IVANHOE ENERGY INC
Form 10-K
March 15, 2012

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

Form 10-K

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

For the fiscal year ended December 31, 2011
Commission file number: 000-30586

Ivanhoe Energy Inc.

(Exact name of registrant as specified in its charter)

Yukon, Canada (State or other jurisdiction of incorporation or organization)	98-0372413 (IRS Employer Identification No.)

654-999 Canada Place
Vancouver, BC, Canada V6C 3E1
(604) 688-8323
(Address and telephone number of the registrant's principal executive offices)

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 The 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. þ Yes o 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 whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). o 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.

Large accelerated filer	o	Accelerated filer	þ
Non-accelerated filer	o	Smaller reporting company	o

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, 2011, the aggregate market value of the registrant's common stock held by non-affiliates of the registrant was $547,464,841 based on the Toronto Stock Exchange closing price on that date. At March 5, 2012, the registrant had 344,139,428 common shares outstanding.

TABLE OF CONTENTS

ABBREVIATIONS

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

bbl	=	barrel	mbbls/d	=	thousand barrels per day
bbls/d	=	barrels per day	mboe	=	thousands of barrels of oil equivalent
boe	=	barrel of oil equivalent	mboe/d	=	thousands of barrels of oil equivalent per day
boe/d	=	barrels of oil equivalent per day	mmbbls	=	million barrels
mbbls	=	thousand barrels	mmbls/d	=	million barrels per day

Oil equivalents compare quantities of oil with quantities of gas or express these different commodities in a common unit. A boe is derived by converting six thousand cubic feet of gas to one barrel of oil (6 mcf/1 bbl). Boes may be misleading, particularly if used in isolation. The conversion ratio is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

CURRENCY AND EXCHANGE RATES

Unless otherwise specified, all reference to "dollars" or to "$" are to US dollars and all references to "Cdn$" are to Canadian dollars. The noon-day exchange rates for Cdn$1.00, as reported by the Bank of Canada, were:

(US$)	2011	2010
Closing	0.98	1.01
High	1.06	1.01
Low	0.94	0.93

Average noon	1.01	0.97

On March 5, 2012, the noon-day exchange rate was US$0.99 for Cdn$1.00.

Table of Contents

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

With the exception of historical information, certain matters discussed in this Annual Report, including those appearing in Items 1 and 2 – Business and Properties and Item 7 – Management’s Discussion and Analysis of Financial Condition and Results of Operations (“MD&A”), are forward-looking statements that involve risks and uncertainties.

Statements that contain words such as “could”, “should”, “can”, “anticipate”, “estimate”, “propose”, “plan”, “expect”, “bel “may” and similar expressions and statements relating to matters that are not historical facts constitute “forward-looking statements” within the meaning of the “safe harbor” provisions of the United States Private Securities Litigation Reform Act of 1995. In particular, forward-looking statements contained in this Annual Report include, but are not limited to statements relating to or associated with individual wells, regions or projects. Any statements as to possible future crude oil prices; future production levels; future royalty and tax levels; future capital expenditures, their timing and their allocation to exploration and development activities; future earnings; future asset acquisitions or dispositions; future sources of funding for the Company’s capital programs; future debt levels; availability of future credit facilities; possible commerciality of the Company’s projects; development plans or capacity expansions; future ability to execute dispositions of assets or businesses; future sources of liquidity, cash flows and their uses; future drilling of new wells; ultimate recoverability of current and long-term assets; ultimate recoverability of reserves or resources; expected operating costs; the expectation of negotiating of an extension to certain of the Company’s production sharing agreements; the expectation of the Company’s ability to comply with the newly enacted safety and environmental rules; estimates on a per share basis; future foreign currency exchange rates, future expenditures and future allowances relating to environmental matters and the Company’s ability to comply therewith; dates by which certain areas will be developed, come on-stream or reach expected operating capacity; and changes in any of the foregoing are forward-looking statements.

Statements relating to “reserves” are forward-looking statements, as they involve the implied assessment, based on estimates and assumptions that the reserves described exist in the quantities predicted or estimated and can be profitably produced in the future.

The forward-looking statements contained in this Annual Report are based on certain assumptions and analyses made by the Company in light of its experience and its perception of historical trends, current conditions and expected future developments as well as other factors it believes are appropriate in the circumstances. By their nature, forward-looking statements involve inherent risks and uncertainties including the risk that the outcome that they predict will not be achieved. Undue reliance should not be placed on forward-looking statements as a number of important factors could cause the actual results to differ materially from the beliefs, plans, objectives, expectations and anticipations, estimates and intentions expressed in the forward-looking statements, including those set out below and those detailed in Item 1A, “Risk Factors,” and Item 7A, “Quantitative and Qualitative Disclosures About Market Risk,” in this Annual Report. Such factors include, but are not limited to: the Company’s short history of limited revenue, losses and negative cash flow from its current exploration and development activities in Canada, Ecuador, China, Mongolia and the United States; the Company’s limited cash resources and consequent need for additional financing; the ability to raise capital as and when required, or to raise capital on acceptable terms; the timing and extent of changes in prices for oil and gas; competition for oil and gas exploration properties from larger, better financed oil and gas companies; environmental risks; title matters; drilling and operating risks; uncertainties about the estimates of reserves and the potential success of the Company’s Heavy-to-light (“HTL™”) technology; the potential success of the Company’s oil and gas properties in Canada, Ecuador, China and Mongolia; the prices of goods and services; the availability of drilling rigs and other support services; legislative and government regulations; political and economic factors in countries in which the Company operates; and implementation of the Company’s capital investment program.

The forward-looking statements contained in this Annual Report are made as of the date hereof and the Company undertakes no obligation to update publicly or revise any forward-looking statements, whether as a result of new information, future events or otherwise, unless required by applicable securities laws. The forward-looking statements contained herein are expressly qualified in their entirety by this cautionary statement.

AVAILABLE INFORMATION

The principal executive offices of Ivanhoe Energy Inc. ("Ivanhoe," the "Company," "we," "our," or "us") are located at 9 Canada Place, Suite 654, Vancouver, British Columbia, V6C 3E1, and our registered and records office is located at 300-204 Black Street, Whitehorse, Yukon, Y1A 2M9.

Electronic copies of the Company's filings with the United States Securities and Exchange Commission (the "SEC") and the Canadian Securities Administrators (the "CSA") are available, free of charge, through our website (www.ivanhoeenergy.com) or, upon request, by contacting our investor relations department at (403) 817-1108. The information on our website is not, and shall not be, deemed to be part of this Annual Report.

Table of Contents

Alternatively, the SEC and the CSA each maintains a website (www.sec.gov and www.sedar.com) that contains our reports, proxy and information statements and other published information that have been filed or furnished with the SEC and the CSA. Further, a copy of this Annual Report is located at the SEC's Public Reference Room at 100 F Street, NE, Washington, D.C. 20549. Information on the operation of the Public Reference Room can be obtained by calling the SEC at 1-800-SEC-0330.

PART I

ITEMS 1 AND 2: BUSINESS AND PROPERTIES

GENERAL

Ivanhoe 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. Core operations are in Canada, Ecuador, China and Mongolia, with business development opportunities worldwide.

The Company was 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, the Company changed its name to Black Sea Energy Ltd. On June 24, 1999, Black Sea Energy Ltd. merged with Sunwing Energy Ltd. ("Sunwing"), and the name was changed to Ivanhoe Energy Inc.

In 2005, Ivanhoe completed a merger with Ensyn Group Inc. ("Ensyn") acquiring the proprietary, patented heavy oil upgrading process called HTL™. In July 2008, the Company acquired from Talisman Energy Canada ("Talisman") oil sand interests, including certain oil sand leases in the Athabasca region of Canada ("Tamarack" or the "Tamarack Project"). Later in 2008, the Company signed a contract with the Ecuador state oil companies to explore and develop Ecuador's Pungarayacu heavy oil field in Block 20. In 2009, Ivanhoe sold its wholly owned subsidiary, Ivanhoe Energy (USA) Inc., disposing of its oil and gas exploration and production operations in the United States ("US"). Also in 2009, the Company acquired a production sharing contract for the Nyalga Block XVI in Mongolia, through the takeover of PanAsian Petroleum Inc., a privately-owned corporation.

CORPORATE STRATEGY

Ivanhoe continues to pursue its core strategies, which are:

— Utilize long-standing knowledge and relationships in the Far East to pursue conventional oil and gas production and exploration opportunities;

— Seek out heavy oil development projects globally that have operational needs that can benefit from our proprietary HTL™ technology; and

— Bias new country entry and business development to projects that, because of their remote setting, geo-political status or operational needs, have been overlooked by the broader industry, subsequently expanding efforts in the new locations to more conventional oil and gas industry activities.

Pursuing Natural Gas in China

Ivanhoe's wholly-owned subsidiary, Sunwing, has been conducting operations in China since the mid-1990s. In particular, Sunwing is focused on a key natural gas exploration project (the Zitong Block) in Sichuan Province of China. Sichuan is the oldest and one of the most productive gas producing regions of China. Sinopec and PetroChina have made significant gas discoveries in blocks adjacent to Sunwing's Zitong Block.

The Sichuan Basin, located in central China approximately 930 miles southwest of Beijing, is the country's largest gas-producing region, currently producing more than 800 mmcf/d and estimated by Chinese officials to contain a natural gas resource potential of 260 tcf. There is a strong and growing local market for natural gas, with approximately 120 million people living within the basin and with well-developed grid connections to adjacent industrial and population areas.

Natural gas sales are regulated in China and current prices are approximately $5.00/mcf at the wellhead. As part of China's commitment to develop cleaner sources of energy, demand for natural gas is projected to continue to grow in the country and Sunwing's goal is to tap into this burgeoning market.

Table of Contents

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 low cost replacement reserves. This has resulted in volatility in oil markets and marked shifts in the demand and supply landscape. Ivanhoe believes 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 types of oil play an important role in our corporate strategy.

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 become increasingly more common.

With regard to non-conventional heavy oil and bitumen, a dramatic increase in interest and activity has been fuelled 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, have generated increased interest in heavy oil resources. Nevertheless, remaining challenges for profitable exploitation include: i) the requirement for steam and electricity to help extract heavy oil; ii) the need for diluent to move the oil once it is at the surface; iii) the heavy versus light oil price differentials that the producer is faced with when the product gets to market; and iv) conventional upgrading technologies are 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

With the application of the HTL™ process, Ivanhoe seeks to address the key heavy oil development challenges and can do so at a relatively small minimum economic scale.

Ivanhoe’s HTL™ upgrading is a partial upgrading process that is designed to operate in facilities as small as 10,000 to 30,000 bbls/d. 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 bbls/d. The HTL™ process 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, with processing times 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. HTL™ has the added advantage of converting the by-products 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:

— virtual elimination of external energy requirements for steam generation and/or power for upstream operations;

— elimination of the need for diluent or blend oils for transport;

— capture of the majority of the heavy versus light oil value differential; and

— relatively small minimum economic scale of operations suited for field upgrading and for smaller field developments.

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 Ivanhoe will have to establish its unique value proposition.

Implementation Strategy

Ivanhoe is an oil and gas company with a unique technology which addresses several major problems confronting the oil and gas industry today and the Company believes it has a competitive advantage because of its patented upgrading process. In addition, because Ivanhoe has experienced thermal recovery teams, the Company is in a position to add value and leverage its technology advantage by working with partners on stranded heavy oil resources around the world.

Table of Contents

The Company's continuing strategy is as follows:

— Advance its two key heavy oil projects – in Canada and Ecuador. Continue to deploy personnel and financial resources in support of the Company's goal to become a significant heavy oil producer.

— Advance the HTL™ process. Additional development work will continue to advance the HTL™ process through the commercial application of HTL™ upgrading in Canada, Ecuador and beyond.

— Advance its natural gas project in the Zitong Block in Sichuan Province, China. Through its wholly-owned subsidiary, Sunwing Energy, proceed with additional planning and operational analysis to develop an appraisal program leading to a full development plan for the Zitong block.

— Enhance the Company's financial position to support its major projects. Implementation of large projects requires significant capital outlays. The Company is working on various financing initiatives and establishing the relationships required for future development activities.

— Build internal capabilities. The Company continues to seek to build its internal leadership and technical capabilities through the addition of key personnel associated with each major project.

— Continue to deploy the personnel and the financial resources to capture additional opportunities for development projects utilizing the Company's HTL™ process. Commercialization of the Company's upgrading process requires close alignment with partners, suppliers, host governments and financiers.

PROPERTY DESCRIPTIONS

Our oil and gas operations are located in three geographic areas: Asia, Canada and Ecuador. The Technology Development area captures costs incurred to develop, enhance and identify improvements in the application of the HTL™ technology. Production, revenues, net income, capital expenditures and identifiable assets for these segments appear in Note 19 to the consolidated financial statements and in the MD&A in this Annual Report.

Asia

China

Zitong

In November 2002, we entered into a 30 year production sharing contract ("PSC") with China National Petroleum Corporation ("CNPC") for the Zitong block, which covers an area of approximately 248,000 gross acres after contractual relinquishments in the Sichuan basin. In 2006, we farmed out 10% of our working interest in the Zitong block to Mitsubishi Gas Chemical Company Inc. of Japan ("MGC") for $4.0 million.

In Phase I of the contract, Ivanhoe reprocessed 1,649 miles of existing 2D seismic data and acquired 705 miles of new 2D seismic data. Two wells were drilled and although both wells encountered expected reservoirs and gas was tested on the second well, neither well demonstrated commercially viable flow rates and both wells were suspended. In Phase II of the contract, the Yixin-2 and Zitong-1 gas wells were drilled in late 2010 and completed in early 2011. Both wells encountered gas in the Xu-4 Formation and were shut-in for pressure build-up following initial flow and pressure tests.

On December 30, 2011, the Company entered into a supplementary agreement to the Contract for Exploration, Development and Production in Zitong Block, Sichuan Basin with CNPC for the Zitong block ("Supplementary Agreement"). The Supplementary Agreement effectively extends the exploration period under the PSC by creating a 36 month evaluation phase beginning July 1, 2011, for the performance of additional work. The Supplementary Agreement is subject to ratification by the Ministry of Commerce of the People's Republic of China.

On January 11, 2012, Ivanhoe signed a binding Memorandum of Understanding which contemplates a transaction (the "Zitong Transaction") whereby Ivanhoe will assign its entire working interest in the Zitong PSC to Shell China Exploration and Production Company Limited ("Shell"). Completion of the Zitong Transaction is subject to government approvals and other prescribed conditions, including rights of first refusal by both CNPC and Ivanhoe's working interest partner, MGC.

Dagang

Ivanhoe's oil production originates in the Kongnan oilfield in Dagang, Hebei Province, China (the "Dagang field"). We have a 30 year PSC with CNPC, covering an area of 10,255 gross acres. From 2000 to 2007, we drilled 46 wells and commercial production commenced on January 1, 2009. The project reached cost recovery in

Table of Contents

September 2009 and our working interest decreased to 49%. Operations in the Dagang field will revert to CNPC at the end of the 20 year production phase of the contract or earlier if the field is abandoned.

In 2011, quotas restricted production to 80,000 gross tonnes or 1,600 bbls/d gross. Actual production in 2011 averaged 967 bbls/d net. The production quota in 2012 remains set at 80,000 gross tonnes.

Mongolia

Through a merger with PanAsian Petroleum Inc. in November 2009, we acquired a PSC for the Nyalga Block XVI in the Khenti and Tov provinces in Mongolia. The block covers an area of approximately 3.1 million gross acres, after a 25% relinquishment in 2010. The five year exploration period is divided into three consecutive phases, consisting of two years (“Phase I”), one year (“Phase II”) and two years (“Phase III”), with the ability to nominate a two year extension following Phase I or Phase II.

During the initial seismic program, approximately 16% of the block in the Delgerkhaan area was declared by the Mongolian government to be a historical site and operations in this area were suspended. A letter from the Mineral Resources and Petroleum Authority of Mongolia (“MRPAM”) stated that the obligations under year one of Phase I would be extended for one year from the time the Company is allowed to re-enter the suspended area. To date, access has not been granted and discussions with MRPAM are ongoing. As a result, the government adjusted the dates on which the project year begins. Phase II is now considered to have commenced on July 20, 2010.

From late 2009 through the first quarter of 2010, the Company acquired an additional 465 kilometres of 2-D seismic across Block XVI, for a total of 925 kilometres of 2-D seismic data over the Kherulen sub-basin. The seismic was used to drill two wells in 2011. The first exploration well, N16-1E-1A, was drilled and abandoned as the well did not encounter oil shows in the reservoir. The Company observed oil staining, fluorescence and increases in background gas at its second exploration well site at N16-2E-B.

Canada

Tamarack, acquired from Talisman in 2008, is a 6,880 acre lease located approximately 10 miles northeast of Fort McMurray, Alberta, Canada. The Tamarack integrated oil sands project (“Tamarack” or the “Tamarack Project”) is comprised of a two-phased 40,000 bbl/d steam-assisted gravity drainage thermal recovery (“SAGD”) and HTL™ facility. Our independent reserve evaluator, GLJ Petroleum Consultants Ltd. (“GLJ”), has assigned total 3P reserves of 219 mmbbls of bitumen to Tamarack. Talisman held a 20% back-in right which expired in July 2011. Additionally, in 2011, Ivanhoe repaid a $40 million promissory note to Talisman that was part of the initial purchase price.

Ivanhoe filed an Environmental Impact Assessment for the Tamarack Project in November 2010. Regulators completed their initial review of the Company’s application and, as is customary, provided an initial set of Supplemental Information Requests in the third quarter of 2011. The Company submitted the supplemental information to the regulators in the fourth quarter of 2011.

As the regulatory process unfolds, Ivanhoe continues to engage and consult with numerous local and aboriginal stakeholders to identify potential project impacts and mitigations and economic and employment opportunities for residents of area communities. It is anticipated that the regulatory approval process will be completed later in 2012. Project advancement, as currently envisaged, is subject to regulatory approval, financing and board sanction.

Ecuador

In October 2008, Ivanhoe Energy Ecuador Inc., an indirect wholly owned subsidiary, signed a 30 year contract with the Ecuador state oil companies Petroecuador and Petroproduccion. The contract gives Ivanhoe the right to explore and develop the Pungarayacu heavy oil field in Block 20, an area of 426 square miles, approximately 125 miles southeast of Quito, Ecuador's capital city. The Company anticipates using HTL™ technology, as well as providing advanced oilfield technology, expertise and capital to develop, produce and upgrade heavy oil from the Pungarayacu field. The Company may also explore for lighter oil in the contract area and blend any light oil discoveries with the heavy oil for delivery to Petroproduccion.

In 2010, Ivanhoe drilled its first two appraisal wells in the Pungarayacu field. The second, IP-5b, well was successfully drilled, cored and logged to a total depth of 1,080 feet. The well was perforated in the Hollin oil sands and steam was successfully injected into the reservoir resulting in production of heated heavy oil. In 2011, the heavy crude oil extracted from the IP-5B well was successfully upgraded to local pipeline specifications using Ivanhoe's proprietary HTL™ upgrading process. Later in 2011, the Company completed a 190-kilometre 2-D seismic survey over the southern portion

Table of Contents

of Block 20. Following the analysis of the seismic program, Ivanhoe began preparing to drill one exploration well into the deeper Hollin and pre-cretaceous horizons in the southern part of the Pungarayacu Block to test the potential of lighter oil resources, which would prove beneficial for blending purposes and overall project economics.

