Twin Butte Energy Ltd.

ANNUAL INFORMATION FORM

for the year ended December 31, 2010

March 25, 2011

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ABBREVIATIONS

Crude Oil and Natural Gas Liquids		**Natural Gas**	
bbl	one barrel	Mcf	one thousand cubic feet
bbl	barrels	MMcf	one million cubic feet
bbl/d	barrels per day	Bcf	one billion cubic feet
Mbbl	thousand barrels		
BOE	barrels of oil equivalent of natural gas on the basis of 1 BOE for 6 Mcf of natural gas (unless otherwise indicated)	Mcf/d	one thousand cubic feet per day
MBOE	one thousand barrels of oil equivalent	MMcf/d	one million cubic feet per day
MMBOE	one million barrels of oil equivalent	GJ	gigajoule
BOE/d	barrels of oil equivalent per day	GJs/d	gigajoules per day
NGL	natural gas liquids	Btu	British thermal unit
stb	standard stock tank barrel	MMbtu	million British thermal units

BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of six Mcf to one bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This conversion factor is an industry accepted norm and is not based on either energy content or current prices.

Other

AECO	EnCana Corp.'s natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale
m^3	cubic metres
$000's	thousands of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

CONVERSIONS

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	**To**	**Multiply By**
Mcf	thousand cubic metres ("10^3m^3")	0.0282
thousand cubic metres	Mcf	35.494
bbl	cubic metres ("m^3")	0.159
cubic metres	bbl	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

CERTAIN DEFINITIONS

In this Annual Information Form, the following words and phrases have the following meanings, unless the context otherwise requires:

"**ABCA**" means the *Business Corporations Act* (Alberta), together with any amendments thereto and all regulations promulgated thereunder;

"**Buffalo**" means Buffalo Resources Corp., a corporation which was amalgamated pursuant to the ABCA and which was amalgamated with Twin Butte following the Buffalo Arrangement;

"**Buffalo Arrangement**" means Twin Butte's acquisition of all of the outstanding common shares of Buffalo completed on October 14, 2009 pursuant to a plan of arrangement under the ABCA, as more particularly described under "General Development of the Business – Three Year History".

"**Can-Able**" means Can-Able Energy Ltd., a corporation which was incorporated pursuant to the ABCA and which was amalgamated with Twin Butte following the Can-Able Acquisition;

"**Can-Able Acquisition**" means Twin Butte's acquisition of all of the outstanding common shares of Can-Able in July 2009, as more particularly described under "General Development of the Business – Three Year History";

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

"**Common Shares**" means the common shares in the capital of the Corporation as currently constituted;

"**E4**" means E4 Energy Inc., a corporation which was amalgamated pursuant to the ABCA and which was amalgamated with Twin Butte following the E4 Arrangement;

"**E4 Arrangement**" means Twin Butte's acquisition of all of the outstanding common shares of E4 completed on February 8, 2008 pursuant to a plan of arrangement under the ABCA, as more particularly described under "General Development of the Business – Three Year History";

"**Gross**" means:

(a) in relation to the Corporation's interest in production and reserves, its "company gross reserves", which are the Corporation's working interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Corporation;

(b) in relation to wells, the total number of wells in which the Corporation has an interest; and

(c) in relation to properties, the total area of properties in which the Corporation has an interest.

"**McDaniel**" means McDaniel & Associates Consultants Ltd., independent petroleum consultants, Calgary, Alberta;

"**McDaniel Report**" means the March 7, 2011 report prepared by McDaniel, evaluating the crude oil, natural gas and NGL reserves of Twin Butte, as at December 31, 2010, in accordance with the standards contained in the COGE Handbook and the reserves definitions set out by the Canadian Securities Administrators in NI 51-101 and the COGE Handbook;

"**Net**" means:

(d) in relation to the Corporation's interest in production and reserves, the Corporation's working interest (operating and non-operating) share after deduction of royalties obligations, plus the Corporation's royalty interest in production or reserves;

(e) in relation to wells, the number of wells obtained by aggregating the Corporation's working interest in each of its gross wells; and

(f) in relation to the Corporation's interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.

"**NI 51-101**" means National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* adopted by the Canadian Securities Administrators;

"**TSX**" means the Toronto Stock Exchange; and

"**Twin Butte**" or the "**Corporation**" means Twin Butte Energy Ltd., a corporation amalgamated pursuant to the ABCA.

CONVENTIONS

Certain terms used herein are defined under the heading "Glossary of Terms".

Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars.

Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

Unless otherwise specified, information in this Annual Information Form is as at the end of the Corporation's most recently completed financial year, being December 31, 2010.

FORWARD-LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, financial and business prospects and financial outlook, reserve and production estimates, drilling and re-completion plans, timing of drilling, re-completion and tie-in of wells, productive capacity of wells and productive capacity of wells and capital expenditures and the timing thereof, the effect of government announcements, proposals and legislation, plans regarding hedging, expected or anticipated production rates, timing of expected production increases, weighting of production between different commodities, expected commodity prices, exchange rates, production expenses, transportations costs and other costs and expenses, maintenance of productive capacity and capital expenditures and methods of financing thereof, may be forward-looking statements. Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions may be used to identify these forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to management. Forward-looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources and the risk factors outlined under "Risk Factors" and elsewhere herein. The recovery and reserve estimates of the Corporation's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

Forward-looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although the Corporation believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because the Corporation can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this Annual Information Form, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which the Corporation operates; the timely receipt of any required regulatory approvals; the ability of the Corporation to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which the Corporation has an interest in to operate the field in a safe, efficient and effective manner; the ability of the Corporation to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development of exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of the Corporation to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Corporation operates; and the ability of the Corporation to successfully market its oil and natural gas products.

Readers are cautioned that the foregoing list of factors is not exhaustive. Although the forward-looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward-looking statements. Investors should not place undue reliance on forward-looking statements. These forward-looking statements are made as of the date hereof and the Corporation assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

Forward-looking statements and other information contained herein concerning the oil and gas industry and the Corporation's general expectations concerning this industry is based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Corporation believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Corporation is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

CORPORATE STRUCTURE

Name, Address and Incorporation

Twin Butte Energy Ltd.

Head Office:	Registered Office:
Suite 410, 396 – 11th Avenue S.W.	Suite 1400, 350 – 7th Avenue S.W.
Calgary, Alberta T2R 0C5	Calgary, Alberta T2P 3N9

Twin Butte was formed upon the amalgamation under the ABCA on May 31, 1997 of Altarex Corp. and Altarex Inc. to form "Altarex Corp.". On June 27, 1997, the newly formed Altarex Corp. filed Articles of Amendment to add in certain other provisions to allow the company to hold meetings of shareholders at any place within Canada or the United States. On November 21, 2000, Altarex Corp. filed Articles of Amendment to consolidate its common shares on the basis of one post-consolidated common share for each four pre-consolidated common shares.

On February 3, 2004, Articles of Arrangement were filed with respect to a plan of arrangement under section 193 of the ABCA among the Corporation, the Corporation's securityholders, Altarex Medical Corp. ("**Altarex Medical**") and Nova Bancorp Investments Ltd. (the "**Arrangement**"). Pursuant to the Arrangement Articles of Amendment were filed which resulted in the following: (a) the reorganization of the Corporation's share capital to create new classes of non-voting common shares (the "**Non-Voting Shares**") and voting common shares; (b) the change of the name of the Corporation to "Twin Butte Energy Ltd."; and (c) the deletion of the class of common shares (the "**Pre-Arrangement Shares**") and the re-designation of the new class of voting common shares as the Common Shares.

Prior to the Arrangement, Altarex Medical was a wholly-owned subsidiary of the Corporation. Pursuant to the Arrangement: (a) all of the Corporation's biotechnology assets were transferred, together with all associated contractual obligations and liabilities to Altarex Medical, in consideration for 40,000,000 common shares of Altarex Medical (the "**Altarex Medical Shares**") and the subscription by the Corporation for 12,746,935 additional Altarex Medical Shares for $5,045,000 in cash; (b) the issuance to Nova Bancorp Investments Ltd. of $4,770,985 principal amount of 10% convertible demand notes of Twin Butte, convertible into Non-Voting Shares of Twin Butte at a ratio of 2,583 Non-Voting Shares per $1,000 of principal (the "**Convertible Notes**"); (c) the cancellation of all outstanding stock options and warrants of the Corporation; and (d) the exchange of the Pre-Arrangement Shares on the following basis: (i) shareholders who held more than 1,000 Pre-Arrangement Shares received one Common Share of Twin Butte and ten Altarex Medical Shares for every ten Pre-Arrangement Shares held; (ii) shareholders who held 151 to 1,000 Pre-Arrangement Shares received an aggregate payment equal to $0.05 and one Altarex Medical Share for each Pre-Arrangement Share held; and (iii) shareholders who held 150 Pre-Arrangement Shares or less, received an aggregate cash payment equal to $0.55 for each Pre-Arrangement Share held.

On June 7, 2006, Twin Butte filed Articles of Amendment under the ABCA to convert the Non-Voting Shares of the Corporation into Common Shares. On May 28, 2007, Twin Butte filed Articles of Amendment under the ABCA to consolidate its then outstanding Common Shares on the basis of one post-consolidated Common Share for each five pre-consolidated Common Shares.

On February 8, 2008, following the completion of the E4 Arrangement, Twin Butte amalgamated with E4 to form "Twin Butte Energy Ltd.".

On July 13, 2009, following the completion of the Can-Able Acquisition, Twin Butte amalgamated with Can-Able to form "Twin Butte Energy Ltd.".

On October 14, 2009, following the completion of the Buffalo Arrangement, Twin Butte amalgamated with Buffalo to form "Twin Butte Energy Ltd.". Unless otherwise stated, disclosure in this Annual Information Form of the share capital of Twin Butte is presented after giving effect to the foregoing amendments to the Articles of Twin Butte.

GENERAL DEVELOPMENT OF THE BUSINESS

Three Year History

The following is a summary of the significant events in the development of the Corporation's business over the last three completed financial years.

Year Ended December 31, 2008

On February 8, 2008, Twin Butte acquired all of the outstanding common shares of E4 pursuant to the E4 Arrangement for aggregate consideration of approximately $57.3 million before closing adjustments, comprised of the issuance of 15,663,021Common Shares and the assumption of approximately $19.9 million of net debt and working capital deficiencies. Prior to the acquisition, E4's common shares were listed on the TSX Venture Exchange and it was a reporting issuer in various provinces of Canada. At the time of the acquisition, E4's production was approximately 1,075 BOE/d (approximately 45% oil and liquids and 55% natural gas). The principal properties of E4 were in the Provost, Alberta area and the Airport and Oak, British Columbia areas and approximately 86,000 net acres of undeveloped land near Fort St. John, British Columbia.

On December 18, 2008, the Corporation completed a private placement of 3,704,000 Common Shares issued on a "flow-through" basis at a price of $1.35 per share for gross proceeds of approximately $5 million.

Year Ended December 31, 2009

On June 1, 2009, Twin Butte completed the disposition of assets in northeast British Columbia for approximately $9.8 million including closing adjustments. The disposition included 1,847 net undeveloped acres of land.

In July 2009, Twin Butte acquired all of the outstanding common shares of Can-Able, a private company, for aggregate consideration of approximately $10.6 million, comprised of the issuance of 8,229,968 Common Shares and the assumption of approximately $2.5 million of associated debt. Can-Able's primary assets were located in west central Alberta at Ansell and Ricinus.

On October 14, 2009, Twin Butte acquired all of the outstanding common shares of Buffalo pursuant to the Buffalo Arrangement, for aggregate consideration of approximately $120.5 million before closing adjustments, comprised of the issuance of 54,355,942 Common Shares and the assumption of approximately $70.0 million of net debt and working capital deficiencies. Prior to the acquisition, Buffalo's common shares were listed on the TSX Venture Exchange and it was a reporting issuer in various provinces of Canada. At the time of the acquisition, Buffalo's production was approximately 2,900 BOE/d (approximately 45% oil and liquids and 55% natural gas). The principal properties of Buffalo were in the Frog Lake and Whitecourt, Alberta areas and Buffalo had approximately 125,000 net acres of undeveloped land.

In December 2009 and January 2010, Twin Butte divested itself of a number of non-core producing and non-producing assets for gross proceeds of approximately $13.3 million. Production associated with the assets disposed of was approximately 280 BOE/d.

Year Ended December 31, 2010

On February 2, 2010, Twin Butte completed a public offering of 18,400,000 Common Shares issued at a price of $1.25 per share for gross proceeds of $23 million.

