Twin Butte Energy Ltd.

ANNUAL INFORMATION FORM

for the year ended December 31, 2008

March 27, 2009

TABLE OF CONTENTS

Page

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, 2008.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements contained in this Annual Information Form constitute forward-looking statements. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe" and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Corporation believes that the expectations reflected in these forward-looking statements are based on reasonable assumptions but no assurance can be given that these expectations will prove to be correct and the forward-looking statements included in this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form and the Corporation undertakes no obligation to update or revise any forward-looking statements except as expressly required by applicable securities laws.

In particular, this Annual Information Form contains forward-looking statements pertaining to the following:

- the performance characteristics of the Corporation's oil and natural gas properties;
- oil and natural gas production levels and the sources of their growth;
- capital expenditure programs;
- the estimated quantity of oil and natural gas reserves and recovery rates;
- projections of commodity prices and costs;
- supply and demand for oil and natural gas;
- planned construction and expansion of facilities;
- drilling plans;
- availability of rigs, equipment and other goods and services;
- procurement of drilling licenses;
- reserve life;
- plans for and results of exploration and development activities;
- expectations regarding the Corporation's ability to raise capital and to continually add to reserves through acquisitions, exploration and development;
- treatment under governmental regulatory regimes and tax laws; and
- realization of the anticipated benefits of acquisitions and dispositions.

With respect to such forward-looking statements the Corporation has made assumptions regarding, among other things, the Corporation's ability to obtain equity and debt financing on satisfactory terms, oil and natural gas prices; well production rates and reserve volumes; the Corporation's ability to add production and reserves through its exploration and development activities; capital expenditure levels; the availability and cost of labour and other industry services; interest and foreign exchange rates; and the continuance of existing royalty regimes.

The Corporation's actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Annual Information Form:

- general economic, market and business conditions in Canada, the United States and globally;
- volatility in market prices for oil and natural gas;

- risks inherent in oil and natural gas operations, including production risks associated with sour hydrocarbons;
- operational dependence on other companies;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands, skilled personnel and services;
- unanticipated operating events which can reduce production or cause production to be shut in or delayed;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems;
- actions by governmental authorities, including increases in taxes;
- the availability of capital on acceptable terms;
- fluctuations in foreign exchange or interest rates and stock market volatility;
- failure to obtain industry partner and other third party consents and approvals, when required; and
- the other factors discussed under "Risk Factors" in this Annual Information Form.

Statements relating to "reserves" or "resources" are by their nature forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described can be profitably produced in the future. These factors should not be construed as exhaustive.

CORPORATE STRUCTURE

Name, Address and Incorporation

Twin Butte Energy Ltd.

Head Office:
Suite 600, 324 – 8th Avenue S.W.
Calgary, Alberta T2P 2Z2

Registered Office:
Suite 1400, 350 – 7th Avenue S.W.
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.". 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

Historical Development of the Business

Three Year History

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

On May 29, 2006, Twin Butte issued 3,726,641 Non-Voting Shares upon the exercise of warrants at an exercise price of $0.43 per share for gross proceeds of $1,602,456. On May 31, 2006, Twin Butte issued 1,267,481 Non-Voting Shares upon the exercise of warrants at an exercise price of $0.43 per share for gross proceeds of $545,017.

On May 31, 2006, Twin Butte issued 8,250,000 warrants ("**Management Warrants**") that were registered in the name of Twin Butte and were held pursuant to the terms of an employee benefit trust. Each Management Warrant entitled the holder to acquire one Common Share at an exercise price of $0.40 per share on or before December 31, 2006. All of the Management Warrants were exercised prior to December 31, 2006. The Common Shares acquired on exercise of the Management Warrants were held by Twin Butte in trust for an employee benefit trust.

On June 1, 2006, Drilcorp Energy Ltd. ("**Drilcorp**") and 1195936 Alberta Ltd., a wholly-owned subsidiary of Twin Butte, amalgamated, with the amalgamated corporation continuing to carry on business as a wholly owned subsidiary of Twin Butte (the "**Drilcorp Amalgamation**"). Twin Butte issued an aggregate of 19,641,493 Common Shares and paid $7,850,000 in cash to acquire Drilcorp pursuant to the Drilcorp Amalgamation. Following the closing of the transaction, the amalgamated corporation was voluntarily dissolved on June 2, 2006 and all of the liabilities, property, assets and rights, tangible and intangible, of the amalgamated corporation were assumed by Twin Butte as the corporation's sole shareholder.

On June 2, 2006, Kerogen Petroleum Ltd. ("**Kerogen**") and 1222589 Alberta Ltd., a wholly-owned subsidiary of Twin Butte, amalgamated, with the amalgamated corporation continuing to carry on business as a wholly-owned subsidiary of Twin Butte (the "**Kerogen Amalgamation**"). Twin Butte issued an aggregate of 14,392,139 Common Shares to acquire Kerogen pursuant to the Kerogen Amalgamation. Following the closing of the transaction, the amalgamated corporation was voluntarily dissolved on June 2, 2006 and all of the liabilities, property, assets and rights, tangible and intangible, of the amalgamated corporation were assumed by Twin Butte as the corporation's sole shareholder.

On June 6, 2006, Twin Butte completed a private placement of 17,000,000 Common Shares at a price of $0.40 per share for gross proceeds of $6,800,000.

On June 7, 2006, all of the issued and outstanding Non-Voting Shares of Twin Butte were converted to Common Shares.

On June 13, 2006, the Common Shares commenced trading on the TSXV under the symbol "TBE".

In July and August 2006, Twin Butte issued an aggregate of 1,947,509 Common Shares upon the exercise of warrants at an exercise price of $0.43 per share for gross proceeds of $837,429.

On December 1, 2006, the Corporation graduated to the TSX.

On February 27, 2007, the Corporation completed a brokered underwritten private placement of 14,635,000 Common Shares issued on a "flow-through" basis pursuant to the Tax Act at a price of $0.82 per share for gross proceeds of $12,000,700.

On May 28, 2007, Twin Butte consolidated its Common Shares on the basis of one post-consolidated Common Share for each five pre-consolidated Common Shares.

On June 28, 2007, Twin Butte completed an acquisition of producing assets, undeveloped land and infrastructure in the Thunder/Leaman area of west central Alberta for approximately $28,200,000 after standard closing adjustments. For a description of the oil and gas properties acquired pursuant to the Thunder/Leaman Acquisition see "Description of Principal Properties – Thunder/Leaman – West Central Alberta".

On July 17, 2007, Twin Butte completed a bought deal private placement of 5,550,000 Common Shares at a price of $3.00 per share for gross proceeds of $16,650,000.

On February 8, 2008, Twin Butte acquired all of the issued and outstanding common shares of E4 pursuant to the E4 Arrangement. See "General Development of the Business – Significant Acquisition".

On October 23, 2008, the Corporation commenced a normal course issuer bid to acquire up to 3,079,323 Common Shares through the facilities of the TSX. See "Normal Course Issuer Bid".

On December 18, 2008, the Corporation completed a brokered underwritten private placement of 3,704,000 Common Shares issued on a "flow-through" basis pursuant to the Tax Act at a price of $1.35 per share for gross proceeds of $5,000,400.

In January 2009, the Board of Directors approved Twin Butte's 2009 capital and operating plan. In light of the prevailing economic slowdown and uncertainty in near term commodity prices Twin Butte, like many of its peers has elected to execute a capital program which will be entirely funded from cash flow. It is Twin Butte's intent to match spending to cash flow in the first half of the year until greater clarity is gained on the operating environment and market conditions. Paramount to the Board of Directors' plan is to maintain balance sheet flexibility while positioning Twin Butte for long-term growth within its focus areas.

Capital spending in 2009, is now anticipated to be between $10 and $12 million concentrated in northeast British Columbia as well as in Jayar and Thunder Alberta. The program will entail drilling up to eight gross (7.5 net) wells, numerous recompletion and tie-in of standing well operations, as well as a number of two and three dimensional seismic programs. The Board of Directors and the new management team at Twin Butte are committed to adding value for Twin Butte's shareholders through the long term execution of its business plan. The current economic environment dictates a cautious approach to spending. With a current inventory of over 100 drilling locations and 150,000 net undeveloped acres of land, the Board of Directors and management of Twin Butte will pursue creative ways to monetize these opportunities while growing Twin Butte's presence within its core focus areas.