RESERVES, PRODUCTION AND RELATED INFORMATION

In addition to the information provided below, please refer to the “Supplementary Disclosures About Oil and Gas Production Activities (Unaudited)” set forth in Item 8 in this Annual Report for certain details regarding the Company’s oil and gas proved reserves, the estimation process and production by country. We have not filed with nor included in reports to any other US federal authority or agency, any estimates of total proved oil reserves since the beginning of the last fiscal year.

The following table presents estimated proved, probable and possible oil reserves as of December 31, 2011:

Summary of Oil and Gas Reserves Using Average 2011 Prices(1)

		China		Canada	Total
(mbbl)	Dagang	Other	Total China	Tamarack	Consolidated
Proved					
Developed	1,146	75	1,221	–	1,221
Undeveloped	421	–	421	–	421
Total proved	1,567	75	1,642	–	1,642
Probable					
Developed	375	–	375	–	375
Undeveloped	447	–	447	175,684	176,131
Total probable	822	–	822	175,684	176,506
Total proved plus probable	2,389	75	2,464	175,684	178,148
Possible					
Developed	–	–	–	–	–
Undeveloped	–	–	–	43,809	43,809

(1) Reserves are the Company’s total gross reserves before royalty deductions.

China

Proved Reserves

Proved reserves at December 31, 2011 were 1,729 mbbls. Production during the year was offset by in-field performance improvements from continued water injections and our ongoing hydraulic fracture stimulation program in the Dagang field. Four wells were drilled in 2011, and, in combination with geological review and reservoir mapping, supported additional future drilling locations.

In 2011,153 mbbls were transferred from proved undeveloped to the proved developed category.

Probable Reserves

At December 31, 2011, probable reserves in China were 822 mbbls. Additional probable reserves were assigned based on production improvements and increased recovery factors discussed under proved reserves.

Basis of Reserve Estimates

Reserve estimates were calculated using recovery forecasts based on historical production, supported by volumetric estimates using geological parameters. Recoveries rarely exceed 15% of the volumetrically calculated original oil-in-place per well spacing, which is judged acceptable for a water flood in a light oil reservoir. Improvements in production history and production declines are used for a review of producing reserves. With further mapping and geological reviews, proved and probable undeveloped reserves may then be assigned to future drilling and well optimizations.

Table of Contents

Canada

Probable and Possible Reserves

No additional reserves were assigned to Tamarack in 2011 as further reserve development is subject to regulatory approval of the Company's application for the project, sanctioning by the Board of Directors and further delineation drilling.

Possible reserves are within the Tamarack Project application area, but have a lower degree of certainty compared to our probable reserves due to lower quality reservoir characteristics or decreased certainty based on the level of reservoir delineation.

Basis of Reserves Estimates

Recovery estimates for Tamarack are based on a combination of reservoir simulation, detailed reservoir characterization and analogue project performance

Internal Control over Reserve Estimation

Management is responsible for the estimates of oil and gas reserves and for preparing related disclosures. Estimates and related disclosures in this Annual Report are prepared in accordance with SEC requirements, generally accepted industry practices in the US and the standards of the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") modified to reflect SEC requirements. As a Canadian public company, we are also subject to the disclosure requirements of National Instrument 51-101 (''NI 51-101'') of the CSA, which requires us to disclose reserves and other oil and gas information in accordance with the prescribed standards of NI 51-101 which differ, in certain respects, from SEC requirements. See the Special Note to Canadian Investors on page 11.

The process of estimating reserves requires complex judgments and decision making based on available geological, geophysical, engineering and economic data. To estimate the economically recoverable oil and gas reserves and related future net cash flows, we consider many factors and make various assumptions including:

— expected reservoir characteristics based on geological, geophysical and engineering assessments;

— future production rates based on historical performance and expected future operating and investment activities;

— future oil and gas prices and quality differentials;

— assumed effects of regulation by governmental agencies; and

— future development and operating costs.

We believe these factors and assumptions are reasonable based on the information available to us at the time we prepared our estimates. However, 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.

Reserve estimates are categorized by the level of confidence that they will be economically recoverable. Proved reserves are those quantities of oil and gas, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible in future years from known reservoirs under existing economic conditions, operating methods and government regulations. The term “reasonable certainty” implies a high degree of confidence that the quantities of oil and gas actually recovered will equal or exceed the estimate. To achieve reasonable certainty, the technologies used in the estimation process have been demonstrated to yield results with consistency and repeatability.

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. Therefore, probable reserves have a higher degree of uncertainty than proved reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. Although possible reserve locations are found by “stepping out” from proved reserve locations, estimates of probable and possible reserves are, by their nature, more speculative than estimates of proved reserves and, accordingly, are subject to substantially greater risk of being realized.

Our reserve estimates were prepared by GLJ and reviewed by our in-house Senior Engineering Advisor (“SEA”). Our SEA is a professional engineer (P.Eng.) in Alberta, with over 29 years of broad petroleum engineering experience in the oil and gas industry in Canada and internationally. His past experience includes reserves estimations for government filings, reservoir development engineering for both oil and gas projects, economic evaluations for potential acquisitions and dispositions, production operations, project management, budgeting and corporate planning.

Table of Contents

All reserve information in this Annual Report is based on estimates prepared by GLJ. The technical personnel responsible for preparing the reserve estimates at GLJ meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas by the Society of Petroleum Engineers. GLJ is an independent firm of petroleum engineers, geologists, geophysicists and petrophysicists; they do not own an interest in our properties and are not employed on a contingent fee basis.

Our Board of Directors reviews the current reserve estimates and related disclosures as presented by the independent qualified reserves evaluators in their reserve report. Our Board of Directors has approved the reserve estimates and related disclosures.

Special Note to Canadian Investors

Ivanhoe is a SEC registrant and files annual reports on Form 10-K; accordingly, our reserves estimates and regulatory securities disclosures are prepared based on SEC disclosure requirements. In 2003, the CSA adopted NI 51-101 which prescribes standards that Canadian companies are required to follow in the preparation and disclosure of reserves and related information.

Until 2010, we had an exemption from certain requirements of NI 51-101 which permitted us to substitute disclosures based on SEC requirements for some of the annual disclosure required by NI 51-101 and to prepare our reserve estimates and related disclosures in accordance with SEC requirements, generally accepted industry practices in the US as promulgated by the Society of Petroleum Engineers and the standards of the COGE Handbook, modified to reflect SEC requirements. This exemption is no longer available to us for reserve reporting in Canada.

We have, however, received another exemption from the CSA which, among other things, allows us to disclose reserves and related information in accordance with applicable US disclosure requirements provided that we also make disclosure of our reserves and other oil and gas information in accordance with applicable NI 51-101 requirements. We disclose reserve information in accordance with applicable US disclosure requirements in this Annual Report. We disclose reserves and other oil and gas information in accordance with applicable NI 51-101 requirements in our Form 51-101F1, Statement of Reserves Data and Other Oil and Gas Information, which is filed with the CSA and available at www.sedar.com.

The reserve quantities disclosed in this Annual Report represent reserves calculated on an average, first-day-of-the-month price during the 12 month period preceding the end of the year for 2011, using the standards contained in SEC Regulations S-X and S-K and Accounting Standards Codification 932 Extractive Activities – Oil and Gas (section 235-55), formerly 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 US, 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 an average, first-day-of-the-month price during the 12 month period preceding and existing 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 reserves by geographic area only, whereas NI 51-101 requires disclosure of more reserve categories and product types; 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.

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 and NI 51-101 requirements may be material.

Table of Contents

Production, Sales Prices and Production Costs

	2011	2010
Oil production (bbls/d)	967	788
Average sales price ($/bbl)	105.93	75.52
Average operating costs (1) ($/bbl)	44.10	33.05

(1) Average operating costs per unit of production, based on net interest after royalties, represent lifting costs, including a windfall gain levy. According to the “Administrative Measures on Collection of Windfall Gain Levy on Oil Exploitation Business,” enterprises exploiting and selling oil in China are subject to a windfall gain levy (the “Windfall Levy”) if the monthly weighted average price of oil exceeds a certain threshold. Average operating costs exclude depletion and depreciation, income taxes, interest, selling and general administrative expenses

Ivanhoe’s oil production originates in Asia, specifically the Dagang and Daqing fields in China. The majority of our production comes from Dagang and is sold to the Chinese national petroleum company.

Drilling Activity

	Net Exploratory			Net Development			Total
(net wells)(1)	Productive	Dry Holes	Total	Productive	Dry Holes	Total	Wells Drilled
Asia							
2011	–	1.0	1.0	2.5	–	2.5	3.5

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

Wells in Progress

At December 31, 2011, we were not actively drilling any wells.

Producing Oil Wells

The Company does not have any producing gas wells. The Company had 49.0 gross (24.0 net) productive oil wells in Asia, as at December 31, 2011.

Acreage

	Developed Acres		Undeveloped Acres(1)	
	Gross	Net	Gross	Net
Asia – China(2)	1,724	845	253,496	225,683
Asia – Mongolia	–	–	3,107,907	3,107,907
Canada	–	–	7,520	7,520
Latin America	–	–	272,639	272,639

(1) Undeveloped acreage is considered to be those acres on which wells have not been drilled or completed to a point that would permit production of commercial quantities of oil and gas regardless of whether or not such acreage contains proved reserves.

(2)

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

The Tamarack lease in Canada will expire in October 2016, but Ivanhoe has sufficient drill density to be granted a continuation by the Alberta Department of Energy one year prior to expiry or upon first production, whichever comes first.

We signed a specific services contract with the state oil companies of Ecuador in October 2008 that allows us to develop Block 20 for a term of 30 years, extendable by mutual agreement of the parties, for two additional periods of five years each, depending on the interests of the State and in conformity with local laws.

Subsequent to the completion of Phase II of the Zitong PSC, acreage not identified for development and future production was relinquished to CNPC in 2011. The remaining Zitong acreage will be relinquished upon termination of the PSC in 2032.

Under the terms of the Dagang PSC, acreage in the Dagang field will revert to CNPC upon contract termination in 2027, at the latest, unless Ivanhoe abandons the field before then.

Table of Contents

Acreage in Mongolia is subject to periodic relinquishments up to the end of the exploration period and the remaining acreage designated for appraisal and development will expire 20 years after the final commercial discovery on the Nyalga block.

TECHNOLOGY DEVELOPMENT

The Company's Technology Development segment captures HTL™ activities. In April 2005, Ivanhoe merged with Ensyn and thereby obtained an exclusive, irrevocable license to the HTL™ process for all applications other than biomass. The Company has since continued to expand patent coverage to protect innovations to the HTL™ technology and to significantly extend Ivanhoe's portfolio of HTL™ intellectual property. Ivanhoe is the assignee of five granted US patents and currently has six US patent applications pending. In other countries, the Company has 11 patents granted and 41 patents are pending. In addition, Ivanhoe owns exclusive, irrevocable licenses to 21 global patents for the rapid thermal processing process as it pertains to petroleum. The expiration date for Ivanhoe's key patents is 2028.

Ivanhoe has a feedstock test facility ("FTF") at the Southwest Research Institute in San Antonio, Texas. The FTF is a small 10-15 bbls/d, highly flexible, state-of-the-art facility which will permit analysis of crude oil in small volumes. In 2010, the FTF supported basic and front-end engineering for a commercial-scale HTL™ plant for the Tamarack Project in Canada. In 2011, activities at the FTF focused on the assay and analyses related to the successful upgrading of the heavy oil recovered from the Pungarayacu IP-5B well in Ecuador.

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

Environmental Regulations

Our oil and gas and HTL™ operations are subject to various levels of government regulation 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.

Environmental legislation imposes, among other things, restrictions, liabilities and obligations in connection with the generation, handling, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances to the environment. As well, environmental laws regulate the qualities and compositions of the products sold and imported. Environmental legislation also requires that wells, facility sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, certain types of operations, including exploration and development projects and significant changes to certain existing projects, may require the submission and approval of environmental impact assessments. Compliance with environmental legislation can require significant expenditures and failure to comply with environmental legislation may result in the imposition of fines and penalties and liability for clean-up costs and damages. We anticipate that changes in environmental legislation may require, among other things, reductions in emissions to the air from our operations and result in increased capital expenditures.

Operations in Canada are governed by comprehensive federal, provincial and municipal regulations. We submitted the Regulatory Application/Environmental Impact Assessment for the Tamarack Project to the Government of Alberta in November 2010. The regulatory process is expected to conclude near the end of 2012. In addition, the Company will be required to obtain numerous ancillary approvals prior to commencing operations and will be subject to ongoing environmental monitoring and auditing requirements.

Table of Contents

China, Mongolia 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 statements prepared for individual projects, located on the Company's website.

Government Regulations

Our business is subject to certain federal, state, provincial 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 gas, as well as environmental and safety matters. In addition, the Chinese and Mongolian governments regulate various aspects of foreign company operations in their respective countries. Such laws and regulations have generally become more stringent in recent years in Canada, Ecuador, China and Mongolia, 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, 2011, we had 212 employees actively engaged in the business. None of our employees are unionized.

ITEM 1A: RISK FACTORS

Our operations are exposed to various risks, some of which are common to other companies in the oil and gas industry and some of which are unique to our operations. Certain risks set out below constitute "forward-looking statements" and readers should refer to the "Special Note Regarding Forward-Looking Statements" on page 4.

Our ability to continue as a going concern may be adversely affected by inadequate funding

We have a history of operating losses and cash flow from operating activities will not be sufficient to meet our current obligations and fund future capital projects. Historically, we have relied upon equity capital as our principal source of funding. The operation of our business is dependent upon our ability to obtain additional capital to preserve our interests in current projects and to meet obligations associated with future projects. We may seek financing from a combination of strategic investors and/or public and private debt and equity markets, either at a parent company level or at the project level. There is no assurance that we will be able to obtain such financing or obtain it on favorable terms and any future equity issuances may be dilutive to investors. Obtaining financing may be hampered by the inability to attract strategic investors to our projects on acceptable terms, volatility in equity and debt markets and a sustained decrease in the market price of our common shares. Without access to additional financing or other cash generating activities, there is material uncertainty that casts substantial doubt that the Company will be able to continue as a going concern.

We may not be able to fund our substantial capital requirements

Our business is capital intensive and the advancement of our exploration projects in China and Mongolia, development projects in Canada and Ecuador and HTL™ initiatives require significant funding. Since cash flows from existing operations are insufficient to fund future capital expenditures, we intend to finance future capital projects with a combination of strategic investors and/or public and private debt and equity markets, either at a parent company level or at the project level or from the sale of existing assets. There is no assurance that we will be able to obtain such financing or obtain it on favorable terms and any future equity issuances may be dilutive to investors. Obtaining financing in the future may be hampered by the inability to attract strategic investors to our projects on acceptable terms, volatility in equity and debt markets and a sustained decrease in the market price of our common shares. If we fail to obtain adequate funding when needed, we may have to delay or forego 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.

Talisman’s security interest in our assets could impede our ability to secure third party debt

Through our acquisition of Tamarack in 2008, we incurred a series of debt obligations in favor of Talisman secured by a first fixed charge and security interest in the Tamarack oil sands leases and a general security interest in all of our present and after acquired property, other than our equity interests in our subsidiaries (through which we hold our assets in China, Mongolia and Ecuador and our HTL™ technology). Although we have satisfied substantially all of the material debt obligations we owed to Talisman, we remain subject to a contingent payment obligation of up to Cdn$15.0 million, which is also secured by Talisman’s security interest. This contingent obligation becomes due and payable if and when we obtain the requisite government and other approvals necessary to develop the northern border of one of the leases. We are obliged to use commercially reasonable efforts to obtain these approvals. However, despite our efforts, the risks inherent in oil field development, including potential environmental considerations, create significant uncertainty as to

Table of Contents

when, if ever, we will be able to obtain these approvals and, consequently, we cannot predict when, if ever, this contingent obligation will become due and payable or when Talisman's security interest will be released and discharged.

The Talisman security interest restricts our ability to grant security over our Tamarack project assets to secure debt obligations to third parties that we may create in the future. Assets unencumbered by the Talisman security interest may be insufficient as collateral to secure these obligations. This could adversely affect our ability to obtain debt financing or to obtain it on favorable terms. Since Talisman's security interest secures a contingent obligation of potentially indefinite duration, we cannot predict when, and on what terms, we will be able to mitigate this risk.

The volatility of oil prices may affect our financial results

Our revenues, operating results, profitability and future growth are highly dependent on the price of 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.

Oil prices may fluctuate widely in response to relatively minor changes in supply and demand, 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 ("OPEC") 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; and proximity and capacity of oil pipelines and other transportation facilities. These factors and the volatility of the energy markets make it extremely difficult to predict future oil price movements with any certainty.

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

We may be required 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" in Item 7, MD&A, of this Annual Report.

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. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment, the assumptions used regarding prices for oil and gas, production volumes, required levels of operating and capital expenditures and quantities of recoverable oil reserves. 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 oil and gas prices after the date of the estimate may result in revisions to our reserve estimates. Revisions to prior estimates may be material.

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

There can be no assurance that the costs we incur on exploration or development will result in an acceptable level of economic return. We may misinterpret geological or engineering data, which may result in material losses from 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 production costs.

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

We operate in a highly competitive environment and compete with oil and gas companies and other individual producers and operators, many of which have longer operating histories and substantially greater financial and other resources. Many of these companies not only explore for and produce oil and gas, but also carry on refining operations and market petroleum and other products on a worldwide basis. We also compete with companies in other industries supplying energy, fuel and other needs to consumers. Our larger competitors, by reason of their size and relative financial strength, can more easily access capital markets 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

Table of Contents

business and handle longer periods of reduced oil and gas prices more easily. Our competitors may be able to pay more for productive oil and gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects.

We compete with other companies to recruit and retain the limited number of individuals who possess the requisite skills and experience 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 employees with the abilities and expertise we require will be available.

Changes to laws, regulations and government policies in the jurisdictions in which we operate could adversely affect our ability to develop our projects

Our projects in Canada, Ecuador, China and Mongolia are subject to various international, federal, state, provincial, territorial and local laws and regulations relating to the exploration for and the development, production, upgrading, marketing, pricing, taxation and transportation of heavy oil, bitumen and related products and other matters, including environmental protection.

The exercise of discretion by governmental authorities under existing legislation and regulations, the amendment of existing legislation and regulations or the implementation of new legislation or regulations, affecting the oil and gas industry could materially increase the cost of developing and operating our projects and could have a material adverse impact on our business. There can be no assurance that laws, regulations and government policies relevant to our 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 our projects and increase 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 government 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 denied. There is no assurance that 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 our projects.

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

Our operations are governed by various international, federal, state, provincial, territorial and local laws and regulations. Oil, gas, oil sands and heavy oil extraction, upgrading and transportation operations are subject to extensive regulation. 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 in 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.