On November 30, 2010, Twin Butte completed the acquisition of conventional heavy oil producing assets primarily in the Frog Lake area of northeastern Alberta for a purchase price net of standard closing adjustments of $19.5 million. At the time of the acquisition, the assets which included wells and associated production facilities were producing approximately 500 bbls per day of oil. The acquisition included 10.2 gross (10.1 net) sections of crown land and operated production in the Frog Lake area directly adjacent to Twin Butte's existing Frog Lake operations. Twin Butte financed the acquisition from its credit facilities with a syndicate of financial institutions which, post closing the transaction, were increased to an aggregate of $128 million comprised of a $28 million demand revolving operating facility and a $100 million demand revolving production facility (the "**Credit Facilities**").

Significant Acquisitions

The Corporation did not complete any significant acquisitions during its most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102 – *Continuous Disclosure Obligations.*

DESCRIPTION OF THE BUSINESS

General

Twin Butte is a Calgary, Alberta based oil and gas company engaged in the exploration, development and production of oil and natural gas in the Western Canadian Sedimentary Basin. The Corporation's focus is to increase its underlying value through a combination of a focused development and exploitation program, strategic acquisitions and some exploration. Over the next few years it is Twin Butte's intent to establish a portfolio of assets of varying maturity to maintain the overall predictability of the Corporation's cash flow stream. When possible, the Corporation will operate its assets working in areas with year round access, thereby minimizing time delays between prospect generation and first production and maintaining more efficient cost controls.

Business Plan and Growth Strategy

Twin Butte has approximately 250,000 net undeveloped acres of land with core areas of operation currently focused in Frog Lake, eastern Alberta plains including Princess and Bruce, west central Alberta including Whitecourt, Thunder/Leaman, Deep Basin including Ansell, Jayar and Pincher Creek. The Corporation's business plan is to grow the Corporation with an integrated strategy including acquisitions, development and exploration drilling, farm-in opportunities, joint ventures, land acquisitions and exploitation focusing on the Corporation's core areas. The Corporation plans to pursue a balanced portfolio of crude oil and natural gas prospects. However, the Corporation will be largely opportunity driven and will focus its expenditures on opportunities that provide the greatest economic return, recognizing that all drilling involves substantial risk and that a high degree of competition exists for prospects. The Corporation plans to focus on its oil prospects during the next year. No assurance can be given that drilling will prove successful in establishing commercially recoverable reserves. See "Risk Factors".

To achieve sustainable and profitable growth, the Corporation believes in controlling the timing, costs and future development of its projects whenever possible. Accordingly, the Corporation will seek to become the operator of its projects to the greatest extent possible.

It is anticipated that any future acquisitions will be financed through a combination of equity and/or debt. The Corporation will seek out, analyze and complete asset and/or corporate acquisitions where value creation opportunities have been identified that have the potential to increase shareholder value and returns, taking into account the Corporation's financial position, taxability and access to debt and equity financing. The Board of Directors of Twin Butte may, in its discretion, approve asset or corporate acquisitions or investments that do not conform to these guidelines based upon the Board of Directors' consideration of the qualitative aspects of the subject properties including risk profile, technical upside, reserve life and asset quality.

Planned Exploration and Development Activity During 2011

The Board of Directors of Twin Butte approved a 2011 net capital program of $65 million. The program which represents an expenditure level of slightly less than anticipated cashflow is 100 percent oil weighted thereby further increasing Twin Butte's anticipated liquid production ratio to just over 70 percent by year end 2011. Twin Butte will continue to build and enhance its resource style gas drilling inventory in the Deep Basin and Bruce in anticipation of natural gas price increases.

The 2011 capital program will be allocated approximately 70% to Frog Lake, 15% to Princess and 15% to other, including land, seismic and capitalized overhead. Twin Butte anticipates the drilling of 152 gross (103 net) wells in combination with a recompletion/workover program and some various land and seismic costs. With a defined drilling inventory of 500 wells, management of Twin Butte believes that Frog Lake offers a repeatable and scalable long term oil play to the Corporation.

Approximately 20% of the capital program will be allocated to enhance two additional areas in the Corporation's oil drilling inventory, with a waterflood and development drilling program at Bruce, and the development of a new horizontal Pekisko play at Princess.

Based on current natural gas prices, Twin Butte does not plan to drill any gas wells in 2011 but will continue to inventory gas based projects for a future period when economics for gas plays are expected to be more compelling.

Specialized Skill and Knowledge

Twin Butte believes that its management team has all of the key components to a successful exploration and production company: strong technical skills; expertise in planning and financial controls; ability to execute on business development opportunities; capital markets expertise; extensive experience in oil and gas exploration and development in Western Canada; and an entrepreneurial spirit that allows Twin Butte to effectively identify, evaluate and execute on value-added initiatives. See "Directors and Executive Officers".

Competitive Conditions

The oil and natural gas industry is intensely competitive in all its phases. Twin Butte competes with numerous other participants in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Twin Butte's competitors include resource companies which have greater financial resources, staff and facilities than those of Twin Butte. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. Twin Butte believes that its competitive position is equivalent to that of other oil and gas issuers of similar size and at a similar stage of development.

Cyclical Nature of Business

The Corporation's business is generally cyclical. The exploration and development of oil and natural gas reserves is dependent on access to areas where drilling is to be conducted. Seasonal weather variation, including freeze-up and break-up, will affect access in certain circumstances.

Employees

As at December 31, 2010, Twin Butte had 42 full-time employees and three consultants. All of the consultants and 33 of the full-time employees were located at Twin Butte's office in Calgary and nine of the full-time employees were located in the field.

DESCRIPTION OF PRINCIPAL PROPERTIES

The following is a description of Twin Butte's principal oil and natural gas properties and minor exploration properties as at December 31, 2010. Unless otherwise specified, gross, net acres, well count and production information are as at December 31, 2010.

Alberta

Frog Lake

The Frog Lake property is located approximately 75 kilometres northwest of Lloydminster with lands on the Frog Lake First Nations lands and on Crown land just to the south of the First Nations lands ("**Frog Lake South**"). Twin Butte's original interest in Frog Lake was acquired in October 2009 and added to in November 2010. Twin Butte's working interests at Frog Lake range from 11 percent to 100 percent. The Frog Lake property produced approximately 1,918 BOE/d in 2010, representing approximately 29 percent of Twin Butte's production volumes for the year. This production consisted of 98 percent of heavy oil and two percent of natural gas. Production at December 31, 2010 was approximately 3,058 BOE/d in this area. The main zones are 400 to 550 metres deep and include the Mclaren, Sparky, GP and Rex formations. Oil production is currently trucked to third party processing facilities where it is sold.

Twin Butte's land position consists of 33,100 gross acres with approximately 5,300 net undeveloped acres, and the current plan would see a drilling density of one well per 10 acres when fully developed. Twin Butte drilled 78 gross wells in 2010 and plans to drill approximately 100 gross wells in 2011 on the First Nations lands with an average working interest of 50 percent and an additional 38 wells on the Frog Lake South lands at a 100 percent working interest. Twin Butte has identified more than 500 locations in this area for future development and has 3-D seismic over most of the lands.

Plains

The Plains region is on the eastern half of Alberta running from east of Calgary to southeast of Edmonton, and includes operational areas such as Bruce and Jenner/Princess. Production from this region was approximately 1,540 BOE/d in 2010, consisting of approximately 31 percent of oil and liquids and 69 percent of natural gas. This region is known for both oil and natural gas and producing zones in this region include the Viking, Lloydminster, Glauconite and Pekisko with depths ranging from 700 to 1,000 metres.

Production in the region generally goes to a combination of Twin Butte operated facilities and third party operated facilities. Twin Butte has approximately 94,960 net undeveloped acres in this region.

In 2010, Twin Butte drilled nine gross (nine net) wells in this region and intends to drill approximately 11 wells in 2011 looking to test Lloydminster oil in Bruce and Pekisko oil in Jenner/Princess.

West Central Alberta

The west central Alberta region is 125 kilometres northwest of Edmonton and stretches to northwestern Alberta and northeastern British Columbia, including operations in strike areas of Whitecourt and Thunder. Production from this region was approximately 1,853 BOE/d in 2010, consisting of approximately 14 percent of oil and liquids and 86 percent of natural gas. This region is known for both oil and natural gas and producing zones in this region include the Viking, upper and lower Manville, Nordegg and Banff formations with depths ranging from 800 to 1,800 metres.

Production in the region goes to a combination of Twin Butte operated facilities and third party operated facilities. Twin Butte has approximately 112,785 net undeveloped acres in this region.

Deep Basin

The Deep Basin region starts approximately 160 kilometres west of Edmonton and runs northwest for approximately 125 kilometres including the Ansell and Jayar operational areas. Production from this region was approximately 740 BOE/d for 2010 consisting of approximately 71 percent natural gas with the balance being oil and NGL's. The deep basin is generally comprised of wells with depths in the 2,200 to 2,500 metre range and Twin Butte has production in the Cardium, Dunvegan and Notikewin zones.

Twin Butte drilled one gross (0.65 net) wells here in 2010 and does not currently have any plans to drill any wells in this region in 2011

Twin Butte has approximately 13,815 net undeveloped acres in this region.

Pincher Creek

The Pincher Creek area is 20 kilometres southeast of Pincher Creek, Alberta. This area was acquired in October 2009 pursuant to the Buffalo Arrangement and production from this region was approximately 520 BOE/d in 2010, consisting of approximately 87 percent of natural gas. This area was initially developed in the 1960's and has produced more than 500 Bcf of gas to date with more than 50 Bcf remaining. The gas in this region is from the Turner Valley group zone and is approximately 10 percent sour with H2S, which requires special processing capabilities at the gas plant.

Production in the region goes to the Shell Canada Waterton gas plant. Twin Butte has a 100 percent interest in the Pincher Creek Unit which covers 41 sections of land and a 60 percent interest in one non-unit well.

The Corporation did not drill any wells in this region in 2010 and is not planning to drill any wells in the region in 2011.

Twin Butte has approximately 20,270 net undeveloped acres in this region.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated March 25, 2011. The effective date of the Statement is December 31, 2010 and the preparation date of the Statement is March 7, 2011.

Disclosure of Reserves Data

The reserves data set forth below (the "**Reserves Data**") is based upon an evaluation by McDaniel with an effective date of December 31, 2010 contained in the McDaniel Report. The Reserves Data summarizes the crude oil, NGL and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using forecast prices and costs. The McDaniel Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and the COGE Handbook. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which Twin Butte believes is important to the readers of this information. The Corporation engaged McDaniel to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of Twin Butte's reserves are in Canada and, specifically, in the provinces of Alberta, British Columbia and Saskatchewan.

The Report on Reserves Data by McDaniel & Associates Consultants Ltd. in accordance with Form 51-101F2 and the Report of Twin Butte Management and Directors on Oil and Gas Disclosure in accordance with Form 51-101F3 are attached to this Annual Information Form as Schedules "A" and "B", respectively.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of the Corporation's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.