Significant Acquisition

The Corporation completed one significant acquisition during its most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102 – *Continuous Disclosure Obligations.* On February 8, 2008, Twin Butte acquired all of the issued and outstanding common shares of E4, a publicly traded company with properties in Alberta and northeast British Columbia, pursuant to the E4 Arrangement. Pursuant to the E4 Arrangement, Twin Butte issued 15,663,021 Common Shares to the former shareholders of E4 based on an exchange ratio of 0.3673 of a Common Share for each common share of E4. The total consideration in connection with the acquisition of E4 was approximately $57.3 million, before closing adjustments and including approximately $19.9 million of E4's net debt and working capital assumed at closing of the E4 Arrangement. As a result of the E4 Arrangement, Twin Butte acquired all of the crude oil and natural gas interests that were formerly held, directly or indirectly, by E4 and approximately 86,000 net acres of undeveloped land near Fort St. John, British Columbia. For a description of the oil and gas properties acquired pursuant to the E4 Arrangement see "Description of Principal Properties".

Mr. Paul Starnino, the former President and Chief Executive Officer of E4, and Mr. Jim Brown, a former director of E4, joined the Board of Directors of Twin Butte upon completion of the E4 Arrangement.

Further information respecting the E4 Arrangement is contained in the Business Acquisition Report of Twin Butte dated May 8, 2008 filed on SEDAR at www.sedar.com.

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 strategic acquisitions and a focused exploration development and exploitation program. 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 153,000 net undeveloped acres of land with core areas of operation currently focused in east central Alberta at Provost and Oyen, in west central Alberta at Thunder/Leaman, in northwestern Alberta at Jayar and in the Fort St. John area of northeast British Columbia. 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. 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.

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

Companies operating in the petroleum industry must manage risks which are beyond the direct control of company personnel. Among these risks are those associated with exploration, environmental damage, commodity prices, foreign exchange rates and interest rates.

The oil and natural gas industry is intensely competitive and Twin Butte will be required to compete with a substantial number of other corporations which may have greater technical or financial resources. With the maturing nature of the Western Canadian Sedimentary Basin, the access to new prospects is becoming more and more competitive and complex. Management believes that Twin Butte will be able to explore and develop new production and reserves with the objective of increasing its cash flow and reserve base.

Twin Butte will attempt to enhance its competitive position by operating in areas where its technical personnel are able to reduce some of the risks associated with exploration, production and marketing because they are familiar with the areas of operation.

Cycles

The Corporation's business is generally not 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, affect access in certain circumstances.

Environmental Protection

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Compliance with such legislation can require significant expenditures or result in operational restrictions. 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, all of which might have a significant negative impact on earnings and overall competitiveness. See "Industry Conditions – Environmental Regulation".

Employees

As at March 27, 2009, Twin Butte had 19 full-time employees and two consultants, all of whom were located at its office in Calgary except for three full-time employees that 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, 2008. Unless otherwise specified, gross, net acres, well count and production information are as at December 31, 2008.

Alberta

Oyen – East Central Alberta

The Oyen property is located approximately 375 kilometres southeast of Edmonton, Alberta. The Oyen property produced approximately 445 BOE/d in 2008, representing approximately 15% of Twin Butte's total production volumes in 2008, 18% of which was oil and NGL's and 82% of which was natural gas. Twin Butte's interests in Oyen consist of working interests, ranging from 45% to 100% and averaging 98%. Twin Butte operates 32 gross (32 net) wells associated with this property. Twin Butte's primary targets in this area are light oil and gas production from the Viking formation, gas from the Mannville group and oil and gas production from the Bakken formation. Production from the area is processed at third party processing facilities which have excess capacity.

The Oyen property consists of 21,280 gross (21,280 net) acres of undeveloped land.

Twin Butte did not drill any wells on the Oyen property during the year ended December 31, 2008 and does not plan to drill any wells on the Oyen property in 2009.

Provost/Richdale – East Central Alberta

The Provost/Richdale property is located approximately 12 kilometres east of Castor, Alberta or approximately 150 kilometres east of Red Deer, Alberta. Twin Butte acquired a portion of this property pursuant to the E4 Arrangement. The Provost/Richdale property produced approximately 707 BOE/d in 2008, representing approximately 24% of Twin Butte's total production volumes in 2008, 52% of which was oil and NGL's and 48% of which was natural gas. Twin Butte's property interests in Provost/Richdale consist of working interests ranging from 7.5% to 100% and averaging 70%. Twin Butte operates 78 gross (64.1 net) wells associated with this property. Well depths average 1,000 metres in this area and target the Viking formation. Oil production from the area is processed primarily through Twin Butte owned batteries and gas production generally goes to third party processing facilities.

As at December 31, 2008, the Provost/Richdale property consisted of 23,485 gross (20,460 net) acres of undeveloped land.

For the year ended December 31, 2008, exploration and development activity on the Provost/Richdale property included the drilling of 4 gross (4.0 net) wells as well as related facilities expenditures to bring the wells on-stream. Planned exploration and development activity in the Provost/Richdale area for 2009 includes the drilling of 1 gross (1 net) well and facility optimization.

Jayar – Northwestern Alberta

The Jayar property is located approximately 100 kilometres south of Grande Prairie, Alberta. The Jayar property produced approximately 637 BOE/d in 2008, representing approximately 22% of Twin Butte's total production volumes in 2008, 31% of which was oil and NGL's and 69% of which was natural gas. Twin Butte's interests in Jayar consist of working interests ranging from 17% to 100% and averaging 77%. Twin Butte operates 32 gross (25 net) wells associated with this property. Well depths average 2,400 metres in this area and target the Cardium and Dunvegan zones. Production from the area is processed at the Twin Butte-operated Jayar Plant at 6-8-62-3W6M.

The Jayar property consists of 800 gross (626 net) acres of undeveloped land.

For the year ended December 31, 2008, exploration and development activity on the Jayar property included the drilling of 1 gross (0.86 net) well and related facilities expenditures to bring the well on-stream. No wells are currently planned to be drilled on the Jayar property in 2009.

Thunder/Leaman – West Central Alberta

The Thunder/Leaman property is located approximately 75 kilometres west of Edmonton, Alberta. This property was acquired pursuant to the Thunder/Leaman Acquisition. The Thunder/Leaman property produced approximately 715 BOE/d in 2008, representing approximately 24% of Twin Butte's total production volumes in 2008, 13% of which was oil and NGL's and 87% of which was natural gas. Twin Butte's interests in Thunder/Leaman consist of working interests ranging from 2% to 100% and averaging 56%. Twin Butte operates 52 gross (40 net) wells associated with this property. Production from the area is primarily processed at Twin Butte operated facilities with minor production going to third party facilities.

The Thunder/Leaman property consists of 56,486 gross (34,808 net) acres of undeveloped land.

For the year ended December 31, 2008, exploration and development activity on the Thunder/Leaman property included the drilling of 3.0 gross (3.0 net) wells and related facilities expenditures to bring the wells on-stream. Planned exploration and development activity in the Thunder/Leaman area for 2009 includes the drilling of 3 gross (3 net) wells and facility optimization.

British Columbia

BC South – Northeast British Columbia

The BC South property is located in northeast British Columbia, approximately five kilometres from Fort St. John, British Columbia. Twin Butte acquired this property pursuant to the E4 Arrangement. Annual production for the property was approximately 270 BOE/d, representing approximately 9% of Twin Butte's total production volumes in 2008, 16% of which was oil and 84% of which was natural gas. Twin Butte's interests in BC South consist of working interests ranging from 40% to 100% and averaging 90%. Twin Butte operates 14 gross (13 net) wells associated with this property. Production from the area is delivered to Spectra through Twin Butte facilities.

The BC South property consists of 20,548 gross (19,611 net) acres of undeveloped land.

Twin Butte did not drill any wells on the BC South property during the year ended December 31, 2008. Planned exploration and development activity in the BC South area for 2009 includes the drilling of 3 gross (2.5 net) wells and facility optimization.

Minor Properties

Twin Butte also has a number of minor non-core properties located throughout Alberta, British Columbia and Saskatchewan. These properties account for approximately 2% of the Corporation's current production. Twin Butte does not currently intend to focus a material amount of time on these properties.

At December 31, 2008, aggregate Twin Butte acreage included 105,611 gross (62,609 net) acres of developed land and 195,308 gross (153,721 net) acres of undeveloped land.

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 27, 2009. The effective date of the Statement is December 31, 2008 and the preparation date of the Statement is March 11, 2009.

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, 2008 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 and British Columbia.