The costs of complying with environmental laws and regulations in the future may harm our business. Furthermore, future changes in environmental laws and regulations may 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 or our ability to develop or operate our projects in a manner consistent with our current expectations. No assurance can be given that environmental laws will not limit project development or materially increase the cost of production, development or exploration activities or otherwise adversely affect our financial condition, results of operations or prospects.

Table of Contents

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

Our operations are subject to many risks inherent in the oil and gas industry, including 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, any of which could cause us to experience material losses.

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.

Under environmental 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, if environmental damage occurs.

SAGD technologies for in-situ recovery of heavy oil and bitumen are energy intensive and may be unsustainable

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. Current SAGD technologies for in-situ recovery of heavy oil and bitumen are energy intensive, requiring significant consumption of natural gas and other fuels for the production of steam used in the recovery process. The amount of steam required in the production process can also vary and impact costs. The performance of the reservoir can also impact the timing and levels of production using SAGD technology. While the technology is now being used by several producers, commercial application of this technology is still in the early stages relative to other methods of production and, accordingly, in the absence of an extended operating history, there can be no assurances with respect to the sustainability of SAGD operations.

We may not successfully commercialize our HTL™ technology

Success in commercializing our HTL™ technology in the oil and gas industry depends on our ability to economically design, construct and operate commercial-scale plants and a variety of other factors, many of which are outside our control. To date, commercial-scale HTL™ plants have only been constructed in the bio-mass industry.

Technological advances could render our HTL™ technology 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 progress. It is possible that those advances could cause our HTL™ technology to become uncompetitive or obsolete.

Alternate sources of energy could lower the demand for our HTL™ technology

Alternative sources of energy are continually under development. If reliance upon petroleum based fuels decreases, the demand for our HTL™ upgraded product may decline. It is possible that technological advances in engine design and performance could reduce the use of petroleum based fuels, which would also lower the demand for our HTL™ upgraded product.

Efforts to commercialize our HTL™ technology may give rise to claims of infringement upon the patents or other 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 other rights of others in this technology until after we have made a substantial investment in the development and commercialization of projects utilizing the technology. Third parties may claim that the technology infringes upon past, present or future patented technologies. Legal actions could be brought against us and our licensors 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

Table of Contents

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.

A breach of confidentiality obligations could put us at competitive risk and potentially damage our business

While discussing potential business relationships with third parties, we may disclose confidential information on operating results or proprietary intellectual property. Although confidentiality agreements are signed by third parties prior to the disclosure of any confidential information, a breach could put us at competitive risk and may cause significant damage to our business. The harm to our business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, we will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to our business that such a breach of confidentiality may cause.

Certain projects are at a very early stage of development

Our projects are at varying stages of development. We have submitted the Regulatory Application/Environmental Impact Assessment for the Tamarack Project to the Government of Alberta. The regulatory process is expected to take approximately 24 months; however, we could be forced to go to a hearing and there is no assurance that the process will be completed on a timely basis. Construction of the Tamarack Project could be significantly delayed. Additionally, the Government of Alberta may not approve the project as proposed, or it may place certain conditions upon the approval, which could significantly impair the economics of the project. Our Zitong project in China and projects in Ecuador and Mongolia are at a very early stage of development; no reserves have yet been established and no detailed feasibility or engineering studies have yet been produced.

There can be no assurances that these projects will be completed within any anticipated time frame or within the parameters of any anticipated capital cost. We have yet to establish a defined schedule for financing and fully developing such projects. In our efforts to continue developing 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.

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

With respect to the heavy oil leases that we acquired from Talisman, 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, if at all.

Aboriginal peoples have claimed aboriginal title and rights to large areas of land in western Canada where oil and gas operations are conducted, including claims that, if successful, could affect the timing of the development of our heavy oil leases, or the manner in which we can conduct future operations, and have a material 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.

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 will comply with the dispute resolution provisions or otherwise voluntarily submit to arbitration.

Government policy in Ecuador may change to discourage foreign investment or requirements not 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.

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.

Our principal shareholder may significantly influence our business

As at the date of this Annual Report, our largest shareholder, Robert M. Friedland, owned approximately 15.49% 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 all of our key management and technical personnel and we cannot assure that these individuals will remain with us in the future. An unexpected partial or total loss of their services would harm our business.

Information 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 the availability and cost of capital; the 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; personnel; success or failure of activities in similar areas; changes in estimates of project completion costs; and our ability to attract other industry partners to acquire a portion of the working interest to reduce costs and exposure to risks.

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. Our plans regarding our projects might change.

ITEM 1B: UNRESOLVED STAFF COMMENTS

None.

Table of Contents

ITEM 3: LEGAL PROCEEDINGS

The Company is a defendant in a lawsuit filed November 20, 2008, in the United States District Court for the District of Colorado by Jack J. Grynberg and three affiliated companies. The suit alleged bribery and other misconduct and challenged 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 plaintiffs' claims were for unspecified damages or ownership of the Company's interest in the Pungarayacu field. The Company and related defendants filed motions to dismiss the lawsuit for lack of jurisdiction. The Court granted the motion and dismissed the case without prejudice. The Court granted Mr. Robert Friedland's request to sanction plaintiffs and plaintiffs' counsel for their conduct related to bringing the suit by awarding Mr. Friedland fees and costs. The Ivanhoe corporate defendants, including the Company, also have been awarded costs and fees as the prevailing parties in the trial court.

On August 13, 2010, the plaintiffs filed a notice of appeal challenging the district court's judgment and some of its related orders. The appeal is currently pending in the United States Court of Appeals for the Tenth Circuit. Briefing on the appeal is complete and the Court heard oral arguments on May 9, 2011, in Denver, Colorado. There has been no ruling as of yet on the appeal. The likelihood of loss or gain resulting from the lawsuit, and the estimated amount of ultimate loss or gain, are not determinable or reasonably estimable at this time.

On December 30, 2010, the Company received a demand for arbitration from GAR Energy and Associates, Inc. ("GAR Energy") and Gonzalo A. Ruiz and Janis S. Ruiz as successors in interest to and assignees of GAR Energy. GAR Energy subsequently abandoned its demand for arbitration and filed suit against the Company and subsidiaries in the Superior Court for Kern County, California on March 11, 2011. The lawsuit alleges breach of contract, fraud and other misconduct arising from a consulting agreement and various other agreements between GAR Energy and the Company relating to the Pungarayacu heavy oil field. The plaintiffs seek actual damages of $250,000, a portion of the Company's interest in the Pungarayacu field and other miscellaneous relief. The Company removed the case to the United States District Court for the Eastern District of California and all of the defendants have answered and filed counterclaims for attorneys' fees. Defendants filed a motion to dismiss certain claims and to compel arbitration of others. Plaintiffs' filed a motion to remand the case to state court. On December 23, 2011, the Magistrate Judge denied plaintiffs' motion to remand and issued findings and recommendations that would send all of the parties and all of the claims to arbitration should the district court Judge assigned to the case adopt them. On January 19, 2012 the district court Judge adopted the Magistrate Judge's findings and recommendations in full, ordered the parties to arbitration and stayed the district court proceedings to allow for the completion of the arbitration. The likelihood of loss or gain resulting from this dispute, and the estimated amount of ultimate loss or gain, are not determinable or reasonably estimable at this time.

PART II

ITEM 5: MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common shares trade on the Toronto Stock Exchange (the "TSX") and The NASDAQ Capital Market ("NASDAQ") under the symbols "IE" and "IVAN" respectively. The trading range of our common shares is as follows:

		TSX (Cdn$)		NASDAQ (US$)	
		High	Low	High	Low
2011	Q1	3.58	2.67	3.67	2.75
	Q2	2.84	1.58	2.97	1.60
	Q3	1.96	1.02	2.03	0.99

	Q4	1.47	0.75	1.46	0.72
2010	Q1	3.90	2.90	3.79	2.75
	Q2	3.36	1.97	3.37	1.87
	Q3	2.19	1.59	2.08	1.50
	Q4	2.89	2.15	2.88	2.10
2009	Q1	1.53	0.57	1.22	0.45
	Q2	2.16	1.38	1.85	1.10
	Q3	2.98	1.31	2.81	1.13
	Q4	3.25	2.20	3.12	2.02

On December 30, 2011, the closing price of our common shares was Cdn$1.12 on the TSX and $1.12 on NASDAQ.

Table of Contents

As at December 31, 2011, a total of 344,139,428 of our common shares were issued and outstanding and held by 187 holders of record with an estimated 26,343 additional shareholders whose common shares were held for them in street name or nominee accounts.

DIVIDENDS

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

EXEMPTIONS FROM CERTAIN NASDAQ MARKETPLACE RULES

As a Canadian issuer listed on NASDAQ, we are not required to comply with certain of NASDAQ's Marketplace Rules and instead may comply with applicable Canadian requirements. As a foreign private issuer, we are only required to comply with the following NASDAQ rules: (i) we must have an audit committee that satisfies applicable NASDAQ requirements and that is composed of directors each of whom satisfy NASDAQ's prescribed independence standards; (ii) we must provide NASDAQ with prompt notification after an executive officer of the Company becomes aware of any material non-compliance by us with any applicable NASDAQ Marketplace Rule; (iii) our common shares must be eligible for a Direct Registration Program operated by a clearing agency registered under Section 17A of the Exchange Act; and (iv) we must provide a brief description of any significant differences between our corporate governance practices and those followed by US companies quoted on NASDAQ.

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

ENFORCEABILITY OF CIVIL LIABILITIES

We are a company incorporated under the laws of the Yukon Territory of Canada. Some of our directors, controlling shareholders, officers and representatives of the experts named in this Annual Report reside outside the US and a substantial portion of their assets and our assets are located outside the US. As a result, it may be difficult to effect service of process within the US upon the directors, controlling shareholders, officers and representatives of experts who are not residents of the US or to enforce against them judgments obtained in the courts of the US based upon the civil liability provisions of the federal securities laws or other laws of the US. 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 US, in original actions or in actions for enforcement of judgments of US courts, of liabilities based solely upon civil liability provisions of the US 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.

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 investor 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

Table of Contents

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 (a "Cultural Business"). 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 2012 is Cdn$330 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 through the ownership of common shares. 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 announced certain forthcoming amendments (the "Amendments") to the Investment Act. Once they come into force, the Amendments would generally raise the thresholds that trigger governmental review. Specifically, with respect to WTO investors, the Amendments would see the thresholds for the review of direct acquisitions of control of a business which is not a Cultural Business increase from the current Cdn$330 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 come into force, 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 Amendments will come into force when the government enacts regulations which, among other things, will provide how the "enterprise value" is to be determined.

The Investment Act also provides that the Minister of Industry may initiate a review of any acquisition by a non-Canadian of our common shares or assets if the Minister considers that the acquisition "could be injurious to (Canada's) national security".

Amounts that we may, in the future, pay or credit, or be deemed to have paid or credited, to shareholders as dividends in respect of the common shares held at a time when the beneficial owner is 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-US 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 US resident that is entitled to the benefits of the Convention is generally 15%. However, if the beneficial owner of such dividends is a US resident corporation that is entitled to the benefits of the Convention and 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 US 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.

PERFORMANCE GRAPH

See table under “Executive Compensation” set forth in Item 11 in this Annual Report.

SALES OF UNREGISTERED SECURITIES

All securities we issued during the years ended December 31, 2011 and 2010, which were not registered under the Act, have been detailed in previously filed Form 10-Qs and Form 8-Ks.

Table of Contents

ITEM 6. SELECTED FINANCIAL DATA

SUMMARY OF SELECTED FINANCIAL DATA

The following table presents selected financial data based on International Financial Reporting Standards ("IFRS") for the two most recent financial years.

($000s, except per share amounts)	2011	2010
Results of Operations		
Revenues	37,979	21,928
Net loss	(25,276)	(26,582)
Net loss per share – basic and diluted	(0.07)	(0.08)
Financial Position		
Total assets	413,710	394,418
Long term debt	61,892	–
Long term derivative instruments	1,617	–
Long term provisions	1,919	3,008

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

The following MD&A should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2011 (the "Financial Statements"). The Financial Statements have been prepared in accordance with and using accounting policies in full compliance with IFRS and International Accounting Standards ("IAS") issued by the International Accounting Standards Board ("IASB") and Interpretations of the International Financial Reporting Interpretations Committee, effective for the Company's reporting for the year ended December 31, 2011.

As a foreign private issuer in the US, Ivanhoe is permitted to file with the SEC financial statements prepared under IFRS without a reconciliation to US generally accepted accounting principles ("GAAP"). It is possible that some of our accounting policies under IFRS could be different from US GAAP.

The date of this discussion is March 15, 2012. Unless otherwise noted, tabular amounts are in thousands of US dollars. Oil and gas production, revenue, reserves and related measures are presented net of royalty payments to governments.

Table of Contents

HIGHLIGHTS

($000, except as stated)	2011	2010
Production (bbls/d)	967	788
Realized oil prices ($/bbl)	105.93	75.52
Oil revenue	37,403	21,720
Capital expenditures	51,060	70,980
Cash flow used in operating activities	(26,245)	(31,290)
Net loss	(25,276)	(26,582)
Net loss per share – basic and diluted	(0.07)	(0.08)

Oil production increased in 2011 as Ivanhoe received additional volumes to offset capital expenditures incurred at Dagang in 2011. Additional production, in combination with stronger realized prices, resulted in higher oil revenue for the Company. The net loss in 2011 was $25.3 million compared to a $26.6 million net loss in 2010. Although oil revenue increased in 2011, net income was impacted by higher operating and general and administrative expenses as well as lower non-cash foreign currency exchange and derivative instrument gains in comparison to 2010. The current year also benefitted from lower exploration and evaluation expenses than in the prior year.

Capital expenditures totaled $51.1 million in 2011. In China, the Yixin-2 and Zitong-1 gas wells at the Company’s Zitong project in China were tested and fracture stimulated. At Dagang, four wells were drilled and completed in 2011. A well drilled in 2010 was also completed in early 2011. The fracture stimulation program at Dagang continued throughout 2011.

In the Nyalga basin of Mongolia, Ivanhoe’s first exploration well, N16-1E-1A, was drilled and abandoned as the well did not encounter oil shows in the reservoir. The Company observed oil staining, fluorescence and increases in background gas at its second exploration well site at N16-2E-B.

In Canada, regulators completed their initial review of the Company’s application for the Tamarack Project and, as is customary, provided the Company with an initial set of Supplemental Information Requests in the third quarter of 2011. The Company submitted the supplemental information to the regulators in the fourth quarter of 2011. Project advancement, as currently envisaged, is subject to regulatory approval and financing.

In Ecuador, Ivanhoe completed a 190-kilometre 2-D seismic survey of Block 20. Following analysis of the seismic program, the Company plans to drill an exploration well into the deeper Hollin and pre-cretaceous horizons in the southern part of the Pungarayacu Block. The well will test the potential for lighter oil resources, which would prove beneficial for blending purposes and overall project economics.

RESULTS OF OPERATIONS

Revenue

	2011	2010
Oil revenue ($000s)	37,403	21,720
Production		
Asia (net bbls)		
Dagang	341,258	273,868
Daqing	11,842	13,751

Total production	353,100	287,619
Average daily production (bbls/d)	967	788
Pricing		
Average realized oil price ($/bbl)	105.93	75.52
Average Brent ($/bbl)	110.63	80.25

Oil revenue in 2011 rose in comparison to 2010 due to a combination of higher production volumes and stronger realized prices. Gross oil production from the Dagang field in China was relatively constant. However, the terms of the Company's PSC at Dagang with CNPC stipulate that capital expenditures are to be funded 100% by Ivanhoe and CNPC's portion of the costs are reimbursed through the receipt of additional oil sales. Due to higher levels of capital activity at Dagang in 2011, additional oil production was allocated to Ivanhoe.

Table of Contents

Dagang production is sold at the prior three month rolling average price of Cinta crude, which historically averages $2.00/bbl less than Brent crude, the standard the Company uses for its China reserve estimates. Following the increase in Cinta crude prices in 2011, our realized oil prices rose compared to 2010.

Netbacks

($/bbl)	2011	2010
Realized oil prices(1)	105.93	75.52
Less operating costs		
Field operating	(19.68)	(19.81)
Windfall Levy	(23.18)	(11.59)
Engineering and support costs	(1.24)	(1.76)
Net operating revenue(1)	61.83	42.36
Depletion	(19.54)	(21.54)
Net revenue from operations(1)	42.29	20.82

(1) Realized oil prices per barrel, net operating revenue per barrel and net revenue from operations per barrel do not have standardized meanings prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. Please refer to the Non-IFRS Financial Measures under the Advisories section in this MD&A for more details.

Operating Costs

($000s)	2011	2010
Asia		
Field operating	6,947	5,699
Windfall Levy	8,185	3,333
Engineering support	438	507
	15,570	9,539
Technology Development		
FTF operating costs	4,561	4,086
Total operating costs	20,131	13,625

Operating costs in China rose by $6.0 million in 2011 in comparison to 2010. The increase is primarily attributable to the Windfall Levy administered by the People's Republic of China which rises with higher oil prices. Historically, the Windfall Levy was imposed at progressive rates from 20% to 40% on the portion of the monthly weighted average sales price exceeding $40.00/bbl. Effective November 1, 2011, the Ministry of Finance of the People's Republic of China raised the Windfall Levy threshold to $55.00/bbl.

Field operating costs in total increased over the prior year due to additional production volumes in 2011. However, on a per barrel basis, field operating costs in 2011 were consistent with the prior year.

Operating costs in the Technology Development segment are incurred at the Company's Feedstock Test Facility ("FTF") at the Southwest Research Institute in San Antonio, Texas. FTF operating costs in 2011 are higher than in 2010 due to activities associated with assay and analyses related to the successful upgrading of the heavy oil recovered from the Pungarayacu IP-5B well in Ecuador and planned maintenance costs associated with enhancements implemented at the FTF in the second quarter of 2011.

Exploration and Evaluation

Costs of exploring for, and evaluating, oil and gas properties are initially capitalized as intangible exploration and evaluation assets and charged to exploration and evaluation ("E&E") expense only if sufficient reserves cannot be established. In 2011, $2.1 million of drilling costs were expensed in connection with the exploration well in Mongolia that was plugged and abandoned. In addition, it was determined that $0.7 million of expenditures related to the seismic program in Ecuador would have limited future value and were therefore charged to E&E expense.

Following the drilling of the Zitong-1 and Yixin-2 wells, areas excluding those identified for development and future production were to be relinquished at the end of 2010; consequently $3.5 million of geological costs incurred in prior periods were expensed as E&E costs in 2010. Ivanhoe drilled two appraisal wells on Block 20 in Ecuador in 2010. The first appraisal well, IP-15, encountered cementing and completion problems prior to steam injection operations, therefore testing was suspended without recovering oil. As a result, $4.9 million of drilling and testing costs were expensed as E&E costs in the fourth quarter of 2010.

Table of Contents

General and Administrative

G&A expenses incurred in 2011 were $5.6 million higher in comparison to 2010. Staff costs rose $4.5 million as a result of the Company's growing commitments to its projects around the world. Professional fees increased as incremental legal costs of $1.4 million were incurred in connection with the proceedings described in Part I, Item 3 of this Form 10-K and $0.4 million of additional contract engineering costs related to Ivanhoe's HTL™ technology were incurred to investigate new applications. G&A in 2011 also includes $0.3 million of financing and filing fees associated with the Cdn$73.3 million convertible unsecured subordinated debentures ("Convertible Debentures") issued in the second quarter of 2011. Rising costs in 2011 were offset by lower charitable contributions; in 2010, the Company committed to a $1.0 million donation to flood victims in Ecuador.