Reserves Data

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2010
FORECAST PRICES AND COSTS

	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids	
Reserves Category	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**
Proved Developed Producing	1,096.8	977.0	2,254.2	1,775.7	63,449.8	54,180.9	1,244.7	816.4
Proved Developed Non-Producing	75.6	66.2	535.5	410.4	2,777.3	2,257.5	43.6	29.0
Proved Undeveloped	337.7	281.7	4,657.5	3,712.0	8,771.6	7,428.5	177.1	126.7
Total Proved	1,510.1	1,325.0	7,447.1	5,898.2	74,998.7	63,866.8	1,465.3	972.1
Total Probable	883.8	746.5	7,118.9	5,354.3	35,019.5	29,440.5	697.5	466.4
Total Proved Plus Probable	2,393.9	2,071.5	14,566.1	11,252.4	110,018.2	93,307.4	2,162.9	1,438.5

	Net Present Values OF Future Net Revenue ($000's)										
	Before Income Taxes Discounted At (%/year)					After Income Taxes Discounted at (%/year)					Unit Value Before Income Tax Discounted at 10%/year
Reserves Category	**0**	**5**	**10**	**15**	**20**	**0**	**5**	**10**	**15**	**20**	**($/boe)**
Proved Developed Producing	382,257.8	257,771.6	202,887.8	171,790.2	151,323.8	364,061.5	253,189.4	201,540.4	171,342.8	151,160.6	13.35
Proved Developed Non-Producing	23,191.5	19,003.4	15,796.0	13,300.9	11,331.7	17,390.5	16,347.8	14,529.6	12,674.1	11,010.9	14.14
Proved Undeveloped	145,835.5	112,757.1	91,375.0	75,844.2	63,878.0	109,372.8	86,449.1	71,189.4	59,753.7	50,707.0	13.77
Total Proved	551,284.6	389,532.1	310,058.8	260,935.2	226,533.4	490,824.8	355,986.3	287,259.4	243,770.7	212,878.4	13.51
Total Probable	418,618.7	274,962.5	207,016.0	164,619.5	134,921.7	313,746.6	204,638.5	152,802.0	120,510.3	97,976.5	14.24
Total Proved Plus Probable	969,903.4	664,494.8	517,074.7	425,554.7	361,455.0	804,571.4	560,624.8	440,061.4	364,281.0	310,854.9	13.79

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2010
FORECAST PRICES AND COSTS
($000's)

Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Well Abandonment Costs	Future Net Revenue Before Income Taxes	Future Income Taxes	Future Net Revenue After Future Income Taxes
Proved	1,402,438	232,124	514,697	85,267	19,066	551,285	60,460	490,825
Proved Plus Probable	2,386,031	428,007	807,086	156,987	24,047	969,903	165,332	804,571

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2010
FORECAST PRICES AND COSTS

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year) ($000's)	Unit Value Before Income Taxes (discounted at 10%/year) ($/Mcf) ($/bbl)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	40,763	38.18
	Heavy Oil (including solution gas and other by-products)	151,937	25.76
	Natural Gas (including by-products but excluding solution gas from oil wells)	117,359	1.96
	Total	310,059	19.48
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	60,561	34.40
	Heavy Oil (including solution gas and other by-products)	298,645	26.54
	Natural Gas (including by-products but excluding solution gas from oil wells)	157,869	1.83
	Total	517,075	18.78

Notes to Reserves Data Tables:

(1) Columns may not add due to rounding.

(2) The crude oil, natural gas liquids and natural gas reserve estimates presented in this Annual Information Form are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below:

Reserve Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions, which are generally accepted as being reasonable and shall be disclosed.

Reserves are classified according to the degree of certainty associated with the estimates:

(a) **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(b) **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

(a) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

(i) **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(ii) **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(b) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

(3) "**forecast prices and costs**" are those:

(a) generally acceptable as being a reasonable outlook of the future; and

(b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which Twin Butte is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

The forecast summary table under the "Pricing Assumptions" below identifies benchmark reference prices that apply to Twin Butte.

(4) "**future income taxes**" estimated:

(c) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;

(d) without deducting estimated future costs that are not deductible in computing taxable income;

(e) taking into account estimated tax credits and allowances; and

(f) applying to the future pre-tax net cash flows relating to Twin Butte's oil and gas activities the appropriate year-end statutory tax rates, taking into account future tax rates already legislated.

(5) "**development well**" means a well drilled inside the established limits of an oil or gas reservoir or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

(6) "**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(g) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

(h) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;

(i) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(j) provide improved recovery systems.

(7) "**exploration well**" means a well that is not a development well, a service well or a stratigraphic test well.

(8) "**exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(k) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;

(l) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

(m) dry hole contributions and bottom hole contributions;

(n) costs of drilling and equipping exploratory wells; and

(o) costs of drilling exploratory type stratigraphic test wells.

(9) "**service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

Pricing Assumptions

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS

Year	WTI Cushing Oklahoma ($US/bbl)	Light Sweet Crude Oil at Edmonton 40° API ($Cdn/bbl)	Medium Bow River Crude Oil 21° API ($Cdn/bbl)	Hardisty Heavy 12° API ($Cdn/bbl)	Natural Gas AECO-C Spot ($Cdn/ MMBtu)	Natural Gas Liquids Edmonton Cond ($Cdn/bbl)	Natural Gas Liquids Edmonton Propane ($Cdn/bbl)	Natural Gas Liquids Edmonton Butane ($Cdn/bbl)	Inflation Rates (1) %/Year	Exchange Rate (2) ($US/$Cdn)
Forecast										
2011	85.00	84.20	72.80	66.70	4.25	88.20	44.90	67.90	2.0	0.975
2012	87.70	88.40	75.00	68.70	4.90	90.40	47.70	71.20	2.0	0.975
2013	90.50	91.80	75.10	68.60	5.40	93.90	50.30	74.00	2.0	0.975
2014	93.40	94.80	77.50	70.80	5.90	96.90	52.70	76.40	2.0	0.975
2015	96.30	97.70	80.00	73.00	6.35	99.90	55.00	78.70	2.0	0.975
2016	99.40	100.90	82.50	75.40	6.75	103.10	57.30	81.30	2.0	0.975
2017	101.40	102.90	84.20	76.90	7.10	105.20	58.80	82.90	2.0	0.975
2018	103.40	104.90	85.90	78.40	7.40	107.20	60.40	84.50	2.0	0.975
2019	105.40	107.00	87.50	80.00	7.60	109.30	61.70	86.20	2.0	0.975
2020	107.60	109.20	89.30	81.60	7.75	111.60	63.00	88.00	2.0	0.975
2021	109.70	111.30	91.10	83.20	7.85	113.70	64.10	89.70	2.0	0.975
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.975

Notes:
(1) Inflation rates used for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.

Reconciliation of Changes in Reserves

The following table sets out the reconciliation of Twin Butte's gross reserves based on forecast prices and costs by principal product type:

	Light and Medium Oil			Heavy Oil			Associated and Non-Associated Gas			Natural Gas Liquids		
Factors	**Gross Proved (Mbbl)**	**Gross Probable (Mbbl)**	**Gross Proved Plus Probable (Mbbl)**	**Gross Proved (Mbbl)**	**Gross Probable (Mbbl)**	**Gross Proved Plus Probable (Mbbl)**	**Gross Proved (MMcf)**	**Gross Probable (MMcf)**	**Gross Proved Plus Probable (MMcf)**	**Gross Proved (Mbbl)**	**Gross Probable (Mbbl)**	**Gross Proved Plus Probable (Mbbl)**
December 31, 2009	1,651.7	1,078.8	2,730.5	2,031.9	3,555.1	5,587.0	81,086	37,543	118,630	1,724.7	712.8	2,437.5
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	503.0	198.7	701.7	3,062.2	1,989.0	5,051.2	2,077	121	2,198	2.1	13.1	15.2
Technical Revisions	(28.2)	31.6	3.4	521.1	302.9	824.0	244	(2,084)	(1,841)	(150.8)	(13.4)	(164.2)
Acquisitions	0.7	0.1	0.8	2,515.5	1,271.9	3,787.4	174	41	215	-	-	-
Dispositions	(343.1)	(425.5)	(768.6)	-	-	-	(540)	(602)	(1,142)	(9.8)	(15.0)	(24.8)
Production	(273.9)	-	(273.9)	(683.5)	-	(683.5)	(8,042)	-	(8,042)	(100.7)	-	(100.7)
December 31, 2010	1,510.1	883.8	2,393.9	7,447.2	7,118.9	14,566.1	74,999	35,019	110,018	1,465.4	697.5	2,162.9

Notes:
(1) The Corporation has no unconventional reserves (bitumen, synthetic crude oil, natural gas from coal, etc.).
(2) Numbers may not add due to rounding.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following tables set forth the proved undeveloped reserves and the probable undeveloped reserves, each by product type, attributed to the Corporation as at the end of each of the financial years noted.

Proved Undeveloped Reserves

Year	Light and Medium Oil	Heavy Oil	Natural Gas	Natural Gas Liquids	BOE
	(Mbbl)	(Mbbl)	(MMcf)	(Mbbl)	(MBOE)
2010	337.7	4,657.5	8,771.6	177.1	6,634.2
2009	400.3	1,015.0	10,869	291.9	3,518.7
2008	463.8	0.0	4,469	54.1	1,262.7
Prior thereto	236.9	0.0	1,977	23.3	589.7

At year end 2010, proved undeveloped reserves were primarily attributed to drilling locations in the Frog Lake area for heavy oil and the Pincher Creek and Whitecourt areas for natural gas.

Probable Undeveloped Reserves

Year	Light and Medium Crude Oil	Heavy Oil	Natural Gas	Natural Gas Liquids	BOE
	(Mbbl)	(Mbbl)	(MMcf)	(Mbbl)	(MBOE)
2010	343.5	5,132.5	17,544.2	390.8	8,790.8
2009	881.5	3,882.5	29,078	647.2	10,257.5
2008	534.0	0.0	4,597	54.7	1,354.9
Prior thereto	154.9	0.0	2,072	14.5	514.7

At year end 2010, the majority of the probable undeveloped reserves were attributed to drilling locations in the Frog Lake area for heavy oil and the Pincher Creek and Whitecourt areas for natural gas.

In general, once proved and/or probable undeveloped reserves are identified they are scheduled into Twin Butte's development plans. Normally, the Corporation plans to develop its proved and probable undeveloped reserves within two years. A number of factors that could result in delayed or cancelled development are as follows:

- changing economic conditions (due to pricing, operating and capital expenditure fluctuations);
- changing technical conditions (production anomalies (such as water breakthrough, accelerated depletion));
- multi-zone developments (such as a prospective formation completion may be delayed until the initial completion is no longer economic);
- a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and
- surface access issues (landowners, weather conditions, regulatory approvals).

Significant Factors or Uncertainties

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserves estimates contained herein are based on current production forecasts, prices and economic conditions.

As circumstances change and additional data become available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices, and reservoir performance. Such revisions can be either positive or negative.

Other than as discussed above and the various risks and uncertainties that participants in the oil and gas industry are exposed to generally, Twin Butte is unable to identify any important economic factors or significant uncertainties that will affect any particular components of the reserves data disclosed herein. See "Risk Factors".

Future Development Costs

The following table sets forth development costs deducted in the estimation of the Corporation's future net revenue attributable to the reserve categories noted below ($000's):

	Undiscounted Forecast Prices and Costs ($000's)	
Year	**Proved Reserves**	**Proved Plus Probable Reserves**
2011	36,687	48,084
2012	34,837	61,258
2013	10,774	35,054
2014	1,740	10,058
2015	778	1,611
Thereafter	452	924
Total	85,267	156,987

The Corporation expects that the capital listed in the preceding table will be funded through internally generated cash flows and will not have any associated funding costs. Therefore, the capital commitments will not affect the disclosed reserves of future net revenue.

Other Oil and Gas Information

For a description of the Corporation's important oil and gas properties, please see "Description of Principal Properties".

Oil and Gas Wells

The following table sets forth the number and status of wells in which the Corporation had a working interest as at December 31, 2010.

	Oil Wells				**Natural Gas Wells**			
	Producing		**Non-Producing**		**Producing**		**Non-Producing**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	390	194.6	124	74.2	337	215.3	132	77.1
British Columbia	10	5.9	1	1.0	10	8.7	18	14.3
Saskatchewan	5	3.3	10	7.0	-	-	1	1.0
Total	405	203.8	135	82.2	347	224.0	151	92.4

Properties with no Attributable Reserves

The following table sets out the Corporation's developed and undeveloped land holdings as at December 31, 2010.

	Developed Acres		**Undeveloped Acres**		**Total Acres**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	158,679	100,287	298,447	220,087	457,126	320,374
British Columbia	5,319	4,023	39,676	30,220	44,995	34,243
Saskatchewan	1,638	1,291	321	161	1,959	1,452
Total	165,636	105,601	338,444	250,468	504,080	356,069

The Corporation expects that rights to explore, develop and/or exploit 60,325 net acres of its undeveloped land holdings will expire by December 31, 2011. Twin Butte plans to drill or submit applications to continue selected portions of the above acreage.

Additional Information Concerning Abandonment and Reclamation Costs

The Corporation uses the Energy Resources Conservation Board (the "**ERCB**") assigned liability to estimate its abandonment and reclamation costs when available. If ERCB costs are unavailable, the costs are estimated on an area-by-area basis. If representative comparisons are not readily available, an estimate is prepared based on the industry's historical costs. As at December 31, 2010, the Corporation had 602.4 net wells for which it expects to eventually incur abandonment and reclamation costs.

The total abandonment and reclamation costs in respect of proved and probable reserves using forecast prices is $24 million (undiscounted) and $8.8 million (discounted at 10%). One hundred percent of such amounts were deducted as abandonment and reclamation costs in estimating future net revenue of the Corporation in respect of proved and probable reserves as disclosed above.