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, 2008
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	1,201.2	1,075.6	-	-	22,464	18,023	270.9	165.0
Proved Developed Non-Producing	73.5	65.5	-	-	2,516	1,913	14.0	8.3
Proved Undeveloped	463.8	386.9	-	-	4,469	3,276	54.0	32.8
Total Proved	1,738.5	1,528.0	-	-	29,449	23,212	338.9	206.1
Total Probable	1,169.3	995.2	-	-	13,730	10,284	160.0	98.8
Total Proved Plus Probable	2,907.8	2,523.2	-	-	43,179	33,496	498.9	304.9

Reserves Category	Net Present Values of Future Net Revenue ($000's) — Before Income Taxes Discounted At (%/year) 0	5	10	15	20	After Income Taxes Discounted at (%/year) 0	5	10	15	20	Unit Value Before Income Tax Discounted at 10%/year ($/Mcf)($/bbl)
Proved Developed Producing	171,760	135,958	113,861	98,614	87,375	171,760	135,958	113,861	98,614	87,375	21.80
Proved Developed Non-Producing	11,976	9,465	7,612	6,202	5,102	11,976	9,465	7,612	6,202	5,102	15.02
Proved Undeveloped	15,201	7,938	3,222	98	(2,001)	15,201	7,938	3,222	98	(2,001)	2.55
Total Proved	198,937	153,361	124,695	104,914	90,476	198,937	153,361	124,695	104,914	90,476	17.83
Total Probable	122,784	78,701	54,846	40,313	30,809	100,600	66,573	47,632	35,791	27,865	15.15
Total Proved Plus Probable	321,721	232,062	179,541	145,227	121,285	299,537	219,934	172,327	140,705	118,341	16.92

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2008
FORECAST PRICES AND COSTS
($000's)

Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes	Future Income Taxes	Future Net Revenue After Future Income Taxes
Proved	435,760	76,751	111,646	41,684	6,742	198,937	-	198,937
Proved Plus Probable	698,588	127,936	182,083	59,193	7,655	321,721	22,184	299,537

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2008
FORECAST PRICES AND COSTS

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year) ($000's)	Unit Value ($/Mcf) ($/bbl)
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	26,814.7	15.42
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding solution gas from oil wells)	97,880.5	3.11
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	43,011.2	14.79
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding solution gas from oil wells)	136,529.7	2.96

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:

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

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

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

(d) 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:

(a) 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;

(b) 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;

(c) 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

(d) 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:

(a) 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;

(b) 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;

(c) dry hole contributions and bottom hole contributions;

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

(e) 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 Crude Oil 29° API ($Cdn/bbl)	Hardisty Heavy 12° API ($Cdn/bbl)	Natural Gas AECO-C Spot ($Cdn/ MMBtu)	Natural Gas Liquids Edmonton Propane ($Cdn/bbl)	Natural Gas Liquids Edmonton Butane ($Cdn/bbl)	Inflation Rates (1) %/Year	Exchange Rate (2) ($US/$Cdn)
Forecast									
2009	60.00	69.60	54.80	47.00	7.40	44.10	51.00	2.0	0.850
2010	71.40	83.00	65.30	56.10	8.00	50.80	60.80	2.0	0.850
2011	83.20	91.40	72.00	61.80	8.45	55.10	67.00	2.0	0.900
2012	90.20	93.90	73.90	64.00	8.80	56.90	68.80	2.0	0.950
2013	97.40	96.30	75.90	65.60	9.05	58.40	70.50	2.0	1.000
2014	99.40	98.30	77.40	67.00	9.25	59.70	72.00	2.0	1.000
2015	101.40	100.30	79.00	68.80	9.45	60.80	73.50	2.0	1.000
2016	103.40	102.30	80.50	70.20	9.60	62.00	74.90	2.0	1.000
2017	105.40	104.20	82.10	71.60	9.80	63.20	76.30	2.0	1.000
2018	107.60	106.40	83.80	73.00	10.00	64.50	77.90	2.0	1.000
2019	109.70	108.50	85.40	74.50	10.20	65.80	79.50	2.0	1.000
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	1.000

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:

Factors	Light and Medium Oil Gross Proved (Mbbl)	Light and Medium Oil Gross Probable (Mbbl)	Light and Medium Oil Gross Proved Plus Probable (Mbbl)	Heavy Oil Gross Proved (Mbbl)	Heavy Oil Gross Probable (Mbbl)	Heavy Oil Gross Proved Plus Probable (Mbbl)	Associated and Non-Associated Gas Gross Proved (MMcf)	Associated and Non-Associated Gas Gross Probable (MMcf)	Associated and Non-Associated Gas Gross Proved Plus Probable (MMcf)	Natural Gas Liquids Gross Proved (Mbbl)	Natural Gas Liquids Gross Probable (Mbbl)	Natural Gas Liquids Gross Proved Plus Probable (Mbbl)
December 31, 2007	898.7	542.8	1,441.5	-	-	-	18,767	6,982	25,749	237.0	75.6	312.6
Discoveries	9.7	14.6	24.3	-	-	-	1,159	707	1,866	2.7	4.3	7.0
Extensions and Improved Recovery	200.5	130.6	331.1	-	-	-	2,711	2,866	5,577	38.6	54.7	93.3
Technical Revisions	124.6	19.2	143.9	-	-	-	3,428	631	4,059	83.5	21.2	104.7
Acquisitions (1)	777.6	462.0	1,239.6	-	-	-	7,949	2,545	10,494	22.8	4.2	27.0
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Production	(272.6)	-	(272.6)	-	-	-	(4,566)	-	(4,566)	(45.7)	-	(45.7)
December 31, 2008 (2)	1,738.5	1,169.3	2,907.8	-	-	-	29,449	13,730	43,179	338.9	160.0	498.9

Notes:

(1) Reflects the acquisition of E4 pursuant to the E4 Arrangement. See "General Development of the Business – Significant Acquisition".
(2) The Corporation has no unconventional reserves (bitumen, synthetic crude oil, natural gas from coal, etc.).
(3) 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)
2008	463.8	-	4,469	54.1	1,262.7
2007	236.9	-	1,977	23.3	589.7
2006	76.1	-	139	0.4	99.7

At year end 2008, proved undeveloped reserves were primarily attributed to drilling locations in the Jayar, Bulwark and Provost areas. As of the date of this Annual Information Form, all of the locations are expected to be drilled in the next three years.

Probable Undeveloped Reserves

Year	Light and Medium Oil	Heavy Oil	Natural Gas	Natural Gas Liquids	BOE
	(Mbbl)	(Mbbl)	(MMcf)	(Mbbl)	(MBOE)
2008	534	-	4,597	54.7	1,354.9
2007	154.9	-	2072	14.5	514.7
2006	224.5	-	1495	30.2	503.9

At year end 2008, the probable undeveloped reserves were attributed to drilling locations in the Jayar, Bulwark and Provost areas. A majority of these reserves are probable additional volumes assigned to proved undeveloped locations. As of the date of this Annual Information Form, all of the wells are expected to be drilled in the next three years.

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):

Year	Undiscounted Forecast Prices and Costs ($000's) Proved Reserves	Proved Plus Probable Reserves
2009	7,203	7,204
2010	15,425	20,919
2011	14,003	21,309
2012	4,778	9,408
2013	-	-
2014	-	-
2015	-	-
Thereafter	275	353
Total	41,684	59,193

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

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, 2008.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	95	65.4	6	4.1	119	81.8	70	42.6
British Columbia	9	5.3	1	0.5	6	5	23	17.7
Total	104	70.7	7	4.6	125	86.8	93	60.3

Properties with no Attributable Reserves

The following table sets out the Corporation's developed and undeveloped land holdings as at December 31, 2008.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	93,921	54,178	139,660	111,023	233,581	165,897
British Columbia	11,050	7,791	55,648	42,002	66,698	49,793
Saskatchewan	640	640	-	-	640	640
Total	105,611	62,609	195,308	153,721	300,919	216,330

The Corporation expects that rights to explore, develop and/or exploit 26,600 net acres of its undeveloped land holdings will expire by December 31, 2009. 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 its internal historical costs to estimate its abandonment and reclamation costs when available. The costs are estimated on an area-by-area basis. The industry's historical costs are used when available. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment requirements. As at December 31, 2008 the Corporation had 262 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 $6,741,800 (undiscounted) and $4,225,800 (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)
2009	136.1
2010	-
2011	95.5
2012	313.4
Thereafter	6,196.8
Total Undiscounted	6,741.8
Total Discounted at 10%	4,225.8

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 2011. Twin Butte has estimated approximately $192 million of tax pools will be available as at December 31, 2008, which can be used to offset taxable income in future years.

