IVANHOE ENERGY INC
Form 10-K
March 16, 2009

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**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, 2008**
**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<br>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. o Yes þ No

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. o Yes þ No

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. þ Yes o No

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, a non-accelerated filer, or a smaller reporting company. See definitions of large accelerated filer , accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer **o** Accelerated filer þ Non-accelerated filer **o** Non-accelerated filer **o**
(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). o Yes þ No

As of June 30, 2008, the aggregate market value of the registrant s common stock held by non-affiliates of the registrant was $680,645,631 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 10, 2009 |
|---|---|
| Common Shares, no par value | 279,381,187 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:

| | 2008 | 2007 | 2006 | 2005 | 2004 |
|---|---|---|---|---|---|
| Closing | $ 0.82 | $ 1.01 | $ 0.86 | $ 0.86 | $ 0.83 |
| Low | $ 0.77 | $ 0.84 | $ 0.85 | $ 0.79 | $ 0.72 |
| High | $ 1.01 | $ 1.09 | $ 0.91 | $ 0.87 | $ 0.85 |
| Average Noon | $ 0.94 | $ 0.94 | $ 0.88 | $ 0.83 | $ 0.77 |

The average noon rate of exchange reported by the Bank of Canada (the Federal Reserve Bank of New York ceased posting noon exchange rates as of December 31, 2008) for conversion of U.S. dollars into Canadian dollars on March 10, 2009 was $0.78 ($1.00 = Cdn.$1.28).

## 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 express these different commodities in a common unit. In calculating Bbl equivalents (Boe), 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.

## SELECT DEFINED TERMS

Ivanhoe Energy Inc. **Ivanhoe Energy** or **Ivanhoe** or **the Company**

The Company s proprietary, patented rapid thermal processing process ( **RTP™ Process** ) for heavy oil upgrading ( **HTL™ Technology** or **HTL™** )

Syntroleum Corporation s ( **Syntroleum** ) proprietary technology ( **GTL Technology** or **GTL** ) to convert natural gas into ultra clean transportation fuels and other synthetic petroleum products

United States Securities and Exchange Commission **SEC**

Canadian Securities Administrators **CSA**

The Securities Act of 1933 (the **Act** )

Enhanced oil recovery **EOR**

| | |
|---|---|
| Steam Assisted Gravity Drainage | **SAGD** |
| Memorandum of Understanding | **MOU** |
| Toronto Stock Exchange | **TSX** |

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## 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 our short history of limited revenue, losses and negative cash flow from our current exploration and development activities in the U.S., China and Ecuador; our limited cash resources and consequent need for additional financing; our ability to raise additional financing. The availability of financing is dependent in part on the return of the credit and equity markets to normalized conditions. During the fourth quarter of 2008, as a result of the global economic crisis, the terms and availability of equity and debt capital have been materially restricted and financing may not be available when it is required or on acceptable terms. In addition to the above financing risks, uncertainties, risk and other factors also include 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 or continue or 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. Except as required by law, 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

Electronic copies of the Company s filings with the SEC and the CSA are available, free of charge, through its web site (www.ivanhoeenergy.com) or, upon request, by contacting its investor relations department at (604) 688-8323. Alternatively, the SEC and the CSA each maintains a website (www.sec.gov and www.sedar.com ) that contains the Company s periodic reports and other public filings with the SEC and the CSA. The information on our website is not, and shall not be, deemed to be part of this Annual Report on Form 10-K.

## 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 using advanced technologies, including its HTL™ Technology. In mid-2008, the Company acquired two leases located in the heart of the Athabasca oil sands region in Alberta, Canada and recently signed a contract in Ecuador for the appraisal and development of a heavy oil lease in Ecuador. It is anticipated that these sites will provide for the first commercial applications of the Company s HTL Technology in major, integrated heavy oil projects (see Implementation Strategy below). In addition, the Company seeks to selectively expand its reserve base and production through conventional exploration and production of oil and gas.

Core operations are in Canada, the United States, China and Ecuador, with business development opportunities worldwide.

The Company has established a number of geographically focused entities. The parent company, Ivanhoe Energy Inc., will pursue HTL™ opportunities in the Athabasca oil sands of Western Canada and will hold and manage the core HTL™ Technology. A new subsidiary for Latin America recently signed a contract for the appraisal and development of a heavy oil lease in Ecuador. In addition, a subsidiary has been established to undertake activities in the Middle

East and North Africa. These companies complement Sunwing Energy Ltd., the Company s existing, wholly-owned company established for activities in China. Ivanhoe Energy Inc. owns 100% of each of these subsidiaries, although the percentages are expected to decline as they develop their respective businesses and raise capital independently.

We believe this structure will allow the development and financing of multiple HTL™ projects around the world, while minimizing dilution of the Company s existing shareholders. In addition, the alignment with principal energy-producing regions will help to facilitate financing from region-specific strategic investors, some of which already have been identified, and also will enhance flexibility in accessing global capital markets.

The Company s four reportable business segments are: Oil and Gas Integrated, Oil and Gas - Conventional, Business and Technology Development and Corporate. These segments are different than those reported in the Company s previous Form 10-Ks. Due to newly established geographically focused entities and the initiation of two new integrated projects, new segments are being reported to reflect how management now analyzes and manages the Company.

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***Oil and Gas***

Integrated

Projects in this segment have two primary components. The first component consists of conventional exploration and production activities together with enhanced oil recovery techniques such as steam assisted gravity drainage. The second component consists of the deployment of the HTL™ Technology which will be used to upgrade heavy oil at facilities located in the field to produce lighter, more valuable crude. The Company has two such projects currently reported in this segment - a heavy oil project in Alberta and a heavy oil property in Ecuador.

Conventional

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

***Business and Technology Development***

The Company incurs various costs in the pursuit of HTL™ and GTL projects throughout the world. Such costs incurred prior to signing a MOU or similar agreement, are considered to be business and technology development and are expensed as incurred. Upon executing a MOU to determine the technical and commercial feasibility of a project, including studies for the marketability for the projects products, the Company assesses whether 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.

Additionally, the Company incurs costs to develop, enhance and identify improvements in the application of the HTL™ and GTL technologies it owns or licenses. The cost of equipment and facilities acquired, 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.

***Corporate***

The Company s corporate segment consists of costs associated with the board of directors, executive officers, corporate debt, financings and other corporate activities.

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.

## CORPORATE STRATEGY

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

The global oil and gas industry is being impacted by the declining availability of replacement low cost reserves. This has resulted in volatility in oil markets and marked shifts in the demand and supply landscape. Although there has been a great deal of volatility in the price of oil and significant recent price declines, we believe that long term demand and the natural decline of conventional oil production will see the development of higher cost and lower value resources, including heavy oil.

Heavy oil developments can be segregated into two types: conventional heavy oil that flows to the surface without steam enhancement and non-conventional heavy oil and bitumen. While the Company focuses on the non-conventional heavy oil, both play an important role in Ivanhoe Energy s corporate strategy.

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Production of conventional heavy oil has been steadily increasing worldwide, led by Canada and Latin America but with significant contributions from most other 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 heavy oil production has been increasingly more common. Refineries, on the other hand, have not been able to keep up with the need for deep conversion capacity, and heavy versus light oil 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 more effectively access the extensive, heavy oil resources around the world.

These newer technologies, together with higher oil prices seen in the first part of this past year, have generated increased interest in 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, 3) the wide heavy versus light oil price differentials that the producer is faced with when the product gets to market, and 4) conventional upgrading technologies limited to very large scale, high capital cost facilities. 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**

The Company s application of the HTL™ Technology seeks to address the four key heavy oil development challenges outlined above, and can do so at a relatively small minimum economic scale.

Ivanhoe Energy s HTL upgrading is a partial upgrading process that is designed to operate in facilities as small as 10,000 to 30,000 barrels per day produced. This is substantially smaller than the minimum economic scale for conventional stand-alone upgraders such as delayed cokers, which typically operate at scales of over 100,000 barrels per day produced. The Company s HTL Technology is based on carbon rejection, a tried and tested concept in heavy oil processing. The key advantage of HTL is that it is a very fast process, as processing times are typically under a few seconds. This results in smaller, less costly facilities and eliminates the need for hydrogen addition, an expensive, large minimum scale step typically required in conventional upgrading. The Company s HTL Technology has the added advantage of converting the byproducts from the upgrading process into onsite energy, rather than generating large volumes of low value coke.

The HTL process offers significant advantages as a field-located upgrading alternative, integrated with the upstream heavy oil production operation. HTL provides four key benefits to the producer:

1. Virtual elimination of external energy requirements for steam generation and/or power for upstream operations.

2. Elimination of the need for diluent or blend oils for transport.

3. Capture of the majority of the heavy versus light oil value differential.
4. Relatively small minimum economic scale of operations suited for field upgrading and for smaller field developments.

The business opportunities available to the Company correspond to the challenges each potential heavy oil project faces. In Canada, Ecuador, California, Iraq and Oman, all four of the HTL™ advantages identified above come into play. In others, including certain identified opportunities in Colombia 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 Energy value proposition.

**Implementation Strategy**

We are an oil and gas company with a unique technology which addresses several major problems confronting the oil and gas industry today and we believe that we have a competitive advantage because of our patented technology. In addition, because we have experienced thermal recovery teams in Bakersfield and Calgary, we are in a position to add value and leverage our technology advantage by working with partners on stranded heavy oil resources around the world.

The Company s continuing strategy is as follows:

1. ***Build a portfolio of major HTL™ projects.*** Continue to deploy the personnel and the financial resources in support of our goal to capture additional opportunities for development projects utilizing the Company s HTL™ Technology.
2. ***Advance the technology.*** Additional development work will continue to advance the technology through the first commercial application and beyond.
3. ***Enhance the Company s financial position in anticipation of major projects.*** Implementation of large projects requires significant capital outlays. The Company is working on various financing plans and establishing the relationships required for the development activities of the future.
4. ***Build internal capabilities.*** During 2008, significant progress has been made in building execution teams in preparation for the Company s first HTL™ projects. The upstream teams consist of a number of experienced heavy oil petroleum engineers and geologists complemented by a core team of geotechnical experts. In addition, the Company s Houston-based HTL™ technology team has been strengthened with the addition of a number of engineers that have an extensive background in chemical and petroleum refining, project engineering and the development and management of intellectual property. The Company expects to continue filling key positions in its execution mode.
5. ***Build the relationships needed for the future.*** Commercialization of the Company s technologies demands close alignment with partners, suppliers, host governments and financiers.

**INTEGRATED OIL AND GAS PROPERTIES**

**Tamarack Project**

In July 2008, the Company announced the completion of the acquisition of Talisman Energy Canada s ( **Talisman** ) 100% working interests in two leases (Leases 10 and 6) located in the heart of the Athabasca oil sands region in the Province of Alberta, Canada. Lease 10 is a 6,880-acre contiguous block located approximately ten miles (16 km) northeast of Fort McMurray. Lease 6 is a small, un-delineated, 680-acre block, one mile (1.6 km) south of Lease 10. Once the acquisition was complete the development of Lease 10 became known as the **Tamarack Project** or **Tamarack** .

The Tamarack Project will provide the site for the application of Ivanhoe Energy s proprietary, HTL heavy oil upgrading technology in a major, integrated heavy oil project. Tamarack has a relatively high level of delineation (four wells per section). We believe that a high-quality reservoir is present and is an excellent candidate for thermal recovery utilizing the SAGD process. The high quality of the asset is expected to provide for favorable projected operating costs, including attractive steam-oil ratios ( **SOR** ) using SAGD development techniques.

The Company s HTL™ plants at Tamarack are projected ultimately to be capable of operating at production rates of at least 30,000 barrels per day for approximately 25 years. The Company intends to integrate established SAGD thermal recovery techniques with its patented HTL upgrading process, producing and marketing a light, synthetic sour crude.

The Company has commenced planning its Project Tamarack development program in preparation for the submission of permits for an integrated HTL™ project. In general, thermal oil sands projects, including SAGD projects, require a period of initial development, including delineation, permitting and field development, which is followed by relatively stable operations for many years. The integrated HTL™ and SAGD project is expected to produce 20,000 BOPD of bitumen as a first stage and sell a sour synthetic bottomless product, most likely into the US mid-west market.

**Ecuador Project**

In October 2008, Ivanhoe Energy Ecuador Inc., an indirect wholly owned subsidiary, signed a contract with Ecuador state oil companies Petroecuador and Petroproduccion to explore and develop Ecuador s Pungarayacu heavy oil field which is part of Block 20. Block 20 is an area of approximately 426 square miles, approximately 125 miles southeast of Quito, Ecuador s capital.

Under this contract Ivanhoe Energy Ecuador will use the Company s unique and patented HTL™ Technology, as well as provide advanced oil-field technology, expertise and capital to develop, produce and upgrade heavy crude oil from the Pungarayacu field. In addition, Ivanhoe Energy Ecuador has the right to conduct exploration for light oil in the contract area and to use any light oil that it discovers to blend with the heavy oil for delivery to Petroproduccion.

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The contract has an initial term of 30 years and has three phases. The first two phases include the evaluation of the field s production capability and the crude-oil characteristics, as well as construction of the first HTL™ plant. The third phase involves full field development and will include drilling additional exploration and development wells. Additional HTL™ capacity will be added as necessary for expected production.

The Company will be in the approval phase during the first part of 2009 which includes obtaining environmental licenses. If the Company succeeds in getting the necessary approvals it will enter into the appraisal phase which would include obtaining permits to drill, undertaking seismic activity and drilling selected locations. Our analysis of old drilling core data from the Pungarayacu field suggests that there may be oil in the field that is lighter than the bitumen oil seeps that occur at the surface. During the drilling campaign undertaken approximately 25 years ago, geologists on site reported that the oil in the drilling cores fluoresced a bright color which would be inconsistent with bitumen. This coloration in other oil fields around the world is usually a sign of lighter oil. We will not be able to confirm this until we have results from our drilling program planned for later this year.

To recover its investments, costs and expenses, and to provide for a profit, Ivanhoe Energy Ecuador will receive from Petroproduccion a payment of US$37.00 per barrel of oil produced and delivered to Petroproduccion. The payment will be indexed (adjusted) quarterly for inflation, starting from the contract date, using the weighted average of a basket of three U.S. Government-published producer price indices relating to steel products, refinery products and upstream oil and gas equipment.

**CONVENTIONAL OIL AND GAS PROPERTIES**

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

The following table sets forth the estimated quantities of proved reserves and production attributable to our properties:

| Property | Location | 2008 Production (in MBoe) | Percentage of Total 2008 Production | 12/31/2008 Proved Reserves (in MBoe) | Percentage of Total Estimated Proved Reserves |
|---|---|---|---|---|---|
| South Midway | Kern County, California | 189 | 27% | 675 | 38% |
| West Texas | Midland County, Texas | 13 | 2% | 94 | 5% |
| Other | California | 2 | 0% | | 0% |
| Total U.S. | | 204 | 29% | 769 | 43% |
| Dagang | Hebei Province, China | 472 | 68% | 960 | 53% |
| Other | China | 18 | 3% | 72 | 4% |
| Total China | | 490 | 71% | 1,032 | 57% |
| Total | | 694 | 100% | 1,801 | 100% |

Note: See the Supplementary Disclosures About Oil and Gas Production Activities (Unaudited) , which follow the notes to our consolidated financial statements set forth in Item 8 in this Annual Report on Form 10-K, for certain details regarding the Company s oil and gas proved reserves, the estimation process and production by country. Estimates for our U.S. and China operations were prepared by independent petroleum consultants Netherland, Sewell & Associates Inc. and GLJ Petroleum Consultants Ltd., respectively. 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.

**Special Note to Canadian Investors**

Ivanhoe is a 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 received, exemptions from certain NI 51-101 disclosure requirements based on our adherence to SEC disclosure requirements, which differ in certain respects from the prescribed disclosure standards of NI 51-101.

In 2008, as a result of the enactment of amendments to NI 51-101, we were required to re-apply for, and received, exemptions from certain of the amended NI 51-101 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 current 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 requires disclosure of reserves and related future net revenues using forecasted prices, with additional constant pricing disclosure being optional;
- the SEC mandates disclosure of proved and proved developed 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. Please note that the differences between SEC requirements and NI 51-101 may be material.

## United States

### Production and Development

***South Midway***

We currently have 66 producing wells in South Midway of which we are the operator with a working interest of 100% and a 93% net revenue interest. In 2008, we drilled eight new wells on the South Midway properties compared to 2007 when we drilled none. Six of these new wells were in a new pool discovery. As well as being successful wells, these new wells have proved up additional locations. These new wells have initial production rates after steam stimulations of 15-50 Boe/d.

***West Texas***

In 2000, we farmed-in to the Spraberry property, which is a producing property located on 2,500 gross acres in the Spraberry Trend of the Permian Basin in West Texas. We retain working interests ranging from 31% to 48% in 23 wells, which are currently producing approximately 28 net Boe/d compared to 40 net Boe/d at December 31, 2007. The future decline of the oil and gas production rates are expected to be moderate and should lead to consistent performance and long life reserves.

***Other***

In mid-2004, we farmed-in to the McCloud River prospect near the Cymric field in the San Joaquin Basin. After the initial well resulted in a dry hole, a second prospect, North Salt Creek was identified. Due to the prior completion of three producers with attractive pay columns which resulted in oil production with repeated cyclic steam stimulations, three more oil wells were drilled and completed in 2008. Two of the wells are located in the Miocene Antelope Section and the third in a Pliocene sand. One of the wells is expected to produce gas and the other two are oil wells currently awaiting steam stimulation.

In addition to the new producers at Salt Creek, a new water disposal well and facilities have been constructed.

The Company has a 24% working interest in this 1,120 gross-acre prospect.

### 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. This well was full depleted by the end of 2006.

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. 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. Negotiations for farm-outs and other financing opportunities in order to drill this play have been unsuccessful to date. The Company plans to continue to explore its options with regard to the Knights Landing property to seek either a farm out or possible drilling program.

***Aera Exploration Agreement***

The exploration agreement with Aera Energy LLC ( **Aera** ), a company owned by affiliates of ExxonMobil and Shell, 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. The majority of these San Joaquin prospects are fee property with no rental payments to maintain the Company s leases. The timing of drilling on these prospects is dependent on other working interest owners.

**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 10,255 gross acres divided into three 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 into 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. We suspended drilling in late 2005 to allow for detailed evaluation of well productivity and production decline performance. 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, and in the fourth quarter of 2006, we reached agreement with CNPC to reduce the overall scope of the ODP to approximately 44 wells through a modified ODP. This program included a further five development wells to be drilled in 2007. This program has been finalized and all five wells have been completed and placed on production. Further to the previous relinquishment of three of the six blocks that were part of the ODP, an additional 2,759 acres of undeveloped land was relinquished in one of the remaining blocks in 2008. Commercial production commenced on January 1, 2009 as agreed by the parties following conversion of two wells to water injection for pressure maintenance. At such time the Company, pursuant to the terms of the agreement, will be able to recover from CNPC its share of operating costs, currently 18% then 51%

after cost recovery.

No new development wells were drilled in 2008 as compared to 5 in 2007. In 2008, we did, however, fracture stimulate 12 wells and perforate additional sands in 8 other wells. Only a third of the net pay in each of the new five wells was completed and fracture stimulated in 2007. The year-end 2008 gross production rate was 1,700 Bopd (277 Bopd resulting from the five 2007 wells) compared to 1,900 Bopd at the end of 2007 and 1,877 Bopd at the end of 2006. We currently sell our crude oil at a three-month rolling average price of Cinta crude which historically averages approximately $3.00 per barrel less than West Texas Intermediate ( **WTI** ) price.

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### 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 first three-year period was ultimately extended to December 31, 2007. 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 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. The Company is currently discussing additional farm-out interest opportunities with Mitsubishi and other international oil companies.

The Company now has completed the first phase under the Zitong Contract ( **Phase 1** ). This included reprocessing approximately 1,649 miles of existing 2D seismic data and acquiring approximately 705 miles of new 2D seismic data, and interpreting this data. This was followed by drilling two wells, totaling an aggregate of 22,293 feet. Both wells encountered expected reservoirs and gas was tested on the second well, but neither well demonstrated commercially viable flow rates and both have been suspended. The Company may elect to reenter these wells to stimulate or drill directionally in the future.

In December 2007, the Company and Mitsubishi (the **Zitong Partners** ) made a decision to enter into the next three-year exploration phase ( **Phase 2** ). By electing to participate in Phase 2 the Zitong Partners must relinquish 30%, plus or minus 5%, of the Zitong block acreage and complete a minimum work program involving the acquisition of approximately 200 miles of new seismic lines and approximately 23,700 feet of drilling (including the Phase 1 shortfall), with total gross remaining estimated minimum expenditures for this program of $27.4 million. The Phase 2 seismic line acquisition commitment was fulfilled in the Phase 1 exploration program. The Zitong Partners plan to acquire additional seismic data in Phase 2. The partners have requested that CNPC allow the offset of this additional seismic line acquisition against the drilling commitment, reducing the required Phase 2 drilling footage requirement, but no agreement has been reached at this time. The Zitong Partners have relinquished 15% of the Block acreage and will relinquish an additional 10% to complete the Phase I relinquishment requirement. The Zitong Partners contracted Sichuan Geophysical Company to conduct a complete review of the seismic data acquired to date on the block to select the first Phase II drilling location. Drilling is to commence in late 2009 with expected completed drilling, completion and evaluation of the prospect finalized in late 2010. The Zitong Partners 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. Following the completion of Phase 2, the Zitong Partners must relinquish all of the remaining property except any areas identified for development and production. In the event of a discovery, the Zitong Partners believe it would be possible to negotiate to enter a Phase III and reduce the amount of land relinquishment to allow further exploration activities.

## BUSINESS AND TECHNOLOGY DEVELOPMENT

### Heavy to Light Oil Upgrading

#### 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. In addition, Ivanhoe Energy currently has several additional HTL™ patents in various stages of prosecution.

#### Feedstock Test Facility

The Company initiated the construction of the Feedstock Test Facility ( **FTF** ) during 2007. The FTF is a small 10-15 Bbls/d, highly flexible state-of-the-art HTL™ facility which will permit screening of global crude oil for current and potential partners in smaller volumes and at lower costs than required at the Commercial Demonstration Facility ( **CDF** ) (see described below). As we continue to advance our technology, this unit will form an integral part of the ongoing post-commercialization optimization of our products and processes. The FTF will provide additional data and will support the detailed engineering process once the first commercial target location and crude has been established. The FTF will also serve an integral part in supporting all of the Company s commercial operations.

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This facility, costing approximately $8.8 million, is expected to be commissioned during the first quarter of 2009. The FTF is located in San Antonio, Texas.

**Commercial Demonstration Facility**

In 2004, Ensyn constructed a CDF to confirm earlier pilot test results on a larger scale and to test certain processing options. This facility, acquired by the Company as part of the Ensyn merger, was built in the Belridge field, a large heavy oil field owned by Aera. In March 2005, initial performance testing of the CDF was completed successfully and the results of the test were verified by two large independent consulting firms. The CDF demonstrated an overall processing capacity of approximately 1,000 Bbls/d based on whole oil from the Belridge California heavy oil fields and a hot reaction section capacity of approximately 300 Bbls/d.

During 2007, technical developments were led by two important test runs at the CDF: a High Quality configuration was demonstrated on Belridge whole oil vacuum tower bottoms ( **VTBs** ) and a key test was successfully completed processing Athabasca bitumen pursuant to a longstanding technology development agreement with ConocoPhillips Canada Resources Corp. These two key tests were the capstones of the CDF test program and we have now fulfilled the primary technical objectives of the CDF. The goals of the test program were: (1) to confirm in a substantially large facility the key results generated in the early Ensyn pilot plant runs of heavy oil and bitumen which formed the basis of the HTL™ intellectual property, and (2) to provide sufficient data for the design and construction of commercial HTL™ plants.

The Athabasca bitumen CDF test provided important technical information related to the design of full-scale HTL™ facilities. This test coupled with other test run data, correlated the performance of the CDF with earlier runs on the smaller scale pilot facility and validated the assumptions in Ivanhoe Energy s economic models.

The Company plans to have the CDF available through the end of 2009 for potential investor crude evaluations as well as investor due diligence exercises.

**Business Development**

We are pursuing HTL™ business development opportunities around the world, primarily Western Canada, Latin America and the Middle East/North Africa region. Integrated HTL™/SAGD financial models for Athabasca have been updated and refined, incorporating newly revised capital costs from AMEC, and revised price assumptions and currency exchange rate changes. These updated models show that HTL™ integration represents robust value-add for thermal bitumen projects in Western Canada.

We also made significant progress in developing an execution plan with AMEC, our Tier One engineering contractor, for the design and construction of full-scale commercial HTL™ facilities. The Company is proceeding with preliminary, non site-specific engineering related to the first fully commercial HTL™ facility, supported by the recent successful CDF runs.

In October 2004, we signed a 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 17.1 degree 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 as well as an economic evaluation are both complete. Based on this evaluation we submitted a technical proposal to the Iraq Ministry of Oil who have accepted and approved the study and its conclusions.

In the first half of 2007, the Company and INPEX Corporation ( **INPEX** ), Japan s largest oil and gas exploration and production company, signed an agreement to jointly pursue the opportunity to develop the above noted heavy oil field in Iraq. During the second quarter of 2007, INPEX paid $9.0 million to the Company as a contribution towards the Company s historical costs related to the project and certain costs related to the development of its HTL™ upgrading technology.

The agreement provides INPEX with a significant minority interest in the venture, with Ivanhoe Energy retaining a majority interest. Both parties will participate in the pursuit of the opportunity but Ivanhoe will lead the discussions with the Iraqi Ministry of Oil. Should the Company and INPEX proceed with the development and deploy Ivanhoe Energy s HTL™ Technology, certain technology fees would be payable to the Company by INPEX.

In September 2007, the Ministry of Oil requested that we submit a commercial proposal for a 30,000 Bopd Pilot Project to test the reservoir response to thermal recovery methods, optimize the development plan and build/operate the first HTL™ unit for the field. Commercial proposals for a 10,000 Bopd Quick Start Project and a 30,000 Bopd

Pilot Project were both submitted to the Ministry in the latter part of 2008. A meeting took place with the Iraqi Ministry of Oil during November 2008. Negotiations are currently underway on the 10,000 BPD proposal.

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During the fourth quarter of 2007 we signed a MOU with Libya to perform an evaluation of the Haram Field and submit a proposal if warranted. A commercial proposal was submitted in September 2008 to the Libya National Oil Corporation ( **LNOC** ). We expect to be meeting with the LNOC in early 2009 to discuss this proposal.

**Gas-to-Liquids Technology**

**Syntroleum License**

We own a non-exclusive master license entitling us to use Syntroleum s proprietary GTL Technology 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**TM ) 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 Project**

At the present time, the only GTL project we are pursuing is in Egypt. 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 in Egypt that would convert natural gas to ultra-clean liquid fuels. 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. In November 2006, the Company signed a Participation Agreement with H.K. Renewable Energy Ltd. ( **HKRE** ). In August 2007, we signed a Term Sheet with EGAS (a 24% project participant) and HKRE (a 15% project participant) which set out the commercial terms for a 47,000 Bbls/d project to be run on a tolling basis. EGAS agreed 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 satisfactory conclusion of pre-front end engineering and design to confirm commercial viability and financing ability, the negotiation and signature of a definitive agreement and approval by the Company s Board of Directors and the appropriate authorities in Egypt.