The following table sets forth abandonment and reclamation costs deducted in the estimation of the Corporation's future net revenue:

Forecast Prices and Costs (Total Proved) ($000's)

Year	**Abandonment and Reclamation Costs (Undiscounted)**
2011	99
2012	78
2013	68
Thereafter	18,821
Total Undiscounted	19,066
Total Discounted at 10%	7,983

Tax Horizon

The Corporation has no current tax expense and based on current reserve forecasts will be able to realize the benefit of the majority of the non-capital losses and remain non-taxable to at least 2012. Twin Butte has estimated approximately $310 million of tax pools will be available as at December 31, 2010, which can be used to offset taxable income in future years.

Capital Expenditures

The following table summarizes the Corporation's property acquisition (disposition) costs, separately for proved properties and unproved properties, exploration costs and development costs for the year ended December 31, 2010:

	000's
Property acquisition costs	
Proved properties	20,080
Unproved properties	445
Exploration costs	-
Development costs	43,316
Dispositions	(10,743)
Other	2,068
Total	55,166

Note:

(1) Net of drilling royalty credits.

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which Twin Butte participated in the year ended December 31, 2010:

	Exploratory Wells		**Development Wells**	
	Gross	**Net**	**Gross**	**Net**
Natural Gas	-	-	2	2.00
Oil	-	-	84	47.55
Service	-	-	1	1.00
Dry	-	-	1	1.00
Total	-	-	88	51.05

Production Estimates

The following table sets out the volume of the Corporation's production estimated for the year ended December 31, 2011 as evaluated by McDaniel, which is reflected in the estimate of future net revenue disclosed in the tables contained under "Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data".

FORECAST PRICES AND COSTS (1)

	Light and Medium Oil	**Heavy Oil**	**Natural Gas**	**Natural Gas Liquids**	**TOTAL**
Reserves Category	**Gross (bbl/d)**	**Gross (bbl/d)**	**Gross (Mcf/d)**	**Gross (bbl/d)**	**Gross (BOE/d)**
Proved					
Frog Lake	-	3,844	313	-	3,896
Pincher Creek	-	-	3,025	76	580
Viking	187	-	1,941	-	510
Whitecourt	1	-	3,063	14	526
Jayar	86	-	2,332	51	526
Thunder/Leaman	11	-	1,618	16	297
Bulwark	129	-	695	4	249

Reserves Category	Light and Medium Oil Gross (bbl/d)	Heavy Oil Gross (bbl/d)	Natural Gas Gross (Mcf/d)	Natural Gas Liquids Gross (bbl/d)	TOTAL Gross (BOE/d)
Jenner	187	-	-	-	187
Earlie	-	204	-	-	204
Other Properties	326	-	7,311	100	1,638
Total Proved	927	4,048	20,298	261	8,613
Proved Plus Probable					
Frog Lake	-	4,823	323	-	4,873
Pincher Creek	-	-	3,056	76	585
Viking	206	-	2,195	-	571
Whitecourt	1	-	3,149	15	540
Jayar	86	-	2,348	52	529
Thunder/Leaman	11	-	1,632	16	299
Bulwark	136	-	818	5	277
Jenner	223	-	-	-	223
Earlie	-	216	-	-	216
Other Properties	337	-	7,423	104	1,678
Total Proved Plus Probable	1,000	5,039	20,944	268	9,791

Note:
(1) Numbers may not add due to rounding.

The Corporation's Frog Lake field is the only field which accounts for 20% or more of the Corporation's estimated 2011 production in the McDaniel Report.

Production History

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below:

	Quarter Ended			
	2010			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**
Average Daily Production (1)				
Light and Medium Crude Oil (bbl/d)	847	738	743	670
Heavy Oil (bbl/d)	2,491	1,837	1,747	1,405
Gas (Mcf/d)	21,085	21,972	22,423	22,670
NGLs (bbl/d)	310	244	262	287
Combined (BOE/d)	7,161	6,481	6,489	6,140
Average Price Received				
Light and Medium Crude Oil ($/bbl)	74.80	70.35	71.49	77.21
Heavy Oil ($/bbl)	60.98	57.30	56.27	64.47
Gas ($/Mcf)	3.83	3.73	4.17	5.33
NGLs ($/bbl)	66.10	61.57	67.08	70.11
Combined ($/BOE)	44.18	39.21	40.44	46.14
Royalties Paid				
Light and Medium Crude Oil ($/bbl)	13.96	15.67	12.02	13.65
Heavy Oil ($/bbl)	13.03	13.68	15.55	16.95
Gas ($/Mcf)	0.40	0.07	0.54	0.76
NGLs ($/bbl)	25.88	32.52	33.22	30.16
Combined ($/BOE)	8.47	7.97	8.72	9.51

	Quarter Ended			
	2010			
	Dec. 31	Sept. 30	June 30	Mar. 31
Production Costs (2)				
Combined ($/BOE)	15.44	14.51	15.76	15.24
Resulting Netback (3)				
Combined ($/BOE)	22.78	19.91	18.52	21.87

Notes:

(1) Before deduction of royalties.

(2) Operating expenses are composed of direct costs incurred to operate both oil and gas wells and include transportation costs. Operating recoveries associated with operated properties were excluded from operating costs and accounted for as a reduction to general and administrative costs.

(3) Netbacks are calculated by subtracting royalties and operating costs from revenues before hedging.

The following table indicates the Corporation's average daily production from its important fields for the year ended December 31, 2010:

	Light and Medium Crude Oil (bbl/d)	Heavy Oil (bbl/d	Gas (Mcf/d)	NGLS (bbl/d)	BOE (BOE/d)
Frog Lake	-	1,873	271	-	1,918
Plains	464	-	6,352	18	1,540
West Central	180	-	9,539	83	1,853
Deep Basin	106	-	3,162	107	740
Pincher Creek	-	-	2,709	68	520
Total	750	1,873	22,033	276	6,571

For the year ended December 31, 2010, approximately 34% of Twin Butte's gross revenue was derived from natural gas production, 60% was derived from crude oil production and the remaining 6% was derived from NGLs.

Forward Contracts and Marketing

Twin Butte will not be bound by any agreement (including any transportation agreement), directly or through an aggregator, under which it may be precluded from fully realizing, or may be protected from the full effect of, future market prices for oil or natural gas other than as set forth in the table below. In addition, Twin Butte's transportation obligations or commitments for future physical deliveries of oil or natural gas will not exceed Twin Butte's expected related future production from its proved reserves, estimated using forecast prices and costs, as disclosed herein.

As at the date hereof, Twin Butte had the following financial commodity contracts in place:

Commodity Contract	Period	Volume	Price
Oil WTI	January 1 – December 31, 2011	200 bbl/d	Swap $88.00
Oil WTI	January 1 – December 31, 2011	200 bbl/d	Swap $89.40
Oil WTI	January 1 – December 31, 2011	300 bbl/d	Swap $92.04
Oil WTI	February 1 – December 31, 2011	300 bbl/d	Swap $95.05
Oil WTI	March 1 – December 31, 2011	300 bbl/d	Swap $98.05
Oil WTI	January 1 – December 31, 2011	1,000 bbl/d	Call US$95.00
Oil WTI	January 1 – December 31, 2012	1,000 bbl/d	Call US$100.00
Oil WTI	January 1 – December 31, 2012	300 bbl/d	Swap $100.45
Gas AECO GJ	November 1 – October 31, 2011	4,500 GJs/d	Swap $ 5.90
Gas AECO GJ	December 1 – October 31, 2011	1,500 GJs/d	Swap $ 5.90
Gas AECO GJ	January 1 – December 31, 2011	3,000 GJs/d	Call $ 7.00

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining, transportation, and marketing) as a result of legislation enacted by various levels of government and with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta, British Columbia and Saskatchewan, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these regulations or controls will affect the Corporation's operations in a manner materially different than they will affect other oil and natural gas companies of similar size. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing

Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance, and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

Natural Gas

The price of the vast majority of natural gas produced in western Canada is now determined through highly liquid market hubs such as at the Alberta "NIT" (Nova Inventory Transfer) hub rather than through direct negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

The governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements, and market considerations.

Pipeline Capacity

As a result of pipeline expansions over the past several years, there is ample pipeline capacity to accommodate current production levels of oil and natural gas in western Canada and pipeline capacity does not generally limit the ability to produce and market such production.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada United States Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings.

NAFTA prohibits discriminatory border restrictions and export taxes. NAFTA also requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and cash flow within the industry.

Alberta

Producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, currently at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced.

On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" ("**NRF**") containing the Government's proposals for Alberta's new royalty regime which were subsequently implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*. The NRF took effect on January 1, 2009. On March 11, 2010, the Government of Alberta announced changes to Alberta's royalty system intended to increase Alberta's competitiveness in the upstream oil and natural gas sectors, which changes included a decrease in the maximum royalty rates for conventional oil and natural gas production effective for the January 2011 production month. Royalty curves incorporating the changes announced on March 11, 2010 were released on May 27, 2010. Alberta royalties in effect after December 31, 2010 are known as the "Alberta Royalty Framework" ("**ARF**").

With respect to conventional oil, the NRF eliminated the classification system used by the previous royalty structure which classified oil based on the date of discovery of the pool. Under the ARF, royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and incorporates separate variables to account for production rates and market prices. Royalty rates for conventional oil under the NRF ranged from 0-50%, an increase from the previous maximum rates of 30-35% depending on the vintage of the oil, and rate caps were set at $120 per barrel. Effective January 1, 2011, the maximum royalty payable under the ARF was reduced to 40%. The royalty curve for conventional oil announced on May 27, 2010 amends the price component of the conventional oil royalty formula to moderate the increase in the royalty rate at prices higher than $535/m^3 compared to the previous royalty curve.

Royalty rates for natural gas under the ARF are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Royalty rates for natural gas under the NRF ranged from 5-50%, an increase from the previous maximum rates of 5-35%, and rate caps were set at $16.59/GJ. Effective January 1, 2011, the maximum royalty payable under the ARF was reduced to 36%. The royalty curve for natural gas announced on May 27, 2010 amends the price component of the natural gas royalty formula to moderate the increase in the royalty rate at prices higher than $5.25/GJ compared to the previous royalty curve.

Oil sands projects are also subject to the ARF. Prior to payout, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1-9% depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil and Cushing, Oklahoma: rates are 1% when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 1-9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above $55 up to 40% when oil is priced at $120 or higher. An oil sands project reaches payout when its cumulative revenue exceeds its cumulative costs. Costs include specified allowed capital and operating costs related to the project plus a specified return allowance. As part of the implementation of the NRF, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the NRF or the ARF.

Producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold production taxes. The level of the freehold production tax is based on the volume of monthly production and a specified rate of tax for both oil and gas.

In April 2005, the Government of Alberta implemented the Innovative Energy Technologies Program (the "**IETP**"), which has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP is backed by a $200 million funding commitment over a five-year period beginning April 1, 2005 and provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

On April 10, 2008, the Government of Alberta introduced two new royalty programs to be implemented along with the NRF and intended to encourage the development of deeper, higher cost oil and gas reserves. A five-year program for conventional oil exploration wells over 2,000 metres provides qualifying wells with up to a $1 million or 12 months of royalty relief, whichever comes first, and a five-year program for natural gas wells deeper than 2,500 metres provides a sliding scale royalty credit based on depth of up to $3,750 per metre. On May 27, 2010, the natural gas deep drilling program was amended, retroactive to May 1, 2010, by reducing the minimum qualifying depth to 2,000 metres, removing a supplemental benefit of $875,000 for wells exceeding 4,000 metres that are spudded subsequent to that date, and including wells drilled into pools drilled prior to 1985, among other changes.

On November 19, 2008, in response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The five-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this new program, companies drilling new natural gas or conventional deep oil wells (between 1,000 and 3,500 metres) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. Pursuant to the changes made to Alberta's royalty structure announced on March 11, 2010, producers were only able to elect to adopt the transitional royalty rates prior to January 1, 2011 and producers that had already elected to adopt such rates as of that date were permitted to switch to Alberta's conventional royalty structure up until February 15, 2011. On January 1, 2014, all producers operating under the transitional royalty rates will automatically become subject to the ARF. The revised royalty curves for conventional oil and natural gas will not be applied to production from wells operating under the transitional royalty rates.

On March 3, 2009, the Government of Alberta announced a three-point incentive program in order to stimulate new and continued economic activity in Alberta. The program introduced a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program, both applying to conventional oil or natural gas wells drilled between April 1, 2009 and March 31, 2010. The drilling royalty credit provides up to a $200 per metre royalty credit for new wells and is primarily expected to benefit smaller producers since the maximum credit available will be determined using the company's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2010, favouring smaller producers with lower activity levels. The new well incentive program initially applied to wells that began producing conventional oil or natural gas between April 1, 2009 and March 31, 2010 and provided for a maximum 5% royalty rate for the first 12 months of production on a maximum of 50,000 barrels of oil or 500 MMcf of natural gas. In June, 2009, the Government of Alberta announced the extension of these two incentive programs for one year to March 31, 2011. On March 11, 2010, the Government of Alberta announced that the incentive program rate of 5% for the first 12 months of production would be made permanent, with the same volume limitations.