Depletion and Depreciation

Depletion and depreciation expense in 2011 rose in comparison to 2010 due to a combination of factors. Depletion in Asia increased $0.7 million in 2011 due to higher production, despite a lower depletion rate as the result of additional Dagang reserves recorded on January 1, 2011. The depreciation expense incurred by the Technology segment was $0.6 million higher in 2011 due to revisions of the dismantled Commercial Demonstration Facility salvage values reducing depreciation in 2010.

Foreign Exchange

The Company incurred a smaller net foreign exchange gain in 2011 in comparison to the prior year. The Canadian dollar was stronger than the US dollar in the first nine months of 2011, subsequently weakening in the fourth quarter of 2011. Net foreign exchange gains incurred on the translation of the Company's Canadian dollar denominated cash, debt and payables in the first three quarters of 2011 were partially offset by net foreign exchange losses in the fourth quarter.

In the first quarter of 2010, the Company incurred a net foreign exchange gain on the translation of its Canadian dollar cash raised in the Cdn$150.0 million private placement when the Canadian dollar strengthened against the US dollar, which was partially offset by a net foreign exchange loss incurred in the second quarter of 2010 when the Canadian dollar weakened. In the second half of 2010, additional foreign exchange gains were incurred on the translation of monetary items as the Canadian dollar continued to strengthen relative to the US dollar.

Derivative Instruments

In 2011, the unrealized gain on derivative instruments was less than in the prior year. An unrealized gain on the Convertible Debentures totaled $7.8 million and a combination of the expiry and revaluation of the Company's Purchase Warrants resulted in a gain of $4.1 million. Additionally, a gain of $1.2 million was recognized on the revaluation of the convertible portion of the Cdn$40.0 million convertible promissory note issued to Talisman ("Convertible Note"). The revaluation of an option granted to a private investor in January 2010 to acquire an equity interest in one of the Company's subsidiaries created a loss of $0.2 million in the current year.

The $18.6 million unrealized gain recorded in 2010 stemmed from a $15.0 million and $3.6 million gain, respectively, on the revaluation of the Purchase Warrants and Convertible Note.

Gain on Derecognition of Long Term Provision

As part of a 2005 merger agreement, the Company assumed a $1.9 million contingent obligation. In the third quarter of 2011, the Company determined, based on recent events and clarification of contract terms, that satisfaction of the specific contractual contingencies was unlikely and the liability was derecognized.

Provision for Income Taxes

Current taxes increased due to higher oil revenue in 2011 than in the comparable period. Ivanhoe incurred a future tax recovery of $3.4 million in 2011 due to capital spending in China and continued operating loss carryforwards in the US.

Table of Contents

LIQUIDITY AND CAPITAL RESOURCES

Contractual Obligations and Commitments

The following information about our contractual obligations and other commitments summarizes certain liquidity and capital resource requirements. The information presented in the table below does not include planned, but not legally committed, capital expenditures or obligations that are discretionary and/or being performed under contracts which are cancelable with a 30 day notification period.

	Total	2012	2013	2014	2015	After 2015
Long term debt	72,085	–	–	–	–	72,085
Interest on long term debt	18,647	4,145	4,145	4,145	4,145	2,067
Short term debt and interest	10,658	10,658	–	–	–	–
Asset retirement obligations(1)	2,201	–	386	–	–	1,815
Zitong appraisal program	75,510	40,680	31,680	3,150	–	–
Leases	4,508	1,734	1,278	592	402	502
Total	183,609	57,217	37,489	7,887	4,547	76,469

(1) Represents undiscounted asset retirement obligations after inflation. The discounted value of these estimated obligations ($1.6 million) is provided for in the consolidated financial statements.

Long Term Debt and Interest

As described in the Financial Statements, the Company issued Cdn$73.3 million of Convertible Debentures maturing on June 30, 2016. The Convertible Debentures bear interest at an annual rate of 5.75%, payable semi-annually on the last day of June and December of each year, commencing on December 31, 2011.

Short Term Debt and Interest

On December 30, 2011, Ivanhoe entered into a loan agreement for $10.0 million with Ivanhoe Capital Finance Ltd. The funds were advanced on January 3, 2012 and incur interest at a rate of 13.3% per annum. The principal balance matures in 180 days or earlier in the case of certain events.

Decommissioning Provisions

The Company is required to remedy the effect of our activities on the environment at our operating sites by dismantling and removing production facilities and remediating any damage caused. At December 31, 2011, Ivanhoe estimated the total undiscounted, inflated cost to settle its asset retirement obligations in Canada, for the FTF in the US and in Ecuador was $2.2 million. These costs are expected to be incurred in 2013, 2029 and 2038, respectively. Ivanhoe does not make such a provision for decommissioning costs in connection with its oil and gas operations in China as dry holes are abandoned as they occur and productive wells will not be abandoned while the Company has an economic interest in the field.

Leases

The Company has long term leases for office space and vehicles, which expire between 2012 and 2017.

Zitong Appraisal Program

The terms of the Supplementary Agreement call for the completion of an appraisal program by the end of June 2014. The work program is expected to consist of a 160 sq. km of 3D seismic survey, as well as drilling and completing three horizontal wells on the Guan and Wen structures.

Other

Should Ivanhoe receive government and other approvals necessary to develop the northern border of one of the Tamarack Project leases, the Company will be required to make a cash payment to Talisman of up to Cdn$15.0 million, as a conditional, final payment for the 2008 purchase transaction.

From time to time, Ivanhoe 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, common shares, stock options or some combination thereof. Similarly, agreements entered into by the Company may contain cancellation fees or liquidated damages provisions for early termination. These fees are not considered to be material.

Table of Contents

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 Ivanhoe 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 indemnities are not likely to be material.

In the ordinary course of business, the Company is subject to legal proceedings being brought against it. While the final outcome of these proceedings is uncertain, the Company believes that these proceedings, in the aggregate, are not reasonably likely to have a material effect on its financial position or earnings.

Sources and Uses of Cash

The Company's cash flows from operating, investing and financing activities, as reflected in the consolidated statements of cash flows, are summarized in the following table:

	2011	2010
Net cash used in operating activities	(26,245)	(31,290)
Net cash used in investing activities	(85,422)	(68,684)
Net cash provided by financing activities	61,423	138,286

Ivanhoe's cash flow from operating activities is not sufficient to meet its operating and capital obligations over the next twelve months. The Company intends to use its working capital to meet its commitments. However, additional sources of funding will be required to grow the Company's major projects and fully develop its oil and gas properties. Historically, Ivanhoe has used external sources of funding such as public and private equity and debt markets. However, there is no assurance that these sources of funding will be available to the Company in the future or available on acceptable terms.

Operating Activities

Cash used in operating activities in the current year was lower than in 2010 as growth in revenue exceeded increases in operating costs and G&A expenses.

Investing Activities

E&E Expenditures

E&E capital expenditures for the Company in 2011 totaled $37.4 million. The Yixin-2 and Zitong-1 gas wells at the Company's Zitong project in China were tested and fracture stimulated. Subsequent to post-fracture gas flow tests, down-hole electronic recorders were installed to gather additional pressure data during an extended shut-in period. The data was analyzed and will be used in future operations.

In the Nyalga basin of Mongolia, expenditures incurred on the Company's first exploration well at N16-1E-1A were expensed. The drilling rig was mobilized to a second site, N16-2E-B, and drilling commenced in the middle of September where oil staining, fluorescence and increases in background gas were observed.

In Canada, regulators have completed their initial review of the Company's application for the Tamarack Project and, as is customary, provided the Company with an initial set of Supplemental Information Requests in the third quarter of 2011. The Company submitted supplemental information to the regulators in the fourth quarter of 2011.

In Ecuador, the Company completed a 190-kilometre 2-D seismic survey of Block 20. The seismic data will assist in the selection of future drilling locations.

In comparison, Ivanhoe spent $65.3 million on E&E capital expenditure in 2010. The Company successfully drilled two wells, Yixin-2 and Zitong-1, to total depth. Ivanhoe completed its winter delineation drilling program at Tamarack in early 2010 and, in November 2010, submitted its regulatory application to the Government of Alberta. Two appraisal wells were drilled in 2010 on Block 20 in Ecuador. The first appraisal well, IP-15, encountered certain cementing and completion problems prior to steam injection operations and testing was suspended without recovering oil. The second appraisal well, IP-5b, was successfully drilled, cored and logged.

Property, Plant and Equipment Expenditures

In 2011, property, plant and equipment ("PP&E") additions totaled $13.7 million. At Dagang, four wells were drilled and completed. A well drilled in 2010 was also completed in early 2011. The fracture stimulation program at Dagang continued throughout the year.

Table of Contents

In 2010, $5.6 million of PP&E additions were incurred as the Company conducted five fracture stimulations at the Dagang field during the year.

Restricted Cash

Ivanhoe was required to post a $20.0 million performance bond as part of the completion and signing of the Supplementary Agreement with CNPC in December 2011.

Financing Activities

Cash provided by financing activities was lower in 2011 than in the prior year. In June 2011, the Company raised $72.9 million, net of issuance costs, through the issuance of the Convertible Debentures. The net proceeds were used to repay the Convertible Note due to Talisman on July 11, 2011, as well as operating expenses and capital expenditures. In the first quarter of 2011, cash proceeds of $29.9 million were raised through the exercise of purchase warrants and stock options.

In comparison, the Company raised $135.7 million, net of issuance costs, through a private placement of 50 million special warrants at a price of Cdn$3.00 per special warrant in 2010.

Capital Structure

As at December 31,	2011	2010
Debt	–	39,832
Long term debt	61,892	–
Shareholders’ equity	314,137	300,484

Ivanhoe intends to use its cash and cash equivalent balance to fulfill its commitments and partially fund operations in 2012. Cash flow may be insufficient to meet operating requirements in the next twelve months and additional sources of funding, either at a parent company level or at a project level, will be required to grow the Company’s major projects and fully develop its oil and gas properties. Historically, Ivanhoe has used external sources of funding, such as public and private equity and debt markets. Ivanhoe intends to finance its future funding requirements through a combination of strategic investors and/or public and private debt and equity markets, either at a parent company level or at the project level, and through the sale of interests in existing oil and gas properties. There is no assurance that the Company will be able to obtain such financing, or obtain it on favorable terms, and any future equity issuances may be dilutive to current investors. If Ivanhoe cannot secure additional financing, the Company may have to delay its capital programs and forfeit or dilute its rights in existing oil and gas property interests.

CRITICAL ACCOUNTING PRINCIPLES AND ESTIMATES

The Financial Statements have been prepared in accordance with IFRS as issued by the IASB. The Financial Statements are not subject to qualification relating to the application of IFRS as issued by the IASB.

A detailed summary of the Company’s significant accounting policies is included in Note 3 to the Financial Statements. Some of these policies involve critical accounting estimates as they require the Company to make particularly subjective or complex judgments about matters that are inherently uncertain and because of the likelihood that materially different amounts could be reported under different conditions or using different assumptions. The following section discusses critical accounting estimates and assumptions and how they affect the amounts reported in the Company’s Financial Statements.

Intangible E&E Assets

Management must determine if intangible E&E assets, which have not yet resulted in the discovery of proved reserves, should continue to be capitalized or charged to E&E expense. When making this determination, Ivanhoe considers factors such as the Company's drilling results, planned exploration and development activities, the financial capacity of the Company to further develop the property, the ability to use the Company's HTL™ technology in certain projects, lease expiries, market conditions and technical recommendations from its exploration staff.

Although the Company believes its estimates are reasonable and consistent with current conditions, internal planning and expected future operations, such estimates are subject to significant uncertainties and judgments. Ivanhoe cannot predict if an event that triggers impairment will occur, when it will occur or how it will affect the reported asset amounts.

Table of Contents

Impairment

Property, Plant and Equipment

The Company periodically assesses its oil and gas assets, or groups of assets, for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. Among other things, an impairment may be triggered by falling oil and gas prices, a significant negative revision to reserve estimates, the inability to use the Company's HTL™ technology in certain projects, changes in capital costs or the inability to raise sufficient financial resources to further develop the property.

Cash flow estimates for the Company's impairment assessments require significant assumptions about future prices and costs, production, reserves volumes and discount rates, as well as potential benefits from the application of its HTL™ technology. Given the significant assumptions required and the likelihood that actual conditions will differ, the assessment of impairment is considered to be a critical accounting estimate.

It is difficult to determine and assess how a change in future costs, production, reserves volumes, or the application of HTL™ technology could impact Ivanhoe's impairment tests. A 1% increase in the discount rate and a 5% decrease in the forward pricing used in the calculation of cash flows from proved plus probable reserves as at December 31, 2011, would not impair the Company's development project.

Intangible Technology Assets

The Company's intangible technology assets consist of an exclusive, irrevocable license to deploy its HTL™ technology. Ivanhoe annually reviews the technology assets for impairment or if an adverse event or change occurs. Indicators of adverse events could include HTL™ patent expiries, advancements of new technologies or the inability to successfully commercialize the HTL™ technology. The intangible asset impairment is a critical accounting estimate because it requires Ivanhoe to make assumptions about competitive technological developments, the successful commercialization of its HTL™ technology and future cash flows from the HTL™ technology.

Ivanhoe cannot predict if an event that triggers impairment will occur, when it will occur or how it will affect the reported asset amounts. Although the Company believes its estimates are reasonable and consistent with current conditions, internal planning and expected future operations, such estimates are subject to significant uncertainties and judgments.

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 becomes available and as economic conditions impacting oil and gas prices and costs change. Such revisions could be upwards or downwards. For details on our reserve estimation process, refer to the section titled "Reserves, Production and Related Information" in Items 1 and 2 of this Annual Report.

Reserve estimates have a material impact on depletion and the Company's impairment evaluations, which in turn have a material impact on earnings. Total proved and probable reserves estimates are used to determine rates used in the unit-of-production depletion calculations. In the year ended December 31, 2011, depletion expense of $6.9 million was recorded. If proved and probable reserves estimates changed by 10%, the Company's depletion and depreciation expense would have changed by approximately $0.7 million, assuming all other variables remained constant.

Option Pricing Model

The Company uses the Black-Scholes option pricing model to measure the fair value of stock options and equity settled Restricted Share Units (“RSUs”) on the date of grant. Determining the fair value of stock-based awards on the grant date requires judgment, including estimating the expected life of the award, the expected volatility of the Company’s common shares and expected dividends. In addition, judgment is required to estimate the number of awards that are expected to be forfeited. Changes in assumptions can materially affect the estimated fair value, and therefore, the existing models do not necessarily provide precise measures of fair value.

Convertible Debentures

On June 9, 2011, the Company issued Cdn$73.3 million of Convertible Debentures. The Canadian dollar denominated debt is considered to contain an embedded derivative since the functional currency of the Company is the US dollar. As a result, the Convertible Debentures were bifurcated into debt and the convertible option, which was recognized at fair value using the Black-Scholes valuation method. Changes in the fair value of the convertible option are recorded in earnings; therefore the valuation of the convertible option is a critical accounting estimate.

Table of Contents

The Black-Scholes valuation method requires the input of highly subjective assumptions regarding expected volatility of the Company's share price and the risk-free interest rate. If the volatility used to fair value the convertible component at December 31, 2011 decreased by 10%, the fair value of the convertible option would decrease by $1.1 million. If volatility increased by 10%, the fair value of the convertible option would increase by $1.6 million.

Convertible Note

In connection with the acquisition of the Tamarack leases in July 2008 from Talisman, the Company issued a Cdn$40.0 million Convertible Note. The Canadian dollar denominated debt was considered to contain an embedded derivative since the functional currency of the Company is the US dollar. As a result, the Convertible Note was bifurcated into debt and the convertible option, which was recognized at fair value using the Black-Scholes valuation method. Changes in the fair value of the convertible option were recorded in earnings, and as a result, the valuation of the convertible option was a critical accounting estimate prior to the maturity of the Convertible Note on July 11, 2011.

Deferred Income Taxes

Ivanhoe operates in a specialized industry and in several tax jurisdictions. As a result, the Company's income is subject to various rates of taxation. The breadth of the Company's operations and the global complexity of tax regulations require assessments of uncertainties and judgments in estimating the taxes that the Company will ultimately pay. The final taxes paid are dependent upon many factors, including negotiations with taxation authorities in various jurisdictions, uncertain tax positions and resolution of disputes arising from federal, provincial, state and local tax audits.

The deferred income tax liability is a critical accounting estimate because it requires Ivanhoe to make assumptions about the resolution of these uncertainties and the associated final taxes may result in adjustments to the Company's tax assets and tax liabilities.

NEW ACCOUNTING PRONOUNCEMENTS

Transition to International Financial Reporting Standards

Effective January 1, 2011, Ivanhoe adopted IFRS, as issued by the IASB, as the Company's basis for accounting. Most adjustments required on transition to IFRS were made retrospectively against opening retained earnings as of the date of the first comparative statement of financial position. Transitional adjustments relating to those standards where comparative figures are not required to be restated will only be made as of the first day of the year of adoption.

Table of Contents

First-time Adoption of International Financial Reporting Standards

"First-Time Adoption of International Financial Reporting Standards" ("IFRS 1") provides companies adopting IFRS for the first time with a number of optional exemptions and mandatory exceptions to the general requirement for full retrospective application of IFRS where retrospective restatement would either be onerous or would not provide more useful information. As a result of relying upon the exemptions described below, there was no material impact in these areas at the date of transition to IFRS.

Area of IFRS	Summary of Exemption Available
Property, plant and equipment	Companies may elect to report property, plant and equipment from oil and gas operations on the opening statement of financial position on the transition date at a deemed cost, instead of the actual cost, as though IFRS had been adopted retroactively. The deemed cost of an item may be either its fair value at the date of transition to IFRS or an amount reported under Canadian GAAP. The exemption can be applied on an asset-by-asset basis. Ivanhoe elected to report property, plant and equipment from oil and gas operations in its opening statement of financial position on the transition date at the deemed cost previously calculated under Canadian GAAP.
Decommissioning liabilities	In accounting for changes in decommissioning liabilities, IFRS requires changes in such obligations to be added to, or deducted from, the cost of the asset to which they relate. The adjusted depreciable amount of the asset is then depreciated prospectively over its remaining useful life. Rather than recalculating the effect of all such changes throughout the life of the obligation, companies may elect to measure the liability and the related depreciation effects at the date of transition to IFRS. Ivanhoe elected to measure only those decommissioning liabilities outstanding from the FTF on the date of transition to IFRS.
Stock-based compensation	Companies may elect not to apply IFRS 2, "Share-Based Payment," to stock options granted on or before November 7, 2002, or which vested before the date of transition to IFRS. Ivanhoe elected to utilize this exemption for the all stock options awarded after November 7, 2002, that vested before January 1, 2010.
Business combinations	Companies may elect to either restate all past business combinations in accordance with IFRS 3, "Business Combinations," or to apply an elective exemption from applying IFRS 3 to past business combinations. Ivanhoe elected to utilize this exemption and transactions entered into prior to the transition date will not be restated.

