oil from potential resource partners with an initial focus on heavy crude oil from California and Western Canada, including bitumen from Canada s Athabasca tar sands region. In addition, we have validated a number of process enhancements during the CDF test program including flue gas de-sulphurization, heavy metals capture and crude acidity reduction. One of the other continuing objectives of the CDF will be to provide engineering information for the scale-up of the plant to anticipated commercial levels.

In January 2007, the company completed a significant run at its CDF. This run, the most successful to date, was the culmination of a multi-month program that included tailoring the CDF for the processing of heavy crude fractions in configurations matched to specific commercial opportunities that the Company has identified. This run processed California vacuum tower bottoms (VTBs), which are the heaviest component of California heavy oil. These VTBs, which are solid at room temperature, are heavier and more viscous than Athabasca bitumen that is found in the Canadian oil sands.

This test run, performed using a High Yield, or once through configuration, follows a program of enhancements to the CDF. The run confirmed these enhancements and was also geared to the generation of information related to certain new commercial configurations that the company has developed in recent months. These new configurations were developed in the context of commercial opportunities and are the result of extensive analysis of data from prior runs carried out by the Company s technical team as well as outside experts in process engineering and upgrading technology. We believe these new configurations may represent a simple and cost effective alternative for the processing of some of the more challenging heavy crudes around the world. The Company will continue to pursue these innovative configurations in forthcoming tests and analyses.

HTL Business Development

We are pursuing HTL business development opportunities around the world.

In October 2004, we signed an MOU with the Ministry of Oil of Iraq to study and evaluate the shallow Qaiyarah oil field in Iraq. The field s reservoirs contain a large proven accumulation of 17.9 API heavy oil at a depth of about 1,000 feet. We have completed the reservoir assessment and have evaluated various recovery methods. Facility design work is complete and we completed an economic evaluation in the third quarter of 2006. Based on this evaluation we submitted a technical proposal to the Iraq Ministry of Oil. We have since presented the results of the technical proposal to an Iraqi team of experts and are currently responding to their questions. We will offer a commercial proposal for the development of the Qaiyarah oil field subsequent to satisfying all of the Oil Ministry s questions. The Iraq Ministry of Oil is under no obligation to execute the project or to enter into formal commercial negotiations.

GAS-TO-LIQUIDS TECHNOLOGY

Syntroleum License

We own a non-exclusive master license entitling us to use Syntroleum Corporation s (**Syntroleum**) proprietary technology (**GTL Technology** or **GTL**) to convert natural gas into ultra clean transportation fuels and other synthetic petroleum products in an unlimited number of projects with no limit on production volume. 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. 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.
The attraction of the GTL Technology lies in the commercialization of stranded natural gas. Such gas exists in discovered and known reservoirs, but is considered to be stranded based on the relative size of the fields and their remoteness from comparable sized markets. We have performed detailed project feasibility studies for the construction, operation and cost of plants from 47,000 to 185,000 Bbls/d. Additionally, 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.

GTL Business Development

At the present time, we are not actively pursing any GTL projects other than the Egyptian GTL project described herein. In 2005, we signed a memorandum of understanding with Egyptian Natural Gas Holding Company (**EGAS**), the state organization responsible for managing Egypt s natural gas resources, to prepare a feasibility study to construct and operate a GTL plant that would convert natural gas to ultra-clean liquid fuels in Egypt. We completed an engineering design of a GTL plant to incorporate the latest advances in Syntroleum GTL technology and have completed market and pricing analysis for GTL products to reflect changes since the original evaluation was completed several years ago. Plant capacity options of 47,000 and 94,000 Bbls/d were evaluated and in May 2006, we presented the feasibility study report to EGAS along with three commercial proposals. Based on EGAS review, and response to the proposals, we submitted a revised proposal in October 2006. EGAS will agree to commit, at no cost to the project, up to 4.2 trillion cubic feet of natural gas, or approximately 600 MMcf/d for the anticipated 20-year operating life of the project, subject to EGAS completing an economic feasibility analysis of the GTL project for Egypt, the negotiation and signature of a mutually agreeable term sheet and subsequently a definitive agreement and approval by the Company s Board of Directors and the appropriate authorities in Egypt.

OIL AND GAS PROPERTIES

Our principal oil and gas properties are located in California s San Joaquin Basin and Sacramento Gas Basin, the Midland Basin in Texas and the Hebei and Sichuan Provinces in China. Set forth below is a description of these properties.

United States

Production and Development

South Midway

We currently have 59 producing wells in South Midway and are the operator, with a working interest of 100% and a 93% net revenue interest. In 2006, we drilled ten new wells on the South Midway properties compared to 2005 when we drilled one development well, two temperature observation wells and one exploratory well. The ten new wells are producing 150 gross Bopd. Three wells in this program were drilled to test for pool extensions or new pool discoveries. Two extensions were found which will lead to more development work and potential reserves.

In the southern expansion area of South Midway, we have supplemented the cyclic steam project with a pilot to test continuous steam injection into five wells. The project began in October 2005 and by year-end 2005 the production performance was showing good response to the continuous injection. 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. This could add additional probable reserves to our proved undeveloped reserves. The Company should be able to make an assessment as to whether this continuous steam injection was successful by the fourth quarter of 2007. Current production from the southern expansion area is approximately 150 gross Bopd and total South Midway production is approximately 590 gross Bopd.

Other

In 2000, we farmed into the Spraberry property, which is a producing property located on 2,500 gross acres in the Spraberry Trend of the West Texas Permian Basin in Midland County, Texas. After selling a portion of our working interest in 2002 for approximately $3 million, we retain working interests ranging from 31% to 48% in 25 wells, which are currently producing approximately 80 net Boe/d. The declines of the oil and gas rates in this West Texas position should be very moderate over time. The moderate declines should lead to consistent performance and long life reserves.

In mid-2004, we farmed into the McCloud River prospect near the Cymric field in the San Joaquin Basin. We have a 24% working interest in this 880 gross-acre prospect. The initial well resulted in a dry hole. In 2005, a second prospect, North Salt Creek #1, was drilled to 2,500 feet on the acreage and was a discovery, encountering multiple oil and gas bearing horizons. North Salt Creek #1 commenced natural gas sales in September 2005 at a rate of 1,000 Mcf/day. Drilling of two follow-up wells was completed in the fourth quarter of 2005. Multiple targets were encountered in both of these wells. Production testing indicated the reservoir contains heavy 12^{o} API oil. Each of these wells were steamed, the results of which were sub economic. One of the intervals is in a diatomite formation which has a large amount of oil in place. This interval will be tested in another well to be drilled in 2007. More steam stimulation of this diatomite interval will occur in 2007 with the view that successive steam cycles will provide commercial rates of production.

In the first quarter of 2006, we sold our working interest in our three producing wells in the Citrus prospect for $5.4 million. We still hold 2,316 net acreage in this prospect, all of which has been farmed out. As part of this farm out the Company retained a carried 35% working interest in two wells that are expected to be drilled in 2007 to a depth of 5,000 feet. This farm out contemplates up to four wells, and we would retain a 20% working interest in the other two wells that would be drilled to a depth of 9,500 feet.

Exploration

The Company is focusing its exploration efforts on the lower risk opportunities noted below.

Knights Landing

In 2004, we farmed in to the Knights Landing project, which is a 15,700 gross-acre block located in the Sacramento Gas Basin in northern California. We drilled nine new exploratory wells which resulted in three successful completions and six dry holes. Subsequent to this drilling program we increased our working interests in the project and 11 existing producing natural gas wells. By the end of 2005, production from the Knights Landing wells had been fully depleted in all but one well, which was producing at minimal levels.

In late 2005, we acquired a 3-D seismic data program over 25 square miles covering our Knights Landing acreage block. We completed our seismic acquisition program in December 2005 and completed processing and interpretation of the seismic data in 2006. We expect to recommence drilling in the third quarter of 2007. 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.

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. We identified 13 prospects within 11 areas of mutual interest (**AMI**) covering approximately 46,800 gross acres owned by Aera and an additional 24,200 acres of leased mineral rights. Of the 13 prospects submitted, Aera has elected to take a working interest in 10 prospects, resulting in our retention of working interests ranging from 12.5% to 50%. We have a 100% working interest in three prospects in which Aera elected not to participate South Midway, Citrus and North Yowlumne. We will continue to hold exploration rights to the lands within each previously designated and accepted prospect 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.

Other

In December 2005, drilling commenced on the North Yowlumne prospect with a planned total depth of 13,000 feet to test the Stevens sands that have produced over 100 million barrels of oil at the nearby Yowlumne field. The well did not produce commercial quantities of hydrocarbons during several tests and has been suspended indefinitely by the operator. In March 2007, the Company assigned its rights to this property for $1.0 million and retained a carried 15% working interest in future drilling of the prospect.

China

Production and Development

Our producing property in China is a 30-year production-sharing contract with China National Petroleum Corporation (**CNPC**), covering an area of 12,110 gross acres divided into four 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%. 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.

In January 2004, we negotiated farm-out and joint operating agreements with Richfirst Holdings Limited (**Richfirst**) a subsidiary of China International Trust and Investment Corporation (**CITIC**) whereby Richfirst paid $20.0 million to acquire a 40% working interest in the field after Chinese regulatory approvals, which were obtained in June 2004. The farm-out agreement provided Richfirst with the right to convert its working interest in the Dagang field for common shares in the Company at any time prior to eighteen months after closing the farm-out agreement. Richfirst elected to convert its 40% working interest in the Dagang field and in February 2006 we re-acquired Richfirst s 40% working interest.

During 2001, we completed the pilot phase and in 2002 submitted the final draft of our Overall Development Plan (**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. By the end of 2006, we had drilled a total of 39 development wells, as compared to the estimated 115 wells set out in the approved ODP. We suspended drilling in late 2005 to allow for detailed evaluation of well productivity and production decline performance. In the fourth quarter of 2006, we reached agreement with CNPC to reduce the overall scope of the ODP to approximately 44 wells. The year-end 2006 gross production rate was 1,877 Bopd compared to 2,310 Bopd at the end of 2005. We currently sell our crude oil at a three-month rolling average price of Cinta crude currently averaging approximately $3.00 per barrel less than West Texas Intermediate (**WTI**) price. During 2006 we completed 1 well drilled in 2005, fracture stimulated 12 wells and re-completed 13 wells. In addition, we relinquished 2 of the six blocks that were part of the original development plan.

Exploration

In November 2002, we received final Chinese regulatory approval for a 30-year production-sharing contract (the **Zitong Contract**), with CNPC for the Zitong block, which covers an area of approximately 900,000 acres in the Sichuan basin. 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.

In the second quarter of 2005, we drilled our first well, to a depth of approximately 9,000 feet. The well was not commercially viable and cement plugs were set that will allow us to use the surface location and re-enter the well bore for a potential directional hole. In October 2006, the Company commenced drilling a second exploration well which is being drilled to a target depth of 12,800 feet. The completion and testing of the well is anticipated the second quarter 2007.

In 2006, we farmed-out 10% of our working interest in the Zitong block to Mitsubishi Gas Chemical Company Inc. of Japan (**Mitsubishi**) for $4.0 million. Mitsubishi has the option to increase its participating interest to 20% by paying $0.4 million plus costs per percentage point prior to any discovery, or $8.0 million plus costs for an additional 10% interest after completion and testing of the first well drilled under the farm-out agreement. The Company and Mitsubishi (the **Zitong Partners**) will await the results of the second exploration well after which a decision will be made whether or not to enter into the next three-year exploration phase (**Phase 2**). The $4.0 million advance from Mitsubishi was used to pay for the initial well costs and there was no unspent balance at December 31, 2006. If the Company elects not to enter into Phase 2, it will be required to pay CNPC, within 30 days after its election, a cash equivalent of its share of the deficiency in the work program estimated to be $0.3 million after the drilling of the second Phase 1 well. If the Company elects not to enter Phase 2, costs related to the Zitong block in the approximate amount of $8.3 million will be required to be included in the depletable base of the China full cost pool. This may result in a ceiling test impairment related to the China full cost pool in a future period.

If the Zitong Partners elect to participate in Phase 2, they must complete a minimum work program involving the acquisition of approximately 200 miles of new seismic lines, which was satisfied in the Phase 1 expenditures, and approximately 23,000 feet of drilling, with estimated minimum expenditures for the program of $21.6 million excluding seismic acquisition. Following the completion of Phase 2, we must relinquish all of the property except any areas identified for development and production. If the Zitong Partners elect to enter into Phase 2, they 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.

EMPLOYEES

As at December 31, 2006, we had 150 employees and consultants actively engaged in the business. None of our employees are unionized.

RESERVES, PRODUCTION AND RELATED INFORMATION

See the Supplementary Disclosures About Oil and Gas Production Activities , which follows the notes to our consolidated 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 depletion and depreciation, income taxes, interest, selling and administrative expenses.

	Average Sales Price			Average Operating Costs		
	2006	2005	2004	2006	2005	2004
Crude Oil and Natural Gas ($/Boe)						
U.S.	$54.86	$44.01	$34.66	$19.54	$15.64	$11.76
China	$62.04	$49.97	$36.11	$20.58	$ 8.27	$ 8.14

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. Gross wells are the total number of wells in which a working interest is owned and net wells are the sum of fractional working interests owned in gross wells.

	2006				2005				2004			
	Oil Wells		Gas Wells		Oil Wells		Gas Wells		Oil Wells		Gas Wells	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
U.S.	89	73.5	2	1.0	87	69.3	3	1.5	84	67.2	13	11.7
China	42	34.4(1)			43	21.2			21	10.3(1)		

(1) After giving effect to the 40% farm-in/out of Richfirst to the 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 Wells						Dry Wells					
	2006		2005		2004		2006		2005		2004	
	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas
U.S.			1.5	0.2	0.4	3.0	0.6(1)			1.8(2)	1.4	4.0
China										1.0		
Total			1.5	0.2	0.4	3.0	0.6			2.8	1.4	4.0

(1) Includes 0.6 (1 gross) net exploratory wells drilled during 2005 which were determined to be dry in 2006.

(2) Includes 0.8 net (2 gross) exploratory

wells drilled during 2001, which were determined to be dry in 2005.

Development

	Productive Wells						Dry Wells					
	2006		**2005**		**2004**		**2006**		**2005**		**2004**	
	Oil	**Gas**	**Oil**	**Gas**	**Oil**	**Gas**	**Oil**	**Gas**	**Oil**	**Gas**	**Oil**	**Gas**
U.S.	9.0		1.0		7.3						2.0	
China			10.8		7.9							
Total	9.0		11.8		15.2						2.0	

Wells in Progress

At the end of 2006, 2005 and 2004 we had 5.3 (6 gross), 1.1 (3 gross) and 2.9 (6 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, 2006. Gross acres include the interest of others and net acres exclude the interests of others:

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
U.S.	7,691	4,428	96,672	29,373
China (1)	2,969	2,435	888,924	883,306

(1) 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, 2006. Estimates for our U.S. and China operations were prepared by independent petroleum consultants Netherland, Sewell & Associates Inc. and GLJ Petroleum Consultants Ltd., respectively.

	Our Share		Our Share of Before Tax Cash Flows In Thousands of U.S. Dollars Discounted at:			Our Share of After Tax Cash Flows In Thousands of U.S. Dollars Discounted at:		
	Oil (Mbbl)	**Gas (MMcf)**	**0%**	**10%**	**15%**	**0%**	**10%**	**15%**
Net Proved Reserves (1)								
U.S.	1,220	417	$ 30,420	$ 23,088	$ 20,711	$ 30,420	$ 23,088	$ 20,711
China	1,785		53,497	42,792	38,887	53,497	42,792	38,887
	3,005	417	$ 83,917	$ 65,880	$ 59,599	$ 83,917	$ 65,880	$ 59,599

(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 SEC disclosure requirements. 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 SEC requirements for much of the annual disclosure required by NI 51-101 and to prepare our reserves estimates and related disclosures in accordance with SEC requirements, generally accepted industry practices in the U.S. as promulgated by the Society of Petroleum Engineers, and the standards of the Canadian Oil and Gas Evaluation Handbook (the **COGE Handbook**) modified to reflect SEC 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 Statement of Financial Accounting Standards No. 69, Disclosures About Oil and Gas Producing Activities . Such information differs from the corresponding information prepared in accordance with Canadian disclosure standards under NI 51-101. The primary differences between the SEC 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 SEC disclosure requirements and NI 51-101 requirements.

ITEM 1A. 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 may not be able to meet our substantial capital requirements.

Our business is capital intensive and the advancement of either our HTL or GTL project development initiatives will require significant investments in property acquisitions and development activities. Since our revenues from existing operations are insufficient to fund the capital expenditures that will be required to implement our HTL and GTL project development initiatives, we will need to rely on external sources of financing to meet our capital requirements. We have, in the past, relied upon equity capital as our principal source of funding. We may seek to obtain the future funding we will need through debt and equity markets, through project participation arrangements with third parties or from the sale of existing assets, 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. If we fail to obtain the funding that we need when it is required, we may have to forego or delay potentially valuable project acquisition and development opportunities 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.

We might not successfully commercialize our technology, and commercial-scale HTL and GTL plants based on our technology may never be successfully constructed or operated.

No commercial-scale HTL or GTL plant based on our technology has been constructed to date and we may never succeed in doing so. Other developers of competing heavy oil upgrading and gas-to-liquids technologies may have significantly more financial resources than we do and may be able to use this to obtain a competitive advantage. Success in commercializing our HTL and GTL technologies depends on our ability to economically design, construct and operate commercial-scale plants and a variety of factors, many of which are outside our control. We currently have insufficient resources to manage the financing, design, construction or operation of commercial-scale HTL or GTL plants, and we may not be successful in doing so.

Our efforts to commercialize our HTL technology may give rise to claims of infringement upon the patents or proprietary rights of others.

We own a license to use the HTL technology that we are seeking to commercialize but we may not become aware of claims of infringement upon the patents or rights of others in this technology until after we have made a substantial investment in the development and commercialization of projects utilizing it. Third parties may claim that the technology infringes 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 technology. 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 technology. 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 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 heavy oil upgrading technologies competitive with our technology, may have significantly more resources to spend on litigation.

Technological advances could significantly decrease the cost of upgrading heavy oil and, if we are unable to adopt or incorporate technological advances into our operations, our HTL 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, which are integral to the HTL technology that we are seeking to commercialize, less efficient or cause the upgraded product being produced to be of a lesser quality. These advances could also allow competitors to produce upgraded products at a lower cost than that at which our HTL technology is 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 our HTL technology facilities to become uncompetitive.

The development of alternate sources of energy could lower the demand for our HTL technology.

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 our HTL 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.

The volatility of oil prices may affect our financial results.

Our revenues, operating results, profitability and future rate of growth are highly dependent on the price of, and demand for, oil. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. Even relatively modest changes in oil prices may significantly change our revenues, results of operations, cash flows and proved reserves. Historically, the market for oil has been volatile and is likely to continue to be volatile in the future.

The price of oil may fluctuate widely in response to relatively minor changes in the supply of and demand for oil, market uncertainty and a variety of additional factors that are beyond our control, such as weather conditions, overall global economic conditions, terrorist attacks or military conflicts, political and economic conditions in oil producing countries, the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls, the level of demand and the price and availability of alternative fuels, speculation in the commodity futures markets, technological advances affecting energy consumption, governmental regulations and approvals, proximity and capacity of oil pipelines and other transportation facilities.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil price movements with any certainty. Declines in oil prices would not only reduce our revenues, but could reduce the amount of oil we can economically produce. This may result in our having to make substantial downward adjustments to our estimated proved reserves and could have a material adverse effect on our financial condition and results of operations. In addition, a substantial long-term decline in oil prices would severely impact our ability to execute a heavy oil development program

Lower oil prices could negatively impact our ability to borrow.

The amount of borrowings available to us under our revolving bank credit facility is determined by reference to a borrowing base. The amount of our borrowing base is established by our bank and is primarily a function of the quantity and value of our reserves. Our borrowing base is re-determined at least twice a year to take into account changes in our reserve base and prevailing commodity prices. Commodity prices can affect both the value as well as the quantity of our reserves for borrowing base purposes as certain reserves may not be economic at lower price levels. Consequently, the amount of borrowing available to us under our revolving bank credit facility could be adversely affected by extended periods of low commodity prices.

Our ability to sell assets and replace revenues generated from any sale of our existing properties depends upon market conditions and numerous uncertainties.

During 2006, we were involved in negotiations for a business combination transaction involving our China assets that, if completed, would have resulted in our China assets being owned and operated by a separate publicly traded company. Although the transaction was not completed, we are continuing to explore opportunities to generate capital for the ongoing development of our core HTL business, which may involve the sale of some or all of our exploration, development and production assets in China and the U.S. There can be no assurance that we will sell any such assets nor that any such sale, if and when made, will generate sufficient capital for the ongoing development of our core HTL business, which will require the acquisition of one or more properties hosting deposits of heavy oil. Our operating revenues and cash flows would likely decrease significantly following the sale of any material portion of our existing producing assets and would likely remain at lower levels until we were able to replace the lost production with production from new properties.

We may be required to take write-downs if oil prices decline, our estimated development costs increase or our exploration results deteriorate.

We may be required under generally accepted accounting principles in Canada and the U.S. to write down the carrying value of our properties if oil prices decline or if we have substantial downward adjustments to our estimated proved reserves, increases in our estimates of development costs or deterioration in our exploration results. See Critical Accounting Principles and Estimates Impairment of Proved Oil and Gas Properties in Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations of this Annual Report.

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

We carry on business in China and we may, in the future, carry on business in other foreign jurisdictions with governments, governmental agencies or government-owned entities. The foreign legal framework for the agreements through which we carry on business now or in the future, 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.

Estimates of proved reserves and future net revenue may change if the assumptions on which such estimates are based prove to be inaccurate.

Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment and the assumptions used regarding prices for oil and natural gas, production volumes, required levels of operating and capital expenditures, and quantities of recoverable oil reserves. Oil prices have fluctuated widely in recent years. Volatility is expected to continue and price fluctuations directly affect estimated quantities of proved reserves and future net revenues. Actual prices, production, development expenditures, operating expenses and quantities of recoverable oil reserves will vary from those assumed in our estimates, and these variances may be significant. Also, we make certain assumptions regarding future oil prices, production levels, and operating and development costs that may prove incorrect. Any significant variance from the assumptions used could result in the actual quantity of our reserves and future net cash flow being materially different from the estimates we report. In addition, actual results of drilling, testing and production and changes in natural gas and oil prices after the date of the estimate may result in revisions to our reserve estimates. Revisions to prior estimates may be material.

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 Annual Report. Whether we ultimately implement our plans will depend on availability and cost of capital; receipt of HTL technology process test results, 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 interests in licenses, leases and production sharing contracts.

Some of our properties are held under licenses and leases, working interests in licenses and leases or production sharing contracts. If we fail to meet the specific requirements of the instrument through which we hold our interest, it may terminate or expire. We cannot assure you that any or all of the obligations required to maintain our interest in each such license, lease or production sharing contract will be met. Some of our property interests will terminate unless we fulfill such obligations. If we are unable to satisfy these obligations on a timely basis, we may lose our rights in these properties. The termination of our interests in these properties may harm our business.

We may incur significant costs on exploration or development efforts which may prove unsuccessful or unprofitable.

There can be no assurance that the costs we incur on exploration or development will result in an economic return. We may misinterpret geologic or engineering data, which may result in significant losses on unsuccessful exploration or development drilling efforts. We bear the risks of project delays and cost overruns due to unexpected geologic conditions, equipment failures, equipment delivery delays, accidents, adverse weather, government and joint venture partner approval delays, construction or start-up delays and other associated risks. Such risks may delay expected production and/or increase costs of production or otherwise adversely affect our ability to realize an acceptable level of economic return on a particular project in a timely manner or at all.

Our business involves many operating risks that can cause substantial losses; insurance may not protect us against all these risks.

There are hazards and risks inherent in drilling for, producing and transporting oil. These hazards and risks may result in loss of hydrocarbons, environmental pollution, personal injury claims, and other damage to our properties and third parties and include fires, natural disasters, adverse weather conditions, explosions, encountering formations with abnormal pressures, encountering unusual or unexpected geological formations, blowouts, cratering, unexpected operational events, equipment malfunctions, pipeline ruptures, spills, compliance with environmental and government regulations and title problems.

We are insured against some, but not all, of the hazards associated with our business, so we may sustain losses that could be substantial due to events that are not insured or are underinsured. The occurrence of an event that is not covered or not fully covered by insurance could have a material adverse impact on our financial condition and results of operations. We do not carry business interruption insurance and, therefore, the loss and delay of revenues resulting from curtailed production are not insured.

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 and 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.

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 significantly influences our business.

As at the date of this Annual Report, our largest shareholder, Robert M. Friedland, owned approximately 20% of our common shares. As a result, he has the voting power to significantly influence 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 personnel. Given the technological nature of our business, we also rely heavily upon our scientific and technical personnel. Our ability to implement our business strategy may be constrained and the timing of implementation may be impacted if we are unable to attract and retain sufficient personnel. 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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

We have no unresolved staff comments from the SEC staff regarding our periodic or current reports filed under the Act.

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

None.

PART II

ITEM 5. MARKET FOR REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASE OF EQUITY SECURITIES

Market Information

Our common shares trade on the NASDAQ Capital 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 CAPITAL MARKET (IVAN)
(U.S.$)

	2006				2005			
	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr
High	1.65	2.43	2.96	3.27	2.00	2.50	2.95	3.34
Low	1.18	1.40	2.26	1.25	0.99	1.97	1.98	2.04

TORONTO STOCK EXCHANGE (IE)
(CDN$)

	2006				2005			
	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr	4th Qtr	3rd Qtr	2nd Qtr	1st Qtr
High	1.89	2.72	3.31	3.75	2.32	3.06	3.60	4.02
Low	1.36	1.59	2.50	1.44	1.16	2.30	2.52	2.52

On December 29, 2006, the closing prices for our common shares were $1.35 on the NASDAQ Capital Market and Cdn. $1.57 on the Toronto Stock Exchange.

Exemptions from Certain NASDAQ Marketplace Rules

NASDAQ s Marketplace Rules permit foreign private issuers to follow home country practices in lieu of the requirements of certain Marketplace Rules, including the requirement that a majority of an issuer s board of directors be comprised of independent directors determined on the basis of prescribed independence criteria. Applicable Canadian rules pertaining to corporate governance require us to disclose in our management proxy circular, on an annual basis, our corporate governance practices, including whether or not a majority of our board of directors is comprised of independent directors, based on prescribed independence criteria, which differ slightly from the criteria prescribed in the NASDAQ Marketplace Rules.

Although applicable Canadian rules pertaining to corporate governance make reference, as part of a series of non-prescriptive corporate governance guidelines based on what are perceived to be best practices , to the desirability of a board comprised of a majority of independent directors, there is no legal requirement in Canada that mandates a board comprised of a majority of independent directors. As of the date of this Annual Report on Form 10-K, our board of directors consists of 6 individuals who are independent and 5 individuals who are not independent, applying the criteria prescribed by applicable Canadian rules pertaining to corporate governance and the criteria prescribed by the NASDAQ Marketplace Rules. However, if all of the individuals nominated by management for election to our board of directors are elected at our next annual meeting of shareholders on May 3, 2007, our board of directors will consist of 5 individuals who are independent and 6 individuals who are not independent, applying the criteria prescribed by applicable Canadian rules pertaining to corporate governance and the criteria prescribed by the NASDAQ Marketplace Rules.

Enforceability of Civil Liabilities

We are a company incorporated under the laws of the Yukon Territory of Canada and our executive offices are located in British Columbia, Canada. Some of our directors, controlling shareholders, 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 shareholders, 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 shareholders, 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 shareholders or experts named in this Annual Report on Form 10-K.

Holders of Common Shares

As at December 31, 2006, a total of 241,215,798 of our common shares were issued and outstanding and held by 213 holders of record with an estimated 40,002 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 Territory, 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 2007 is Cdn.$281 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), as amended, (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, 2006, we issued securities, which were not registered under the Securities Act of 1933 (the **Act**), as follows:

in February 2006, we issued 8,591,434 shares in exchange for an additional 40% working interest in the Dagang field to CITIC in a transaction exempt from registration under Rule 903 of the Act;

in March 2006, we issued 100 common shares at a price of U.S.$3.20 to an institutional investor pursuant to the exercise of previously issued share purchase warrants in a transaction exempt from registration under Rule 903 of the Act;

in April 2006, we issued 11,400,000 special warrants at U.S.$2.23 per special warrant to institutional and individual investors in a transaction exempt from registration under Rule 903 of the Act. Each special warrant was exercised 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 May 2006. Originally, one common share purchase warrant would entitle the holder to purchase one common share at a price of U.S.$2.63 exercisable until the fifth anniversary date of the special warrant date of issue. In September 2006 these warrants were listed on the Toronto Stock Exchange and the exercise price was changed to Cdn.$2.93.