Because the Company has been working on this project in Egypt for an extended period of time and has not been able to obtain a definitive agreement or appropriate project financing, the Company has impaired the carrying value of the costs associated with GTL. This impairment does not affect the Company s intention to continue to pursue this project.

**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.

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**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 we 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 and Ecuador continue to develop and implement more stringent environmental protection regulations and standards for different industries. Projects are currently monitored by governments based on the approved standards specified in the environmental impact statement prepared for individual projects.

Operations in Canada are still in the preliminary stages but the Company plans to observe all Canadian standards related to environmental management practices.

**Environmental Provisions**

As at December 31, 2008, a $1.8 million provision has been made for future site restoration and plugging and abandonment of wells in the U.S. and $1.9 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 $4.3 million and $2.0 million for the U.S. wells and CDF, respectively. We do not make such a provision for our oil and gas production 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 2008, our provision for future site restoration and plugging and abandonment of U.S. wells increased by $0.2 million and we increased our provision for the CDF by $1.1 million.

**Government Regulations**

Our business is subject to certain federal, state and local laws and regulations in the regions in which we operate 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 both in the U.S. and China, often imposing greater liability on a larger number of potentially responsible parties. Because the requirements imposed by such laws and regulations are frequently changed, we are not able to predict the ultimate cost of compliance.

**EMPLOYEES**

As at December 31, 2008, we had 165 employees and consultants actively engaged in the business. None of our employees are unionized.

**PRODUCTION, WELLS AND RELATED INFORMATION**

See the Supplementary Disclosures About Oil and Gas Production Activities (Unaudited) , 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.

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 (which include Windfall Levy and Production tax) only and exclude depletion and depreciation, income taxes, interest, selling and administrative expenses.

| | Average Sales Price | | | Average Operating Costs | | |
|---|---|---|---|---|---|---|
| | **2008** | **2007** | **2006** | **2008** | **2007** | **2006** |
| **Crude Oil and Natural Gas ($/Boe)** | | | | | | |
| U.S. | $ 88.67 | $ 61.71 | $ 54.86 | $ 25.14 | $ 21.72 | $ 19.54 |
| China | $ 98.73 | $ 64.86 | $ 62.04 | $ 43.92 | $ 26.88 | $ 20.58 |

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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.

| | **2008** | | | | **2007** | | | | **2006** | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **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. | 100 | 82.9 | 2 | 0.5 | 92 | 74.9 | 1 | 0.2 | 89 | 73.5 | 2 | 1.0 |
| China | 44 | 36.1 | | | 44 | 36.1 | | | 42 | 34.4(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** | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **2008** | | **2007** | | **2006** | | **2008** | | **2007** | | **2006** | |
| | **Oil** | **Gas** | **Oil** | **Gas** | **Oil** | **Gas** | **Oil** | **Gas** | **Oil** | **Gas** | **Oil** | **Gas** |
| U.S. | | | | | | | | | | | 0.6(1) | |
| China | | | | | | | | | | 0.9 | | |
| Total | | | | | | | | | | 0.9 | 0.6 | |

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

**Development**

| | **Productive Wells** | | | | | | **Dry Wells** | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **2008** | | **2007** | | **2006** | | **2008** | | **2007** | | **2006** | |
| | **Oil** | **Gas** | **Oil** | **Gas** | **Oil** | **Gas** | **Oil** | **Gas** | **Oil** | **Gas** | **Oil** | **Gas** |
| U.S. | 8.7(1) | 0.2 | 1.2 | | 9.0 | | | | | | | |
| China | | | 4.1 | | | | | | | | | |
| Total | 8.7 | 0.2 | 5.3 | | 9.0 | | | | | | | |

(1) Includes 0.5 (2 gross) net development wells not included in the commercially productive wells table above as these wells are waiting to be steamed.

**Wells in Progress**

At the end of 2008, 2007 and 2006 we had 4.8 (7 gross), 4.3 (5 gross) and 5.3 (6 gross) net wells, respectively, which were either in the process of drilling or suspended.

**Acreage**

The following table sets forth our holdings of developed and undeveloped oil and gas acreage as at December 31, 2008. 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. | 6,011 | 3,440 | 69,003 | 16,452 |
| China (1) | 1,490 | 1,222 | 752,697 | 676,928 |

(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.

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## 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. Some of the following statements are forward-looking and involve risks and uncertainties. Please refer to the Special Note Regarding Forward-Looking Statements set forth on page 4 of this Form 10-K. 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 our HTL™ project development initiatives in Canada and Ecuador will require significant investments in development activities. Since our revenues from existing operations are insufficient to fund the capital expenditures that will be required to implement our HTL™ 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. The availability of financing is dependent in part on the return of the credit and equity markets to normalized conditions. During the fourth quarter of 2008, as a result of the global economic crisis, the terms and availability of equity and debt capital have been materially restricted and financing may not be available when it required or 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 have fixed and contingent payment obligations to Talisman Energy***

We have certain future fixed and contingent payment obligations to Talisman Energy that arose as a result of our acquisition from Talisman Energy of our Athabasca heavy oil leases in 2008. These obligations include a Cdn.$40,000,000 convertible promissory note that, unless converted into Ivanhoe common shares, is due in July, 2011 and a contingent payment of up to Cdn.$15,000,000 that will become due and payable if and when the requisite governmental and other approvals to develop the northern border of one of the Athabasca heavy oil leases are obtained. As with the funds we require for our planned capital expenditures, we intend to finance such future payments through debt and equity markets, arrangements with third parties, either at the Ivanhoe parent company level or at the subsidiary or project level or from the sale of existing assets. There is no assurance that we will be able to obtain such financing on favorable terms or at all and any future equity issuances may be dilutive to investors. Failure to obtain such additional financing could put us in default of our obligations to Talisman Energy, which are secured by a first fixed charge and security interest in favor of Talisman over the Athabasca heavy oil leases and a subordinate security over certain of our present and after acquired property. In the case of such default, Talisman Energy could foreclose on the secured assets, including the leases.

***Our HTL™ projects in Canada and Ecuador are at a very early stage of development***

The HTL projects we plan to establish on our Athabasca heavy oil leases in Canada and our Block 20 project in Ecuador are currently at a very early stage of development and no detailed feasibility or engineering studies have been produced. There can be no assurances that such projects will be completed within any time frame or within the parameters of any determined capital cost. We have yet to establish a defined schedule for financing and developing such projects. In our efforts to develop these projects, we may experience delays, interruption of operations or increased costs as a result of unanticipated events and circumstances. These include breakdowns or failures of equipment or processes; construction performance falling below expected levels of output or efficiency, design errors, challenges to proprietary technology, contractor or operator errors; non-performance by third party contractors; labor disputes, disruptions or declines in productivity; increases in materials or labor costs; inability to attract sufficient numbers of qualified workers; delays in obtaining, or conditions imposed by, regulatory approvals; violation of permit requirements; disruption in the supply of energy; and catastrophic events such as fires, earthquakes, storms or explosions.

***Heavy oil exploration and development involves increased operational risks.***

Oil sands and heavy oil exploration and development are very competitive and involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. As with any petroleum property, there can be no assurance that commercial quantities of economically marketable oil will be produced. The viability and marketability of any production from the properties may be affected by factors and circumstances beyond our control, fluctuations in the market price of oil, proximity and capacity of pipelines and processing equipment, electricity transmission and distribution systems, transportation arrangements, equipment availability and government regulations (including regulations relating to prices, taxes, royalties, land tenure, allowable production, importing and exporting of oil and gas and environmental protection). The extent to which some or all of these factors will affect our business cannot be accurately predicted. If our proposed HTL projects in Canada and Ecuador are developed and become operational, there is no assurance that they will attain production in any specific quantities or within any defined cost framework, or that they will not cease producing entirely in certain circumstances. Because operating costs for production from oil sands and heavy oil fields may be substantially higher than operating costs to produce conventional crude oil, an increase in such costs may render the development and operation of these projects uneconomical. It is possible that other developments, such as increasingly strict environmental and safety laws and regulations and enforcement policies thereunder and claims for damages to property or persons resulting from the operations, could result in substantial costs and liabilities, delays or an inability to complete the proposed project or the abandonment of the proposed project.

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

We intend to integrate established SAGD thermal recovery techniques with our patented HTL upgrading process. Heavy oil recovery using the SAGD process is subject to technical and financial uncertainty. No commercial-scale HTL™ 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 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™ technology 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™ 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.***

Alternative sources of energy are continually under development and those 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 derived products, which would lower the demand for our HTL™ Technology upgraded product.

***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.

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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 bank credit facilities are determined by reference to borrowing bases. The amounts of our borrowing bases are established by our lenders and are primarily functions of the quantity and value of our reserves. Our borrowing bases are 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 amounts of borrowings available to us under our bank credit facilities could be adversely affected by extended periods of low commodity prices.

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

Under generally accepted accounting principles in Canada and the U.S. we may be required 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.

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

We continue 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. 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.

***Our heavy oil project in Canada may be exposed to title risks and aboriginal claims.***

We have not obtained title opinions in respect of the Athabasca heavy oil leases we acquired from Talisman Energy and there is a risk that our ownership of those leases may be subject to prior unregistered agreements or interests or undetected claims or interests that could impair our title. Any such impairment could jeopardize our entitlement to the economic benefits, if any, associated with the leases, which could have a material adverse effect on our financial condition, results of operations and ability to execute our business plans in a timely manner or at all.

Aboriginal peoples have claimed aboriginal title and rights to large areas of land in western Canada where crude oil and natural gas operations are conducted, including a claim filed against the Government of Canada, the Province of Alberta, certain governmental entities and the regional municipality of Wood Buffalo (which includes the City of Fort McMurray, Alberta) claiming, among other things, aboriginal title to large areas of lands surrounding Fort McMurray where most of the oil sands operations in Alberta are located. Such claims, if successful, could affect the title to our heavy oil leases and have a significant adverse effect on our business.

***Our investment in Ecuador may be at risk if the agreement through which we hold our interest in the Block 20 project is challenged or cannot be enforced.***

We hold our interest in the Block 20 heavy oil project in Ecuador through a services agreement with Petroecuador and its subsidiary Petroproduccion. The agreement is governed by the laws of Ecuador. Although the agreement has been translated into English, the official and governing language of the agreement is Spanish and if any discrepancy exists between the official Spanish version of the agreement and the English translation, the official Spanish version prevails. There may be ambiguities, inconsistencies and anomalies between the official Spanish version of the agreement and the English translation that could materially affect how our rights and obligations under the agreement are conclusively interpreted and such interpretations may be materially adverse to our interests.

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The dispute resolution provisions of the Block 20 agreement stipulate that disputes involving industrial property (including intellectual property) and technical or economic issues are subject to international arbitration. Other disputes are subject to resolution through mediation or arbitration in Ecuador. There is a risk that we and the other parties to the Block 20 agreement will be unable to agree upon the proper forum for the resolution of a dispute based on the subject matter of the dispute. There can also be no assurance that the other parties to the Block 20 agreement comply with the dispute resolution provisions of the Block 20 agreement or otherwise voluntarily submit to arbitration.

Government policy in Ecuador may change to discourage foreign investment or requirements not currently foreseen may be implemented. There can be no assurance that our investments and assets in Ecuador will not be subject to nationalization, requisition or confiscation, whether legitimate or not, by any authority or body. While the Block 20 agreement contains provisions for compensation and reimbursement of losses we may suffer under such circumstances, there is no assurance that such provisions would effectively restore the value of our original investment. There can be no assurance that Ecuadorian laws protecting foreign investments will not be amended or abolished or that the existing laws will be enforced or interpreted to provide adequate protection against any or all of the risks described above. There can also be no assurance that the Block 20 agreement will prove to be enforceable or provide adequate protection against any or all of the risks described above.

***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.

***No reserves have yet been established in respect of our HTL™ projects in Canada and Ecuador.***

No reserves have yet been established in respect of our Athabasca heavy oil project in Canada or our Block 20 project in Ecuador. There are numerous uncertainties inherent in estimating reserves, including many factors beyond our control and no assurance can be given that any level of reserves or recovery thereof will be realized. In general, estimates of reserves are based upon a number of assumptions made as of the date on which the estimates were determined, many of which are subject to change and are beyond our control.

***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 may not be able to meet any or all of the obligations required to maintain our interest in each such license, lease or production sharing contract. 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.

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***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 and gas. 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.

***Changes to laws, regulations and government policies in Canada or Ecuador could adversely affect our ability to develop our HTL™ projects.***

Our HTL™ projects in Canada and Ecuador are subject to substantial regulation relating to the exploration for, and the development, production, upgrading, marketing, pricing, taxation, and transportation of bitumen and heavy oil and related products and other matters, including environmental protection.

Legislation and regulations may be changed from time to time in response to economic or political conditions. The exercise of discretion by governmental authorities under existing legislation and regulations, the implementation of new legislation or regulations or the amending of existing legislation and regulations affecting the crude oil and natural gas industry generally could materially increase the costs of developing these projects and could have a material adverse impact on our business. There can be no assurance that laws, regulations and government policies relevant to these projects will not be changed in a manner which may adversely affect our ability to develop and operate them. Failure to obtain all necessary permits, leases, licenses and approvals, or failure to obtain them on a timely basis, could result in delays or restructuring of the projects and increased costs, all of which could have a material adverse effect on our business.

Construction, operation and decommissioning of these projects will be conditional upon the receipt of necessary permits, leases, licenses and other approvals from applicable governmental and regulatory authorities. The approval process can involve stakeholder consultation, environmental impact assessments, public hearings and appeals to tribunals and courts, among other things. An inability to secure local and regional community support could result in the necessary approvals being delayed or stopped. There is no assurance such approvals will be issued, or if granted, will not be appealed or cancelled or will be renewed upon expiry or will not contain terms and conditions that adversely affect the final design or economics of the projects.

***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. Oil sands and heavy oil extraction, upgrading and transportation operations are subject to extensive regulation and various approvals are required before such activities may be undertaken. We are subject to laws and regulations that govern the operation and maintenance of our facilities, the discharge of materials into the environment and other environmental protection issues. These laws and regulations may, among other potential consequences, require that we acquire permits before commencing drilling; restrict the substances that can be released into the environment with drilling and production activities; limit or prohibit drilling activities on protected areas such as wetlands or wilderness areas; require that reclamation measures be taken to prevent pollution from former operations; require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells and remediating contaminated soil and groundwater and require remedial measures be taken with respect to property designated as a contaminated site.

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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. No assurance can be given with respect to the impact of future environmental laws or the approvals, processes or other requirements thereunder on our ability to develop or operate our projects in a manner consistent with our current expectations.

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol, which requires signatory nations to reduce their nation-wide emissions of carbon dioxide and other greenhouse gases. Any significant extraction or upgrading operations we may undertake in respect of our HTL™ project in Canada are likely to produce certain greenhouse gases. The details of the implementation of a federal greenhouse gas reduction program in Canada have not been finalized and it is premature to predict what impact changes to Canadian federal or provincial regulations will have on the Canadian oil and natural gas industry, but if, and when we develop and operate our HTL™ project in Canada, we expect that we will face increased capital and operating costs in order to comply with greenhouse gas emissions targets and/or reductions, which may be material. There is no assurance that any mandatory emission intensity reductions to which we may become subject will be technically and economically feasible to implement. Failure to meet any such requirements or successfully engage alternative compliance mechanisms (such as emissions credits) could materially adversely affect our ability to develop and operate the project.

***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 principal shareholder may significantly influence our business.***

As at the date of this Annual Report, our largest shareholder, Robert M. Friedland, owned approximately 18% 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.

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Development of our heavy oil projects in Canada and Ecuador will require the recruitment and retention of experienced employees. We compete with other companies to recruit and retain the limited number of individuals who possess the requisite skills and experience in the particular areas of expertise that are relevant to our business. This competition exposes us to the risk that we will have to pay increased compensation to such employees or increase the Company s reliance and associated costs from partnering or outsourcing arrangements. There can be no assurance that all of the employees with the necessary abilities and expertise we require will be available.

**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***

The Company is a defendant in a lawsuit filed November 20, 2008 in the U.S. District Court for the District of Colorado by Jack J. Grynberg and three affiliated companies that alleges bribery and other misconduct and challenges the propriety of a contract awarded to the Company s wholly-owned subsidiary Ivanhoe Energy Ecuador Inc. to develop Ecuador s Pungarayacu heavy oil field. The plaintiff s claim is for unspecified damages or ownership of the Company s interest in the Pungarayacu field. The action is at an early stage and the parties are preparing their defense. All defendants have filed motions to dismiss the lawsuit for lack of jurisdiction. While the Company intends to rigorously defend the interest of the Company and its shareholders, the likelihood of any ultimate loss or gain, if any, is not determinable at this time.

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

None.

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## PART II

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

**Market Information**

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

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

| | 2008 | | | | 2007 | | | |
|---|---|---|---|---|---|---|---|---|
| | 4th Qtr | 3rd Qtr | 2nd Qtr | 1st Qtr | 4th Qtr | 3rd Qtr | 2nd Qtr | 1st Qtr |
| High | 1.43 | 3.51 | 3.77 | 1.97 | 2.45 | 2.25 | 2.65 | 2.16 |
| Low | 0.35 | 1.21 | 1.79 | 1.24 | 1.43 | 1.77 | 1.67 | 1.19 |

**TSX (IE)**
**(CDN$)**

| | 2008 | | | | 2007 | | | |
|---|---|---|---|---|---|---|---|---|
| | 4th Qtr | 3rd Qtr | 2nd Qtr | 1st Qtr | 4th Qtr | 3rd Qtr | 2nd Qtr | 1st Qtr |
| High | 1.53 | 3.37 | 3.85 | 1.99 | 2.33 | 2.36 | 2.99 | 2.53 |
| Low | 0.43 | 1.28 | 1.82 | 1.27 | 1.43 | 1.88 | 1.84 | 1.40 |

On December 31, 2008, the closing prices for our common shares were $0.49 on the NASDAQ Capital Market and Cdn. $0.58 on the TSX.

**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 an issuer s independent directors hold regularly scheduled meetings at which only independent directors are present.

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 our independent directors hold regularly scheduled meetings at which only independent directors are present, but there is no legal requirement in Canada for independent directors to hold regularly scheduled meetings at which only independent directors are present.

Although our non-management directors hold meetings from time to time as and when considered necessary or desirable by the independent lead director, such meetings are not regularly scheduled.

**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, 2008, a total of 279,381,187 of our common shares were issued and outstanding and held by 241 holders of record with an estimated 21,000 additional shareholders whose shares were held for them in street name or nominee accounts.

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**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. Currently, 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 2009 is expected to be Cdn.$312 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.

The Canadian Federal Government has recently brought forth certain proposed amendments (the Amendments ) to the Investment Act. If adopted as law, the Amendments would generally raise the thresholds that trigger governmental review. Specifically, with respect to investors based in WTO member nations, the Amendments would see the thresholds for the review of direct acquisitions of control increase from the current Cdn.$312 million (based on book value) to Cdn.$600 million (to be based on the enterprise value of the Canadian business) for the two years after the Amendments becomes law, to Cdn.$800 million in the following two years and then to Cdn.$1 billion for the next two years. Thereafter, the threshold is to be adjusted to account for inflation. The exact specifications of the Amendments still require additional definition and details of how they will be implemented. The Amendments, however, represent a significant change to Canada s regulation of foreign investment.

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%.

**Securities Authorized for Issuance under Equity Compensation Plans**

See table under Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters set forth in Item 12 in this Annual Report on Form 10-K.

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**Performance Graph**

See table under Executive Compensation set forth in Item 11 in this Annual Report on Form 10-K.

**Sales of Unregistered Securities**

All securities we issued during the year ended December 31, 2008, which were not registered under the Act, have been detailed in previously filed Form 10-Qs.

During the year ended December 31, 2007, we issued securities, which were not registered under the Securities Act of 1933 (the **Act** ), as follows:

- in November 2007, we issued 2,000,000 common shares under Rule 903 of the Act at a price of U.S.$2.00 to an institutional investor pursuant to the exercise of previously issued share purchase warrants.

During the year ended December 31, 2006, we issued securities, which were not registered under the Act, as follows:

- in February 2006, we issued 8,591,434 common shares under Rule 903 of the Act to CITIC in exchange for an additional 40% working interest in the Dagang field.
- in March 2006, we issued 100 common shares under Rule 903 of the Act at a price of U.S.$3.20 to an institutional investor pursuant to the exercise of previously issued share purchase warrants.
- in April 2006, we issued 11,400,000 special warrants under Rule 903 of the Act at U.S.$2.23 per special warrant to institutional and individual investors. 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 TSX and the exercise price was changed to Cdn.$2.93.

## ITEM 6. *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. See Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations and Note 19 to our financial statements in this Annual Report on Form 10-K for detailed description of the differences between GAAP applicable in Canada and GAAP applicable in the U.S. as it relates to the Company.

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

| | December 31 | | | | |
|---|---|---|---|---|---|
| | **2008** | **2007** | **2006** | **2005** | **2004** |
| | (stated in thousands of US dollars, except per share amounts) | | | | |
| **Results of Operations** | | | | | |
| Revenues | 69,166 | 33,517 | 48,100 | 29,939 | 17,997 |
| Net loss | (34,193)(1) | (39,207)(1) | (25,492)(1) | (13,512)(1) | (20,725)(1) |
| Net loss per share basic and diluted | (0.13) | (0.16) | (0.11) | (0.07) | (0.12) |
| **Financial Position** | | | | | |
| Total assets | 317,275 | 236,916 | 248,544 | 240,877 | 118,486 |
| Long-term debt | 37,855 | 9,812 | 4,237 | 4,972 | 2,639 |
| Shareholders equity | 257,427 | 197,287 | 228,386 | 204,767 | 103,586 |
| Common shares outstanding (in thousands) | 279,381 | 244,873 | 241,216 | 220,779 | 169,665 |
| **Cash Flow** | | | | | |
| Cash provided by operating activities | 17,053 | 5,489 | 14,352 | 9,870 | 4,032 |
| Capital investments | (25,606) | (31,638) | (17,842) | (43,282) | (46,454) |

(1) Includes asset write-downs and provisions for impairment of $17.7 million, $6.1 million, $5.4 million, $5.6 million and $16.6 million for 2008, 2007, 2006, 2005 and 2004, respectively. See Note 4 to our financial statements under Item 8 in this Annual Report on Form 10-K.

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**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 differences between Canadian and U.S. GAAP, which affect our financial statements, are described in detail in 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 | | | | |
|---|---|---|---|---|---|
| | 2008 | 2007 | 2006 | 2005 | 2004 |
| | (stated in thousands of US dollars, except per share amounts) | | | | |
| **Results of Operations** | | | | | |
| Net loss | (63,051) (1) | (27,392) (1) | (42,421) (1) | (12,106) (1) | (19,696) (1) |
| Net loss per share basic and diluted | (0.24) | (0.11) | (0.18) | (0.06) | (0.12) |
| **Financial Position** | | | | | |
| Total assets | 263,247 | 216,656 | 216,365 | 224,935 | 105,791 |
| Long-term debt | 40,392 | 10,412 | 4,237 | 4,972 | 2,639 |
| Shareholders equity | 199,741 | 170,545 | 189,829 | 188,745 | 90,892 |
| **Cash Flow** | | | | | |
| Cash provided by operating activities | 16,639 | 11,501 | 13,340 | 5,042 | 2,222 |
| Capital investments | (25,192) | (31,371) | (16,830) | (38,454) | (44,644) |

(1) Includes asset write-downs and provisions for impairment of $54.9 million, $5.9 million, $23.5 million, $4.5 million and $15.0 million for 2008, 2007, 2006, 2005 and 2004, respectively. See Note 19 to our financial statements under Item 8 in this Annual Report on Form 10-K.

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**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, 2008. THE CONSOLIDATED FINANCIAL STATEMENTS HAVE BEEN PREPARED IN ACCORDANCE WITH GENERALLY ACCEPTED ACCOUNTING PRINCIPLES ( **GAAP** ) IN CANADA. THE IMPACT OF SIGNIFICANT DIFFERENCES BETWEEN CANADIAN AND U.S. GAAP ON THE FINANCIAL STATEMENTS IS DISCLOSED IN NOTE 19 TO THE CONSOLIDATED FINANCIAL STATEMENTS.

OUR DISCUSSION AND ANALYSIS OF OUR OIL AND GAS ACTIVITIES WITH RESPECT TO OIL AND GAS VOLUMES, RESERVES AND RELATED PERFORMANCE MEASURES IS PRESENTED ON OUR WORKING INTEREST BASIS AFTER ROYALTIES. 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 HTL™ Technology and EOR techniques. In addition, the Company seeks to expand its reserve base and production through conventional exploration and production of oil and gas. Our core operations are currently carried out in China, the United States, Canada and Ecuador, with business development opportunities worldwide. In mid-2008, the Company acquired two leases located in the heart of the Athabasca oil sands region in Alberta, Canada and recently signed a contract in Ecuador for the appraisal and development of a heavy oil lease in Ecuador. It is anticipated that these sites will provide for the first commercial applications of the Company s HTL Technology in major, integrated heavy oil projects.

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 by pipelines. 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 can be 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 a substantial portion 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 2008 Results***

During the year, the value attributed to our reserves of oil and gas based on a standardized measure of discounted future cash flows decreased by 82% to $75.8 million of which $35.5 million is in China and $40.3 million in the U.S. These values decreased principally as a result of significant year-over-year decreases in oil prices as at the end of the year of 50%. Total revenues increased as a result of price increases during a portion of the year and a $12.6 million increase in gains on derivative instruments that were required by the Company s bank loan agreements. General and administrative costs increased as the Company continued to invest significant resources in the development and commercial deployment of its patented HTL heavy oil upgrading technology. In addition, in 2008 the Company made a $15.1 million provision for impairment of its GTL intangible assets and development costs.

In the second and third quarters of 2008, the Company completed three key transactions: 1) the acquisition of what we believe to be high quality oil sand assets in the Athabasca region of Canada (our **Tamarack** project), 2) an agreement with the Government of Ecuador on the development of a major heavy oil block in Ecuador ( **Pungarayacu** ), and 3) a Cdn.$88 million equity financing. With these transactions, the Company has taken significant steps towards its transition to a heavy oil exploration, production and upgrading company.

The remainder of 2008 was dedicated primarily to formulating the development plans for the Tamarack project in Alberta and for Pungarayacu in Ecuador, including advancing the permitting processes. In addition, the Company commissioned and began operating the HTL Feedstock Test Facility in San Antonio, and continues with HTL engineering of commercial scale HTL facilities consistent with the development plans for Tamarack and Pungarayacu.