Table of Contents

Areas of Significance

IFRS had a significant impact on the Company's ongoing accounting in the areas described below, in addition to the impact of transition policy choices made under IFRS 1.

Accounting Policy Area	Impact of Policy Adoption
Exploration and evaluation assets	The Company followed the full cost method of accounting for its oil and gas operations under Canadian ("Cdn") GAAP, whereby all costs related to the exploration for, and development of, oil and gas reserves were capitalized and periodically evaluated for impairment. Under IFRS, exploration costs will initially be capitalized as E&E assets until it can be determined if sufficient quantities of reserves have been found to justify commercial production. If commercial quantities of reserves are found, E&E assets will be reclassified to oil and gas properties and development costs and, if not, E&E assets will be expensed on the consolidated statement of loss. Costs incurred in connection with our projects in Canada, Ecuador, Mongolia and exploration projects in China were reclassified as E&E assets, while producing assets in China continued to be classified as oil and gas properties and development costs on the consolidated statement of financial position.
Impairments	Cdn GAAP generally used a two-step approach to impairment testing: first comparing asset carrying values with undiscounted future cash flows to determine whether impairment exists and then measuring any impairment by comparing asset carrying values with fair values calculated using discounted cash flows. International Accounting Standard 36, "Impairment of Assets," uses a one-step approach for both testing and measuring of impairment, with asset carrying values compared directly with the higher of fair value less costs to sell and value in use (which uses discounted future cash flows). This may potentially result in more write downs where carrying values of assets were previously supported under Cdn GAAP on an undiscounted cash flow basis, but could not be supported on a discounted cash flow basis. IFRS also requires the reversal of any previous impairment losses where circumstances have changed such that impairments have been reduced. Cdn GAAP prohibited the reversal of impairment losses. IFRS will result in greater variability in our operating results and asset carrying values.
Capitalized G&A	G&A directly related to exploration and development activities was capitalized as oil and gas properties and development costs under Cdn GAAP. The threshold to capitalize G&A is higher under IFRS; therefore, less G&A will be capitalized in the future and G&A on the consolidated statement of loss will be higher as a result.
Financial instruments	Under Cdn GAAP, the equity component of the Company's Convertible Note and the common share purchase warrants were classified as shareholders' equity. In accordance with IAS 32, "Financial Instruments: Presentation," financial instruments with an exercise price denominated in a currency other than our functional currency are accounted for as derivatives. Since our Convertible Note and common share purchase warrants are denominated in Cdn dollars and our functional currency is US dollars, these items were reclassified from shareholders' equity to liabilities under IFRS. Additionally, IFRS requires derivative instruments to be recorded at fair value with changes in their fair value recognized in the consolidated statement of loss. This will create variability in our results of operations and the carrying value of liabilities.
Stock-based compensation	Stock options were accounted for using the fair value method under Cdn GAAP. The fair value was determined using the Black- Scholes option pricing model and recorded as compensation expense on a straight-line basis over the period that the stock options

vested. Under IFRS 2, "Share-Based Payment," compensation expense will be charged to earnings on a graded vesting basis. This will accelerate the compensation expense recognized on the consolidated statement of loss in comparison to Cdn GAAP.

New Accounting Pronouncements

The information contained in Note 3.18, Standards and Interpretations Issued But Not Yet Adopted, to our Financial Statements in Part II, Item 8 is incorporated by reference into this Part II, Item 7.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements that would have a material adverse effect on our liquidity, consolidated financial position or results of operations.

Table of Contents

ITEM 7A: QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed in varying degrees to normal market risks inherent in the oil and gas industry, including commodity price risk, foreign currency exchange rate risk, credit risk and liquidity risk. We recognize these risks and manage our operations to minimize our exposures to the extent practicable.

COMMODITY PRICE RISK

Commodity price risk related to oil prices is one of Ivanhoe's most significant market risk exposures. The Company's operating results and financial condition are influenced by the prices the Company receives for its oil production. Oil prices may fluctuate widely in response to a variety of factors including global and domestic economic conditions, weather conditions, political stability, transportation facilities, the price and availability of alternative fuels and government regulations.

Based on estimated 2012 production, a US$1.00/bbl change in the price of oil would increase or decrease net income and cash flows from operations for 2012 by US$0.82/bbl. In the past, Ivanhoe has used derivatives to minimize variability in the Company's cash flow from operations when required to do so by loan covenants. However, no hedging contracts were in place in 2011 and the Company does not anticipate using hedging contracts in 2012 to manage its commodity price risk.

FOREIGN CURRENCY EXCHANGE RATE RISK

Ivanhoe is exposed to foreign currency exchange rate risk as a result of incurring capital expenditures and operating costs in currencies other than the US dollar. A substantial portion of our activities are transacted in or referenced to US dollars, including oil sales in Asia, capital spending in Ecuador and ongoing FTF operations. A portion of our transactions are in other currencies, such as Dagang operating costs paid in Chinese renminbi, Tamarack exploration activities funded in Cdn dollars and the Cdn dollar Convertible Debentures issued in 2011. The Company did not enter into any foreign currency derivatives in 2011, nor do we anticipate using foreign currency derivatives in 2012. To help reduce the Company's exposure to foreign currency exchange rate risk, it seeks to hold assets and liabilities denominated in the same currency when appropriate.

The following table shows the Company's exposure to foreign currency exchange rate risk on its net loss and comprehensive loss for 2011, assuming reasonably possible changes in the relevant foreign currency. This analysis assumes all other variables remain constant.

(Increase) Decrease in Net Loss and Comprehensive Loss	10% Increase or Weakening	10% Decrease or Strengthening
Chinese renminbi	1,953	(2,387)
Canadian dollar	3,685	(3,711)

CREDIT RISK

Ivanhoe is exposed to credit risk with respect to its cash and cash equivalents, restricted cash, accounts receivable, note receivable and long term receivables. The Company's maximum exposure to credit risk at December 31, 2011, is represented by the carrying amount of these non-derivative financial assets. Most of the Company's credit exposures are with counterparties in the energy industry and are therefore exposed to normal industry credit risks. Ivanhoe manages its credit risk by only entering into sales contracts with established entities.

The Company believes its exposure to credit risk related to cash and cash equivalents, as well as restricted cash, is minimal due to the quality of the financial institutions where the funds are held and the nature of the deposit instruments.

Currently, all of the Company's oil production is sold to one national oil corporation. As a result, 96% of the outstanding accounts receivable balance at December 31, 2011 (December 31, 2010 – 85%) is due from a national oil corporation. Long term value-added tax receivable from the Ecuadorian government will be recoverable upon commencement of commercial operations. Ivanhoe considers the risk of default on these items to be low due to the Company's ongoing operations in China and Ecuador.

Table of Contents

LIQUIDITY RISK

Liquidity risk is the risk that suitable sources of funding for the Company's business activities may not be available. Since cash flows from existing operations are insufficient to fund future capital expenditures, we intend to finance future capital projects with a combination of strategic investors and/or public and private debt and equity markets, either at the parent company level or at the project level or from the sale of existing assets. There is no assurance that we will be able to obtain such financing or obtain it on favorable terms.

NON-IFRS FINANCIAL MEASURES

The Company's realized oil price per barrel is calculated by dividing oil revenue by the Company's total production for the respective periods presented. Net operating revenue per barrel is calculated by dividing oil revenue less operating costs by total production for the respective periods presented. Net revenue (loss) from operations per barrel is calculated by subtracting depletion from net operating revenue and dividing by total production for the respective periods presented. The Company believes oil revenue per barrel, net operating revenue per barrel and net revenue (loss) from operations per barrel are important to investors to evaluate operating results and the Company's ability to generate cash. Each of the components used in these calculations can be reconciled directly to the consolidated statement of loss and comprehensive loss. The calculations of oil revenue per barrel, net operating revenue per barrel and net revenue (loss) from operations per barrel may differ from similar calculations of other companies in the oil and gas industry, thereby limiting its usefulness as a comparative measure.

ITEM 8: FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Table of Contents

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

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

We have audited the accompanying consolidated financial statements of Ivanhoe Energy Inc. and subsidiaries (the “Company”), which comprise the consolidated statements of financial position as at December 31, 2011, December 31, 2010 and January 1, 2010, and the consolidated statements of loss and comprehensive loss, statements of changes in equity, and statements of cash flows for the years ended December 31, 2011 and December 31, 2010, and the notes to the consolidated financial statements.

Management’s Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor’s Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Ivanhoe Energy Inc. and subsidiaries as at December 31, 2011, December 31, 2010 and January 1, 2010 and their financial performance and cash flows for the years ended December 31, 2011 and December 31, 2010 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Emphasis of Matter

Without qualifying our opinion, we draw attention to Note 1 in the consolidated financial statements which indicates that as of December 31, 2011, the Company had an accumulated deficit of $298.5 million, and working capital of $30.7 million, excluding assets held for sale and derivative financial liabilities, and during the year ended December

31, 2011, cash used in operating activities was $26.2 million and the Company expects to incur further losses in the development of its business. These conditions, along with other matters as set forth in Note 1, indicate the existence of a material uncertainty that casts substantial doubt about the Company's ability to continue as a going concern.

Other Matter

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, 2011, based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 15, 2012 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche
LLP
Independent Registered Chartered Accountants

March 15, 2012
Calgary, Canada

Table of Contents

PART I FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

IVANHOE ENERGY INC.
Consolidated Statements of Financial Position

(US$000s)	Note	December 31, 2011	December 31, 2010	January 1, 2010
Assets				
Current Assets				
Cash and cash equivalents	5	16,890	68,317	24,362
Restricted cash	6	20,500	–	–
Accounts receivable	11	7,859	6,359	5,021
Note receivable		227	264	225
Prepaid and other		1,411	2,859	771
Assets held for sale	7	41,902	–	–
		88,789	77,799	30,379
Intangible	8	273,986	273,568	207,750
Property, plant and equipment	9	46,979	40,618	41,983
Long term receivables	11	3,956	2,433	839
		413,710	394,418	280,951
Liabilities and Shareholders' Equity				
Current Liabilities				
Accounts payable and accrued liabilities		15,548	21,482	10,779
Debt	10	–	39,832	–
Derivative instruments	11, 12	183	8,447	13,023
Income taxes	14	641	–	530
Decommissioning costs		–	–	753
		16,372	69,761	25,085
Long term debt	10	61,892	–	36,934
Long term derivative instruments	11, 12	1,617	–	–
Long term provisions	13	1,919	3,008	2,187
Deferred income taxes	14	17,773	21,165	22,336
		99,573	93,934	86,542
Shareholders' Equity				
Share capital	16	586,108	550,562	422,322
Contributed surplus	16	26,524	23,141	18,724
Accumulated deficit		(298,495)	(273,219)	(246,637)
		314,137	300,484	194,409
		413,710	394,418	280,951

Nature of operations and going concern	1

(See accompanying Notes to the Consolidated Financial Statements)

36

Table of Contents

IVANHOE ENERGY INC.
Consolidated Statements of Loss and Comprehensive Loss

(US$000s, except share and per share amounts)	Note	Year Ended December 31, 2011	2010
Revenue			
Oil		37,403	21,720
Interest		576	208
		37,979	21,928
Expenses and other			
Operating	21	20,131	13,625
Exploration and evaluation	8	2,774	8,471
General and administrative		48,449	42,807
Depletion and depreciation	9	8,030	6,524
Foreign currency exchange gain		(355)	(3,325)
Derivative instruments gain	11	(12,965)	(18,571)
Interest		361	24
Gain on derecognition of long term provision	13	(1,900)	–
		64,525	49,555
Loss before income taxes		(26,546)	(27,627)
(Provision for) recovery of income taxes			
Current	14	(2,122)	(126)
Deferred	14	3,392	1,171
		1,270	1,045
Net loss and comprehensive loss		(25,276)	(26,582)
Net loss per common share, basic and diluted		(0.07)	(0.08)
Weighted average number of common shares			
Basic and diluted (000s)		342,678	327,442

(See accompanying Notes to the Consolidated Financial Statements)

Table of Contents

IVANHOE ENERGY INC.
Consolidated Statements of Changes in Equity

(US$000s, except share amounts)	Note	Share Capital Shares (000s)	Share Capital Amount	Contributed Surplus	Accumulated Deficit	Total
Balance January 1, 2010		282,559	422,322	18,724	(246,637)	194,409
Net loss and comprehensive loss		–	–	–	(26,582)	(26,582)
Shares issued for cash, net of share issue costs	16	50,000	121,697	–	–	121,697
Shares issued for services		280	799	–	–	799
Exercise of stock options	17	1,524	5,735	(3,940)	–	1,795
Exercise of purchase warrants		2	9	–	–	9
Share-based compensation expense	17	–	–	8,357	–	8,357
Balance December 31, 2010		334,365	550,562	23,141	(273,219)	300,484

(US$000s, except share amounts)	Note	Share Capital Shares (000s)	Share Capital Amount	Contributed Surplus	Accumulated Deficit	Total
Balance January 1, 2011		334,365	550,562	23,141	(273,219)	300,484
Net loss and comprehensive loss		–	–	–	(25,276)	(25,276)
Shares issued for services		169	335	–	–	335
Exercise of stock options	17	985	4,164	(2,231)	–	1,933
Exercise of purchase warrants	16	8,620	31,047	–	–	31,047
Share-based compensation expense	17	–	–	5,614	–	5,614
Balance December 31, 2011		344,139	586,108	26,524	(298,495)	314,137

(See accompanying Notes to the Consolidated Financial Statements)

38

Table of Contents

IVANHOE ENERGY INC.
Consolidated Statements of Cash Flows

(US$000s)	Note	Year Ended December 31, 2011	2010
Operating Activities			
Net loss		(25,276)	(26,582)
Adjustments to reconcile net loss to cash from operating activities			
Depletion and depreciation	9	8,030	6,524
Exploration and evaluation expense	8	–	3,537
Share-based compensation expense	17	5,883	7,557
Unrealized foreign currency exchange gain		(446)	(3,523)
Unrealized derivative instruments gain	11	(12,965)	(18,571)
Current income tax expense	14	2,122	126
Deferred income tax recovery	14	(3,392)	(1,171)
Interest expense		361	24
Finance costs		269	–
Gain on derecognition of long term provision	13	(1,900)	–
Other		50	(38)
Current income tax paid		(1,481)	(656)
Interest paid		(333)	–
Decommissioning costs settled		–	(179)
Changes in non-cash working capital items	22	2,833	1,662
Net cash used in operating activities		(26,245)	(31,290)
Investing Activities			
Intangible expenditures		(37,390)	(65,347)
Property, plant and equipment expenditures		(13,670)	(5,633)
Restricted cash		(20,500)	–
Long term receivables		(1,536)	(1,558)
Interest paid		(4,011)	(1,610)
Changes in non-cash working capital items	22	(8,315)	5,464
Net cash used in investing activities		(85,422)	(68,684)
Financing Activities			
Shares and warrants issued on private placements, net of share issue costs	16	–	135,696
Convertible debentures issued, net of issue costs	10	72,914	–
Repayment of convertible note	10	(41,421)	–
Proceeds from exercise of options and warrants	12, 17	29,873	2,600
Changes in non-cash working capital items	22	57	(10)
Net cash provided by financing activities		61,423	138,286
Foreign exchange gain (loss) on cash and cash equivalents held in a foreign currency		(1,183)	5,643
Increase (decrease) in cash and cash equivalents, for the year		(51,427)	43,955
Cash and cash equivalents, beginning of year		68,317	24,362
Cash and cash equivalents, end of year		16,890	68,317

(See accompanying Notes to the Consolidated Financial Statements)

Table of Contents

IVANHOE ENERGY INC.
Notes to the Consolidated Financial Statements
(tabular amounts in US$000s, except share and per share amounts)

1. NATURE OF OPERATIONS AND GOING CONCERN

Ivanhoe Energy Inc. (the "Company" or "Ivanhoe") is a publicly listed company incorporated in Canada, with limited liability under the legislation of the Yukon. Ivanhoe's common shares are listed on the Toronto Stock Exchange ("TSX") and the NASDAQ Stock Market ("NASDAQ"). The head office, principal address and registered and records office of the Company are located at 999 Canada Place, Suite 654, Vancouver, British Columbia, Canada, V6C 3E1.

Ivanhoe is an independent international heavy oil development and production company focused on pursuing long term growth in its reserves and production. Ivanhoe plans to utilize advanced technologies, such as its HTL™ technology, that are designed to improve recovery of heavy oil resources. In addition, the Company seeks to expand its reserve base and production through conventional exploration and production of oil and gas.

The December 31, 2011 audited consolidated financial statements ("Financial Statements") have been prepared using International Financial Reporting Standards ("IFRS") applicable to a going concern, which contemplates the realization of assets and settlement of liabilities in the normal course of business as they become due and assumes that Ivanhoe will be able to meet its obligations and continue operations for at least its next fiscal year. Realization values may be substantially different from carrying values as shown and these Financial Statements do not give effect to adjustments that may be necessary to the carrying values and classification of assets and liabilities should the Company be unable to continue as a going concern. Such adjustments could be material.

At December 31, 2011, Ivanhoe had an accumulated deficit of $298.5 million and working capital of $30.7 million, excluding assets held for sale and derivative financial liabilities. In the year ended December 31, 2011, cash used in operating activities was $26.2 million and the Company expects to incur further losses in the development of its business. Continuing as a going concern is dependent upon attaining future profitable operations to repay liabilities arising in the normal course of operations and accessing additional capital to develop the Company's properties. Ivanhoe intends to finance its future funding requirements through a combination of strategic investors and/or public and private debt and equity markets, either at a parent company level or at the project level, and through the sale of interests in existing oil and gas properties. There is no assurance that the Company will be able to obtain such financing, or obtain it on favorable terms. Without access to additional financing or other cash generating activities in 2012, there is material uncertainty that casts substantial doubt that the Company will be able to continue as a going concern.

The December 31, 2011 Financial Statements were approved by the Board of Directors and authorized for issue on March 1, 2012.

The Financial Statements are presented in US dollars and all values are rounded to the nearest thousand dollars except where otherwise indicated.

2. BASIS OF PRESENTATION

2.1 Statement of Compliance

The Financial Statements have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB"). The Financial Statements are not subject to qualification relating to the application of IFRS as issued by the IASB.

2.2 Basis of Presentation

The Company adopted IFRS on January 1, 2011, with a transition date of January 1, 2010. Comparative financial information has been restated to comply with IFRS as detailed in Note 27.

The Financial Statements have been prepared on an historical cost basis, except derivative instruments, which are measured at fair value as explained in accounting policies set out in Note 3.

Table of Contents

3. SIGNIFICANT ACCOUNTING POLICIES

3.1 Basis of Consolidation

The Financial Statements incorporate the financial statements of the Company, its subsidiaries, all of which are wholly owned, and special purpose entities that are controlled by the Company. All intercompany balances, transactions, revenue and expenses are eliminated on consolidation. The consolidated accounts are prepared using uniform accounting policies.

Certain of the Company’s exploration and development activities are conducted jointly with others through jointly controlled operations. The Financial Statements reflect only the Company’s proportionate interest in such activities.