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				
	2006	**2005**	**2004**	**2003**	**2002**
	(stated in thousands of US dollars, except per share amounts)				
Financial Position					
Total assets	248,544	240,877	118,486	106,574	107,088
Long-term debt	4,237	4,972	2,639	833	Nil
Shareholders equity	228,386	204,767	103,586	100,537	100,548
Common shares outstanding (in thousands)	241,216	220,779	169,665	161,359	144,466
Capital investments	17,842	43,282	46,454	15,391	18,828
Results of Operations					
Revenues	48,100	29,939	17,997	9,659	8,437
Net loss	(25,492)(1)	(13,512)(1)	(20,725)(1)	(30,179)(1)	(7,130)(1)
Net loss per share basic and diluted	(0.11)	(0.07)	(0.12)	(0.20)	(0.05)

(1) Includes asset write-downs and provisions for impairment of $5.4 million, $5.6 million, $16.6 million, $23.3 million and $2.4 million for 2006, 2005, 2004, 2003 and 2002, respectively. See Note 4 to

our financial statements under Item 8 in 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 Company has restated its U.S. GAAP financial position as at December 31, 2005 and results of operations for the year ended December 31, 2005, to correct the accounting treatment of certain warrants for U.S. GAAP purposes. The warrants that are subject to restatement were issued in 2005. Previously, the Company accounted for these instruments as equity under both Canadian and U.S. GAAP. The treatment of warrants was changed under U.S. GAAP to correct for the application of Statement of Financial Accounting Standard No. 133 Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133). Under SFAS No. 133, share purchase warrants with an exercise price denominated in a currency other than the company s functional currency are accounted for as derivative liabilities. Changes in the fair value of the warrants are required to be recognized in the statement of operations each reporting period for U.S. GAAP purposes. Under the Company s previous U.S. GAAP accounting treatment, no changes in fair value were recorded. At the time that the Company s share purchase warrants are exercised, the value of the warrants will be reclassified to shareholders equity for US GAAP purposes. Under Canadian GAAP, the fair value of the warrants on the issue date is recorded as a reduction to the proceeds from the issuance of common shares, with the offset to the warrant component of equity. The warrants are not revalued to fair value under Canadian GAAP. The cumulative effects of the U.S. GAAP restatement as at December 31, 2005 are as follows: an increase in liabilities of $0.1 million, a decrease in purchase warrants classified within shareholders equity of $2.9 million, and a decrease in accumulated deficit of $2.9 million. The only other 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,

net additional impairment provision for our China oil and gas properties in 2001, 2005 and 2006, net of depletion expense, net additional impairment provision for our U.S. oil and gas properties in 2004, 2005 and 2006, net of depletion expense,

net additional expense from 2001 to 2006 in connection with development costs for our GTL and HTL projects, and

reduction in the net losses from 2002 to 2005 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:

	December 31				
	2006	**2005 (as restated)**	**2004**	**2003**	**2002**
	(stated in thousands of US dollars, except per share amounts)				
Financial Position					
Total assets	216,365	224,935	105,791	94,024	91,921
Shareholders equity as originally reported	188,829	188,825	90,892	87,987	85,279
Prior period adjustment		(80)			
Shareholders equity as restated	188,829	188,745	90,892	87,987	85,279
Results of Operations					
Net loss as originally reported	(42,422)	(14,972)	(19,696)	(27,086)	(8,202)
Prior period adjustment		2,866			
Net loss as restated	(42,422)	(12,106)	(19,696)	(27,086)	(8,202)
Net loss per share basic and diluted	(0.18)	(0.07)	(0.12)	(0.18)	(0.06)
Prior period adjustment		0.01			
Net loss per share as restated	(0.18)	(0.06)	(0.12)	(0.18)	(0.06)

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 FOR THE YEAR ENDED DECEMBER 31, 2006. THE CONSOLIDATED FINANCIAL STATEMENTS HAVE BEEN PREPARED IN ACCORDANCE WITH GENERALLY ACCEPTED ACCOUNTING PRINCIPLES IN CANADA (GAAP). 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. ALL TABULAR AMOUNTS ARE EXPRESSED

IN THOUSANDS OF U.S. DOLLARS, EXCEPT PER SHARE AND PRODUCTION DATA INCLUDING REVENUES AND COSTS PER BOE.

Ivanhoe Energy s Business

Ivanhoe Energy is an independent international heavy oil development and production company focused on pursuing long-term growth in its reserve base and production. Ivanhoe Energy plans to utilize technologically innovative methods designed to significantly improve recovery of heavy oil resources, including the application of the patented rapid thermal processing process (**RTP™ Process**) for heavy oil upgrading (**HTL Technology** or **HTL**) and enhanced oil recovery (**EOR**) techniques. In addition, the Company seeks to expand its reserve base and production through conventional exploration and production (**E&P**) of oil and gas. Finally, the Company is exploring an opportunity to monetize stranded gas reserves through the application of the conversion of natural gas-to-liquids using a technology (**GTL Technology** or **GTL**) licensed from Syntroleum Corporation. Our core operations are in the United States and China, with business development opportunities worldwide.

Ivanhoe Energy s proprietary, patented heavy oil upgrading technology upgrades the quality of heavy oil and bitumen by producing lighter, more valuable crude oil, along with by-product energy which can be used to generate steam or electricity. The HTL Technology has the potential to substantially improve the economics and transportation of heavy oil. There are significant quantities of heavy oil throughout the world that have not been developed, much of it stranded due to the lack of on-site energy, transportation issues, or poor heavy-light price differentials. In remote parts of the world, the considerable reduction in viscosity of the heavy oil through the HTL process will allow the oil to be transported economically over long distances. In addition to a dramatic improvement in oil quality, an HTL facility can yield large amounts of surplus energy for production of the steam and electricity used in heavy oil production. The thermal energy from the HTL process would provide heavy oil producers with an alternative to increasingly volatile prices for natural gas that now is widely used to generate steam. Yields of the low-viscosity, upgraded product are greater than 85% by volume, and high conversion of the heavy residual fraction is achieved. In addition to the liquid upgraded oil product, a small amount of valuable by-product gas is produced, and usable excess heat is generated from the by-product coke.

HTL can virtually eliminate cost exposure to natural gas and diluent, solve the transport challenge, and capture the majority of the heavy to light oil price differential for oil producers. HTL accomplishes this at a much smaller scale and at lower per barrel capital costs compared with established competing technologies, using readily available plant and process components. As HTL facilities are designed for installation near the wellhead, they eliminate the need for diluent and make large, dedicated upgrading facilities unnecessary.

Executive Overview of 2006 Results

Oil and gas revenue increased by 60% or $17.9 million as a result of a combination of a 25% increase in production and a 28% increase in oil and gas prices. However, this improvement was more than offset by an $8.5 million increase in oil and gas operating costs and an $18.1 million increase in depletion and depreciation. A major contributor to the significant increase in depletion and depreciation expense for 2006 was the downward revisions in our China reserve estimates in the fourth quarter of 2005.

For the year, cash flow from operating activities increased by 45% to $14.4 million, an increase of $4.5 million while at the same time we significantly reduced the capital expenditure program associated with our conventional oil and gas exploration and development activities as we more closely focused the Company s activities on the development and deployment of our HTL Technology.

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

	Year ended December 31,		
	2006	**2005**	**2004**
Oil and gas revenue	$ 47,748	$ 29,800	$ 17,795
Net loss	$(25,492)	$(13,512)	$(20,725)
Net loss per share	$ (0.11)	$ (0.07)	$ (0.12)

Average production (Boe/d)	2,178	1,738	1,376
Net operating revenue per Boe	$ 60.06	$ 46.97	$ 35.34
Capital investments	$ 17,842	$ 43,282	$ 46,454
Cash flow from operating activities	$ 14,352	$ 9,870	$ 4,032

Financial Results   Year to Year Change in Net Loss

The following provides a summary analysis of our net losses for each of the three years ended December 31, 2006 and a summary of year-over-year variances for the year ended December 31, 2006 compared to 2005 and for the year ended December 31, 2005 compared to 2004:

	2006	*Favorable (Unfavorable) Variances*	2005	*Favorable (Unfavorable) Variances*	2004
Summary of Net Loss by Significant Components:					
Cash Items:					
Net operating revenues:					
Oil and Gas Revenues:	$ 47,748		$ 29,800		$ 17,795
Production volumes		*$ 8,888*		*$ 4,334*	
Oil and gas prices		*9,060*		*7,671*	
Realized gain on derivative instruments	69	*69*			
Less: Operating costs	(16,133)	*(8,530)*	(7,603)	*(2,530)*	(5,073)
Total net operating revenues	31,684	*9,487*	22,197	*9,475*	12,722
General and administrative, less stock based compensation	(7,648)	*(60)*	(7,588)	*(1,589)*	(5,999)
Business and technology development, less stock based compensation	(7,221)	*(2,416)*	(4,805)	*(2,893)*	(1,912)
Acquisition costs	(736)	*(736)*			
Net interest	(29)	*982*	(1,011)	*(881)*	(130)
Total Cash Variances	16,050	*7,257*	8,793	*4,112*	4,681
Non-Cash Items:					
Unrealized loss on derivative instruments	(493)	*(493)*			
Depletion and depreciation	(32,550)	*(18,103)*	(14,447)	*(6,965)*	(7,482)
Stock based compensation	(2,921)	*(808)*	(2,113)	*(837)*	(1,276)
Write-downs of HTL and GTL investments		*636*	(636)	*(386)*	(250)
Impairment of oil and gas properties	(5,420)	*(420)*	(5,000)	*11,350*	(16,350)
Other	(158)	*(49)*	(109)	*(61)*	(48)
Total Non-Cash Variances	(41,542)	*(19,237)*	(22,305)	*3,101*	(25,406)
Net Loss	$ (25,492)	*$ (11,980)*	$ (13,512)	*$ 7,213*	$ (20,725)

Our net loss for 2006 was $25.5 million ($0.11 per share) compared to our net loss in 2005 of $13.5 million ($0.07 per share). The increase in our net loss from 2005 to 2006 of $12.0 million was due mainly to an $18.1 million increase in a non-cash charge for depletion and depreciation. The increase in unfavorable non-cash charges was offset by an increase in favorable cash variances of $7.3 million, mainly due to an increase of $9.5 million in net operating revenues offset by a $2.5 million increase in general administrative and business and technology development expenses excluding stock based compensation.

Our net loss for 2005 was $13.5 million ($0.07 per share) compared to our net loss in 2004 of $20.7 million ($0.12 per share). The decrease in our net loss from 2004 to 2005 of $7.2 million was due mainly to a $9.5 million increase in net operating revenues and an $11.4 million reduction in impairment of our U.S. and China oil and gas properties. This was partially offset by a $7.0 million increase in depletion and depreciation expense, a $4.5 million increase in general administrative and business and technology development expenses excluding stock based compensation, a $0.9 million net increase in interest and financing costs and a $0.4 million increase in write downs of our HTL and GTL investments.

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

Net Operating Revenues

The following is a comparison of changes in production volumes for the year ended December 31, 2006 when compared to the same period in 2005 and for the year ended December 31, 2005 when compared to the same period for 2004:

	Years ended December 31, Net Boe s 2006	2005	Percentage Change	Years ended December 31, Net Boe s 2005	2004	Percentage Change
China:						
Dagang	554,185	282,582	96%	282,582	190,309	48%
Daqing	20,946	32,236	-35%	32,236	44,626	-28%
	575,131	314,818	83%	314,818	234,935	34%
U.S.:						
South Midway	188,379	196,428	-4%	196,428	183,875	7%
Spraberry	23,242	27,940	-17%	27,940	33,498	-17%
Citrus	4,733	34,257	-86%	34,257	31,008	10%
Knights Landing	237	57,106	-100%	57,106	14,786	286%
Others	3,339	3,943	-15%	3,943	5,447	-28%
	219,930	319,674	-31%	319,674	268,614	19%
	795,061	634,492	25%	634,492	503,549	26%

Net production volumes in 2006 increased 25% from 2005 due to an 83% increase in production volumes in our China properties offset by a 31% decrease in our U.S. properties, resulting in increased revenues of $8.9 million.

Net production volumes in 2005 increased 26% from 2004 due to 34% and 19% increases in production volumes in our China and U.S. properties resulting in increased revenues of $4.3 million.

Oil and gas prices increased 28% per Boe in 2006 generating $9.1 million in additional revenue as compared to 2005. We realized an average of $62.04 per Boe from operations in China during 2006, which was an increase of $12.07 per Boe from 2005 prices and accounted for $7.1 million of our increase in revenues. From the U.S. operations, we realized an average of $54.86 per Boe during 2006, which was an increase of $10.85 per Boe and accounted for $2.0 million of our increased revenues.

Oil and gas prices increased 33% per Boe in 2005 generating $7.7 million in additional revenue as compared to 2004. We realized an average of $49.97 per Boe from our operations in China during 2005, which was an increase of $13.86 per Boe from 2004 prices and accounted for $4.5 million of our increase in revenues. From the U.S. operations, we realized an average of $44.01 per Boe during 2005, which was an increase of $9.35 per Boe and accounted for $3.2 million of our increased revenues.

Operating costs, including production taxes and engineering support, for 2006 and 2005 increased $8.29, or 69.12 %, per Boe, $1.93, or 19 %, per Boe, from the previous years. These costs for 2006 and 2005 increased $8.5 million, and $2.5 million, in absolute terms from the previous years.

China

Production Volumes 2006 vs. 2005

Net production volumes increased 96% at the Dagang field for 2006. As a result of the 2005 development program, oil production volume increased by 22% or by 61.7 Mboe in 2006 when compared to 2005. During 2005 we placed 22 new wells on production and fracture stimulated 13 wells in the northern block of this project and in 2006 we completed one well, fracture stimulated 12 wells and re-completed 13 wells. Additionally, volumes at the Dagang field increased in 2006 when compared to 2005 by 74 % or 209.9 Mboe due to the re-acquisition of Richfirst s 40% working interest in this project in February 2006.

Our royalty percentage from the Daqing field was reduced from 4% to 2% in May 2005 when the operator of the properties reached payout of its investment. As a result, our share of production volumes decreased 35% for 2006 compared to the same period in 2005. In addition, production from the field is declining.

Production Volumes 2005 vs. 2004

Net production volumes increased 48% at the Dagang field for 2005. We placed 22 new wells on production during 2005 bringing to 43 the total number of Dagang wells on production, or available for production. In 2005, we initiated a stimulation program in the northern blocks of the field where we were experiencing less than expected results. We stimulated 13 of our northern block wells and added, on average, incremental production per well of 65 gross Bopd (30 net Bopd), with current production levels of 85 gross Bopd

(40 net Bopd) per well. As at December 31, 2005, 39 wells were on production and producing 2,310 gross Bopd (1,080 net Bopd). This is a 40% increase in production rates compared to 1,655 gross Bopd (774 net Bopd) as at December 31, 2004.

As a result of the May 2005 decrease in our royalty percentage noted above, our share of production volumes decreased 28% for 2005 compared to the same period in 2004.

Operating Costs 2006 vs. 2005

Operating costs in China, including engineering support, increased 149% or $12.31 per Boe for 2006 when compared to 2005. Field operating costs increased due to high power costs, increased workover and maintenance costs, related supervision and increased treatment and processing fees attributable to higher water production rates. With the suspension of our drilling activity at our Dagang field in December 2005, a major portion of our Dagang field office costs, which were previously being capitalized, are now being expensed as part of our operating activities.

Engineering support increased due to a higher allocation of support to production as we reduced our capital activity in the Dagang field in 2006 when compared to 2005. The increase in production volume in 2006 due to the 2005 drilling program at the Dagang field, in relation to the level of support required to operate the field, results in the per Boe decrease for 2006 when compared to 2005.

In March 2006, the Ministry of Finance of the Peoples Republic of China (**PRC**) issued the Administrative Measures on Collection of Windfall Gain Levy on Oil Exploitation Business (the **Windfall Levy Measures**). According to the Windfall Levy Measures, effective as of March 26, 2006, enterprises exploiting and selling crude oil in the PRC are subject to a windfall gain levy (the **Windfall Levy**) if the monthly weighted average price of crude oil is above $40 per barrel. The Windfall Levy is imposed at progressive rates from 20% to 40% on the portion of the weighted average sales price exceeding $40 per barrel. For financial statement presentation the Windfall Levy is included in operating costs. The Windfall Levy resulted in $5.74 per Boe of the overall increase in 2006 when compared to 2005.

Operating Costs 2005 vs. 2004

Operating costs in China, including engineering support, increased 2% or $0.13 per Boe for 2005. Field operating costs increased $1.45 per Boe or 24% in 2005 primarily due to higher power costs, permanent land fees on producing wells, security costs and increased treatment and processing costs due to higher water production rates. These increases were partially offset by reductions in workover and maintenance costs. Engineering support for 2005 decreased $1.32 per Boe or 63% compared to 2004 resulting from the increase in production volumes from the Dagang field in relation to the level of support required to operate the field.

U.S.

Production Volumes 2006 vs. 2005

U.S. production volumes decreased 31% in 2006 when compared to 2005 mainly as a result of the decline in production from the Knights Landing field which had been depleted to minimal levels at the end of 2005 and the sale of our Citrus property effective February 1, 2006.

In addition, our production at South Midway decreased 4% for 2006 primarily as a result of several wells in the southern expansion of South Midway being down while we made repairs to our steam facilities. Contributions from the two in-fill wells in the southern expansion and seven in-fill wells in the primary area of South Midway drilled and completed in the second half of 2006 will not be a major impact until 2007. As at December 31, 2006, we were producing 590 gross Boe/d (543 net Boe/d) at South Midway compared to 536 gross Boe/d (499 net Boe/d) as at December 31, 2005.

Production Volumes 2005 vs. 2004

The 19% increase in U.S. production volumes for 2005 was due mainly to a 286% increase in production at our Knights Landing gas field in northern California. In April 2005, three Knights Landing wells that were drilled and completed in 2004 were connected to a gas sales line and placed on production. As at December 31, 2005, production from the Knights Landing wells had been fully depleted in all but one well, which was producing 12 gross Boe/d (7 net Boe/d) compared to average peak production rates of 411 gross Boe/d (267 net Boe/d) reached in the third quarter of 2005 resulting in a decrease in production volumes of 30.5 gross Mboe (19.9 net Mboe) for the fourth quarter of 2005.

Our production volumes at Citrus for 2005 were up 10% compared to 2004, however, production volumes for the fourth quarter of 2005 were down 7.9 gross Mboe (6.1 net Mboe) from average peak production levels reached in the fourth quarter of 2004 reflecting a natural decline in the wells. As at December 31, 2005, we were producing 77 gross Boe/d (60 Boe/d net) at Citrus compared to 198 gross Boe/d (159 Boe/d net) as at December 31, 2004.

Our production at South Midway increased 7% for 2005 primarily as a result of our continuous steam injection program in the southern expansion of South Midway, which has more than offset the natural decline in production from the wells in the primary section of South Midway. Additionally, in 2005 we drilled one in-fill well in the southern expansion and one successful exploration well adjacent to the primary area of South Midway, which contributed to the increase in production. As at December 31, 2005, we were producing 536 gross Boe/d (499 net Boe/d) at South Midway compared to 542 gross Boe/d (504 net Boe/d) as at December 31, 2004.

The decrease in production volumes in other U.S. properties for 2005 was primarily due to the natural decline in production rates from our Spraberry field in West Texas and as a result of the sale of our interest in the Sledge Hamar property in the fourth quarter of 2004.

Operating Costs 2006 vs. 2005

Operating costs in the U.S., including engineering support and production taxes, in 2006 decreased $0.7 million in absolute terms from 2005. However, on a per Boe basis operating costs increased 25% or $3.90 per Boe in 2006 when compared to 2005. Field operating costs increased $3.00 per Boe for 2006 when compared to 2005, primarily resulting from increases in primary operating costs at South Midway due to several maintenance projects related to the processing facilities. Although costs in the South Midway steaming operations did not fluctuate significantly in absolute terms, they did make up a larger portion of the overall cost per Boe as production in other fields declined. Engineering support increased $0.58 per Boe for 2006, when compared to 2005 as the same level of support was required to operate the fields even though there was a decline in production. Production taxes were up $0.32 per Boe for 2006 when compared to 2005, largely as the result of an increase in ad valorem taxes at South Midway and our Spraberry field in West Texas.

Operating Costs 2005 vs. 2004

Operating costs in the U.S., including engineering support and production taxes, increased 33% or $3.88 per Boe for 2005. Field operating costs increased $2.50 per Boe for 2005 due mainly to an increase in fuel costs incurred for the cyclic and continuous steam operations at South Midway. For 2005, we spent $3.70 per Boe or 32% of our total U.S. field operating costs for fuel at South Midway compared to $1.71 per Boe or 19% of our total U.S. field operating costs in 2004 as a result of the increase in natural gas prices during 2005. However, these increases in natural gas prices for the steaming operations at South Midway were more than offset by the price increase per barrel of oil received from our South Midway production during 2005 as our net operating revenue at South Midway increased $6.46 per Boe from 2004. In addition, our field operating costs increased $1.10 per Boe for 2005 primarily as a result of workovers at Knights Landing to complete new zones in the existing wells as production from the lower zones depleted. Engineering support increased $0.99 per Boe for 2005 due mainly to the start up of production operations at Knights Landing, where we became the operator in December 2004 and due to the start up of continuous steaming operations in the southern expansion of South Midway. Production taxes were up $0.39 per Boe due mainly to a full year assessment of our property values at Citrus and Knights Landing during 2005 and an increase in ad valorem taxes at South Midway due to a refund received in 2004.

* * *

Production and operating information including oil and gas revenue, operating costs and depletion, on a per Boe basis, from 2004 to 2006 are detailed below:

	Year ended December 31,								
		2006			2005			2004	
	U.S.	**China**	**Total**	**U.S.**	**China**	**Total**	**U.S.**	**China**	**Total**
Net Production:									
Boe	219,930	575,131	795,061	319,674	314,818	634,492	268,614	234,935	503,549
Boe/day for the year	603	1,576	2,178	876	863	1,738	734	642	1,376
		Per Boe			Per Boe			Per Boe	

Oil and gas revenue	$ 54.86	$ 62.04	$ 60.06	$ 44.01	$ 49.97	$ 46.97	$ 34.66	$ 36.11	$ 35.34
Field operating costs	14.44	14.07	14.17	11.44	7.49	9.48	8.94	6.04	7.59
Production tax and Windfall Levy	1.15	5.74	4.47	0.83		0.42	0.44		0.23
Engineering support	3.95	0.77	1.65	3.37	0.78	2.08	2.38	2.10	2.25
	19.54	20.58	20.29	15.64	8.27	12.00	11.76	8.14	10.07
Net operating revenue	35.32	41.46	39.77	28.37	41.70	34.99	22.90	27.97	25.27
Depletion	24.23	40.57	36.05	15.53	29.77	22.60	16.80	12.18	14.64
	$ 11.09	$ 0.89	$ 3.72	$ 12.84	$ 11.93	$ 12.39	$ 6.10	$ 15.79	$ 10.63

General and Administrative

Our changes in general and administrative expenses, before and after considering increases in non-cash stock based compensation, for the year ended December 31, 2006 when compared to the same period for 2005 and for the year ended December 31, 2005 when compared to the same period for 2004 were as follows:

	2006 vs. 2005	2005 vs. 2004
Favorable (unfavorable) variances:		
Oil and Gas Activities:		
China	$ 739	$ (1,116)
U.S.	(498)	(188)
Corporate	(892)	(950)
	(651)	(2,254)
Less: stock based compensation	591	665
	$ (60)	$ (1,589)

General and Administrative 2006 vs. 2005

China

General and administrative expenses related to the China operations decreased $0.7 million for 2006 due to a $1.1 million one time charge in 2005 for the write off of deferred costs incurred associated with financing discussions for our Dagang field development project. This decrease was primarily offset by an increase of $0.3 million in foreign currency losses.

U.S.

General and administrative expenses related to U.S. operations increased $0.5 million in 2006. Allocations to capital investments decreased $1.5 million as a result of less capital activity for 2006 when compared to 2005. This increase in expense was offset by a decrease of $0.7 million for bonuses accrued in 2005 compared to nil in 2006, a $0.2 million decrease in stock based compensation and a decrease of $0.2 million for a reduction in contract labor.

Corporate

General and administrative costs related to Corporate activities increased $0.9 million for 2006 when compared to 2005. The increase for 2006 was due to a $0.4 million increase in salaries and benefits (a $0.8 million increase in stock based compensation offset by a decrease of $0.3 million for bonuses accrued in 2005), a $0.2 million increase in outside legal, a $0.3 million increase in financial consulting, a $0.5 million increase in corporate governance costs and a $0.3 million increase for a one time charge in 2006 for the write off of the deferred loan costs on the convertible loan that was paid by way of the issuance of common shares in the April 2006 private placement. These increases were offset by a $0.7 million decrease in reduced professional fees incurred to comply with the provisions of Section 404 of the Sarbanes-Oxley Act of 2002 (**SOX**) as a portion of the 2004 SOX review was performed in the first quarter of 2005. In addition, current year costs for SOX are lower as there are no start up costs that we experienced in 2005.

General and Administrative 2005 vs. 2004

China
General and administrative expenses related to the China operations increased $1.1 million for 2005 due to costs incurred associated with financing discussions for our Dagang field development project.
U.S.
General and administrative expenses related to U.S. operations, before allocations to capital and operating costs, increased $1.4 million for 2005 primarily due to increased labor costs, including non-cash stock based compensation of $0.5 million. This is partially offset by increased allocations of general and administrative expenses to capital investments and operating costs of $0.8 million and $0.4 million, respectively, due to the increased levels of administrative support required for our HTL and GTL projects and due to becoming the operator at Knights Landing in December 2004 and the start up of continuous steaming operations in the southern expansion of South Midway in 2005.
Corporate
General and administrative costs related to Corporate activities increased $1.0 million for 2005 due mainly to a $0.6 million increase in labor costs, including non-cash stock based compensation of $0.2 million, and a $0.6 million increase in professional fees incurred in the first half of 2005 to complete our first year of compliance with the provisions of Section 404 of the Sarbanes-Oxley Act of 2002. This is a partially offset by a $0.2 million reduction in premiums for directors and officers liability insurance.
Business and Technology Development
Our changes in business and technology development, before and after considering increases in non-cash stock based compensation, for the year ended December 31, 2006 when compared to the same period for 2005 and for the year ended December 31, 2005 when compared to the same period for 2004 were as follows:

	2006 vs. 2005	2006 vs. 2005
Favorable (unfavorable) variances:		
HTL	$ (2,506)	$ (3,229)
GTL	(127)	164
	(2,633)	(3,065)
Less: stock based compensation	217	172
	$ (2,416)	$ (2,893)

Business and Technology Development 2006 vs. 2005
As in 2005 most of the focus of our business and technology development activities was on HTL opportunities. Operating expenses of the CDF to develop and identify improvements in the application of the HTL Technology are expensed as part of our business and technology development activities and contributed $1.1 million to the increase in business and technology development for HTL activities in 2006. Part of this increase was due to the CDF operating for a full year in 2006 versus a partial year in 2005. In addition contract services, including engineering work related to CDF processing runs and legal fees related to patents, increased $0.7 million in 2006. The remainder of the increase is related to consulting fees and travel costs to develop opportunities for our HTL Technology.
Business and Technology Development 2005 vs. 2004
During 2005, much of the focus of our business and technology development activities was on HTL opportunities, particularly related to heavy oil processing, which resulted in a $0.2 million reduction in expenses we incurred related to GTL activities. Of the $3.2 million increase in business and technology development expenses for 2005 associated with HTL activities, $1.6 million, including $0.2 million for non-cash stock based compensation, was related to consulting fees and travel costs to develop opportunities for our HTL Technology. In addition, operating expenses of

the CDF to develop and identify improvements in the application of the HTL Technology are expensed as part of our business and technology development activities and contributed $1.6 million to the increase in business and technology development for HTL activities in 2005.

Write-off of Deferred Acquisition Costs

In February 2006, the Company signed a non-binding memorandum of understanding regarding a proposed merger of Sunwing with China Mineral Acquisition Corporation (**CMA**), a U.S. public corporation. In May 2006 the parties entered a definitive agreement for the transaction. CMA s bylaws stipulated that if the transaction was not completed by August 31, 2006 CMA would be required to dissolve and distribute its assets (substantially all of which was cash) to its shareholders. CMA requested, but was unable to obtain, an extension of this deadline from its shareholders. Since the transaction could not be completed by the August 31 deadline, the definitive agreement was terminated and the Company wrote off deferred acquisition costs previously capitalized in the amount of $0.7 million.

Net Interest

Net Interest 2006 vs. 2005

In the fourth quarter of 2005, two convertible loans totaling $8.0 million (see 2005 vs. 2004 analysis below) were exchanged for a $4.0 million term note. This term note was paid off early in the second quarter of 2006. The reduction in interest and financing costs resulting from the reduction in these loans from year to year was $0.8 million. In addition, interest income increased by $0.6 million as average cash balances were significantly higher throughout 2006 when compared to 2005. These favorable increases were offset by a $0.4 million increase in interest and financing costs related to the note with CITIC. This note was part of the consideration for the re-acquisition of the 40% interest in the Dagang field.

Net Interest 2005 vs. 2004

In 2005, we borrowed the full amount of a $6.0 million stand-by loan facility, which we arranged in 2004, and amended the loan agreement to provide the lender the right to convert unpaid principal and interest during the loan term to the Company s common shares. We finalized a second 8% convertible loan agreement with the same lender for $2.0 million. Interest expense and financing costs for 2005 increased $0.8 million in 2005 as a result of these convertible loans. In addition, interest income decreased $0.1 million during 2005.

Depletion and Depreciation

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

Depletion and Depreciation 2006 vs. 2005

Depletion and depreciation increased $18.1 million in 2006, due to an increase in depletion rates of $13.45 per Boe resulting in additional depletion expense of $8.1 million for 2006. Additionally, higher production rates resulted in increase in depletion of $6.2 million for 2006. We began depreciating the CDF in 2006 which also contributed to the overall increase in depletion and depreciation in the amount of $3.8 million for 2006.

China

China s depletion rate for 2006 was $40.57 per Boe compared to $29.77 per Boe for 2005. The increase of $10.80 per Boe resulted in $6.2 million increase in depletion expense for 2006. This increase was due mainly to two factors:

- We suspended new drilling activity in December 2005 at our Dagang field in order to assess production decline performances on recently drilled wells, as well as maximizing cash flow from these operations. As a result, we reduced our estimate of the overall development program and our independent engineering evaluators, GLJ Petroleum Consultants Ltd., revised downward their estimate of our proved reserves at December 31, 2005.

- In the second quarter of 2005, we impaired the cost of our first Zitong block exploration well resulting in $12.5 million of those and other associated costs being included with our proved properties and therefore subject to depletion.

Additionally, increases in production volumes in China accounted for $7.8 million of the increase in depletion expense for 2006.

U.S.