The Company s four reportable business segments are: Oil and Gas Integrated, Oil and Gas - Conventional, Business and Technology Development and Corporate. These segments are different than those reported in the Company s previous financial statements included in its Form 10-Ks and as such the presentation has been changed to conform to the new segments. Due to newly established geographically focused entities and the initiation of two new integrated projects, new segments are being reported to reflect how management now analyzes and manages the Company.

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***Oil and Gas***

Integrated

Projects in this segment will have two primary components. The first component consists of conventional exploration and production activities together with enhanced oil recovery techniques such as steam assisted gravity drainage. The second component consists of the deployment of the HTL™ Technology which will be used to upgrade heavy oil at facilities located in the field to produce lighter, more valuable crude. The Company has two such projects currently reported in this segment a heavy oil project in Alberta and a heavy oil property in Ecuador. The integrated segments were established in 2008 and therefore there is no comparative information for 2007 and 2006.

Conventional

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

***Business and Technology Development***

The Company incurs various costs in the pursuit of HTL™ and GTL projects throughout the world. Such costs incurred prior to signing a MOU or similar agreement, are considered to be business and technology development and are expensed as incurred. Upon executing a MOU to determine the technical and commercial feasibility of a project, including studies for the marketability for the projects products, the Company assesses whether 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.

Additionally, the Company incurs costs to develop, enhance and identify improvements in the application of the HTL™ and GTL technologies it owns or licenses. The cost of equipment and facilities acquired, 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.

***Corporate***

The Company s corporate segment consists of costs associated with the board of directors, executive officers, corporate debt, financings and other corporate activities.

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

| | Year ended December 31, | | |
|---|---|---|---|
| | **2008** | **2007** | **2006** |
| Oil and gas revenue | $ 66,490 | $ 43,635 | $ 47,748 |
| Net loss | $ (34,193) | $ (39,207) | $ (25,492) |
| Net loss per share basic and diluted | $ (0.13) | $ (0.16) | $ (0.11) |
| Average production (Boe/d) | 1,897 | 1,870 | 2,178 |
| Net operating revenue per Boe | $ 57.38 | $ 38.56 | $ 39.77 |
| Cash flow provided by operating activities | $ 17,053 | $ 5,489 | $ 14,352 |
| Capital investments | $ (25,606) | $ (31,638) | $ (17,842) |

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***Financial Results Year to Year Change in Net Loss***

The following provides a summary analysis of our net loss for each of the three years ended December 31, 2008 and a summary of year-over-year variances for the year ended December 31, 2008 compared to 2007 and for the year ended December 31, 2007 compared to 2006:

| | 2008 | *Favorable (Unfavorable) Variances* | 2007 | *Favorable (Unfavorable) Variances* | 2006 |
|---|---|---|---|---|---|
| **Summary of Net Loss by Significant Components:** | | | | | |
| Oil and Gas Revenues: | $ 66,490 | | $ 43,635 | | $ 47,748 |
| Production volumes | | *$ 717* | | *$ (6,732)* | |
| Oil and gas prices | | *22,138* | | *2,619* | |
| Realized gain (loss) on derivative instruments | (9,625) | *(7,977)* | (1,648) | *(1,717)* | 69 |
| Operating costs | (26,652) | *(9,333)* | (17,319) | *(1,186)* | (16,133) |
| General and administrative, less stock based compensation | (15,202) | *(5,830)* | (9,372) | *(1,724)* | (7,648) |
| Business and technology development, less stock based compensation | (5,885) | *2,715* | (8,600) | *(1,379)* | (7,221) |
| Net interest | (815) | *(503)* | (312) | *(283)* | (29) |
| Current income tax provision | (656) | (656) | | | |
| Unrealized gain (loss) on derivative instruments | 11,591 | *20,530* | (8,939) | *(8,446)* | (493) |
| Depletion and depreciation | (31,904) | *(5,380)* | (26,524) | *6,026* | (32,550) |
| Stock based compensation | (3,554) | *175* | (3,729) | *(808)* | (2,921) |
| Provision for impairment of GTL intangible assets and development costs | (15,054) | (15,054) | | | |
| Impairment of oil and gas properties | | *6,130* | (6,130) | *(710)* | (5,420) |
| Write off of deferred financing costs | (2,621) | (2,621) | | | |
| Acquisition costs | | | | *736* | (736) |
| Other | (306) | *(37)* | (269) | *(111)* | (158) |
| Net Loss | $ (34,193) | *$ 5,014* | $ (39,207) | *$ (13,715)* | $ (25,492) |

Our net loss for 2008 was $34.2 million ($0.13 per share) compared to our net loss in 2007 of $39.2 million ($0.16 per share). The decrease in our net loss from 2007 to 2008 of $5.0 million was due to an increase of $14.9 million in combined oil and gas revenues and realized gain on derivative instruments. These were offset by increases in operating costs of $9.3 million, a $3.1 million increase in general and administrative and business and technology development expenses excluding stock based compensation and a $5.4 million increase in depletion and depreciation. In addition, there was a $20.5 million increase in income as a result of unrealized gain on derivative instruments offset by a combined $11.5 million expense increase arising from the impairment of assets.

Our net loss for 2007 was $39.2 million ($0.16 per share) compared to our net loss in 2006 of $25.5 million ($0.11 per share). The increase in our net loss from 2006 to 2007 of $13.7 million was due to decrease of $5.8 million in combined oil and gas revenues and realized loss on derivative instruments, an increase in operating costs of $1.2 million, a $3.1 million increase in general and administrative and business and technology development expenses excluding stock based compensation and an $8.4 million increase in unrealized loss on derivative instruments. These increases were partially offset by a $6.0 million decrease for depletion and depreciation.

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

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## Revenues and Operating Costs

The following is a comparison of changes in production volumes for the year ended December 31, 2008 when compared to the same period in 2007 and for the year ended December 31, 2007 when compared to the same period for 2006:

| | Years ended December 31, Net Boe s | | Percentage | Years ended December 31, Net Boe s | | Percentage |
|---|---|---|---|---|---|---|
| | 2008 | 2007 | Change | 2007 | 2006 | Change |
| **China:** | | | | | | |
| Dagang | 471,817 | 464,206 | 2% | 464,206 | 554,185 | -16% |
| Daqing | 18,096 | 19,379 | -7% | 19,379 | 20,946 | -7% |
| | 489,913 | 483,585 | 1% | 483,585 | 575,131 | -16% |
| **U.S.:** | | | | | | |
| South Midway | 188,911 | 177,745 | 6% | 177,745 | 188,379 | -6% |
| Spraberry | 13,484 | 19,587 | -31% | 19,587 | 23,242 | -16% |
| Others | 1,960 | 1,512 | 30% | 1,512 | 8,309 | -82% |
| | 204,355 | 198,844 | 3% | 198,844 | 219,930 | -10% |
| | 694,268 | 682,429 | 2% | 682,429 | 795,061 | -14% |

Net production volumes in 2008 increased 2% from 2007 due to a 1% increase in production volumes in our China properties and a 3% increase in our U.S. properties, resulting in increased revenues of $0.7 million.

Net production volumes in 2007 decreased 14% from 2006 due to a 16% decrease in production volumes in our China properties and a 10% decrease in our U.S. properties, resulting in decreased revenues of $6.7 million.

Oil and gas prices increased 50% per Boe in 2008 contributing to a $22.1 million increase in revenue as compared to 2007. We realized an average of $98.73 per Boe from operations in China during 2008, which was an increase of $33.87 per Boe from 2007 prices and accounted for $16.6 million of our increase in revenues. From the U.S. operations, we realized an average of $88.97 per Boe during 2008, which was an increase of $26.96 per Boe and accounted for $5.5 million of our increased revenues. We expect crude oil prices and natural gas prices to remain volatile in 2009.

Oil and gas prices increased 6% per Boe in 2007 generating $2.6 million in additional revenue as compared to 2006. We realized an average of $64.86 per Boe from operations in China during 2007, which was an increase of $2.82 per Boe from 2006 prices and accounted for $1.3 million of our increase in revenues. From the U.S. operations, we realized an average of $61.71 per Boe during 2007, which was an increase of $6.85 per Boe and accounted for $1.3 million of our increased revenues.

The increased revenues from higher oil and gas price in 2008 and 2007 were offset by the realized loss on derivatives resulting from settlements from our costless collar derivative instruments. As benchmark prices rise above the ceiling price established in the contract the Company is required to settle monthly (see further details on these contracts below under Unrealized Gain (Loss) on Derivative Instruments ). The Company realized a net loss on these settlements in 2008 of $9.6 million, $5.2 million of which was from the U.S. segment, the balance from the China segment. This compares to a realized net loss in 2007 of $1.6 million and a $0.1 million realized gain in 2006. Changes in these realized settlement gains (losses) by segment are detailed below:

| | Year Ended | *Favorable (Unfavorable)* | Year Ended | *Favorable (Unfavorable)* | Year Ended |
|---|---|---|---|---|---|

| | December 31, 2008 | | *Variances* | | December 31, 2007 | | *Variances* | | December 31, 2006 |
|---|---|---|---|---|---|---|---|---|---|
| China | $ | (4,430) | *$* | *(4,096)* | $ | (334) | *$* | *(334)* | $ |
| U.S. | | (5,195) | | *(3,881)* | $ | (1,314) | | *(1,383)* | 69 |
| | $ | (9,625) | *$* | *(7,977)* | $ | (1,648) | *$* | *(1,717)* | $ 69 |

Operating costs, including Windfall Levy (the **Windfall Levy**) and production taxes and engineering and support costs, for 2008 increased $13.01, or 51%, per Boe for 2008 when compared to 2007. These costs increased $5.09, or 25%, per Boe for 2007 when compared to 2006. Of the total $9.3 million increase in these costs for 2008 compared to 2007, $6.7 million were a result of the change in Windfall Levy which is explained in more detail below under the China Operating Costs section.

***China***

**Production Volumes 2008 vs. 2007**

Net production volumes during 2008 increased by 6,327 Boe when compared to 2007. The normal field decline was offset by the production from five new development wells that were completed and put on production in the second half of 2007, as well as productivity increases from adding new perforations, fracture stimulations and water flood response. The expected production rates for 2009 will be similar to those averaged in 2008, but may be lower than the exit rate at December 31, 2008. At the end of 2008, there were 43 producing wells at the Dagang field and 42 producing wells at the end of 2007.

**Production Volumes 2007 vs. 2006**

The December 31, 2007 exit production rate at Dagang was 1,900 Gross Bopd, compared to 1,877 Gross Bopd at the end of 2006. Normal field decline was offset by the production of 290 Gross Bopd from five new development wells completed and put on production in the second half of 2007. Overall, net production volumes decreased 16% at the Dagang field for 2007 as in addition to normal declines within the field; we incurred abnormal downtimes due to problems encountered with sub-surface equipment. These equipment issues were resolved with a change in equipment suppliers.

**Operating Costs 2008 vs. 2007**

Operating costs in China, including engineering and support costs and Windfall Levy, increased 63% or $17.03 per Boe for 2008 when compared to 2007. Field operating costs increased $3.62 per Boe mainly as a result of a higher percentage of field office costs allocated to operations versus capital as capital activity has decreased. In addition there were more service rig days worked and higher power costs resulting from greater water injection in 2008 when compared to 2007. These increases were offset by decreases resulting from road access costs, insurance coverage and lower project management salaries.

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 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. The cost associated with Windfall Levy has been included in operating costs in our financial statements. Consequently, as oil prices have increased, the amount of the Windfall Levy also increased significantly, resulting in $13.46 per Boe increase in 2008 when compared to 2007.

We expect operating costs in 2009 to decrease on a per barrel basis as compared to 2008. The most significant component of the expected decrease in operating expenses will be related to the Windfall Levy, as oil prices are not expected to reach the same levels in 2009 as 2008. In addition, there will be a decrease in operating costs due to the ability to charge CNPC for its share of operating costs, as commercial production status, currently 18% then 51% after cost recovery, will commence on January 1, 2009. These increases will be somewhat offset by an increase in office costs allocated to operations as we continue to reduce the number of capital projects.

**Operating Costs 2007 vs. 2006**

Operating costs in China, including engineering and support costs and Windfall Levy, increased 31% or $6.30 per Boe for 2007 when compared to 2006. Field operating costs increased $4.01 per Boe. In addition to the excessive down hole maintenance problems mentioned above, which resulted in increased workover and maintenance costs, increased power costs, additional operator salaries and higher supervision charges in relation to reduced volumes contributed to the increase. The Windfall Levy resulted in a $1.94 per Boe increase for 2007 partially as a result of the 2007 being the first full year of the Levy and partially due to higher oil prices. Engineering and support costs for 2007 increased by $0.35 per Boe or 46% as we reduced the number of capital projects.

***U.S.***

**Production Volumes 2008 vs. 2007**

There was a 3% increase in U.S. production volume for 2008 as compared to 2007. The overall changes to the U.S. production volumes were mainly due to the 2008 first quarter drilling program at South Midway. In addition, an increase in production in 2008 was due to increased steaming in the first two months of 2008 and abnormal downtimes in the steaming operations in 2007 due the absence of our two steam generators for extended period of time. The 2008 first quarter drilling program at South Midway is expected to offset natural declines within this field and to provide additional future drilling locations. Increases at South Midway were offset by smaller decreases in our Spraberry field in West Texas where there was a significant downtime related to down hole leak problems. As at December 31, 2008, we were producing 560 gross Boe/d (520 net Boe/d) at South Midway compared to 517gross Boe/d (496 net Boe/d) as at December 31, 2007. In 2009, we expect production volumes at South Midway will decline as there are no plans to drill new wells in this property. We also expect that production volumes at West Texas will continue decline modestly.

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**Production Volumes 2007 vs. 2006**

As at December 31, 2007, we were producing 517 gross Boe/d (496 net Boe/d) at South Midway compared to 590 gross Boe/d (543 net Boe/d) as at December 31, 2006. U.S. production volumes decreased 10% in 2007 when compared to 2006 mainly due to a decline in production at South Midway resulting from steam generator downtime during the second and third quarters, along with certain wells taken offline to be soaked and steamed once that steaming operation came back on line. The purchase of a second steam generator and the retrofit of an existing generator allowed for a full steaming program in 2008. In addition to the natural declines in production within our Spraberry field in West Texas, production was also hampered by a key producer being down for repairs in the third quarter.

**Operating Costs 2008 vs. 2007**

Operating costs in the U.S., including engineering and support costs and production taxes, increased 16% per Boe for 2008 when compared to 2007. Field operating costs increased $4.21 per Boe mainly due to an increase in steaming operations at South Midway. Both steam generators were down in the latter part of the first quarter and through the second quarter of 2007. In addition, the price of natural gas has been significantly higher in 2008 when compared to 2007. Additional maintenance costs and workovers at the Spraberry field in West Texas in 2008 added to the overall increase in costs. In addition, oil field expenses in general increased due to the demand both in California and nationwide during 2008. Typically as oil prices rise so does drilling activity. The Company anticipates the costs associated with the oil service industry to decrease in 2009 as demand has decreased. The expectation for overall operating expense in 2009 is otherwise unknown as natural gas prices are expected to remain volatile and the Company can not predict the number or extent of workover projects.

**Operating Costs 2007 vs. 2006**

Operating costs in the U.S., including engineering and support costs and production taxes, increased 11% or $2.18 per Boe for 2007 when compared to 2006. Field operating costs increased $0.97 per Boe due to increases to maintenance costs and workovers at Spraberry and steaming projects in the diatomite formation at North Salt Creek. These increases were somewhat offset due to a reduction in our South Midway steaming operations as we were in the process of replacing a steam generator, including purchasing and subsequent retro fit, which was completed and put on line in the third quarter. We also had our other steam generator down for repairs during the second quarter. In addition to this overall increase, engineering and support costs for 2007 increased by $1.11 per Boe mainly due to a higher allocation of support to production as capital activity decreased.

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

| | Year ended December 31, | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2008 | | | 2007 | | | 2006 | | |
| | China | U.S. | Total | China | U.S. | Total | China | U.S. | Total |
| Net Production: | | | | | | | | | |
| Boe | 489,913 | 204,355 | 694,268 | 483,585 | 198,844 | 682,429 | 575,131 | 219,930 | 795,061 |
| Boe/day for the period | 1,339 | 558 | 1,897 | 1,325 | 545 | 1,870 | 1,576 | 603 | 2,178 |
| | | Per Boe | | | Per Boe | | | Per Boe | |
| Oil and gas revenue | $ 98.73 | $ 88.67 | $ 95.77 | $ 64.86 | $ 61.71 | $ 63.94 | $ 62.04 | $ 54.86 | $ 60.06 |
| Field operating costs | 21.70 | 19.62 | 21.09 | 18.08 | 15.41 | 17.30 | 14.07 | 14.44 | 14.17 |
| Windfall Levy (China) and Production tax (U.S.) | 21.14 | 1.31 | 15.30 | 7.68 | 1.25 | 5.81 | 5.74 | 1.15 | 4.47 |
| Engineering and support costs | 1.08 | 4.21 | 2.00 | 1.12 | 5.06 | 2.27 | 0.77 | 3.95 | 1.65 |
| | 43.92 | 25.14 | 38.39 | 26.88 | 21.72 | 25.38 | 20.58 | 19.54 | 20.29 |
| Net operating revenue | 54.81 | 63.53 | 57.38 | 37.98 | 39.99 | 38.56 | 41.46 | 35.32 | 39.77 |
| Depletion | 47.22 | 29.88 | 42.12 | 39.73 | 29.38 | 36.71 | 40.57 | 24.23 | 36.05 |
| Net revenue (loss) from operations | $ 7.59 | $ 33.65 | $ 15.26 | $ (1.75) | $ 10.61 | $ 1.85 | $ 0.89 | $ 11.09 | $ 3.72 |

**General and Administrative**

Changes in general and administrative expenses, before and after considering increases in non-cash stock based compensation, by segment for the year ended December 31, 2008 when compared to the same period for 2007 and for the year ended December 31, 2007 when compared to the same period for 2006 were as follows:

| | 2008 vs. 2007 | 2007 vs. 2006 |
|---|---|---|
| **Favorable (unfavorable) variances:** | | |
| Oil and Gas Activities: | | |
| Canada | $ (1,653) | $ |
| Ecuador | (658) | |
| China | (204) | (705) |
| U.S. | (393) | (342) |
| Corporate | (3,206) | (849) |
| | (6,114) | (1,896) |
| Less: stock based compensation | 284 | 172 |
| | $ (5,830) | $ (1,724) |

**General and Administrative 2008 vs. 2007**

***Canada***

As noted elsewhere in this Annual Report, the Company acquired working interests in two leases located in Alberta, Canada in July 2008. General and administrative costs related to Canada in 2008 consist of hiring key staff, reallocation of existing resources and some initial office setup costs. In prior periods, some of these costs were recorded in the Business and Technology Development segment.

***Ecuador***

As noted elsewhere in this Annual Report, in the fourth quarter of 2008 the Company signed a contract to explore and develop Block 20. General and administrative costs related to Ecuador in 2008 consist of travel costs, contract services, hiring key staff, reallocation of existing resources and some initial office setup costs.

***China***

General and administrative expenses related to the China operations increased $0.2 million for 2008 as compared to 2007 mainly resulting from increases in consulting and audit fees, rent and facility costs and unrealized foreign exchange loss.

***U.S.***

General and administrative expenses related to the U.S. operations increased $0.4 million for 2008 as compared to 2007 mainly resulting from a lower allocation to capital and operations, provision for uncollectible accounts related to certain joint interest billings, offset by reallocation of staff to business and technology development.

***Corporate***

General and administrative costs related to Corporate activities increased $3.2 million for 2008 when compared to 2007. The overall increase was mainly due to the following increases; $0.6 million provision for uncollectible accounts, corporate aircraft costs of $1.0 million, and increases in third party recruiting fees of $0.5 million and foreign exchange losses of $1.1 million.

**General and Administrative 2007 vs. 2006**

***China***

General and administrative expenses related to the China operations increased $0.7 million for 2007 mainly due to a decrease in allocations to capital investments as a result of fewer capital projects in 2007 when compared to 2006.

***U.S.***

General and administrative expenses related to U.S. operations increased $0.3 million in 2007. Allocations to capital investments and operations decreased $0.9 million as a result of less capital activity for 2007 when compared to 2006 and discretionary bonuses paid in 2007. This increase in expense was offset by a decrease of $0.5 million for salaries and benefits, which was a result of reallocation of resources to HTL™ activities beginning in the second half of 2006 and continuing through all of 2007.

***Corporate***

General and administrative costs related to Corporate activities increased $0.8 million for 2007 when compared to 2006. The increase for 2007 was due to a $1.4 million increase in salaries and benefits partially resulting from discretionary bonuses paid in 2007, the addition of new executives mid way through 2006, and other key personnel added in 2007. This increase was offset by a decrease in outside legal costs of $0.2 million, a decrease in professional fees incurred to comply with the provisions of Section 404 of the Sarbanes-Oxley Act of 2002 ( **SOX** ) in the amount of $0.1 million and a $0.3 million decrease 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.

**Business and Technology Development**

Changes in business and technology development costs, before and after considering increases in non-cash stock based compensation, for the year ended December 31, 2008 when compared to 2007 and for the year ended December 31, 2007 when compared to 2006 were as follows:

**Business and Technology Development 2008 vs. 2007**

Business and technology development expenses decreased $3.2 million (including changes in stock based compensation) in 2008 when compared to 2007, mainly as a result of a decrease in CDF operating costs due to several heavy oil upgrading runs in the first and second quarters of 2007. These decreases were offset by increases in compensation costs as the Company assembled a core HTL™ technology team.

### Business and Technology Development 2007 vs. 2006

Business and technology development expenses increased $2.0 million in 2007 compared to 2006 as we focused on business and technology development activities related to HTL™ opportunities. The overall increase in HTL™ related to salaries and benefits was $1.4 million. In addition to a reallocation of resources (see G&A explanations above) to HTL™, and 2007 discretionary bonuses, key personnel were added to this segment throughout 2007 as the Company developed its commercialization program for its technology. This increase was partially offset by an increased $0.5 million allocation to capital investments. This segment also increased as a result of $0.3 million higher operating costs at the CDF. Operating expenses of the CDF to develop and identify improvements in the application of the HTL™ Technology are a part of our business and technology development activities. This increase was in part the result of several heavy oil upgrading runs in the first and second quarters of 2007, including a key Athabasca bitumen test run. The Company used the information derived from the Athabasca bitumen test run for the design and development of full-scale commercial projects. In addition, the HTL™ segment increased $0.4 million as a result of higher outside engineering fees and legal fees related to patents and $0.6 million due to a shift in resources from GTL. The remainder of the increase is related to consulting fees and travel costs to develop opportunities for our HTL™ Technology.

## Net Interest

### Net Interest 2008 vs. 2007

Interest expense increased $0.8 million for 2008 when compared to 2007 partially due to an additional draw on our U.S. loan, borrowings under a new loan for our China operations in the fourth quarter of 2007 and a short term loan that was outstanding from May 2008 to August 2008. Interest income also increased slightly in 2008 when compared to 2007 due to cash deposits from the July 2008 private placement.

### Net Interest 2007 vs. 2006

Interest expense was higher in 2007 when compared to 2006 partially due to an additional draw down on our U.S. loan and the funding of a new loan for China. These higher amounts were offset by a decrease related to the early pay off of the term note (see 2006 vs. 2005 analysis below). In addition, interest income decreased by $0.3 million as average cash balances were lower throughout 2007 when compared to 2006.

## Unrealized Gain (Loss) on Derivative Instruments

As required by the Company s lenders, the Company entered into costless collar derivatives to minimize variability in its cash flow from the sale of approximately 75% of the Company s estimated production from its South Midway Property in California and Spraberry Property in West Texas over a two-year period starting November 2006 and a six-month period starting November 2008. The derivatives have a ceiling price of $65.20, and $70.08, per barrel and a floor price of $63.20, and $65.00, per barrel, respectively, using WTI as the index traded on the NYMEX. Also as a result of a requirement of the Company s lenders, the Company entered into a costless collar derivative to minimize variability in its cash flow from the sale of approximately 50% of the Company s estimated production from its Dagang field in China over a three-year period starting September 2007. This derivative has a ceiling price of $84.50 per barrel and a floor price of $55.00 per barrel using the WTI as the index traded on the NYMEX.

The Company is required to account for these contracts using mark-to-market accounting. As forecasted benchmark prices exceed the ceiling prices set in the contract, the contracts have negative value or a liability. These benchmark prices reached record highs at the beginning of the third quarter of 2008 before steadily declining at the end of the fourth quarter to a level that is the lowest dating back several years. For the year ended December 31, 2008, the Company had $11.6 million unrealized gains in these derivative transactions. This compares to an unrealized net loss in 2007 of $8.9 million and $0.5 million in 2006. Changes in these unrealized settlement (losses) and gains by segment are detailed below:

| | Year Ended December 31, 2008 | *Favorable (Unfavorable) Variances* | Year Ended December 31, 2007 | *Favorable (Unfavorable) Variances* | Year Ended December 31, 2006 |
|---|---|---|---|---|---|

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| China | $ | 6,117 | *$* | *10,776* | $ | (4,659) | *$* | *(4,659)* | $ | |
| U.S. | | 5,474 | | *9,754* | | (4,280) | | *(3,787)* | | (493) |
| | $ | 11,591 | *$* | *20,530* | $ | (8,939) | *$* | *(8,446)* | $ | (493) |

**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 2008 vs. 2007

Depletion and depreciation increased $5.4 million for 2008 as compared to 2007. This is partially due to a $1.2 million increase in depreciation of the CDF, increases in depletion rates for China and in the U.S.

***China***

China s depletion rate increased $7.50 per Boe for 2008 when compared to 2007, resulting in a $3.7 million increase in depletion expense for 2008. The increase in the rates from year to year was mainly due to an impairment of the drilling and completion costs associated with the second Zitong exploration well in the fourth quarter of 2007. The remaining increase of $0.2 million was related to increased production.

***U.S.***

The U.S. depletion rate for 2008 was $29.88 per Boe compared to $29.38 per Boe for 2007, an increase of $0.50 per Boe resulting in a $0.2 million increase in depletion expense.

***Business and Technology Development***

Depreciation of the CDF is calculated using the straight-line method over its current useful life which is based on the existing term of the agreement with Aera Energy LLC to use their property to test the CDF. A formal study was conducted in 2008 whereby the estimated salvage value of the property was decreased and the asset retirement obligation was increased resulting in an increased depreciable base.

### Depletion and Depreciation 2007 vs. 2006

Depletion and depreciation decreased $6.0 million in 2007, partially due to reduced depletion of $3.6 million. The overall reduction in depletion was mainly the result of lower production rates which resulted in a decrease in depletion of $4.2 million for 2007. This decrease was somewhat offset by a higher depletion rate of $36.71 per Boe which resulted in additional depletion expense of $0.6 million. Reduced depreciation of the CDF as a result of a longer depreciation period also contributed to the overall decrease in depletion and depreciation in the amount of $2.4 million for 2007.