3.2 Foreign Currency Translation

The Company and its subsidiaries’ reporting currency and the functional currency of its operations is the US dollar as this is the principal currency of the economic environments in which they operate.

Monetary assets and liabilities denominated in foreign currencies are translated at the exchange rate in effect on the date of the statement of financial position. Non-monetary assets and liabilities, as well as operating transactions, are translated at the exchange rate prevailing at the time of the transaction. Translation gains and losses are reflected in earnings.

3.3 Cash and Cash Equivalents

Cash and cash equivalents includes cash on hand, deposits at banks, restricted cash and short term highly liquid investments with original maturities of three months or less.

3.4 Restricted Cash

Restricted cash balances that are not expected to be released within three months or less are reported separately from restricted cash balances included in cash and cash equivalents.

3.5 Intangible Assets

i. Exploration and Evaluation Assets

Costs of exploring for, and evaluating, oil and gas properties are initially capitalized as intangible exploration and evaluation assets (“E&E assets”). Costs may include license fees, technical studies, seismic programs, exploratory drilling and directly attributable general and administrative costs. Interest on borrowings incurred to finance qualifying E&E assets is capitalized.

If E&E assets result in sufficient proved reserves to justify commercial production and technical feasibility can be established, the assets will be tested for impairment and reclassified as property, plant and equipment (“PP&E”). If E&E assets result in sufficient reserves to justify commercial production, but those reserves cannot be classified as proved, the assets will be tested for impairment and continue to be capitalized as intangible assets as long as progress is being made to assess the reserves and economic viability of the well and/or related project. If sufficient reserves cannot be established, the corresponding E&E assets are charged to exploration and evaluation expense (“E&E expense”).

E&E assets which may be attributable to a broad exploration area, such as license fees, technical studies or seismic programs, will be reclassified to PP&E or charged to E&E expense to best reflect the nature of the assets. Costs incurred prior to establishing the legal right to explore an area are charged to E&E expense as incurred.

ii. Technology Assets

The Company's HTL™ technology license ("Technology Assets") consist of an exclusive, irrevocable license to deploy its HTL™ technology. Technology Assets are measured at cost and classified as an intangible asset. Amortization of the Technology Assets will commence when the technology is available for use in field operations.

iii. Derecognition

An intangible asset is derecognized on disposal or when no future economic benefits are expected from use or disposal. Gains or losses arising from derecognition are measured as the difference between the net disposal proceeds and the carrying amount of the asset and are recognized in profit or loss when the intangible asset is derecognized.

Table of Contents

3.6 Property, Plant and Equipment

i. Oil and Gas Property and Equipment

PP&E is reported at cost less accumulated depletion, depreciation and accumulated impairment losses. PP&E may include the purchase price, reclassified E&E assets, any costs directly attributable to bringing the asset to the location and condition necessary for its intended use and decommissioning costs. Interest on borrowings incurred to finance qualifying PP&E is capitalized until the asset is capable of fulfilling its intended use.

PP&E is depleted using the unit-of-production method based on proved plus probable reserves, taking into account associated future development costs. For purposes of these calculations, production and reserves of natural gas are converted to barrels on an energy equivalent basis at a ratio of six thousand cubic feet of natural gas for one barrel of oil. Depletion rates are updated annually unless there is a material change in circumstances, in which case they would be updated more frequently.

ii. Other Assets

Furniture and equipment are depreciated on a straight-line basis over the estimated useful life of the respective assets, ranging from three to five years. The Feedstock Test Facility ("FTF") is depreciated over its expected economic life of 20 years.

3.7 Assets Held for Sale

Non-current assets are classified as held for sale if their carrying amounts will be recovered through a sale transaction rather than through continuing use. This classification is required when the sale is highly probable and the asset is available for immediate sale in its present condition. For the sale to be highly probable, management must be committed to a plan to sell the asset, the asset must be actively marketed for sale at a price that is reasonable in relation to its fair value and the sale is expected to be completed within one year.

Non-current assets classified as held for sale are measured at the lower of the carrying amount and fair value less costs to sell, with impairments recognized in the consolidated statement of loss in the period measured. Non-current assets held for sale are presented in current assets within the consolidated statement of financial position. Assets held for sale are not depleted, depreciated or amortized.

3.8 Impairment

The Company periodically assesses tangible and intangible assets or groups of assets for impairment annually or earlier whenever events or changes in circumstances indicate the carrying value of an asset may not be recoverable. Individual assets are grouped into cash generating units for impairment purposes at the lowest level at which there are identifiable cash inflows that are largely independent of the cash inflows of other groups of assets.

If indicators of impairment exist, the recoverable amount of the asset group is estimated. An asset group's recoverable amount is the higher of its fair value less costs to sell and its value in use. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and risks specific to the asset. Where the carrying amount of an asset group exceeds its recoverable amount, the asset group is considered impaired and is written down to its recoverable amount.

Previously recognized impairment losses are reversed if there has been a change in the estimates used to determine the asset group's recoverable amount. If that is the case, the carrying amount of the asset group is increased to its revised recoverable amount which cannot exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized in prior periods. Such a reversal is recognized in earnings. Subsequent to a reversal of impairment, the depletion or depreciation expense is adjusted in future periods to allocate the asset group's revised carrying amount, less any residual value, over its remaining useful life.

3.9 Decommissioning Provision

The Company recognizes a provision for decommissioning costs when it has an obligation to dismantle and remove its PP&E or restore the site on which it is located. The provision is estimated as the present value of the expected future expenditures, determined in accordance with local conditions and requirements, discounted at a risk-free rate. A corresponding amount is added to the carrying value of the related asset and is amortized as an expense over the economic life of the asset. The carrying amount of the provision is increased for the passage of time and adjusted for changes to the current market-based discount rate, amount and/or timing of the underlying cash flows needed to settle the obligation. Actual decommissioning costs incurred reduce the obligation. Any difference between the recorded decommissioning provision and the actual costs incurred is recorded as a gain or loss in the settlement period.

3.10 Provisions and Contingencies

Provisions are recognized when the Company has a present obligation (legal or constructive) that has arisen as a result of a past event and it is probable that a future outflow of resources will be required to settle the obligation, provided that a reliable estimate can be made of the amount of the obligation.

Provisions are measured at the present value of the expenditures expected to be required to settle the obligation using a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the obligation. When it is appropriate to discount a provision, the increase in the provision due to passage of time is recognized as interest expense.

3.11 Financial Assets

Financial assets are classified as i) loans and receivables, ii) available-for-sale, iii) financial assets at fair value through profit or loss, or iv) as held-to-maturity. Ivanhoe determines the classification of its financial assets upon initial recognition. Financial assets are recognized initially at fair value and subsequent measurement depends upon their classification.

i. Loans and Receivables

Loans and receivables are non-derivative financial assets, with fixed or determinable payments, that are not quoted in an active market. Such assets are carried at amortized cost using the effective interest method if the time value of money is significant. Gains and losses are recognized in income when the loans and receivables are derecognized or impaired, as well as through the amortization process. The Company's cash and cash equivalents, restricted cash, accounts receivable, note receivable and long term receivables are classified as loans and receivables.

ii. Available-for-Sale

Available-for-sale financial assets are measured at fair value, with gains or losses recognized within other comprehensive income. Accumulated changes in fair value are recorded as a separate component of equity until the investment is derecognized or impaired. The Company does not currently have any financial assets classified as available for sale.

iii. Financial Assets at Fair Value Through Profit or Loss

Financial assets are classified as fair value through profit or loss ("FVTPL") when the financial asset is held for trading or it is designated as FVTPL. Financial assets classified as FVTPL are measured at fair value with unrealized gains and losses recognized through earnings. The Company currently does not have any financial assets classified at FVTPL.

iv. Held-to-Maturity

Held-to-maturity investments are non-derivative financial assets with fixed or determinable payments and fixed maturity dates that the Company has the intent and ability to hold to maturity. These investments are recognized on a trade date basis and are subsequently measured at amortized cost using the effective interest method. The Company does not currently have any financial assets classified as held-to-maturity.

v. Impairment

Financial assets, other than those at FVTPL, are assessed for indicators of impairment annually. Financial assets are impaired when there is evidence that the estimated future cash flows of the investment have been impacted. For financial assets carried at amortized cost, the amount of the impairment is the difference between the asset's carrying amount and the present value of the estimated future cash flows, discounted at the financial asset's original effective interest rate.

The carrying amount of all financial assets, excluding accounts receivables, is directly reduced by the impairment loss. The carrying amount of accounts receivable is reduced through the use of an allowance account. Subsequent recoveries of amounts previously written off are recorded against the allowance account. Changes in the carrying amount of the allowance account are recognized in earnings.

With the exception of available-for-sale equity instruments, which are revalued through other comprehensive income, if, in a subsequent period, the amount of the impairment loss decreases and the decrease relates to an event occurring after the impairment was recognized, the previously recognized impairment loss is reversed through earnings. On the date of the impairment reversal, the carrying amount of the financial asset cannot exceed its amortized cost had it not been impaired.

vi. Derecognition

Financial assets are derecognized when the rights to receive cash flows from the investments have expired, or have been transferred, and the Company has transferred substantially all risks and rewards of ownership.

3.12 Financial Liabilities

Financial liabilities are classified as i) financial liabilities at FVTPL or ii) as other financial liabilities measured at amortized cost. Ivanhoe determines the classification of its financial liabilities upon initial recognition. The measurement of financial liabilities depends on their classification.

i. Financial Liabilities at Fair Value Through Profit or Loss

Financial liabilities classified as FVTPL include financial liabilities held for trading and financial liabilities designated upon initial recognition as FVTPL. Derivatives, including bifurcated embedded derivatives, are also classified as FVTPL. Changes in the fair value of financial liabilities classified as FVTPL are recognized through earnings. The Company’s derivative instruments are classified as financial liabilities at FVTPL.

ii. Other Financial Liabilities

Financial liabilities classified as other financial liabilities are initially recognized at fair value less directly attributable transaction costs. After initial recognition, other financial liabilities are measured at amortized cost using the effective interest method. The Company’s accounts payable and accrued liabilities, debt, long term obligation and long term accrued liabilities are classified as other financial liabilities.

3.13 Oil and Gas Revenue

Sales of oil and gas production are recognized when the risks and rewards of ownership pass to the buyer, collection is reasonably assured and the price is reasonably determinable. Oil and gas revenue represents the Company’s share and is recorded net of royalty payments to governments and other mineral interest owners.

3.14 Income Tax

Income tax expense represents the sum of tax currently payable and deferred tax.

i. Current income tax

Income tax assets and liabilities are measured at the amount expected to be recovered from, or paid to, the taxation authorities. The tax rates and tax laws used to compute the amount are those that are enacted or substantively enacted by the date of the statement of financial position.

ii. Deferred income tax

Using the liability method, deferred income tax is provided for on taxable and deductible differences between the tax basis of assets and liabilities in comparison to their carrying amounts for financial reporting purposes.

Deferred income tax liabilities are recognized for all taxable temporary differences, except:

— where the deferred income tax liability arises from the initial recognition of goodwill or of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither accounting profit nor taxable profit or loss; and

— in respect of taxable temporary differences associated with investments in subsidiaries, jointly controlled entities and associates, where the timing of the reversal of the temporary differences can be controlled and it is probable that the temporary differences will not reverse in the foreseeable future.

Table of Contents

Deferred income tax assets are recognized for all deductible temporary differences, carry-forward of unused tax credits and unused tax losses, to the extent that it is probable that taxable profit will be available against which the deductible temporary differences and the carry-forward of unused tax credits and unused tax losses can be utilized except:

— where the deferred income tax asset relating to the deductible temporary difference arises from the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss; and

— in respect of deductible temporary differences associated with investments in subsidiaries, jointly controlled entities and associates, deferred tax assets are recognized only to the extent that it is probable that the temporary differences will reverse in the foreseeable future and taxable profit will be available against which the temporary differences can be utilized.

The carrying amount of deferred tax assets is reviewed at each date of the statement of financial position and reduced to the extent that it is no longer probable that sufficient taxable profit will be available to allow all, or part, of the deferred income tax asset to be utilized. Unrecognized deferred income tax assets are reassessed at each date of the statement of financial position and are recognized to the extent that it has become probable that future taxable profit will allow the deferred tax asset to be recovered.

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply to the year when the asset is expected to be realized or the liability is expected to be settled, based on tax rates (and tax laws) that have been enacted or substantively enacted at the date of the statement of financial position.

Deferred income tax relating to items recognized directly in equity is recognized in equity and not in earnings.

Deferred income tax assets and deferred income tax liabilities are offset if, and only if, a legally enforceable right exists to set off current tax assets against current tax liabilities and the deferred tax assets and liabilities relate to income taxes levied by the same taxation authority on either the same taxable entity or different taxable entities which intend to either settle current tax liabilities and assets on a net basis, or to realize the assets and settle the liabilities simultaneously, in each future period in which significant amounts of deferred tax assets or liabilities are expected to be settled or recovered.

3.15 Borrowing Costs

For qualifying assets, which take a substantial period of time to get ready for intended use, interest on borrowings incurred to finance E&E assets and PP&E is capitalized until the asset is capable of fulfilling its intended use. Capitalized borrowing costs cannot exceed the actual interest and financing costs incurred. All other interest and financing costs are recognized in earnings in the period in which they are incurred.

3.16 Share-Based Payments

Equity settled share-based payments in the form of stock options granted to directors, employees and those providing similar services to Ivanhoe and its subsidiaries, are measured at fair value on the grant date and expensed on a graded basis over the vesting period of each annual installment. The cumulative expense for equity settled transactions incorporates a forfeiture rate to reflect the Company's best estimate of the number of equity instruments that will ultimately vest.

Cash settled share-based payments, such as the restricted share units granted to eligible employees, are measured at fair value on the grant date and are re-valued at each subsequent reporting period until vested. The awards are expensed on a graded basis over the vesting period of each annual installment. A forfeiture rate is applied in the same manner as described for equity settled awards. No expense is recognized for awards that do not ultimately vest.

Shares issued from the stock bonus plan are measured at fair value on the grant date.

3.17 Income or Loss per Common Share

Basic net income or loss per common share is computed by dividing net income by the weighted average number of common shares outstanding during the period. Diluted net income per common share amounts are calculated based on net income divided by dilutive common shares. Dilutive common shares are arrived at by adding common shares issuable on conversion of options or purchase warrants to weighted average common shares, assuming that proceeds received from the exercise of in-the-money stock options and purchase warrants are used to purchase common shares at the average market price; dilution from the Company’s convertible debt is considered using the “if converted” method.

Table of Contents

3.18 Standards and Interpretations Issued But Not Yet Adopted

The Company has reviewed new and revised accounting pronouncements listed below, that have been issued, but are not yet effective. The Company has not yet evaluated the impact of these changes on its financial statements.

i. IFRS 9 Financial Instruments ("IFRS 9")

IFRS 9 was issued in November 2009 and is intended to replace IAS 39, "Financial Instruments: Recognition and Measurement" ("IAS 39") in phases. IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, as opposed to the multiple rules in IAS 39. The approach is based on how an entity manages its financial instruments given its business model and the contractual cash flow characteristics of the financial assets. The standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39. IFRS 9 is effective for reporting periods beginning on or after January 1, 2015.

ii. IFRS 10 Consolidated Financial Statements ("IFRS 10")

IFRS 10 was issued in May 2011 and sets a single basis for consolidation, that being control of an entity. IFRS 10 replaces portions of IAS 27, "Consolidated and Separate Financial Statements" and Standing Interpretations Committee 12, "Special Purpose Entities" that provide a single model on how entities should prepare consolidated financial statements. This standard is effective for reporting periods on or after January 1, 2013, with earlier adoption permitted.

iii. IFRS 11 Joint Arrangements ("IFRS 11")

IFRS 11, issued in May 2011, establishes principles for financial reporting by entities involved in a joint arrangement and distinguishes between joint operations and joint ventures. IFRS 11 supersedes the current IAS 31, "Interests in Joint Ventures" and Standing Interpretations Committee 13, "Jointly Controlled Entities-Non Monetary Contributions by Venturers" and is effective for reporting periods beginning on or after January 1, 2013, with earlier adoption permitted.

iv. IFRS 12 Disclosure of Interests in Other Entities ("IFRS 12")

IFRS 12, issued in May 2011, establishes a single set of disclosure objectives, and requires minimum disclosures designed to meet those objectives, regarding interests in subsidiaries, joint arrangements, associates or unconsolidated structured entities. IFRS 12 is intended to combine the disclosure requirements on interests in other entities currently located throughout different standards. This standard is effective for reporting periods on or after January 1, 2013, with earlier adoption permitted.

v. IFRS 13 Fair Value Measurements ("IFRS 13")

IFRS 13, issued in May 2011, defines fair value, sets out a single IFRS framework for measuring fair value and requires disclosures about fair value measurements. IFRS 13 applies to IFRS that require or permit fair value measurements or related disclosures, except in specified circumstances. IFRS 13 is to be applied for reporting periods beginning on or after January 1, 2013, with earlier adoption permitted.

vi. IAS 28 Investments in Associates and Joint Ventures ("IAS 28")

IAS 28 was amended in 2011 which prescribes the accounting for investments in associates and sets out the requirements for the application of the equity method when accounting for investments in associates and joint ventures. IAS 28 is effective for reporting periods beginning on or after January 1, 2013, with earlier adoption permitted.

There are no other standards or interpretations in issue, but not yet adopted, that are anticipated to have a material effect on the reported loss or net assets of the Company.

4. CRITICAL ACCOUNTING JUDGMENTS AND KEY SOURCES OF ESTIMATION UNCERTAINITY

The preparation of financial statements in accordance with IFRS requires management to make estimates and assumptions in certain circumstances that affect reported amounts. The most sensitive estimates affecting the Financial Statements are in the areas set out below. Actual results may differ from these estimates.

Table of Contents

4.1 Critical Judgments in Applying Accounting Policies

i. E&E Assets

Management must determine if E&E assets, which have not yet resulted in the discovery of proved reserves, should continue to be capitalized or charged to E&E expense. When making this determination, management considers factors such as the Company's drilling results, planned exploration and development activities, the financial capacity of the Company to further develop the property, the ability to use the Company's HTL™ technology in certain projects, lease expiries, market conditions and technical recommendations from its exploration staff.

ii. Impairment

a. Property, Plant and Equipment

Ivanhoe annually evaluates its oil and gas assets or groups of assets for impairment or whenever events or changes in circumstances indicate the carrying value may not be recoverable. Among other things, an impairment may be triggered by falling oil and gas prices, a significant negative revision to reserve estimates, the inability to use the Company's HTL™ technology in certain projects, changes in capital costs or the inability to raise sufficient financial resources to further develop the property. Cash flow estimates for the Company's impairment assessments require significant assumptions about future prices and costs, production, reserves, discount rates and potential benefits from the application of its HTL™ technology.

b. Intangible Technology Assets

Ivanhoe annually reviews the intangible Technology Assets for impairment or if an adverse event or change occurs. Indicators of adverse events could include HTL™ patent expiries, advancements of new technologies or the inability to successfully commercialize the HTL™ technology. The impairment of the Technology Assets requires management to make assumptions about competitive technological developments, the successful commercialization of the Company's HTL™ technology and future cash flows from the HTL™ technology.