The U.S. depletion rate for 2006 was $24.23 per Boe compared to $15.53 per Boe for 2005, an increase of $8.70 per Boe resulting in a $1.9 million increase in depletion expense. This increase was mainly due to the impairment of the remaining cost of our Northwest

Lost Hills #1-22 exploration well as at December 31, 2005, resulting in $8.9 million of those costs being included with our proved properties and therefore subject to depletion in the first quarter of 2006. In addition, the impairment of other properties in December 2006, including Yowlumne, LAK Ranch and Catfish Creek, resulted in $4.8 million of those costs being included with our proved properties and therefore subject to depletion in the fourth quarter of 2006. Increases in revisions to reserve estimates at December 31, 2006, mainly at South Midway, slightly offset the additional costs being added to the pool. Production volume decreases in the U.S. resulted in a $1.6 million decrease in our depletion expense for 2006.

HTL

The CDF was in a commissioning phase as at December 31, 2005 and, as such, had not been depreciated as at December 31, 2005. The commissioning phase ended in January 2006 and the CDF was placed into service. In 2006 $3.8 million of depreciation was recorded for the CDF.

Depletion and Depreciation 2005 vs. 2004

Depletion and depreciation increased $7.0 million in 2005, $5.1 million of which was due to the increase in depletion rates to $22.60 per Boe in 2005 compared to $14.64 per Boe in 2004 and $1.9 million was due to increased production volumes from 2004.

China

China s depletion rate for 2005 was $29.77 per Boe compared to $12.18 per Boe for 2004, an increase of $17.59 per Boe resulting in a $5.5 million increase in depletion expense for 2005. Our depletion rate for the fourth quarter of 2005 was $43.76 per Boe compared to $14.33 per Boe for the same period in 2004. These increases were due mainly to the reduced overall development program at our Dagang field and the subsequent reduction by our independent engineering evaluators, GLJ Petroleum Consultants of their estimate of our proved reserves as at December 31, 2005. We also impaired the cost of our first Zitong block exploration well resulting in $12.2 million of those and other associated costs being included with our proved properties and therefore subject to depletion.

Additionally, increases in production volumes in China accounted for $1.0 million of the increase in depletion expense for 2005.

U.S.

The U.S. depletion rate for 2005 was $15.53 per Boe compared to $16.80 per Boe for 2004, a decrease of $1.27 per Boe resulting in a $0.4 million decrease in depletion expense for 2005. Our depletion rate for the fourth quarter of 2005 was $18.01 per Boe compared to $14.96 per Boe for the same period in 2004. Production volume increases in the U.S. resulted in a $0.9 million increase in our depletion expense for 2005.

Write-Down of HTL and GTL Investments

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

Write-Down of HTL and GTL Investments 2006 vs. 2005

In 2006, we had no write downs for our HTL and GTL projects. This compares to the write down of $0.3 million related to our GTL project in Bolivia and $0.3 million related to our MOU with Ecopetrol for a heavy crude project in Colombia in 2006.

Write-Down of HTL and GTL Investments 2005 vs. 2004

In 2005, we wrote down $0.3 million related to our GTL project in Bolivia and $0.3 million related to our MOU with Ecopetrol for the Colombia Llanos Heavy Basin Crude Project . We wrote down our investment in the GTL project in Bolivia due to the impact that political and fiscal uncertainty in Bolivia could have on the viability of a GTL plant and our investment in the MOU with Ecopetrol as our bid to participate in the project was not successful. This compares to the write down of $0.3 million in 2004 for our investment in the Oman GTL project.

Impairment of Oil and Gas Properties

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

Impairment of Oil and Gas Properties 2006 vs. 2005

We impaired our China oil and gas properties by $5.4 million in 2006, compared to $5.0 million in 2005. The 2006 impairment was mainly the result of increased operating costs of the Dagang field, including costs of the Windfall Levy established in March 2006.

Impairment of Oil and Gas Properties 2005 vs. 2004

We impaired our China oil and gas properties by $5.0 million in 2005, compared to a $16.4 million impairment of our U.S. oil and gas properties in 2004. As a result of production decline performance and drilling results from the wells drilled in the northern blocks of the Dagang field, we reduced our estimate of the overall field development program and our independent engineering evaluators have revised downward their estimate of our proved reserves as at December 31, 2005. Additionally, we impaired 70% of our costs incurred in the Zitong block due to an unsuccessful first exploration well resulting in those costs, equal to $12.2 million, being included with the carrying value of proved properties for the ceiling test calculation.

As a result of the unsuccessful test of the Northwest Lost Hills # 1-22 well in January 2006, we fully evaluated the Northwest Lost Hills prospect as at December 31, 2005 resulting in an addition of $8.9 million to the carrying value of our U.S. cost center for the ceiling test calculation. However, no impairment of our U.S. oil and gas properties was required in 2005 for Canadian GAAP purposes.

Financial Condition, Liquidity and Capital Resources

Sources and Uses of Cash

Our net cash and cash equivalents increased by $7.2 million for the year ended December 31, 2006 compared to decreases of $2.6 million and $5.2 million for the same periods in 2005 and 2004, respectively.

Operating Activities

Our operating activities provided $14.4 million in cash for the year ended December 31, 2006 compared to $9.9 million and $4.0 million for the same periods in 2005 and 2004. The increases in cash from operating activities for the years ended December 31, 2006 and 2005 were mainly due to increases in net production volumes of 25% and 26%, respectively, and increases in oil and gas prices of 28% and 33%, respectively. The increases in net revenues for the years ended December 31, 2006 and 2005 were partially offset by increases of $2.5 million and $4.5 million, respectively, in general and administrative and business and technology development expenses, excluding stock based compensation for the year ended December 31, 2006 when compared to the same period in 2005.

Investing Activities

Our investing activities used $25.6 million in cash for the year ended December 31, 2006 compared to $51.1 million used in investing activities for the same period in 2005. For 2006, we reduced our capital asset expenditures by $25.4 million principally as a result of reduced expenditures for new drilling at our Dagang project of $17.3 million, reduced exploration expenditures of $4.5 million at our Zitong project and reduced expenditures of $2.6 million on projects in Iraq. In 2006, we generated $6.0 million of cash from asset sales in the U.S. compared to nil for the year ended December 31, 2005. In addition, during 2005, we spent $18.6 million on the Ensyn merger, which was completed in April 2005, including $6.8 million on the acquisition of the remaining joint venture interest in the CDF, and we advanced $1.2 million under a consultancy agreement. These decreases in our investing activities for the year ended December 31, 2006 were partially offset by a $24.7 million increase in our non-cash working capital associated with our investing activities.

Our investing activities used $51.1 million in cash for the year ended December 31, 2005 compared to $34.7 million used in investing activities for the same period in 2004. Our capital expenditures declined by $3.2 million, principally as a result of reduced exploration expenditures in our California properties. For the year ended December 31, 2005, compared to the same period in 2004, we spent $13.5 million more on the Ensyn merger, which was completed in April 2005, and we advanced $1.2 million during 2005 under a consultancy agreement. In addition, we had no sales of assets for the year ended December 31, 2005 compared to $14.0 million of cash generated from asset sales, the majority in China, for the comparable period in 2004. These increases in our investing activities for the year ended

December 31, 2005 were partially offset by an $11.9 million decrease in cash required for our capital investment activities for 2005 when compared to the same period in 2004, which was mainly due to an $8.8 million increase in our non-cash working capital associated with our investing activities.

Financing Activities

Our financing activities provided $18.4 million in cash for year ended December 31 2006 compared to $38.6 million of cash provided by financing activities for the year ended December 31 2005. The $20.2 million decrease in cash from financing activities is mainly due to a $7.1 million decrease in cash from private placements and exercises of warrants and options in addition to a $13.7 million decrease in net debt financing.

In April 2006 the Company closed a private placement of 11.4 million special warrants at $2.23 per special warrant for a total of $25.4 million. Each special warrant entitles the holder to receive, at no additional cost, one common share and one common share purchase warrant. All of the special warrants were subsequently exercised for common shares and common share purchase warrants. Each common share purchase warrant originally entitled the holder to purchase one common share at a price of $2.63 per share until the fifth anniversary date of the closing. In September 2007, these warrants were listed on the Toronto Stock Exchange and the exercise price was changed to Cdn.$2.93. Of the proceeds, $4.0 million has been used to pay down long-term debt and the balance will be used to pursue opportunities for the commercial deployment of the Company s heavy oil upgrading technology, to advance its oil and gas operations and for general corporate purposes.

Our financing activities provided $38.6 million in cash for the year ended December 31, 2005 compared to $25.5 million of cash provided by financing activities for the comparable period in 2004. We closed three special warrant financings by way of private placements during the year ended December 31, 2005 and issued 13.8 million common shares for net proceeds of $26.7 million compared to two special warrant financings by way of private placements for the year ended December 31, 2004 and issued 7.2 million common shares for $20.4 million. A special warrant is a security sold for cash which may be exercised to acquire, for no additional consideration, a common share or, in certain circumstances, a common share and a common share purchase warrant. We generated $4.5 million more from the exercise of stock options and common share purchase warrants for the year ended December 31, 2005 compared to the same period in 2004.

We generated $6.3 million in cash from net debt financing for the year ended December 31, 2005 compared to $3.3 million in cash for the same period in 2004. For the year ended December 31, 2005, we received $8.0 million from two convertible loans, $4.0 million of which was refinanced in November 2005 by the issuance of 2.5 million common shares. For the year ended December 31, 2004, we received $4.0 million from our bank loan facility to develop the southern expansion of South Midway. For the years ended December 31, 2005 and 2004 we made principal payments on our bank loan of $1.7 million and $0.7 million, respectively.

Outlook for 2007

Our 2007 capital program budget ranges from approximately $20 million to $25 million and will encompass both continuing development of our existing producing oil and gas properties to maximize near-term cash flow and to further the development and deployment of our proprietary HTL oil upgrading technology. Management s plans include alliances or other arrangements with entities with the resources to support the Company s projects as well as project financing, debt and mezzanine financing or the sale of equity securities in order to generate sufficient resources to meet its capital investment and operating objectives. The Company intends to utilize revenue from existing operations to fund the transition of the Company to a heavy oil exploration, production and upgrading company and non-heavy oil related investments in our portfolio will be leveraged or monetized to capture value and provide maximum return for the Company. No assurances can be given that we will be able to enter into one or more alternative business alliances with other parties or raise additional capital. If we are unable to enter into such business alliances or obtain adequate additional financing, we will be required to curtail our operations, which may include the sale of assets.

Contractual Obligations and Commitments

The table below summarizes and cross-references the contractual obligations and commitments that are reflected in our consolidated balance sheets and/or disclosed in the accompanying Notes:

	Payments Due by Year (stated in thousands of U.S. dollars)					
	Total	**2007**	**2008**	**2009**	**2010**	**After 2010**
Consolidated Balance Sheets:						
Note payable current portion *(Note 6)*	$ 2,147	$ 2,147	$	$	$	$
Long term debt *(Note 6)*	4,237		3,825	412		
Asset retirement obligation *(Note 7)*	1,953		742	17	484	710
Long term obligation *(Note 8)*	1,900			1,900		
Other Commitments:						
Interest payable (1)	653	437	212	4		
Lease commitments *(Note 8)*	3,990	998	970	776	651	595
Zitong exploration commitment *(Note 8)*	906	906				
Total	$ 15,786	$ 4,488	$ 5,749	$ 3,109	$ 1,135	$ 1,305

(1) This is the estimated future interest payments on our notes payable and long term debt using the rates of interest in effect as at December 31, 2006.

We have excluded our normal purchase arrangements as they are discretionary and/or being performed under contracts which are cancelable immediately or with a 30-day notification period.

Critical Accounting Principles and Estimates

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

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

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

Full Cost Accounting We follow Accounting Guideline 16 Oil and Gas Accounting Full Cost (**AcG 16**) in accounting for our oil and gas properties. Under the full cost method of accounting, all exploration and development costs associated with lease and royalty interest acquisition, geological and geophysical activities, carrying charges for unproved properties, drilling both successful and unsuccessful wells, gathering and production facilities and equipment, financing, administrative costs directly related to capital projects and asset retirement costs are capitalized on a country-by-country cost center basis. As at December 31, 2006, the carrying values of our U.S. and China cost centers were $37.1 million and $64.7 million, respectively.

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

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

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

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

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

- calculating our unit-of-production depletion rates. Proved reserves are used to determine rates that are applied to each unit-of-production in calculating our depletion expense. In 2006, oil and gas depletion of $28.7 million was recorded in depletion and depreciation expense. If our reserve estimates changed by 10%, our depletion and depreciation expense for 2006 would have changed by approximately $2.6 million assuming no other changes to our reserve profile. See Depletion below.

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

Management is responsible for estimating the quantities of proved oil and natural gas reserves and preparing related disclosures. Estimates and related disclosures are prepared in accordance with SEC requirements, generally accepted industry practices in the U.S. as promulgated by the Society of Petroleum Engineers, and the standards of the COGE Handbook modified to reflect SEC requirements.

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

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

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

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

Another critical factor affecting our depletion rate is our determination that an impairment of unproved oil and gas properties has occurred. Costs incurred on an unproved oil and gas property are excluded from the depletion rate calculation until it is determined whether proved reserves are attributable to an unproved oil and gas property or upon determination that an unproved oil and gas property has been impaired. An unproved oil and gas property would likely be impaired if, for example, a dry hole has been drilled and there are no firm plans to continue drilling on the property. Also, the likelihood of partial or total impairment of a property increases as the expiration of the lease term approaches and there are no plans to drill on the property or to extend the term of the lease. We assess each of our unproved oil and gas properties for impairment on a quarterly basis. If we determine that an unproved oil and gas property has been totally or partially impaired we include all or a portion of the accumulated costs incurred for that unproved oil and gas property in the calculation of our unit-of production depletion rate. As at December 31, 2006, we had $5.8 million and $8.3 million of costs incurred on unproved oil and gas properties in the U.S. and China, respectively.

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

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

For Canadian GAAP, AcG 16 requires recognition and measurement processes to assess impairment of oil and gas properties (**ceiling test**). In the recognition of an impairment, the carrying value[1] of a cost center is compared to the undiscounted future net cash flows of that cost center s proved reserves using estimates of future oil and gas prices and costs plus the cost of unproved properties that

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have been excluded from the depletion calculation. If the carrying value is greater than the value of the undiscounted future net cash flows of the proved reserves plus the cost of unproved properties excluded from the depletion calculation, then the amount of the cost center s potential impairment must be measured. A cost center s impairment loss is measured by the amount its carrying value exceeds the discounted future net cash flows of its proved and probable reserves using estimates of future oil and gas prices and costs plus the cost of unproved properties that have been excluded from the depletion calculation and which contain no probable reserves. The net cash flows of a cost center s proved and probable reserves are discounted using a risk-free interest rate. The amount of the impairment loss is recognized as a charge to the results of operations and a reduction in the net carrying amount of a cost center s oil and gas properties. We provided for $16.3 million in a ceiling test impairment for our U.S. cost center for the year ended December 31, 2004, and $5.4 million and $5.0 million for the years ended December 31, 2006 and 2005, respectively, for our China cost center.

For U.S. GAAP, we follow the requirements of the SEC s Regulation S-X Article 4-10(c)4 for determining the limitation of capitalized costs. Accordingly, the carrying value[(1)] of a cost center s oil and gas properties cannot exceed the discounted future net cash flows of its proved reserves using period-end oil and gas prices and costs plus (i) the cost of properties that have been excluded from the depletion calculation and (ii) the lower of cost or estimated fair value of unproved properties included in the depletion calculation less income tax effects related to differences between the book and tax basis of the properties. The net cash flows of a cost center s proved reserves are discounted by ten percent. The amount of the impairment loss is recognized as a charge to the results of operations and a reduction in the net carrying amount of a cost center s oil and gas properties. We provided for $7.6 million, $2.8 million and $15.0 million in ceiling test impairments for our U.S. cost center for the years ended December 31, 2006, 2005 and 2004, respectively, and $15.9 and $1.7 million for the years ended December 31, 2006 and 2005 for our China cost center.

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

Asset Retirement For Canadian GAAP, we follow Canadian Institute of Chartered Accountants (**CICA**) Section 3110, Asset Retirement Obligations which requires asset retirement costs and liabilities associated with site restoration and abandonment of tangible long-lived assets be initially measured at a fair value which approximates the cost a third party would incur in performing the tasks necessary to retire such assets. The fair value is recognized in the financial statements at the present value of expected future cash outflows to satisfy the obligation. Subsequent to the initial measurement, the effect of the passage of time on the liability for the asset retirement obligation (accretion expense) and the amortization of the asset retirement cost are recognized in the results of operations. We measure the expected costs required to retire our producing U.S. oil and gas properties at a fair value, which approximates the cost a third party would incur in performing the tasks necessary to abandon the field and restore the site. We do not make such a provision for our oil and gas operations in China as there is no obligation on our part to contribute to the future cost to abandon the field and restore the site. Asset retirement costs are depleted using the unit of production method based on estimated proved reserves and are included with depletion and depreciation expense. The accretion of the liability for the asset retirement obligation is included with interest expense.

For U.S. GAAP, we follow SFAS No. 143, Accounting for Asset Retirement Obligations which conforms in all material respects with Canadian GAAP.

Research and Development We incur various expenses in the pursuit of HTL and GTL projects, including HTL Technology for heavy oil processing, throughout the world. For Canadian GAAP, such expenses incurred prior to signing an MOU, or similar agreements, are considered to be business and technology development expenses and are charged to the results of operations as incurred. Upon executing an MOU to determine the technical and commercial feasibility of a project, including studies for the marketability of the projects products, we assess that the feasibility and related costs incurred have potential future value, are probable of leading to a definitive agreement for the exploitation of proved reserves and should be capitalized. If no definitive agreement is reached, then the capitalized costs, which are deemed to have no future value, are written down to our results of operations with a corresponding reduction in our investments in HTL or GTL assets. For the years ended December 31, 2006, 2005 and 2004, we wrote down nil, \$0.6 million and \$0.3 million, respectively, of capitalized negotiation and feasibility costs associated with our HTL and GTL projects which did not result in definitive agreements.

Additionally, we incur costs to develop, enhance and identify improvements in the application of the HTL and GTL technologies we license or own. We follow CICA Section 3450 Research and Development Costs in accounting for the development costs of equipment and facilities acquired or constructed for such purposes. Development costs are capitalized and amortized over the expected economic life of the equipment or facilities commencing with the start up of commercial operations for which the equipment or facilities are intended. We review the recoverability of such capitalized development costs annually, or as changes in circumstances indicate the development costs might be impaired, through an evaluation of the expected future discounted cash flows from the associated projects. If the carrying value of such capitalized development costs exceeds the expected future discounted cash flows, the excess is written down to the results of operations with a corresponding reduction in the investments in HTL and GTL assets.

Costs incurred in the operation of equipment and facilities used to develop or enhance HTL and GTL technologies prior to commencing commercial operations are business and technology development expenses and are charged to the results of operations in the period incurred.

For U.S. GAAP, we follow SFAS No. 2, Research and Development . As with Canadian GAAP, costs of equipment or facilities that are acquired or constructed for research and development activities are capitalized as tangible assets and amortized over the expected economic life of the equipment or facilities commencing with the start up of commercial operations for which the equipment or facilities are intended. However, for U.S. GAAP such facilities must have alternative future uses to be capitalized. As with Canadian GAAP, expenses incurred in the operation of research and development equipment or facilities prior to commencing commercial operations are business and technology development expenses and are charged to the results of operations in the period incurred. The major difference for U.S. GAAP purposes is that feasibility, marketing and related costs incurred prior to executing a definitive agreement are considered to be research and development costs and are expensed as incurred. For the years ended December 31, 2006, 2005 and 2004, we expensed $1.0 million, $4.8 million and $2.1 million, respectively, of feasibility, marketing and related costs incurred prior to executing definitive agreements.

Intangible Assets Our intangible assets consists of the underlying value of an exclusive, irrevocable license we acquired in the merger with Ensyn to deploy, worldwide, the RTP^{TM} **Process** for petroleum applications (HTL Technology) as well as the exclusive right to deploy the RTP^{TM} **Process** in all applications other than biomass and a master license from Syntroleum permitting us to use the Syntroleum Process in an unlimited number of projects around the world and. For Canadian GAAP, we follow CICA Section 3062 Goodwill and Other Intangible Assets whereby intangible assets, acquired individually or with a group of other assets, are initially recognized and measured at cost. Intangible assets with finite lives are amortized over their useful lives whereas intangible assets with indefinite useful lives are not amortized unless it is subsequently determined to have a finite useful life. Intangible assets are reviewed annually for impairment, or when events or changes in circumstances indicate that the carrying value of an intangible asset may not be recoverable. If the carrying value of an intangible asset exceeds its fair value or expected future discounted cash flows, the excess is written down to the results of operations with a corresponding reduction in the carrying value of the intangible asset. The HTL Technology and the Syntroleum GTL master license have finite lives, which correlate with the useful lives of the facilities we expect to develop that will use the technologies. The amount of the carrying value of the technologies we assign to each facility will be amortized to earnings on a basis related to the operations of the facility from the date on which the facility is placed into service. We evaluate the carrying values of the HTL Technology and the Syntroleum GTL master license annually, or as changes in circumstances indicate the intangible assets might be impaired, based on an assessment of its fair market value.

For U.S. GAAP, we follow SFAS No. 142, Goodwill and Other Intangible Assets which conforms in all material respects with Canadian GAAP.

Derivative Instruments Our derivative instruments consist of costless collar contracts. These contracts are effective economic hedges; however, they may not qualify for hedge accounting due to the very detailed and complex rules outlined in CICA Accounting Guideline 13, Hedging Relationships (**AcG13**). This guideline sets out the criteria that must be met in order to apply hedge accounting for derivatives. The guideline provides detailed guidance on the identification, designation, documentation and effectiveness of hedging relationships for purposes of applying hedge accounting, and the discontinuance of hedge accounting. Gains and losses on derivative instruments designated and that qualify as hedges under this guideline are recognized in earnings in the same period as the related hedged item. Ineffective hedging relationships and hedges not designated in a hedging relationship are carried as fair value in the statement of financial position, and subsequent changes in the fair value are recorded in the results of operations. The Company uses the fair value method of accounting for all derivative transactions. Fair values are determined based on third-party statements for the amounts that would be paid or received to settle these instruments prior to maturity and recorded on the balance sheet with changes in the fair value recorded in the statement of operations as a gain or loss.

For U.S. GAAP, we follow SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (**SFAS 133**) which conforms in all material respects with Canadian GAAP with respect to the treatment of costless collars.

Impact of New and Pending Canadian GAAP Accounting Standards

In December 2006 the CICA approved Section 1535 Capital Disclosures (**S.1535**), Section 3862 Financial Instruments Disclosures (**S.3862**), and Section 3863 Financial Instruments Presentation (**S.3863**). S.1535 establishes standard disclosing information about an entity s capital and how it is managed. The objective of S.3862 is to require entities to provide disclosures in their financial statements that enable users to evaluate both the significance of financial instruments for the entity s financial position and performance; and the nature and extent of risks arising from financial instruments to which the entity is exposed during the period and at the balance sheet date, and how the entity manages those risks. The purpose of S.3863 is to enhance financial statement users understanding of the significance of financial instruments to an entity s financial position, performance and cash flows. These Sections apply to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2007. Management is in the process of reviewing the requirements of these recent Sections.

In July 2006 the CICA approved Section 1506 Accounting Changes (**S.1506**). The objective of this Section is to prescribe the criteria for changing accounting policies, together with the accounting treatment and disclosure of changes in accounting policies, changes in accounting estimates and corrections of errors. This Section is intended to enhance the relevance and reliability of an entity s financial statements and the comparability of those financial statements over time and with the financial statements of other entities. This Section applies to interim and annual financial statements relating to fiscal years beginning on or after January 1, 2007. The impact of this statement is determined as changes in accounting policies are needed in the financial statements.

Canada s Accounting Standards Board is expected to put forth in the second half of 2007 recommendations for accounting of business combinations. Whether the Company would be materially affected by the proposed amended recommendations would depend upon the specific facts of the business combinations, if any, occurring on or after January 1, 2007. Generally, the proposed recommendations will result in measuring business acquisitions at the fair value with transaction costs expensed as incurred.

In early 2006, Canada s Accounting Standards Board ratified a strategic plan that will result in Canadian GAAP, as used by public companies, being converged with International Financial Reporting Standards over a transitional period. The Accounting Standards Board has developed and published a detailed implementation plan with an expected changeover to International Financial Reporting Standards on January 1, 2011.

In January 2005, the CICA approved Section 1530 Comprehensive Income (**S.1530**), Section 3855 Financial Instruments Recognition and Measurement (**S.3855**) and Section 3865 Hedges (**S.3865**) to harmonize financial instrument and hedge accounting with U.S. GAAP and introduce the concept of comprehensive income. S.1530 requires presentation of certain gains and losses outside of net income, such as unrealized gains and losses related to hedges or other derivative instruments. S.3855 establishes standards for recognizing and measuring financial assets and financial liabilities and non-financial derivatives as required to be disclosed under Section 3861 Financial Instruments Disclosure and Presentation . S.3865 establishes standards for how and when hedge accounting may be applied. The Company applies SFAS No. 133 Accounting for Derivative Instruments and Hedging Activities for U.S. GAAP purposes and will not implement S.3865 for Canadian GAAP for hedging activities and will continue to apply fair value accounting. These sections apply to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006. The Company adopted these standards January 1, 2007, with no material impact on the Company s financial statements.

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

In February 2007, the Financial Accounting Standards Board (**FASB**) issued Statement of Financial Accounting Standards No. 159, The Fair Value Option for Financial Assets and Financial Liabilities (including an amendment of FASB Statement No. 115) (**SFAS No. 159**). The statement would create a fair value option under which an entity may irrevocably elect fair value as the initial and subsequent measurement attribute for certain financial assets and financial liabilities on a contract-by-contract basis, with changes in fair value recognized in earnings as those changes occur. This Statement is effective as of the beginning of an entity s first fiscal year that begins after November 15, 2007. Management is in the process of reviewing the requirements of this recent statement.

In December 2006, the FASB published an exposure draft titled Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement 133 . The proposed Statement would amend and expand the disclosure requirements in SFAS 133, and other related literature. This proposed Statement is intended to provide an enhanced understanding of how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under SFAS 133 and its related interpretations, and how derivative instruments affect an entity s financial position, results of operations, and cash flows. Management is in the process of reviewing the requirements of this recent proposed statement

In September 2006, the U.S. Securities and Exchange Commission issued Staff Accounting Bulletin 108 (**SAB 108**). The interpretations in this bulletin express the staff s views regarding the process of quantifying financial statement misstatements and are being issued to address diversity in practice in quantifying financial statement misstatements and the potential under current practice for the build up of improper amounts on the balance sheet. SAB 108 did not have a material impact on the Company s financial statements.

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 157, Fair Value Measurements (**SFAS No. 157**). This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. This statement does not require any new fair value measurements; however, for some entities the application of this statement will change current practice. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years, although early adoption is permitted. Management is in the process of reviewing the requirements of this recent statement.

In June 2006, the FASB issued FASB Interpretation No. 48 (**FIN 48**) Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109 . The interpretation clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with SFAS No. 109, Accounting for Income Taxes. The evaluation of a tax position in accordance with this interpretation is a two-step process. Under the recognition step an enterprise determines whether it is more likely than not that a tax position will be sustained upon examination based on the technical merits of the position. Under the measurement step a tax position that meets the more-likely-than-not recognition threshold is measured to determine the amount of benefit to recognize in the financial statements. The tax position is measured at the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. FIN 48 is effective for fiscal years beginning after December 15, 2006. Earlier application of the provisions of this interpretation is encouraged if the enterprise has not yet issued financial statements, including interim financial statements, in the period this interpretation is adopted. Management does not believe the requirements of this interpretation will have a material impact on its financial statements.

In February 2006, the FASB issued SFAS No. 155, Accounting for Certain Hybrid Financial Instruments an amendment of FASB statements No. 133 and 140 (**SFAS No. 155**). SFAS No. 155 resolves issues surrounding the application of the bifurcation requirements to beneficial interests in securitized financial assets. In general, this statement permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation. SFAS No. 155 is effective for all financial instruments acquired or issued after the beginning of an entity s first fiscal year that begins after September 15, 2006 and is not expected to have a material impact on the Company s financial statements.

In May 2005, the FASB issued SFAS No. 154 (**SFAS No. 154**) Accounting Changes and Error Corrections a replacement of APB Opinion No. 20 and FASB Statement No. 3 . SFAS No. 154 changes the requirements for the accounting for and reporting of a change in accounting principle. APB Opinion No. 20 previously required that most voluntary changes in accounting principle be recognized by including in net income of the period of the change the cumulative effect of changing to the new accounting principle. SFAS No. 154 requires retrospective application to prior periods financial statements for changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS No. 154 applies to all voluntary changes in accounting principle. SFAS No. 154 also applies to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. When a pronouncement includes specific transition provisions, those provisions should be followed. SFAS No. 154 carries forward without change to the guidance contained in APB Opinion No. 20 for reporting the correction of an error in previously issued financial statements and a change in accounting estimate. SFAS No. 154 also carries forward the guidance in APB Opinion No. 20 requiring justification of a change in accounting principle on the basis of preferability. SFAS No. 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. The impact of this Statement is determined as changes in accounting policies are needed in the financial statements.

On September 30, 2005, the FASB issued an Exposure Draft that would amend SFAS No. 128, Earnings per Share , to clarify guidance for mandatorily convertible instruments, the treasury stock method, contracts that may be settled in cash or shares and contingently issuable shares. The proposed Statement would be effective for interim and annual periods ending after June 15, 2006. Retrospective application would be required for all changes to SFAS No. 128, except that retrospective application would be prohibited for contracts that were either settled in cash to prior adoption to require cash settlement. Management is in the process of reviewing the requirements of this recent exposure draft.

Off Balance Sheet Arrangements

At December 31, 2006 and 2005, we did not have any relationships with unconsolidated entities or financial partnerships, such as structured finance or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. In addition, we do not engage in trading activities involving non-exchange traded contracts. As such, we are not materially exposed to any financing, liquidity, market or credit risk that could arise if we had engaged in such relationships. We do not have relationships and transactions with persons or entities that derive benefits from their non-independent relationship with us, or our related parties, except as disclosed herein.