In addition to the foregoing, on May 27, 2010, in conjunction with the release of the new royalty curves, the Government of Alberta announced a number of new initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "**Emerging Resource and Technologies Initiative**"). Specifically:

- coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;

- shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;

- horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and

- horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

The Emerging Resource and Technologies Initiative will be reviewed in 2014, and the Government of Alberta has committed to providing industry with three years notice at that time if it decides to discontinue the program.

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, currently at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced. The amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 ("old oil"), between October 31, 1975 and June 1, 1998 ("new oil"), or after June 1, 1998 ("third-tier oil"). The royalty calculation takes into account the production of oil on a well-by-well basis, the specified royalty rate for a given vintage of oil, the average unit selling price of the oil and any applicable royalty exemptions. Royalty rates are reduced on low productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas as an incentive for the production and marketing of natural gas which might otherwise have been flared.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the level of the freehold production tax is based on the volume of monthly production. For natural gas, the freehold production tax is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas.

British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity wells. These include both royalty credit and royalty reduction programs, including the following:

- *Summer Royalty Credit Program* providing a royalty credit of 10% of drilling and completion costs up to $100,000 for wells drilled between April 1 and November 30 of each year, intended to increase summer drilling activity, employment and business opportunities in northeastern British Columbia;

- *Deep Royalty Credit Program* providing a royalty credit equal to approximately 23% of drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 2,300 metres spudded between December 1, 2003 and September 1, 2009;

- *Deep Re-Entry Royalty Credit Program* providing royalty credits for deep re-entry wells with a true vertical depth greater than 2,300 metres and a re-entry date subsequent to December 1, 2003;

- *Deep Discovery Royalty Credit Program* providing the lesser of a three-year royalty holiday or 283,000,000 m^3 of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation with a spud date after November 30, 2003;

- *Coalbed Gas Royalty Reduction and Credit Program* providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 m^3 as well as a royalty credit for coalbed gas wells equal to $50,000 for wells drilled on Crown land and a tax credit equal to $30,000 for wells drilled on freehold land;

- *Marginal Royalty Reduction Program* providing royalty reductions for low productivity natural gas wells with average monthly production under 25,000 m^3 during the first 12 production months and average daily production less than 23 m^3 for every metre of marginal well depth;

- *Ultra-Marginal Royalty Reduction Program* providing additional royalty reductions for low productivity shallow natural gas wells with a true vertical depth of less than 2,300 metres, average monthly production under 60,000 m^3 during the first 12 production months and average daily production less than 11.5 m^3 (development wells) or 17 m^3 (exploratory wildcat wells) for every 100 metres of marginal well depth; and

- *Net Profit Royalty Reduction Program* providing reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

Oil produced from an oil well that is located on either Crown or freehold land and completed in a new pool discovered subsequent to June 30, 1974 may also be exempt from the payment of a royalty for the first 36 months of production or 11,450 m^3 of production, whichever comes first.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program (the "**Infrastructure Royalty Credit Program**") which provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and gas areas. In both 2009 and 2010, the Government of British Columbia allocated $120 million in royalty credits for oil and gas companies under the Infrastructure Royalty Credit Program.

On August 6, 2009, the Government of British Columbia announced an oil and gas stimulus package designed to attract investment in and create economic benefits for British Columbia. The stimulus package includes four royalty initiatives related primarily to natural gas drilling and infrastructure development. Natural gas wells spudded within the 10-month period from September 1, 2009 to June 30, 2010 and brought on production by December 31, 2010 qualify for a 2% royalty rate for the first 12 months of production, beginning from the first month of production for the well (the "**Royalty Relief Program**"). British Columbia's existing Deep Royalty Credit Program was permanently amended for wells spudded after August 31, 2009 by increasing the royalty deduction on deep drilling for natural gas by 15% and extending the program to include horizontal wells drilled to depths of between 1,900 and 2,300 metres. Wells spudded between September 1, 2009 and June 30, 2010 may qualify for both the Royalty Relief Program and the Deep Royalty Credit Program but will only receive the benefits of one program at a time. An additional $50 million was also allocated to be distributed through the Infrastructure Royalty Credit Program to stimulate investment in oilfield-related road and pipeline construction.

Saskatchewan

In Saskatchewan, the amount payable as Crown royalty or freehold production tax in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is classified as "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil", "third tier oil", "new oil" and "old oil") depend on the finished drilling date of a well and are applied to each of the three crude oil types slightly differently. Heavy oil is classified as third tier oil (having a finished drilling date on or after January 1, 1994 and before October 1, 2004), fourth tier oil (having a finished drilling date on or after October 1, 2002) or new oil (not classified as either third tier oil or fourth tier oil). Southwest designated oil uses the same definitions of third and fourth tier oil but new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002. For non-heavy oil other than southwest designated oil, the same classification is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil. Where average wellhead prices are below the established base prices of \$100 per m^3 for third and fourth tier oil and \$50 per m^3 for new oil and old oil, base royalty rates are applied. Base royalty rates are 5% for all fourth tier oil, 10% for heavy oil that is third tier oil or new oil, 12.5% for southwest designated oil that is third tier oil or new oil, 15% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20% for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30% for all fourth tier oil, 25% for heavy oil that is third tier oil or new oil, 35% for southwest designated oil that is third tier oil or new oil, 35% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45% for old oil.

The amount payable as Crown royalty or freehold production tax in respect of natural gas production is determined by a sliding scale based on the actual price received, the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. Like conventional oil, natural gas may be classified as "non-associated gas" or "associated gas" and royalty rates are determined according to the finished drilling date of the respective well. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non-associated natural gas. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of more than 3,500 m^3 of gas for every m^3 of oil, and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act, 2010* which replaces the existing *Freehold Oil and Gas Production Tax Act* and is intended to facilitate more efficient payment of freehold production taxes by industry. No regulations have been passed with respect to the calculation of freehold production taxes under the new Act.

As with conventional oil production, base prices are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of \$50 per thousand m^3 for third and fourth tier gas and \$35 per thousand m^3 for new gas and old gas, base royalty rates are applied. Base royalty rates are 5% for all fourth tier gas, 15% for third tier or new gas, and 20% for old gas. Where average well-head prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30% for all fourth tier gas, 35% for third tier and new gas, and 45% for old gas.

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, including the following:

- *Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 8,000 m^3 for deep development vertical oil wells, 4,000 m^3 for non-deep exploratory vertical oil wells and 16,000 m^3 for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations);

- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m^3 for qualifying exploratory gas wells;

- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 6,000 m^3 for non-deep horizontal oil wells and 16,000 m^3 for deep horizontal oil wells (more than 1,700 metres or within certain formations);

- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* treating incremental production from waterflood projects as fourth tier oil for the purposes of royalty calculation;

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005* providing Crown royalty and freehold tax determinations based in part on the profitability of enhanced recovery projects pre- and post-payout;

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005* providing a Crown royalty of 1% of gross revenues on enhanced oil recovery projects pre-payout and 20% post-payout and a freehold production tax of 0% on operating income from enhanced oil recovery projects pre-payout and 8% post-payout;

- *Royalty/Tax Regime for High Water-Cut Oil Wells* granting "third tier oil" royalty/tax rates to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities; and

- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m^3 for horizontal gas wells.

In 1975, the Government of Saskatchewan introduced a Royalty Tax Rebate ("**RTR**") as a response to the Government of Canada disallowing crown royalties and similar taxes as a deductible business expense for income tax purposes. As of January 1, 2007, the remaining balance of any unused RTR will be limited in its carry forward to seven years since the Government of Canada's initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income. Saskatchewan's RTR will be wound down as a result of the Government of Canada's plan to reintroduce full deductibility of provincial resource royalties for corporate income tax purposes.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Each of the provinces of Alberta, British Columbia and Saskatchewan has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license. On March 29, 2007, British Columbia's policy of deep rights reversion was expanded for new leases to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of their primary term.

In Alberta, the NRF includes a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license.

Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. The order in which these agreements will receive the reversion notice will depend on their vintage and location, with the older leases and licenses receiving reversion notices first beginning in January 2011. Leases and licences that were granted prior to January 1, 2009 but continued after that date will not be subject to shallow rights reversion until they reach the end of their primary term and are continued (at which time deep rights reversion will be applied); thereafter, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

In December 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans. The *Alberta Land Stewardship Act* (the "**ALSA**") was proclaimed in force in Alberta on October 1, 2009, providing the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA are deemed to be legislative instruments equivalent to regulations and are binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licenses, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment. Although no regional plans have been established under the ALSA, the planning process is underway for the Lower Athabasca Region (which contains the majority of oil sands development) and the South Saskatchewan Region. While the potential impact of the regional plans established under the ALSA cannot yet be determined, it is clear that such regional plans may have a significant impact on land use in Alberta and may affect the oil and gas industry.

Climate Change Regulation

Federal

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Kyoto Protocol**"), which requires a reduction in greenhouse gas ("**GHG**") emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005 and commits Canada to reduce its GHG emissions levels to 6% below 1990 "business-as-usual" levels by 2012.

On February 14, 2007, the House of Commons passed Bill C-288, *An Act to ensure Canada meets its global climate change obligations under the Kyoto Protocol*. The resulting *Kyoto Protocol Implementation Act* came into force on June 22, 2007. Its stated purpose is to "ensure that Canada takes effective and timely action to meet its obligations under the Kyoto Protocol and help address the problem of global climate change." It requires the federal Minister of the Environment to, among other things, produce an annual climate change plan detailing the measures to be taken to ensure Canada meets its obligations under the Kyoto Protocol. It also authorizes the establishment of regulations respecting matters such as emissions limits, monitoring, trading and enforcement.

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets apply to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets.

The Updated Action Plan makes a distinction between "Existing Facilities" and "New Facilities". For Existing Facilities, the Updated Action Plan requires an emissions intensity reduction of 18% below 2006 levels by 2010 followed by a continuous annual emissions intensity improvement of 2%. "New Facilities" are defined as facilities beginning operations in 2004 and include both greenfield facilities and major facility expansions that (i) result in a 25% or greater increase in a facility's physical capacity, or (ii) involve significant changes to the processes of the facility. New Facilities will be given a three-year grace period during which no emissions intensity reductions will be required. Targets requiring an annual 2% emissions intensity reduction will begin to apply in the fourth year of commercial operation of a New Facility. Further, emissions intensity targets for New Facilities will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time. The method of applying this cleaner fuel standard has not yet been determined. In addition, the Updated Action Plan indicates that targets for the adoption of carbon capture and storage ("**CCS**") technologies will be developed for oil sands in-situ facilities, upgraders and coal-fired power generators that begin operations in 2012 or later. These targets will become operational in 2018, although the exact nature of the targets has not yet been determined.

Given the large number of small facilities within the upstream oil and gas and natural gas pipeline sectors, facilities within these sectors will only be subject to emissions intensity targets if they meet certain minimum emissions thresholds. That threshold will be (i) 50,000 tonnes of CO_2 equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalents per facility per year for the upstream oil and gas facility; and (iii) 10,000 BOE/d/company. These regulatory thresholds are significantly lower than the regulatory threshold in force in Alberta, discussed below. In all other sectors governed by the Updated Action Plan, all facilities will be subject to regulation.

Four separate compliance mechanisms are provided for in the Updated Action Plan in respect of the above targets: Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at $15 per tonne of CO_2 equivalent for the 2010 to 2012 period, rising to $20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce GHG emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as described above.

The offset system is intended to encourage emissions reductions from activities outside of the regulated sphere, allowing non-regulated entities to participate in and benefit from emissions reduction activities. In order to generate offset credits, project proponents must propose and receive approval for emissions reduction activities that will be verified before offset credits will be issued to the project proponent. Those credits can then be sold to regulated entities for use in compliance or non-regulated purchasers that wish to either purchase the offset credits for cancellation or banking for future use or sale.

Under the Updated Action Plan, regulated entities will also be able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol which facilitates investment by developed nations in emissions-reduction projects in developing countries. The purchase of such Emissions Reduction Credits will be restricted to 10% of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations.

Finally, a one-time credit of up to 15 million tonnes worth of emissions credits will be awarded to regulated entities for emissions reduction activities undertaken between 1992 and 2006. These credits will be both tradable and bankable.