Capital Expenditures

The following table summarizes capital expenditures (including corporate acquisitions and capitalized general administrative expenses) related to the Corporation's activities for the year ended December 31, 2008:

	000's
Exploration, drilling and completions	31,608
Development, equipping and facilities	6,348
Net Property acquisitions (Proved Properties)	-
Property acquisitions (Unproved Properties)	-
Corporate acquisitions	59,742
Geological and geophysical	1,067
Other	3,349
Total	102,114

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, 2008:

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Natural Gas	3.0	3.0	3.0	3.0
Oil	-	-	13.0	12.9
Service	-	-	-	-
Dry	1.0	1.0	1.0	1.0
Total	4.0	4.0	17.0	16.9

Production Estimates

The following table sets out the volume of the Corporation's production estimated for the year ended December 31, 2009 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)

Reserves Category	Light and Medium Oil Gross (bbl/d)	Natural Gas Gross (Mcf/d)	Natural Gas Liquids Gross (bbl/d)	TOTAL Gross (BOE/d)
Proved				
Thunder/Leaman	38.3	3,355	53.9	651
Provost	297.7	1,849	7.1	613
Jayar	130.9	2,360	50.3	575
Oyen	68.4	1,677	-	348
Other Properties	152.0	3,984	11.8	827
Total Proved	687.3	13,224	123.1	3,014
Proved Plus Probable				
Thunder/Leaman	38.9	3,659	55.3	704
Provost	308.8	1,917	7.6	645
Jayar	134.6	2,486	53.0	602
Oyen	71.6	1,756	-	364
Other Properties	162.3	4,142	12.2	865
Total Proved Plus Probable	716.2	14,015	128.1	3,180

Note:

(1) Numbers may not add due to rounding.

Although some area totals listed above exceed 20% of the Corporation's 2009 forecast production, there are no individual fields on their own that exceed 20%.

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 2008			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production (1)				
Light and Medium Crude Oil (bbl/d)	806	847	785	540
Gas (Mcf/d)	12,669	13,298	12,823	11,096
NGLs (bbl/d)	121	139	129	110
Combined (BOE/d)	3,039	3,202	3,051	2,500
Average Price Received				
Light and Medium Crude Oil ($/bbl)	57.00	113.51	113.71	92.17
Gas ($/Mcf)	7.18	8.34	10.85	8.37
NGLs ($/bbl)	50.88	92.54	96.55	81.69
Combined ($/BOE)	47.07	68.69	78.91	60.67
Royalties Paid				
Light and Medium Crude Oil ($/bbl)	7.05	15.10	14.30	10.80
Gas ($/Mcf)	1.51	1.74	1.56	1.62
NGLs ($/bbl)	8.88	31.61	22.03	25.12
Combined ($/BOE)	8.54	12.59	11.15	10.64
Production Costs (2)				
Combined ($/BOE)	15.78	14.35	16.46	14.00
Resulting Netback (3)				
Combined ($/BOE)	22.75	41.75	51.30	36.03

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, 2008:

	Light and Medium Crude Oil (bbl/d)	Gas (Mcf/d)	NGLS (bbl/d)	BOE (BOE/d)
Jayar	142	2,636	56	637
Thunder/Leaman	43	3,732	50	715
Provost	360	2,034	8	707
Oyen	79	2,195	1	446
B.C. North	71	195	3	106
B.C. South	37	1,372	6	260
Total	732	12,164	124	2,873

Substantially all of Twin Butte's crude oil production for the year ended December 31, 2008 was 100% light and medium quality crude oil (25° API or greater).

For the year ended December 31, 2008, approximately 57% of Twin Butte's gross revenue was derived from natural gas production, 37% 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 for the remainder of 2009:

Commodity Contract	Period	Volume	Price
Oil collar	March 1 - Dec 31, 2009	100 bbl/d	US$60.00 - US$195.00 WTI

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by 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 controls or regulations will affect the Corporation's operations in a manner materially different than they would affect other oil and 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 and Natural Gas

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 the markets, the value of refined products, the supply/demand balance, and other contractual terms. 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 licence requires a public hearing and the approval of the Governor in Council.

The price of natural gas is determined by 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 a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such 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

Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market natural gas production. In addition, the pro-rationing of capacity on the inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, United States of America, 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 domestic use (based upon 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 voluntary measures which only restrict the volume of exports; and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum or maximum export or import price requirements, provided, in the case of export price requirements, any prohibition in any circumstances in which any other form of quantitative restriction is prohibited, and in the case of import-price requirements, such requirements do not apply with respect to enforcement of countervailing and anti-dumping orders and undertakings.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector by 2010 and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, which is important for Canadian natural gas exports.

Provincial Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection, and other matters. The royalty regime 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. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the 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, and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. Royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments and would increase the net income and funds from operations of such producers. However, the trend in recent years has been for provincial governments to eliminate, amend or allow such incentive programs to expire without renewal, and consequently few such incentive programs are currently operative.

The Canadian federal corporate income tax rate levied on taxable income is 19.5% effective January 1, 2008 for active business income including resource income. With the elimination of the corporate surtax effective January 1, 2008 and other rate reductions introduced in the October 2007 Economic Statement and Notice of Ways and Means Motion, 2006 Federal Budget, the federal corporate income tax rate will decrease to 15% in four additional steps: 19% on January 1, 2009, 18% on January 1, 2010, 16.5% on January 1, 2011 and 15% on January 1, 2012.

Alberta

In Alberta, companies are granted the right to explore, produce and develop petroleum and natural gas resources in exchange for royalties, bonus bid payments and rents. On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" (the "**NRF**") containing the Government's proposals for Alberta's new royalty regime, which was followed by the Mines and Minerals (New Royalty Framework) Amendment Act, 2008, which was given Royal Assent on December 2, 2008. The NRF and the applicable new legislation became effective on January 1, 2009. The NRF establishes new royalty rates for conventional oil, natural gas and oil sands. The new royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and increases the old royalty from 30% to 35% applied to the old and new tiers, to up to 50% and with rate caps once the price of conventional oil reaches $120 per barrel. The sliding rate formula includes in its calculation the price of oil and well production.

With respect to natural gas, and similar to the conventional oil framework, the royalties outlined in the NRF are set by a single sliding rate formula ranging from 5% to 50% with a rate cap once the price of natural gas reaches $16.59/GJ. In response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced on November 19, 2008, the introduction of a five year program of transitional royalty rates with the intent of promoting new drilling,. Under this new program companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 metres) will be 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. In order to qualify for this program wells must be drilled during the period starting on November 19, 2008 and ending on December 31, 2013. Following this period all new wells drilled will automatically be subject to the NRF.

On April 10, 2008, the Government of Alberta introduced two new royalty programs that will encourage the development of deep oil and gas reserves, and these are: (a) a five-year oil program for exploration wells over 2,000 metres that will provide royalty adjustments to offset higher drilling costs and provide a greater incentive for producers to continue to pursue new, deeper oil plays (these oil wells will qualify for up to a $1 million or 12 months of royalty offsets, whichever comes first); and (b) a five-year natural gas deep drilling program that will replace the existing program in order to encourage continued deep gas exploration for wells deeper than 2,500 metres (the program will create a sliding scale of royalty credit according to depth, of up to $3,750 per metre). These new programs are to be implemented along with the NRF.

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provided various incentives for exploring and developing oil reserves in Alberta. However, the Alberta Government announced in August of 2006 that four royalty programs were to be amended, a new program was to be introduced and the Alberta Royalty Tax Credit Program was to be eliminated, effective January 1, 2007. The programs affected by this announcement were: (i) Deep Gas Royalty Holiday; (ii) Low Productivity Well Royalty Reduction; (iii) Reactivated Well Royalty Exemption; and (iv) Horizontal Re-Entry Royalty Reduction. The program introduced was the Innovative Energy Technologies Program (the "**IETP**") which has a stated objective of promoting the producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP provides royalty reductions which are presumed to reduce financial risk. Alberta Energy decides which projects qualify and the level of support that will be provided. The deadline for the IETP's final round of applications was September 20, 2008. The successful applicants for the first two rounds have been announced, and those for the third round selection are scheduled to be announced in the first half of 2009. The technical information gathered from this program is to be made public once a two-year confidentiality period expires.