Related Party Transactions

The Company has entered into agreements with a number of entities, which are related through common directors or shareholders, to provide administrative or technical personnel, office space or facilities. The Company is billed on a cost recovery basis. The costs incurred in the normal course of business with respect to the above arrangements amounted to $3.0 million, $3.0 million and $1.6 million for the years ended December 31, 2006, 2005 and 2004, respectively. As at December 31, 2006 and 2005, amounts included in accounts payable under these arrangements were $0.3 million and $0.5 million, respectively.

Certain Factors Affecting the 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 producing 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.

Environmental Regulations

Our conventional oil and gas and HTL 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. 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.

China is becoming increasingly aware of the need to protect the environment. State government is working on developing and implementing more stringent national environmental protection regulations and standards for different industries. Projects are currently monitored by provincial and local governments based on the approved standards specified in the environmental impact statement prepared for individual projects.

Environmental Provisions

As at December 31, 2006, a $1.5 million provision has been made for future site restoration and plugging and abandonment of wells in the U.S. and $0.5 million for the removal of the CDF and restoration of the Aera site occupied by the CDF. The future cost of these obligations is estimated at $2.0 million and $0.5 million for the U.S. wells and CDF, respectively. We do not make such a provision for our oil and gas operations in China, as there is no obligation on our part to contribute to the future cost to abandon the field and restore the site. During 2006, we reduced our provision for future site restoration and plugging and abandonment of U.S. wells by $0.2 million and increased our provision for the CDF by $0.4 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.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Equity Market Risks

We currently have limited production in the U.S. and China, which have not generated sufficient cash from operations to fund our exploration and development activities. Historically, we have relied on the equity markets as the primary source of capital to fund our expansion and growth opportunities. Based on our current plans, we estimate that we will need approximately $20.0 to $25.0 million to fund our capital investment programs for 2007.

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

Commodity Price Risk

Commodity price risk related to crude oil prices is one of our most significant market risk exposures. Crude oil prices and quality differentials are influenced by worldwide factors such as OPEC actions, political events and supply and demand fundamentals. To a lesser extent we are also exposed to natural gas price movements. Natural gas prices are generally influenced by oil prices, North American supply and demand and local market conditions. We estimate that our net income and cash from operations for 2007 would change $0.3 million and $0.1 million for every $1.00/Bbl change in WTI prices and $0.50/Mcf in natural gas prices, respectively.

We periodically engage in the use of derivatives to hedge our cash flow from operations and currently have a costless collar contract in place as at December 31, 2006. The Company entered into this costless collar derivative to hedge its cash flow from the sale of approximately 400-500 barrels of its U.S. oil production per day over a two year period starting November 2006 as part of its recently concluded banking arrangements. The derivative had a ceiling price of $65.20 per barrel and a floor price of $63.20 per barrel using WTI as the index traded on the NYMEX. See Note 13 to the Consolidated Financial Statements.

Decreases in oil and natural gas prices would negatively impact our results of operations as a direct result of a reduction in revenues but may also do so in the ceiling test calculation for the impairment of our oil and gas properties. On a quarterly basis, we compare the value of our proved and probable reserves, using estimated future oil and gas prices[(1)], to the carrying value of our oil and gas properties. The ceiling test calculation is sensitive to oil and gas prices and in a period of declining prices could result in a charge to our results of operations as we experienced in 2001 when we recorded a $14.0 million provision for impairment for Canadian GAAP and an additional $10.0 million for U.S. GAAP mainly due to a decline in oil and gas prices. Decreases in oil and gas prices from those used in our ceiling test calculation as at December 31, 2006 as discussed above in Critical Accounting Principles and Estimates Impairment of Proved Oil and Gas Properties may result in additional impairment provisions of our oil and gas properties.

(1) The recoverable value of probable reserves is included only for the measurement of the impairment of the carrying value of oil and gas properties as required under Canadian GAAP but not for U.S. GAAP. Additionally, U.S. GAAP requires the use of period end oil and gas prices to measure the amount of the impairment rather than estimated future oil and gas prices as required by Canadian GAAP. See Critical Accounting Principles and Estimates for the difference between Canadian and U.S. GAAP in calculating the impairment provision for oil and gas properties.

Foreign Currency Rate Risk

In the international petroleum industry, most production is bought and sold in U.S. dollars or with reference to the U.S. dollar. Accordingly, we do not expect to face foreign exchange risks associated with our production revenues. Most of our business transactions, in the countries in which we operate, are conducted in U.S. dollars or currencies, such as Chinese renminbi, which was pegged to the U.S. dollar. During the third quarter of 2005, the Chinese central government increased the value of its renminbi and abandoned its exchange rate previously pegged to the U.S. dollar in favor of a link to a basket of world currencies. We incurred immaterial foreign currency exchange gains or losses during the three years ended December 31, 2006. We do not expect fluctuations in any of the currencies in which we transact business to have a material impact on our consolidated financial statements.

Interest Rate Risk

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

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA
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REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Shareholders of
Ivanhoe Energy Inc.:

We have audited the accompanying consolidated balance sheets of Ivanhoe Energy Inc. and subsidiaries as of December 31, 2006 and 2005 and the consolidated statements of operations and shareholders equity and cash flow for each of the years in the three-year period ended December 31, 2006. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Ivanhoe Energy Inc. and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2006 in conformity with Canadian generally accepted accounting principles.

The consolidated financial statements for the year ended December 31, 2005 have been restated with respect to Note 19, Additional Disclosures Required Under U.S. Generally Accepted Accounting Principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company s internal control over financial reporting as of December 31, 2006, based on the criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 7, 2007 expressed an unqualified opinion on management s assessment of the effectiveness of the Company s internal control over financial reporting and an unqualified opinion on the effectiveness of the Company s internal control over financial reporting.

(signed) Deloitte & Touche LLP
Independent Registered Chartered Accountants
Calgary, Canada
March 7, 2007

COMMENTS BY INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS ON CANADA UNITED STATES OF AMERICA REPORTING DIFFERENCES

The standards of the Public Company Accounting Oversight Board (United States) require the addition of an explanatory paragraph when the financial statements are affected by conditions and events that cast substantial doubt on the Company s ability to continue as a going concern, such as those described in Note 2 to the financial statements. In addition, the standards of the Public Company Accounting Oversight Board (United States) require the addition of an explanatory paragraph when there are changes in accounting principles that have a material effect on the comparability of the financial statements, such as the change described in Note 19 (iii) to the Company s financial statements. Although we conducted our audits in accordance with both Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), our report to the Board of Directors and Shareholders dated March 7, 2007 is expressed in accordance with Canadian reporting standards which do not permit a reference to such conditions and events in the auditors report when these are adequately disclosed in the financial statements.

(signed) Deloitte & Touche LLP
Independent Registered Chartered Accountants
Calgary, Canada
March 7, 2007

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

	As at December 31, 2006	2005
Assets		
Current Assets		
Cash and cash equivalents	$ 13,879	$ 6,724
Accounts receivable (net of allowance for doubtful accounts of $116 and $83 as at December 31, 2006 and 2005, respectively) *(Note 3)*	7,435	9,994
Prepaid and other current assets	773	338
	22,087	17,056
Oil and gas properties and investments, net *(Note 4)*	121,918	119,654
Intangible assets technology *(Note 5)*	102,153	102,068
Long term assets	2,386	2,099
	$ 248,544	$ 240,877
Liabilities and Shareholders Equity		
Current Liabilities		
Accounts payable and accrued liabilities	$ 9,428	$ 25,791
Notes payable current portion *(Note 6)*	2,147	1,667
Asset retirement obligations current portion *(Note 7)*		950
Derivative instruments *(Note 13)*	493	
	12,068	28,408
Notes payable *(Note 6)*	4,237	4,972
Asset retirement obligations *(Note 7)*	1,953	830
Long term obligation *(Note 8)*	1,900	1,900
Commitments and contingencies *(Note 8)*		
Going concern and basis of presentation *(Note 2)*		
Shareholders Equity		
Share capital, issued and outstanding 241,215,798 common shares; December 31, 2005 220,779,335 common shares	318,725	291,088
Purchase warrants *(Note 9)*	23,955	5,150
Contributed surplus	6,489	3,820

Accumulated deficit	(120,783)	(95,291)
	228,386	204,767
	$ 248,544	$ 240,877

(See accompanying Notes to the Consolidated Financial Statements)

Approved by the Board:

(signed) David R. Martin Director	(signed) Brian Downey Director

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IVANHOE ENERGY INC.
Consolidated Statements of Operations
(stated in thousands of U.S. Dollars, except share amounts)

	Year Ended December 31,		
	2006	**2005**	**2004**
Revenue			
Oil and gas revenue	$ 47,748	$ 29,800	$ 17,795
Loss on derivative instruments *(Note 13)*	(424)		
Interest income	776	139	202
	48,100	29,939	17,997
Expenses			
Operating costs	16,133	7,603	5,073
General and administrative	10,180	9,529	7,275
Business and technology development	7,610	4,978	1,913
Depletion and depreciation	32,550	14,447	7,482
Interest expense and financing costs	963	1,258	379
Write off of deferred acquisition costs *(Note 18)*	736		
Write-downs and provision for impairment *(Notes 4)*	5,420	5,636	16,600
	73,592	43,451	38,722
Net Loss	$ (25,492)	$ (13,512)	$ (20,725)
Net Loss per share Basic and Diluted *(Note 15)*	$ (0.11)	$ (0.07)	$ (0.12)
Weighted Average Number of Shares (in thousands)	235,640	195,803	167,612

(See accompanying Notes to the Consolidated Financial Statements)

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

	Share Capital		Purchase	Contributed	Accumulated	
	Shares (thousands)	Amount	Warrants	Surplus	Deficit	Total
Balance December 31, 2003	161,359	$ 161,075	$	$ 516	$ (61,054)	$ 100,537
Net loss					(20,725)	(20,725)
Shares issued for:						
Private placements, net of share issue costs *(Note 9)*	7,173	20,428				20,428
Exercise of options *(Note 10)*	975	1,767		(44)		1,723
Services	158	347				347
Stock based compensation				1,276		1,276
Balance December 31, 2004	169,665	183,617		1,748	(81,779)	103,586
Net loss					(13,512)	(13,512)
Shares and purchase warrants issued for:						
Merger, net of share issue costs *(Note 18)*	30,000	74,907				74,907
Private placements, net of share issue costs *(Note 9)*	13,842	21,834	4,837			26,671
Refinance of convertible debt *(Note 6 and 9)*	2,454	4,000	313			4,313
Exercise of purchase warrants *(Note 9)*	4,515	6,133				6,133
Exercise of options *(Note 10)*	111	156		(41)		115
Services	192	441				441
Stock based compensation				2,113		2,113
Balance December 31, 2005	220,779	291,088	5,150	3,820	(95,291)	204,767
Net loss					(25,492)	(25,492)
Shares and purchase warrants issued for:						
Acquisition of oil and gas assets *(Note 18)*	8,591	20,000				20,000
Private placements, net of share issue costs *(Note*	11,400	6,493	18,805			25,298

9)						
Exercise of options *(Note 10)*	297	743		(252)		491
Services	149	401				401
Stock based compensation				2,921		2,921
Balance December 31, 2006	241,216	$ 318,725	$ 23,955	$ 6,489	$ (120,783)	$ 228,386

(See accompanying Notes to the Consolidated Financial Statements)

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

	Year Ended December 31,		
	2006	**2005**	**2004**
Operating Activities			
Net loss	$ (25,492)	$ (13,512)	$ (20,725)
Items not requiring use of cash:			
Depletion and depreciation	32,550	14,447	7,482
Write-down and provision for impairment *(Notes 4)*	5,420	5,636	16,600
Stock based compensation *(Note 10)*	2,921	2,113	1,276
Write off of deferred acquisition costs *(Note 18)*	736		
Unrealized loss on derivative instruments *(Note 13)*			
Write off of debt financing costs		857	
Other	600	108	47
Changes in non-cash working capital items *(Note 16)*	(2,876)	221	(648)
	14,352	9,870	4,032
Investing Activities			
Capital investments	(17,842)	(43,282)	(46,454)
Merger, net of working capital *(Note 18)*		(10,096)	
Merger and acquisition related costs *(Note 18)*	(736)	(1,712)	(5,016)
Acquisition of joint venture interest *(Note 18)*		(6,750)	
Proceeds from sale of assets *(Note 4)*	5,950		13,958
Advance payments	(125)	(1,200)	
Other	(116)	(97)	(410)
Changes in non-cash working capital items *(Note 16)*	(12,708)	12,022	3,264
	(25,577)	(51,115)	(34,658)
Financing Activities			
Shares issued on private placements, net of share issue costs *(Note 9)*	25,298	26,671	20,428
Proceeds from exercise of options and warrants *(Notes 9 and 10)*	491	6,248	1,723
Share issue costs on shares issued for Merger		(93)	
Proceeds from debt obligations, net of financing costs *(Note 6)*	1,280	8,000	14,000
Payments of debt obligations *(Note 6)*	(8,689)	(1,667)	(10,694)
Other		(512)	
	18,380	38,647	25,457
Increase (decrease) in cash and cash equivalents, for the period	7,155	(2,598)	(5,169)
Cash and cash equivalents, beginning of year	6,724	9,322	14,491
Cash and cash equivalents, end of year	$ 13,879	$ 6,724	$ 9,322

(See accompanying Notes to the Consolidated Financial Statements)

IVANHOE ENERGY INC.
Notes to the Consolidated Financial Statements
(all tabular amounts are expressed in thousands of U.S. Dollars, except share amounts)

1. NATURE OF OPERATIONS

Ivanhoe Energy Inc., a Canadian company, including its subsidiaries, is an independent international heavy oil development and production company focused on pursuing long-term growth in its reserves and production. Ivanhoe Energy plans to utilize technologically innovative methods designed to significantly improve recovery of heavy oil resources, including the anticipated commercial application of the patented rapid thermal processing process (**RTP[TM] Process**) for heavy oil upgrading (**HTL Technology** or **HTL**) and enhanced oil recovery (**EOR**) techniques. In addition, the Company seeks to expand its reserve base and production through conventional exploration and production (**E&P**) of oil and gas. Finally, the Company is exploring an opportunity to monetize stranded gas reserves through the application of the conversion of natural gas-to-liquids using a technology (**GTL Technology** or **GTL**) licensed from Syntroleum Corporation. Our core operations are currently carried out in the United States and China with business development opportunities worldwide.

2. SIGNIFICANT ACCOUNTING POLICIES

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

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

In particular, the amounts recorded for depletion, depreciation and accretion of the oil and gas properties and for asset retirement obligations are based on estimates of reserves and future costs. By their nature, these estimates, and those related to future cash flows used to assess impairment of oil and gas properties and investments as well as intangible assets, are subject to measurement uncertainty and the impact on the financial statements of future periods could be material.

Going Concern and Basis of Presentation

The Company s financial statements as at and for the year ended December 31, 2006 have been prepared on a going concern basis, which contemplates the realization of assets and the settlement of liabilities and commitments in the normal course of business. The Company incurred a net loss of $25.5 million for the year ended December 31, 2006, and as at December 31, 2006, had an accumulated deficit of $120.8 million and positive working capital of $10.0 million. The Company currently anticipates incurring substantial expenditures to further its capital investment programs and the Company s cash flow from operating activities will not be sufficient to both satisfy its current obligations and meet the requirements of these capital investment programs. Recovery of capitalized costs related to potential HTL and GTL projects is dependent upon finalizing definitive agreements for, and successful completion of, the various projects. Management s plans include alliances or other arrangements with entities with the resources to support the Company s projects as well as project financing, debt and mezzanine financing or the sale of equity securities in order to generate sufficient resources to assure continuation of the Company s operations and achieve its capital investment objectives. The Company intends to utilize revenue from existing operations to fund the transition of the Company to a heavy oil exploration, production and upgrading company and non-heavy oil related investments in our portfolio will be leveraged or monetized to capture value and provide maximum return for the Company. The outcome of these matters cannot be predicted with certainty at this time and therefore the Company may not be able to continue as a going concern. These consolidated financial statements do not include any adjustments to the amounts and classification of assets and liabilities that may be necessary should the Company be unable to continue as a going concern.

Principles of Consolidation

These consolidated financial statements include the accounts of Ivanhoe Energy Inc. and its subsidiaries, all of which are wholly owned.

The Company conducts most exploration, development and production activities in its oil and gas business jointly with others. The Company s accounts reflect only its proportionate interest in the assets and liabilities of these joint ventures.

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

Foreign Currency Translation

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

Cash and Cash Equivalents

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

Financial Instruments

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

Oil and Gas Properties

<u>Full Cost Accounting</u>

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

<u>Depletion</u>

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

<u>Impairment of Proved Oil and Gas Properties</u>

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

Asset Retirement Costs

The Company measures the expected costs required to abandon its producing U.S. oil and gas properties and the HTL commercial demonstration facility (**CDF**) at a fair value which approximates the cost a third party would incur in performing the tasks necessary to abandon the field and restore the site. The fair value is recognized in the financial statements at the present value of expected future cash outflows to satisfy the obligation as a liability with a corresponding increase in the related asset. Subsequent to the initial measurement, the effect of the passage of time on the liability for the asset retirement obligation (accretion expense) is recognized in the results of operations and included with interest expense. Actual costs incurred upon settlement of the obligation are charged against the obligation to the extent of the liability recorded. Any difference between the actual costs incurred upon settlement of the obligation and the recorded liability is recognized as a gain or loss in the results of operations in the period in which the settlement occurs.

Asset retirement costs associated with the producing U.S. oil and gas properties are being depleted using the unit of production method based on estimated proved reserves and are included with depletion and depreciation expense. Asset retirement costs associated with the CDF are depreciated over the life of the CDF which commenced when the facility was placed into service.

The Company does not make such a provision for its oil and gas operations in China as there is no obligation on the Company s part to contribute to the future cost to abandon the field and restore the site.

Development Costs

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

Additionally, the Company incurs costs to develop, enhance and identify improvements in the application of the HTL and GTL technologies it licenses or owns. The cost of equipment and facilities acquired, such as the CDF, or construction costs for such purposes, are capitalized as development costs and amortized over the expected economic life of the equipment or facilities, commencing with the start up of commercial operations for which the equipment or facilities are intended. The CDF will be used to develop and identify improvements in the application of the HTL Technology by processing and testing heavy crude feedstock of prospective partners until such time as the CDF is sold, dismantled or redeployed.

The Company reviews the recoverability of such capitalized development costs annually, or as changes in circumstances indicate the development costs might be impaired, through an evaluation of the expected future discounted cash flows from the associated projects. If the carrying value of such capitalized development costs exceeds the expected future discounted cash flows, the excess is written down in the results of operations with a corresponding reduction in the investments in HTL and GTL assets.

Costs incurred in the operation of equipment and facilities used to develop or enhance HTL and GTL technologies prior to commencing commercial operations are business and technology development expenses and are charged to the results of operations in the period incurred.

Furniture and Equipment

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

Intangible Assets

Intangible assets are initially recognized and measured at cost. Intangible assets with finite lives are amortized over their estimated useful lives. Intangible assets are reviewed at least annually for impairment, or when events or changes in circumstances indicate that the carrying value of an intangible asset may not be recoverable. If the carrying value of an intangible asset exceeds its fair value or expected future discounted cash flows, the excess is written down to the

results of operations with a corresponding reduction in the carrying value of the intangible asset.
The Company owns intangible assets in the form of an exclusive, irrevocable license to employ the RTP^{TM} Process for all applications other than biomass and a GTL master license from Syntroleum Corporation (**Syntroleum**). The Company will assign the carrying

value of the HTL Technology and the Syntroleum GTL master license to the number of facilities it expects to develop that will use the HTL Technology and the Syntroleum GTL process respectively. The amount of the carrying value of the technologies assigned to each HTL or GTL facility will be amortized to earnings on a basis related to the operations of the HTL or GTL facility from the date on which the facility is placed into service. The carrying value of the HTL Technology and the Syntroleum GTL master license are evaluated for impairment annually, or as changes in circumstances indicate the intangible assets might be impaired, based on an assessment of their fair market values.

Oil and Gas Revenue

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

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

Earnings or Loss Per Share

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

Income Taxes

The Company follows the liability method of accounting for future income taxes. Under the liability method, future income taxes are recognized to reflect the expected future tax consequences arising from tax loss carry-forwards and temporary differences between the carrying value and the tax basis of the Company s assets and liabilities. A valuation allowance is recorded against any future income tax asset if the Company is not more likely than not to be able to utilize the tax deductions associated with the future income tax asset.

Stock Based Compensation

The Company has an Employees and Directors Equity Incentive Plan consisting of stock option (See Note 10), bonus and an employee share purchase plan. The Company accounts for equity-based compensation under this plan using the fair value based method of accounting for all stock options granted after January 1, 2002. Compensation costs are recognized in the results of operations over the periods in which the stock options vest for all stock options granted based on the fair value of the stock options at the date granted. The Company uses the Black-Scholes option-pricing model for determining the fair value of stock options issued at grant date. As of the date stock options are granted, the Company estimates a percentage of stock options issued to employees and directors it expects to be forfeited. Compensation costs are not recognized for stock option awards forfeited due to a failure to satisfy the service requirement for vesting. Compensation costs are adjusted for the actual amount of forfeitures in the period in which the stock options expire.

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

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

Derivative Activities

From time to time, the Company enters into derivative financial instruments to reduce price volatility and establish minimum prices for a portion of its oil and natural gas production. No contracts are entered into for trading or speculative purposes and the Company accounts for all financial derivative contacts based on the fair value method. Fair values are determined based on third-party statements for the amounts that would be paid or received to settle these instruments prior to maturity and recorded on the balance sheet with changes in the fair value recorded in the statement of operations as a gain or loss (See Note 13).

Impact of New and Pending Canadian GAAP Accounting Standards

In December 2006, the Canadian Institute of Chartered Accountants (**CICA**) approved Section 1535 Capital Disclosures (**S.1535**), Section 3862 Financial Instruments Disclosures (**S.3862**), and Section 3863 Financial Instruments Presentation (**S.3863**). S.1535 establishes standards for disclosing information about an entity s capital and how it is managed. The objective of S.3862 is to require entities to provide disclosures in their financial statements that enable users to evaluate both the significance of financial instruments for the entity s financial position and performance; and the nature and extent of risks arising from financial instruments to which the entity is exposed during the period and at the balance sheet date, and how the entity manages those risks. The purpose of S.3863 is to enhance financial statement users understanding of the significance of financial instruments to an entity s financial position, performance and cash flows. These Sections apply to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2007. Management is in the process of reviewing the requirements of these recent Sections.

In July 2006 the CICA approved Section 1506 Accounting Changes (**S.1506**). The objective of this Section is to prescribe the criteria for changing accounting policies, together with the accounting treatment and disclosure of changes in accounting policies, changes in accounting estimates and corrections of errors. This Section is intended to enhance the relevance and reliability of an entity s financial statements and the comparability of those financial statements over time and with the financial statements of other entities. This Section applies to interim and annual financial statements relating to fiscal years beginning on or after January 1, 2007. The impact of this statement is determined as changes in accounting policies are needed in the financial statements.

Canada s Accounting Standards Board is expected to put forth in the second half of 2007 recommendations for accounting of business combinations. Whether the Company would be materially affected by the proposed amended recommendations would depend upon the specific facts of the business combinations, if any, occurring on or after January 1, 2007. Generally, the proposed recommendations will result in measuring business acquisitions at the fair value with transaction costs expensed as incurred.

In early 2006, Canada s Accounting Standards Board ratified a strategic plan that will result in Canadian GAAP, as used by public companies, being converged with International Financial Reporting Standards over a transitional period. The Accounting Standards Board has developed and published a detailed implementation plan with an expected changeover to International Financial Reporting Standards on January 1, 2011.

In January 2005, the CICA approved Section 1530 Comprehensive Income (**S.1530**), Section 3855 Financial Instruments Recognition and Measurement (**S.3855**) and Section 3865 Hedges (**S.3865**) to harmonize financial instrument and hedge accounting with U.S. GAAP and introduce the concept of comprehensive income. S.1530 requires presentation of certain gains and losses outside of net income, such as unrealized gains and losses related to hedges or other derivative instruments. S.3855 establishes standards for recognizing and measuring financial assets and financial liabilities and non-financial derivatives as required to be disclosed under Section 3861 Financial Instruments Disclosure and Presentation . S.3865 establishes standards for how and when hedge accounting may be applied. The Company applies SFAS No. 133 Accounting for Derivative Instruments and Hedging Activities for U.S. GAAP purposes and will not implement S.3865 for Canadian GAAP for hedging activities and will continue to apply fair value accounting. These sections apply to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006. The Company adopted these standards January 1, 2007, with no material impact on the Company s financial statements.

3. CONCENTRATION OF CREDIT RISKS

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

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

	Accounts Receivable as at December 31,		Oil and Gas Revenues for the Year Ended December 31,		
	2006	2005	2006	2005	2004
U.S. Customers					
A	$ 776	$ 738	$ 10,351	$ 8,812	$ 6,140
B	142	110	1,094	1,166	1,040
C	57	80	277	351	300
D		327	236	1,607	1,202
All others	17	88	107	2,133	629
	992	1,343	12,065	14,069	9,311
China Customer					
A	5,572	3,519	35,683	15,731	8,484
	6,564	4,862	47,748	29,800	17,795
Receivables from partners	592	4,888			
Other receivables	279	244			
	$ 7,435	$ 9,994	$ 47,748	$ 29,800	$ 17,795

Accounts receivable as at December 31, 2006 and 2005 in the table above include $0.6 million and $4.9 million, respectively, of costs billed to joint venture partners where the Company is the operator and advances to partners for joint operations where the Company is not the operator.

4. OIL AND GAS PROPERTIES AND INVESTMENTS

Capital assets categorized by segment are as follows:

	As at December 31, 2006				
	Oil and Gas				
	U.S.	China	HTL	GTL	Total
Oil and Gas Properties:					
Proved	$ 102,884	$ 106,171	$	$	$ 209,055
Unproved	5,765	8,279			14,044
	108,649	114,450			223,099
Accumulated depletion	(21,249)	(39,372)			(60,621)
Accumulated provision for impairment	(50,350)	(10,420)			(60,770)
	37,050	64,658			101,708
HTL and GTL Investments:					
Feasibility studies and other deferred costs			7,020	5,054	12,074
Commercial demonstration facility			11,700		11,700
Accumulated depreciation			(3,789)		(3,789)

			14,931	5,054	19,985
Furniture and equipment	530	115	80		725
Accumulated depreciation	(414)	(56)	(30)		(500)
	116	59	50		225
	$ 37,166	$ 64,717	$ 14,981	$ 5,054	$ 121,918

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	As at December 31, 2005				
	Oil and Gas				
	U.S.	China	HTL	GTL	Total
Oil and Gas Properties:					
Proved	$ 99,721	$ 71,760	$	$	$ 171,481
Unproved	9,676	5,320			14,996
	109,397	77,080			186,477
Accumulated depletion	(15,920)	(16,036)			(31,956)
Accumulated provision for impairment	(50,350)	(5,000)			(55,350)
	43,127	56,044			99,171
HTL and GTL Investments:					
Feasibility studies and other deferred costs			6,142	4,570	10,712
Commercial demonstration facility			9,599		9,599
			15,741	4,570	20,311
Furniture and equipment	485	95	15		595
Accumulated depreciation	(380)	(37)	(6)		(423)
	105	58	9		172
	$ 43,232	$ 56,102	$ 15,750	$ 4,570	$ 119,654

Oil and Gas Properties

In 2006, and 2004, the Company disposed of U.S. oil and gas property interests with proceeds totaling $6.0 million and $0.5 million. The sale proceeds were credited to the carrying value of its U.S. oil and gas properties as the sales did not significantly alter the depletion rate for the U.S. cost center.

During 2000 and 2001, the Company acquired mineral rights in several East Texas prospects under a joint venture with a subsidiary of Unocal Corp. (**Unocal**). Unocal, as operator of the joint venture, was to fund, over a five-year period ending in December 2005, the drilling costs for the first several exploration wells to match $10.1 million in leasehold, seismic and processing costs the Company incurred on these East Texas prospects. Through December 2005, Unocal had spent $8.5 million in exploration drilling and elected to pay the Company $1.6 million for the deficiency in their drilling commitment rather than drill additional exploration wells. The Company credited the $1.6 million payment to the carrying value of its U.S. oil and gas properties as the payment did not significantly alter the depletion rate for the U.S. cost center.

The Company currently holds a production-sharing contract with China National Petroleum Corporation (**CNPC**) to develop existing oil properties in the Dagang region. In January 2004, the Company signed farm-out and joint operating agreements with Richfirst Holdings Limited (**Richfirst**) a wholly-owned subsidiary of China International Trust and Investment Corporation, to acquire a 40% working interest in the Dagang field for an up-front payment of $20.0 million following receipt of Chinese regulatory approvals in June 2004. The carrying value of the Company s China oil and gas properties was reduced by $13.5 million for the amount of the proceeds associated with the farm-in of Richfirst to the Dagang field as the reduction in the carrying value did not significantly alter the depletion rate of the China cost center. The farm-out agreement provided Richfirst with the right to convert its working interest in the

Dagang field for the Company s common shares at any time prior to eighteen months after closing the farm-out agreement. Richfirst elected to convert its 40% working interest in the Dagang field and in February 2006 the Company re-acquired Richfirst s 40% working interest (See Note 18). Subsequent to the re-acquisition of Richfirst s 40% working interest, the Company incurred 100% of the costs to earn 82% of the production, before recovery of costs incurred, reverting to a 49% share post cost recovery.