4.2 Key Sources of Estimation Uncertainty

i. Oil and Gas Reserves

The process of estimating quantities of reserves is inherently uncertain and complex. It requires significant judgment 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 becomes available and as economic conditions impacting oil and gas prices and costs change. Such revisions could be upwards or downwards. Reserve estimates have a material impact on depletion and the Company's impairment evaluations, which in turn have a material impact on earnings.

The recoverable value of the Company's PP&E is calculated based on future net cash flows from proved plus probable reserves, discounted at a pre-tax rate that includes risks specific to the asset. A 1% increase in the discount rate and a 5% decrease in the forward pricing used in the calculation of cash flows from proved plus probable reserves as at December 31, 2011, would not impair the Company's development projects.

ii. HTL™ Technology

Future cash flows from HTL™ technology is a key source of estimation uncertainty as it requires management to make assumptions about the successful commercialization of the HTL™ technology and competitive technological developments. Success in commercializing the HTL™ technology in the oil and gas industry depends on the Company's ability to economically design, construct and operate commercial-scale plants and a variety of other factors. Ivanhoe expects that technological advances in the processes and procedures for upgrading heavy oil and bitumen into lighter, less viscous products will continue to progress. It is possible that those advances could cause the HTL™ technology to become uncompetitive or obsolete.

iii. Option Pricing Models

The Company uses the Black-Scholes option pricing model to measure the fair value of stock options and equity settled Restricted Share Units ("RSUs") on the date of grant. Determining the fair value of stock-based awards on the grant date requires judgment, including estimating the expected life of the award, the expected volatility of the Company's common shares and expected dividends. In addition, judgment is required to estimate the number of awards that are expected to be forfeited. Changes in assumptions can materially affect the estimated fair value, and therefore, the existing models do not necessarily provide precise measures of fair value.

iv. Convertible Note and Convertible Debentures

In connection with the acquisition of the Tamarack leases in July 2008 from Talisman Energy Canada ("Talisman"), the Company issued a Cdn$40.0 million convertible promissory note (the "Convertible Note"). The Canadian dollar denominated debt is considered to contain an embedded derivative since the functional currency of the Company is the US dollar. As a result, the Convertible Note was bifurcated into debt and the convertible option, which was recognized at fair value using the Black-Scholes valuation method. The Black-Scholes valuation method requires the input of highly subjective assumptions regarding expected volatility of the Company's share price and risk-free interest rate, and is therefore considered to be a crucial accounting estimate.

On June 9, 2011, the Company issued Cdn$73.3 million of 5.75% convertible unsecured subordinated debentures ("Convertible Debentures"). The Canadian dollar denominated debt is considered to contain an embedded derivative since the functional currency of the Company is the US dollar. As a result, the Convertible Debentures were bifurcated into debt and the convertible option, which was recognized at fair value using the Black-Scholes valuation method. The Black-Scholes valuation method requires the input of highly subjective assumptions regarding expected volatility of the Company's share price and risk-free interest rate, and is therefore considered to be a crucial accounting estimate.

v. Deferred Income Taxes

Ivanhoe operates in a specialized industry in several tax jurisdictions. As a result, income is subject to various rates of taxation. The breadth of the Company's operations and the global complexity of tax regulations require assessments of uncertainties and judgments in estimating the taxes it will ultimately pay. The final taxes paid are dependent upon many factors, including negotiations with taxing authorities in various jurisdictions, uncertain tax positions and resolution of disputes arising from federal, provincial, state and local tax audits. The resolution of these uncertainties and the associated final taxes may result in adjustments to the Company's tax assets and tax liabilities.

5. CASH AND CASH EQUIVALENTS

	December 31, 2011	December 31, 2010	January 1, 2010
Cash at banks and on hand	16,867	10,147	6,797
Term deposits	–	57,670	–
Money market accounts	–	–	14,715
Restricted cash	23	500	2,850
	16,890	68,317	24,362

Restricted cash includes funds pledged as security for a letter of credit with a short term maturity.

6. RESTRICTED CASH

	December 31, 2011	December 31, 2010	January 1, 2010

Ecuador performance bond	500	–	–
Zitong performance bond	20,000	–	–
	20,500	–	–

In December 2011, Ivanhoe was required to post a $20.0 million performance bond as part of the completion and signing of a supplementary agreement to the Contract for Exploration, Development and Production in Zitong Block, Sichaun Basin with China National Petroleum Corporation ("CNPC") for the Zitong block ("Supplementary Agreement").

Table of Contents

7. ASSETS HELD FOR SALE

Sunwing Zitong Energy (“SZE”), a wholly owned subsidiary of the Company, signed a binding Memorandum of Understanding to assign 100% of its participating interest in the Zitong Production Sharing Contract (“PSC”) to Shell. The transaction is subject to government approvals and other prescribed conditions. There is no assurance that this transaction will close as described.

In exchange for SZE’s interest in the Zitong block, Ivanhoe will receive a cash payment of up to $85.0 million as reimbursement for past qualified and recoverable costs incurred. In addition, Ivanhoe will receive a further cash payment upon closing of up to $75.0 million, contingent on the timing of the receipt of full government approvals and third-party consents and waivers for the transaction. Should SZE receive government approval for the transaction, Shell will become liable for the performance bond disclosed in Note 6, resulting in a release of restricted cash back to the Company.

The carrying value of the Zitong asset, which is comprised of E&E expenditures, was $41.9 million at December 31, 2011; capital expenditures were previously reported in the Asia segment.

8. INTANGIBLE ASSETS

	Exploration and Evaluation Assets					
	Asia	Canada	Latin America	Total	HTL™ Technology	Total Intangible Assets
Cost						
Balance January 1, 2010	14,411	94,431	6,755	115,597	92,153	207,750
Additions	27,261	29,324	17,704	74,289	–	74,289
Exploration and evaluation expense	(3,537)	–	(4,934)	(8,471)	–	(8,471)
Balance December 31, 2010	38,135	123,755	19,525	181,415	92,153	273,568
Additions	23,094	9,697	12,303	45,094	–	45,094
Exploration and evaluation expense	(2,124)	–	(650)	(2,774)	–	(2,774)
Assets reclassified as held for sale	(41,902)	–	–	(41,902)	–	(41,902)
Balance December 31, 2011	17,203	133,452	31,178	181,833	92,153	273,986

Amortization of the HTL™ technology has not commenced and its carrying value had not been impaired since it was acquired in 2005.

Intangible assets within the Asia segment exclude a 10% partner working interest in the Zitong block.

In the year ended December 31, 2011, $2.1 million (December 31, 2010 – $2.1 million) of employee benefits directly attributable to E&E assets were capitalized. In addition, in the year ended December 31, 2011, $0.3 million (December 31, 2010 – $0.8 million) related to share-based compensation costs were capitalized to E&E assets.

Table of Contents

9. PROPERTY, PLANT AND EQUIPMENT

	Oil and Gas Property and Equipment					
	Asia	Canada	Latin America	Total	Other Assets	Total PP&E
Cost						
Balance January 1, 2010	31,816	–	–	31,816	11,373	43,189
Additions	4,123	–	–	4,123	1,648	5,771
Disposals	–	–	–	–	(12)	(12)
Balance December 31, 2010	35,939	–	–	35,939	13,009	48,948
Additions	12,923	–	–	12,923	1,471	14,394
Disposals	–	–	–	–	(3)	(3)
Balance December 31, 2011	48,862	–	–	48,862	14,477	63,339
Accumulated Depletion and Depreciation						
Balance January 1, 2010	–	–	–	–	1,206	1,206
Depletion and depreciation	6,196	–	–	6,196	934	7,130
Disposals	–	–	–	–	(6)	(6)
Balance December 31, 2010	6,196	–	–	6,196	2,134	8,330
Depletion and depreciation	6,899	–	–	6,899	1,132	8,031
Disposals	–	–	–	–	(1)	(1)
Balance December 31, 2011	13,095	–	–	13,095	3,265	16,360
Net Book Value						
As at January 1, 2010	31,816	–	–	31,816	10,167	41,983
As at December 31, 2010	29,743	–	–	29,743	10,875	40,618
As at December 31, 2011	35,767	–	–	35,767	11,212	46,979

Oil and Gas Property and Equipment

In the year ended December 31, 2011, $0.1 million (December 31, 2010 – $0.1 million) of employee benefits directly attributable to PP&E were capitalized.

Other Assets

Other assets include the Company's FTF at the Southwest Research Institute in San Antonio, Texas, and general furniture and fixtures.

The Company performed a ceiling test calculation at December 31, 2011 and 2010 and January 1, 2010 to assess the recoverable value of its oil and gas properties. The present value of future net revenue from the Company's proved plus probable reserves exceeded the carrying value of the Company's oil and gas properties in 2011 and 2010 therefore no impairment was recorded.

Security

Should Ivanhoe receive government and other approvals necessary to develop the northern border of one of the Tamarack leases, the Company will be required to make a cash payment to Talisman of up to Cdn$15.0 million, as a conditional, final payment for the 2008 purchase transaction (Note 15). The contingent payment is secured by a first fixed charge and security interest in favor of Talisman, including over the oil sands leases, and a general security interest in all of the Company's present and after acquired property other than equity interests in the Company's subsidiaries (through which it holds assets in China, Mongolia and Ecuador and the HTL™ technology).

Table of Contents

10. DEBT

10.1 Convertible Note

	December 31, 2011	December 31, 2010	January 1, 2010
Convertible Note	–	40,217	38,005
Unamortized discount	–	(385)	(1,071)
Carrying amount	–	39,832	36,934

In connection with the acquisition of the Tamarack leases in July 2008, the Company issued the Cdn$40.0 million Convertible Note which matured on July 11, 2011 and was repaid in full.

In the year ended December 31, 2011, $1.5 million (December 31, 2010 – $2.5 million) of interest and accretion from the Convertible Note was capitalized to E&E assets. No interest from the Convertible Note was recorded as interest expense in the year ended December 31, 2011 (December 31, 2010 – nil).

10.2 Convertible Debentures

	December 31, 2011	December 31, 2010	January 1, 2010
Convertible Debentures	72,085	–	–
Unamortized financing costs and derivative instrument	(10,193)	–	–
Carrying amount	61,892	–	–

On June 9, 2011, the Company issued Cdn$73.3 million in 5.75% convertible unsecured subordinated debentures at a price of Cdn$1,000 per debenture. The issuance included a public offering of Cdn$50.0 million. The issuance also included Cdn$23.3 million in privately placed debentures with the same terms as the public offering.

The Convertible Debentures mature on June 30, 2016, pay interest semi-annually on June 30 and December 31 and are convertible at a price of Cdn$3.36 per share. They are redeemable after June 30, 2014 at Ivanhoe's option with the redemption price being settled using either cash or common shares.

The carrying amount of the Convertible Debentures at December 31, 2011 was $61.9 million. The Canadian dollar denominated debt is considered an embedded derivative since the functional currency of the Company is the US dollar and, as such, the option was bifurcated and recognized at fair value as a long term derivative liability as further described in Note 12.1. The remaining unamortized amount is composed of $8.6 million of unamortized value related to the derivative as well as $1.6 million in transaction costs. Transaction costs of $0.3 million were allocated to the derivative and charged to earnings at initial recognition.

Interest incurred on the Convertible Debentures was recorded as follows:

	Year ended December 31, 2011	Year ended December 31, 2010
Interest expense	333	–
Capitalized to E&E	2,878	–

Capitalized to PP&E	319	–
Total interest incurred on Convertible Debentures	3,530	–

51

Table of Contents

11. FINANCIAL INSTRUMENTS

11.1 Fair Value of Financial Instruments Measured at Amortized Cost

Except as detailed below, the fair value of the Company's financial instruments recognized at amortized cost approximates their carrying value due to the short term maturity of these instruments.

	December 31, 2011	December 31, 2010	January 1, 2010
Convertible Debentures			
Carrying amount	61,892	–	–
Fair value	51,901	–	–

The fair value of the liability component of the Convertible Debentures was estimated using the closing price of the publically traded debentures at December 31, 2011.

11.2 Financial Instruments Measured at Fair Value Through Profit and Loss

The Company classifies its financial instruments according to the fair value hierarchy outlined in IFRS 7, "Financial Instruments: Disclosures," as described below:

— Level 1 – using quoted prices in active markets for identical assets or liabilities.

— Level 2 – using inputs for the asset or liability, other than quoted prices, that are observable either directly (i.e. as prices) or indirectly (i.e. derived from prices).

— Level 3 – using inputs for the asset or liability that are not based on observable market data, such as prices based on internal models or other valuation methods.

The following table presents the Company's derivative instruments measured at FVTPL:

	Level 1		Level 2		Level 3	
	2006 Purchase Warrants	2009 & 2010 Purchase Warrants	2008 Convertible Component of Debt	2011 Convertible Component of Debentures	Subsidiary Option	Total Fair Value
Balance January 1, 2010	7,582	667	4,773	–	–	13,022
Issuance of purchase warrants	–	13,999	–	–	–	13,999
Exercise of purchase warrants	(3)	–	–	–	–	(3)
Derivative gains through profit and loss	(1,964)	(13,050)	(3,557)	–	–	(18,571)
Balance December 31, 2010	5,615	1,616	1,216	–	–	8,447
Issuance of convertible debentures	–	–	–	9,852	–	9,852
Exercise of options	(2)	(3,107)	–	–	–	(3,109)
Derivative (gains) losses through profit and loss	(3,267)	2,968	(1,216)	(7,810)	183	(9,142)

Expiration of purchase warrants through profit and loss	(2,346)	(1,477)	–	–	–	(3,823)
Foreign exchange gains	–	–	–	(425)	–	(425)
Balance December 31, 2011	–	–	–	1,617	183	1,800

The gain on derivative instruments of $13.0 million for the year ended December 31, 2011, (December 31, 2010 – $18.6 million) originated from the expiration and revaluation of derivative instruments measured at FVTPL.

Where the instrument is quoted in an active market, the movement in fair value due to credit risk is calculated as the change in fair value that is not attributable to changes in market risk. Where the instrument is not quoted in an active market, the fair value is calculated using a valuation technique that incorporates credit risk by discounting the cash flows using a credit-adjusted rate which reflects the level at which the Company could issue similar instruments at the reporting date. The amount of change in the fair value, during the period and cumulatively, of designated financial liabilities through FVTPL that is attributable to changes in credit risk is determined to be nil.

Table of Contents

11.3 Risks Arising from Financial Instruments

In the normal course of operations, the Company is exposed to market risks resulting from movements in commodity prices, foreign currency exchange rates and interest rates, which may result in fluctuations in the fair value or future cash flows of its financial instruments.

i. 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. Oil prices and quality differentials are influenced by worldwide factors such as Organization of Petroleum Exporting Countries (“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. However, no hedging contracts were in place in the year for 2011.

ii. Foreign Currency Exchange Rate Risk

Ivanhoe is exposed to foreign currency exchange rate risk as a result of incurring capital expenditures and operating costs in currencies other than the US dollar. A substantial portion of the Company’s activities are transacted in, or referenced to, US dollars, including oil sales in Asia, capital spending in Ecuador and ongoing FTF operations. A portion of transactions are in other currencies, such as Asia operating costs paid in Chinese renminbi, Canada exploration activities funded in Canadian dollars and the Convertible Debentures issued in Canadian dollars in 2011. The Company did not enter into any foreign currency derivatives in 2011. To help reduce the Company’s exposure to foreign currency exchange rate risk, the Company seeks to hold assets and liabilities denominated in the same currency when appropriate.

The following table shows the Company’s exposure to foreign currency exchange rate risk on its net loss and comprehensive loss for 2011, assuming reasonably possible changes in the relevant foreign currency. This analysis assumes all other variables remain constant.

(Increase) Decrease in Net Loss and Comprehensive Loss	Change From a 10% Increase or Weakening	Change From a 10% Decrease or Strengthening
Chinese renminbi	1,953	(2,387)
Canadian dollar	3,685	(3,711)

iii. Interest Rate Risk

Interest rate risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate as a result of changes in market interest rates. Interest rate risk arises from interest-bearing borrowings which have a variable interest rate. The Company’s net loss and comprehensive loss would not have been impacted by an interest rate change in 2011 as interest related to the Convertible Debentures is fixed and interest resulting from the Convertible Note was capitalized to E&E assets.

iv. Credit Risk

Ivanhoe is exposed to credit risk with respect to its cash and cash equivalents, restricted cash, accounts receivable, note receivable and long term receivables. The Company’s maximum exposure to credit risk at December 31, 2011, is represented by the carrying amount of these non-derivative financial assets.

The Company believes its exposure to credit risk related to cash and cash equivalents and restricted cash is minimal due to the quality of the financial institutions where the funds are held and the nature of the deposit instruments. Most of the Company's credit exposures are with counterparties in the energy industry and are therefore exposed to normal industry credit risks. Ivanhoe manages its credit risk by entering into sales contracts only with established entities.

Currently, all of the Company's oil production is sold to one national oil corporation. As a result, 96% of the outstanding accounts receivable balance at December 31, 2011 (December 31, 2010 – 85%, January 1, 2010 – 94%) is due from a national oil corporation. Long term receivables are primarily composed of value-added tax receivable amounts from the Ecuadorian government and will be recoverable upon commencement of commercial operations. Ivanhoe considers the risk of default on these items to be low due to the Company's ongoing operations in China and Ecuador.

Table of Contents

	December 31, 2011	December 31, 2010	January 1, 2010
Accounts receivable – current	7,859	6,329	5,004
Accounts receivable – over 90 days	–	30	17
	7,859	6,359	5,021

v. Liquidity Risk

Liquidity risk is the risk that suitable sources of funding for the Company’s business activities may not be available. Since cash flows from existing operations are insufficient to fund operations and future capital expenditures, Ivanhoe intends to finance future capital projects with a combination of strategic investors and/or public and private debt and equity markets, either at the parent company level or at the project level or from the sale of existing assets. There is no assurance that the Company will be able to obtain such financing, or obtain it on favorable terms.

The contractual maturity of the fixed rate derivative and non-derivative financial liabilities are shown in the table below. The amounts presented represent the future undiscounted cash flows and therefore may not equate to the values presented in the statement of financial position.

As at December 31, 2011	Less than 1 year	1 to 2 years	3 to 4 years
Derivative financial liabilities			
Subsidiary option	183	–	–
Convertible debenture	–	–	1,617
Non-derivative financial liabilities			
Accounts payable and accrued liabilities	15,548	–	–
Debt and interest	4,145	8,290	78,297

12. DERIVATIVE INSTRUMENTS

12.1 Convertible Debentures

The Company issued Cdn$73.3 million in Convertible Debentures in the second quarter of 2011, as described in Note 10.2. The outstanding principal amount is convertible into common shares of the Company. The fair value of the convertible component was $1.6 million at December 31, 2011, calculated with the Black-Scholes valuation method using a risk-free interest rate of 1.27%, a dividend yield of 0.0%, a weighted average volatility factor of 40% and an expected life of 4.5 years.