The NRF includes a policy of "shallow rights reversion". The Government of Alberta started to implement this policy on January 1, 2009 and its intent is to maximize the development of currently undeveloped resources that is consistent with the Government of Alberta's objective of maximizing recovery of known gas resources, while increasing royalty revenues. The policy's stated objective is for the mineral rights to shallow gas geological formations that are not being developed to revert back to the Government and be made available for resale, and in the event of non-productive shallow wells, to sever the rights from shallow zones and encourage increased production from up-hole zones. The shallow rights reversion policy affects all petroleum and natural gas agreements; however, the timing of the reversion will differ depending on whether the leases and licenses were acquired prior to January 1, 2009 or subsequent to January 1, 2009. Leases granted after January 1, 2009 will be subject to shallow rights reversion at the expiry of the primary term, and in the event of a licence the policy will apply at the expiry of the intermediate term. 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 lease or licence holder can make a request to extend this period. The order in which these agreements will receive the reversion notice will depend on the vintage of their term, with the older leases and licenses receiving a reversion notice first. Leases or licences that were granted prior January 1, 2009 but have not yet been continued will have a grace period until they are continued under section 15 of the *P&G Tenure Regulation* and be subject to deeper rights reversion prior to receiving a shallow rights reversion notice.

On March 3, 2009, the Government of Alberta announced a three-point incentive program to stimulate new and continued economic activity in Alberta which included a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program. Under the drilling royalty credit program a $200 per metre royalty credit will be available on new conventional oil and natural gas wells drilled between April 1, 2009 and March 31, 2010, subject to certain maximum amounts. The maximum credits available will be determined by the Corporation's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2010. Based on the Corporation's 2008 production it will be entitled to a maximum credit of 50% of royalties payable in the period April 1, 2009 and March 31, 2010. The new well incentive program will apply to wells beginning production of conventional oil and natural gas between April 1, 2009 and March 31, 2010 and provides for a maximum 5% royalty rate for the first 12 months of production, up to a maximum of 50,000 barrels or 500 Mmcf of natural gas.

The three-point incentive program also includes an investment of $30 million by the Government of Alberta in abandonment and reclamation projects for orphan wells. The stated objective of this investment is to encourage the clean-up of inactive oil and gas wells and to stimulate new activity within the services sector.

British Columbia

Producers of oil and natural gas in the Province of British Columbia are required to pay annual rental payments with respect to the Crown leases and royalties and freehold production taxes in respect of oil and gas produced from Crown and freehold lands. The amount payable as a royalty in respect of oil depends on the type of oil, the value of the oil, the quantity of oil produced in a month, and the vintage of the oil. Generally, 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 rates are calculated in three stages, which take into account the vintage of the oil, if the oil produced has already been sold and any royalty exempt value applicable (exempt wells). Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production or 11,450m^3 produced, whichever comes first; and the royalties for third-tier oil are the lowest reflecting the higher costs of exploration and extraction that the producers would incur. The royalty payable on natural gas is determined by a sliding scale based on a reference price, which is the greater of the price obtained by the producer, and a prescribed minimum price. However, when the reference price is below the select price (a parameter used in the royalty rate formula), the royalty rate is fixed. As an incentive for the production and marketing of natural gas, which may have been flared, natural gas produced in association with oil has a lower royalty then the royalty payable on non-conservation gas.

On May 30, 2003, the Ministry of Energy and Mines for the Province of British Columbia announced an Oil and Gas Development Strategy for the Heartlands ("**Strategy**"). The Strategy is a comprehensive program to address road infrastructure, targeted royalties and regulatory reduction, and British Columbia service sector opportunities. In addition, the Strategy will result in economic and employment opportunities for communities in British Columbia's heartlands.

Some of the financial incentives in the Strategy include:

- Royalty credits towards the construction, upgrading, and maintenance of road infrastructure in support of resource exploration and development. Funding will be contingent upon an equal contribution from industry. This program has evolved over past years as a result of the Province's stated objective to increase competitiveness, and on March 2, 2009 the Government of British Columbia announced the 2009 Infrastructure Royalty Credit Program ("**Program**") which allocates $120 million in royalty credits for oil and gas companies. The Program provides access to royalty credits to oil and gas companies with respect to certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and gas areas. Companies must apply to the Ministry of Energy and Mines for British Columbia prior to 2:00 p.m. on April 30, 2009 to be considered for approval under the program.

- Changes to provincial royalties: new royalty rates for low productivity natural gas to enhance marginally economic resources plays, royalty credits for deep gas exploration to locate new sources of natural gas, and royalty credits for summer drilling to expand the drilling season.

The British Columbia Energy Plan announced on February 27, 2007 outlines the requirements for the development of goals for conservation, energy efficiency and clean energy. In addition, its stated goal is to promote competitiveness through the implementation of a Net Profit Royalty Program ("**NPRP**") among others, and facilitate the development of the oil and gas industry. The NPRP's objective is to share the capital risk of successful developments. Pursuant to the Net Profit Royalty Regulation, the holder of a lease can apply to pay monthly net profit royalties on production of oil and for natural gas wells within a proposed project. The amount paid is calculated on the producer's interest in the project, and it ranges from 2% to 5% of the gross revenue and 15% to 35% of the net revenues received. In addition, it depends at which stage the well is, which may be either pre-payout, after-payout or already producing marketable gas.

The Government of British Columbia has introduced a few more royalty programs, in addition to the ones previously mentioned, including a royalty program for deep discovery wells, royalty programs with a stated goal of attracting investment to less productive shallow gas wells (Ultra-Marginal Royalty Program), and the implementation of royalty credits to assist the development of the coalbed gas reserves found in the Province of British Columbia.

Saskatchewan

In Saskatchewan, the amount payable as a royalty in respect of oil depends on the vintage of the oil, the type of oil, the quantity of oil produced in a month, and the value of the oil. For Crown royalty and freehold production tax purposes, crude oil is considered "heavy oil", "southwest designated oil", or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil" introduced October 1, 2002, "third tier oil", "new oil" and "old oil") of oil production are applicable to each of the three crude oil types. The Crown royalty and freehold production tax structure for crude oil is price sensitive and varies between the base royalty rates of 5% for all "fourth tier oil" to 20% for "old oil". Marginal royalty rates are 30% for all "fourth tier oil" to 45% for "old oil".

The amount payable as a royalty in respect of natural gas is determined by a sliding scale based on a reference price (which is the greater of the amount obtained by the producer and a prescribed minimum price), the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. 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. The royalty and production tax classifications of gas production are "fourth tier gas" introduced October 1, 2002, "third tier gas", "new gas", and "old gas". The Crown royalty and freehold production tax for gas is price sensitive and varies between the base royalty rate of 5% for "fourth tier gas" and 20% for "old gas". The marginal royalty rates are between 30% for "fourth tier gas" and 45% for "old gas".

On October 1, 2002, the following changes were made to the royalty and tax regime in Saskatchewan:

- A new Crown royalty and freehold production tax regime applicable to associated natural gas (gas produced from oil wells) that is gathered for use or sale and is produced from: (a) oil wells with a finished drilling date on or after October 1, 2002, and (b) 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 cubic metres of gas for every cubic metre of oil. The royalty/tax will be payable on associated natural gas produced from an oil well that exceeds approximately 65,000 cubic metres in a month. The associated natural gas royalty/tax regime will apply to gas produced from oil wells affected by concurrent production approvals after October 1, 2002 if the oil wells meet (a) or (b) above.

- A modified system of incentive volumes and maximum royalty/tax rates applicable to the initial production from oil wells and gas wells with a finished drilling date on or after October 1, 2002, was introduced. The incentive volumes are applicable to various well types and are subject to a maximum royalty rate of 2.5% and a freehold production tax rate of zero per cent.

- The elimination of the re-entry and short section horizontal oil well royalty/tax categories. All horizontal oil wells with a finished drilling date on or after October 1, 2002, will receive the "fourth tier" royalty/ tax rates and new incentive volumes.

- A horizontal oil well, with a finished drilling date on or after October 1, 2002, that is a non-deep oil well qualifies for a 6,000 cubic metre incentive volume.

- A horizontal oil well, with a finished drilling date on or after October 1, 2002, that is a deep oil well qualifies for a 16,000 cubic metre incentive volume.

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.