The United Nations Framework Convention on Climate Change is working towards establishing a successor to the Kyoto Protocol. From December 7 to 18, 2009, a meeting between government leaders and representatives from approximately 170 countries in Copenhagen, Denmark (the "**Copenhagen Conference**") resulted in the Copenhagen Accord, which reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. From November 29 to December 10, 2010, a meeting between representatives from approximately 190 countries in Cancun, Mexico resulted in the Cancun Agreements, in which developed countries committed to additional measures to help developing countries deal with climate change. Unlike the Kyoto Protocol, however, neither the Copenhagen Accord nor the Cancun Agreements establish binding GHG emissions reduction targets.

In response to the Copenhagen Accord, the Government of Canada indicated on January 29, 2010 that it will seek to achieve a 17% reduction in GHG emissions from 2005 levels by 2020. This goal is similar to the goal expressed in previous policy documents which were discussed above.

Although draft regulations for the implementation of the Updated Action Plan were intended to be published in the fall of 2008 and become binding on January 1, 2010, no such regulations have been proposed to date. Further, representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. As a result, it is unclear to what extent, if any, the proposals contained in the Updated Action Plan will be implemented.

On December 23, 2010, the United States Environmental Protection Agency indicated its intention to impose GHG emissions standards for fossil fuel-fired power plants by July 2011 and for refineries by December, 2011.

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the "**CCEMA**") on December 4, 2003, amending it through the *Climate Change and Emissions Management Amendment Act* which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach similar to the Updated Action Plan and aims for a 50% reduction from 1990 emissions relative to GDP by 2020.

Alberta facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Similar to the Updated Action Plan, the CCEMA and the associated *Specified Gas Emitters Regulation* make a distinction between "Established Facilities" and "New Facilities". Established Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2000 or that have completed eight or more years of commercial operation. Established Facilities are required to reduce their emissions intensity to 88% of their baseline for 2008 and subsequent years, with their baseline being established by the average of the ratio of the total annual emissions to production for the years 2003 to 2005. New Facilities are defined as facilities that completed their first year of commercial operation on December 31, 2000, or a subsequent year, and have completed less than eight years of commercial operation, or are designated as New Facilities in accordance with the *Specified Gas Emitters Regulation*. New Facilities are required to reduce their emissions intensity by 2% from baseline in the fourth year of commercial operation, 4% of baseline in the fifth year, 6% of baseline in the sixth year, 8% of baseline in the seventh year, and 10% of baseline in the eighth year. Unlike the Updated Action Plan, the CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA contains compliance mechanisms that are similar to the Updated Action Plan. Regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund (the "**Fund**") at a rate of $15 per tonne of CO_2 equivalent. Unlike the Updated Action Plan, CCEMA contains no provisions for an increase to this contribution rate. Emissions credits can be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta. Unlike the Updated Action Plan, the CCEMA does not contemplate a linkage to external compliance mechanisms such as the Kyoto Protocol's Clean Development Mechanism.

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*, which deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

British Columbia

In February, 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The initial level of the tax was set at $10 per tonne of CO_2 equivalent and rose to $15 per tonne of CO_2 equivalent on July 1, 2009 and $20 per tonne of CO_2 equivalent on July 1, 2010. It is scheduled to further increase at a rate of $5 per tonne of CO_2 equivalent on July 1 of every year until it reaches $30 per tonne of CO_2 equivalent on July 31, 2012. In order to make the tax revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

On April 3, 2008, British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "**Cap and Trade Act**") which received royal assent on May 29, 2008 and will come into force by regulation of the Lieutenant Governor in Council. Unlike the emissions intensity approach taken by the federal government and the Government of Alberta, the Cap and Trade Act establishes an absolute cap on GHG emissions. It is expected that GHG emissions restrictions will be applied to facilities emitting more than 25,000 tonnes of CO_2 equivalents per year, which will be required to meet established targets through a combination of emissions allowances issued by the Government of British Columbia and the purchase of emissions offsets generated through activities that result in a reduction in GHG emissions. Although more specific details of British Columbia's cap and trade plan have not yet been finalized, on January 1, 2010, new reporting regulations came into force requiring all British Columbia facilities emitting over 10,000 tonnes of CO_2 equivalents per year to begin reporting their emissions. Facilities reporting emissions greater than 25,000 tonnes of CO_2 equivalents per year are required to have their emissions reports verified by a third party.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The MRGGA received Royal Assent on May 20, 2010 and will come into force on proclamation. Regulations under the MRGGA have also yet to be proclaimed, but draft versions indicate that Saskatchewan will adopt the goal of a 20% reduction in GHG emissions from 2006 levels by 2020 and permit the use of pre-certified investment credits, early action credits and emissions offsets in compliance, similar to both the federal and Alberta climate change initiatives. It remains unclear whether the scheme implemented by the MRGGA will be based on emissions intensity or an absolute cap on emissions.

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Corporation may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Corporation's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Corporation will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, management of the Corporation may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Corporation.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, the Corporation explores for and produces sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation. In accordance with industry practice, the Corporation is not fully insured against all of these risks, nor are all such risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Corporation could incur significant costs. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and continued in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. Although economic conditions improved towards the latter portion of 2009 and in 2010, as anticipated, the recovery from the recession has been slow in various jurisdictions including in Europe and the United States and has been impacted by various ongoing factors including sovereign debt levels and high levels of unemployment which continue to impact commodity prices and to result in high volatility in the stock market.

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by numerous factors beyond its control. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. The Corporation may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

The prices of oil and natural gas prices may be volatile and subject to fluctuation. Any material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or gas and a reduction in the volumes of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Corporation's expected net production revenue and a reduction in its oil and gas acquisition, development and exploration activities. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions, in the United States and Canada, the actions of OPEC, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing credit and liquidity concerns. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

In addition, bank borrowings available to the Corporation may, in part, be determined by the Corporation's borrowing base. A sustained material decline in prices from historical average prices could reduce the Corporation's borrowing base, therefore reducing the bank credit available to the Corporation which could require that a portion, or all, of the Corporation's bank debt be repaid.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired business may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of, so that the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Corporation, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Corporation.

Operational Dependence

Other companies operate some of the assets in which the Corporation has an interest. As a result, the Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others therefore depends upon a number of factors that may be outside of the Corporation's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Project Risks

The Corporation manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. The Corporation's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Corporation's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;

- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Corporation could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

Competition

The petroleum industry is competitive in all its phases. The Corporation competes with numerous other organizations in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. The Corporation's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "Industry Conditions". Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for natural gas and crude oil and increase the Corporation's costs, any of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and gas operations, the Corporation will require licenses from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Climate Change

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases and require the Corporation to comply with greenhouse gas emissions legislation in Alberta and British Columbia or that may be enacted in other provinces. The Corporation may also be required comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which is now expected to be modified to ensure consistency with the regulatory scheme for greenhouse gas emissions adopted by the United States. The direct or indirect costs of these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The future implementation or modification of greenhouse gases regulations, whether to meet the limits required by the Kyoto Protocol, the Copenhagen Accord or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition. See "Industry Conditions – Climate Change Regulation".

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Material increases in the value of the Canadian dollar negatively impact the Corporation's production revenues. Future Canadian/United States exchange rates could accordingly impact the future value of the Corporation's reserves as determined by independent evaluators.

To the extent that the Corporation engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Corporation may contract.

An increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, which could negatively impact the market price of the Common Shares of the Corporation.

Substantial Capital Requirements

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. In addition, uncertain levels of near term industry activity coupled with the present global credit crisis exposes the Corporation to additional access to capital risk. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Additional Funding Requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Corporation's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Corporation. Continued uncertainty in domestic and international credit markets could materially affect the Corporation's ability to access sufficient capital for its capital expenditures and acquisitions, and as a result, may have a material adverse effect on the Corporation's ability to execute its business strategy and on its business, financial condition, results of operations and prospects.

Availability of Credit Facilities

The Credit Facilities are available until demanded by the lenders and are subject to periodic review by and at the discretion of the lenders, with the next scheduled review to occur in April 2011. Any failure of the Corporation to repay or refinance any or all of the Credit Facilities upon demand by the lenders on acceptable terms or to comply with applicable covenants under the

Credit Facilities could have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. There is no assurance that the Corporation will be able to refinance any or all of the Credit Facilities in the event of a demand by the lenders on acceptable terms, or on any basis.

Leverage and Restrictive Covenants

The ability of the Corporation to make payments or advances will be subject to applicable laws and contractual restrictions in the instruments governing any indebtedness of the Corporation (including the Credit Facilities). The degree to which the Corporation is leveraged could have important consequences for shareholders including: (i) the Corporation's ability to obtain additional financing for working capital, capital expenditures or acquisitions in the future may be limited; (ii) all or part of the Corporation's cash flow from operations may be dedicated to the payment of the principal of and interest on the Corporation's indebtedness, thereby reducing funds available for future operations; (iii) the Corporation's borrowings are at variable rates of interest, which exposes the Corporation to the risk of increased interest rates; and (iv) the Corporation may be more vulnerable to economic downturns and be limited in its ability to withstand competitive pressures. These factors could have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

The Credit Facilities contain numerous covenants that limit the discretion of management of the Corporation with respect to certain business matters. These covenants will place restrictions on, among other things, the ability of the Corporation to create liens or other encumbrances, to pay dividends or make certain other payments, investments, loans and guarantees and to sell or otherwise dispose of assets and merge or consolidate with another entity. In addition, the Credit Facilities contain a number of financial covenants that will require the Corporation to meet certain financial ratios and financial condition tests. A failure to comply with the obligations in the Credit Facilities could result in a default which, if not cured or waived, would permit acceleration of the relevant indebtedness. If the indebtedness under the Credit Facilities were to be accelerated due to a demand by the lenders, there can be no assurance that the assets of the Corporation would be sufficient to repay in full that indebtedness.

Issuance of Debt

From time to time the Corporation may enter into transactions to acquire assets or the shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Corporation's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Corporation may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time, could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

From time to time the Corporation may enter into agreements to receive fixed prices on a portion of its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Corporation will not benefit from such increases and the Corporation may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, the Corporation will not benefit from the fluctuating exchange rate. Similarly, from time to time, the Corporation may enter into agreements to fix the underlying future interest payable on outstanding indebtedness under the Credit Facilities; however, if interest rates are less than the rates fixed by the Corporation, the Corporation will not benefit from the fluctuating interest rate.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Corporation and may delay exploration and development activities.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Corporation's claim which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, the Corporation's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Corporation's oil and gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and has not been updated and thus does not reflect changes in the Corporation's reserves since that date.

Insurance

The Corporation's involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Corporation maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, such risks are not, in all circumstances, insurable or, in certain circumstances, the Corporation may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Geo-Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle-East, and other areas of the world, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of the Corporation's net production revenue.

In addition, the Corporation's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation will not have insurance to protect against the risk from terrorism.

Dilution

The Corporation may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Corporation which may be dilutive.

Management of Growth

The Corporation may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Corporation to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Corporation to deal with this growth may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Expiration of Licences and Leases

The Corporation's properties are held in the form of licences and leases and working interests in licences and leases. If the Corporation or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Corporation's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Dividends

The Corporation has not paid any dividends on its outstanding shares. Payment of dividends in the future will be dependent on, among other things, the cash flow, results of operations and financial condition of the Corporation, the need for funds to finance ongoing operations and other considerations as the Board of Directors of the Corporation considers relevant.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. The Corporation is not aware that any claims have been made in respect of its properties and assets; however, if a claim arose and was successful such claim may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Corporation.

Third Party Credit Risk

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

Conflicts of Interest

Certain directors of the Corporation are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA. See "Directors and Executive Officers – Conflicts of Interest".

Reliance on Key Personnel

The Corporation's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have any key person insurance in effect for the Corporation. The contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

DIVIDENDS

Twin Butte has not declared or paid any dividends on the Common Shares or preferred shares during the three most recently completed financial years. Any decision to pay dividends on the Common Shares will be made by the Board of Directors on the basis of Twin Butte's earnings, financial requirements and other conditions existing at such future time.

In accordance with the Credit Facilities, the Corporation must obtain approval of its lenders prior to paying a dividend on the Common Shares.

DESCRIPTION OF CAPITAL STRUCTURE

The authorized capital of Twin Butte consists of an unlimited number of Common Shares and an unlimited number of preferred shares issuable in series, each having the rights, privileges, restrictions and conditions described below.

Common Shares

Holders of Common Shares are entitled to one vote per share at meetings of shareholders of Twin Butte, to receive dividends if, as and when declared by the Board of Directors of Twin Butte and to receive pro rata the remaining property and assets of Twin Butte upon its dissolution, liquidation or winding-up, subject to the rights of shares having priority over the Common Shares.