***China***

Decreases in production volumes in China resulted in a decrease in depletion expense of $3.7 million for 2007 when compared to 2006.

China s depletion rate decreased $0.86 per Boe to $39.73 for 2007 when compared to 2006, resulting in a $0.4 million decrease in depletion expense. The decrease in the rates from year to year was mainly due to a $5.4 million ceiling test write down in the fourth quarter of 2006. This decrease was somewhat offset by an increase to the depletable pool in the fourth quarter of 2007 for the impairment of the drilling costs associated with the second exploration well in the Zitong Block.

***U.S.***

The U.S. depletion rate for 2007 was $29.38 per Boe compared to $24.23 per Boe for 2006, an increase of $5.15 per Boe resulting in a $1.0 million increase in depletion expense. This increase was mainly due to the 2006 fourth quarter impairment of certain properties, including North Yowlumne, LAK Ranch and Catfish Creek, resulting in $4.8 million of those costs being included with our proved properties and therefore subject to depletion. In addition, the capital spending we incurred in 2007 was related to facilities, versus drilling, and therefore did not correspondingly increase our reserve base.

Additionally, decreases in production volumes in the U.S. accounted for $0.5 million of the decrease in depletion expense for 2007.

***Business and Technology Development***

Depreciation of the CDF is calculated using the straight-line method over its current useful life which is based on the existing term of the agreement with Aera Energy LLC 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 extended to coincide with the new term of the agreement. In addition to the change in life, depreciation expense also decreased as a result of a reduction in the depreciable base during the second quarter of 2007 due to a portion of the payment from INPEX being applied against those costs.

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**Provision for Impairment of GTL Intangible Assets and Development Costs**

The Company has been pursuing a GTL project for an extended period of time and has not been able to obtain a definitive agreement or appropriate financing. As a result the Company has impaired the entire carrying value of the costs associated with GTL as at December 31, 2008. The carrying value for GTL development costs of $5.1 million and intangible GTL license costs of $10.0 million have been reduced to nil with a corresponding reduction in our results of operations. This impairment does not affect the Company s intention to continue to pursue the current GTL project in Egypt.

In 2007 and 2006, we had no write downs of our GTL assets.

**Write-off of Deferred Financing Costs**

The Company incurred professional fees and expenses associated with the pursuit of corporate financing initiatives by the Company s Chinese subsidiary, Sunwing Energy. In the fourth quarter of 2008 this financing initiative was postponed indefinitely and therefore the associated costs were written down to nil with a corresponding reduction in our results of operations.

**Provision for 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 2008 vs. 2007**

We did not impair our oil and gas properties in 2008, compared to $6.1 million impairment of our China oil and gas properties in 2007.

**Impairment of Oil and Gas Properties 2007 vs. 2006**

We impaired our China oil and gas properties by $6.1 million in 2007, compared to $5.4 million in 2006. The 2007 impairment was mainly the result of impairing our costs incurred in the Zitong block due to an unsuccessful second exploration well resulting in those costs of $17.6 million being included with the carrying value of proved properties for the ceiling test calculation. The 2006 impairment was a result increased operating costs of the Dagang field, including cost of the Windfall Levy established in March 2006.

***Financial Condition, Liquidity and Capital Resources***

**Sources and Uses of Cash**

Net cash and cash equivalents increased by $27.9 million for the year ended December 31, 2008 compared to a decrease of $2.5 million for 2007 and a decrease of $7.2 million for 2006.

**Operating Activities**

Our operating activities provided $17.1 million in cash for the year ended December 31, 2008 compared to $5.5 million and $14.4 million for the same periods in 2007 and 2006. The increase in cash from operating activities for the year ended December 31, 2008 was mainly due to a 50% increase in oil and gas production prices offset by an increase in expenses, as well as an increase in changes in non-cash working capital when compared to 2007. The decrease in cash from operating activities for the year ended December 31, 2007 was mainly due to a decrease in net production volumes of 14% offset by an increase in oil and gas prices of 6%, net of realized loss on derivative instruments associated with oil and gas operations. In addition, increases to operating costs, general and administrative and business and technology development expenses also reduced operating cash flows.

**Investing Activities**

Our investing activities used $49.3 million in cash for the year ended December 31, 2008 compared to $22.3 million for the same period in 2007 and $25.6 million for 2006. For 2008, the main reason for the differences is the $22.3 million paid as part of the cost of the acquisition of the100% working interests in two leases located in the Athabasca oil sands region in the Province of Alberta, Canada (see Note 18 in the accompanying financial statements for more details). In addition the Company received $10.0 million in proceeds from the sale of assets and a recovery of development costs in 2007, compared to nil in 2008 and $6.0 million in proceeds from asset sales in 2006. There was also a decrease in capital asset expenditures of $6.0 million for 2008 as compared to 2007 and increase of $13.8 million for 2007 when compared to 2006.

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Changes in capital investments by segment are detailed below:

| | For the Year Ended December 31, | | | For the Year Ended December 31, | | |
|---|---|---|---|---|---|---|
| | 2008 | 2007 | (Increase) Decrease | 2007 | 2006 | (Increase) Decrease |
| Oil and Gas Activities: | | | | | | |
| Canada | $ 6,484 | $ | $ (6,484) | $ | $ | $ |
| Ecuador | 1,369 | | (1,369) | | | |
| China | 8,378 | 23,488 | 15,110 | 23,488 | 9,086 | (14,402) |
| U.S. | 4,542 | 3,052 | (1,490) | 3,052 | 5,550 | 2,498 |
| Business and Technology Development | 4,833 | 5,098 | 265 | 5,098 | 3,206 | (1,892) |
| | $ 25,606 | $ 31,638 | $ 6,032 | $ 31,638 | $ 17,842 | $ (13,796) |

***Canada***

As noted above, two leases located in Canada were acquired in the third quarter of 2008. Capital investments this quarter consisted of capitalized interest, seismic/ERT and environmental work. In 2008, the overall focus has been on delineation activities, engineering and pre-filing regulatory requirements.

***Ecuador***

The increase in 2008 of $1.4 million of investment activities is due to a new project s activities related to the signing of a contract to explore and develop Ecuador s Pungarayacu heavy-oil field using our HTL[TM] upgrading technology.

***China***

The decrease in investment in China in 2008 compared to 2007 was the result of a $9.6 million decrease in capital spending at Zitong and a $5.5 million decrease in capital spending at Dagang. Spending at Zitong during 2008 was limited to expenditures relating to the commencement of the second phase of the exploration program which were relatively minor compared to the drilling and completion costs incurred during 2007 for completing the first phase of the program which was concluded in December 2007. At Dagang, we spud five new development wells in 2007 compared to 2008 where we only completed a series of fracture stimulation projects. The increase from 2006 to 2007 was the result of a $9.1 million increase at our Zitong project and $5.3 million increase for the five new wells in 2007 at our Dagang project.

***U.S.***

The $1.5 million increase in U.S. capital spending in 2008 compared to 2007 was mainly due to the eight well drilling program at South Midway in 2008 compared to the cost of a new steam generator in 2007. This amount was offset by a decrease in cash inflows from asset sales of $1.0 million in the U.S. in 2007, compared to $6.0 million for the same period in 2006 when we had a ten well drilling program at South Midway.

***Business and Technology Development***

The decrease in capital spending during 2008 when compared to 2007 was due to the timing of costs relating to the construction and delivery of the Feedstock Test Facility ( **FTF** ). The increase of $1.9 million, when comparing 2007 to 2006, resulted from expenditures for the FTF increasing by $3.9 million which were offset by decreased expenditures of $1.2 million for the CDF and $0.4 million for GTL and $0.4 million for other capitalized development costs.

**Financing Activities**

Financing activities for the year ended December 31, 2008 consisted mainly of an equity private placement in the third quarter of 2008. In July 2008, the Company completed a Cdn.$88.0 million private placement consisting of 29,334,000 special warrants ( **Special Warrants** ) at Cdn.$3.00 per Special Warrant (the **Offering** ). Each Special Warrant entitled the holder to one common share of the Company upon exercise of the Special Warrant. In August 2008, all of the Special Warrants were exercised for 29,334,000 common shares. The net proceeds from the Offering of the Special Warrants was approximately Cdn.$83.4 million.

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In addition, in April 2008, the Company obtained a loan from a third party finance company in the amount of Cdn.$5.0 million bearing interest at 8% per annum. At the lender s option the principal and accrued and unpaid interest was converted in August 2008 into the Company s common shares at a conversion price of Cdn.$2.24 per share.

These cash inflows were offset by $2.6 million in professional fees and expenses associated with the pursuit of corporate financing initiatives by the Company s Chinese subsidiary, Sunwing Energy and the payment at maturity on December 31, 2008 of a promissory note to Talisman in the principal amount of Cdn.$12.5 million plus accrued interest.

Financing activities for the year ended December 31, 2007 consisted of three draws totaling $13.0 million ($12.4 million net of financing costs) on two separate loan facilities. This increase in borrowings was offset by scheduled debt payments of $2.5 million. In 2006, we repaid notes in the amount of $5.5 million prior to maturity, made scheduled repayments of long-term debt of $3.2 million offset by an initial draw on a bank loan facility of $1.5 million ($1.3 million net of financing costs). Financing activities in 2007 also consisted of $4.0 million received from the exercise of warrants compared to 2006 when there were no warrants exercised but there was a $25.3 million private placement of common shares.

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 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 TSX and the exercise price was changed to Cdn.$2.93.

**Outlook for 2009**

Our 2009 capital program budget ranges from approximately $15 million to $20 million and will encompass the following: a) continuing development of our existing producing oil and gas properties to maximize near-term cash flow, b) the preparation of Tamarack and Pungarayacu for development, and c) engineering and development costs related to the preparation of our proprietary HTL™ oil upgrading technology for full scale deployment in Canada and Ecuador. Management s plans for financing its 2009 requirements and beyond include the potential for alliances or other arrangements with strategic partners as well as traditional project financing, debt and mezzanine financing or the sale of equity securities.

Discussions with potential strategic partners are focused primarily on national oil companies and other sovereign or government entities from Asian and Middle Eastern countries that have approached the Company and expressed interest in participating in the Company s heavy oil activities in Ecuador, Canada and around the world.

The Company intends to utilize revenue from existing operations to fund the continuing 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.

In addition to Tamarack and Pungarayacu, the Company will continue to pursue ongoing discussions related to other HTL heavy oil opportunities in Canada, Latin America, the Middle East and North Africa.

***Contractual Obligations and Commitments***

The table below summarizes the contractual obligations that are reflected in our 2008 consolidated balance sheets and/or disclosed in the accompanying Notes:

| | Payments Due by Year (stated in thousands of U.S. dollars) | | | | | |
|---|---|---|---|---|---|---|
| | **Total** | **2009** | **2010** | **2011** | **2012** | **After 2012** |
| Consolidated Balance Sheets: | | | | | | |
| Note payable current portion | $ 5,612 | $ 5,612 | $ | $ | $ | $ |
| Long term debt | 37,855 | | 6,549 | 31,306 | | |
| Asset retirement obligation | 3,738 | 15 | 1,928 | | | 1,795 |
| Long term obligation | 1,900 | | | | 1,900 | |
| Other Commitments: | | | | | | |
| Interest payable | 8,238 | 3,165 | 2,884 | 2,189 | | |
| Lease commitments | 3,337 | 1,191 | 1,009 | 680 | 331 | 126 |
| Zitong exploration commitment | 24,694 | 13,123 | 11,571 | | | |
| Total | $ 85,374 | $ 23,106 | $ 23,941 | $ 34,175 | $ 2,231 | $ 1,921 |

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, fair market value of derivatives, 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, 2008, the carrying values of our Canada, Ecuador, China and the U.S. cost centers were $81.1 million, $1.5 million, $48.1 million and $32.6 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. 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.

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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 2008, oil and gas depletion of $29.2 million was recorded in depletion and depreciation expense. If our reserve estimates changed by 10%, our depletion and depreciation expense for 2008 would have changed by approximately $2.3 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 who are 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, 2008, we had $81.1 million, $1.5 million, $5.2 million and $4.2 million of costs incurred on unproved oil and gas properties in Canada, Ecuador, China and the U.S., 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 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 adjusted for political and economic risk on a country-by-country basis. 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 nil, $6.1 million and $5.4 million in a ceiling test impairment for our China cost center for the years ended December 31, 2008, 2007 and 2006, respectively.

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 future net cash flows, discounted at 10%, 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 (iii) income tax effects related to differences between the book and tax basis of the properties. 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 $20.3 million, nil and $7.6 million in ceiling test impairments for our U.S. cost center for the years ended December 31, 2008, 2007 and 2006, respectively, and $21.6 million, $5.9 million and $15.9 million for the years ended December 31, 2008, 2007 and 2006 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 Obligations* 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 a 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 a 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, 2008, 2007 and 2006, we wrote down $5.1 million, nil and nil, respectively, of capitalized negotiation and feasibility costs associated with our GTL projects which did not result in definitive agreements with no write downs in those same periods related to our HTL™ projects.

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, 2008, 2007 and 2006, we expensed $0.4 million, $0.3 million and $1.0 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 to deploy, worldwide, the RTP™ Process for petroleum applications (HTL™ Technology) as well as the exclusive right to deploy the RTP™ 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. 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.

***2008 Accounting Changes***

On January 1, 2008, the Company adopted three new accounting standards that were issued by the Canadian Institute of Chartered Accountants ( **CICA** ): Handbook Section 1535 Capital Disclosures ( **S.1535** ), Handbook Section 3862 Financial Instruments Disclosures ( **S.3862** ), and Handbook 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. The latter two replaced Handbook Section.3861 Financial Instruments Disclosure and Presentation . The Company adopted the new standards on January 1, 2008 with additional disclosures included in these consolidated financial statements. There was no transitional adjustment to the consolidated financial statements as a result of having adopted these standards.

***Impact of New and Pending Canadian GAAP Accounting Standards***

In February 2008, the CICA issued Handbook Section 3064, Goodwill and Intangible assets, ( **S.3064** ) replacing Handbook Section 3062, Goodwill and Other Intangible Assets ( **S.3062** ) and Handbook Section 3450, Research and Development Costs . S.3064 will be applicable to financial statements relating to fiscal years beginning on or after October 1, 2008. Accordingly, the Company will adopt the new standards for its fiscal year beginning January 1, 2009. The new section establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition and of intangible assets by profit-oriented enterprises. Standards concerning goodwill are unchanged from the standards included in the previous S.3062. Management has concluded that the requirements of this new Section as they relate to goodwill will not have a material impact on its consolidated financial statements.

Also in February 2008, the CICA amended portions of Handbook Section 1000, Financial Statement Concepts , which the CICA concluded permitted deferral of costs that did not meet the definition of an asset. The amendments apply to annual and interim financial statements relating to fiscal years beginning on or after October 1, 2008. Upon adoption of S.3064 and the amendments to Section 1000 on January 1, 2009, capitalized amounts that no longer meet the definition of an asset will be expensed retrospectively. Management has concluded that the requirements of this new Section will not have a material impact on its consolidated financial statements.

Effective January 1, 2008, the Company implemented amendments to CICA Handbook Section 1400 General Standards of Financial Statement Presentation that incorporates going concern guidance. These changes require management to make an assessment of an entity s ability to continue as a going concern when preparing financial statements. Financial statements shall be prepared on a going concern basis unless management either intends to liquidate the entity or to cease trading, or has no realistic alternative but to do so. When management is aware, in making its assessment, of material uncertainties related to events or conditions that may cast significant doubt upon the entity s ability to continue as a going concern, those uncertainties shall be disclosed. The new requirements are applicable to all entities and are effective for annual financial statements relating to fiscal years beginning on or after January 1, 2008. There was no material impact on the Company s consolidated financial statements as the Company already going concern disclosure in its consolidated financial statements.

***Convergence of Canadian GAAP with International Financial Reporting Standards***

In April 2008, the CICA published the exposure draft Adopting IFRSs in Canada . The exposure draft proposes to incorporate International Financial Reporting Standards ( **IFRS** ) into the CICA Accounting Handbook effective for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. At this date, publicly accountable enterprises will be required to prepare financial statements in accordance with IFRS.

Under IFRS, the primary audience is capital markets and, as a result, there is significantly more disclosure required, specifically for quarterly reporting. Further, while IFRS uses a conceptual framework similar to Canadian GAAP, there are significant differences in accounting policy which must be addressed. The Company has not completed development of its IFRS changeover plan, which will include project structure and governance, deployment of resources and training, analysis of key GAAP differences and a phased plan to assess accounting policies under IFRS as well as potential IFRS 1 exemptions. The Company hopes to complete its project scoping, which will include a timetable for assessing the impact on data systems, internal controls over financial reporting, and business activities, such as financing and compensation arrangements, once the exemptions as described below relating to full cost oil and gas companies have been determined.

The International Accounting Standards Board ( **IASB** ) has stated that it plans to issue an exposure draft relating to certain amendments to IFRS 1 in order to make it more useful to Canadian entities adopting IFRS for the first time. One such exemption relating to full cost oil and gas accounting is expected to result in a reduced administrative transition from the current Canadian AcG-16 to IFRS. It is anticipated that this exposure draft will not result in an amended IFRS 1 standard until late in 2009. The amendment will potentially permit the Company to apply IFRS prospectively to its full cost pool, rather than the retrospective assessment of capitalized exploration and development expenses, with the proviso that a ceiling test, under IFRS standards, be conducted at the transition date.

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

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities ( **SFAS No. 161** ). The new standard is intended to improve financial reporting about derivative instruments and hedging activities by requiring enhanced disclosures to enable investors to better understand their effects on an entity s financial position, financial performance, and cash flows. It is effective beginning January 1, 2009. Management has concluded that the requirements of this recent statement will not have a material impact on its financial statements.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements ( **SFAS No. 157** ). This statement defines fair value, establishes a framework for measuring fair value in GAAP, and expands disclosures about fair value measurements. The Company adopted the provisions of SFAS No. 157 effective January 1, 2008. The implementation of this standard did not have a material impact on the consolidated financial statements as the current policy on accounting for fair value measurements is consistent with this guidance. The Company has, however, provided additional prescribed disclosures not required under Canadian GAAP.

In December 2008, the SEC released Final Rule, Modernization of Oil and Gas Reporting to revise the existing Regulation S-K and Regulation S-X reporting requirements to align with current industry practices and technological advances. The new disclosure requirements include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. In addition, the new disclosure requirements require a company to (a) disclose its internal control over reserves estimation and report the independence and qualification of its reserves preparer or auditor, (b) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserve audit and (c) report oil and gas reserves using an average price based upon the prior 12-month period rather than period-end prices. The provisions of this final ruling will become effective for disclosures in our Annual Report on Form 10-K for the year ended December 31, 2009. Management is currently evaluating the impact of these changes on its financial statements.

***Off Balance Sheet Arrangements***

At December 31, 2008 and 2007, 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. These entities provide access to an aircraft, the services of administrative and technical personnel and office space or facilities in Vancouver, London and Singapore. The Company is billed on a cost recovery basis. For the year ended December 31, 2008 the costs incurred in the normal course of business with respect to the above arrangements amounted to $3.0 million ($3.3 million for 2007 and $3.0 million for 2006), and are recorded in general and administrative expense in the statement of operations. As at December 31, 2008 amounts included in accounts payable and accrued liabilities on the balance sheet under these arrangements were $0.1 million ($0.2 million at December 31, 2007).

**ITEM 7A. *QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK***

We are exposed to normal market risks inherent in the oil and gas business, including equity market risk, commodity price risk, foreign-currency rate risk, interest rate risk and credit risk. We recognize these risks and manage our operations to minimize our exposures to the extent practicable.

**NON-TRADING**

***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 $15 to $20 million to fund our capital investment programs for 2009.

We can give no assurance that we will be successful in obtaining financing as and when needed. Factors beyond our control, such as the recent credit crisis, 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 the recent credit crisis, 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. Using the Company s 2008 actual worldwide crude oil production levels as an estimate for 2009 production, a $1.00/Bbl change in the realized price of oil, would increase or decrease net income and cash from operations for 2009 by $0.7 million. Using the Company s 2008 actual natural gas production levels as an estimate for

2009 production, a $1.00/Mcf change in the realized price of natural gas would increase or decrease net income and cash from operations for 2009 by less than $0.1 million.

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We periodically engage in the use of derivatives to minimize variability in our cash flow from operations and currently have costless collar contracts put in place as part of our bank loan facilities. The Company entered into costless collar derivatives to minimize variability in its cash flow from the sale of approximately 75% of the Company s estimated production from its South Midway Property in California and Spraberry Property in West Texas over a two-year period starting November 2006 and a six-month period starting November 2008. The derivatives had a ceiling price of $65.20, and $70.08, per barrel and a floor price of $63.20, and $65.00, per barrel, respectively, using WTI as the index traded on the NYMEX. The Company also entered into a costless collar derivative to minimize variability in its cash flow from the sale of approximately 50% of the Company s estimated production from its Dagang field in China over a three-year period starting September 2007. This derivative had a ceiling price of $84.50 per barrel and a floor price of $55.00 per barrel using WTI as the index traded on the NYMEX. See Note 12 to the Consolidated Financial Statements.

On December 31, 2008, the Company s open positions on the derivatives mentioned above had a fair value of $2.2 million. A 10% increase in oil prices would reduce the fair value by approximately $1.1 million, while a 10% decrease in prices would increase the fair value by approximately $1.1 million. The fair value change assumes volatility based on prevailing market parameters at December 31, 2008.

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, 2008 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***

Foreign currency risk refers to the risk that the value of a financial commitment, recognized asset or liability will fluctuate due to changes in foreign currency rates. The main underlying economic currency of the Company s cash flows is the U.S. dollar. This is because the Company s major product, crude oil, is priced internationally in U.S. dollars. Accordingly, the Company does not expect to face foreign exchange risks associated with its production revenues. However, some of the Company s cash flow stream relating to certain international operations is based on the U.S. dollar equivalent of cash flows measured in foreign currencies. The majority of the operating costs incurred in the Chinese operations are paid in Chinese renminbi. The majority of costs incurred in the administrative offices in Vancouver and Calgary, as well as some business development costs, are paid in Canadian dollars. In addition, with the recent property acquisition in Alberta (see Note 18) the Company s Canadian dollar expenditures have increased during the last half of 2008 along with an increase in cash and debt balances denominated in Canadian dollars. Disbursement transactions denominated in Chinese renminbi and Canadian dollars are converted to U.S. dollar equivalents based on the exchange rate as of the transaction date. Foreign currency gains and losses also come about when monetary assets and liabilities, mainly short term payables and receivables, denominated in foreign currencies are translated at the end of each month. The estimated impact of a 10% strengthening or weakening of the Chinese renminbi, and Canadian dollar, as of December 31, 2008 on net loss and accumulated deficit for the year ended December 31, 2008 is a $3.6 million increase, and a $3.7 million decrease, respectively. To help reduce the Company s exposure to foreign currency risk it seeks to maximize the expenditures and contracts denominated in U.S. dollars and minimize those denominated in other currencies, except for its Canadian activities where it attempts to hold cash denominated in Canadian dollars in order to manage its currency risk related to outstanding debt and current liabilities denominated in Canadian dollars.

***Interest Rate Risk***

Interest rate risk refers to the risk that the value of a financial instrument or cash flows associated with the instrument will fluctuate due to the changes in market interest rates. Interest rate risk arises from interest-bearing borrowings which have a variable interest rate. The Company currently has two separate bank loan facilities, a promissory note and a convertible note with fluctuating interest rates. The Company estimates that its net loss and accumulated deficit for the year ended December 31, 2008 would have changed $0.2 million for every 1% change in interest rates as of December 31, 2008. The Company is not currently actively attempting to mitigate this interest rate risk given the limited amount and term of its borrowings and the current global interest rate environment.

***Credit Risk***

The Company is exposed to credit risk with respect to its cash held with financial institutions, accounts receivable and advance balances. The Company believes its exposure to credit risk related to cash held with financial institutions is minimal due to the quality of the institutions where the cash is held and the nature of the deposit instruments. Most of the Company s accounts receivable balances relate to oil and natural gas sales and are exposed to typical industry credit risks. In addition, accounts receivable balances consist 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. The advance balance relates to an arrangement whereby scheduled advances were made to a third party contractor associated with negotiating an HTL™ and/or GTL project for the Company. The Company manages its credit risk by entering into sales contracts only with established entities and reviewing its exposure to individual entities on a regular basis. Of the $4.9 million trade receivables balance as at December 31, 2008, $3.1 million is due from a single customer and $0.4 million is due from another single customer. There are no other customers who represent more than 5% of the total balance of trade receivables. Included in the Company s trade receivable balance are debtors with a carrying amount of $0.4 million as of the year ended December 31, 2008 which are past due at the reporting date for which the Company has not provided an allowance, as there has not been a significant change in credit quality and the amounts are still considered recoverable. During the quarter ended September 30, 2008 the Company recorded an allowance associated with the advance balance for the entire outstanding amount of $0.7 million. The provision was recorded in General and Administrative expense in the accompanying Statement of Operations and Comprehensive Loss. There were no other changes to the allowance for credit losses account during the three-month period ended December 31, 2008 and no other losses associated with credit risk were recorded during this same period.

***Liquidity Risk***

Liquidity risk is the risk that suitable sources of funding for the Company s business activities may not be available, which means it may be forced to sell financial assets or non-financial assets, refinance existing debt, raise new debt or issue equity. The Company s present plans to generate sufficient resources to assure continuation of its operations and achieve its capital investment objectives include alliances or other arrangements with entities with the resources to support the Company s projects as well as project financing, debt financing or the sale of equity securities. The availability of financing is dependent in part on the return of the credit and equity markets to normalized conditions. During the fourth quarter of 2008, as a result of the global economic crisis, the terms and availability of equity and debt capital have been materially restricted and financing may not be available when it required or on commercially acceptable terms.

**TRADING**

We do not enter into contracts for trading or speculative purposes. As such, we are not materially exposed to any financing, liquidity, market or credit risk that could arise if we had entered into such contracts.

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**ITEM 8.** ***FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA***
**Index to Financial Statements and Related Information**

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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 (the Company ) as at December 31, 2008 and 2007, and the related consolidated statements of operations and comprehensive loss, shareholders equity and cash flows for each of the three years in the period ended December 31, 2008. 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 the standards of the Public Company Accounting Oversight Board (United States). These 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 at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in Canada.

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 2 to the consolidated financial statements, the Company s recurring losses from operations and accumulated deficit raise substantial doubt about its ability to continue as a going concern. Management s plans concerning these matters are also discussed in Note 2 to the consolidated financial statements. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company s internal control over financial reporting as of December 31, 2008, 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 February 26, 2009 expressed an unqualified opinion on the Company s internal control over financial reporting.