At December 31, 2005, the Company held a 100% working interest in a thirty-year production-sharing contract with CNPC in a contract area, known as the Zitong block located in the northwestern portion of the Sichuan Basin. In January 2006, the Company farmed-out 10% of its working interest in the Zitong block to Mitsubishi Gas Chemical Company Inc. of Japan (**Mitsubishi**) for $4.0 million (See Note 8). Under the terms of the production-sharing contract, the Company and Mitsubishi will develop natural gas deposits within the block and in return will receive approximately 75% of the revenue until costs are recovered and approximately 45% thereafter. CNPC has the option, at the end of appraisal activities, to participate with the Company in any proposed field developments, with up to a 51% working interest.

Costs as at December 31, 2006 and 2005 of $14.0 million and $15.0 million, related to unproved oil and gas properties have been excluded from costs subject to depletion and depreciation. Included in that same depletion calculation were $14.7 million and $11.0 million for future development costs associated with proven undeveloped reserves as at December 31, 2006 and 2005.

For the years ended December 31, 2006 and 2005, general and administrative expenses related directly to oil and gas acquisition, exploration and development activities, and investments in HTL and GTL projects of $3.2 million and $4.6 million, respectively, were capitalized.

The Company performed a ceiling test calculation at December 31, 2006 and 2005 to assess the recoverable value of its U.S. Oil and Gas Properties. Based on this calculation, the present value of future net revenue from the Company s proved plus probable reserves exceeded the carrying value of the Company s U.S. Oil and Gas Properties. This same calculation resulted in an impairment of $16.4 million for 2004. The Company performed this same calculation for its China properties at December 31, 2006 and 2005 resulting in an impairment of $5.4 million and $5.0 million. At December 31, 2004, the present value of future net revenue from the Company s proved plus probable reserves exceeded the carrying value of the Company s China Oil and Gas Properties.

Prices used in calculating the expected future cash flows were based on the following benchmark prices adjusted for gravity, transportation and other factors as required by sales agreements:

	As at December 31. 2006		**As at December 31. 2005**		**As at December 31. 2004**	
	West Texas Intermediate (per Bbl)	**Henry Hub** (per Mcf)	**West Texas Intermediate** (per Bbl)	**Henry Hub** (per Mcf)	**West Texas Intermediate** (per Bbl)	**Henry Hub** (per Mcf)
2005	NA	NA	NA	NA	$42.00	$ 6.20
2006	NA	NA	$57.00	$10.50	$40.00	$ 6.00
2007	$62.00	$ 7.25	$55.00	$ 8.75	$38.00	$ 5.75
2008	$60.00	$ 7.50	$51.00	$ 7.50	$36.00	$ 5.50
2009	$58.00	$ 7.50	$48.00	$ 7.00	$34.00	$ 5.50
2010	$57.00	$ 7.50	$46.50	$ 6.75	$33.00	$ 5.50
2011	$57.00	$ 7.50	$45.00	$ 6.50	$33.00	$ 5.50
2012	$57.50	$ 7.75	$45.00	$ 6.50	$33.00	$ 5.50
2013	$58.50	$ 7.90	$46.00	$ 6.65	$33.50	$ 5.60
2014	$59.75	$ 8.05	$46.75	$ 6.75	$34.00	$ 5.65
2015	$61.00	$ 8.20	$47.75	$ 6.90	$34.50	$ 5.75
2016	$62.25	$ 8.40	$48.75	$ 7.05	2% per year	2% per year
2017	$63.50	$ 8.55	2% per year	2% per year	2% per year	2% per year
Thereafter	2% per year	2% per year	2% per year	2% per year	2% per year	2% per year

Heavy- to-Light

In 2005, the Company acquired the CDF for $8.9 million as part of the Ensyn merger and subsequent purchase of the remaining interest in the CDF Joint Venture (as defined in Note 18) that it did not own. The CDF was in a commissioning phase as at December 31, 2005 and, as such, the $8.9 million was not depreciated, nor impaired, for the year ended December 31, 2005. The commissioning phase ended in January 2006 and the CDF was placed into service and depreciated straight-line over its current useful life based on the existing term of an agreement with a third party oil and gas producer to use their property to test the CDF. The end term of this agreement was extended in August 2006 from December 31, 2006 to December 31, 2008 and the useful life was prospectively extended to coincide with the new term of the agreement. There was no revenue associated with the CDF operations for the years ended December 31, 2006 and 2005.

For the year ended December 31, 2005, the Company wrote down $0.3 million related to its HTL Investments. There were no write downs of HTL investments required for the years ended December 31, 2006 and 2004.

Gas-to-Liquids

For the years ended December 31, 2005 and 2004, the Company wrote down $0.3 million and $0.3 million, of capitalized costs associated with its GTL projects which did not result in definitive agreements. No write downs of GTL projects were required for the year ended December 31, 2006.

5. INTANGIBLE ASSETS TECHNOLOGY

The Company s intangible assets consist of the following:

HTL Technology

In the Ensyn merger, the Company acquired an exclusive, irrevocable license to deploy, worldwide, the RTP™ Process for petroleum applications (HTL Technology) as well as the exclusive right to deploy RTP™ Process in all applications other than biomass. The Company s carrying value of the HTL Technology as at December 31, 2006 and 2005 was $92.2 million and $92.1 million.

Syntroleum GTL Master License

The Company owns a master license from Syntroleum Corporation (**Syntroleum**) permitting the Company to use Syntroleum s proprietary GTL process in an unlimited number of projects around the world. The Company s master license expires on the later of April 2015 or five years from the effective date of the last site license issued to the Company by Syntroleum. In respect of GTL projects in which both the Company and Syntroleum participate no additional license fees or royalties will be payable by the Company and Syntroleum will contribute, to any such project, the right to manufacture specialty and lubricant products. Both companies have the right to pursue GTL projects independently, but the Company would be required to pay the normal license fees and royalties in such projects. The Company s carrying value of the Syntroleum GTL master license as at December 31, 2006 and 2005 was $10.0 million.

These intangible assets were not amortized and their carrying values were not impaired for the years ended December 31, 2006, 2005 and 2004.

6. NOTES PAYABLE

Notes payable consisted of the following as at:

	December 31, 2006	December 31, 2005
Non-interest bearing promissory note, due 2006 through 2009	$ 5,336	$
Variable rate bank note, 8.25%, due 2008	1,500	
Variable rate bank note, 7.375%, due 2006 though 2007		2,639
8% promissory note, due 2007		4,000
	6,836	6,639
Less:		
Unamortized discount	(452)	
Current maturities	(2,147)	(1,667)
	(2,599)	(1,667)
	$ 4,237	$ 4,972

Promissory Notes

In February 2006, the Company re-acquired the 40% working interest in the Dagang oil project not already owned by the Company. Part of the consideration was the issuance by the Company of a non-interest bearing, unsecured promissory note in the principal amount of approximately $7.4 million ($6.5 million after being discounted to net present value). The note is payable in 36 equal monthly installments commencing March 31, 2006 (See Note 18).

As at December 31, 2004, the Company had a $6.0 million stand-by loan facility. In February 2005, the Company borrowed the full amount available under this stand-by loan facility and amended the loan agreement to provide the lender with the right to convert, at the lender s election, unpaid principal and interest during the loan term into common shares of the Company at $2.25 per share. In May 2005, the Company entered into a second convertible loan agreement with the same lender for $2.0 million which provided the lender the right to convert, at the lender s election, unpaid principal and interest during the loan term into common shares of the Company at $2.15 per share.

In November 2005, the Company entered into an agreement with the lender of the two convertible loans referred to above to repay \$4.0 million of these loans by issuing 2,453,988 common shares of the Company at \$1.63 per share and to refinance the residual \$4.0 million outstanding with a new \$4.0 million promissory note due November 23, 2007 and bearing interest, payable monthly, at a rate of 8% per annum. The previously granted conversion rights attached to the two previously outstanding convertible loans were cancelled and the Company issued to the lender 2,000,000 purchase warrants, each of which entitles the holder to purchase one common share at a price of \$2.00 per share until November 2007. This note was repaid in April 2006 (See Note 9).

Bank Notes

In October 2006 the Company obtained a $15 million Senior Secured Revolving/Term Credit Facility with an initial borrower base of $8 million from an international bank. The facility is for two years, the first 18 months in the form of a revolver and at the end of 18 months, the then outstanding amount will convert into a six-month amortizing loan. Depending on the drawn amount, interest, at the Company s option, will be either at 1.75% to 2.25%, above the bank s base rate or 2.75% to 3.25% over the London Inter-Bank Offered Rate (**LIBOR**). The loan terms include the requirement for the Company to enter into two-year commodity derivative contracts (See Note 13) covering approximately 75% of the Company s estimated production from its South Midway Property in California and Spraberry Property in West Texas. The facility is secured by a mortgage on both of these properties. During the year the Company drew $1.5 million on this facility.

In February 2003, the Company obtained a bank facility for up to $5.0 million to develop the southern expansion of its South Midway field. The bank facility was fully drawn in July 2004 and repayment of the principal and interest commenced in August 2004 with interest at 0.5% above the bank s prime rate or 3.0% over the LIBOR, at the option of the Company. The principal and interest were repayable, monthly, over a three-year period ending July 2007. The note was secured by all the Company s rights and interests in the South Midway properties. This note was repaid in advance of its scheduled maturity date from the proceeds of the Company s new credit facility (see above).

Advance Payable

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

Revolving Line of Credit

The Company has a revolving credit facility for up to $1.25 million from a related party, repayable with interest at U.S. prime plus 3%. The Company did not draw down any funds from this credit facility for the years ended December 31, 2006 and 2005.

The scheduled maturities of the notes payable, excluding unamortized discount, as at December 31, 2006 were as follows:

2007	$ 2,460
2008	3,960
2009	416
	$ 6,836

7. ASSET RETIREMENT OBLIGATIONS

The Company provides for the expected costs required to abandon its producing U.S. oil and gas properties and the CDF. The undiscounted amount of expected future cash flows required to settle the Company s asset retirement obligations for these assets as at December 31, 2006 was estimated at $2.5 million. These payments are expected to be made over the next 40 years with the bulk of the payments 2008 to 2014. To calculate the present value of these obligations, the Company used an inflation rate ranging from 3% to 4% and the expected future cash flows have been discounted using a credit-adjusted risk-free rate ranging from 5% to 7%. The changes in the Company s liability for the two-year period ended December 31, 2006 were as follows:

	2006	2005
Carrying balance, beginning of year	$ 1,780	$ 749
Liabilities incurred	139	1,052
Liabilities settled		(2)
Accretion expense	86	76
Revisions in estimated cash flows	(52)	(95)

	1,953	1,780
Less: current portion		(950)
Carrying balance, end of year	$ 1,953	$ 830

8. COMMITMENTS AND CONTINGENCIES

Zitong Block Exploration Commitment

Under the production-sharing contract for the Zitong block, the Company was obligated to conduct a minimum exploration program during the first three years ending December 1, 2005 (**Phase 1**). The Phase 1 work program included acquiring approximately 300 miles of new seismic lines, reprocessing approximately 1,250 miles of existing seismic and drilling a minimum of approximately 23,000 feet. The Company completed Phase 1 with the exception of drilling approximately 13,800 feet. The first Phase 1 exploration well drilled in 2005 was suspended, having found no commercial quantities of hydrocarbons. Drilling on the second exploration well commenced in October 2006, but it was not expected to be completed and tested by November 30, 2006, the deadline for completing the Phase 1 exploration program. In September 2006 the Company submitted a letter to PetroChina requesting that a further extension be granted to the Phase 1 exploration program. The Company received a letter of approval from PetroChina for an extension of Phase 1 to September 30, 2007.

In January 2006, the Company farmed-out 10% of its working interest in the Zitong block to Mitsubishi Gas Chemical Company Inc. of Japan (**Mitsubishi**) for $4.0 million. Mitsubishi has the option to increase its participating interest to 20% by paying $0.4 million plus costs per percentage point prior to any discovery, or $8.0 million plus costs for an additional 10% interest after completion and testing of the first well drilled under the farm-out agreement.

The Company and Mitsubishi (the **Zitong Partners**) will await the results of the second exploration well (see above) after which a decision will be made whether or not to enter into the next three-year exploration phase (**Phase 2**). The $4.0 million advance from Mitsubishi was used to pay for the initial well costs and there was no unspent balance at December 31, 2006. If the Company elects not to enter into Phase 2, it will be required to pay CNPC, within 30 days after its election, a cash equivalent of its share of the deficiency in the work program estimated to be $0.3 million after the drilling of the second Phase 1 well. If the Company elects not to enter Phase 2, costs related to the Zitong block in the approximate amount of $8.3 million will be required to be included in the depletable base of the China full cost pool. This may result in a ceiling test impairment related to the China full cost pool in a future period.

If the Zitong Partners elect to participate in Phase 2, they must complete a minimum work program involving the acquisition of approximately 200 miles of new seismic lines and approximately 23,000 feet of drilling, with estimated minimum expenditures for the program of $21.6 million. Following the completion of Phase 2, the Zitong Partners must relinquish all of the property except any areas identified for development and production. If the Zitong Partners elect to enter into Phase 2, they must complete the minimum work program or will be obligated to pay to CNPC the cash equivalent of the deficiency in the work program for that exploration phase.

Income Taxes

The Company s income tax filings are subject to audit by taxation authorities, which may result in the payment of income taxes and/or a decrease its net operating losses available for carry-forward in the various jurisdictions in which the Company operates. While the Company believes it tax filings do not include uncertain tax positions, the results of potential audits or the effect of changes in tax law cannot be ascertained at this time. The Company has received preliminary indication from local Chinese tax authorities as to a potential change in the rule under which development costs are deducted from taxable income effective for the 2006 tax year. The Company has received no formal notification of any rule changes and expects to continue to make its tax filings consistent with those of prior years and to initiate formal discussions of the matter with Chinese tax authorities.

Long Term Obligation

As part of the Ensyn merger, the Company assumed an obligation to pay $1.9 million in the event, and at such time that, the sale of units incorporating the HTL Technology for petroleum applications reach a total of $100.0 million. This obligation was recorded in the Company s consolidated balance sheet.

Other Commitments

As part of the Ensyn merger, the Company assumed an obligation to advance to a former affiliate of Ensyn (the **Former Ensyn Affiliate**) up to approximately $0.4 million if the Former Ensyn Affiliate cannot meet certain debt servicing ratios required under a Canadian municipal government loan agreement. The principal amount of this loan is repayable in nine equal annual installments commencing April 1, 2006 and ending April 1, 2014. The parent corporation of the Former Ensyn Affiliate has agreed to indemnify the Company for any amounts advanced to the

Former Ensyn Affiliate under the loan agreement.

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

Lease Commitments

The Company expended $0.8 million, $0.6 million and $0.5 million for each of the years ended December 31, 2006, 2005 and 2004 on operating leases relating to the rental of office space, which expire between August 2008 and March 2012. Such leases frequently provide for renewal options and require the Company to pay for utilities, taxes, insurance and maintenance expenses.

As at December 31, 2006, future net minimum lease payments for operating leases (excluding oil and gas and other mineral leases) were the following:

2007	$ 998
2008	970
2009	776
2010	651
2011	476
Thereafter	119
	$ 3,990

9. SHARE CAPITAL

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

Private Placements

On April 7, 2006, the Company closed a special warrant financing by way of private placement for $25.3 million. The financing consisted of 11,400,000 special warrants issued for cash at $2.23 per special warrant. Each special warrant entitled the holder to receive, at no additional cost, one common share and one common share purchase warrant. All of the special warrants were subsequently exercised for common shares and common share purchase warrants. Each common share purchase warrant originally entitled the holder to purchase one common share at a price of $2.63 per share until the fifth anniversary date of the closing. In September 2007, these warrants were listed on the Toronto Stock Exchange and the exercise price was changed to Cdn.$2.93.

From 2004 to 2006, the Company closed six special warrant financings by way of private placement for net cash proceeds of $25.3 million in 2006, $26.7 million in 2005 and $20.4 million in 2004. A special warrant is a security sold for cash which may be exercised to acquire, for no additional consideration, a common share or, in certain circumstances, a common share and a common share purchase warrant. As part of these special warrant financings, the Company issued 32,414,756 common shares for cash, 2,453,988 common shares for the repayment of $4.0 million of convertible debt (See Note 6) and 34,868,744 purchase warrants. Each purchase warrant entitles the holder to purchase additional common shares of the Company at various exercise prices per share.

Purchase Warrants

The following reflects the changes in the Company s purchase warrants and common shares issuable upon the exercise of the purchase warrants for the three-year period ended December 31, 2006:

	Purchase Warrants	Common Shares Issuable
	(thousands)	
Balance December 31, 2003	10,279	5,765
Purchase warrants issued for:		
Private placements	7,173	3,587
Balance December 31, 2004	17,452	9,352
Purchase warrants issued for:		
Private placements	16,296	16,296
Refinance of convertible debt	2,000	2,000
Purchase warrants exercised	(9,029)	(4,515)
Purchase warrants expired	(1,250)	(1,250)
Balance December 31, 2005	25,469	21,883
Purchase warrants expired	(7,173)	(3,587)
Private placements	11,400	11,400
Balance December 31, 2006	29,696	29,696

For the year ended December 31, 2005, 9,029,412 purchase warrants were exercised for the purchase of 4,514,706 common shares at an average exercise price of U.S. $1.36 per share for a total of $6.1 million.
As at December 31, 2006, the following purchase warrants were exercisable to purchase common shares of the Company until the expiry date at the price per share as indicated below:

		Purchase Warrants					
Year of Issue	Price per Special Warrant	Issued	Exercisable	Common Shares Issuable	Value ($U.S. 000)	Expiry Date	Exercise Price per Share
			(thousands)				
2005	Cdn. $3.10	4,100	4,100	4,100	$ 2,412	April 2007	Cdn. $3.50
2005	Cdn. $3.10	1,000	1,000	1,000	534	July 2007	Cdn. $3.50
2005	U.S. $1.63	11,196	11,196	11,196	1,891	November 2007	U.S. $2.50
2005	n/a	2,000	2,000	2,000	313	November 2007	U.S. $2.00
2006	U.S.$2.23	11,400	11,400	11,400	18,805	May 2011	Cdn. $2.93
		29,696	29,696	29,696	$ 23,955		

The weighted average exercise price of the exercisable purchase warrants as at December 31, 2006 was U.S. $2.56 per share.
The Company calculated a value of $18.8 million and $5.2 million for the purchase warrants issued in 2006 and 2005. This value was calculated in accordance with the Black-Scholes (**B-S**) pricing model using a weighted average

risk-free interest rate of 4.4% and 3.1%, a dividend yield of 0.0%, a weighted average volatility factor of 75.3% and 50.9% and an expected life of 5 and 2 years for 2006 and 2005, respectively.

10. STOCK BASED COMPENSATION

The Company has an Employees and Directors Equity Incentive Plan under which it can grant stock options to directors and eligible employees to purchase common shares, issue common shares to directors and eligible employees for bonus awards and issue shares under a share purchase plan for eligible employees. The total shares under this plan cannot exceed 20 million.

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

The fair value of each option award is estimated on the date of grant using the B-S option-pricing formula and amortized on a straight-line attribution approach with the following weighted-average assumptions for the years presented:

	2006	2005	2004
Expected term (in years)	5.3	4.0	4.0
Volatility	82.6%	77.3%	107.6%
Dividend Yield	0.0%	0.0%	0.0%
Risk-free rate	4.3%	3.5%	4.0%

The Company s expected term represents the period that the Company s stock-based awards are expected to be outstanding and was determined based on historical experience of similar awards, giving consideration to the contractual terms of the stock-based awards, vesting schedules and expectations of future employee behavior as influenced by changes to the terms of its stock-based awards. The fair values of stock-based payments were valued using the B-S valuation method with an expected volatility factor based on the Company s historical stock prices. The B-S valuation model calls for a single expected dividend yield as an input. The Company has not paid and does not anticipate paying any dividends in the near future. The Company bases the risk-free interest rate used in the B-S valuation method on the implied yield currently available on Canadian zero-coupon issue bonds with an equivalent remaining term. When estimating forfeitures, the Company considers historical voluntary termination behavior as well as future expectations of workforce reductions. The estimated forfeiture rate as at December 31, 2006 and 2005 is 23.0% and 24.2%. The Company recognizes compensation costs only for those equity awards expected to vest.

The weighted average grant-date fair value of stock option granted during 2006, 2005 and 2004 was Cdn.$1.92, Cdn.$1.72 and Cdn$1.93.

For the years ended December 31, 2006, 2005 and 2004 the Company s stock based compensation was $2.9 million, $2.1 million and $1.3 million, respectively.

The following table summarizes changes in the Company s outstanding stock options:

	December 31, 2006		December 31, 2005		December 31, 2004	
	Number of Stock Options (thousands)	Weighted-Average Exercise Price (Cdn.$)	Number of Stock Options (thousands)	Weighted-Average Exercise Price (Cdn.$)	Number of Stock Options (thousands)	Weighted-Average Exercise Price (Cdn.$)
Outstanding at beginning of year	10,278	$2.21	8,246	$2.65	8,949	$2.64
Granted	3,419	$3.02	3,664	$2.84	608	$2.52
Exercised	(297)	$2.05	(111)	$1.52	(975)	$2.43
Cancelled/forfeited	(1,030)	$3.40	(1,521)	$6.14	(336)	$2.96
Outstanding at end of year	12,370	$2.34	10,278	$2.21	8,246	$2.65
Options exercisable at end of year	7,720	$1.92	6,547	$1.74	6,698	$2.44

The aggregate intrinsic value of total options outstanding as well as options exercisable as at December 31, 2006 was $4.1 million. The total intrinsic value of options exercised during the year ended December 31, 2006 was $0.2 million.

The following table summarizes information respecting stock options outstanding and exercisable as at December 31, 2006:

	Stock Options Outstanding			Stock Options Exercisable		
		Weighted-Average			Weighted-Average	
Range of	Number	Remaining	Weighted-Average	Number	Remaining	Weighted-Average

Exercise Prices (Cdn.$)	Outstanding (thousands)	Contractual Life (Years)	Exercise Price (Cdn.$)	Exercisable (thousands)	Contractual Life (Years)	Exercise Price (Cdn.$)
$0.50	3,817	1.6	$ 0.50	3,817	1.6	$ 0.50
$1.56 to $2.18	630	4.0	$ 1.88	299	3.6	$ 1.91
$2.42 to $3.62	7,293	4.1	$ 3.05	3,100	3.0	$ 3.04
$5.37 to $7.00	630	1.9	$ 5.75	504	1.9	$ 5.75
$0.50 to $7.00	12,370	3.2	$ 2.34	7,720	2.3	$ 1.92

11. RETIREMENT PLAN

In 2001, the Company adopted a defined contribution retirement or thrift plan (**401(k) Plan**) to assist U.S. employees in providing for retirement or other future financial needs. Employees contributions (up to the maximum allowed by U.S. tax laws) were matched 100% by the Company in 2006. The Company s matching contributions to the 401(k) Plan were $0.4 million, $0.3 million and $0.2 million for the years ended December 31, 2006, 2005 and 2004.

12. SEGMENT INFORMATION

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

Oil and Gas

The Company explores for, develops and produces crude oil and natural gas in the U.S. and in China. The Company seeks projects requiring relatively low initial capital outlays to which it can apply innovative technology and enhanced recovery techniques in developing them. In the U.S., the Company s exploration, development and production activities are primarily conducted in California and Texas. In China, the Company s development and production activities are conducted at the Dagang oil field located in Hebei Province and exploration activities in the Zitong block located in Sichuan Province.

HTL

The Company seeks to increase its oil reserves through the deployment of our HTL Technology. The technology is intended to be used to upgrade heavy oil at facilities located in the field to produce lighter, more valuable crude. In addition, an HTL facility can yield surplus energy for producing steam and electricity used in heavy-oil production. The thermal energy from the RTP™ Process provides heavy-oil producers with an alternative to natural gas that now is widely used to generate steam.

GTL

The Company holds a master license from Syntroleum to use its proprietary GTL technology to convert natural gas into synthetic fuels. The master license allows the Company to use Syntroleum s proprietary process in an unlimited number of GTL projects throughout the world to convert natural gas into an unlimited volume of ultra clean transportation fuels and other synthetic petroleum products.

Corporate

The Company s corporate office is in Canada with its operational office in the U.S. For this note, any amounts for the corporate office in Canada are included in Corporate**.**

The accounting policies for each segment are consistent with the accounting policies disclosed in Note 2.

	Year Ended December 31, 2006					
	Oil and Gas					
	U.S.	China	HTL	GTL	Corporate	Total
Oil and gas revenue	$ 12,065	$ 35,683	$	$	$	$ 47,748
Loss on derivative instruments	(424)					(424)
Interest income	139	63			574	776
	11,780	35,746			574	48,100
Operating costs	4,299	11,834				16,133
General and administrative	1,676	1,337			7,167	10,180
Business and technology development			6,177	1,433		7,610
Depletion and depreciation	5,378	23,345	3,812	10	5	32,550
Interest expense and financing costs	290	156	10		507	963
Write off of deferred acquisition costs		736				736
Write-downs and provision for impairment		5,420				5,420
	11,643	42,828	9,999	1,443	7,679	73,592
Net Income (Loss)	$ 137	$ (7,082)	$ (9,999)	$ (1,443)	$ (7,105)	$ (25,492)
Capital Investments	$ 5,550	$ 9,086	$ 2,722	$ 484	$	$ 17,842
Identifiable Assets (As at December 31, 2006)	$ 42,158	$ 72,970	$ 107,186	$ 15,081	$ 11,149	$ 248,544

	Year ended December 31, 2005					
	Oil and Gas					
	U.S.	China	HTL	GTL	Corporate	Total
Oil and gas revenue	$ 14,069	$ 15,731	$	$	$	$ 29,800
Interest income	30	7			102	139
	14,099	15,738			102	29,939
Operating costs	5,001	2,602				7,603
General and administrative	1,178	2,076			6,275	9,529
Business and product development			3,671	1,307		4,978
Depletion and depreciation	5,039	9,378	13	11	6	14,447

Interest expense and financing costs	311		4		943	1,258
Write-downs and provision for impairment		5,000	357	279		5,636
	11,529	19,056	4,045	1,597	7,224	43,451
Net Income (Loss)	$ 2,570	$ (3,318)	$ (4,045)	$ (1,597)	$ (7,122)	$ (13,512)
Capital Investments	$ 6,514	$ 30,730	$ 4,982	$ 1,056	$	$ 43,282
Identifiable Assets (As at December 31, 2005)	$ 48,070	$ 65,020	$ 107,869	$ 14,609	$ 5,309	$ 240,877

	Year ended December 31, 2004					
	Oil and Gas					
	U.S.	China	HTL	GTL	Corporate	Total
Oil and gas revenue	$ 9,311	$ 8,484	$	$	$	$ 17,795
Interest income	10	16			176	202
	9,321	8,500			176	17,997
Operating costs	3,159	1,914				5,073
General and administrative	990	960			5,325	7,275
Business and technology development			442	1,471		1,913
Depletion and depreciation	4,594	2,864	4	16	4	7,482
Interest expense	195				184	379
Write-downs and provision for impairment	16,350			250		16,600
	25,288	5,738	446	1,737	5,513	38,722
Net Income (Loss)	$ (15,967)	$ 2,762	$ (446)	$ (1,737)	$ (5,337)	$ (20,725)
Capital Investments	$ 17,428	$ 26,965	$ 1,966	$ 95	$	$ 46,454
Identifiable Assets (As at December 31, 2004)	$ 48,465	$ 44,960	$ 2,441	$ 13,867	$ 8,753	$ 118,486

13. DERIVATIVE INSTRUMENTS

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

The Company entered into a costless collar derivative to hedge its cash flow from the sale of approximately 400-500 barrels of its U.S. oil production per day over a two year period starting November 2006. The derivative had a ceiling price of $65.20 per barrel and a floor price of $63.20 per barrel using WTI as the index traded on the NYMEX. For the year ended December 31, 2006, the Company had realized gains of $0.1 million on derivative transactions, offsetting $0.5 million of unrealized losses. Both realized and unrealized gains and losses on derivatives were recognized in the results of operations.

For the years ended December 31, 2005 and 2004 the Company had no derivative activities.

14. INCOME TAXES

The Company and its subsidiaries are required to individually file tax returns in each of the jurisdictions in which they operate. The provision for income taxes differs from the amount computed by applying the statutory income tax rate to the net losses before income taxes. The combined Canadian federal and provincial statutory rates as at December 31, 2006, 2005 and 2004 were 32.12%, 33.6% and 33.6%, respectively. The sources and tax effects for the differences were as follows**:**

Year ended December 31,

	2006	2005	2004
Tax benefit computed at the combined Canadian federal and provincial statutory income tax rates	$ (8,188)	$ (4,543)	$ (6,968)
Effect of change in effective income tax rates on future tax assets	870		(488)
Foreign net losses affected at lower income tax rates	113	1,457	(246)
Expiry of tax loss carry-forwards	1,583	1,734	977
Effect of change in foreign exchange rates	(14)	(659)	(3,433)
Stock-based compensation not deductible for income tax purposes	1,031	756	375
Tax credit carry-forward	(428)	(362)	(1,094)
Change in prior year estimate of tax loss carry-forwards	503	(368)	1,756
Other permanent differences	161		1,250
Other	(66)	16	(5)
	(4,435)	(1,969)	(7,876)
Valuation allowance	4,435	1,969	7,876
	$	$	$

Significant components of the Company s future net income tax assets and liabilities were as follows:

	As at December 31,			
	2006		2005	
	Future Income Tax		Future Income Tax	
	Assets	Liabilities	Assets	Liabilities
Oil and gas properties and investments	$	$ (22,694)	$	$ (19,673)
Intangibles		(36,778)		(36,746)
Tax loss carry-forwards	78,834		71,774	
Tax credit carry-forward	1,884		1,456	
Valuation allowance	(21,246)		(16,811)	
	$ 59,472	$ (59,472)	$ 56,419	$ (56,419)

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

The tax loss carry-forwards in Canada are Cdn. $43.4 million and in the U.S. $93.9 million. The tax loss carry-forwards in Canada expire between 2007 and 2013 and in the U.S. between 2016 and 2026. In China, the Company has available for carry-forward against future Chinese income $84.7 million of cost basis. The loss of approximately Cdn. $55.3 million from the Russian operations in 2000, being the aggregate investment, not including accounting write-downs, less proceeds received on settlement is a capital loss for Canadian income tax purposes, available for carry-forward against future Canadian capital gains indefinitely and is not included in the future income tax assets above.