Preferred Shares

Each series of preferred shares shall consist of such number of shares and have such rights, privileges, restrictions and conditions as may be determined by the Board of Directors of Twin Butte prior to the issuance thereof. With respect to the payment of dividends and distribution of assets in the event of liquidation, dissolution or winding-up of Twin Butte, whether voluntary or involuntary, the preferred shares are entitled to preference over the Common Shares and any other shares ranking junior to the preferred shares from time to time and may also be given such other preferences over the Common Shares and any other shares ranking junior to the preferred shares as may be determined at the time of creation of such series.

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSX under the symbol "TBE". The following table sets forth the high and low sales prices (which are not necessarily the closing prices) and the trading volumes for the Common Shares on the TSX as reported by the TSX for the periods indicated:

	Price Range ($)		Trading
Period	**High**	**Low**	**Volume**
2010			
January	1.39	0.92	16,598,546
February	1.44	1.14	12,058,801
March	1.49	1.22	16,629,911
April	1.59	1.29	12,276,011
May	1.54	1.18	7,707,610
June	1.42	1.33	5,385,717
July	1.34	1.25	1,701,211
August	1.32	1.25	3,403,410
September	1.48	1.25	17,524,774
October	1.69	1.45	18,819,028
November	1.99	1.60	19,860,040
December	2.19	1.88	15,629,761
2011			
January	2.73	2.00	29,626,034
February	3.23	2.68	31,124,627
March (1 to 24)	3.44	2.77	17,383,863

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

To the knowledge of management of the Corporation, none of the securities of the Corporation are held in escrow or are subject to a contractual restriction on transfer as at the date hereof.

DIRECTORS AND EXECUTIVE OFFICERS

Name, Occupation and Security Holding

The following table sets forth certain information in respect to Twin Butte's directors and executive officers:

Name, Province and Country of Residence	Position(s) with Twin Butte (1)	Principal Occupation During the Five Years Preceding
David M. Fitzpatrick (2)(3) Alberta, Canada	Chairman and Director	Independent businessman since July 2007 and prior thereto President and Chief Executive Officer of Shiningbank Energy Ltd., administrator of Shiningbank Energy Income Fund (oil and gas fund).
R. James Brown (2)(4) Alberta, Canada	Director	Independent businessman since January 1, 2009 and prior thereto, Vice President and Chief Financial Officer of Fording Canadian Coal Trust, Fording (GP) ULC and Elk Valley Coal.
John A. Brussa (3) Alberta, Canada	Director	Partner, Burnet, Duckworth & Palmer LLP (law firm).

Name, Province and Country of Residence	Position(s) with Twin Butte [(1)]	Principal Occupation During the Five Years Preceding
Warren Steckley (2)(3)(4) Alberta, Canada	Director	President and Chief Operating Officer of Barnwell of Canada, Limited (oil and gas company).
William A. Trickett (4) Alberta, Canada	Director	Independent businessman since October 14, 2009 and prior thereto President and Chief Executive Officer of Buffalo (oil and gas company).
James Saunders Alberta, Canada	President, Chief Executive Officer and Director	President and Chief Executive Officer of Twin Butte since November 5, 2008 and Chairman of Twin Butte from December 13, 2005 to November 5, 2008; Independent businessman from September 2006 to December 13, 2006; and prior thereto Chairman and Chief Executive Officer of Prairie Schooner Petroleum Ltd. (oil and gas company).
R. Alan Steele Alberta, Canada	Vice President, Finance, Chief Financial Officer and Corporate Secretary	Vice President, Finance and Chief Financial Officer of Twin Butte since October 2007; prior thereto, Vice-President, Finance, Chief Financial Officer and interim Chief Executive Officer of Bear Ridge Resources Ltd. (oil and gas company) since February 2007; prior thereto, Vice President, Finance and Chief Financial Officer of Twin Butte since September 2006; and prior thereto, Vice President, Finance and Chief Financial Officer of Ketch Resources Ltd., administrator of Ketch Resources Trust (oil and gas trust).
Bruce W. Hall Alberta, Canada	Chief Operating Officer	Chief Operating Officer of Twin Butte since January 3, 2011; prior thereto, Vice President, Corporate Development of Twin Butte from June 9, 2009 to January 3, 2011 and prior thereto Vice President, Engineering of Alberta Clipper Energy Inc. (oil and gas company).
R.D. (Bob) Bowman Alberta, Canada	Vice President, Operations	Vice President, Operations of Twin Butte since June 1, 2010; prior thereto President of BCF Resources Ltd. (private oil and gas consulting company) from January 2008 to June 1, 2010 and prior thereto President and Chief Operating Officer of Action Energy Inc. (oil and gas company).
Neil Cathcart Alberta, Canada	Vice President, Exploration	Vice President, Exploration of Twin Butte since November 13, 2008; and prior thereto, Vice President, Exploration at Revolve Energy Ltd. (oil and gas company).
J. Michael Fabi Alberta, Canada	Vice President, Engineering	Vice President, Engineering of Twin Butte since December 1, 2008; prior thereto, Vice President, Engineering of Napa Energy Ltd. (oil and gas company) from December 2006 to October 2008; and prior thereto, Vice President, Engineering of Grey Wolf Exploration Inc. (oil and gas company).
Colin Ogilvy Alberta, Canada	Vice President, Land	Vice President, Land of Twin Butte since November 13, 2008; prior thereto, President and Chief Executive Officer of Rival Energy Ltd. (oil and gas company).

Notes:

(1) All of the directors of Twin Butte have been appointed to hold office until the next annual general meeting of shareholders or until their successor is duly elected or appointed, unless their office is earlier vacated. Messrs. Fitzpatrick, Brown, Brussa, Steckley,

Trickett and Saunders have been directors of Twin Butte since December 8, 2008, February 8, 2008, March 22, 2011, July 13, 2009, October 14, 2009 and December 30, 2005, respectively.

(2) Member of the Audit Committee.

(3) Member of the Compensation, Nominating and Corporate Governance Committee.

(4) Member of the Reserves Committee.

(5) Twin Butte does not have an Executive Committee.

As at the date of this Annual Information Form, the number of Common Shares beneficially owned, or controlled or directed, directly or indirectly, by all of the directors and officers of Twin Butte is 5,771,255 Common Shares, being approximately 4.5% of the issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Cease Trade Orders

To the knowledge of Twin Butte, no director or executive officer of Twin Butte (nor any personal holding company of any of such persons) is, as of the date of this Annual Information Form, or was within ten years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including Twin Butte), that: (a) was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, an "**Order**"), that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (b) was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

Bankruptcies

To the knowledge of Twin Butte, except as described below, no director or executive officer of Twin Butte (nor any personal holding company of any of such persons) or shareholder holding a sufficient number of securities of Twin Butte to affect materially the control of Twin Butte: (a) is, as of the date of this Annual Information Form, or has been within the ten years before the date of this Annual Information Form, a director or executive officer of any company (including Twin Butte) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (b) has, within the ten years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

John A. Brussa, a director of Twin Butte, was a director of Imperial Metals Limited, a corporation engaged in both oil and gas and mining operations, in the year prior to that corporation implementing a plan of arrangement under the *Companies Act* (British Columbia) and under the *Companies' Creditors Arrangement Act* (Canada) which resulted in the separation of its two businesses. The reorganization resulted in the creation of two public corporations, Imperial Metals Corporation and IEI Energy Inc. (previously Rider Resources Ltd.), both of which were traded on the Toronto Stock Exchange following the reorganization. The plan of arrangement was completed in April 2002.

Penalties or Sanctions

To the knowledge of Twin Butte, no director or executive officer of Twin Butte (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of securities of Twin Butte to affect materially the control of Twin Butte, has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

There are potential conflicts of interest to which the directors and officers of the Corporation will be subject in connection with the operations of the Corporation. In particular, certain of the directors and officers of the Corporation are involved in managerial and/or director positions with other oil and gas companies whose operations may, from time to time, be in direct competition with those of the Corporation or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of the Corporation. Conflicts, if any, will be subject to the procedures and remedies available under the ABCA. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the ABCA.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal Proceedings

Except as set forth below, none of the Corporation or any of its subsidiaries is a party to any legal proceeding nor was it a party to any legal proceeding during the financial year ended December 31, 2010, nor is the Corporation aware of any contemplated legal proceeding involving the Corporation or its subsidiaries or any of its property which involves a claim for damages exclusive of interest and costs that may exceed 10% of the current assets of the Corporation. On February 25, 2009, Divestco Inc. ("**Divestco**") commenced a claim against Twin Butte Energy Ltd. (**Twin Butte**) and several Devon Energy Corporations (**Devon**). Divestco alleges that Devon breached a seismic data license agreement by reproducing or displaying Divestco seismic data to Twin Butte and other third parties. Divestco alleges breach of copyright and breach of confidence by Twin Butte by its accessing and further displaying the seismic data. Divestco seeks an injunction to prevent further disclosure of the seismic data, termination of the license agreement, damages of $3,725,578.00 for a loss of license fee to Twin Butte and a further $3,725,578.00 for a loss of license fee to other potential licensees, and the accounting and disgorgement of any profits made by Twin Butte and Devon under a farm-in agreement entered into after Twin Butte's access to the seismic data. Twin Butte filed a Statement of Defence on May 7, 2009 in which it acknowledges that it viewed the Divestco seismic data, pursuant to an agreement between the parties and in accordance with industry custom and practice, but denies that Twin Butte made any reproduction of or misused the data in any way. The parties have exchanged records and examinations for discovery of selected Devon employees have been completed. Part of the discovery information included evidence that Twin Butte had not in fact viewed the Divestco seismic data, but a Devon compiled merged data set that included many component data, including the Divestco seismic data. On April 29, 2010, Twin Butte amended its Statement of Defence to reflect the nature of the data it viewed. Discoveries of former Twin Butte employees have not yet been scheduled.

Regulatory Actions

During the year ended December 31, 2010, there were no (i) penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority; (ii) any other penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision, or (iii) settlement agreements the Corporation entered into before a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There are no material interests, direct or indirect, of any director or executive officer of the Corporation, any person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of any class or series of the Corporation's outstanding voting securities, or any associate or affiliate of any of the foregoing persons or companies, in any transaction within the three most recently completed financial years or during the current financial year which has materially affected or is reasonably expected to materially affect the Corporation, other than as disclosed elsewhere in this Annual Information Form.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares is Valiant Trust Company at its principal offices in Calgary, Alberta and its agent's offices in Toronto, Ontario.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business (unless otherwise required by applicable securities requirements to be disclosed), the Corporation has not entered into any material contracts during the last financial year, or before the last financial year which are still in effect.

INTERESTS OF EXPERTS

Names of Experts

The only persons or companies who are named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Corporation during, or relating to, the Corporation's most recently completed financial year, and whose profession or business gives authority to the report, valuation statement or opinion made by the person or company, are PricewaterhouseCoopers LLP, the Corporation's independent auditors, and McDaniel, the Corporation's independent engineering evaluators.

Interests of Experts

To the Corporation's knowledge, there were no registered or beneficial interests, direct or indirect, in any securities or other property of the Corporation or of one of its associates or affiliates: (i) held by McDaniel or by the "designated professionals" (as defined in Form 51-102F2 to National Instrument 51-102) of McDaniel, when McDaniel prepared the report, valuation, statement or opinion referred to herein as having been prepared by McDaniel; (ii) received by McDaniel or by the "designated professionals" of McDaniel, after the time specified above; or (iii) to be received by McDaniel or by the "designated professionals" of McDaniel; except in each case for the ownership of Common Shares, which in respect of McDaniel and McDaniel's "designated professionals", as a group, has at all relevant times represented less than one percent of the outstanding Common Shares. In addition, neither McDaniel, nor any director, officer or employee of McDaniel, is or is expected to be elected, appointed or employed as a director, officer or employee of the Corporation or of any associate or affiliate of the Corporation.

Neither PricewaterhouseCoopers LLP or McDaniel, nor any director, officer or employee of PricewaterhouseCoopers LLP or McDaniel is or is expected to be elected, appointed or employed as a director, officer or employee of the Corporation or of any associate or affiliate of the Corporation.

PricewaterhouseCoopers LLP is independent of the Corporation within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

The Mandate and Terms of Reference of the Audit Committee of the Board of Directors is attached hereto as Schedule "C".