(signed) Deloitte & Touche LLP

Independent Registered Chartered Accountants

Calgary, Canada

February 26, 2009

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

| | As at December 31, 2008 | 2007 |
|---|---|---|
| **Assets** | | |
| Current Assets: | | |
| Cash and cash equivalents *(Note 12)* | $ 39,265 | $ 11,356 |
| Accounts receivable *(Note 12)* | 4,870 | 9,376 |
| Advance *(Note 12)* | | 825 |
| Prepaid and other current assets | 1,658 | 602 |
| Derivative instruments *(Note 12)* | 2,159 | |
| | 47,952 | 22,159 |
| Oil and gas properties and development costs, net *(Note 3)* | 176,550 | 111,853 |
| Intangible assets technology *(Note 4)* | 92,153 | 102,153 |
| Long term assets | 620 | 751 |
| | $ 317,275 | $ 236,916 |
| **Liabilities and Shareholders Equity** | | |
| Current Liabilities: | | |
| Accounts payable and accrued liabilities *(Note 12)* | $ 10,093 | $ 9,538 |
| Income tax payable *(Note 12)* | 650 | |
| Debt current portion *(Note 5 and 12)* | 5,612 | 6,729 |
| Derivative instruments *(Note 12)* | | 9,432 |
| | 16,355 | 25,699 |
| Long term debt *(Note 5 and 12)* | 37,855 | 9,812 |
| Asset retirement obligations *(Note 6)* | 3,738 | 2,218 |
| Long term obligation *(Note 7)* | 1,900 | 1,900 |
| | 59,848 | 39,629 |
| Commitments and contingencies *(Note 7)* | | |
| Going concern and basis of presentation *(Note 2)* | | |
| Shareholders Equity: | | |
| Share capital, issued 279,381,187 common shares; December 31, 2007 244,873,349 common shares | 413,857 | 324,262 |
| Purchase warrants *(Note 8)* | 18,805 | 23,078 |
| Contributed surplus | 16,862 | 9,937 |
| Convertible note *(Note 8)* | 2,086 | |

| | | | | |
|---|---|---|---|---|
| Accumulated deficit | | (194,183) | | (159,990) |
| | | 257,427 | | 197,287 |
| | $ | 317,275 | $ | 236,916 |

(See accompanying Notes to the Consolidated Financial Statements)

**Approved by the Board:**

| | |
|---|---|
| (signed) Robert M. Friedland<br>Director | (signed) Brian F. Downey<br>Director |

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

| | Year Ended December 31, 2008 | 2007 | 2006 |
|---|---|---|---|
| **Revenue** | | | |
| Oil and gas revenue *(Note 12)* | $ 66,490 | $ 43,635 | $ 47,748 |
| Gain (loss) on derivative instruments *(Note 12)* | 1,966 | (10,587) | (424) |
| Interest income | 710 | 469 | 776 |
| | 69,166 | 33,517 | 48,100 |
| **Expenses** | | | |
| Operating costs | 26,652 | 17,319 | 16,133 |
| General and administrative | 18,190 | 12,076 | 10,180 |
| Business and technology development | 6,453 | 9,625 | 7,610 |
| Depletion and depreciation | 31,904 | 26,524 | 32,550 |
| Interest expense and financing costs | 1,829 | 1,050 | 963 |
| Provision for impairment of GTL intangible asset and development costs *(Notes 3 and 4)* | 15,054 | | |
| Write off of deferred financing costs *(Note 13)* | 2,621 | | |
| Provision for impairment of oil and gas properties *(Note 3)* | | 6,130 | 5,420 |
| Write off of deferred acquisition costs | | | 736 |
| | 102,703 | 72,724 | 73,592 |
| **Loss before Income Taxes** | (33,537) | (39,207) | (25,492) |
| Current provision for income taxes *(Note 14)* | (656) | | |
| **Net Loss and Comprehensive Loss** | $ (34,193) | $ (39,207) | $ (25,492) |
| **Net Loss per share Basic and Diluted** | $ (0.13) | $ (0.16) | $ (0.11) |
| **Weighted Average Number of Shares (in thousands) Basic and Diluted** *(Note 15)* | 258,815 | 242,362 | 235,640 |

(See accompanying Notes to the Consolidated Financial Statements)

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

| | Share Capital | | Purchase | Contributed | Convertible | Accumulated | |
|---|---|---|---|---|---|---|---|
| | Shares (thousands) | Amount | Warrants | Surplus | Note | Deficit | Total |
| Balance December 31, 2005 | 220,779 | $ 291,088 | $ 5,150 | $ 3,820 | $ | $ (95,291) | $ 204,767 |
| Net loss and comprehensive 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 8)* | 11,400 | 6,493 | 18,805 | | | | 25,298 |
| Exercise of options *(Note 9)* | 297 | 743 | | (252) | | | 491 |
| Employee bonuses | 149 | 401 | | | | | 401 |
| Compensation calculated for stock option grants *(Note 9)* | | | | 2,921 | | | 2,921 |
| Balance December 31, 2006 | 241,216 | 318,725 | 23,955 | 6,489 | | (120,783) | 228,386 |
| Net loss and comprehensive loss | | | | | | (39,207) | (39,207) |
| Shares issued for: | | | | | | | |
| Exercise of purchase warrants *(Note 8)* | 2,000 | 4,313 | (313) | | | | 4,000 |
| Exercise of options *(Note 9)* | 1,231 | 431 | | (52) | | | 379 |
| Employee bonuses | 427 | 793 | | | | | 793 |
| Expiry of purchase warrants *(Note 8)* | | | (564) | 564 | | | |
| Compensation calculated for stock option grants *(Note 9)* | | | | 2,936 | | | 2,936 |
| Balance December 31, 2007 | 244,874 | 324,262 | 23,078 | 9,937 | | (159,990) | 197,287 |
| Net loss and comprehensive loss | | | | | | (34,193) | (34,193) |
| Shares issued for: | | | | | | | |
| Private placements, net of share issue costs *(Note 8)* | 29,334 | 82,451 | | | | | 82,451 |
| Exercise of convertible debt *(Note 8)* | 2,291 | 4,862 | | | | | 4,862 |
| Exercise of options *(Note 9)* | 2,666 | 1,792 | | (587) | | | 1,205 |
| Employee bonuses | 216 | 490 | | | | | 490 |
| Convertible note issued *(Note 8)* | | | | | 2,086 | | 2,086 |
| Expiry of purchase warrants *(Note 8)* | | | (4,273) | 4,273 | | | |
| Compensation calculated for stock option grants *(Note 9)* | | | | 3,239 | | | 3,239 |
| Balance December 31, 2008 | 279,381 | $ 413,857 | $ 18,805 | $ 16,862 | $ 2,086 | $ (194,183) | $ 257,427 |

(See accompanying Notes to the Consolidated Financial Statements)

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

| | Year Ended December 31, 2008 | 2007 | 2006 |
|---|---|---|---|
| **Operating Activities** | | | |
| Net loss and comprehensive loss | $ (34,193) | $ (39,207) | $ (25,492) |
| Items not requiring use of cash: | | | |
| Depletion and depreciation | 31,904 | 26,524 | 32,550 |
| Write-downs and provision for impairment *(Note 3 and 4)* | 15,054 | 6,130 | 5,420 |
| Stock based compensation *(Note 9)* | 3,554 | 3,729 | 2,921 |
| Unrealized (gain) loss on derivative instruments *(Note 12)* | (11,591) | 8,939 | 493 |
| Write off of deferred financing costs *(Note 13)* | 2,621 | | |
| Unrealized foreign exchange loss | 1,762 | | |
| Provision for uncollectible accounts (Note 12) | 1,016 | | |
| Write off of deferred acquisition costs | | | 736 |
| Other | 783 | 649 | 600 |
| Abandonment costs settled *(Note 6)* | | (792) | |
| Changes in non-cash working capital items *(Note 16)* | 6,143 | (483) | (2,876) |
| | 17,053 | 5,489 | 14,352 |
| **Investing Activities** | | | |
| Capital investments | (25,606) | (31,638) | (17,842) |
| Acquisition of oil and gas assets *(Note 18)* | (22,308) | | |
| Proceeds from sale of assets *(Note 3)* | 100 | 1,000 | 5,950 |
| Recovery of development costs *(Note 3)* | | 9,000 | |
| Advance repayments (payments) | 200 | 500 | (125) |
| Merger and acquisition related costs | | | (736) |
| Other | (777) | 28 | (116) |
| Changes in non-cash working capital items *(Note 16)* | (930) | (1,177) | (12,708) |
| | (49,321) | (22,287) | (25,577) |
| **Financing Activities** | | | |
| Shares issued on private placements, net of share issue costs *(Note 8)* | 82,451 | | 25,298 |
| Proceeds from exercise of options and warrants *(Notes 8 and 9)* | 1,205 | 4,379 | 491 |
| Proceeds from debt obligations, net of financing costs *(Note 5)* | 5,490 | 12,356 | 1,280 |
| Payments of debt obligations *(Note 5)* | (15,750) | (2,460) | (8,689) |
| Payments of deferred financing costs *(Note 13)* | (2,621) | | |
| Other | (50) | | |
| Changes in non-cash working capital items *(Note 16)* | 26 | | |
| | 70,751 | 14,275 | 18,380 |

| | | | |
|---|---|---|---|
| **Foreign Exchange Loss on Cash and Cash Equivalents Held in a Foreign Currency** | (10,574) | | |
| **Increase (decrease) in Cash and Cash Equivalents, for the year** | 27,909 | (2,523) | 7,155 |
| Cash and cash equivalents, beginning of year | 11,356 | 13,879 | 6,724 |
| **Cash and Cash Equivalents, end of year** | $ 39,265 | $ 11,356 | $ 13,879 |

(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 and per share amounts)**

## 1. NATURE OF OPERATIONS

Ivanhoe Energy Inc. (the **Company** or **Ivanhoe Energy** ), a Canadian company, 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™ 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. Our core operations are currently carried out in China, the United States, Canada and Ecuador.

## 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 and depreciation of the oil and gas properties and accretion 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 development costs 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, 2008 have been prepared in accordance with Canadian generally accepted accounting principles applicable to a going concern, which assumes that the Company will continue in operation for the foreseeable future and will be able to realize its assets and discharge its liabilities in the normal course of operations. The Company incurred a net loss of $34.2 million for the year ended December 31, 2008, and as at December 31, 2008, had an accumulated deficit of $194.2 million and positive working capital of $31.6 million. The Company currently anticipates incurring substantial expenditures to further its capital development programs, particularly those related to the development of two recently acquired oil sands leases in Alberta and the development of a heavy oil field in Ecuador. 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. The continued existence of the Company is dependent upon its ability to obtain capital to fund further development and to meet obligations to preserve its interests in these properties and to meet the obligations associated with other potential HTL projects. The Company intends to finance the future payments required for its capital projects from a combination of strategic investors and/or traditional debt and equity markets, either at a parent company level or at the project level. Traditional debt and equity markets may not be accessible at the current time and as such 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 and its subsidiaries, all of which are wholly owned.

The Company conducts a portion of its 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 functional currency of the Company is the U.S. Dollar 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.

***Oil and Gas Properties***

*Full Cost Accounting*

The Company follows the full cost method of accounting for oil and gas operations whereby all exploration and development expenditures are capitalized on a country-by-country (cost center) basis. Such expenditures include lease and royalty interest acquisition costs, geological and geophysical expenses, carrying charges for unproved properties, costs of drilling both successful and unsuccessful wells, gathering and production facilities and equipment, financing, administrative costs related to capital projects and asset retirement costs. 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. The amount of interest costs capitalized for qualifying assets is intended to be that portion of the interest cost incurred during the assets acquisition periods that theoretically could have been avoided if expenditures for the assets had not been made. Unusually significant investments in unproved properties and major development projects that are not being currently depreciated, depleted, or amortized and on which exploration or development activities are in progress are assets qualifying for capitalization of interest cost. Similarly, in a cost center with no production, significant properties and projects on which exploration or development activities are in progress are assets qualifying for capitalization of interest costs.

*Depletion*

The Company s share of costs for proved oil and gas properties accumulated within each cost center, including a provision for future development costs, are depleted using the unit-of-production method over the life of the Company s share of estimated remaining proved oil and gas reserves net of royalties. 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. 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. The conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

*Impairment of Proved Oil and Gas Properties*

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 adjusted for political and economic risk on a country-by-country basis. 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. Unproved properties and major development projects are assessed on a quarterly basis for possible impairments or reductions in value. If a reduction in value has occurred, the impairment is transferred to the carrying value of proved 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 HTL™ facilities 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 carrying balance of the related capital asset 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 a 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 carrying balance of the HTL™ and GTL development costs.

Additionally, the Company incurs costs to develop, enhance and identify improvements in the application of the HTL™ and GTL technologies it owns or licenses. The cost of equipment and facilities acquired, such as the HTL™ commercial demonstration facility ( **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 carrying balance of the HTL™ and GTL development costs.

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™ Process for all applications other than biomass and a GTL master license from 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.

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***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 when incurred 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 if converted method is used in calculating diluted earnings per share for the convertible debentures. 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. 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. The effect of a change in income tax rates on future tax liabilities and assets is recognized in income in the period in which the change occurs, provided that the income tax rates are substantively enacted.

***Stock Based Compensation***

The Company has an Employees and Directors Equity Incentive Plan consisting of a stock option plan, a bonus plan and an employee share purchase plan. 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.

***Financial Assets and Liabilities***

*Financial assets*

The Company s financial assets are comprised of cash and cash equivalents, accounts receivable, advances and derivative instruments. These financial assets are classified as loans and receivables or held for trading financial assets as appropriate. The classification of financial assets is determined at initial recognition. When financial assets are recognized initially, they are measured at fair value, normally being the transaction price. Transaction costs for all financial assets are expensed as incurred.

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Financial assets are classified as held for trading if they are acquired for sale in the short term. Cash and cash equivalents and derivatives in a positive fair value position are also classified as held for trading. Held for trading assets are carried on the balance sheet at fair value with gains or losses recognized in the consolidated statement of operations. The estimated fair value of held for trading assets is determined by reference to quoted market prices and, if not available, on estimates from third-party brokers or dealers.

Loans and receivables are non-derivative financial assets with fixed or determinable payments. Accounts receivable and advances have been classified as loans and receivables. Such assets are carried at amortized cost, as the time value of money is not significant. Gains and losses are recognized in income when the loans and receivables are derecognized or impaired.

The Company assesses at each balance sheet date whether a financial asset carried at cost is impaired. If there is objective evidence that an impairment loss exists, the amount of the loss is measured as the difference between the carrying amount of the asset and its fair value. The carrying amount of the asset is reduced with the amount of the loss recognized in earnings.

*Financial liabilities*

Financial liabilities are classified as held for trading financial liabilities or other financial liabilities as appropriate. Financial liabilities include accounts payable and accrued liabilities, derivative financial instruments, credit facilities, long term obligation and long term debt. The classification of financial liabilities is determined at initial recognition.

Held for trading financial liabilities represent financial contracts that were acquired for sale in the short term or derivatives that are in a negative fair market value position.

The estimated fair value of held for trading liabilities is determined by reference to quoted market prices and, if not available, on estimates from third-party brokers or dealers.

Other financial liabilities are non-derivative financial liabilities with fixed or determinable payments.

Short term other financial liabilities are carried at cost as the time value of money is not significant. Accounts payable and accrued liabilities and credit facilities have been classified as short term other financial liabilities. Gains and losses are recognized in income when the short term other financial liability is derecognized. Transaction costs for short term other financial liabilities are expensed as incurred.

Long term other financial liabilities are measured at amortized cost. Long-term debt and long term obligation have been classified as long term other financial liabilities. Transaction costs for long term other financial liabilities are deducted from the related liability and accounted for using the effective interest rate method.

*Derivative Financial Instruments*

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 currently uses costless collar derivative instruments to manage this exposure.

Derivative financial instruments are classified as held for trading and recorded on the consolidated balance sheet at fair value, either as an asset or as a liability under current assets or current liabilities, respectively. Changes in the fair value of these financial instruments, or unrealized gains and losses, are recognized in the statement of operations as revenues in the period in which they occur.

Gains and losses related to the settlement of derivative contracts, or realized gains and losses, are recognized as revenues in the statement of operations.

Contracts to buy or sell non-financial items that are not in accordance with the Company s expected purchase, sale or usage requirements are accounted for as derivative financial instruments.

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***2008 Accounting Changes***

On January 1, 2008, the Company adopted three new accounting standards that were issued by the Canadian Institute of Chartered Accountants ( **CICA** ): Handbook Section 1535 Capital Disclosures ( **S.1535** ), Handbook Section 3862 Financial Instruments Disclosures ( **S.3862** ), and Handbook 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. The latter two replaced Handbook Section.3861 Financial Instruments Disclosure and Presentation . The Company adopted the new standards on January 1, 2008 with additional disclosures included in these consolidated financial statements. There was no transitional adjustment to the consolidated financial statements as a result of having adopted these standards.

***Impact of New and Pending Canadian GAAP Accounting Standards***

In February 2008, the CICA issued Handbook Section 3064, Goodwill and Intangible assets, ( **S.3064** ) replacing Handbook Section 3062, Goodwill and Other Intangible Assets ( **S.3062** ) and Handbook Section 3450, Research and Development Costs . S.3064 will be applicable to financial statements relating to fiscal years beginning on or after October 1, 2008. Accordingly, the Company will adopt the new standards for its fiscal year beginning January 1, 2009. The new section establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition and of intangible assets by profit-oriented enterprises. Standards concerning goodwill are unchanged from the standards included in the previous S.3062. Management has concluded that the requirements of this new Section will not have a material impact on its consolidated financial statements.

Also in February 2008, the CICA amended portions of Handbook Section 1000, Financial Statement Concepts , which the CICA concluded permitted deferral of costs that did not meet the definition of an asset. The amendments apply to annual and interim financial statements relating to fiscal years beginning on or after October 1, 2008. Upon adoption of S.3064 and the amendments to Section 1000 on January 1, 2009, capitalized amounts that no longer meet the definition of an asset will be expensed retrospectively. Management has concluded that the requirements of this new Section will not have a material impact on its consolidated financial statements.

Effective January 1, 2008, the Company implemented amendments to CICA Handbook Section 1400 General Standards of Financial Statement Presentation that incorporates going concern guidance. These changes require management to make an assessment of an entity s ability to continue as a going concern when preparing financial statements. Financial statements shall be prepared on a going concern basis unless management either intends to liquidate the entity or to cease trading, or has no realistic alternative but to do so. When management is aware, in making its assessment, of material uncertainties related to events or conditions that may cast significant doubt upon the entity s ability to continue as a going concern, those uncertainties shall be disclosed. The new requirements are applicable to all entities and are effective for annual financial statements relating to fiscal years beginning on or after January 1, 2008. There was no material impact on the Company s consolidated financial statements as the Company already going concern disclosure in its consolidated financial statements.

***Convergence of Canadian GAAP with International Financial Reporting Standards***

In April 2008, the CICA published the exposure draft Adopting IFRSs in Canada . The exposure draft proposes to incorporate International Financial Reporting Standards ( **IFRS** ) into the CICA Accounting Handbook effective for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. At this date, publicly accountable enterprises will be required to prepare financial statements in accordance with IFRS.

The International Accounting Standards Board ( **IASB** ) has stated that it plans to issue an exposure draft relating to certain amendments to IFRS 1 in order to make it more useful to Canadian entities adopting IFRS for the first time. One such exemption relating to full cost oil and gas accounting is expected to result in a reduced administrative transition from the current Canadian AcG-16 to IFRS. It is anticipated that this exposure draft will not result in an amended IFRS 1 standard until late in 2009. The amendment will potentially permit the Company to apply IFRS prospectively to its full cost pool, rather than the retrospective assessment of capitalized exploration and development expenses, with the proviso that a ceiling test, under IFRS standards, be conducted at the transition date.

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**3. OIL AND GAS PROPERTIES AND DEVELOPMENT COSTS**

The Company has four reportable business segments: Oil and Gas Integrated, Oil and Gas Conventional, Business and Technology Development and Corporate as further described in Note 11. These segments are different than those reported in the Company s previous financial statements included in its Form 10-Ks and as such the presentation has been changed to conform to the new segments. Capital assets categorized by segment are as follows:

| | As at December 31, 2008 | | | | | |
|---|---|---|---|---|---|---|
| | Oil and Gas | | | | Business and Technology | |
| | Integrated | | Conventional | | | |
| | **Canada** | **Ecuador** | **China** | **U.S.** | **Development** | **Total** |
| Oil and Gas Properties: | | | | | | |
| Proved | $ | $ | $ 141,089 | $ 113,002 | $ | $ 254,091 |
| Unproved | 81,090 | 1,454 | 5,233 | 3,067 | | 90,844 |
| | 81,090 | 1,454 | 146,322 | 116,069 | | 344,935 |
| Accumulated depletion | | | (81,717) | (33,197) | | (114,914) |
| Accumulated provision for impairment | | | (16,550) | (50,350) | | (66,900) |
| | 81,090 | 1,454 | 48,055 | 32,522 | | 163,121 |
| Development Costs: | | | | | | |
| Feasibility studies and other deferred costs: | | | | | | |
| HTL™ | | | | | 801 | 801 |
| GTL | | | | | 5,054 | 5,054 |
| Accumulated provision for impairment | | | | | (5,054) | (5,054) |
| Feedstock test facility | | | | | 8,770 | 8,770 |
| Commercial demonstration facility | | | | | 11,036 | 11,036 |
| Accumulated depreciation | | | | | (7,713) | (7,713) |
| | | | | | 12,894 | 12,894 |
| Furniture and equipment | 20 | 90 | 120 | 538 | 406 | 1,174 |
| Accumulated depreciation | (6) | | (80) | (476) | (77) | (639) |
| | 14 | 90 | 40 | 62 | 329 | 535 |
| | $ 81,104 | $ 1,544 | $ 48,095 | $ 32,584 | $ 13,223 | $ 176,550 |

| | As at December 31, 2007 | | | |
|---|---|---|---|---|
| | Oil and Gas Conventional | | Business and Technology | |
| | **China** | **U.S.** | **Development** | **Total** |
| Oil and Gas Properties: | | | | |

| | | | | |
|---|---|---|---|---|
| Proved | $ 134,648 | $ 107,040 | $ | $ 241,688 |
| Unproved | 3,297 | 4,373 | | 7,670 |
| | 137,945 | 111,413 | | 249,358 |
| Accumulated depletion | (58,583) | (27,091) | | (85,674) |
| Accumulated provision for impairment | (16,550) | (50,350) | | (66,900) |
| | 62,812 | 33,972 | | 96,784 |
| Development Costs: | | | | |
| Feasibility studies and other deferred costs: | | | | |
| HTL™ | | | 389 | 389 |
| GTL | | | 5,054 | 5,054 |
| Feedstock test facility | | | 4,724 | 4,724 |
| Commercial demonstration facility | | | 9,903 | 9,903 |
| Accumulated depreciation | | | (5,159) | (5,159) |
| | | | 14,911 | 14,911 |
| Furniture and equipment | 119 | 529 | 107 | 755 |
| Accumulated depreciation | (77) | (449) | (71) | (597) |
| | 42 | 80 | 36 | 158 |
| | $ 62,854 | $ 34,052 | $ 14,947 | $ 111,853 |

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***Oil and Gas Properties***

In 2008, the Company disposed of U.S. Oil and Gas Properties interests with proceeds totaling $0.1 million ($1.0 million in 2007 and $6.0 in 2006). 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.

Costs as at December 31, 2008 of $90.8 million ($7.7 million at December 31, 2007), related to unproved oil and gas properties have been excluded from costs subject to depletion and depreciation. Included in that same depletion calculation were $6.7 million for future development costs associated with proven undeveloped reserves as at December 31, 2008 ($8.9 million at December 31, 2007). The oil and gas properties in Canada and Ecuador have not had any oil and gas production and have been excluded from the ceiling test as undeveloped land.

The Company performed a ceiling test calculation at December 31, 2008, 2007 and 2006 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 in each of those years. The Company performed this same calculation for its China Oil and Gas Properties at December 31, 2008, 2007 and 2006 resulting in no impairment in 2008 and an impairment of $6.1 million and $5.4 million in 2007 and 2006 respectively.

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, 2008** | | **As at December 31, 2007** | | **As at December 31, 2006** | |
|---|---|---|---|---|---|---|
| | **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) |
| 2007 | NA | NA | NA | NA | $ 62.00 | $ 7.25 |
| 2008 | NA | NA | $ 92.00 | $ 7.50 | $ 60.00 | $ 7.50 |
| 2009 | $ 57.50 | $ 7.00 | $ 88.00 | $ 8.25 | $ 58.00 | $ 7.50 |
| 2010 | $ 68.00 | $ 7.50 | $ 84.00 | $ 8.25 | $ 57.00 | $ 7.50 |
| 2011 | $ 74.00 | $ 8.00 | $ 82.00 | $ 8.25 | $ 57.00 | $ 7.50 |
| 2012 | $ 85.00 | $ 8.75 | $ 82.00 | $ 8.25 | $ 57.50 | $ 7.75 |
| 2013 | $ 92.01 | $ 9.20 | $ 82.00 | $ 8.25 | $ 58.50 | $ 7.90 |
| 2014 | $ 93.85 | $ 9.38 | $ 82.00 | $ 8.45 | $ 59.75 | $ 8.05 |
| 2015 | $ 95.73 | $ 9.57 | $ 82.00 | $ 8.62 | $ 61.00 | $ 8.20 |
| 2016 | $ 97.64 | $ 9.76 | $ 82.02 | $ 8.79 | $ 62.25 | $ 8.40 |
| 2017 | $ 99.59 | $ 9.96 | $ 83.66 | $ 8.96 | $ 63.50 | $ 8.55 |
| 2018 | $ 101.59 | $ 10.16 | 2% per year | $ 9.14 | 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 |

***Development Costs***

In late 2004, the Company signed a memorandum of understanding with the Iraqi Ministry of Oil to evaluate a specific, large heavy oil field and its commercial development potential using Ivanhoe Energy s HTL™ Technology. Since that time, the Company has carried out a detailed analysis and has generated data regarding the applicability of its HTL™ Technology for the development of the field.

In the first half of 2007, the Company and INPEX Corporation ( **INPEX** ), a Japanese oil and gas exploration and production company, signed an agreement to jointly pursue the opportunity to develop the above noted heavy oil field in Iraq. During the second quarter of 2007, INPEX paid $9.0 million to the Company as a contribution towards the Company s past costs related to the project and certain costs related to the development of its HTL™ Technology. The payment was credited to the carrying value of its Iraq and CDF HTL™ Development Costs related to this project.

The agreement provides INPEX with a minority interest in the venture, with Ivanhoe Energy retaining a majority interest. Both parties will participate in the pursuit of the opportunity but Ivanhoe will lead the discussions with the Iraqi Ministry of Oil. Should the Company and INPEX proceed with the development and deploy Ivanhoe Energy s HTL™ Technology, certain technology fees would be payable to the Company by INPEX.

At December 31, 2007 the CDF had one year remaining in its useful life. This useful life was extended to December 31, 2009 concurrent with the extension of the existing term of an agreement with a third party oil and gas producer to use its property for the CDF site location. The Feedstock Test Facility ( **FTF** ) was entering into the commissioning phase at December 31, 2008 and, as such, was not depreciated, nor impaired for the year ended December 31, 2008.