15. NET LOSS PER SHARE

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

	Year ended December 31, (thousands of shares)		
	2006	2005	2004
Richfirst conversion rights	1,104	9,631	9,537
Stock options	3,292	3,211	3,796
Purchase warrants	121	862	2,107
	4,517	13,704	15,440

Richfirst had the right to exchange its working interest in the Dagang field for common shares in the Company at any time prior to eighteen months after the closing of the January 2004 Dagang field farm-out agreement (see Note 18). For purposes of this calculation, the number of the Company s common shares issuable to Richfirst upon conversion were based on Richfirst s initial investment in the Dagang field of $20.0 million converted at the average of the monthly high and low trading prices of the Company s common shares on the Toronto Stock Exchange at the average monthly U.S. dollar to Canadian dollar exchange rates during the eighteen-month period.

Additionally, the earnings per share calculations would have included the following weighted average items had the exercise prices exceeded the average market prices of the common shares:

	Year ended December 31, (thousands of shares)		
	2006	2005	2004
Stock options	7,022	5,103	3,669

Purchase warrants	25,184	9,689	4,082
Convertible debt		1,161	
	32,206	15,953	7,751

16. SUPPLEMENTAL CASH FLOW INFORMATION

Supplemental cash flow information for each of the years ended December 31 was as follows:

	Year Ended December 31, 2006	2005	2004
Cash paid during the period for:			
Income taxes	$ 5	$ 20	$ 3
Interest	$ 430	$ 1,138	$ 317
Investing and Financing activities, non-cash:			
Acquisition of oil and gas assets *(see Note 18)*			
Shares issued	$ 20,000	$	$
Debt issued	6,547		
Receivable applied to acquisition	1,746		
	$ 28,293	$	$
Shares issued for Merger *(see Note 18)*	$	$ 75,000	$
Refinance of convertible debt ***(see Note 6)***	$	$ 4,000	$
Changes in non-cash working capital items			
Operating Activities:			
Accounts receivable	$ (1,375)	$ (1,635)	$ (1,949)
Prepaid and other current assets	(434)	16	(403)
Accounts payable and accrued liabilities	(1,067)	1,840	1,704
	(2,876)	221	(648)
Investing Activities			
Accounts receivable	2,188	(2,982)	(708)
Prepaid and other current assets	(1)	457	
Accounts payable and accrued liabilities	(14,895)	14,547	3,972
	(12,708)	12,022	3,264
	$ (15,584)	$ 12,243	$ 2,616

17. RELATED PARTY TRANSACTIONS

The Company has entered into agreements with a number of entities, which are related through common directors or shareholders, to provide administrative or technical personnel, office space or facilities. The Company is billed on a cost recovery basis. The costs incurred in the normal course of business with respect to the above arrangements amounted to $3.0 million, $3.0 million and $1.6 million for the years ended December 31, 2006, 2005 and 2004, respectively. As at December 31, 2006 and 2005, amounts included in accounts payable under these arrangements were $0.3 million and $0.5 million, respectively.

18. MERGER AND ACQUISITIONS

On April 15, 2005, the Company acquired all the issued and outstanding common shares of Ensyn Group, Inc. (**Ensyn**) pursuant to a merger between Ensyn and a wholly owned subsidiary of the Company (**Merger**) in accordance with an Agreement and Plan of Merger dated December 11, 2004 (**Merger Agreement**). At the completion of the Merger the Company paid $10.0 million in cash and issued approximately 30 million common shares of the Company (**Merger Shares**) in exchange for all of the issued and outstanding Ensyn common shares. Just prior to the Merger, Ensyn spun off all of its business not related to the utilization of the application of the patented rapid thermal processing for heavy oil upgrading to a separate company that was excluded from the Merger. Ten million of the Merger Shares issued were deposited in an escrow fund and are being held to secure certain obligations on the part of the former Ensyn stockholders to indemnify the Company for damages in the event of any breaches of representations, warranties and covenants in the Merger Agreement and certain liabilities, including those arising from any failure by Ensyn to meet certain development milestones set out in the Merger Agreement. Subject to any prior claims by the Company for indemnification, one-half of the Merger Shares in this escrow fund will be released to the Ensyn shareholders as of (i) the date that the Company, Ensyn or any of their respective controlled affiliate enters into a definitive agreement with an unaffiliated third party for the construction or use of a process plant equipped with HTL Technology and having a minimum daily input processing capacity of 10,000 Bop/d (an **HTL Plant**) or (ii) the second anniversary of the closing date of the Merger, whichever is earlier. The balance of the Merger Shares will be released, subject to any prior claims by the Company for indemnification, as of (i) the date that the Company, Ensyn or any of their respective controlled affiliates enters into a second definitive agreement for the construction or use of an HTL Plant, (ii) the second anniversary of the date of the initial definitive agreement for the construction or use of any HTL Plant, or (iii) the third anniversary of the closing date of the Merger, whichever is earliest.

As part of the Merger, the Company acquired a 50% interest in a joint venture (**CDF Joint Venture**), which owned the CDF located in California s San Joaquin Basin, as well as certain rights to manufacture HTL facilities. In November 2005, the Company acquired the remaining 50% in the joint venture for $6.75 million, which effectively dissolved the joint venture. Accordingly, 100% of the net assets of the RTP™ Joint Venture were included in the Company s consolidated balance sheet as at December 31, 2005.

The January 2004 Dagang field farm-out agreement between the Company and Richfirst, provided Richfirst with the right to exchange its working interest in the Dagang field for common shares of the Company at any time prior to eighteen months after the closing of the farm-out transaction contemplated by the agreement. Richfirst elected to exchange its 40% working interest in the Dagang field and, in February 2006, the Company re-acquired Richfirst s 40% working interest for total consideration of $28.3 million consisting of $20.0 million paid by way of the issuance to Richfirst of 8,591,434 common shares of the Company, a non-interest bearing, unsecured promissory note in the principal amount approximately $7.4 million ($6.5 million after being discounted to net present value) and the forgiveness of $1.8 million of unpaid joint venture receivables. The promissory note is payable in 36 equal monthly installments commencing March 31, 2006. The Company has the right, during the three-year loan repayment period, to require Richfirst to convert the remaining unpaid balance of the promissory note into common shares of Sunwing Energy Ltd (**Sunwing**), the Company s wholly-owned subsidiary, or another company owning all of the outstanding shares of Sunwing, subject to Sunwing or the other company having obtained a listing of its common shares on a prescribed stock exchange. The number of shares issued would be determined by dividing the then outstanding principal balance under the promissory note by the issue price of shares of the newly listed company issued in the transaction that results in the listing, less a 10% discount.

In February 2006, the Company signed a non-binding memorandum of understanding regarding a proposed merger of Sunwing with China Mineral Acquisition Corporation (**CMA**), a U.S. public corporation. In May 2006 the parties entered a definitive agreement for the transaction which was later terminated. As a result, the Company wrote off deferred acquisition costs previously capitalized in the amount of $0.7 million.

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

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

Consolidated Balance Sheets

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

Shareholders Equity and Oil and Gas Properties and Investments

	As at December 31, 2006					
	Oil and Gas Properties and Investments	Derivative Instruments	Shareholders Equity Share Capital and Warrants	Contributed Surplus	Accumulated Deficit	Total
Canadian GAAP	$ 121,918	$ 493	$ 342,680	$ 6,489	$ (120,783)	$ 228,386
Adjustments for:						
Reduction in stated capital (i)			74,455		(74,455)	
Accounting for stock based compensation (ii)			(387)	(3,361)	3,748	
Ascribed value of shares issued for U.S. royalty interests, net (iv)	1,358		1,358			1,358
Fair value adjustment of derivative instruments (iii)		6,378	(8,552)		2,174	(6,378)
Provision for impairment (v)	(26,270)				(26,270)	(26,270)
Depletion adjustments due to differences in provision for impairment (vi)	4,402				4,402	4,402
HTL and GTL development costs expensed (vii)	(11,669)				(11,669)	(11,669)
U.S. GAAP	$ 89,739	$ 6,871	$ 409,554	$ 3,128	$ (222,853)	$ 189,829

	As at December 31, 2005					
	Oil and Gas Properties and Investments	Derivative Instruments - as restated (See Note 19 iii)	Shareholders Equity (as restated - see Note 19 iii) Share Capital and Warrants	Contributed Surplus	Accumulated Deficit	Total
Canadian GAAP	$ 119,654	$	$ 296,238	$ 3,820	$ (95,291)	$ 204,767
Adjustments for:						
Reduction in stated capital (i)			74,455		(74,455)	
Accounting for stock based compensation (ii)			(316)	(3,432)	3,748	
	1,358		1,358			1,358

Ascribed value of shares issued for U.S. royalty interests, net (iv)						
Fair value adjustment of derivative instruments (iii)		80	(2,946)		2,866	(80)
Provision for impairment (v)	(8,150)				(8,150)	(8,150)
Depletion adjustments due to differences in provision for impairment (vi)	1,562				1,562	1,562
HTL and GTL development costs expensed (vii)	(10,712)				(10,712)	(10,712)
U.S. GAAP	$ 103,712	$ 80	$ 368,789	$ 388	$ (180,432)	$ 188,745

Shareholders Equity

(i) In June 1999, the shareholders approved a reduction of stated capital in respect of the common shares by an amount of $74.5 million being equal to the accumulated deficit as at December 31, 1998. Under U.S. GAAP, a reduction of the accumulated deficit such as this is not recognized except in the case of a quasi reorganization. The effect of this is that under U.S. GAAP, share capital and accumulated deficit are increased by $74.5 million as at December 31, 2006 and 2005.

(ii) For Canadian GAAP, the Company accounts for all stock options granted to employees and directors since January 1, 2002 using the fair value based method of accounting. Under this method, compensation costs are recognized in the financial statements over the stock options vesting period using an option-pricing model for determining the fair value of the stock options at the grant date. For U.S. GAAP, prior to January 1, 2006 the Company applied APB Opinion No. 25, as interpreted by FASB Interpretation No. 44, in accounting for its stock option plan and did not recognize compensation costs in its financial statements for stock options issued to employees and directors. This resulted in a reduction of $3.7 million in the accumulated deficit as at December 31, 2006 and 2005, equal to accumulated stock based compensation for stock options granted to employees and directors since January 1, 2002 expensed through December 31, 2005 under Canadian GAAP.

In December 2004, the Financial Accounting Standards Board (**FASB**) issued a revision to SFAS No. 123, Accounting for Stock Based Compensation which supersedes APB No. 25, Accounting for Stock Issued to Employees . This statement (**SFAS No. 123(R)**) requires measurement of the cost of employee services received in exchange for an award of equity instruments based on the fair value of the award on the date of the grant and recognition of the cost in the results of operations over the period during which an employee is required to provide service in exchange for the award. No compensation cost is recognized for equity instruments for which employees do not render the requisite service. The Company elected to implement this statement on a modified prospective basis starting in the first quarter of 2006. Under the modified prospective basis the Company began recognizing stock based compensation in its U.S. GAAP results of operations for the unvested portion of awards outstanding as at January 1, 2006 and for all awards granted after January 1, 2006. There were no differences in the Company s stock based compensation expense in its financial statements for Canadian GAAP and U.S. GAAP for the year ended December 31, 2006.

(iii) The Company has restated its U.S. GAAP financial position as at December 31, 2005 and results of operations for the year ended December 31, 2005, to correct the accounting treatment of warrants for U.S. GAAP purposes. The warrants that are subject to restatement were issued in 2005. Previously, the Company accounted for these instruments as equity under both Canadian and U.S. GAAP. The treatment of warrants was changed under U.S. GAAP to correct for the application of Statement of Financial Accounting Standard No. 133 Accounting for Derivative Instruments and Hedging Activities (**SFAS No. 133**). Under SFAS No. 133, share purchase warrants with an exercise price denominated in a currency other than the company s functional currency are accounted for as derivative liabilities. Changes in the fair value of the warrants are required to be recognized in the statement of operations each reporting period for U.S. GAAP purposes. Under the Company s previous U.S. GAAP accounting treatment, no changes in fair value were recorded. At the time that the Company s share purchase warrants are exercised, the value of the warrants will be reclassified to shareholders equity for US GAAP purposes. Under Canadian GAAP, the fair value of the warrants on the issue date is recorded as a reduction to the proceeds from the issuance of common shares, with the offset to the warrant component of equity. The warrants are not revalued to fair value under Canadian GAAP. The cumulative effects of the restatement as at December 31, 2005 are as follows: an increase in liabilities of $0.1 million, a decrease in purchase warrants classified within shareholders equity of $2.9 million, and a decrease in accumulated deficit of $2.9 million.

The following table outlines the impact of the restatement on previously reported U.S. GAAP balances as at December 31, 2005:

	As previously reported	Adjustments	As Restated
Derivative liability		80	80
Share Capital and Warrants	371,735	(2,946)	368,789
Accumulated deficit	(183,298)	2,866	(180,432)
Shareholders equity	188,825	(80)	188,745
Net loss	(14,972)	2,866	(12,106)
Net loss per share basic and diluted	(0.07)	0.01	(0.06)

<u>Oil and Gas Properties and Investments</u>

(iv) For U.S. GAAP purposes, the aggregate value attributed to the acquisition of U.S. royalty rights during 1999 and 2000 was $1.4 million higher, due to the difference between Canadian and U.S. GAAP in the value ascribed to the shares issued, primarily resulting from differences in the recognition of effective dates of the transactions.

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

properties that have been excluded from the depletion calculation. In the measurement of the impairment, the future net cash flows of a cost center s proved and probable reserves are discounted using a risk-free interest rate.
In the ceiling test evaluation for U.S. GAAP purposes, under Regulation S-X, future net cash flows from proved reserves using period-end, non-escalated prices and costs, are discounted to present value at 10% per annum and compared to the carrying value of oil and gas properties. The Company performed the ceiling test in accordance with U.S. GAAP and determined that for 2006 an impairment provision of $15.9 million was required on its China properties compared to a $5.4 million impairment provision under Canadian GAAP. For the Company s U.S. properties, a $7.6 million impairment was required for 2006 on its U.S. properties compared to no impairment being required for Canadian GAAP. The differences in the ceiling test impairments by period for the U.S. and China properties between U.S. and Canadian GAAP as at December 31, 2006 are as follows:

	Ceiling Test Impairments		(Increase)
	U.S. GAAP	Canadian GAAP	Decrease
U.S. Properties			
Prior to 2004	$ 34,000	$ 34,000	$
2004	15,000	16,350	1,350
2005	2,800		(2,800)
2006	7,600		(7,600)
	59,400	50,350	(9,050)
China Properties			
Prior to 2004	10,000		(10,000)
2004			
2005	1,700	5,000	3,300
2006	15,940	5,420	(10,520)
	27,640	10,420	(17,220)
	$ 87,040	$ 60,770	$ (26,270)

(vi) The differences in the amount of impairment provisions between U.S. and Canadian GAAP resulted in a reduction in accumulated depletion of $4.4 million and $1.6 million as at December 31, 2006 and 2005, respectively.

(vii) As more fully described under Investments in HTL and GTL Projects in Note 2, for Canadian GAAP the Company capitalizes certain costs incurred for HTL and GTL projects subsequent to executing an MOU to determine the technical and commercial feasibility of a project, including studies for the marketability for the project s products. If no definitive agreement is reached, then the project s capitalized costs, which are deemed to have no future value, are written down and charged to the results of operations with a corresponding reduction in the investments in HTL and GTL assets. For U.S. GAAP, feasibility, marketing and related costs incurred prior to executing a HTL or GTL definitive agreement are considered to be research and development and are expensed as incurred. As at December 31, 2006 and 2005, the Company capitalized $11.7 million and $10.7 million, respectively, for Canadian GAAP, which was expensed for U.S. GAAP purposes.

Consolidated Statements of Operations

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

	Year ended December 31,	
2006	2005	2004

	Net Loss	**Net Loss Per Share**	**Net Loss - as restated (See Note 20 iii)**	**Net Loss Per Share - as restated (See Note 20 iii)**	**Net Loss**	**Net Loss Per Share**
Canadian GAAP	$ (25,492)	$ (0.11)	$ (13,512)	$ (0.07)	$ (20,725)	$ (0.12)
Stock based compensation expense (viii)			1,788	0.01	1,173	0.01
Provision for impairment (v and ix)	(18,120)	(0.08)	500		1,350	0.01
Depletion adjustments due to differences in provision for impairment (ix)	2,840	0.01	1,080	0.01	316	
HTL and GTL development costs expensed, net (x)	(958)		(4,828)	(0.02)	(1,810)	(0.02)
Fair value adjustment of derivative instruments (iii)	(692)		2,866	0.01		
U.S. GAAP	$ (42,422)	$ (0.18)	$ (12,106)	$ (0.06)	$ (19,696)	$ (0.12)
Weighted Average Number of Shares under U.S. GAAP (in thousands)		235,640		195,803		167,612

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(viii) As more fully discussed under Stock Based Compensation in Note 2, for Canadian GAAP the Company recognizes compensation costs using the fair value based method of accounting for stock options granted to employees and directors after January 1, 2002. As discussed under Shareholders Equity in this note, for U.S. GAAP, the Company applied APB Opinion No. 25, as interpreted by FASB Interpretation No. 44, in accounting for its stock option plan and did not recognize compensation costs in its financial statements for stock options issued to employees and directors prior to January 1, 2006. This resulted in a reduction of $1.8 million and $1.2 million in the net losses for the years ended December 31, 2005 and 2004. Also, discussed under Shareholders Equity in this note, for U.S. GAAP, the Company implemented SFAS 123(R) on January 1, 2006 which resulted in no differences in stock based compensation expense for the year ended December 31, 2006.

(ix) As discussed under Oil and Gas Properties and Investments in this note, there is a difference in performing the ceiling test evaluation under the full cost method of accounting between U.S. and Canadian GAAP. Application of the ceiling test evaluation under U.S. GAAP has resulted in an accumulated net increase in impairment provisions on the Company s U.S. and China oil and gas properties of $26.3 million as at December 31, 2006. This net increase in U.S. GAAP impairment provisions has resulted in lower depletion rates for U.S. GAAP purposes and a reduction of $2.8 million, $1.1 million and $0.3 million in the net losses for the years ended December 31, 2006, 2005 and 2004.

(x) As more fully described under Oil and Gas Properties and Investments in this note, for Canadian GAAP, feasibility, marketing and related costs incurred prior to executing a HTL or GTL definitive agreement are capitalized and are subsequently written down upon determination that a project s future value has been impaired. For U.S. GAAP, such costs are considered to be research and development and are expensed as incurred. For the years ended December 31, 2006, 2005 and 2004, the Company expensed $1.0 million, $4.8 million and $1.8 million, respectively, in excess of the Canadian GAAP write-downs during those corresponding years.

Stock Based Compensation

Had stock based compensation expense been determined based on fair value at the stock option grant date, consistent with the method of SFAS No. 123, Accounting for Stock Based Compensation , prior to January 1, 2006 the Company s net loss and net loss per share would have been increased to the pro forma amounts indicated below:

	Year ended December 31, 2005	2004
Net loss under U.S. GAAP	$ (12,106)	$ (19,696)
Stock-based compensation expense determined under the fair value based method for employee and director awards	(1,911)	(1,869)
Pro forma net loss under U.S. GAAP	$ (14,017)	$ (21,565)
Basic loss per common share under U.S. GAAP:		
As reported	$ (0.06)	$ (0.12)
Pro forma	$ (0.07)	$ (0.13)
Weighted Average Number of Shares under U.S. GAAP (in thousands)	195,803	167,612
Stock options granted during the period (thousands)	2,889	458
Weighted average exercise price	$ 2.41	$ 1.88
Weighted average fair value of options granted during the year	$ 1.52	$ 1.40

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

A summary of the Company s unvested options as at December 31, 2006, and changes during the year then ended, is presented below:

	Number of Stock Options (thousands)	Weighted-Average Grant Date Fair Value (Cdn.$)
Outstanding at December 31, 2005	3,731	$ 1.47
Granted	3,419	$ 1.46
Vested	(2,084)	$ 1.48
Cancelled/forfeited	(416)	$ 1.39
Outstanding at December 31, 2006	4,650	$ 1.46

As at December 31, 2006, there was $9.1 million of total unrecognized compensation costs related to unvested share-based compensation arrangements granted by the Company. That cost is expected to be recognized over a weighted-average period of 1.9 years. The total fair value of shares vested during the year ended December 31, 2006 was $3.1 million.

Pro Forma Effect of Merger and Acquisition

The Company s U.S. GAAP consolidated results of operations for the year ended December 31, 2005 included a net loss of $2.0 million, or $0.01 per share, associated with the operations acquired from Ensyn after the completion of the Merger on April 15, 2005. Had the Merger been completed on January 1, 2005 or 2004, the U.S. GAAP pro forma revenue, net loss and net loss per share of the merged entity for the years ended December 31, 2005 and 2004 would have been as follows:

	Year Ended December 31, (unaudited)					
	2005			2004		
	Revenue	Net Loss	Net Loss Per Share	Revenue	Net Loss	Net Loss Per Share
As reported	$ 29,939	$ (12,106)	$ (0.06)	$ 17,997	$ (19,696)	$ (0.12)
Pro forma adjustments	736	(730)		371	(2,248)	
	$ 30,675	$ (12,836)	$ (0.06)	$ 18,368	$ (21,944)	$ (0.12)
Pro Forma Weighted Average Number of Shares (in thousands)			204,186			197,612

Had the acquisition of Richfirst s 40% working interest in the Dagang field been completed January 1, 2006 or 2005, the U.S. GAAP pro forma revenue, net loss and net loss per share of the consolidated operations for the years ended December 31, 2006 and 2005 would have been as follows:

	Year ended December 31, (unaudited)					
	2006			2005		
	Revenue	Net Income (Loss)	Net Income (Loss) Per Share	Revenue	Net Income (Loss)	Net Income (Loss) Per Share
As reported	$ 48,100	$ (42,422)	$ (0.18)	$ 29,939	$ (12,106)	$ (0.06)
Pro forma adjustments	1,051	809		9,336	3,419	0.02
	$ 49,151	$ (41,613)	$ (0.18)	$ 39,275	$ (8,687)	$ (0.04)
Pro Forma Weighted Average Number of Shares (in thousands)			236,840			204,394

Consolidated Statements of Cash Flow

As a result of the expensing of HTL and GTL development costs as required under U.S. GAAP, the statement of cash flow as reported would result in cash from operating activities of $13.3 million, $5.0 million and $2.2 million for the years ended December 31, 2006, 2005 and 2004. Additionally, capital investments reported under investing activities would be $16.8 million, $38.5 million and $44.6 million for the years ended December 31, 2006, 2005 and 2004, respectively.

Additional U.S. GAAP Disclosures

Oil and Gas Properties and Investments

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

	As at December 31, 2006			As at December 31, 2005		
	U.S.	China	Total	U.S.	China	Total
Property acquisition costs	$ 21,494	$ 31,137	$ 52,631	$ 20,613	$ 2,418	$ 23,031
Royalty rights acquired	10,582		10,582	10,582		10,582
Exploration costs	42,519	18,010	60,529	41,289	15,525	56,814
Development costs	35,412	65,014	100,426	38,272	58,861	97,133
Commercial demonstration facility	12,104		12,104	9,600		9,600
Support equipment and general property	685	329	1,014	556	315	871
	122,796	114,490	237,286	120,912	77,119	198,031
Accumulated depletion and depreciation	(24,717)	(35,790)	(60,507)	(16,015)	(14,804)	(30,819)
Provision for impairment	(59,400)	(27,640)	(87,040)	(51,800)	(11,700)	(63,500)
	$ 38,679	$ 51,060	$ 89,739	$ 53,097	$ 50,615	$ 103,712

U.S. development costs as at December 31, 2006, 2005 and 2004 included $1.2 million, $1.5 million and $0.6 million, respectively, of asset retirement costs.

As at December 31, 2006, the costs of unproved properties included in oil and gas properties, which have been excluded from the depletion and ceiling test calculations, were as follows:

		Incurred in			
	Total	2006	2005	2004	Prior to 2004
Property Acquisition	$ 2,568	$ 248	$ (145)	$ 448	$ 2,017
Royalty rights	659				659
Exploration	10,849	2,427	3,715	3,008	1,699
	$ 14,076	$ 2,675	$ 3,570	$ 3,456	$ 4,375

The following is a summary of unproved oil and gas properties by prospect for the U.S. and China cost centers as at December 31, 2006:

		Incurred in			
	Total	**2006**	**2005**	**2004**	**Prior to 2004**
U.S.					
North Yowlumne	1,149	135	(35)	288	761
Knights Landing	2,158	310	1,848		
East Texas	176	26	(9)	8	151
San Joaquin Basin prospects other	2,314	104	59	193	1,958
	5,797	575	1,863	489	2,870
China					
Zitong Block	8,279	2,100	1,707	2,967	1,505
	$ 14,076	$ 2,675	$ 3,570	$ 3,456	$ 4,375

In March 2007, the Company assigned its rights to the North Yowlumne prospect for $1 million and retained a carried 15% working interest in future drilling of the prospect.

Accounts Payable and Accrued Liabilities

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

	As at December 31,	
	2006	**2005**
Accounts payable and accruals	$ 9,231	$ 23,955
Accrued salaries and related expenses	76	1,397
Accrued interest	11	22
Other accruals	110	417
	$ 9,428	$ 25,791

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

In February 2007, the Financial Accounting Standards Board (**FASB**) issued Statement of Financial Accounting Standards No. 159, The Fair Value Option for Financial Assets and Financial Liabilities (including an amendment of FASB Statement No. 115) (**SFAS No. 159**). The statement would create a fair value option under which an entity may irrevocably elect fair value as the initial and subsequent measurement attribute for certain financial assets and financial liabilities on a contract-by-contract basis, with changes in fair value recognized in earnings as those changes occur. This Statement is effective as of the beginning of an entity s first fiscal year that begins after November 15, 2007. Management is in the process of reviewing the requirements of this recent statement.

In December 2006, the FASB published an exposure draft titled Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement 133 . The proposed Statement would amend and expand the disclosure requirements in FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, and other related literature. This proposed Statement is intended to provide an enhanced understanding of how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and how derivative instruments affect an entity s financial position, results of operations, and cash flows. Management is in the process of reviewing the requirements of this recent proposed statement

In September 2006, the U.S. Securities and Exchange Commission issued Staff Accounting Bulletin 108 (**SAB 108**). The interpretations in this bulletin express the staff s views regarding the process of quantifying financial statement misstatements and are being issued to address diversity in practice in quantifying financial statement misstatements and the potential under current practice for the build up of improper amounts on the balance sheet. SAB 108 did not have a material impact on the Company s financial statements.

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 157, Fair Value Measurements (**SFAS No. 157**). This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. This statement does not require any new fair value measurements; however, for some entities the application of this statement will change current practice. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years, although early adoption is permitted. Management is in the process of reviewing the requirements of this recent statement.

In June 2006, the FASB issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109 (**FIN 48**). The interpretation clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with SFAS No. 109, Accounting for Income Taxes. The evaluation of a tax position in accordance with this interpretation is a two-step process. Under the recognition step an enterprise determines whether it is more likely than not that a tax position will be sustained upon examination based on the technical merits of the position. Under the measurement step a tax position that meets the more-likely-than-not recognition threshold is measured to determine the amount of benefit to recognize in the financial statements. The tax position is measured at the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. FIN 48 is effective for fiscal years beginning after December 15, 2006. Earlier application of the provisions of this interpretation is encouraged if the enterprise has not yet issued financial statements, including interim financial statements, in the period this interpretation is adopted. Management does not believe the requirements of this interpretation will have a material impact on its financial statements.

In February 2006, the FASB issued SFAS No. 155, Accounting for Certain Hybrid Financial Instruments an amendment of FASB statements No. 133 and 140 (**SFAS No. 155**). SFAS No. 155 resolves issues surrounding the application of the bifurcation requirements to beneficial interests in securitized financial assets. In general, this statement permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation. SFAS No. 155 is effective for all financial instruments acquired or issued after the beginning of an entity s first fiscal year that begins after September 15, 2006 and is not expected to have a material impact on the Company s financial statements.

In May 2005, the FASB issued SFAS No. 154 (**SFAS No. 154**) Accounting Changes and Error Corrections a replacement of APB Opinion No. 20 and FASB Statement No. 3 . SFAS No. 154 changes the requirements for the accounting for and reporting of a change in accounting principle. APB Opinion No. 20 previously required that most voluntary changes in accounting principle be recognized by including in net income of the period of the change the cumulative effect of changing to the new accounting principle. SFAS No. 154 requires retrospective application to prior periods financial statements for changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS No. 154 applies to all voluntary changes in accounting principle. SFAS No. 154 also applies to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. When a pronouncement includes specific transition provisions, those provisions should be followed. SFAS No. 154 carries forward without change to the guidance contained in APB Opinion No. 20 for reporting the correction of an error in previously issued financial statements and a change in accounting estimate. SFAS No. 154 also carries forward the guidance in APB Opinion No. 20 requiring justification of a change in accounting principle on the basis of preferability. SFAS No. 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. The impact of this Statement is determined as changes in accounting policies are needed in the financial statements.

On September 30, 2005, the FASB issued an Exposure Draft that would amend SFAS No. 128, Earnings per Share , to clarify guidance for mandatorily convertible instruments, the treasury stock method, contracts that may be settled in cash or shares and contingently issuable shares. The proposed Statement would be effective for interim and annual periods ending after June 15, 2006. Retrospective application would be required for all changes to SFAS No. 128, except that retrospective application would be prohibited for contracts that were either settled in cash to prior adoption to require cash settlement. Management is in the process of reviewing the requirements of this recent exposure draft.