On June 19, 2007, the Government of Saskatchewan introduced the Orphan Well and Facility Liability Management Program pursuant to the amendment of the Oil and Gas Conservation *Act* and the *Oil and Gas Conservation Regulations*, 1985. The program includes a security deposit, which has two purposes: (i) preventing any person with insufficient financial capability from acquiring oil and gas wells or facilities; and (ii) in the case of a bankrupt company, the funds cover the decommissioning and reclaiming of orphan properties. An additional change introduced is the mandatory licensing of all upstream oil and gas facilities in Saskatchewan.

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 from two years, 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.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. 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. 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.

Environmental legislation in the Province of Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (the "**EPEA**"), which came into force on September 1, 1993, and the *Oil and Gas Conservation Act* (Alberta) (the "**OGCA**"). The EPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations, and significantly increased penalties. In 2006, the Alberta Government enacted regulations pursuant to the EPEA to specifically target sulphur oxide and nitrous oxide emissions from industrial operations including the oil and gas industry. In addition, the reduction emission guidelines outlined in the *Climate Change and Emissions Management Amendment Act* came into effect on July 1, 2007 ("**CCEMAA**"). Under this legislation, Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12%. Industries have three options to choose from in order to meet the reduction requirements outlined in this legislation, and these are: (i) by making improvement to operations that result in reductions; (ii) by purchasing emission credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emission; or (iii) by contributing to the Climate Change and Emissions Management Fund (the "**Fund**"). Industries can either choose one of these options or a combination thereof. Pursuant to CCEMAA and the *Specified Gas Emitters Regulation*, companies were obliged to reduce their emission intensity by 12% by March 31, 2008. Alberta industries have achieved 2.6 million tonnes of actual reduction, due to changes in operations and investing on verified offset projects. In addition, certain companies contributed $40 million to the Fund. It is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

On January 24, 2008, the Alberta Government announced a new climate change action plan that will cut Alberta's projected 400 million tonnes of emissions in half by 2050. This plan is based on three areas: (i) carbon capture and storage, which will be mandatory for *in situ* oil sand facilities that use heavy fuels for steam generation; (ii) energy conservation and efficiency; and (iii) greening production through increased investment in clean energy technology, including supporting research on new oil sands extraction processes, as well as the funding of projects that reduce the cost of separating carbon dioxide from other emissions supporting carbon capture and storage. In addition to this action plan, the Provincial Energy Strategy unveiled on December 11, 2008 is expected to, among other things, support the upgrading, refining and petrochemical clusters existing in the Province, market Alberta's energy internationally, review the emission targets and carbon charges applied to large facilities, and promote the innovation of energy technology by encouraging investment in research and development.

British Columbia's Environmental Assessment Act became effective June 30, 1995. This legislation rolls the previous processes for the review of major energy projects into a single environmental assessment process with public participation in the environmental review process. On February 27, 2007 the Government of British Columbia unveiled the Energy Plan outlining the Province's strategy towards the environment and which includes targeting for zero net greenhouse gas emissions, promoting new investments in innovation, and becoming the world's leader in sustainable environmental management. For this purpose, on December 18, 2007 proposals were sought for applications to the Innovative Clean Energy Fund, in order to attract new technologies that will help solve energy and environmental issues. With regards to the oil and natural gas industry the objective is to achieve clean energy through conservation and energy efficient practices, whilst competitiveness is advocated in order to attract investment for the development of the oil and natural gas sector. Among the changes to be implemented are: (i) a new of

Net Profit Royalty Program; (ii) the creation of a Petroleum Registry; (iii) the establishment of an infrastructure royalty program (combining roads and pipelines); (iv) the elimination of routine flaring at producing wells; (v) the creation of policies and measures for the reduction of emissions; (vi) the development of unconventional resources such as tight gas and coalbed gas; and (vii) new the Oil and Gas Technology Transfer Incentive Program that encourages the research, development and use of innovative technologies to increase recoveries from existing reserves and promotes responsible development of new oil and gas reserves. Furthering these initiatives, the Government of British Columbia introduced on July 1, 2008, revenue-neutral carbon tax legislation that is applied to all fossil fuels used in the Province of British Columbia. The tax would be phased in, and the initial rate would be based on CO2e of $10 per tonne for the first six months of 2009 and $15 per tonne for the last six months of 2009, following $5 per tonne increases on July of every year until 2012. Tax credits and reductions will be used in order to offset the tax revenues that the Government of British Columbia would receive otherwise. On April 3, 2008, the Government of British Columbia introduced the Greenhouse Gas Reduction (Cap and Trade) Act which will allow participation in the Western Climate Initiative cap and trade systems being developed. The system establishes a limit on emissions, and allows regulated emitters to buy/sell emission allowances or offset emits. The emitter is obliged to obtain emission allowances (compliance units) equal to the amount of greenhouse gases emitted within a certain period of time, and that are supposed to be surrendered to the Government of British Columbia as compliance proof.

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Kyoto Protocol**"). The Kyoto Protocol calls for Canada to reduce its greenhouse gas emissions to 6% below 1990 "business-as-usual" levels between 2008 and 2012. Given revised estimates of Canada's normal emissions levels, this target translates into an approximately 40% gross reduction in Canada's current emissions. It is questionable, based on the Updated Action Plan announced by the Federal Government (see below), that the Kyoto Protocol target of 6% below 1990 emission levels will be enforced in Canada. Bill C-288, which is intended to ensure that Canada meets its global climate change obligations under the Kyoto Protocol, was passed by the House of Commons on February 14, 2007. On April 26, 2007, the Federal Government released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "**Action Plan**") also known as ecoACTION which includes the regulatory framework for air emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy using products.

The Government of Canada and the Province of Alberta released on January 31, 2008 the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among others: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and (iii) targeting research to lower the cost of technology.

In order to strengthen the Action Plan, on March 10, 2008, the Government of Canada released "Turning the Corner – Taking Action to Fight Climate Change" (the "**Updated Action Plan**") which provides some additional guidance with respect to the Government's plan to reduce greenhouse gas emissions by 20% by 2020 and by 60% to 70% by 2050.

The Updated Action Plan is primarily directed towards industrial emissions from certain specified industries including the oil sands, oil and gas and refining. The Updated Action Plan is intended to create a carbon emissions trading market, including an offset system, to provide incentive to reduce greenhouse gas emission and establish a market price for carbon. There are mandatory reductions of 18% from the 2006 baseline starting in 2010 and an additional 2% in subsequent years for existing facilities. This target will be applied to regulated sectors on a facility-specific, sector-wide or corporate basis; in the case of oil sands production, petroleum refining, natural gas pipelines and upstream oil and gas the target will be considered facility-specific (sectors in which the facilities are complex and diverse, or where emissions are affected by factors beyond the control of the facility operator). Emissions from new facilities, which are those built between 2004 and 2011, will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time, and will be granted a 3-year grace period during which no emissions intensity targets will apply. Targets will begin to apply on the fourth year of commercial operation and the baseline will be the third year's emissions intensity, with a 2% continuous annual emission intensity improvement required. The definition of new facility also includes greenfield facilities, major expansions constituting more than a 25% increase in a facility's physical capacity, as well as transformations to a facility that involve significant changes to its processes. For upstream oil and gas and natural gas pipelines, it will be applied using a sector-specific approach. For the oil sands, its application will be process-specific, oil sands plants built in 2012 and later, those which use heavier hydrocarbons, up-graders and *in-situ* production will have mandatory standards in 2018 that will be based on carbon capture and storage.

In the following regulated sectors, the Updated Action Plan will apply only to facilities exceeding a minimum annual emissions threshold: (i) 50,000 tonnes of CO_2 equivalent per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalent per upstream oil and gas facility; and (iii) 10,000 boe/d/company. These proposed thresholds are significantly stricter than the current Alberta regulatory threshold of 100,000 tonnes of CO_2 equivalent per year per facility.

Four separate compliance mechanisms are provided in respect of the above targets: Technology Fund contributions, offset credits, clean development credits and credits for early action. The most significant of these compliance mechanisms, at least initially, will be the Technology Fund and for which regulated entities will be able to contribute in order to comply with emissions intensity reductions. The contribution rate will increase over time, beginning at $15 per tonne for the 2010-12 period, rising to $20 per tonne in 2013, and thereafter increasing at the nominal rate of GDP growth. Contribution limits will correspondingly 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 greenhouse gas 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 mentioned 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 cancel the offset credits or bank them 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. 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.

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not currently possible to predict either the nature of those requirements or the impact on the Corporation and its operations and financial condition at this time.

Trends

There are a number of trends that have been developing in the oil and gas industry during the past several years that appear to be shaping the near future of the business.