For the year ended December 31, 2008, the Company had no impairments (nil in 2007 and 2006) related to its HTL™ Development Costs.

***Gas-to-Liquids***

The Company is exploring an opportunity in Egypt 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 ( **Syntroleum** ). Because the Company has been pursuing this project for an extended period of time and has not been able to obtain a definitive agreement or appropriate project financing, the Company has impaired the carrying value of the costs associated with GTL as at December 31, 2008. The carrying value for GTL development costs of $5.1 million and intangible GTL assets of $10.0 million (see Note 4), were reduced to nil with a corresponding reduction in our results of operations. This impairment does not affect the Company s intention to continue to pursue this project.

**4. INTANGIBLE ASSETS TECHNOLOGY**

The Company s intangible assets consist of the following:

***HTL™ Technology***

In the 2005 merger with the Ensyn Group, Inc. ( **Ensyn** ), the Company acquired an exclusive, irrevocable license to deploy, worldwide, the RTP™ Process for petroleum applications as well as the exclusive right to deploy the RTP™ Process in all applications other than biomass. The Company s carrying value of the HTL™ Technology as at December 31, 2008 and 2007 was $92.2 million. Since the company acquired the technology, it has continued to expand its patent coverage to protect innovations to the HTL™ Technology as they are developed and to significantly extend the Company s portfolio of HTL™ intellectual property. The Company is the assignee of three granted patents and currently has five patent applications pending in the U.S. The Company also has multiple patents pending in numerous other countries. This intangible asset was not amortized and its carrying value was not impaired for the years ended December 31, 2008, 2007 and 2006.

***Syntroleum GTL Master License***

The Company owns a master license from 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. 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, 2008 and 2007 was nil and $10.0 million.

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. As described in Note 3 to these financial statements the GTL intangible asset balance of $10 million was impaired and charged to the results of operations with a corresponding reduction in intangible GTL assets (see Note 3). These intangible assets were not amortized and their carrying values were not impaired for the years ended December 31, 2007 and 2006.

## 5. LONG TERM DEBT

Notes payable consisted of the following as at:

| | December 31, 2008 | December 31, 2007 |
|---|---|---|
| Variable rate bank note, (5.46% at December 31, 2008), due April 2009 | $ 5,200 | $ 4,500 |
| Variable rate bank note (5.33% at December 31, 2008) due September 2010 | 7,000 | 10,000 |
| Non-interest bearing promissory note, due April 2009 | 416 | 2,876 |
| Convertible note (5.50% at December 31, 2008) due July 2011 | 32,787 | |
| | 45,403 | 17,376 |
| Less: | | |
| Unamortized discount | (4) | (139) |
| Unamortized deferred financing costs | (1,932) | (696) |
| Current maturities | (5,612) | (6,729) |
| | (7,548) | (7,564) |
| | $ 37,855 | $ 9,812 |

***Bank Loan***

In October 2006, the Company arranged a Senior Secured Revolving/Term Credit Facility of up to $15 million with an initial borrowing base of $8 million. In October 2008, the original due date of the revolving facility of October 2008 was extended to April 2009 and $5.2 million was outstanding at December 31, 2008. 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 12) covering up to 14,700 Bbls per month of the Company s production from its South Midway Property in California and Spraberry Property in West Texas. As part of reestablishing the borrowing base amount, the Company was required to enter into an additional commodity derivative contract (see Note 12). The facility is secured by a mortgage on both of these properties. The Company made an initial $1.5 million draw of this facility in October 2006, a subsequent draw of $3.0 million in September 2007 and a final draw of $0.7 million in April 2008.

In September 2007 the Company obtained a bank loan for a $30 million Revolving/Term Credit Facility with an initial borrowing base of $10 million. The facility is a revolving facility with a three-year term with interest payable only during the term. Interest will be three-month LIBOR plus 3.75%. The loan terms include the requirement for the Company to enter into three-year commodity derivative contracts (See Note 12) covering up to 18,000 Bbls per month of the Company s production from its Dagang field in China. The facility is secured by a pledge of collections from the Company s monthly oil sales in China and by a pledge of shares of the Company s Chinese subsidiaries. The Company made an initial $7.0 million draw of this facility in September 2007 and a subsequent draw of $3.0 million in December of 2007. In December 2008 $3.0 million of this loan was repaid.

***Promissory Notes***

In connection with the acquisition in July 2008 described in Note 18, the Company issued a promissory note (the **2008 Note** ) to Talisman Energy Canada ( **Talisman** ) in the principal amount of Cdn.$12.5 million bearing interest at a rate per year equal to the prime rate plus 2%, calculated daily and not compounded. The 2008 Note matured and the principal and related interest was paid on December 31, 2008.

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).

***Convertible Note***

Also in connection with the acquisition in July 2008 described in Note 18, the Company issued a convertible promissory note (the **Convertible Note** ) to Talisman in the principal amount of Cdn.$40.0 million bearing interest at a rate per year equal to the prime rate plus 2%, calculated daily and not compounded, payable semi-annually and maturing in July 2011. The Convertible Note is convertible (as to the outstanding principal amount), at Talisman s option, into a maximum of 12,779,552 common shares of the Company at Cdn.$3.13 per common share. There were no conversions of this note as of December 31, 2008.

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Under Canadian GAAP, the Convertible Note is assessed based on the substance of the contractual arrangement in determining whether it exhibits the fundamental characteristic of a financial liability or equity. Management has concluded that this debt instrument mainly exhibits characteristics that are liability in nature, however, the embedded conversion feature is equity in nature and is required to be bifurcated and disclosed separately within shareholders equity. Management has applied a residual basis method and has valued the liability component first and assigned the residual value to the equity component. Management has fair valued the liability component by discounting the expected interest and principal payments using an interest rate of 8.75% being management s estimate of the expected interest payments for a similar instrument without the conversion feature. The liability component was valued at Cdn.$37.9 million and the remaining balance of Cdn.$2.1 million was allocated to the equity component. The liability component will be accreted over the three-year maturity period to bring the liability back to Cdn.$40.0 million using the effective interest method.

The Company s obligations under the Convertible Note and the Contingent Payment (see Note 18) are secured by a first fixed charge and security interest in favor of Talisman against the acquired Talisman leases and the related assets acquired by the Company pursuant to the Talisman lease acquisition, and a subordinate security interest in and to all other present and after-acquired property of the Company other than the shares of any subsidiary of Ivanhoe Energy. The Talisman security interest also does not extend to any assets of any subsidiary of Ivanhoe Energy.

***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, 2008, 2007 and 2006.

The scheduled maturities of the Company s long term debt, excluding unamortized discount and unamortized deferred financing costs, as at December 31, 2008 were as follows:

| | |
|---|---|
| 2009 | $ 5,616 |
| 2010 | 7,000 |
| 2011 | 32,787 |
| | $ 45,403 |

Interest expense included in Interest Expense and Financing Costs in the statement of operations was $1.7 million for the year ended December 31, 2008 ($0.9 million for 2007 and $0.9 million for 2006). For the year ended December 2008, $1.7 million (nil in 2007 and 2006) in interest was capitalized to oil and gas properties and development costs in the balance sheet.

## 6. 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, 2008 was estimated at $6.3 million. These payments are expected to be made over the next 30 years; with over half of the payments during 2010 to 2025. To calculate the present value of these obligations, the Company used an inflation rate of 3% and the expected future cash flows have been discounted using a credit-adjusted risk-free rate of 6%. The changes in the Company s liability for the two-year period ended December 31, 2008 were as follows:

| | As at December, 31 2008 | As at December, 31 2007 |
|---|---|---|
| Carrying balance, beginning of year | $ 2,218 | $ 1,953 |
| Liabilities incurred | 236 | 20 |
| Liabilities settled | | (792) |
| Accretion expense | 171 | 119 |

| | | | | |
|---|---|---|---|---|
| Revisions in estimated cash flows | | 1,113 | | 918 |
| Carrying balance, end of period | $ | 3,738 | $ | 2,218 |

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### 7. COMMITMENTS AND CONTINGENCIES

***Zitong Block Exploration Commitment***

At December 31, 2005, the Company held a 100% working interest in a thirty-year production-sharing contract with China National Petroleum Corporation ( **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.

Under this production-sharing contract, the Company was obligated to conduct a minimum exploration program during the first three years ending December 1, 2005 ( **Phase 1** ). The Company completed Phase 1 with a drilling shortfall of approximately 700 feet. In December 2007, the Company and Mitsubishi (the **Zitong Partners"**) made a decision to enter into the next three-year exploration phase ( **Phase 2** ). The shortfall in Phase I drilling will be carried over into Phase 2.

By electing to participate in Phase 2 the Zitong Partners must relinquish 30%, plus or minus 5%, of the Zitong block acreage and complete a minimum work program involving the acquisition of approximately 200 miles of new seismic lines and approximately 23,700 feet of drilling (including the Phase 1 shortfall), with total gross remaining estimated minimum expenditures for this program of $27.4 million. The Phase 2 seismic line acquisition commitment was fulfilled in the Phase 1 exploration program. The Zitong Partners plan to acquire additional seismic data in Phase 2. The partners have requested that CNPC allow the offset of this additional seismic against the drilling commitment, reducing the required Phase 2 drilling footage requirement, but no agreement has been reached at this time. The Zitong Partners have relinquished 15% of the Block acreage and will relinquish an additional 10% to complete the Phase I relinquishment requirement. The Zitong Partners contracted Sichuan Geophysical Company to conduct a complete review of the seismic data acquired to date on the block to select the first Phase II drilling location. Drilling is planned to commence in late 2009 with expected completed drilling, completion and evaluation of this prospect finalized in 2010. The Zitong Partners must complete the minimum work program by the end of the Phase 2 period, December 31, 2010, or will be obligated to pay to CNPC the cash equivalent of the deficiency in the work program for that exploration phase. Following the completion of Phase 2, the Zitong Partners must relinquish all of the remaining property except any areas identified for development and production.

***Long Term Obligation***

As part of its 2005 merger with Ensyn Group, Inc., 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.

***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 its tax filings do not include uncertain tax positions, except as noted below, the results of potential audits or the effect of changes in tax law cannot be ascertained at this time.

The Company has an uncertain tax position in China related to when its entitlement to take tax deductions associated with development costs commenced. In March 2007, the Company received a 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 discussed this matter with Chinese tax authorities and subsequently filed its 2006 tax return for Sunwing s wholly-owned subsidiary Pan-China Resources Ltd. ( **Pan-China** ) taking a new filing position in which development costs are capitalized and amortized on a straight line basis over six years starting in the year the development costs are incurred rather than deducted in their entirety in the year incurred. This change resulted in a $50.3 million reduction in tax loss carry-forwards in 2007 with an equivalent increase in the tax basis of development costs available for application against future Chinese income. The Company has received no formal notification of this rule change; however it will continue to file tax returns under this new approach. To the extent that there is a different interpretation in the timing of the deductibility of development costs this could potentially result in an increase in the current tax provision of $2.0 million.

The Company has an uncertain tax position related to the calculation of a gain on the consideration received from two farm-out transactions (Richfirst January 2004 see Note 5 and Mitsubishi January 2006 see under Zitong Block

Exploration Commitment in this Note 7) and the designation of whether the taxable gains may be subject to a withholding tax of 10% pursuant to Chinese tax law for income derived by a foreign entity. The Company is waiting for the Chinese tax authorities to reply to its request to validate in writing that its current treatment of such tax position is appropriate. To the extent that the calculation of a gain is interpreted differently and the amounts are subject to withholding tax there would be an additional current tax provision of approximately $0.7 million.

No amounts have been recorded in the financial statements related to the above mentioned uncertain tax positions as management has determined the likelihood of an unfavorable outcome to the Company to be low.

***Other Commitments***

From time to time the Company enters into consulting agreements whereby a success fee may be payable if and when either a definitive agreement is signed or certain other contractual milestones are met. Under the agreements, the consultant may receive cash, Company shares, stock options or some combination thereof. These fees are not considered to be material in relation to the overall capital costs and funding requirements of the individual projects.

See Note 18 for a commitments related to acquisition of properties in Alberta.

The Company may provide indemnities to third parties, in the ordinary course of business, that are customary in certain commercial transactions such as purchase and sale agreements. The terms of these indemnities 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 indemnities would not materially affect the financial position of the Company.

***Lease Commitments***

For the year ended December 31, 2008 the Company expended $1.2 million ($1.1 million in 2007 and $0.8 million in 2006) on operating leases relating to the rental of office space, which expire between July 2010 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, 2008, future net minimum payments for operating leases (excluding oil and gas and other mineral leases) were the following:

| | | |
|---|---|---|
| 2009 | $ | 1,191 |
| 2010 | | 1,009 |
| 2011 | | 680 |
| 2012 | | 331 |
| 2013 | | 126 |
| | $ | 3,337 |

## 8. SHARE CAPITAL AND WARRANTS

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.

***Special Warrants Offering***

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.

In July 2008, the Company completed a Cdn.$88.0 million private placement consisting of 29,334,000 special warrants at Cdn.$3.00 per special warrant (the **Offering** ). Each of these special warrants entitled the holder to one common share of the Company upon exercise of the special warrant. In August 2008, all of these special warrants were exercised for 29,334,000 common shares. The net proceeds from the Offering was approximately Cdn.$83.4 million after deducting the agents commission of Cdn.$4.0 million and the expenses of the Offering of Cdn.$0.6 million. The Company used Cdn.$22.5 million of the net proceeds of the Offering to complete the cash component of the Talisman lease acquisition described in Note 18.

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.

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***Convertible Notes***

As described in Note 5, in connection with the acquisition in July 2008, the Company issued the Convertible Note to Talisman in the principal amount of Cdn.$40.0 million bearing interest at a rate per year equal to the prime rate plus 2%, calculated daily and not compounded, and payable semi-annually, maturing in July 2011 and convertible (as to the outstanding principal amount), at Talisman s option, into a maximum of 12,779,552 common shares of the Company at Cdn.$3.13 per common share. Also described in Note 5, management accounted for this convertible note by assigning a portion of the value, Cdn.$2.1 million, of the instrument to equity.

In April 2008, the Company obtained a loan from a third party finance company in the amount of Cdn.$5.0 million bearing interest at 8% per annum. The principal and accrued and unpaid interest matured and was repayable in August 2008. In August 2008, the lender exercised its option to convert the entire outstanding balance into the Company s common shares at the conversion price of Cdn.$2.24 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, 2008:

| | **Purchase Warrants** | **Shares Issuable** |
|---|---|---|
| | **(thousands)** | |
| 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 |
| Purchase warrants exercised | (2,000) | (2,000) |
| Purchase warrants expired | (1,200) | (1,200) |
| Balance December 31, 2007 | 26,496 | 26,496 |
| Purchase warrants expired | (15,096) | (15,096) |
| Private placements | 29,334 | 29,334 |
| Purchase warrants exercised | (29,334) | (29,334) |
| Balance December 31, 2008 | 11,400 | 11,400 |

For the year ended December 31, 2008, 29.3 million purchase warrants (2,000,000 in 2007 and nil in 2006) were exercised for the purchase of common shares please refer to details under Special Warrants Offering (2,000,000 in 2007 at an average exercise price of U.S. $2.00 per share for 2007 for a total of $4.0 million).

The expiration of 15.1 million (1.2 million in 2007) purchase warrants in 2008 resulted in the carrying value of $4.3 million ($0.6 million in 2007) associated with these warrants being reclassified from Purchase Warrants to Contributed Surplus at the time of expiration.

As at December 31, 2008, 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:

| **Year of Issue** | **Price per Special Warrant** | **Number of Common Shares Issued** | **Purchase Warrants Issued** | **Exercisable** | **Common Shares Issuable** | **Value** | **Expiry Date** | **Exercise Price per Share** | **Cash Value on Exercise** |
|---|---|---|---|---|---|---|---|---|---|

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | **($U.S. 000)** | | | **($U.S. 000)** |
| | | | **(thousands)** | | | | | | |
| 2006 | U.S.$2.23 | 11,400 | 11,400 | 11,400 | 11,400 | 18,805 | May 2011 | Cdn. $2.93(1) | 27,379 |

(1) 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 2006, these warrants were listed on the Toronto Stock Exchange and the exercise price was changed to Cdn.$2.93.

The weighted average exercise price of the exercisable purchase warrants as at December 31, 2008 was U.S. $2.40 per share.

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The Company calculated a value of $18.8 million for the purchase warrants issued in 2006. 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%, a dividend yield of 0.0%, a weighted average volatility factor of 75.3% and an expected life of 5 years.

**9. 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 number of common shares that may be issued under this plan cannot exceed 29.3 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. Additionally, in 2007, the Company granted share option awards whose vesting is contingent upon meeting various departmental and company-wide goals.

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

| | **2008** | **2007** | **2006** |
|---|---|---|---|
| Expected term (in years) | 4.0 | 3.7 | 5.5 |
| Volatility | 63.6% | 73.5% | 82.5% |
| Dividend Yield | 0.0% | 0.0% | 0.0% |
| Risk-free rate | 3.1% | 4.1% | 4.4% |

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, 2008 is 25.9% (23.1% at December 31, 2007 and 23.0% at December 31, 2006). The Company recognizes compensation costs only for those equity awards expected to vest.

The weighted average grant-date fair value of stock options granted during 2008 was Cdn.$0.90 (Cdn.$1.09 in 2007 and Cdn$1.92 in 2006).

For the years ended December 31, 2008 the Company s stock based compensation related to option awards was $3.1 million ($2.9 million in 2007 and $2.9 million in 2006). The Company s stock based compensation related to share bonus awards was $0.5 million for the year ended December 31, 2008 ($0.8 million in 2007). Stock based compensation was recorded as general and administrative and business and technology development expense in the statement of operations. In addition, $0.2 million of the Company s stock based compensation related to option awards was capitalized to oil and gas properties and development costs in the balance sheet during December 31, 2008.

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

| | December 31, 2008 | | December 31, 2007 | | December 31, 2006 | |
|---|---|---|---|---|---|---|
| | 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 | 12,945 | $ 2.37 | 12,370 | $ 2.34 | 10,278 | $ 2.21 |
| Granted | 3,832 | $ 1.79 | 3,843 | $ 1.05 | 3,419 | $ 3.02 |
| Exercised | (3,067) | $ 0.90 | (1,477) | $ 0.62 | (297) | $ 2.05 |
| Expired | (580) | $ 5.78 | (1,017) | $ 3.12 | (448) | $ 3.62 |
| Forfeited | (1,217) | $ 3.05 | (774) | $ 2.69 | (582) | $ 3.22 |
| Outstanding at end of year | 11,913 | $ 2.32 | 12,945 | $ 2.37 | 12,370 | $ 2.34 |
| Options exercisable at end of year | 5,062 | $ 2.61 | 6,932 | $ 2.24 | 7,720 | $ 1.92 |

The aggregate intrinsic value of total options outstanding as well as options exercisable as at December 31, 2008 was nil as there were no options in the money. The total intrinsic value of options exercised during the year ended December 31, 2008 was $5.4 million ($2.1 million in 2007 and $0.2 million in 2006), and the cash received from exercise of options during the year ended December 31, 2008 was $1.2 million ($0.4 million in 2007 and $0.5 million in 2006).

The following table summarizes information respecting stock options outstanding and exercisable as at December 31, 2008:

| | Stock Options Outstanding | | | Stock Options Exercisable | | |
|---|---|---|---|---|---|---|
| Range of Exercise Prices (Cdn.$) | Number Outstanding (thousands) | Weighted-Average Remaining Contractual Life (Years) | Weighted-Average Exercise Price (Cdn.$) | Number Exercisable (thousands) | Weighted-Average Remaining Contractual Life (Years) | Weighted-Average Exercise Price (Cdn.$) |
| $1.52 to $2.25 | 6,097 | 3.8 | $ 1.80 | 1,432 | 3.6 | $ 1.83 |
| $2.29 to $3.44 | 5,504 | 2.3 | $ 2.84 | 3,432 | 2.0 | $ 2.87 |
| $3.53 to $3.62 | 312 | 1.9 | $ 3.55 | 198 | 1.8 | $ 3.56 |
| $1.52 to $3.62 | 11,913 | 3.1 | $ 2.32 | 5,062 | 2.4 | $ 2.61 |

A summary of the Company s unvested options as at December 31, 2008, 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, 2007 | 6,013 | $ | 1.12 |
| Granted | 3,831 | $ | 0.90 |
| Vested | (2,692) | $ | 0.68 |
| Cancelled/forfeited | (301) | $ | 0.03 |
| Outstanding at December 31, 2008 | 6,851 | $ | 0.98 |

**Unvested options outstanding at December 31, 2008 by type:**

| | |
|---|---|
| Based on fulfulling service conditions | 5,412 |
| Based on fulfulling performance conditions | 1,439 |
| | 6,851 |

As at December 31, 2008, there was $2.9 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 1.7 years. The total fair value of shares vested during the year ended December 31, 2008 was $3.0 million ($2.9 million in 2007 and $3.1 million in 2006).

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**10. RETIREMENT PLAN**

In 2001, the Company adopted a defined contribution retirement or thrift plan ( **401(k) Plan** ) to assist U.S. employees in providing for retirement or other future financial needs. Employees contributions (up to the maximum allowed by U.S. tax laws) were matched 100% by the Company in 2008. For the year ended December 31, 2008 the Company s matching contributions to the 401(k) Plan was $0.5 million ($0.5 million in 2007 and $0.4 million in 2006).

**11. SEGMENT INFORMATION**

The Company has four reportable business segments: Oil and Gas Integrated, Oil and Gas Conventional, Business and Technology Development and Corporate. These segments are different than those reported in the Company s previous financial statements included in its Form 10-Ks and as such the presentation has been changed to conform to the new segments. Due to newly established geographically focused entities and the initiation of two new integrated projects, new segments are being reported to reflect how management now analyzes and manages the Company.

***Oil and Gas***

Integrated

Projects in this segment will have two primary components. The first component consists of conventional exploration and production activities together with enhanced oil recovery techniques such as steam assisted gravity drainage. The second component consists of the deployment of the HTL™ Technology which will be used to upgrade heavy oil at facilities located in the field to produce lighter, more valuable crude. The Company has two such projects currently reported in this segment a heavy oil project in Alberta (see Note 18) and a heavy oil property in Ecuador (see Note 18). The integrated segments were established in 2008 and therefore there is no comparative information for 2007 and 2006.

Conventional

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

***Business and Technology Development***

The Company incurs various costs in the pursuit of HTL™ and GTL projects throughout the world. Such costs incurred prior to signing a MOU or similar agreement, are considered to be business and technology development and are expensed as incurred. Upon executing a MOU to determine the technical and commercial feasibility of a project, including studies for the marketability for the projects products, the Company assesses whether 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.

Additionally, the Company incurs costs to develop, enhance and identify improvements in the application of the HTL™ and GTL technologies it owns or licenses. The cost of equipment and facilities acquired, 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.

***Corporate***

The Company s corporate segment consists of costs associated with the board of directors, executive officers, corporate debt, financings and other corporate activities.

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The following tables present the Company s segment information for the three years ended December 31, 2008.

| | Year Ended December 31, 2008 | | | | | | |
|---|---|---|---|---|---|---|---|
| | Oil and Gas | | | | Business and Technology Development | Corporate | Total |
| | Integrated | | Conventional | | | | |
| | Canada | Ecuador | China | U.S. | | | |
| **Revenue** | | | | | | | |
| Oil and gas revenue | $ | $ | $ 48,370 | $ 18,120 | $ | $ | $ 66,490 |
| Gain on derivative instruments | | | 1,688 | 278 | | | 1,966 |
| Interest income | | | 50 | 98 | | 562 | 710 |
| | | | 50,108 | 18,496 | | 562 | 69,166 |
| **Expenses** | | | | | | | |
| Operating costs | | | 21,515 | 5,137 | | | 26,652 |
| General and administrative | 1,653 | 658 | 2,245 | 2,411 | | 11,223 | 18,190 |
| Business and technology development | 189 | | | | 6,264 | | 6,453 |
| Depletion and depreciation | 3 | | 23,135 | 6,143 | 2,618 | 5 | 31,904 |
| Interest expense and financing costs | | | 821 | 520 | 76 | 412 | 1,829 |
| Provion for impairment of GTL intangible assets and development costs | | | | | 15,054 | | 15,054 |
| Write off of deferred financing costs | | | 2,621 | | | | 2,621 |
| | 1,845 | 658 | 50,337 | 14,211 | 24,012 | 11,640 | 102,703 |
| **Income (Loss) before Income Taxes** | (1,845) | (658) | (229) | 4,285 | (24,012) | (11,078) | (33,537) |
| **Provision for income taxes** | | | | | | | |
| Current | | | (650) | (4) | (2) | | (656) |
| **Net Income (Loss) and Comprehensive Income (Loss)** | $ (1,845) | $ (658) | $ (879) | $ 4,281 | $ (24,014) | $ (11,078) | $ (34,193) |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Capital Investments** | $ 6,484 | $ 1,369 | $ 8,378 | $ 4,542 | $ 4,833 | $ | $ 25,606 |
| **Identifiable Assets: As at December 31, 2008** | $ 81,126 | $ 1,766 | $ 64,901 | $ 37,480 | $ 105,587 | $ 26,415 | $ 317,275 |

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| | Year Ended December 31, 2007 | | | | |
|---|---|---|---|---|---|
| | Oil and Gas Conventional | | Business and Technology | | |
| | China | U.S. | Development | Corporate | Total |
| **Revenue** | | | | | |
| Oil and gas revenue | $ 31,365 | $ 12,270 | $ | $ | $ 43,635 |
| Loss on derivative instruments | (4,993) | (5,594) | | | (10,587) |
| Interest income | 58 | 152 | | 259 | 469 |
| | 26,430 | 6,828 | | 259 | 33,517 |
| **Expenses** | | | | | |
| Operating costs | 13,000 | 4,319 | | | 17,319 |
| General and administrative | 2,042 | 2,018 | | 8,016 | 12,076 |
| Business and technology development | | | 9,625 | | 9,625 |
| Depletion and depreciation | 19,222 | 5,884 | 1,412 | 6 | 26,524 |
| Interest expense and financing costs | 281 | 427 | 29 | 313 | 1,050 |
| Provision for impairment of oil and gas properties | 6,130 | | | | 6,130 |
| | 40,675 | 12,648 | 11,066 | 8,335 | 72,724 |
| **Net Loss and Comprehensive Loss** | $ (14,245) | $ (5,820) | $ (11,066) | $ (8,076) | $ (39,207) |
| **Capital Investments** | $ 23,488 | $ 3,052 | $ 5,098 | $ | $ 31,638 |
| **Identifiable Assets: As at December 31, 2007** | $ 73,298 | $ 40,726 | $ 117,529 | $ 5,363 | $ 236,916 |

| | Year Ended December 31, 2006 | | | | |
|---|---|---|---|---|---|
| | Oil and Gas Conventional | | Business and Technology | | |
| | China | U.S. | Development | Corporate | Total |
| **Revenue** | | | | | |
| Oil and gas revenue | $ 35,683 | $ 12,065 | $ | $ | $ 47,748 |
| Loss on derivative instruments | | (424) | | | (424) |
| Interest income | 63 | 139 | | 574 | 776 |
| | 35,746 | 11,780 | | 574 | 48,100 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Expenses** | | | | | | | | | | |
| Operating costs | | 11,834 | | 4,299 | | | | | | 16,133 |
| General and administrative | | 1,337 | | 1,676 | | | | 7,167 | | 10,180 |
| Business and technology development | | | | | | 7,610 | | | | 7,610 |
| Depletion and depreciation | | 23,345 | | 5,378 | | 3,822 | | 5 | | 32,550 |
| Interest expense and financing costs | | 156 | | 290 | | 10 | | 507 | | 963 |
| Write off of deferred acquisition costs | | 736 | | | | | | | | 736 |
| Provision for impairment of oil and gas properties | | 5,420 | | | | | | | | 5,420 |
| | | 42,828 | | 11,643 | | 11,442 | | 7,679 | | 73,592 |
| **Net Income (Loss) and Comprehensive Income (Loss)** | $ | (7,082) | $ | 137 | $ | (11,442) | $ | (7,105) | $ | (25,492) |
| **Capital Investments** | $ | 9,086 | $ | 5,550 | $ | 3,206 | $ | | $ | 17,842 |

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## 12. FINANCIAL INSTRUMENTS AND FINANCIAL RISK FACTORS

The accounting classification of each category of financial instruments, and their carrying amounts (which approximate fair value), are set out below.

| | As at December 31, 2008 | | | | |
|---|---|---|---|---|---|
| | Loans and receivables | Available-for-sale financial assets | Held-for-trading | Financial liabilities measured at amortized cost | Total carrying amount |
| Financial Assets: | | | | | |
| Cash and cash equivalents | $ | $ | $ 39,265 | $ | $ 39,265 |
| Accounts receivable | 4,870 | | | | 4,870 |
| Derivative instruments | | | 2,159 | | 2,159 |
| Financial Liabilities: | | | | | |
| Accounts payable and accrued liabilities | | | | (10,093) | (10,093) |
| Long term obligation | | | | (1,900) | (1,900) |
| Long term debt | | | | (43,467) | (43,467) |
| | $ 4,870 | $ | $ 41,424 | $ (55,460) | $ (9,166) |

| | As at December 31, 2007 | | | | |
|---|---|---|---|---|---|
| | Loans and receivables | Available-for-sale financial assets | Held-for-trading | Financial liabilities measured at amortized cost | Total carrying amount |
| Financial Assets: | | | | | |
| Cash and cash equivalents | $ | $ | $ 11,356 | $ | $ 11,356 |
| Accounts receivable | 9,376 | | | | 9,376 |
| Advance | 825 | | | | 825 |
| Financial Liabilities: | | | | | |
| Accounts payable and accrued liabilities | | | | (9,538) | (9,538) |
| Derivative instruments | | | (9,432) | | (9,432) |
| Long term obligation | | | | (1,900) | (1,900) |
| Long term debt | | | | (16,541) | (16,541) |
| | $ 10,201 | $ | $ 1,924 | $ (27,979) | $ (15,854) |

***Financial Risk Factors***

The Company is exposed to a number of different financial risks arising from typical business exposures as well as its use of financial instruments including market risk relating to commodity prices, foreign currency exchange rates and interest rates, credit risk and liquidity risk. There have been no significant changes to the Company s exposure to risks nor to management s objectives, policies and processes to manage risks from the previous year except discussed below under Liquidity Risk . The risks associated with our financial instruments and our policies for minimizing these risks are detailed below.