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

	QUARTER ENDED							
	2006				2005			
	4th Qtr	3rd Qtr (restated)	2nd Qtr (restated)	1st Qtr (restated)	4th Qtr (restated)	3rd Qtr (restated)	2nd Qtr (restated)	1st Qtr
Total revenue	$ 11,137	$ 14,015	$ 13,084	$ 9,864	$ 8,651	$ 8,907	$ 6,645	$ 5,736
Net loss:								
Canadian GAAP	$ (11,323)	$ (4,388)	$ (4,405)	$ (5,376)	$ (8,885)	$ (2,113)	$ (1,031)	$ (1,483)
U.S. GAAP as originally reported	$ (18,255)	$ (7,117)	$ (3,982)	$ (12,112)	$ (8,557)	$ (1,843)	$ (1,564)	$ (3,008)
Prior period adjustment		*1,695*	*1,653*	*(4,304)*	*1,012*	*2,373*	*(519)*	
U.S. GAAP as restated	$ (18,255)	$ (5,422)	$ (2,329)	$ (16,416)	$ (7,545)	$ 530	$ (2,083)	$ (3,008)
Net loss per share:								
Canadian GAAP	$ (0.05)	$ (0.02)	$ (0.02)	$ (0.02)	$ (0.04)	$ (0.01)	$ (0.01)	$ (0.01)
U.S. GAAP as originally reported	$ (0.07)	$ (0.03)	$ (0.02)	$ (0.05)	$ (0.03)	$ (0.01)	$ (0.01)	$ (0.02)
Prior period adjustment		*0.01*	*0.01*	*(0.02)*		*0.01*		
U.S. GAAP as restated	$ (0.07)	$ (0.03)	$ (0.01)	$ (0.07)	$ (0.03)	$ 0.00	$ (0.01)	$ (0.02)

The Company has restated its U.S. GAAP financial position for certain of the quarters in fiscal 2006 and 2005 to correct the accounting treatment of warrants for U.S. GAAP purposes (as noted in the above table). The warrants that are subject to restatement were issued in 2005 and 2006. Previously, the Company accounted for these instruments as equity under both Canadian and U.S. GAAP. The treatment of warrants was changed under U.S. GAAP to correct for the application of Statement of Financial Accounting Standard No. 133 Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133). Under SFAS No. 133, share purchase warrants with an exercise price denominated in a currency other than the company s functional currency are accounted for as derivative liabilities. Changes in the fair value of the warrants are required to be recognized in the statement of operations each reporting period for U.S. GAAP purposes. Under the Company s previous U.S. GAAP accounting treatment, no changes in fair value were recorded. At the time that the Company s share purchase warrants are exercised, the value of the warrants will be reclassified to shareholders equity for US GAAP purposes. Under Canadian GAAP, the fair value of the warrants on the issue date is recorded as a reduction to the proceeds from the issuance of common shares, with the offset to the warrant component of equity. The warrants are not revalued to fair value under Canadian GAAP. The above table presents the impact on the affected quarters.

The Canadian GAAP net loss in the fourth quarter of 2006 was primarily due to an impairment provision of $4.8 million for the China oil and gas properties. The U.S. GAAP loss in the fourth quarter of 2006 was primarily due to impairment provisions of $8.3 million and $4.5 million for the China and U.S. oil and gas properties, respectively.

The Canadian GAAP net loss in the fourth quarter of 2005 was primarily due to an impairment provision of $5.0 million for the China oil and gas properties. The U.S. GAAP loss in the fourth quarter of 2005 was primarily due to impairment provisions of $1.7 million and $2.8 million for the China and U.S. oil and gas properties, respectively.

SUPPLEMENTARY DISCLOSURES ABOUT OIL AND GAS PRODUCTION ACTIVITIES (UNAUDITED)

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

Oil and Gas Reserves

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

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

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

Reserves presented in this section represent the Company s share of reserves, excluding royalty interests of others. The reserves were based on the estimates by the independent petroleum engineering firms of GLJ Petroleum Consultants Ltd. and Netherland, Sewell & Associates, Inc. for the China and U.S. reserves, respectively.

The changes in the Company s net proved oil and gas reserves for the three-year period ended December 31, 2006 were as follows:

	Oil (MBbl)			Gas (MMcf)
	U.S.	**China**	**Total**	**U.S.**
Net proved reserves, December 31, 2003	1,563	15,699	17,262	695
Revisions of previous estimates	(121)	(1,360)	(1,481)	87
Extensions and discoveries	240		240	1,289
Purchases of reserves in place				819
Production	(234)	(235)	(469)	(207)
Sale of reserves in place	(18)	(6,196)	(6,214)	
Net proved reserves, December 31, 2004	1,430	7,908	9,338	2,683
Revisions of previous estimates	60	(6,293)	(6,233)	(601)
Extensions and discoveries	19		19	98
Production	(237)	(315)	(552)	(495)
Net proved reserves, December 31, 2005	1,272	1,300	2,572	1,685
Revisions of previous estimates	54	179	233	(214)
Extensions and discoveries	189		189	
Purchases of reserves in place		881	881	
Production	(208)	(575)	(783)	(66)
Sale of reserves in place	(87)		(87)	(988)
Net proved reserves, December 31, 2006	1,220	1,785	3,005	417
Net proved developed reserves as at:				
December 31, 2004	1,187	1,142	2,329	2,365
December 31, 2005	1,099	1,071	2,170	1,405
December 31, 2006	1,003	1,330	2,333	417

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

The following standardized measure of discounted future net cash flows from proved oil and gas reserves was computed using period end statutory tax rates, costs and prices of $55.33, $55.77 and $40.25 per barrel of oil in 2006, 2005 and 2004, respectively, and $5.64, $9.80 and $5.94 per Mcf of gas in 2006, 2005 and 2004, respectively. A discount rate of 10% was applied in determining the standardized measure of discounted future net cash flows.

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

- future production from proved reserves will differ from estimated production;
- future production will also include production from probable and potential reserves;
- future, rather than year end, prices and costs will apply; and

existing economic, operating and regulatory conditions are subject to change.

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

	2006		
	U.S.	China	Total
Future cash inflows	$ 65,101	$ 103,526	$ 168,627
Future development and restoration costs	2,990	11,660	14,650
Future production costs	31,691	38,369	70,060
Future net cash flows	30,420	53,497	83,917
10% annual discount	7,332	10,705	18,037
Standardized measure	$ 23,088	$ 42,792	$ 65,880

	2005		
	U.S.	China	Total
Future cash inflows	$ 83,418	$ 76,533	$ 159,951
Future development and restoration costs	2,890	8,136	11,026
Future production costs	32,699	12,828	45,527
Future income taxes		1,584	1,584
Future net cash flows	47,829	53,985	101,814
10% annual discount	15,655	10,686	26,341
Standardized measure	$ 32,174	$ 43,299	$ 75,473

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

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

	2006		
	U.S.	China	Total
Sale of oil and gas, net of production costs	$ (7,766)	$ (23,849)	$ (31,615)
Net changes in prices and production costs	(4,851)	(12,907)	(17,758)
Extensions and discoveries, net of future production and development costs	1,355		1,355
Net change in future development costs	(682)	(7,800)	(8,482)
	2,572	4,686	7,258

Development costs incurred during the period that reduced future development costs			
Revisions of previous quantity estimates	319	5,187	5,506
Accretion of discount	3,217	4,664	7,881
Net change in income taxes		815	815
Purchases of reserves in place		25,645	25,645
Sale of reserves in place	(4,405)		(4,405)
Changes in production rates (timing) and other	1,155	3,052	4,207
Decrease	(9,086)	(507)	(9,593)
Standardized measure, beginning of year	32,174	43,299	75,473
Standardized measure, end of year	$ 23,088	$ 42,792	$ 65,880

	2005		
	U.S.	China	Total
Sale of oil and gas, net of production costs	$ (9,068)	$ (13,129)	$ (22,197)
Net changes in prices and production costs	15,110	20,016	35,126
Extensions and discoveries	1,051		1,051
Net change in future development costs	(694)	46,380	45,686
Revisions of previous quantity estimates	(1,492)	(150,588)	(152,080)
Accretion of discount	5,078	26,798	31,876
Net change in income taxes		24,993	24,993
Increase (decrease)	9,985	(45,530)	(35,545)
Standardized measure, beginning of year	22,189	88,829	111,018
Standardized measure, end of year	$ 32,174	$ 43,299	$ 75,473

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

Costs incurred in oil and gas property acquisition, exploration, and development activities for the Company s U.S. and China properties were as follows:

	For the year ended December 31,		
	2006	2005	2004
U.S.			
Property acquisition			
Proved	$	$	$ 3,204
Unproved	881	(1,682)	1,572
Exploration	1,230	6,169	4,351
Development	3,465	2,912	8,389
	5,576	7,399	17,516

China

Property acquisition			
Proved	28,719		
Exploration	2,485	6,931	6,925
Development	6,153	23,756	19,975
	37,357	30,687	26,900
Total	$ 42,933	$ 38,086	$ 44,416

The credit in U.S. unproved property acquisition additions for the year ended December 31, 2005 included the $1.6 million commitment payment received from Unocal as discussed in Note 4.

U.S. development cost additions for the years ended December 31, 2006, 2005 and 2004 included $0.1 million, $1.0 million and $0.2 million of asset retirement costs, respectively.

The U.S. GAAP depletion rates, calculated on a per unit of net production basis, were as follows:

U.S.	
Year ended December 31, 2006	$ 22.11
Year ended December 31, 2005	$ 14.91
Year ended December 31, 2004	$ 16.52

China

Year ended December 31, 2006	$36.46
Year ended December 31, 2005	$27.00
Year ended December 31, 2004	$11.19

The results of operations from producing activities for the years ended December 31 were as follows:

		2006			2005			2004	
	U.S.	China	Total	U.S.	China	Total	U.S.	China	Total
Oil and gas revenue	$ 12,065	$ 35,683	$ 47,748	$ 14,069	$ 15,731	$ 29,800	$ 9,311	$ 8,484	$ 17,795
Operating costs	4,299	11,834	16,133	5,001	2,602	7,603	3,159	1,914	5,073
Depletion	4,858	20,967	25,824	4,756	8,507	13,263	4,428	2,633	7,061
Provision for impairment	7,600	15,940	23,540	2,800	1,700	4,500	15,000		15,000
Results of operations from producing activities	$ (4,692)	$ (13,058)	$ (17,749)	$ 1,512	$ 2,922	$ 4,434	$ (13,276)	$ 3,937	$ (9,339)

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

The Company s management, including our Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the design and operation of the Company s disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of December 31, 2006. Based upon this evaluation, management concluded that these controls and procedures were (1) designed to ensure that information required to be disclosed in the Company s reports under the Exchange Act is accumulated and communicated to the Company s Chief Executive Officer and Chief Financial Officer and (2) effective in accomplishing those objectives, in that they provide reasonable assurance that information required to be disclosed by the Company in the reports that it files or submits under the Securities Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms. Any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives.

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed by, or under the supervision of, the Company s principal executive and principal financial officers and effected by the Company s board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that:

Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company;

Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and

Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. The Company s management assessed the effectiveness of the Company s internal control over financial reporting as of December 31, 2006. In making this assessment, the Company s management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework.* Based on our assessment, management has concluded that, as of December 31, 2006, the Company s internal control over financial reporting was effective based on those criteria. Management has reviewed the results of its assessment with the Audit Committee of the Board of Directors. The Company s independent registered Chartered

Accountants, Deloitte & Touche LLP, has audited our assessment of the effectiveness of the Company s internal control over financial reporting as of December 31, 2006, as stated in their report which immediately follows.

/s/ Joseph I. Gasca	/s/ W. Gordon Lancaster
Joseph I. Gasca	W. Gordon Lancaster
President and Chief Executive Officer	Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Shareholders of
Ivanhoe Energy Inc.:

We have audited management s assessment, included in the accompanying Management Report on Internal Control Over Financial Reporting, that Ivanhoe Energy Inc. (the Company) maintained effective internal control over financial reporting as of December 31, 2006, based on the criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of the Company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed by, or under the supervision of, the company s principal executive and principal financial officers, or persons performing similar functions, and effected by the company s board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management s assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2006 of the Company and our report dated March 7, 2007 expressed an unqualified opinion on those financial statements and includes a separate paragraph referring to a restatement of the financial statements and a separate report titled Comments by Independent Registered Chartered Accountants on Canada United States of America Reporting Differences referring to conditions and events that cast substantial doubt on the Company s ability to continue as a going concern and a change in accounting principle.

(signed) Deloitte & Touche LLP
Independent Registered Chartered Accountants
Calgary, Canada
March 7, 2007

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

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

Name, Age and Municipality of Residence	Position with the Registrant	Present Occupation and Principal Occupation for the Past Five Years
DAVID R. MARTIN, age 75 Santa Barbara, California	Executive Co-Chairman of the Board (since May 2006) and Director (since August 1998)	Executive Co-Chairman of the Board, Ivanhoe Energy Inc., (May 2006 Present); Chairman of the Board, Ivanhoe Energy Inc. (August 1998 May 2006); President, Cathedral Mountain Corporation (1997 present)
A. ROBERT ABBOUD, age 77 Barrington Hills, IL	Independent Co-Chairman and Lead Director (since May 2006)	President, A. Robert Abboud and Company, a private investment company (1984 present)
ROBERT M. FRIEDLAND, age 56 Singapore	Deputy Chairman Capital Markets (since June, 1999) and Director (since February 1995)	Chairman and President, Ivanhoe Capital Corporation, a Singapore based venture capital company principally involved in establishing and financing international mining and exploration companies (1987 present); Chairman and Director, Ivanhoe Mines Ltd. (March 1994 present)
E. LEON DANIEL, age 70 Park City, Utah	Deputy Chairman Projects and Engineering, (since May 2006) and Director (since August 1998)	Deputy Chairman Projects and Engineering, Ivanhoe Energy Inc. (May 2006 present); President and Chief Executive Officer, Ivanhoe Energy Inc. (June, 1999 May 2006)
R. EDWARD FLOOD, age 61 Reno, Nevada	Director (since June 1999)	Chairman of the Board, Western Uranium Corporation (March 2007- present); Director, Ivanhoe Mines Ltd. (May 1999 present); Deputy Chairman, Ivanhoe Mines Ltd. (May 1999 February 2007); Mining Analyst, Haywood Securities (May, 1999 September 2001)
SHUN-ICHI SHIMIZU, age 67 Tokyo, Japan	Director (since July 1999)	Managing Director of C.U.E. Management Consulting Ltd. (1994 present)
HOWARD R. BALLOCH, age 55 Beijing, China	Director (since January 2002)	President, The Balloch Group (July 2001 present); President, Canada China Business

		Council (July 2001 2006); Canadian Ambassador to China, Mongolia and Democratic Republic of Korea (April 1996 July 2001)
J. STEVEN RHODES, age 55 Los Angeles, California	Director (since December 2003)	Chairman and Chief Executive Officer, Claiborne - Rhodes, Inc. (2001 present); Senior Vice President, First Southwest Company (1999 2001)
ROBERT G. GRAHAM, age 53 Ottawa, Ontario	Director (since April 2005)	President and CEO, Ensyn Corporation (April 2005 present) Chairman and CEO, Ensyn Group (October 1984 April 2005)
ROBERT A. PIRRAGLIA, age 57 Belmont, Massachusetts	Director (since April 2005)	Chief Operating Officer and Vice President, Ensyn Corporation (April 15, 2005 present); Chief Operating Officer and Vice President, Ensyn Group, Inc. (September 1998 April 2005)

Name, Age and Municipality of Residence	Position with the Registrant	Present Occupation and Principal Occupation for the Past Five Years
BRIAN DOWNEY, C.M.A. age 65 Lake in the Hills, Illinois	Director (since July 2005)	President, Downey & Associates Management Inc. (July 1986 present); Financial Advisor, Lending Solutions, Inc. (January 2002 present); Partner/Owner, Lending Solutions, Inc. (November 1995 January 2002)
JOSEPH I. GASCA, age 50 The Woodlands, Texas	President and Chief Executive Officer (since January 2007)	President and Chief Executive Officer, Ivanhoe Energy Inc. (January 2007 present); President and Chief Operating Officer, Ivanhoe Energy Inc. (July 2006 January 2007); Region Technical Director Europe/Asia BG Group (January 2006 June 2006); General Manager Operations; BG Group (August 2004 December 2005); Chief Operating Officer, Mosaic Natural Resources Ltd. (January 2003 July 2004); President, Star Insight Ltd. (May 2002- July 2004
W. GORDON LANCASTER, C.A. age 63 Vancouver, British Columbia	Chief Financial Officer (since January 2004)	Chief Financial Officer, Ivanhoe Energy Inc. (January 2004 present); Vice President Finance and Chief Financial Officer, Xantrex Technology Inc. (July 2003 December 2003); Vice President Finance and Chief Financial Officer, Power Measurement, Inc. (August 2000 June 2003)
PATRICK CHUA, age 51 Hong Kong, China	Executive Vice-President (since June 1999)	Executive Vice-President, Ivanhoe Energy Inc. (June 1999 present); Chairman, Sunwing Energy Ltd. (Bermuda) (April 2004 present); President, Sunwing Energy Ltd. (Bermuda) (March 2000 April 2004)
GERALD MOENCH, age 58 Lethbridge, Alberta	Executive Vice-President (since June 1999)	Executive Vice-President, Ivanhoe Energy Inc. (June, 1999 present); President, Sunwing Energy Ltd. (Bermuda) (April 2004 present)

All of our directors, with the exception of Mr. A. Robert Abboud, who was appointed to the Board in May 2006, were elected at our last annual general meeting of shareholders held on May 4, 2006. The term of office of each director concludes at our next annual general meeting of shareholders, unless the director s office is earlier vacated in accordance with our by-laws. There are no family relationships among any of our directors, officers or key employees.
Under the terms of our acquisition of Ensyn, we granted to Ensyn the right to designate two individuals for appointment to our Board of Directors and agreed to use reasonable best efforts to nominate Ensyn s designees for re-election to our Board of Directors annually for at least five years. Ensyn s designees, Dr. Robert Graham and Mr. Robert Pirraglia, were originally appointed to the Board of Directors on April 15, 2005.
As required under the *Business Corporations Act* (Yukon), our Board of Directors has an Audit Committee. We also have a Compensation Committee and a Nominating and Corporate Governance Committee. The members of the Audit Committee are Messrs. Brian Downey, Howard R. Balloch and Robert A. Pirraglia. Mr. Downey, one of our independent directors, has been determined by the Board of Directors to be an Audit Committee financial expert. We

believe that Mr. Downey s prior experience working as a Certified Management Accountant and significant financial and business experience at the executive levels of management qualifies him to be an Audit Committee financial expert. The members of the Compensation Committee are Messrs. Howard R. Balloch (Chair), R. Edward Flood, J. Steven Rhodes and Brian Downey. The members of the Nominating and Corporate Governance Committee are Messrs. Howard R. Balloch (Chair), R. Edward Flood, J. Steven Rhodes and Robert A. Pirraglia.

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

Other Directorships
Messrs. Howard R. Balloch, R. Edward Flood and Robert M. Friedland are all directors of Ivanhoe Mines Ltd.
Mr. Balloch is also a director of Methanex Corporation, East Energy Corp. and Tiens Biotech Group USA Inc.
Mr. Flood is also a director of Jinshan Gold Mines Inc., Asia Gold Corp., American Gold Capital Corp. and Western Uranium Corporation.

Code of Business Conduct and Ethics
We have a Code of Business Conduct and Ethics applicable to all employees, consultants, officers and directors regardless of their position in our organization, at all times and everywhere we do business. The Code of Business Conduct and Ethics provides that our employees, consultants, officers and directors will uphold our commitment to a culture of honesty, integrity and accountability and that we require the highest standards of professional and ethical conduct from our employees, consultants, officers and directors. Our Code of Business Conduct and Ethics has been filed as Exhibit 14.1 to our 2006 Annual Report on Form 10-K. A copy of our Code of Business Conduct and Ethics may be obtained, without charge, by request to Ivanhoe Energy Inc., Suite 654-999 Canada Place, Vancouver, British Columbia, Canada V6C 3E1, Attention: Corporate Secretary or by phone to 604-688-8323.

ITEM 11. EXECUTIVE COMPENSATION
In accordance with the requirements of applicable securities legislation in Canada, the following executive compensation disclosure is provided in respect of our Chief Executive Officer and Chief Financial Officer as at December 31, 2006, and each of our three most highly compensated executive officers whose annual compensation exceeded Cdn.$150,000 in the year ended December 31, 2006 (collectively, the **Named Executive Officers**). During the year ended December 31, 2006, the aggregate compensation paid to all of our executive officers whose annual compensation exceeded Cdn.$40,000 was U.S.$1,441,760.

Summary Compensation Table
The following table sets forth a summary of all compensation paid during the years ending December 31, 2006, 2005 and 2004 to each of the Named Executive Officers.

Summary Compensation Table ($U.S.)

		Annual Compensation			Long Term Compensation			
					Awards		Payouts	
Name and Principal Position	Year	Salary	Bonus (6)	Other Annual Compensation	Securities Under Options/SARs Granted (#)	Restricted Shares or Restricted Share Units	LTIP Payouts	All Other Compen-sation (U.S.$) (7)
David R. Martin Executive Co-Chairman (1)	2006	270,000	90,000					20,000
	2005	270,000						16,200
	2004	200,000	60,000					12,792
E. Leon Daniel Deputy Chairman Projects and Engineering (2)	2006	340,000	100,000					20,000
	2005	340,000			500,000			16,200
	2004	300,000	90,000					12,792
Joseph I. Gasca President and Chief Executive	2006	152,417			1,000,000			9,200
	2005							

Officer (5)	2004			
W. Gordon Lancaster Chief Financial Officer	2006	231,000	80,000	
(4)	2005	225,000		
	2004	200,000	60,000	250,000
Patrick Chua Executive Vice President	2006	108,000		
(3)	2005	144,000	27,000	
	2004	144,000		
Gerald Moench Executive Vice President	2006	188,760		100,000
(3)	2005	174,460	51,480	
	2004	165,000	41,250	

(1) Mr. Martin was appointed Executive Co-Chairman in May 2006 and has been Chairman and director since August 1998.

(2) Mr. Daniel was appointed Deputy Chairman-Projects and Engineering in May 2006, was President and Chief Executive Officer from June 1999 until May 2006, and has been a director of the Company since August 1998.

(3) Mr. Moench and Mr. Chua were appointed as Executive Vice President in June 1999.

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

(5) Mr. Gasca was appointed President and Chief Operating Officer effective July 2006 and was designated the Chief Executive Officer effective January 29, 2007.

(6)

Bonuses earned were paid in cash and common shares from our Employees and Directors Equity Incentive Plan at fair market value on the date of approval by the Compensation Committee.

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

Long Term Incentive Plan

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

Options and Stock Appreciation Rights (SARs)

During the year ended December 31, 2006, Mr. Moench received an incentive stock option to acquire 100,000 common shares which vest over four years and expire on the 5th anniversary of the date of grant. Following the approval of the Toronto Stock Exchange on June 14, 2006, Mr. Gasca received an incentive stock option to acquire 1,000,000 common shares which vest over three years and expire on the 10th anniversary of the date of grant. No other stock options or SARs were granted to our Named Executive Officers in the year ended December 31, 2006.

Option/SAR Grants in Last Fiscal Year

Name (a)	Number of Securities Underlying Options/SARs Granted (#) (b)	Percent of Total Options/ SARs Granted to Employees in Financial Year (c)	Exercise or Base Price ($/Security) (d)	Market Value of Securities Underlying Options/ SARs on the Date of Grant ($/Security) (e)	Expiration Date (f)
Joseph I. Gasca	1,000,000	29.2%	U.S. $2.85	2,850,000	July 5, 2016
Gerald Moench	100,000	2.9%	U.S. $3.06	306,000	March 8, 2011

Aggregated Option Exercises

None of our Named Executive Officers exercised options during the year ended December 31, 2006.

Aggregated Option Exercises in Last Fiscal Year and Fiscal Year End Option Values

Name	Shares Acquired on Exercise (#)	Value Realized ($U.S.)	Number of Securities Underlying Unexercised Options at December 31, 2006 (#) Exercisable/Unexercisable	Value of Unexercised In-the-Money Options at December 31, 2006 ($U.S.) Exercisable/Unexercisable
Joseph I. Gasca			250,000/750,000	
W. Gordon Lancaster			200,000/50,000	
David R. Martin			3,400,000/0	3,131,348/0
E. Leon Daniel			366,667/300,000	153,498/0
Gerald Moench			70,000/80,000	
Patrick Chua			60,000/0	

Option and SAR Repricings

No options or stock appreciation rights were re-priced during the year ended December 31, 2006.

Defined Benefit and Actuarial Plan

We do not presently provide a pension plan for our employees. However, in 2001, the Company adopted a defined contribution retirement or thrift plan (**401(k) Plan**) to assist U.S. employees in providing for retirement or other future financial needs. Employees contributions (up to the maximum allowed by U.S. tax laws) were matched 100% by the Company in 2006. The Company s matching contributions to the 401(k) Plan were $0.4 million, $0.3 million and $0.2 million for the years ended December 31, 2006, 2005 and 2004.

Employment Contracts, Termination of Employment and Change-In-Control Arrangements

We have written contracts of employment with Messrs. Joseph I. Gasca, E. Leon Daniel and W. Gordon Lancaster. Otherwise, we have no written employment contracts or termination of employment or change of control arrangements with any of our Named Executive Officers. Each of the written employment contracts we have with the Named Executive Officers allows us to terminate the Named Executive Officer for cause in which case the Named Executive Officer would have no entitlement to any compensation with respect to the termination. None of the contracts provides for a change of control arrangement.

Mr. Gasca s employment contract respecting his employment as President and Chief Operating Officer commenced on May 15, 2006. Mr. Gasca was elevated to the position of President and Chief Executive Officer on January 29, 2007 with no amendments made to the initial employment contract. Mr. Gasca s contract provides for an annual salary of not less than $310,000 over the term of employment of three years from the date of commencement, unless terminated earlier in accordance with the provisions of the contract. The Corporation may terminate Mr. Gasca s employment for cause, or, on a lump sum payment of an amount equal to twelve monthly payments of Mr. Gasca s base salary, without cause. Under the terms of the contract, Mr. Gasca was granted incentive stock options exercisable to acquire 1,000,000 common shares which are exercisable for ten years and vest over three years. In the event of a change of control of the Company, Mr. Gasca is entitled to receive a lump sum payment in an amount equal to his annual base salary. At the discretion of the Company s board of directors, Mr. Gasca is eligible for an annual bonus in an amount determined by the Board.

Mr. Daniel s contract provides for an annual salary of not less than $300,000 over the term of employment of five years, commencing on April 30, 2002, unless terminated earlier in accordance with the provisions of the contract. Either party may terminate the contract upon one year s notice provided however that we may terminate Mr. Daniel s employment at any time without notice by paying him an amount equal to the lesser of one year s salary or the prorated amount of his annual salary that he would have earned between the date of termination and the expiration of the contract term. Mr. Daniel is eligible to receive a cash bonus and a stock bonus each year, as determined by the Compensation Committee. Mr. Daniel is entitled to participate in our employee benefit programs on the same basis as all of our other employees.

As of January 1, 2004, we entered into an employment contract with Mr. Lancaster having no fixed term of employment and providing for an initial annual salary of $200,000, subject to review annually by the Compensation Committee, and the same benefit entitlements available to our other executive officers. Under the terms of the contract, Mr. Lancaster was granted an initial incentive stock option to acquire 250,000 common shares, which vest over four years and expire on the 5th anniversary of the date of grant. We may terminate Mr. Lancaster s employment for any reason by delivering to him six months written notice.

The Corporation does not have employment contracts with any other of its Named Executive Officers.

Director Compensation

Each independent director other than Mr. A. Robert Abboud receives director fees of $2,000 per month. Mr. Abboud receives an annual fee of $250,000 for acting as the Independent Co-Chairman and Lead Director of the Company. Mr. Brian Downey receives an additional payment of $7,500 per annum for acting as the Chairman of the Audit Committee. The Chairman of the Compensation and Benefits Committee and the Chairman of the Nominating and Corporate Governance Committee, Mr. Howard Balloch, receives an additional payment of $5,000 per annum per Committee for acting as such. Each independent director, with the exception of Mr. A. Robert Abboud, receives a fee of $1,000 for participation in each Board of Directors meeting and each Committee meeting attended in person or via conference call. The Company did not pay any other cash or fixed compensation to its directors for acting as such.

The Company reimburses its directors for expenses they reasonably incur in the performance of their duties as directors and the directors are also eligible to participate in the Company s Employees and Directors Equity Incentive Plan.

Employees and Directors Equity Incentive Plan

Our Employees and Directors Equity Incentive Plan, as amended (the **Plan**) consists of three component plans: a common share option plan (the **Share Option Plan**), a common share bonus plan (the **Share Bonus Plan**), and a common share purchase plan (the **Share Purchase Plan**). The purpose of the Plan is to advance our corporate interests by encouraging equity participation by our directors, officers, employees and service providers through the acquisition of our shares.

The following is a brief description of the terms of the Plan.

Share Option Plan

The Share Option Plan allows the Board of Directors to grant options to acquire our common shares in favor of our directors, officers, employees and service providers. Options are subject to adjustment in the event of a subdivision or consolidation of our common shares, an amalgamation, or other corporate event affecting our common shares. Participation in the Share Option Plan is limited to directors, officers, employees and service providers who are, in the opinion of our Board of Directors, in a position to contribute to our future growth and success.

In determining the number of common shares made subject to an option, we consider, among other things, the optionee s relative present and potential contribution to our success and to the prevailing policies of each stock exchange on which our shares are listed. The Board of Directors determines the date of grant, the number of optioned common shares, the exercise price per share, the vesting period and the exercise period. The minimum exercise price of any option granted under the Share Option Plan is the weighted average price of our common shares on the principal stock exchange on which our common shares trade for the five trading days prior to the date of grant. Unless earlier terminated upon an optionee s death or termination of employment or appointment, options are exercisable for a period of up to ten years. We may, in our discretion, accelerate unvested options if a take-over bid is made for our common shares.