The first trend is the volatility of commodity prices. Natural gas is a commodity influenced by factors within North America. A tight supply-demand balance for natural gas causes significant elasticity in pricing, whereas higher than average storage levels tend to depress natural gas pricing. Drilling activity, weather, fuel switching and demand for electrical generation are all factors that affect the supply-demand balance. Recently, liquefied natural gas shipments to North America have also resulted in natural gas supply and natural gas pricing being based more on factors other than supply and demand in North America. Changes to any of these or other factors create price volatility.

Crude oil is influenced by the world economy, Organization of the Petroleum Exporting Countries' ("**OPEC**") ability to adjust supply to world demand and weather. Political events also trigger large fluctuations in price levels. The current global financial crisis has reduced liquidity in financial markets thereby restricting access to financing and has caused significant volatility to commodity prices. Petroleum prices are expected to remain volatile for the remainder of 2009 as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing global credit and liquidity concerns. See "Risk Factors – Global Financial Crisis".

The impact on the oil and gas industry from commodity price volatility is significant. During periods of high prices, producers generate sufficient cash flows to conduct active exploration programs without external capital. Increased commodity prices frequently translate into very busy periods for service suppliers triggering premium costs for their services. Purchasing land and properties similarly increase in price during these periods. During low commodity price periods, acquisition costs drop, as do internally generated funds to spend on exploration and development activities. With decreased demand, the prices charged by the various service suppliers also decline.

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore effected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. Material increases in the value of the Canadian dollar may negatively impact production revenues from Canadian producers. Such increases may also negatively impact the future value of such entities' reserves as determined by independent evaluators. In recent years, the Canadian dollar has increased materially in value against the United States dollar although the Canadian dollar has recently decreased from such levels. "See "Risk Factors – Prices, Markets and Marketing".

A second trend within the Canadian oil and gas industry is the "renewal" of private and small junior oil and gas companies starting up business. These companies often have experienced management teams from previous industry organizations that have disappeared as a part of the ongoing industry consolidation. Many are able to raise capital and recruit well qualified personnel. To the extent that this trend continues, the Corporation will have to compete with these companies and others to attract qualified personnel.

A third trend currently affecting the oil and gas industry is the impact on capital markets caused by investor uncertainty in the global economy. The capital market volatility in Canada has also been affected by uncertainties surrounding the economic impact that the Kyoto Protocol and other environmental initiatives will have on the sector and, in more recent times, by the tax changes relating to income trusts and other "specified investment flow-through" entities ("**SIFTs**") and by the NRF and new Alberta government royalty programs implemented along with the NRF. The impact of the NRF and these new royalty programs is still being determined and will vary company to company based on the percentage of production in Alberta, their commodity mix and depths of production, among other things. The amount and degree of these impacts have yet to be determined.

Pursuant to the existing provisions of the Tax Act, to the extent that a SIFT has any income for a taxation year after certain inclusions and deductions, the SIFT will be permitted to deduct all amounts of income which are paid or become payable by it to unitholders in the year. Under the legislation which received Royal Assent on June 22, 2007, SIFTs will be liable for tax at a rate consistent with the taxes currently imposed on corporations commencing in January 2011, provided that the SIFT experiences only "normal growth" and no "undue expansion" before then, in which case the tax could be imposed prior to the January 2011 deadline. Although the tax changes will not affect the method in which the Corporation will be taxed, it may have an impact on the ability of a SIFT to purchase producing assets from oil and gas exploration and production companies (as well as the price that a SIFT is willing to pay for such an acquisition) thereby affecting exploration and production companies' ability to be sold to a SIFT which has been a key "exit strategy" in recent years for oil and gas companies. This may be a benefit for the Corporation as it will compete with SIFTs for the acquisition of oil and gas properties from junior producers. However, it may also limit the Corporation's ability to sell producing properties or pursue an exit strategy.

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.

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 are continuing 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. These factors have negatively impacted company valuations and will impact the performance of the global economy going forward.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing global credit and liquidity concerns.

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 proved reserves and borrowing capacity 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.

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.

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.

Kyoto Protocol

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". The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases which will require the Corporation to comply with the new regulatory framework announced on March 10, 2008 by the Government of Canada which is intended to force large industries to reduce emissions of greenhouse gases, in addition to the proposed *Clean Air Act* (Canada) of 2006 and Alberta's recently enacted *Climate Change and Emissions Management Act* and *Specified Gas Emitters Regulation.* 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. See "Industry Conditions – Environmental Regulation".

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. 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. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Kyoto Protocol 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 – Environmental 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 effected 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 although the Canadian dollar has recently decreased from such levels. 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.

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 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.

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.

Dividends

Twin Butte has not declared or paid any dividends on the outstanding Common Shares. 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. At present, Twin Butte does not anticipate declaring and paying any dividends in the near future.

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.

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. Twin Butte 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. There are no restrictions that could prevent the Corporation from paying dividends.

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.

NORMAL COURSE ISSUER BID

On October 23, 2008, the Corporation commenced a normal course issuer bid (the "**Normal Course Issuer Bid**") for the repurchase by the Corporation of up to 3,079,323 Common Shares through the facilities of the TSX. As of March 27, 2009, the Corporation had not acquired any Common Shares pursuant to the Normal Course Issuer Bid. The Normal Course Issuer Bid expires on October 22, 2009. Shareholders may obtain a copy of the notice filed with the TSX in respect of the Normal Course Issuer Bid, without charge, upon written request to the Corporation at Suite 600, 324 – 8th Avenue S.W., Calgary, Alberta, T2P 2Z2, Attention: Corporate Secretary.

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**
2008			
January	2.25	2.02	359,852
February	2.75	2.02	1,421,959
March	2.50	2.21	1,959,482
April	3.25	2.30	4,509,203
May	3.35	2.85	3,209,596
June	4.33	3.20	4,158,027
July	4.30	3.10	1,038,122
August	3.56	2.75	1,556,327
September	3.00	1.80	2,398,608
October	2.00	0.67	2,703,345
November	1.40	0.99	933,593
December	1.10	0.60	2,064,916
2009			
January	0.90	0.50	1,013,681
February	0.58	0.35	1,241,539
March (1 - 26)	0.56	0.38	3,581,213

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTIONS ON TRANSFER

To the knowledge of management of the Corporation, the following table sets forth the number of securities of each class of the Corporation held in escrow or that are subject to a contractual restriction on transfer and the percentage that number represents of the outstanding securities of the class as at the date hereof.

Designation of Class	Number of Securities Held in Escrow or that are Subject to a Contractual Restriction on Transfer	Percentage of Class
Common Shares	104,375	0.2%

Note:

(1) The 104,375 Common Shares are legended to the effect that such Common Shares cannot be traded until April 16, 2009. The Common Shares are held by employees of Twin Butte.

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 Fitzpatrick Alberta, Canada	Chairman and Director	Independent businessman since July 2007; 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; prior thereto, Vice President and Chief Financial Officer of Fording Canadian Coal Trust, Fording (GP) ULC and Elk Valley Coal from October 2005 until January 2009 and prior thereto, Vice President, Finance and Chief Financial Officer of High Point Resources Ltd. (oil and gas company) from March 2004 to August 2005.
Paul Colborne (2)(3) Alberta, Canada	Director	Chairman of TriStar Oil & Gas Ltd. (oil and gas company) since December 2005; prior thereto, President and Chief Executive Officer of StarPoint Energy Ltd. (oil and gas company) from September 2003 to December 2005; and prior thereto, President and Chief Executive Officer of Crescent Point Energy Ltd. (oil and gas company).
Craig Hruska (3)(4) Alberta, Canada	Director	Chairman of Scollard Energy Inc. (oil and gas company) since December 2007; and prior thereto, President and Chief Executive Officer of Scolland Energy Inc.
Ken Mullen (2)(3) Alberta, Canada	Director	President and Chief Executive Officer of Savanna Energy Services Corp. (oilfield services company).