***Market Risk***

Market risk is the risk that the fair value or future cash flows of our financial instruments will fluctuate because of changes in market prices. Components of market risk to which we are exposed are discussed below.

*Commodity Price Risks*

Commodity price risk refers to the risk that the value of a financial instrument or cash flows associated with the instrument will fluctuate due to the changes in market commodity prices. Crude oil prices and quality differentials are influenced by worldwide factors such as OPEC actions, political events and supply and demand fundamentals. The Company may periodically use different types of derivative instruments to manage its exposure to price volatility as well as being a requirement of the Company s lenders.

The Company entered into costless collar derivatives to minimize variability in its cash flow from the sale of up to 14,700 Bbls per month of the Company s production from its South Midway Property in California and Spraberry Property in West Texas over a two-year period starting November 2006 and a six-month period starting November 2008. The derivatives had a ceiling price of $65.20, and $70.08, per barrel and a floor price of $63.20, and $65.00, per barrel, respectively, using WTI as the index traded on the NYMEX. The Company also entered into a costless collar derivative to minimize variability in its cash flow from the sale of up to 18,000 Bbls per month of the Company s production from its Dagang field in China over a three-year period starting September 2007. This derivative had a ceiling price of $84.50 per barrel and a floor price of $55.00 per barrel using the WTI as the index traded on the NYMEX. All of the above contacts were put in place as part of the Company s bank loan facilities. Results of these derivative transactions for the three years ended December 31, 2008:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| Realized gains (losses) on derivative transactions | $ (9,625) | $ (1,648) | $ 69 |
| Unrealized gains (losses) on derivative transactions | 11,591 | (8,939) | (493) |
| | $ 1,966 | $ (10,587) | $ (424) |

Both realized and unrealized gains and losses on derivatives have been recognized in the results of operations.

On December 31, 2008, the Company s open positions on the derivative assets referred to above had a fair value of $2.2 million. A 10% increase in oil prices would reduce the fair value, and consequently increase the net loss, by approximately $1.1 million, while a 10% decrease in prices would increase the fair value, and consequently reduce the net loss, by approximately $1.1 million. The fair value change assumes volatility based on prevailing market parameters at December 31, 2008.

*Foreign Currency Exchange Rate Risk*

Foreign currency risk refers to the risk that the value of a financial commitment, recognized asset or liability will fluctuate due to changes in foreign currency rates. The main underlying economic currency of the Company s cash flows is the U.S. dollar. This is because the Company s major product, crude oil, is priced internationally in U.S. dollars. Accordingly, the Company does not expect to face foreign exchange risks associated with its production revenues. However, some of the Company s cash flow stream relating to certain international operations is based on the U.S. dollar equivalent of cash flows measured in foreign currencies. The majority of the operating costs incurred in the Chinese operations are paid in Chinese renminbi. The majority of costs incurred in the administrative offices in Vancouver and Calgary, as well as some business development costs, are paid in Canadian dollars. In addition, with the recent property acquisition in Alberta (see Note 18) the Company s Canadian dollar expenditures have increased during the last half of 2008 along with an increase in cash and debt balances denominated in Canadian dollars. Disbursement transactions denominated in Chinese renminbi and Canadian dollars are converted to U.S. dollar equivalents based on the exchange rate as of the transaction date. Foreign currency gains and losses also come about when monetary assets and liabilities, mainly short term payables and receivables, denominated in foreign currencies are translated at the end of each month. The estimated impact of a 10% strengthening or weakening of the Chinese renminbi, and Canadian dollar, as of December 31, 2008 on net loss and accumulated deficit for the year ended December 31, 2008 is a $3.6 million increase, and a $3.7 million decrease, respectively. To help reduce the Company s exposure to foreign currency risk it seeks to maximize the expenditures and contracts denominated in U.S. dollars and minimize those denominated in other currencies, except for its Canadian activities where it attempts to hold cash denominated in Canadian dollars in order to manage its currency risk related to outstanding debt and current liabilities denominated in Canadian dollars.

*Interest Rate Risk*

Interest rate risk refers to the risk that the value of a financial instrument or cash flows associated with the instrument will fluctuate due to the changes in market interest rates. Interest rate risk arises from interest-bearing borrowings which have a variable interest rate. The Company currently has two separate bank loan facilities and a convertible note with fluctuating interest rates. The Company estimates that its net loss and accumulated deficit for the year ended December 31, 2008 would have changed $0.2 million for every 1% change in interest rates as of December 31, 2008. The Company is not currently actively attempting to mitigate this interest rate risk given the limited amount and term of its borrowings and the current global interest rate environment.

*Credit Risk*

The Company is exposed to credit risk with respect to its cash held with financial institutions, accounts receivable, derivative contracts and advance balances. The Company believes its exposure to credit risk related to cash held with financial institutions is minimal due to the quality of the institutions where the cash is held and the nature of the deposit instruments. Most of the Company s accounts receivable balances relate to oil and natural gas sales to pipelines, refineries, major oil companies and foreign national petroleum companies and are exposed to typical industry credit risks. In addition, accounts receivable balances consist 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. The advance balance relates to an arrangement whereby scheduled advances were made to a third party contractor associated with negotiating an HTL™ and/or GTL project for the Company. The Company manages its credit risk by entering into sales contracts only with established entities and reviewing its exposure to individual entities on a regular basis.

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

| | Accounts Receivable as at December 31, | | Oil and Gas Revenue for the Year Ended December 31, | | |
|---|---|---|---|---|---|
| | **2008** | **2007** | **2008** | **2007** | **2006** |
| U.S. Customers | | | | | |
| A | $ 436 | $ 1,138 | $ 16,679 | $ 10,903 | $ 10,351 |
| B | 50 | 207 | 1,011 | 1,011 | 1,094 |
| C | 57 | 72 | 267 | 271 | 277 |
| D | | | 92 | 74 | 236 |
| All others | 18 | 27 | 72 | 11 | 107 |
| | 561 | 1,444 | 18,121 | 12,270 | 12,065 |
| China Customer | | | | | |
| A | 3,057 | 6,564 | 48,369 | 31,365 | 35,683 |
| | 3,618 | 8,008 | 66,490 | 43,635 | 47,748 |
| Receivables from partners | 613 | 815 | | | |
| Other receivables | 639 | 553 | | | |
| | $ 4,870 | $ 9,376 | $ 66,490 | $ 43,635 | $ 47,748 |

As noted below, included in the Company s trade receivable balance are debtors with a carrying amount of $0.4 million as of the year ended December 31, 2008 which are past due at the reporting date for which the Company has not provided an allowance, as there has not been a significant change in credit quality and the amounts are still considered recoverable. The Company defines past due by the specific contract terms associated with each transaction (e.g. oil sales generally have a one two month lag, joint venture billings generally are between 15 45 days). During the quarter ended September 30, 2008 the Company recorded an allowance associated with the advance balance for the entire outstanding amount of $0.7 million. In addition, the Company recorded an allowance for the entire outstanding amount of $0.4 million related to an amount owed to the Company by a joint interest partner in the fourth quarter of 2008. These provisions were recorded in General and Administrative expense in the accompanying Statement of Operations and Comprehensive Loss. There were no other changes to the allowance for credit losses account during the three-month period ended December 31, 2008 and no other losses associated with credit risk were recorded during this same period.

| | **December 31, 2008** | **December 31, 2007** |
|---|---|---|
| Accounts Receivable: | | |
| Neither impaired nor past due | $ 4,509 | $ 8,259 |
| Impaired (net of valuation allowance) | | |
| Not impaired and past due in the following periods: | | |
| within 30 days | 108 | 347 |
| 31 to 60 days | 46 | |
| 61 to 90 days | 72 | 4 |
| over 90 days | 135 | 766 |

| | | | | |
|---|---|---|---|---|
| | | 4,870 | | 9,376 |
| Advance | | | | |
| Not impaired and past due over 90 days | | | | 825 |
| | $ | 4,870 | $ | 10,201 |

Our maximum exposure to credit risk is based on the recorded amounts of the financial assets above.

*Liquidity Risk*

Liquidity risk is the risk that suitable sources of funding for the Company s business activities may not be available, which means it may be forced to sell financial assets or non-financial assets, refinance existing debt, raise new debt or issue equity. The Company s present plans to generate sufficient resources to assure continuation of its operations and achieve its capital investment objectives include alliances or other arrangements with entities with the resources to support the Company s projects as well as project financing, debt financing or the sale of equity securities. However, the availability of financing, in particular project funding, is dependent in part on the return of the credit and equity markets to normalized conditions. During the fourth quarter of 2008, as a result of the global economic crisis, the terms and availability of equity and debt capital have been materially restricted and financing may not be available when it required or on commercially acceptable terms.

The contractual maturity of the fixed and floating rate financial liabilities and derivatives are shown in the table below. The amounts presented represent the future undiscounted principal and interest cash flows and therefore do not equate to the values presented in the balance sheet.

| | As at December 31, 2008 Contractual Maturity (Nominal Cash Flows) | | | | As at December 31, 2007 Contractual Maturity (Nominal Cash Flows) | | | |
|---|---|---|---|---|---|---|---|---|
| | Less than 1 year | 1 to 2 years | 2 to 5 years | Over 5 years | Less than 1 year | 1 to 2 years | 2 to 5 years | Over 5 years |
| Derivative financial liabilities: | | | | | | | | |
| Costless Collars oil price commodity | $ | $ | $ | $ | $ 7,156 | $ 2,276 | $ | $ |
| Non derivative financial liabilities: | | | | | | | | |
| Trade accounts payable | $ 4,835 | $ | $ | $ | $ 6,897 | $ | $ | $ |
| Accruals | $ 5,258 | $ | $ | $ | $ 2,641 | $ | $ | $ |
| Long term debt and interest | $ 8,777 | $ 9,432 | $ 33,495 | $ | $ 8,240 | $ 1,541 | $ 10,277 | $ |

**13. CAPITAL MANAGEMENT**

The Company manages its capital so that the Company and its subsidiaries will be able to continue as a going concern and to create shareholder value through exploring, appraising and developing its assets including the major initiative of implementing multiple, full-scale, commercial HTL heavy oil projects in Canada and internationally. There have been no significant changes in management s objectives, policies and processes to manage capital or the components of capital from the previous year. However, the availability of financing, in particular project funding, is dependent in part on the return of the credit and equity markets to normalized conditions. During the fourth quarter of 2008, as a result of the global economic crisis, the terms and availability of equity and debt capital have been materially restricted and financing may not be available when it required or on commercially acceptable terms.

The Company defines capital as total equity or deficiency plus cash and cash equivalents and long term debt. Total equity is comprised of share capital, purchase warrants, convertible note, contributed surplus, shares to be issued and accumulated deficit as disclosed in Note 8. Cash and cash equivalents consist of $39.3 million and $11.4 million at December 31, 2008 and December 31, 2007 and are composed entirely of bank balances in checking accounts with excess cash in money market accounts which invest primarily in government securities with less than 90 day maturities... Long term debt is disclosed in Note 5.

The Company s management reviews the capital structure on a regular basis to maintain the most optimal debt to equity balance. In order to maintain or adjust its capital structure, the Company may refinance its existing debt, raise new debt, seek cost sharing arrangements with partners or issue new shares.

In 2008, the Company expensed $2.6 million of deferred financing costs that were directly attributable to a proposed offering of securities for its wholly-owned Chinese subsidiary.

The Company s U.S. and Chinese oil and gas subsidiaries are subject to financial covenants, such as interest coverage ratios, under each of their revolving/term credit facilities which are measured on a quarterly or semi-annual basis. The Company is in compliance with all financial covenants for the year ended December 31, 2008.

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**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, 2008, 2007 and 2006 were 29.5%, 32.12% and 32.12%, respectively. The sources and tax effects for the differences were as follows:

| | Year ended December 31, 2008 | 2007 | 2006 |
|---|---|---|---|
| Tax benefit computed at the combined Canadian federal and provincial statutory income tax rates | $ (9,893) | $ (12,593) | $ (8,188) |
| Foreign net losses affected at lower income tax rates | 5,084 | 905 | 113 |
| Effect of change in foreign exchange rates | 3,006 | (2,879) | (14) |
| Expiry of tax loss carry-forwards | 2,875 | 2,440 | 1,583 |
| Stock-based compensation not deductible | 905 | 1,001 | 1,031 |
| Financing costs not deductible | 695 | | |
| Net currency exchange losses not deductible | 402 | | |
| Change in prior year estimate of tax loss carry-forwards | (430) | (483) | 503 |
| Realized derivative (gains)/losses not taxable/deductible | (422) | 1,248 | |
| Effect of change in effective income tax rates on future tax assets | (331) | 6,109 | 870 |
| Other permanent differences | (58) | 778 | 95 |
| Tax credit carry-forward | | 607 | (428) |
| | 1,833 | (2,867) | (4,435) |
| Valuation allowance | (1,833) | 2,867 | 4,435 |
| | $ | $ | $ |

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

| | As at December 31, 2008 Future Income Tax Assets | 2008 Future Income Tax Liabilities | 2007 Future Income Tax Assets | 2007 Future Income Tax Liabilities |
|---|---|---|---|---|
| Oil and gas properties and investments | $ | $ (1,972) | $ | $ (3,330) |
| Intangibles | | (37,089) | | (36,976) |
| Derivative contracts | | (292) | 1,989 | |
| Tax loss carry-forwards | 60,355 | | 61,152 | |
| Tax credit carry-forward | 1,278 | | 1,278 | |
| Valuation allowance | (22,280) | | (24,113) | |
| | $ 39,353 | $ (39,353) | $ 40,306 | $ (40,306) |

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.$45.4 million, in China $35.5 million and in the U.S. $101.2 million. Tax loss carry-forwards in Ecuador are nominal. The tax loss carry-forwards in Canada expire between 2009 and 2028 and in the U.S. between 2016 and 2028. In China, the tax loss carry-forwards have no expiration period. A loss of approximately Cdn.$55.3 million from the disposition of 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.

The amount of current income tax payable at December 31, 2008 associated with income taxes for China equaled $0.7 million.

**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, | | |
|---|---|---|---|
| | **2008** | **2007** | **2006** |
| | (thousands of shares) | | |
| Stock options | 1,374 | 2,433 | 3,292 |
| Richfirst conversion rights | | | 1,104 |
| Purchase warrants | | | 121 |
| Convertible debt | 6,943 | | |
| | 8,317 | 2,433 | 4,517 |

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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, | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| | (thousands of shares) | | |
| Stock options | 9,944 | 8,616 | 7,022 |
| Purchase warrants | 16,399 | 28,898 | 25,184 |
| | 26,343 | 37,514 | 32,206 |

**16. SUPPLEMENTAL CASH FLOW INFORMATION**

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| **Cash paid during the period for** | | | |
| Income taxes | $ 6 | $ 6 | $ 5 |
| Interest | $ 1,431 | $ 479 | $ 430 |
| **Investing and Financing activities, non-cash** | | | |
| **Acquisition of oil and gas assets** | | | |
| Debt issued | $ 52,052 | $ | $ 6,547 |
| Shares issued | | | 20,000 |
| Receivable applied to acquisition | | | 1,746 |
| | $ 52,052 | $ | $ 28,293 |
| **Conversion of debt to shares** | | | |
| Extinguishment of debt | $ 4,737 | $ | $ |
| Extinguishment of interest | 125 | | |
| | $ 4,862 | $ | $ |
| **Shares issued for bonuses** | $ 490 | $ 793 | $ 401 |
| **Stock based compensation capitalized** | $ 175 | $ | $ |
| **Changes in non-cash working capital items** | | | |
| **Operating Activities** | | | |
| Accounts receivable | $ 4,159 | $ (1,734) | $ (1,375) |
| Prepaid and other current assets | (136) | 85 | (434) |
| Accounts payable and accrued liabilities | 1,470 | 1,166 | (1,067) |

| | | | |
|---|---|---|---|
| Income tax payable | 650 | | |
| | 6,143 | (483) | (2,876) |
| **Investing Activities** | | | |
| Accounts receivable | (44) | (207) | 2,188 |
| Prepaid and other current assets | (70) | 86 | (1) |
| Accounts payable and accrued liabilities | (816) | (1,056) | (14,895) |
| | (930) | (1,177) | (12,708) |
| **Financing Activities** | | | |
| Accounts payable and accrued liabilities | 26 | | |
| | $ 5,239 | $ (1,660) | $ (15,584) |

Cash and cash equivalents at December 31, 2008, and 2007, are composed entirely of bank balances in checking accounts with excess cash in money market accounts which invest primarily in government securities with less than 90 day maturities.

**17. RELATED PARTY TRANSACTIONS**

The Company has entered into agreements with a number of entities which are related or controlled through common directors or shareholders. These entities provide access to an aircraft, the services of administrative and technical personnel, and office space or facilities in Vancouver, London and Singapore. The Company is billed on a cost recovery basis. For the year ended December 31, 2008 the costs incurred in the normal course of business with respect to the above arrangements amounted to $3.0 million ($3.3 million for 2007 and $3.0 million for 2006), and are recorded in general and administrative expense in the statement of operations. As at December 31, 2008 amounts included in accounts payable and accrued liabilities on the balance sheet under these arrangements were $0.1 million ($0.2 million at December 31, 2007).

## 18. ACQUISTION AND PROJECT RELATED AGREEMENTS

***Canada***

In July 2008, the Company completed the acquisition of Talisman Energy Canada s ( **Talisman** ) 100% working interests in two leases located in the Athabasca oil sands region in the Province of Alberta, Canada. The total purchase price was Cdn.$90.0 million, of which an initial payment of Cdn.$22.5 million was made on closing. In addition to this initial payment the Company issued a promissory note to Talisman in the principal amount of Cdn.$12.5 million bearing interest at a rate per year equal to the prime rate plus 2% which matured and was paid on December 31, 2008 and a second promissory note to Talisman in the principal amount of Cdn.$40.0 million bearing interest at a rate per annum equal to the prime rate plus 2%, maturing in July 2011 and convertible (as to the outstanding principal amount), at Talisman s option, into a maximum of 12,779,552 common shares of the Company at Cdn.$3.13 per common share.

The Company may also be required to make a cash payment to Talisman of Cdn.$15 million if the requisite government and other approvals necessary to develop the northern border of one of the leases (the Contingent Payment ) are obtained. No amount is recorded in the financial statements for this payment as at December 31, 2008 as the chance of occurrence can not be determined at this time.

Talisman retains a back-in right (the **Back-in Right** ), exercisable once per lease until July 11, 2011, to re-acquire up to a 20% undivided interest in each lease. The purchase price payable by Talisman were it to exercise the Back-in Right in respect of a particular lease would be an amount equal to 20% of:

(a) 100% of the Company s acquisition cost and certain expenses in respect of the relevant lease if the Back-in Right is exercised on or before July 11, 2009;

(b) 150% of the Company s acquisition cost and certain expenses in respect of the relevant lease if the Back-in Right is exercised after July 11, 2009 but on or before July 11, 2010; or

(c) 200% of the Company s acquisition cost and certain expenses in respect of the relevant lease if the Back-in Right is exercised after July 11, 2010 but on or before July 11, 2011.

Until July 11, 2011, Talisman has the right of first offer to acquire any interests in heavy oil projects in the Province of Alberta that the Company or any of its subsidiaries wishes to sell, excluding the acquired leases.

***Ecuador***

In October 2008, Ivanhoe Energy Ecuador Inc. ( **IE Ecuador** ) entered into a contract with Empresa Estatal de Petroleos del Ecuador, Petroecuador ( **Petroecuador** ), the state oil company of Ecuador, and its affiliate, Empresa Estatal de Exploracion y Produccion de Petroleos del Ecuador, Petroproduccion ( **Petroproduccion** ) to explore and develop an oil field in Ecuador that includes the Pungarayacu heavy-oil field, utilizing the Company s HTL$^{TM}$ technology. IE Ecuador is a wholly-owned subsidiary of Ivanhoe Energy Latin America Inc. ( **IE Latin America** ), a wholly-owned subsidiary of the Company.

IE Ecuador will lead the development of the project. The contract is guaranteed by its parent company IE Latin America, which will obtain or provide funding and financing for IE Ecuador s operations under the contract. The contract s 30-year term may be extended by mutual agreement. To recover its investments, costs and expenses, and to provide for a profit, IE Ecuador will receive from Petroproduccion a payment of US$37.00 per barrel of oil produced and delivered to Petroproduccion. The payment will be indexed (adjusted) quarterly for inflation, starting from the contract date, using the weighted average of a basket of three US Government-published producer price indices relating to steel products, refinery products and upstream oil and gas equipment.

***China***

The Company currently holds a production-sharing contract with 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** ), to acquire a 40% working interest in the Dagang field for payment of $20.0 million. 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 repayable 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.

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## 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:

| | As at December 31, 2008 | | | | As at December 31, 2007 | | | |
|---|---|---|---|---|---|---|---|---|
| | Canadian GAAP | Increase (Decrease) | Notes | U.S. GAAP | Canadian GAAP | Increase (Decrease) | Notes | U.S. GAAP |
| **Assets** | | | | | | | | |
| Current Assets: | | | | | | | | |
| Cash and cash equivalents | $ 39,265 | | | $ 39,265 | $ 11,356 | | | $ 11,356 |
| Accounts receivable | 4,870 | | | 4,870 | 9,376 | | | 9,376 |
| Advance | | | | | 825 | | | 825 |
| Prepaid and other current assets | 1,658 | | | 1,658 | 602 | 96 | (xi) | 698 |
| Derivative instruments | 2,159 | | | 2,159 | | | | |
| Total Current Assets | 47,952 | | | 47,952 | 22,159 | 96 | | 22,255 |
| Oil and gas properties and development costs, net | 176,550 | 1,358 | (iv) | 122,071 | 111,853 | 1,358 | (iv) | 90,897 |
| | | (67,850) | (v) | | | (25,990) | (v) | |
| | | 13,031 | (vi) | | | 9,334 | (vi) | |
| | | (1,018) | (vii) | | | (5,658) | (vii) | |
| Intangible assets technology | 92,153 | | | 92,153 | 102,153 | | | 102,153 |
| Long term assets | 620 | 451 | (xi) | 1,071 | 751 | 600 | (xi) | 1,351 |
| Total Assets | $ 317,275 | $ (54,028) | | $ 263,247 | $ 236,916 | $ (20,260) | | $ 216,656 |
| **Liabilities and Shareholders Equity** | | | | | | | | |
| Current Liabilities: | | | | | | | | |
| Accounts payable and accrued liabilities | $ 10,093 | | | $ 10,093 | $ 9,538 | $ | | $ 9,538 |
| Income tax payable | 650 | | | 650 | | | | |
| Debt current portion | 5,612 | | | 5,612 | 6,729 | 96 | (xi) | 6,825 |
| Derivative instruments | | 1,121 | (iii) | 1,121 | 9,432 | 5,786 | (iii) | 15,218 |
| Total Current Liabilities | 16,355 | 1,121 | | 17,476 | 25,699 | 5,882 | | 31,581 |
| Long term debt | 37,855 | 451 | (xi) | 40,392 | 9,812 | 600 | (xi) | 10,412 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | 2,086 | (viii) | | | | | |
| Asset retirement obligations | 3,738 | | | 3,738 | 2,218 | | | 2,218 |
| Long term obligation | 1,900 | | | 1,900 | 1,900 | | | 1,900 |
| Total Liabilities | 59,848 | 3,658 | | 63,506 | 39,629 | 6,482 | | 46,111 |
| Shareholders Equity: | | | | | | | | |
| Share capital | 413,857 | 74,455 | (i) | 502,372 | 324,262 | 74,455 | (i) | 412,879 |
| | | (498) | (ii) | | | (396) | (ii) | |
| | | 1,358 | (iv) | | | 1,358 | (iv) | |
| | | 13,200 | (iii) | | | 13,200 | (iii) | |
| Purchase warrants | 18,805 | (18,805) | (iii) | | 23,078 | (21,218) | (iii) | 1,860 |
| Contributed surplus | 16,862 | (3,250) | (ii) | 10,665 | 9,937 | (3,352) | (ii) | 6,051 |
| | | (2,947) | (iii) | | | (534) | (iii) | |
| Convertible note | 2,086 | (2,086) | (viii) | | | | | |
| Accumulated deficit | (194,183) | (119,113) | | (313,296) | (159,990) | (90,255) | | (250,245) |
| Total Shareholders Equity | 257,427 | (57,686) | | 199,741 | 197,287 | (26,742) | | 170,545 |
| Total Liabilities and Shareholders Equity | $ 317,275 | $ (54,028) | | $ 263,247 | $ 236,916 | $ (20,260) | | $ 216,656 |

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*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.