Share Bonus Plan

The Share Bonus Plan permits our Board of Directors to issue up to an aggregate maximum of 2,000,000 of our common shares as bonus awards to our directors, officers, employees and service providers on a discretionary basis having regard to such merit criteria as the Board of Directors may determine. As at December 31, 2006, there were 705,602 shares available to be issued from the Share Bonus Plan.

Share Purchase Plan

Participation in the Share Purchase Plan is limited to employees who have completed at least one year (or less, at the discretion of the Board of Directors) of continuous service on a full-time basis and who are designated by the Board of Directors as eligible to participate in the Share Purchase Plan.

Eligible employees may contribute up to 10% of their annual basic salary to the Share Purchase Plan in semi-monthly installments. We then make contributions on a quarterly basis equal to the employee s contribution.

At the end of each calendar quarter, the eligible employee receives a number of our common shares equal to the aggregate amount contributed by the employee participant and by us, on the participant s behalf, divided by the weighted average trading price of our common shares on our principal stock exchange during the previous three months.

The Share Purchase Plan component of the Plan has not yet been activated.

General

The aggregate maximum number of our common shares, which we may issue, or reserve for issuance under the Plan, is currently 20,000,000 common shares. Any increase is subject to Toronto Stock Exchange approval and approval by our shareholders. The maximum number of our common shares which we may, at any time, reserve for issuance to any one person under the Plan may not exceed 5% of our issued and outstanding common shares. As at December 31, 2006, there were 1,266,994 unallocated shares available to be issued from our Plan.

Our Board of Directors has the right to amend, modify or terminate our Plan. However, any amendment to the Plan which would materially increase the benefits under the Plan, materially modify the requirements as to eligibility for participation in the Plan or materially change the number of our common shares that may be issued or reserved for issuance under the Plan, is subject to Toronto Stock Exchange approval and the approval of our shareholders.

Proposed Amendments

We are planning to seek the approval of our shareholders at the next annual meeting of shareholders scheduled to be held on May 3, 2007 to amend and restate the existing Plan to: (i) increase the maximum number of common shares available for issuance thereunder from 20,000,000 common shares to 24,000,000 common shares; (ii) increase the maximum number of common shares of the Company which may be allocated for issuance under the Bonus Plan component of the Existing Plan from 2,000,000 common shares to 2,400,000 common shares; (iii) replace the existing terms thereof governing the circumstances and manner in which the Incentive Plan may be amended with more detailed and prescriptive provisions in order to comply with recently enacted changes to the rules and policies of The Toronto Stock Exchange (**TSX**) respecting equity incentive plan amendments; (iv) formally recognize the role of the Compensation Committee in administering the Plan; (v) provide for the automatic extension of the exercise term of any incentive

stock option issued under the Incentive Plan that would otherwise expire during a blackout period if the holder of the option is prevented from exercising the incentive stock option due to blackout period trading restrictions; and (vi) make other technical amendments to the Incentive Plan. The TSX has approved the proposed amendments to the Incentive Plan, subject to approval by the shareholders at the May 2007 annual meeting.

Composition of the Compensation Committee

During the year ended December 31, 2006, our Compensation Committee consisted of Messrs. Howard R. Balloch, R. Edward Flood, J. Steven Rhodes and Brian Downey who joined the Committee in May 2006. Since the beginning of the most recently completed financial year, which ended on December 31, 2006, none of Messrs. Balloch, Flood, Rhodes or Downey was indebted to the Company or any of its subsidiaries or had any material interest in any transaction or proposed transaction which has materially affected or would materially affect the Company or any of its subsidiaries. None of the Company s executive officers serve as a member of the Compensation Committee or Board of Directors of any entity that has an executive officer serving as a member of the Compensation Committee or Board of Directors of the Company.

Report on Executive Compensation

Our executive compensation program is administered by the Compensation Committee. The members of the Compensation Committee are all independent, non-management directors. Following review and approval by the Compensation Committee, decisions relating to executive compensation are reported to, and approved by, the full Board of Directors. The Compensation Committee has directed the preparation of this report and has approved its contents and its submission to shareholders.

Our approach to executive compensation is motivated by a desire to align the interests of our executive officers as closely as possible with the interests of our company and its shareholders as a whole. In determining the nature and quantum of compensation for our executive officers we are seeking to achieve the following objectives: to provide a strong incentive to management to contribute to the achievement of our short-term and long-term corporate goals; to ensure that the interests of our executive officers and the interests of our shareholders are aligned; to enable us to attract, retain and motivate executive officers of the highest caliber in light of the strong competition in our industry for qualified personnel, and to recognize that the successful implementation of our company s corporate strategy cannot necessarily be measured, at this stage of its development, only with reference to quantitative measurement criteria of corporate or individual performance. We take all of these factors into account in formulating our recommendations to the Board of Directors respecting the compensation to be paid to each of our executive officers.

The compensation that we pay to our executive officers generally consists of cash, equity and equity incentives. Our compensation policy reflects a belief that an element of total compensation for our executive officers should be at risk in the form of common shares or incentive stock options, so as to create a strong incentive to build shareholder value.

The Compensation Committee oversees and sets the general guidelines and principles for the implementation of our executive compensation policies, assesses the individual performance of our executive officers and makes recommendations to the Board of Directors. Based on these recommendations, the Board of Directors makes decisions concerning the nature and scope of the compensation to be paid to our executive officers.

The base salaries of our executive officers have traditionally been determined using a subjective assessment of each individual s performance, experience and other factors we believe to be relevant, including prevailing industry demand for personnel having comparable skills and performing similar duties, the compensation the individual could reasonably expect to receive from a competitor and Ivanhoe s ability to pay. We have also considered recommendations from outside compensation consultants and used compensation data obtained from publicly available sources. We believe that the salaries we have traditionally paid to our executive officers reasonably approximate the median level of most of the comparative compensation data to which we had access. All of our executive officers are eligible to receive discretionary bonuses, based upon our subjective assessment of Ivanhoe s overall performance in relation to its ongoing implementation of corporate strategy and achievement of corporate objectives and of each executive officer s contribution to such performance and achievement.

The relationship of corporate performance to executive compensation under our executive compensation program is created, in part, through equity compensation mechanisms. Incentive stock options, which vest and become exercisable through the passage of time, link the bulk of our equity-based executive compensation to shareholder return, measured by increases in the market price of our common shares. We also make, as and when we consider it warranted, recommendations to the Board of Directors respecting discretionary bonus awards of common shares to our employees, including our executive officers. Such awards are intended to recognize extraordinary contributions to the achievement of corporate objectives.

Eligibility for participation from time to time in the various equity incentive mechanisms available under our Plan is determined after we have thoroughly reviewed and taken into consideration the individual performance and contribution to overall corporate performance by each prospective participant. All outstanding stock options that have been granted under our Plan were granted at prices not less than 100% of the fair market value of Ivanhoe common shares on the dates such options were granted.

We continue to believe that stock-based incentives encourage and reward effective management that results in long-term corporate financial success, as measured by stock appreciation. Stock-based incentives awarded to our executive officers are based on the Compensation Committee s subjective evaluation of each executive officer s ability to influence our long-term growth and to reward outstanding individual performance and contributions to our business. Other factors influencing our recommendations respecting the nature and scope of the equity compensation and equity incentives to be awarded to our executive officers in a given year include: awards made in previous years and, particularly in the case of equity incentives, the number of incentive stock options that remain outstanding and exercisable from grants in previous years and the exercise price and the remaining exercise term of those outstanding stock options.

In 2005, based on a report prepared by an external consultant and an internal review of our compensation policies and practices, we adopted some general guidelines and benchmarks for setting executive and management compensation at levels consistent with competitive industry standards and practices: (i) individual salaries would be targeted at the mid-points of ranges paid to individuals occupying equivalent positions in similar companies; (ii) annual bonuses would be awarded on the basis of criteria established in each year, with 75% of a bonus to be tied to corporate-wide or departmental achievements measurable by quantifiable targets, project acquisitions (where relevant) and/or stock value, and the remaining 25% to be based on subjective criteria; (iii) annual bonuses would generally not exceed amounts that would bring individual compensation levels up to the top quartile of the competitive marketplace; (iv) bonuses would continue to be made up of a combination of cash and common shares; and (v) the total budgetary burden of bonuses would be anticipated in annual budgeting.

During 2006 the Compensation Committee recommended, and the Board of Directors adopted, a series of quantitative criteria and performance targets upon which an element of the executive compensation, over and above salary, to be paid to certain specified executive officers in respect of the 2006 fiscal year would be based. The specified executive officers are David Martin, Executive Co-Chairman (until May 2006, the Chairman), Leon Daniel, Deputy Chairman Projects and Engineering (until May 2006, the President and Chief Executive Officer), Gordon Lancaster, Chief Financial Officer, and certain Vice-Presidents. Each of the specified executive officers was eligible to receive bonus awards, payable in cash or shares, of up to a maximum of 200% of base salary (subject to an upper limit of US$1 million for each specified executive officer) contingent upon the achievement of measurable corporate performance targets including market price appreciation in respect of our common shares (up to 25% of base salary), net production (up to 15% of base salary), net operating cash flow (up to 25% of base salary), net reserves value (up to 10% of base salary for each specified executive officer other than Chief Financial Officer), new project value (up to 100% of base salary for each specified executive officer other than Chief Financial Officer) and subjective criteria determined on the basis of Compensation Committee recommendations (up to 25% of base salary for each executive officer other than Chief Financial Officer, and up to 35% of base salary for Chief Financial Officer). For 2006, we awarded bonuses to executive officers as follows: (i) $90,000 to Mr. Martin, of which $30,000 was based on meeting performance targets and $60,000 was based on subjective criteria, which bonus consisted of a cash payment of $15,000 and the issuance of 38,660 common shares; (ii) $100,000 to Mr. Daniel, of which $34,000 was based on meeting performance targets and $66,000 was based on subjective criteria, which bonus consisted of a cash payment of $17,000 and the issuance of 42,783 common shares; and (iii) $80,000 to Mr. Lancaster, of which $50,000 was based on meeting performance targets and $30,000 was based on subjective criteria, which bonus consisted of a cash payment of $25,000 and the issuance of 28,351 common shares.

The base salary of our Deputy Chairman Projects and Engineering, who was, until May 2006, our Chief Executive Officer (**CEO**), was set by his employment contract, the material terms of which are described under Employment Contracts, Termination of Employment and Change-in-Control Arrangements . This contract also provides that he is eligible to receive, on an annual basis, a cash bonus and a non-cash bonus in an amount determined by the Compensation Committee based on such criteria as the Committee may determine from time to time. Having regard to the general benchmarks we adopted for setting executive compensation generally and a review of management salaries in late 2005, his salary for 2005 and 2006 was increased by $40,000.

The base salary of our current CEO (who joined us in May 2006 as our President and Chief Operating Officer) was set by his employment contract, material terms of which are described under Employment Contracts, Termination of

Employment and Change-in-Control Arrangements . Under the terms of his employment contract, our current CEO was granted incentive stock options to acquire 1,000,000 common shares which vest over three years and are exercisable for ten years. The salary and stock option compensation offered to our current CEO at the time of his appointment was based on competitive market factors, his level of experience and responsibility, the compensation practices of other industry participants, and the negotiations that took place in connection with his appointment. Our current CEO s employment contract also provides that he is eligible to receive an annual bonus at the discretion of the Board of Directors based on performance criteria determined by the Board. Given his relatively recent appointment, we did not specify our current CEO as one of the executive officers whose executive compensation in respect of the 2006 fiscal year, over and above salary, would be based, in part, on specified quantitative criteria and performance targets.

For 2007 we have adopted a compensation program which will apply to our executive officers, including our CEO, as well as our employees. The compensation program is designed to provide incentives to work for, and stay with, the Company and to drive strong

Company performance, and to differentially reward skills more critical to our business plans. Under the 2007 program, the Company strives to pay near term compensation, using a pay grade system consistent with industry practice, that is competitive with industry while providing incentive compensation that outperforms other options that employees and prospective employees might find in the marketplace.

Under the 2007 compensation program, annual salary increases will be based on performance and rated based on agreed objectives. Using a pay grade system, target and maximum bonus award levels and maximum incentive compensation will be benchmarked with industry. For executive officers and higher paid employees, bonus award levels will be determined based on job specific criteria in addition to overall performance rating. The composition of annual bonus awards will be a combination of Company common shares and cash. For most pay grades, the target cash award is set at 15% of salary and the maximum cash award is set at 22.5% of annual salary. For the incentive compensation component of our 2007 program, we intend to use the same pay grade system for outlining the target and maximum incentive compensation that is achievable for an executive or employee. For executives and higher pay grade employees, annual incentive compensation awards will be provided based on specific performance criteria, value to the Company in terms of skills, knowledge and experience, completion of specific projects as well as subjective criteria. Incentive compensation awards for executives and upper pay grade employees are expected to include stock options, and may include other securities such as restricted shares.

Submitted on behalf of the Compensation Committee:

Mr. Howard R. Balloch
Mr. R. Edward Flood
Mr. J. Steven Rhodes
Mr. Brian Downey

Performance Graph

The following graph and table compares the cumulative shareholder return on a $100 investment in our common shares to a similar investment in companies comprising the S&P/TSX Composite Index, including dividend reinvestment, for the period from December 31, 2001 to December 31, 2006.

	As at December 31, (Cdn.$)					
	2001	**2002**	**2003**	**2004**	**2005**	**2006**
Ivanhoe Energy Inc.	$100	$20	$134	$ 84	$ 34	$ 43
S&P/TSX Composite Index	$100	$88	$111	$127	$158	$185

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Except as set forth below, no person or group is known to beneficially own 5% or more of our issued and outstanding common shares. Based on information known to us, the following table sets forth the beneficial ownership of each such person or group in our common shares as at March 8, 2007.

Title of Class	Name and Address of Beneficial Owner	Number of Shares Beneficially Owned (1)	Percentage of Class
Common Shares	Robert M. Friedland No. 1 Temasek Avenue #37-02 Millenia Tower Singapore 039192	51,011,725(2)	20.48
Common Shares	Directors and Executive Officers as a Group (15 persons)	64,102,909(3)	25.74

(1) Beneficial ownership is determined in accordance with the rules of the SEC and generally includes voting or investment power with respect to securities. Unissued common shares subject to options, warrants or other convertible securities currently exercisable or convertible, or exercisable or convertible within 60 days, are deemed outstanding for the purpose of computing the beneficial ownership of

common shares of the person holding such convertible security but are not deemed outstanding for computing the beneficial ownership of common shares of any other person.

(2) 50,594,620 common shares are held indirectly through Newstar Securities SRL, Premier Mines SRL and Evershine SRL, companies controlled by Mr. Friedland.

(3) Includes 5,312,667 unissued common shares issuable to directors and senior officers upon exercise of incentive stock options.

Security Ownership of Management

The following table sets forth the beneficial ownership as at March 8, 2007 of our common shares by each of our directors, our Named Executive Officers and by all of our directors and executive officers as a group:

Title of Class	Name of Beneficial Owner	Amount and Nature of Beneficial Ownership (1) (a)	Percentage of Class (b)	Incentive Stock Options Included in (a) (c)
Common Shares	David R. Martin	4,373,069	1.76	3,400,000
Common Shares	A. Robert Abboud	516,000	0.21	116,000

Common Shares	Robert M. Friedland	51,011,725(2)	20.48	
Common Shares	E. Leon Daniel	1,146,683	0.46	466,667
Common Shares	R. Edward Flood	115,029	0.05	90,000
Common Shares	Shun-ichi Shimizu	120,100	0.05	20,000
Common Shares	Howard R. Balloch	90,000	0.04	90,000
Common Shares	J. Steven Rhodes	201,000	0.08	200,000
Common Shares	Robert G. Graham	5,328,755	2.14	110,000
Common Shares	Robert A. Pirraglia	366,266	0.15	140,000
Common Shares	Brian Downey	80,000	0.03	80,000
Common Shares	Joseph I. Gasca	250,000	0.10	250,000
Common Shares	W. Gordon Lancaster	251,451	0.10	200,000
Common Shares	Patrick Chua	139,712	0.06	60,000
Common Shares	Gerald Moench	113,119	0.05	90,000
Common Shares	All directors and executive officers as a group (15 persons)	64,102,909	25.74	5,312,667

(1) Beneficial ownership is determined in accordance with the rules of the SEC and generally includes voting or investment power with respect to securities. Unissued common shares subject to options, warrants or other convertible securities currently exercisable or

convertible, or exercisable or convertible within 60 days, are deemed outstanding for the purpose of computing the beneficial ownership of common shares of the person holding such convertible security but are not deemed outstanding for computing the beneficial ownership of common shares of any other person.

(2) 50,594,620 common shares are held indirectly through Newstar Securities SRL, Premier Mines SRL and Evershine SRL, companies controlled by Mr. Friedland.

Securities Authorized for Issuance under Equity Compensation Plans

Our Plan, the material terms of which are summarized in Item 11 Executive Compensation, is the only equity compensation plan we have in effect. The Plan is intended to further align the interests of our directors and management with our company s long-term performance and the long-term interests of our shareholders. Our shareholders have approved the Plan and all amendments thereto other than the proposed amendments summarized under the heading Proposed Amendments in Item 11 Executive Compensation, which will be submitted to our shareholders for approval at our next annual meeting of shareholders scheduled for May 3, 2007. The following information is as at December 31, 2006:

Equity Compensation Plan Information

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by Security holders	11,369,721	Cdn. $2.27	1,266,994
Equity compensation plans not approved by Security holders (1)	1,000,000	Cdn. $3.18	
Total	12,369,721	Cdn. $2.34	1,266,994

(1) Consists of incentive stock options granted to Mr. Joseph Gasca as an inducement to accepting employment with the Company. These incentive stock options were not granted under the Company s existing Plan previously approved by shareholders and the common shares reserved for issuance to Mr. Gasca upon the exercise of these incentive stock options are not included in the total number of common shares reserved for issuance under the existing Plan. Under the rules and policies of the Toronto Stock Exchange, security based compensation arrangements offered as inducements to prospective employees do not require shareholder approval.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTORS INDEPENDENCE

Transactions with Management and Others

We borrowed $1.25 million from Ivanhoe Capital Finance Ltd., a company wholly owned by Mr. Robert M. Friedland our Deputy Chairman and a director. The unsecured loan was repaid with accrued interest, at U.S. prime plus 3%, in September 2003. We negotiated a revolving credit facility of $1.25 million to re-establish or extend that loan in the future as needs arise.

Certain Business Relationships

We are party to cost sharing agreements with other companies wholly or partially owned by Mr. Robert M. Friedland. Through these agreements, we share office space, furnishings, equipment, air travel and communications facilities in Vancouver, Beijing and Singapore. We also share the costs of employing administrative and non-executive management personnel at these offices. During the year ended December 31, 2006, our share of costs for the Vancouver and Singapore offices was $1,238,486.

During the year ended December 31, 2006, we paid $769,466 to a wholly owned subsidiary of Ensyn Corporation, an unaffiliated company that was spun off from Ensyn Group, Inc. as a result of our acquisition of Ensyn Group, Inc. on April 15, 2005. Of this amount, $244,061 was reimbursement of salary, benefits and travel expenses for one of our directors, Mr. Robert Graham, in his position as Chief Executive Officer and President of Ensyn Corporation. The remaining amount of $525,405 was paid to Ensyn Corporation s wholly owned subsidiary during the year ended December 31, 2006 for technical services provided to us. Mr. Graham owns an approximate 24% equity interest in Ensyn Corporation.

During the year ended December 31, 2006, a company controlled by Mr. Shun-ichi Shimizu, one of our directors, received $881,119 for consulting services and out of pocket expenses.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The following table summarizes the aggregate fees billed by Deloitte & Touche LLP:

	Year ended December 31, Cdn.($000)	
	2006	**2005**
Audit fees (a)	$ 835	$ 751
Audit related fees (b)	112	45
Tax fees (c)	135	75
All other fees (d)		
	$ 1,082	$ 871

(a) Fees for audit services billed in 2006 and 2005 consisted of:

Audit of our annual financial statements

Reviews of our quarterly financial statements

Comfort letters, statutory and regulatory audits, consents and other services related to Canadian and U.S. securities regulatory matters

Review of our internal controls over financial reporting in compliance with the requirements of the Sarbanes Oxley Act of 2002.

(b) Fees for audit related services billed in 2006 and 2005 consist of financial and tax analysis in contemplation of our proposed mergers with China Mineral Acquisition Corporation and Ensyn Group, Inc., respectively.

(c) Fees for tax services billed in 2006 and 2005 consisted of tax compliance and tax planning and advice:

Fees for tax compliance services totaled Cdn.$71,000 and Cdn.$43,600 in 2006 and 2005, respectively. Tax compliance services are services rendered based upon facts already in existence or transactions that have already occurred to document, compute, and obtain government approval for amounts to be included in tax filings and consisted of:

i. Federal, state and local income tax return assistance

ii. Preparation of expatriate tax returns

iii. Assistance with tax return filings in certain foreign jurisdictions

Fees for tax planning and advice services totaled Cdn.$64,000 and Cdn.$31,000 in 2006 and 2005, respectively. Tax planning and advice are services rendered with respect to proposed transactions or that alter a transaction to obtain a particular tax result. Such services consisted of:

i. Tax advice related to structuring certain proposed mergers, acquisitions and disposals.

(d) All other fees includes fees for services billed in 2006 and 2005 other than the services reported as Audit fees , Audit related fees , or Tax fees .

In considering the nature of the services provided by Deloitte & Touche LLP, the Audit Committee determined that such services are compatible with the provision of independent audit services. The Audit Committee discussed these services with Deloitte & Touche LLP and our management to determine that they are permitted under the rules and regulations concerning auditor independence promulgated by the SEC to implement the Sarbanes-Oxley Act of 2002, as well as the American Institute of Certified Public Accountants.

Audit Committee Pre-Approval Policy

Before Deloitte & Touche LLP is engaged by us or our subsidiaries to render audit or non-audit services, the engagement is approved by our Audit Committee.

The Audit Committee has adopted a pre-approval policy for audit or non-audit service engagements. This policy describes the permitted audit, audit related, tax, and other services (collectively, the **Disclosure Categories**) that Deloitte & Touche LLP may perform. The policy requires that, prior to the beginning of each fiscal year, a description of the services (the **Service List**) expected to be performed by Deloitte & Touche LLP in each of the Disclosure Categories in the following fiscal year be presented to the Audit Committee for approval. Services provided by Deloitte & Touche LLP during the following year that are included in the Service List are pre-approved following the policies and procedures of the Audit Committee.

Any requests for audit, audit related, tax, and other services not contemplated on the Service List must be submitted to the Audit Committee for specific pre-approval and cannot commence until such approval has been granted. Normally, pre-approval is provided at regularly scheduled meetings. However, the authority to grant a specific pre-approval between meetings, as necessary, has been delegated to the Chairman of the Audit Committee. The Chairman must update the Audit Committee at the next regularly scheduled meeting of any services that were granted specific pre-approval.

In addition, although not required by the rules and regulations of the SEC, the Audit Committee generally requests a range of fees associated with each proposed service on the Service List and any services that were not originally included on the Service List. Providing a range of fees for a service incorporates appropriate oversight and control of the independent auditor relationship, while permitting us to receive immediate assistance from the independent auditor when time is of the essence. On a quarterly basis, the Audit Committee reviews the status of services and fees incurred year-to-date against the original Service List and the forecast of remaining services and fees for the fiscal year.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

We refer you to the Financial Statements and Supplementary Data in Item 8 of this report where these documents are listed. The following exhibits are filed as part of this Annual Report on Form 10-K:

Exhibits

3.1	Articles of Ivanhoe Energy Inc. as amended to September 28, 2005 (Incorporated by reference to Exhibit 3.1 of Form 10-K filed with the Securities and Exchange Commission on March 15, 2006)
3.2	Bylaws of Ivanhoe Energy Inc. as amended May 15, 2001 and further amended March 8, 2007
10.1	Petroleum Contract for Kongnan Block, Dagang Oilfield of the People s Republic of China dated September 8, 1997 between China National Petroleum Corporation and Pan-China Resources Ltd., as amended June 11, 1999 (Incorporated by reference to Exhibit 3.15 of Form 20-F filed with the Securities and Exchange Commission on February 28, 2000)
10.2	Master License Agreement Amendment No. 1 dated October 11, 2000 between Syntroleum Corporation and Ivanhoe Energy Inc. (Incorporated by reference to Exhibit 10.18 of Form 10-K filed with the Securities and Exchange Commission on March 16, 2001)
10.3	Petroleum Contract dated September 19, 2002 between China National Petroleum Corporation and Pan-China Resources Ltd. for Zitong Block, Sichuan Basin of the People s Republic of China (Incorporated by reference to Exhibit 10.12 of Form 10-K filed with the Securities and Exchange Commission on March 19, 2003)
10.4	Strategic Development Alliance Letter Agreement dated September 26, 2002 between Ivanhoe Energy Inc. and CITIC Energy Ltd. (Incorporated by reference to Exhibit 10.13 of Form 10-K filed with the Securities and Exchange Commission on March 19, 2003)
10.5	Employees and Directors Equity Incentive Plan (Incorporated by reference to Exhibit 10.15 of Form 10-K filed with the Securities and Exchange Commission on March 15, 2004)
10.6	Amendment No. 2 to Master License Agreement between Syntroleum Corporation and the Company dated June 1, 2002 (Incorporated by reference to Exhibit 10.6 of Form 10-K filed with the Securities and Exchange Commission on March 15, 2006).
10.7	Amendment No. 3 to Master License Agreement between Syntroleum Corporation and the Company dated July 1, 2003 (Incorporated by reference to Exhibit 10.17 of Form 10-K filed with the Securities and Exchange Commission on March 15, 2004)
10.8	Terms of Agreement Conversion of Participating Interest by Richfirst dated February 18, 2006 among Richfirst Holdings Limited, Pan-China Resources Limited, Sunwing Energy Ltd. and the Company (Incorporated by reference to Exhibit 10.2 of Form 8-K filed with the Securities and Exchange Commission on February 24, 2006)
10.9	Amended and Restated License Agreement dated December 8, 1997 between Ensyn Technologies Inc. and Ensyn Group, Inc. and as amended on February 12, 1999 (Incorporated by reference to Exhibit 10.12 of Form 10-K filed with the Securities and Exchange Commission on March 15, 2006).

10.10 Employment Agreement dated April 30, 2002 between Ivanhoe Energy Inc. and E. Leon Daniel (Incorporated by reference to Exhibit 10.21 of Form 10-K filed with the Securities and Exchange Commission on March 10, 2005)

10.11 Employment Agreement dated November 25, 2003 between Ivanhoe Energy Inc. and W. Gordon Lancaster (Incorporated by reference to Exhibit 10.22 of Form 10-K filed with the Securities and Exchange Commission on March 10, 2005)

Exhibits

10.12	Employment Agreement, dated May 15, 2006 between Ivanhoe Energy Inc. and Joseph I. Gasca (Incorporate by reference to Exhibit 10.1 of Form 8-K filed with the Securities and Exchange Commission on May 26, 2006).
10.13	Stock Purchase Agreement, dated May 12, 2006 between Ivanhoe Energy Inc., Sunwing Holding Corporation, Sunwing Energy Ltd and China Mineral Acquisition Corporation (Incorporated by reference to Exhibit 10.1 of Form 8-K filed with the Securities and Exchange Commission on May 17, 2006)
10.14	Termination of Stock Purchase Agreement, dated August 31, 2006, between Ivanhoe Energy Inc., Sunwing Holding Corporation, Sunwing Energy Ltd. and China Mineral Acquisition Corporation (Incorporated by reference to Exhibit 99.1 of Form 8-K filed with the Securities and Exchange Commission on September 1, 2006).
14.1	Code of Business Conduct and Ethics (Incorporated by reference to Exhibit 14.1 of Form 10-K filed with the Securities and Exchange Commission on March 15, 2004)
21.1	Subsidiaries of Ivanhoe Energy Inc.
23.1	Consent of GLJ Petroleum Consultants Ltd., Petroleum Engineers
23.2	Consent of Netherland, Sewell & Associates, Inc.
23.3	Consent of Deloitte & Touche LLP
31.1	Certification by the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification by the Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification by the Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

SIGNATURES

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

IVANHOE ENERGY INC.

By: /s/ Joseph I. Gasca
Name: Joseph I. Gasca
Title: President and Chief Executive Officer
Dated: March 8, 2007

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

Signature	Title	Date
/s/ JOSEPH I. GASCA Joseph I. Gasca	President and Chief Executive Officer (Principal Executive Officer)	March 8, 2007
/s/ W. GORDON LANCASTER W. Gordon Lancaster	Chief Financial Officer (Principal Financial and Accounting Officer)	March 8, 2007
/s/ DAVID R. MARTIN David Martin	Executive Co-Chairman of the Board and Director	March 8, 2007
/s/ A. ROBERT ABBOUD A. Robert Abboud	Independent Co-Chairman and Lead Director	March 8, 2007
/s/ ROBERT M. FRIEDLAND Robert M. Friedland	Deputy Chairman Capital Markets and Director	March 8, 2007
/s/ E. LEON DANIEL E. Leon Daniel	Deputy Chairman Projects and Engineering and Director	March 8, 2007
/s/ R. EDWARD FLOOD R. Edward Flood	Director	March 8, 2007
/s/ SHUN-ICHI SHIMIZU Shun-ichi Shimizu	Director	March 8, 2007
/s/ HOWARD R. BALLOCH Howard Balloch	Director	March 8, 2007
/s/ J. STEVEN RHODES J. Steven Rhodes	Director	March 8, 2007
/s/ ROBERT G. GRAHAM Robert G. Graham	Director	March 8, 2007
/s/ ROBERT A. PIRRAGLIA	Director	March 8, 2007

Robert A. Pirraglia		
/s/ BRIAN DOWNEY Brian Downey	Director	March 8, 2007

EXHIBIT INDEX

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