If the volatility used to fair value the convertible component decreased by 10%, the fair value would decrease by $1.1 million. If volatility increased by 10%, the fair value of the convertible option would increase by $1.6 million.

12.2 Convertible Note

The Company issued a Cdn$40.0 million Convertible Note, as described in Note 10.1. The outstanding principal amount was convertible, at Talisman’s option, into common shares of the Company. The fair value of the convertible component was nil at December 31, 2011 (December 31, 2010 – $1.2 million) as the Convertible Note was paid in full on July 11, 2011.

12.3 Subsidiary Option

In January 2010, one of the Company’s subsidiaries granted a private investor an option (the “Subsidiary Option”) to acquire an equity interest in the subsidiary representing 20% of the subsidiary’s currently issued share capital (16.67% of the enlarged share capital immediately following the exercise of the Subsidiary Option) for Cdn$25.0 million. Upon exercising the Subsidiary Option, Cdn$25.0 million of existing inter-corporate indebtedness owed by the subsidiary to the Company (through an intermediate subsidiary) would be converted into additional common shares of the subsidiary, thereby diluting the private investor’s equity interest to 14.286%. The Subsidiary Option was valid for one year and expired unexercised on January 26, 2012. The option was determined to have a nominal value on the date of grant.

The fair value of the Subsidiary Option as at December 31, 2011 was $0.2 million, calculated using the Black-Scholes valuation method using an estimated share value of $17.99, an exercise price of $30.00 per share, a risk-free interest rate of

Table of Contents

1.00%, a dividend yield of 0.0%, an expected life of approximately one month and an estimated volatility of 87.1%, which approximates the volatility of Ivanhoe's publically traded common shares.

12.4 Purchase Warrants

The following table reflects the changes in the Company's purchase warrants outstanding:

(000s)	Purchase Warrants	Shares Issuable
Balance January 1, 2010	12,135	12,135
Private placements	12,500	12,500
Exercised	(2)	(2)
Balance December 31, 2010	24,633	24,633
Exercised	(8,620)	(8,620)
Expired	(16,013)	(16,013)
Balance December 31, 2011	–	–

All of the Company's purchase warrants expired in 2011 and no purchase warrants remain outstanding at December 31, 2011.

At December 31, 2010, the following purchase warrants were exercisable:

Year of Issue	Price Per Special Warrant	Outstanding(1) (000s)	Fair Value ($US000s)	Expiry Date	Exercise Price Per Share	Cash Value on Exercise ($US000s)	Valuation Method
2006	US$2.23	11,398	5,615	May 2011	Cdn$2.93(2)	33,577	Quoted Market Price
2009	N/A	735	11	Feb 2011	Cdn$4.05	2,993	Black-Scholes
2010	Cdn$3.00	10,417	1,326	Feb 2011	Cdn$3.16	33,095	Black-Scholes
2010	Cdn$3.00	2,083	279	Feb 2011	Cdn$3.16	6,619	Black-Scholes
		24,633	7,231			76,284	

(1) One common share is issuable for each purchase warrant upon exercise.

(2) Each common share purchase warrant originally entitled the holder to purchase one common share at a price of US$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.

At December 31, 2010, the fair value of the purchase warrants issued in 2009 and 2010 was calculated using a weighted average risk-free interest rate of 1.0%, a dividend yield of 0.0%, a weighted average volatility factor of 66.6% and an expected life of two months.

13. LONG TERM PROVISIONS

	December 31, 2011	December 31, 2010
Decommissioning provision		

Balance, beginning of year	1,108	1,040
Liabilities incurred	–	642
Liabilities settled	–	(179)
Revisions in cash flow estimates	59	(488)
Unwinding of discount	27	23
Change in discount rates	373	70
Balance, end of year	1,567	1,108
Long term obligation	–	1,900
Long term accrued liabilities	352	–
	1,919	3,008

55

Table of Contents

13.1 Decommissioning Provision

The decommissioning provision represents the present value of decommissioning costs related to oil and gas properties in Canada, the FTF, and oil and gas properties in Ecuador, which are expected to be incurred in 2013, 2029 and 2038 respectively. The Company records a provision for the estimated future cost of decommissioning oil and gas properties and the FTF on a discounted basis. The provision for the costs of decommissioning these oil and gas properties and the FTF has been estimated, using current prices and discounted using a risk-free interest rate of 1.1% to 2.4% at December 31, 2011 (December 31, 2010 – 2.0% to 3.7%).

The Company does not make such a provision for decommissioning costs in connection with its oil and gas operations in China as dry holes are abandoned as they occur and productive wells will not be abandoned while the Company has an economic interest in the field.

13.2 Long term obligation

As part of a 2005 merger agreement, the Company assumed a $1.9 million contingent obligation. In the third quarter of 2011, the Company determined, based on recent events and clarification of contract terms, that satisfaction of the specific contractual contingencies was unlikely and the liability was derecognized.

13.3 Long term accrued liabilities

Long term accrued liabilities include share-based payments arising from cash-settled awards from the Restricted Share Unit plan (Note 17) and a finance lease obligation related to vehicle leases in Ecuador.

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 rates to the net losses before income taxes. The combined Canadian federal and provincial statutory rates as at December 31, 2011 and 2010 were 26.5% and 28.0%, respectively. The sources and tax effects for the differences are as follows:

	For the year ended December 31,			
	2011		2010	
Loss from continuing operations before income taxes	(26,546	)	(27,627	)
Combined Canadian federal and provincial statutory rates	26.5	%	28.0	%
Tax benefit	(7,035	)	(7,736	)
Compensation not deductible	1,410		1,604	
Tax losses and deferred deductions not recognized as deferred tax assets	10,111		5,830	
Foreign net losses affected at higher income tax rates	(867	)	(396	)
Expiry of tax loss carry-forwards	172		982	
Derivative and other gains not taxable	(3,784	)	–	
Share issue costs	(662	)	(633	)
Net currency exchange gains not taxable	(144	)	(911	)
Change in prior year estimate of tax loss carry-forwards	368		(1,306	)
Effect of change in effective income tax rates on deferred tax assets	–		1,096	
Other differences	(839	)	425	
Provision for (recovery of) income taxes	(1,270	)	(1,045	)

Table of Contents

Significant components of the Company’s deferred income tax assets and liabilities are as follows:

	December 31, 2011		December 31, 2010	
	Assets	Liabilities	Assets	Liabilities
Assets held for sale	10,475	(10,475)	–	–
Property, plant and equipment	3,325	(3,344)	–	(1,379)
Intangible assets	–	(39,209)	–	(48,021)
Tax loss carry-forwards	21,105	–	27,885	–
Tax credit carry-forwards	350	–	350	–
	35,255	(53,028)	28,235	(49,400)

As at December 31, 2011, the Company’s deferred income tax liability is $17.8 million in the consolidated statement of financial position, which is composed of $14.1 million in the US tax jurisdiction, $1.0 million in China and $2.7 million related to Mongolia.

The Company has recorded deferred tax assets only to the extent that they offset deferred tax liabilities in respect of income taxes expected to be levied by a particular taxation authority on a particular taxable entity or where different taxable entities can be expected to realize the assets and settle the liabilities simultaneously.

The Company has not recorded deferred income tax assets in respect of the following:

	December 31, 2011	December 31, 2010
Tax loss carry-forwards	172,617	139,390
Financing costs	6,334	6,801
	178,951	146,191

The consolidated loss carry-forward amounts and the year of expiry as at December 31, 2011, are shown in the following table. In China, the loss carry-forwards have no expiration period. A loss of approximately Cdn$55.3 million from the disposition of Russian operations in 2000, is a capital loss for Canadian income tax purposes, and is available for carry-forward against future Canadian capital gains indefinitely and is not included in the deferred income tax assets above.

Year of Expiry	
2012	2,327
2014	5,426
2015	7,040
2018	2,093
2019	1,078
2020 to 2025	5,508
2026 to 2031	175,141
No expiry	81,115
	279,728

As at December 31, 2011, the Company’s loss carry-forwards is composed of $144.2 million in Canada, $81.1 million in China and $54.4 million in the United States.

At December 31, 2011, current income taxes payable is $0.6 million (December 31, 2010 – nil; January 1, 2010 – $0.5 million).

Table of Contents

15. COMMITMENTS AND CONTINGENCIES

15.1 Zitong Appraisal Program

The terms of the Supplementary Agreement call for the completion of a $75.5 million appraisal program by the end of June 2014.

15.2 Operating Lease Arrangements

In the year ended December 31, 2011, the Company expended $1.8 million (December 31, 2010 – $1.4 million) on operating leases relating to the rental of office space, which expire between June 2012 and March 2017.

At December 31, 2011, future net minimum payments for operating leases were:

2012	1,734
2013	1,278
2014	592
2015	402
After 2015	502
	4,508

15.3 Other

Should Ivanhoe receive government and other approvals necessary to develop the northern border of one of the Tamarack leases, the Company will be required to make a cash payment to Talisman of up to Cdn$15.0 million, as a conditional, final payment for the 2008 purchase transaction.

From time to time, Ivanhoe 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, common shares, stock options or some combination thereof. Similarly, agreements entered into by the Company may contain cancellation fees or liquidated damages provisions for early termination. These fees are not considered to be material.

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 Ivanhoe 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 indemnities are not likely to be material.

In the ordinary course of business, the Company is subject to legal proceedings being brought against it. While the final outcome of these proceedings is uncertain, the Company believes that these proceedings, in the aggregate, are not reasonably likely to have a material effect on its financial position or earnings.

16. SHAREHOLDERS' EQUITY

16.1 Share Capital

Authorized	Unlimited common shares with no par value
	Unlimited preferred shares with no par value

Issued and Outstanding 344,139,428 common shares (December 31, 2010 – 334,365,482)
Nil preferred shares (December 31, 2010 – nil)

In 2011, cash proceeds of $29.9 million were raised through the exercise of purchase warrants and stock options.

In 2010, the Company raised $135.7 million, net of $6.0 million of issuance costs, through a private placement of 50 million special warrants at a price of Cdn$3.00 per special warrant. The Canadian dollar purchase warrants were considered to contain an embedded derivative since the functional currency of the Company is the US dollar. As a result, they were bifurcated into debt and the convertible option, which was recognized at a fair value of approximately $14.0 million using the Black-Scholes valuation method.

Table of Contents

See the Consolidated Statements of Changes in Equity for the change in common shares issued in the years ended December 31, 2011 and 2010.

16.2 Contributed Surplus

Contributed surplus at January 1, 2010 consisted solely of share-based compensation expense from equity settled awards.

17. SHARE-BASED PAYMENTS

Share-based transactions were charged to earnings, as general and administrative or operating expenses, or capitalized to E&E assets as follows:

	Year ended December 31, 2011	Year ended December 31, 2010
Share-based expense related to		
Equity settled transactions	5,614	7,557
Cash settled transactions	269	–
Total share-based expense	5,883	7,557
Share-based payments capitalized as E&E assets	335	799

17.1 Stock Option Plan

Details of transactions under the Company's stock option plan are as follows:

	December 31, 2011		December 31, 2010	
	Number of Stock Options (000s)	Weighted Average Exercise Price (Cdn$)	Number of Stock Options (000s)	Weighted Average Exercise Price (Cdn$)
Outstanding, beginning of year	16,927	2.24	15,013	2.27
Granted	2,924	2.06	6,041	2.56
Exercised	(1,687)	2.44	(2,743)	2.28
Expired	(710)	2.90	(635)	2.60
Forfeited	(1,706)	2.46	(749)	2.64
Outstanding, end of year	15,748	2.14	16,927	2.24
Exercisable, end of year	8,231	2.13	7,324	2.19

Shares authorized for issue under the option plan at December 31, 2011 were 24.1 million (December 31, 2010 – 23.4 million).

The weighted average share price per option at the date of exercise for stock options exercised in the year ended December 31, 2011 was Cdn$3.15 (December 31, 2010 – Cdn$3.23).

Table of Contents

The weighted average fair value of stock options granted from the stock option plan during the year ended December 31, 2011 was Cdn$1.22 (December 31, 2010 – Cdn$1.81) per option at the grant date using the Black-Scholes option pricing model. The weighted average assumptions used for the calculation were:

Year ended December 31,	2011		2010	
Expected life (in years)	6.4		6.3	
Volatility (1)	74.0	%	87.3	%
Dividend yield	–		–	
Risk-free rate	2.2	%	2.6	%
Estimated forfeiture rate	6.6	%	5.5	%

(1) Expected volatility factor based on historical volatility of the Company's publicly traded common shares.

The following table summarizes information in respect of stock options outstanding and exercisable at December 31, 2011:

Range of Exercise Prices (Cdn$)	Outstanding (000s)	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price (Cdn$)
0.92 to 1.29	1,000	7.0	0.92
1.30 to 1.89	3,942	1.8	1.61
1.90 to 2.79	9,524	4.3	2.34
2.80 to 3.44	1,282	5.0	3.27
	15,748	3.9	2.14

17.2 Restricted Share Unit Plan

The Company adopted a restricted share unit ("RSU") plan in the second quarter of 2011 under which it may issue restricted share units to eligible employees. RSUs vest evenly over three years and are settled in shares or cash on the anniversary date. RSUs do not entitle the holder to voting rights until they have vested and shares have been provided to the participant.

Details of transactions under the Company's RSU plan are as follows:

	December 31, 2011	
	Number of RSUs (000s) (1)	Weighted Average Fair Value (Cdn$)
Outstanding, beginning of year	–	–
Granted	1,115	1.62
Forfeited	(178)	2.08
Outstanding, end of year	937	1.53

(1) Includes RSUs that will be withheld on behalf of employees to satisfy statutory tax withholding requirements.

The weighted average fair value of RSU's granted during the year ended December 31, 2011 was Cdn$1.62 per RSU at the grant date using the Black-Scholes option pricing model. The weighted average assumptions used for the calculation were:

	Year ended December 31, 2011	
Expected life (in years)	3.0	
Volatility (1)	64.8	%
Dividend yield	–	
Risk-free rate	1.2	%
Estimated forfeiture rate	6.1	%

(1) Expected volatility factor based on historical volatility of the Company's publicly traded common shares.

Table of Contents

The liabilities arising from the RSUs to be settled by way of cash payments and the intrinsic value of those liabilities are:

	December 31, 2011
Current liabilities related to RSUs	152
Long term liabilities related to RSUs	117
Intrinsic value of vested RSUs	–

18. RETIREMENT PLANS

In 2001, the Company adopted a defined contribution retirement or thrift plan (“401(k) Plan”) to assist US employees in providing for retirement or other future financial needs. Employees’ contributions (up to the maximum allowed by US tax laws) are matched 100% by the Company. Payments are also made to a state managed plan for employees in China.

For the year ended December 31, 2011, the Company paid $0.4 million for retirement plan contributions (year ended December 31, 2010 – $0.4 million).

19. SEGMENT INFORMATION

Ivanhoe’s organizational structure reflects its various operating activities and the geographic areas in which it operates. Oil and gas operations are divided into three geographic segments: Asia, Canada and Latin America. Asian operations capture the Company’s oil production in Dagang and Daqing and exploration at Zitong in China as well as exploration in Mongolia. The Canadian segment comprises activities from Ivanhoe’s oil sands development project at Tamarack in Alberta, Canada. Latin America consists of exploration and development of Block 20 in Ecuador.

The Technology Development area captures costs incurred to develop, enhance and identify improvements in the application of the Company’s HTL™ technology. The Corporate area consists of costs that are not directly allocable to operating projects, such as executive officers, corporate financings and other general corporate activities.

The accounting policies of the segments are the same as the Company’s consolidated accounting policies. Segment results include transactions between business segments. Corporate activities undertaken on behalf of a segment are allocated at cost. Oil revenue is classified according to the geographic location of the production. Segment liabilities include intercompany balances.

Table of Contents

The following tables present the Company’s segment income (loss), capital investments and identifiable assets and liabilities.

Year ended December 31, 2011	Asia	Canada	Latin America	Technology Development	Corporate	Total
Revenue						
Oil(1)	37,403	–	–	–	–	37,403
Interest	4	–	–	–	572	576
	37,407	–	–	–	572	37,979
Expenses						
Operating	15,570	–	–	4,561	–	20,131
Exploration and evaluation	2,124	–	650	–	–	2,774
General and administrative	12,086	3,257	7,645	4,026	21,435	48,449
Depletion and depreciation	7,053	9	138	555	275	8,030
Foreign currency exchange (gain) loss	275	(6)	3	–	(627)	(355)
Derivative instruments (gain) loss	183	–	–	–	(13,148)	(12,965)
Interest	26	6	32	8	289	361
Gain on derecognition of long term provision	–	–	–	–	(1,900)	(1,900)
	37,317	3,266	8,468	9,150	6,324	64,525
Income (loss) before income taxes	90	(3,266)	(8,468)	(9,150)	(5,752)	(26,546)
(Provision for) recovery of income taxes						
Current	(2,115)	–	–	–	(7)	(2,122)
Deferred	(989)	–	–	(1,389)	5,770	3,392
	(3,104)	–	–	(1,389)	5,763	1,270
Net income (loss) and comprehensive income (loss)	(3,014)	(3,266)	(8,468)	(10,539)	11	(25,276)
Capital investments – Intangible	20,390	6,280	10,720	–	–	37,390
Capital investments – Property, plant and equipment	12,733	–	43	879	15	13,670
As at December 31, 2011						
Assets(2)	107,902	133,880	40,216	102,435	29,277	413,710
Liabilities(3)	140,621	144,531	64,362	87,822	(337,763)	99,573
As at December 31, 2010						
Assets(2)	85,273	123,890	24,392	101,899	58,964	394,418
Liabilities(3)	114,980	131,277	42,162	76,747	(271,232)	93,934
As at January 1, 2010						
Assets(2)	57,528	94,594	7,778	101,893	19,158	280,951

Liabilities(3)	81,047	98,262	13,145	56,909	(162,821)	86,542

(1) All revenues in Asia are generated from the sale of oil production in China to one customer.

(2) Assets include investments in subsidiaries that are eliminated for consolidation within the Corporate segment.

(3) Liabilities for the Corporate segment include intercompany receivables of $428.7 million at December 31, 2011 (December 31, 2010 – $352.5 million; January 1, 2010 – $216.7 million) resulting in a negative balance.

Table of Contents

Year ended December 31, 2010	Asia	Canada	Latin America	Technology Development	Corporate	Total
Revenue						
Oil(1)	21,720	–	–	–	–	21,720
Interest	6	–	–	–	202	208
	21,726	–	–	–	202	21,928
Expenses						
Operating	9,539	–	–	4,086	–	13,625
Exploration and evaluation	3,537	–	4,934	–	–	8,471
General and administrative	8,413	3,719	9,525	953	20,197	42,807
Depletion and depreciation	6,303	9	52	(83)	243	6,524
Foreign currency exchange gain	(62)	(15)	–	–	(3,248)	(3,325)
Derivative instruments gain	–	–	–	–	(18,571)	(18,571)
Interest	–	6	8	10	–	24
	27,730	3,719	14,519	4,966	(1,379)	49,555
Income (loss) before income taxes	(6,004)	(3,719)	(14,519)	(4,966)	1,581	(27,627)
(Provision for) recovery of income taxes						
Current	(111)	–	–	–		