(ii) Under 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.

In December 2004, the Financial Accounting Standards Board ( **FASB** ) issued a revision to Statement of Financial Accounting Standards ( **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.

(iii) The Company accounts for purchase warrants as equity under Canadian GAAP. The accounting treatment of warrants under U.S. GAAP reflects the application of SFAS 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 a 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. At the time that the Company s share purchase warrants are exercised, the value of the warrants will be reclassified to shareholders equity for U.S. 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.

*Oil and Gas Properties and Development Costs*

(iv) Under U.S. GAAP, 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.

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(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. In the ceiling test evaluation for U.S. GAAP purposes, the Company limits, on a country-by-country basis, the capitalized costs of oil and gas properties, net of accumulated DD&A and deferred income taxes, to (a) the estimated future net cash flows from proved oil and gas reserves using period-end, non-escalated prices and costs, discounted to present value at 10% per annum, plus (b) the cost of properties not being amortized (e.g. major development projects) and (c) the lower of cost or fair value of unproved properties included in the costs being amortized less (d) income tax effects related to difference between the book and tax basis of the properties referred to in (b) and (c) above. If capitalized costs exceed this limit, the excess is charged as a provision for impairment. Unproved properties and major development projects are assessed on a quarterly basis for possible impairments or reductions in value. If a reduction in value has occurred, the impairment is transferred to the carrying value of proved oil and gas properties. The differences in the ceiling test impairments by period for the U.S. and China Oil and Gas Properties between U.S. and Canadian GAAP as at December 31, 2008 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) |
| 2007 | | | |
| 2008 | 20,300 | | (20,300) |
| | 79,700 | 50,350 | (29,350) |
| **China Properties** | | | |
| Prior to 2004 | 10,000 | | (10,000) |
| 2004 | | | |
| 2005 | 1,700 | 5,000 | 3,300 |
| 2006 | 15,940 | 5,420 | (10,520) |
| 2007 | 5,850 | 6,130 | 280 |
| 2008 | 21,560 | | (21,560) |
| | 55,050 | 16,550 | (38,500) |
| | $ 134,750 | $ 66,900 | $ (67,850) |

(vi) The cumulative differences in the amount of impairment provisions between U.S. and Canadian GAAP resulted in reductions in accumulated depletion.

(vii) As more fully described under Development Costs in Note 2, under Canadian GAAP, the Company capitalizes certain development costs incurred for HTL™ and GTL projects subsequent to executing a 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 HTL™ and GTL development costs. Under U.S. GAAP, feasibility, marketing and related costs incurred prior to executing an HTL™ or GTL definitive agreement are considered to be research and development and are expensed as incurred.

(viii) As described in Note 5, under Canadian GAAP the Company was required to bifurcate the value of the Convertible Debt, allocating a portion to long term debt and a portion to equity. Under U.S. GAAP, the convertible debt securities in their entirety are classified as debt. This resulted in an increase in long term debt and a decrease in equity of $2.1 million for U.S. GAAP when compared to Canadian GAAP as at December 31, 2008. Under Canadian GAAP, the liability component will be accreted over the three-year maturity period to bring the liability back to Cdn.$40.0 million using the effective interest method.

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*Deferred Financing Costs*

(xi) As more fully described under Financial Assets and Liabilities in Note 2, for Canadian GAAP the Company accounts for deferred financing costs, or transaction costs, as a reduction from the related liability and accounted for using the effective interest method. For U.S. GAAP purposes, these costs are classified as other assets and amortized over the expected term of the financial liability.

***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, 2008 | | | |
|---|---|---|---|---|
| | Canadian GAAP | Increase (Decrease) | Notes | U.S. GAAP |
| **Revenue** | | | | |
| Oil and gas revenue | $ 66,490 | | | $ 66,490 |
| Gain on derivative instruments | 1,966 | 4,665 | (iii) | 6,631 |
| Interest income | 710 | | | 710 |
| Total Revenue | 69,166 | 4,665 | | 73,831 |
| **Expenses** | | | | |
| Operating costs | 26,652 | | | 26,652 |
| General and administrative | 18,190 | | | 18,190 |
| Business and technology development | 6,453 | | | 6,453 |
| Depletion and depreciation | 31,904 | (3,697) | (ix) | 28,207 |
| Interest expense and financing costs | 1,829 | | | 1,829 |
| Provision for impairment of HTL™ and GTL intangible assets and development costs | 15,054 | (4,640) | (x) | 10,414 |
| Write off of deferred financing costs | 2,621 | | | 2,621 |
| Provision for impairment of oil and gas properties | | 41,860 | (ix) | 41,860 |
| Total Expenses | 102,703 | 33,523 | | 136,226 |
| **Loss before Income Taxes** | (33,537) | (28,858) | | (62,395) |
| Current provision for income taxes | (656) | | | (656) |
| **Net Loss and Comprehensive Loss** | (34,193) | (28,858) | | (63,051) |
| Accumulated Deficit, beginning of year | (159,990) | (90,255) | | (250,245) |
| **Accumulated Deficit, end of year** | $ (194,183) | $ (119,113) | | $ (313,296) |
| **Net Loss per share Basic and Diluted** | $ (0.13) | $ (0.11) | | $ (0.24) |

| | | |
|---|---|---|
| **Weighted Average Number of Shares (in thousands)** | | |
| **Basic and Diluted** | 258,815 | 258,815 |

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| | Year Ended December 31, 2007 | | | |
|---|---|---|---|---|
| | Canadian GAAP | Increase (Decrease) | Notes | U.S. GAAP |
| **Revenue** | | | | |
| Oil and gas revenue | $ 43,635 | $ | | $ 43,635 |
| Loss on derivative instruments | (10,587) | 592 | (iii) | (9,995) |
| Interest income | 469 | | | 469 |
| Total Revenue | 33,517 | 592 | | 34,109 |
| **Expenses** | | | | |
| Operating costs | 17,319 | | | 17,319 |
| General and administrative | 12,076 | | | 12,076 |
| Business and technology development | 9,625 | | | 9,625 |
| Depletion and depreciation | 26,524 | (4,932) | (ix) | 21,592 |
| Interest expense and financing costs | 1,050 | | | 1,050 |
| Provision for impairment of HTL™ and GTL intangible assets and development costs | | (6,011) | (x) | (6,011) |
| Provision for impairment of oil and gas properties | 6,130 | (280) | (ix) | 5,850 |
| Total Expenses | 72,724 | (11,223) | | 61,501 |
| **Net Loss and Comprehensive Loss** | (39,207) | 11,815 | | (27,392) |
| Accumulated Deficit, beginning of year | (120,783) | (102,070) | | (222,853) |
| **Accumulated Deficit, end of year** | $ (159,990) | $ (90,255) | | $ (250,245) |
| **Net Loss per share Basic and Diluted** | $ (0.16) | $ 0.05 | | $ (0.11) |
| **Weighted Average Number of Shares (in thousands)** | | | | |
| **Basic and Diluted** | 242,362 | | | 242,362 |

| | Year Ended December 31, 2006 | | | |
|---|---|---|---|---|
| | Canadian GAAP | Increase (Decrease) | Notes | U.S. GAAP |
| **Revenue** | | | | |
| Oil and gas revenue | $ 47,748 | $ | | $ 47,748 |
| Loss on derivative instruments | (424) | (691) | (iii) | (1,115) |
| Interest income | 776 | | | 776 |
| Total Revenue | 48,100 | (691) | | 47,409 |

| | | | | |
|---|---|---|---|---|
| **Expenses** | | | | |
| Operating costs | 16,133 | | | 16,133 |
| General and administrative | 10,180 | | | 10,180 |
| Business and technology development | 7,610 | | | 7,610 |
| Depletion and depreciation | 32,550 | (2,840) | (ix) | 29,710 |
| Interest expense and financing costs | 963 | | | 963 |
| Provision for impairment of HTL™ and GTL intangible assets and development costs | | 958 | (x) | 958 |
| Provision for impairment of oil and gas properties | 5,420 | 18,120 | (ix) | 23,540 |
| Write off of deferred acquisition costs | 736 | | | 736 |
| Total Expenses | 73,592 | 16,238 | | 89,830 |
| **Net Loss and Comprehensive Loss** | (25,492) | (16,929) | | (42,421) |
| Accumulated Deficit, beginning of year | (95,291) | (85,141) | | (180,432) |
| **Accumulated Deficit, end of year** | $ (120,783) | $ (102,070) | | $ (222,853) |
| **Net Loss per share Basic and Diluted** | $ (0.11) | $ (0.07) | | $ (0.18) |
| **Weighted Average Number of Shares (in thousands)** | | | | |
| **Basic and Diluted** | 235,640 | | | 235,640 |

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(ix) As discussed under Oil and Gas Properties and Development Costs in this note, there is a difference between U.S. and Canadian GAAP in performing the ceiling test evaluation under the full cost method of accounting rules. 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. This net increase in U.S. GAAP impairment provisions has resulted in lower depletion rates for U.S. GAAP purposes and a reduction in the net losses for the years ended December 31, 2008, 2007 and 2006.

(x) As more fully described under Oil and Gas Properties and Development Costs 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.

As more fully described under Note 3, the Company and INPEX have signed an agreement to jointly pursue the opportunity to develop a heavy oil field in Iraq that Ivanhoe believes is a suitable candidate for its patented HTL™ heavy oil upgrading technology. In the second quarter of 2007, the Company received a $9.0 million payment related to this agreement which was credited to the carrying value of its Iraq and CDF HTL™ Investments related to this project for Canadian GAAP purposes. The prior costs for Iraq projects had previously been expensed for U.S. GAAP purposes therefore that portion of the proceeds, $6.3 million, was credited to the statement of operations for U.S. GAAP purposes. For the year ended December 31, 2008 the Company recorded nil ($6.3 million in 2007 and nil in 2006) as a reduction to net loss for U.S. GAAP when compared to Canadian GAAP due to the recovery of prior costs expensed for U.S. GAAP and capitalized for Canadian GAAP.

As more fully described under Note 3, the Company wrote off $5.1 million in GTL development costs under Canadian GAAP. These costs had already been expensed under U.S. GAAP in previous periods and therefore this transaction reduced the net loss for U.S. GAAP purposes in 2008.

*Pro Forma Effect of Merger and Acquisition*

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

| | Year ended December 31, 2006 (unaudited) | | |
|---|---|---|---|
| | **Revenue** | **Net Loss** | **Net Loss Per Share** |
| As reported | $ 47,409 | $ (42,421) | $ (0.18) |
| Pro forma adjustments | 1,051 | 809 | |
| | $ 48,460 | $ (41,612) | $ (0.18) |
| Pro Forma Weighted Average Number of Shares (in thousands) | | | 236,840 |

***Income Taxes***

On January 1, 2007, the Company adopted the provisions of FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes ( **FIN 48** ), an interpretation of FASB Statement No. 109, Accounting for Income Taxes. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The interpretation requires that the Company recognize the impact of a tax position in the financial statements if that position is more likely than not of being sustained on audit, based on the technical merits of the position. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods and disclosure. In accordance with the provisions of FIN 48, any cumulative effect resulting from the change in accounting principle is to be recorded as an adjustment to the opening balance of deficit.

The implementation of FIN 48 did not result in any adjustment to the Company s beginning tax positions. The Company continues to fully recognize its tax benefits, which are offset by a valuation allowance to the extent that it is more likely than not that the deferred tax assets will not be realized. As at December 31, 2008 and December 31, 2007, the Company did not have any unrecognized tax benefits.

The Company files federal and provincial income tax returns in Canada. The Company s U.S. and China subsidiaries file federal, state and local income tax returns in the U.S and China, as applicable. The Company may be subject to a reassessment of federal and provincial income taxes by Canadian tax authorities for a period of four years from the date of mailing of the original Notice of Assessment in respect of any particular taxation year. The U.S. federal statute of limitations for assessment of income tax is generally closed for the Company s tax years ending on or prior to 2003. In certain circumstances, the U.S. federal statute of limitations can reach beyond the standard three year period. U.S. state statutes of limitations for income tax assessment vary from state to state. There is no statute of limitations for audit of tax years in China. Tax authorities have not audited any of the Company s, or its subsidiaries , income tax returns or issued Notices of Assessment for any tax years.

The Company recognizes any interest accrued related to unrecognized tax benefits in interest expense and penalties in interest expense and financing costs. During the years ended December 31, 2008, 2007 and 2006, there were no charges for interest or penalties.

***Consolidated Statements of Cash Flows***

As a result of the expensing of HTL™ and GTL development costs as required under U.S. GAAP and the recovery of such costs, the statement of cash flows as reported would result in cash surplus from operating activities of $16.6 million, $11.5 million and $13.3 million for the years ended December 31, 2008, 2007 and 2006. Additionally, capital investments reported under investing activities would be $25.2 million, $31.4 million and $16.8 million for the years ended December 31, 2008, 2007 and 2006, respectively.

***Additional U.S. GAAP Disclosures***

*Oil and Gas Properties and Development Costs*

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

| | As at December 31, 2008 | | | | | |
|---|---|---|---|---|---|---|
| | Canada | Ecuador | China | U.S. | Business and Technology Development | Total |
| Property acquisition costs | $ 75,732 | $ 863 | $ 31,137 | $ 22,672 | $ | $ 130,404 |
| Royalty rights acquired | | | | 10,582 | | 10,582 |
| Capitalized Interest | 1,672 | | | | | 1,672 |
| Exploration costs | 3,686 | 591 | 31,578 | 42,759 | | 78,614 |
| Development costs | | | 83,315 | 41,413 | | 124,728 |
| HTL™ facilities | | | | | 19,590 | 19,590 |
| Support equipment and general property | 20 | 90 | 412 | 538 | 406 | 1,466 |
| | 81,110 | 1,544 | 146,442 | 117,964 | 19,996 | 367,056 |
| Accumulated depletion and depreciation | (6) | | (72,030) | (30,571) | (7,628) | (110,235) |
| Provision for impairment | | | (55,050) | (79,700) | | (134,750) |
| | $ 81,104 | $ 1,544 | $ 19,362 | $ 7,693 | $ 12,368 | $ 122,071 |

| | As at December 31, 2007 | | | |
|---|---|---|---|---|
| | China | U.S. | Business and Technology Development | Total |

| | | | | |
|---|---|---|---|---|
| Property acquisition costs | $ 31,137 | $ 22,196 | $ | $ 53,333 |
| Royalty rights acquired | | 10,582 | | 10,582 |
| Capitalized Interest | | | | |
| Exploration costs | 29,621 | 42,721 | | 72,342 |
| Development costs | 76,895 | 37,272 | | 114,167 |
| HTL™ facilities | | | 14,412 | 14,412 |
| Support equipment and general property | 410 | 529 | 108 | 1,047 |
| | 138,063 | 113,300 | 14,520 | 265,883 |
| Accumulated depletion and depreciation | (51,643) | (25,315) | (5,138) | (82,096) |
| Provision for impairment | (33,490) | (59,400) | | (92,890) |
| | $ 52,930 | $ 28,585 | $ 9,382 | $ 90,897 |

As at December 31, 2008, 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:

| | Total | Incurred in 2008 | 2007 | 2006 | Prior to 2006 |
|---|---|---|---|---|---|
| Property Acquisition | $ 77,901 | $ 77,209 | $ 33 | $ 24 | $ 635 |
| Royalty rights | 659 | | | | 659 |
| Exploration | 12,315 | 7,290 | 258 | 212 | 4,555 |
| | $ 90,875 | $ 84,499 | $ 291 | $ 236 | $ 5,849 |

The following is a summary of unproved oil and gas properties by prospect as at December 31, 2008:

| | Total | Incurred in 2008 | 2007 | 2006 | Prior to 2006 |
|---|---|---|---|---|---|
| **Canada** | | | | | |
| Tamarack | $ 81,090 | $ 81,090 | $ | $ | $ |
| **Ecuador** | | | | | |
| Block 20 | 1,454 | 1,454 | | | |
| **China** | | | | | |
| Zitong Block | 5,233 | 1,935 | 258 | 57 | 2,983 |
| **U.S.** | | | | | |
| Knights Landing | 1,000 | | | 144 | 856 |
| San Joaquin Basin prospects other | 2,098 | 20 | 33 | 35 | 2,010 |
| | 3,098 | 20 | 33 | 179 | 2,866 |
| | $ 90,875 | $ 84,499 | $ 291 | $ 236 | $ 5,849 |

With regard to the Tamarack Project in Canada, the Company plans to continue on the path for submitting a regulatory application, for the first phase of development, in the 3rd quarter of 2010.

With regard to Block 20 in Ecuador, the Company will be in the approval phase during the first part of 2009 which includes obtaining environmental licenses. If the Company succeeds in getting the necessary approvals it will enter into the appraisal phase which would include obtaining permits to drill, undertaking seismic activity and drilling selected locations.

With regards to the Zitong Block prospect, the Company plans to complete its review of the seismic data acquired to date on the block to select the first Phase II drilling location in the first part of 2009, commence drilling in late 2009 and complete drilling, completion and conclude final evaluation in late 2010.

The Company plans to continue to explore its options with regard to the Knight s Landing property to seek either a farm out or possible drilling program. The majority of the San Joaquin prospects are fee property with no rental payments to maintain the Company s leases. The timing of drilling on these prospects is dependent on other working interest owners.

*Accounts Payable and Accrued Liabilities*

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

| | As at December 31, 2008 | 2007 |
|---|---|---|
| Trade payables | $ 4,835 | $ 6,896 |
| Accrued general and administrative expenses | 1,130 | 722 |
| Accrued operating expenses | 558 | 561 |
| Accrued capital expenditures | 2,163 | 620 |
| Accrued salaries and related expenses | 328 | 82 |
| Accrued interest | 1,027 | 65 |
| Other accruals | 52 | 592 |
| | $ 10,093 | $ 9,538 |

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In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements ( **SFAS No. 157** ). This statement defines fair value, establishes a framework for measuring fair value in GAAP, and expands disclosures about fair value measurements. The Company adopted the provisions of SFAS No. 157 effective January 1, 2008. The implementation of this standard did not have a material impact on the consolidated financial statements as the current policy on accounting for fair value measurements is consistent with this guidance. The Company has, however, provided additional prescribed disclosures not required under Canadian GAAP.

SFAS No. 157 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The three levels of the fair value hierarchy are described below:

**Level 1:** Values based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical assets or liabilities.

**Level 2:** Values based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the asset or liability.

**Level 3:** Values based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement.

As required by SFAS No. 157 when the inputs used to measure fair value fall within different levels of the hierarchy, the level within which the fair value measurement is categorized is based on the lowest level input that is significant to the fair value measure in its entirety.

The following table presents the company s fair value hierarchy for those assets and liabilities measured at fair value on a recurring basis as of December 31, 2008.

| | As at December 31, 2008 | | | |
|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total |
| Derivative instruments assets | $ | $ 2,159 | $ | $ 2,159 |
| Derivative instruments liabilities | $ 1,121 | $ | $ | $ 1,121 |

The fair value measurement of derivative instruments assets related to the Company s costless collars are considered Level 2 and the fair value measurement of derivative instruments liabilities related to its purchase warrants denominated in Cdn.$ are considered Level 1.

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

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities ( **SFAS No. 161** ). The new standard is intended to improve financial reporting about derivative instruments and hedging activities by requiring enhanced disclosures to enable investors to better understand their effects on an entity s financial position, financial performance, and cash flows. It is effective beginning January 1, 2009. Management has concluded that the requirements of this recent statement will not have a material impact on its financial statements.

In December 2008, the SEC released Final Rule, Modernization of Oil and Gas Reporting to revise the existing Regulation S-K and Regulation S-X reporting requirements to align with current industry practices and technological advances. The new disclosure requirements include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. In addition, the new disclosure requirements require a company to (a) disclose its internal control over reserves estimation and report the independence and qualification of its reserves preparer or auditor, (b) file reports when a third party is relied upon to prepare reserves estimates or conducts a reserve audit and (c) report oil and gas reserves using an average price based upon the prior 12-month period rather than period-end prices. The provisions of this final ruling will become effective for disclosures in our Annual Report on Form 10-K for the year ended December 31, 2009. Management is still evaluating the impact of these changes on its financial statements.

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

| | QUARTER ENDED | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 2008 | | | | 2007 | | | |
| | 4th Qtr | 3rd Qtr | 2nd Qtr | 1st Qtr | 4th Qtr | 3rd Qtr | 2nd Qtr | 1st Qtr |
| Total revenue: | | | | | | | | |
| Canadian GAAP | $ 25,143 | $ 35,626 | $ (2,772) | $ 11,169 | $ 5,848 | $ 8,823 | $ 9,589 | $ 9,257 |
| U.S. GAAP | $ 30,538 | $ 50,267 | $ (14,975) | $ 8,001 | $ 6,966 | $ 12,393 | $ 7,685 | $ 7,065 |
| Net income (loss): | | | | | | | | |
| Canadian GAAP | $ (13,980) | $ 10,062 | $ (21,731) | $ (8,544) | $ (18,849) | $ (7,232) | $ (6,579) | $ (6,547) |
| U.S. GAAP | $ (45,399) | $ 25,824 | $ (32,981) | $ (10,495) | $ (16,094) | $ (2,551) | $ (1,211) | $ (7,536) |
| Net income (loss) per share: | | | | | | | | |
| Canadian GAAP | $ (0.05) | $ 0.04 | $ (0.09) | $ (0.03) | $ (0.07) | $ (0.03) | $ (0.03) | $ (0.03) |
| U.S. GAAP | $ (0.17) | $ 0.10 | $ (0.13) | $ (0.04) | $ (0.07) | $ (0.01) | $ | $ (0.03) |

The differences in the net loss and net loss per share for the second quarter of 2007 were due mainly to the treatment of the payment by INPEX for past costs paid by the Company related to its Iraq project and HTL™ Technology development costs. Approximately $6.3 million of this payment was applied to capital balances for Canadian GAAP purposes and as reduction to net loss for U.S. GAAP purposes. The differences in the net loss and net loss per share for the third quarter of 2007 were mainly due to an additional $3.6 million fair value adjustment of derivative instruments for U.S. GAAP. The differences in the net loss and net loss per share for the second quarter of 2008 were mainly due to an additional negative $12.2 million fair value adjustment of derivative instruments for U.S. GAAP. The differences in the net income and net income per share for the third quarter of 2008 were mainly due to an additional $14.6 million positive fair value adjustment of derivative instruments for U.S. GAAP. The differences in the net loss and net loss per share for the fourth quarter of 2008 were mainly due to the additional ceiling test write downs for U.S. GAAP.

**SUPPLEMENTARY DISCLOSURES ABOUT OIL AND GAS PRODUCTION ACTIVITIES (UNAUDITED)**
**(all tabular amounts are expressed in thousands of U.S. Dollars, except reserves and depletion rate amounts)**

The following information about the Company s oil and gas producing activities is presented in accordance with U.S. SFAS 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.

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The changes in the Company s net proved oil and gas reserves for the three-year period ended December 31, 2008 were as follows:

| | Oil (MBbl) U.S. | China | Total | Gas (MMcf) U.S. |
|---|---|---|---|---|
| Net proved reserves, December 31, 2005 | 1,272 | 1,300 | 2,572 | 1,685 |
| Revisions of previous estimates | 54 | 179(1) | 233 | (214) |
| Extensions and discoveries | 189(2) | | 189 | |
| Purchases of reserves in place | | 881(3) | 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 |
| Revisions of previous estimates | 84 | (22) | 62 | (52) |
| Extensions and discoveries | 23 | | 23 | |
| Production | (192) | (483) | (675) | (31) |
| Net proved reserves, December 31, 2007 | 1,135 | 1,280 | 2,415 | 334 |
| Revisions of previous estimates | (294)(4) | 242(5) | (52) | (168)(6) |
| Extensions and discoveries | 103(7) | | 103 | |
| Production | (199) | (490) | (689) | (22) |
| Net proved reserves, December 31, 2008 | 745 | 1,032 | 1,777 | 144 |

(1) These technical revisions were due to production performance, plus ongoing production optimizations.

(2) This adjustment was related to a new pool discovery in the Company s South Midway prospect.

(3) In February of 2006 the Company re-acquired its 40% working interest in the Dagang field.

(4)

The oil reserve revision decrease is due to the low year end oil prices and its resulting affect on the economic limit for the Midway Sunset and West Texas properties.

(5) The oil reserve revision is due to better performance of the Dagang property in relation to the 2007 Reserve Report.

(6) The gas reserve revision decrease is due to the underperformance of the West Texas properties in relation to the 2007 Reserve Report.

(7) The oil reserve additions are new locations in an area of the Midway Sunset Field prove up by the drilling program in the Spring of 2008.

***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 $37.49, $89.18 and $55.33 per barrel of oil in 2008, 2007 and 2006, respectively, and $7.2, $8.54 and $5.64 per Mcf of gas in 2008, 2007 and 2006, 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:

| | 2008 | | |
|---|---|---|---|
| | U.S. | China | Total |
| Future cash inflows | $ 24,742 | $ 42,906 | $ 67,648 |
| Future development and restoration costs | 2,790 | 3,310 | 6,100 |
| Future production costs | 18,046 | 22,934 | 40,980 |
| Future net cash flows | 3,906 | 16,662 | 20,568 |
| 10% annual discount | 940 | 2,576 | 3,516 |
| Standardized measure | $ 2,966 | $ 14,086 | $ 17,052 |

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| | 2007 | | |
|---|---|---|---|
| | **U.S.** | **China** | **Total** |
| Future cash inflows | $ 99,301 | $ 118,911 | $ 218,212 |
| Future development and restoration costs | 3,490 | 5,190 | 8,680 |
| Future production costs | 38,935 | 52,446 | 91,381 |
| Future income taxes | | 1,010 | 1,010 |
| Future net cash flows | 56,876 | 60,265 | 117,141 |
| 10% annual discount | 13,616 | 10,674 | 24,290 |
| Standardized measure | $ 43,260 | $ 49,591 | $ 92,851 |

| | 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 |

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:

**2008**