Composition of the Audit Committee

The Audit Committee of the Corporation is currently comprised of R. James Brown (Chair), David M. Fitzpatrick and Warren Steckley. The following table sets out the assessment of each Audit Committee member's independence, financial literacy and relevant educational background and experience supporting such financial literacy.

Name and Municipality of Residence	Independent	Financially Literate	Relevant Education and Experience
R. James Brown Calgary, Alberta	Yes	Yes	Mr. Brown's education and experience relevant to the performance of his responsibilities as an Audit Committee member are derived from his experience as Vice President and Chief Financial Officer of Fording Canadian Coal Trust, Fording (GP) ULC and Elk Valley Coal from October 2005 until January 2009; prior thereto, Vice President, Finance and Chief Financial

Name and Municipality of Residence	Independent	Financially Literate	Relevant Education and Experience
			Officer of High Point Resources Ltd. (oil and gas company) from March 2004 to August 2005; and prior thereto, Vice President, Finance and Chief Financial Officer of Terraquest Energy Inc. (oil and gas company). He has over 25 years of experience in the oil and gas industry, including ten years as Chief Financial Officer with High Point Resources Inc., Dorset Exploration Ltd., Richland Petroleum Inc., and Terraquest Energy Inc. He has also developed practical experience and understanding of procedures for financial reporting from his service on boards and audit committees of numerous publicly traded companies. Mr. Brown holds a Bachelor of Commerce degree from the University of Calgary and is a Chartered Accountant.
David M. Fitzpatrick Calgary, Alberta	Yes	Yes	Mr. Fitzpatrick's education and experience relevant to the performance of his responsibilities as an audit committee member are derived from his experience as President, Chief Executive Officer and a director of Shiningbank Energy Ltd. from 1996 to 2007. Mr. Fitzpatrick has over 29 years of experience in the oil and gas industry. He has also developed practical experience and understanding of procedures for financial reporting from his service on boards and audit committees of numerous publicly traded companies. Mr. Fitzpatrick obtained his BSc. in Geological Engineering from Queens University, and has obtained the Chartered Director Designation from the DeGroote School of Business.
Warren Steckley Calgary, Alberta	Yes	Yes	Mr. Steckley's education and experience relevant to the performance of his responsibilities as an Audit Committee member are derived from his experience as President and Chief Operating Officer of Barnwell of Canada, Limited (oil and gas company) since 1998 and prior thereto, his five years of experience in corporate finance at PowerWest Financial Ltd. (now ARC Resources Ltd.). Through his interaction with Chief Financial Officers over the years, Mr. Steckley has developed practical experience and understanding of procedures for financial reporting. He has also developed practical experience and understanding of procedures for financial reporting from his service on boards and audit committees of numerous publicly traded companies. Mr. Steckley obtained a BSc. in Mechanical Engineering and a Master of Business Administration from the University of Alberta.

Pre-Approval of Policies and Procedures

Under the Mandate and Terms of Reference of the Audit Committee, the Audit Committee is required to review and pre-approve any non-audit services to be provided to the Corporation or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Audit Committee may delegate to one or more independent members the authority to pre-approve non-audit services, provided that the member report to the Audit Committee at the next scheduled meeting such pre-approval and the member comply with such other procedures as may be established by the Audit Committee from time to time.

The Audit Committee has determined that in order to ensure the continued independence of the auditors, only limited non-audit related services will be provided to the Corporation by PricewaterhouseCoopers LLP and in such case, only with the prior approval of the Audit Committee.

External Auditors Service Fees

The following table sets forth the audit service fees billed by Twin Butte's external auditors, PricewaterhouseCoopers LLP, for the periods indicated:

Type of Fees and Fiscal Year Ended	Aggregate Fees Billed	Description of Services
Audit Fees		
Fiscal Year Ended December 31, 2010	$124,000	Audit of financial statements and review of interim financial statements
	$25,000	IFRS transition
Fiscal Year Ended December 31, 2009	$117,500	Audit of financial statements and review of interim financial statements
Audit – Related Fees		
Fiscal Year Ended December 31, 2010	$7,500	Professional services rendered in respect of component evaluation of IFRS templates and with respect to responding to a continuous disclosure review by the Alberta Securities Commission
Fiscal Year Ended December 31, 2009	$31,000	Professional services rendered with respect to the completion of the information circular of Buffalo and of the business acquisition report in connection with the Buffalo Arrangement
Tax Fees		
Fiscal Year Ended December 31, 2010	$Nil	
Fiscal Year Ended December 31, 2009	$Nil	
All Other Fees		
Fiscal Year Ended December 31, 2010	$Nil	
Fiscal Year Ended December 31, 2009	$40,000	Due diligence fees related to the Buffalo Arrangement

ADDITIONAL INFORMATION

Additional information relating to Twin Butte may be found on SEDAR at www.sedar.com.

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Twin Butte's securities and securities authorized for issuance under equity compensation plans will be contained in Twin Butte's information circular – proxy statement relating to the annual meeting of shareholders to be held on May 26, 2011.

Additional information is also provided in Twin Butte's financial statements and management's discussion and analysis for the year ended December 31, 2010, which documents may be found on SEDAR at www.sedar.com.

SCHEDULE "A"

REPORT ON RESERVES DATA BY MCDANIEL & ASSOCIATES CONSULTANTS LTD. IN ACCORDANCE WITH FORM 51-101F2

To the Board of Directors of Twin Butte Energy Ltd. (the "**Corporation**"):

1. We have evaluated the Corporation's reserves data as at December 31, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Corporation's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Corporation evaluated by us for the year ended December 31, 2010, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Corporation's management:

Independent Qualified Reserves Evaluator	**Description and Preparation Date of Evaluation Report**	**Location of Reserves (Country or Foreign Geographic Area)**	**Net Present Value of Future Net Revenue ($ thousands – before income taxes, 10% discount rate)**			
			Audited	**Evaluated**	**Reviewed**	**Total**
McDaniel & Associates Consultants Ltd.	Evaluation of P&NG Reserves of Twin Butte Energy Ltd. as at December 31, 2010, prepared March 7, 2011	Canada	-	517,074.7	-	517,074.7

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our report referred to in paragraph 4 for events and circumstances occurring after its preparation date.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

   Executed as to our report referred to above:

McDaniel & Associates Consultants Ltd., Calgary, Alberta, Canada, March 25, 2011.

Per: (Signed) P.A. Welch, P.Eng
P.A. Welch, P.Eng
President and Managing Director

SCHEDULE "B"

REPORT OF TWIN BUTTE MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE IN ACCORDANCE WITH FORM 51-101F3

Management of Twin Butte Energy Ltd. (the "**Corporation**") is responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved and probable reserves and related future net reserves as at December 31, 2010, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the Board of Directors of the Corporation has:

(a) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the Board of Directors of the Corporation has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved:

(a) the content and filing with securities regulatory authorities of Form 51-101 F1 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

DATED as of March 25, 2011.

(Signed) James Saunders
President and Chief Executive Officer

(Signed) Bruce W. Hall
Chief Operating Officer

(Signed) Warren Steckley
Director and Chairman of the Reserves Committee

(Signed) William A. Trickett
Director and Member of the Reserves Committee

SCHEDULE "C"

TWIN BUTTE ENERGY LTD.

AUDIT COMMITTEE

MANDATE AND TERMS OF REFERENCE

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of Twin Butte Energy Ltd. ("**Twin Butte**" or the "**Corporation**") to which the Board has delegated its responsibility for the oversight of the following:

1. nature and scope of the annual audit;

2. the oversight of management's reporting on internal accounting standards and practices;

3. the review of financial information, accounting systems and procedures;

4. financial reporting and financial statements,

and has charged the Committee with the responsibility of recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information.

The primary objectives of the Committee are as follows:

1. to assist directors of Twin Butte ("**Directors**") in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of the Corporation and related matters;

2. to provide better communication between Directors and external auditors;

3. to enhance the external auditor's independence;

4. to increase the credibility and objectivity of financial reports; and

5. to strengthen the role of the outside Directors by facilitating in depth discussions between Directors on the Committee, management of Twin Butte ("**Management**") and external auditors.

Membership of Committee

1. The Committee will be comprised of at least three (3) Directors or such greater number as the Board may determine from time to time and all members of the Committee shall be "independent" (as such term is used in National Instrument 52-110 – Audit Committees ("**NI 52-110**") unless the Board determines that the exemption contained in NI 52-110 is available and determines to rely thereon.

2. The Board may from time to time designate one of the members of the Committee to be the Chair of the Committee.

3. All of the members of the Committee must be "financially literate" (as defined in NI 52-110) unless the Board determines that an exemption under NI 52-110 from such requirement in respect of any particular member is available and determines to rely thereon in accordance with the provisions of NI 52-110.

Mandate and Responsibilities of Committee

It is the responsibility of the Committee to:

1. Oversee the work of the external auditors, including the resolution of any disagreements between Management and the external auditors regarding financial reporting.

2. Satisfy itself on behalf of the Board with respect to Twin Butte's internal control systems.

3. Review the annual and interim financial statements of the Corporation and related management's discussion and analysis ("**MD&A**") prior to their submission to the Board for approval. The process should include but not be limited to:

    - reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future years' financial statements;

    - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;

    - reviewing accounting treatment of unusual or non-recurring transactions;

    - ascertaining compliance with covenants under loan agreements;

    - reviewing disclosure requirements for commitments and contingencies;

    - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;

    - reviewing unresolved differences between Management and the external auditors; and

    - obtain explanations of significant variances with comparative reporting periods.

4. Review the financial statements, prospectuses and other offering documents, MD&A, annual information forms ("**AIF**") and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of Twin Butte's disclosure of all other financial information and will periodically assess the accuracy of those procedures.

5. Review and approve the disclosure of audit committee information required to be included in the AIF of the Corporation prior to its filing with regulatory authorities.

6. With respect to the appointment of external auditors by the Board:

    - recommend to the Board the external auditors to be nominated;

    - recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors will report directly to the Committee;

    - on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Corporation to determine the auditors' independence;

    - when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and

    - review and pre-approve any non-audit services to be provided to Twin Butte or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Committee may delegate to one or more independent members the authority to pre-approve non-audit services, provided that the member(s) report to the Committee at the next scheduled meeting such pre-approval and the member(s) comply with such other procedures as may be established by the Committee from time to time.

7. Review with external auditors (and internal auditor if one is appointed by Twin Butte) their assessment of the internal controls of Twin Butte, their written reports containing recommendations for improvement, and Management's response and follow-up to any identified weaknesses. The Committee will also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Twin Butte and its subsidiaries.

8. Review risk management policies and procedures of Twin Butte (i.e. hedging, litigation and insurance).

9. Establish a procedure for:

    - the receipt, retention and treatment of complaints received by Twin Butte regarding accounting, internal accounting controls or auditing matters; and

    - the confidential, anonymous submission by employees of Twin Butte of concerns regarding questionable accounting or auditing matters.

10. Review and approve Twin Butte's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of the Corporation.

The Committee has authority to communicate directly with the internal auditors (if any) and the external auditors of the Corporation. The Committee will also have the authority to investigate any financial activity of Twin Butte. All employees of Twin Butte are to cooperate as requested by the Committee.

The Committee may also retain persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at such compensation as established by the Committee and at the expense of Twin Butte without any further approval of the Board.

Meetings and Administrative Matters

1. At all meetings of the Committee every resolution shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall be entitled to a second or casting vote.

2. The Chair will preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee that are present will designate from among such members the Chair for purposes of the meeting.

3. A quorum for meetings of the Committee will be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee will be the same as those governing the Board unless otherwise determined by the Committee or the Board.

4. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee will be taken. The Chief Financial Officer of Twin Butte will attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.

5. The Committee will meet with the external auditor at least once per year (in connection with the preparation of the year-end financial statements) and at such other times as the external auditor and the Committee consider appropriate.

6. Agendas, approved by the Chair, will be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.

7. The Committee may invite such officers, directors and employees of the Corporation and its subsidiaries as it sees fit from time to time to attend at meetings of the Committee and assist in the discussion and consideration of the matters being considered by the Committee.

8. Minutes of the Committee will be recorded and maintained and circulated to Directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board.

9. The Committee may retain persons having special expertise and may obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation.

10. Any members of the Committee may be removed or replaced at any time by the Board and will cease to be a member of the Committee as soon as such member ceases to be a Director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy exists on the Committee, the remaining members may exercise all its powers so long as two (2) members remain on the Committee. Subject to the foregoing, following appointment as a member of the Committee each member will hold such office until the Committee is reconstituted.

11. Any issues arising from these meetings that bear on the relationship between the Board and Management should be communicated to the Chairman of the Board by the Committee Chair.