Name, Province and Country of Residence	Position(s) with Twin Butte [1]	Principal Occupation During the Five Years Preceding
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, 2006 to December 8, 2008; prior thereto Chairman and Chief Executive Officer of Prairie Schooner Petroleum Ltd. (oil and gas company) from September 2004 to September 2006; and prior thereto, President and Chief Executive Officer of Great Northern Exploration Ltd. (oil and gas company).
Paul Starnino [4] Alberta, Canada	Director	Independent businessman since February 8, 2008; prior thereto, President and Chief Executive Officer of E4 from August 2005 to February 8, 2008; prior thereto, President and Chief Executive Officer of P3 Energy Ltd. (oil and gas company) from January 2005 to August 2005; and prior thereto, President and Chief Executive Officer of E3 Energy Inc. (oil and gas company).
Warren Steckley Alberta, Canada	Director	President and Chief Operating Officer of Barnwell of Canada, Limited (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; prior thereto, Vice President, Finance and Chief Financial Officer of Ketch Resources Trust since January 2005; and prior thereto, Vice President, Finance and Chief Financial Officer of Bear Creek Energy Ltd. (oil and gas company).
Neil Cathcart Alberta, Canada	Vice President, Exploration	Vice President, Exploration of Twin Butte since November 13, 2008; prior thereto, Vice President, Exploration at Revolve Energy Ltd. (oil and gas company) from December 2004 until November 2008; and prior thereto, Vice President Exploration at Revolution Energy Inc. (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).
Greg Hodgson Alberta, Canada	Vice President, Production and Operations	Vice President, Production and Operations of Twin Butte since May 31, 2007; prior thereto, Vice President, Production and Operations of Standard Energy Corporation (oil and gas company) from October 2006 until April 2007; prior thereto, Manager, Operations for Prairie Schooner Petroleum Ltd. (oil and gas company) from January 2005 until September 2006; and prior thereto, Manager, Facilities and Construction for Penn West Petroleum Ltd. (oil and gas company).

Name, Province and Country of Residence	Position(s) with Twin Butte (1)	Principal Occupation During the Five Years Preceding
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. Mr. Saunders has been a director of Twin Butte since December 30, 2005, Messrs. Brown and Starnino have been directors of Twin Butte since February 8, 2008. Messrs. Colborne and Mullen have been directors of Twin Butte since February 28, 2006 and Mr. Hruska has been a director of Twin Butte since August 29, 2006. Mr. Fitzpatrick has been a director of Twin Butte since December 8, 2008.
(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 5,795,946 Common Shares, being approximately 12.3% of the issued and outstanding Common Shares.

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 2008 financial year, 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 in the Court of Queen's Bench of Alberta against Twin Butte and a licensee of certain seismic data with whom Twin Butte is jointly exploring and developing certain oil and gas lands. Divestco alleges that the licencee breached its seismic data license agreement by reproducing or displaying Divestco seismic data to Twin Butte and other third parties. Divestco alleges that Twin Butte breached Divestco's copyright and confidence in 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 for a loss of license fee to Twin Butte and a further $3,725,578 for a loss of license fee to other potential licensees, and the accounting and disgorgement of any profits made by Twin Butte and the licencee resulting from the joint use of the seismic data. Twin Butte did not copy the data nor reproduce it and believes its use of such data, in conjunction with the licencee, was within industry standards and practice. Twin Butte further believes that the damages claimed are excessive and unwarranted in the circumstances. The matter is currently under review by Twin Butte's legal counsel.

Regulatory Actions

There were no penalties or sanctions imposed by a court relating to securities legislation or otherwise or by a regulatory body, including securities regulatory authorities, against the Corporation nor were there any settlement agreements entered into with a court relating to securities legislation or with a securities regulatory authority during the financial year ended December 31, 2008.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There are no material interests, direct or indirect, of any director or executive officer of the Company, 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 during the year ended December 31, 2008 or during the current financial year that has materially affected or will 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

Other than contracts entered into in the ordinary course of business, there are no material contracts entered into by Twin Butte during the year ended December 31, 2008 which can reasonably be regarded as presently material.

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, no registered or beneficial interests, direct or indirect, in any securities or other property of the Corporation or of one of the Corporation's associates or affiliates (i) were held by McDaniel, when McDaniel prepared the report, valuation, statement or opinion in question, (ii) were received by McDaniel after McDaniel prepared the report, valuation, statement or opinion in question, or (iii) is to be received by McDaniel.

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), Ken Mullen and Paul Colborne. 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 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.
Ken Mullen Calgary, Alberta	Yes	Yes	Mr. Mullen's education and experience relevant to the performance of his responsibilities as an Audit Committee member are derived from his experience as the President and Chief Executive Officer of Savanna Energy Services Corp., a publicly-traded oil field services Corporation. Mr. Mullen was previously President and Chief Executive Officer of Plains Energy Services Ltd. Through his interaction with Chief Financial Officers over the years, Mr. Mullen 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. Prior to joining Plains Energy Services Ltd., Mr. Mullen practised law, specializing in corporate tax planning, structuring of acquisitions, corporate combinations, and as a Chartered Accountant specializing in corporate tax and finance planning. Mr. Mullen obtained a Bachelor of Commerce degree from the University of Calgary in 1983 and a Bachelor of Laws degree from the University of Calgary in 1992.
Paul Colborne Calgary, Alberta	Yes	Yes	Mr. Colborne's education and experience relevant to the performance of his responsibilities as an Audit Committee member are derived from his experience as Chairman of Tristar Oil & Gas Ltd. since December 2005. From September 2003 to December 2005, Mr. Colborne was the President and Chief Executive Officer of StarPoint Energy Ltd. From October 2001 to August 2003, Mr. Colborne was the President and Chief Executive Officer of Crescent Point Energy Ltd., a Calgary-based junior oil and gas exploration and production company whose shares were listed on the TSX. From 1993 to February 2001, Mr. Colborne was the President and Chief Executive Officer of Startech Energy Inc., an intermediate oil and gas exploration and production company. Through his interaction with Chief Financial Officers over the

Name and Municipality of Residence	Independent	Financially Literate	Relevant Education and Experience
			years, Mr. Colborne 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. Colborne obtained a Bachelor of Laws degree and a Bachelor of Arts degree in Economics from the University of Calgary.

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, 2008	$110,000	Audit of financial statements and review of interim financial statements
Fiscal Year Ended December 31, 2007	$85,000	Audit of financial statements and review of interim financial statements
Audit – Related Fees		
Fiscal Year Ended December 31, 2008	$29,000	Professional services rendered with respect to the information circular and business acquisition report related to the acquisition of E4 and due diligence related to a private placement
Fiscal Year Ended December 31, 2007	$40,000	Professional services rendered with respect to the completion of the business acquisition report in connection with the Thunder/Leaman Acquisition and due diligence related to private placements
Tax Fees		
Fiscal Year Ended December 31, 2008	$4,325	Review of tax returns
Fiscal Year Ended December 31, 2007	$4,000	Review of tax returns
All Other Fees		
Fiscal Year Ended December 31, 2008	$Nil	
Fiscal Year Ended December 31, 2007	$Nil	

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 is contained in Twin Butte's information circular – proxy statement dated March 31, 2009 relating to the annual and special meeting of shareholders to be held on May 14, 2009.

Additional information is also provided in Twin Butte's financial statements and management's discussion and analysis for the year ended December 31, 2008, which documents may be found on SEDAR at www.sedar.com.

GLOSSARY OF TERMS

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

"**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 amalgamated pursuant to the ABCA;

"**E4 Arrangement**" means the plan of arrangement under the ABCA involving Twin Butte, E4 and the shareholders of E4 completed on February 8, 2008, as more particularly described under "General Development of the Business – Significant Acquisition";

"**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 11, 2009 report prepared by McDaniel, evaluating the crude oil, natural gas and NGL reserves of Twin Butte, as at December 31, 2008, 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;

"**Petroleum Substances**" means petroleum, natural gas and related hydrocarbons, (including condensate and NGLs) and all other substances (including sulphur and its compounds), whether liquid, solid or gaseous and whether hydrocarbons or not, produced in association therewith;

"**Tax Act**" means the *Income Tax Act* (Canada) R.S.C. 1985, c.1 (5th Supp.), as amended;

"**Thunder/Leaman Acquisition**" means the acquisition by the Corporation on June 28, 2007 of certain producing assets, undeveloped land and infrastructure in the Thunder/Leaman area of West Central Alberta for approximately $28,200,000 after standard closing adjustments, as more particularly described under "General Development of the Business";

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

"**TSXV**" means the TSX Venture Exchange Inc.; and

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

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

CONVERSION

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

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, 2008. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2008, 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, 2008, 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, 2008, prepared March 11, 2008	Canada	-	179,540.9	-	179,540.9

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. 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. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

   Executed as to our report referred to above:

McDaniel & Associates Consultants Ltd., Calgary, Alberta, Canada, March 27, 2009.

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**") are 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, 2008, 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. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(Signed) James Saunders
President and Chief Executive Officer

(Signed) J. Michael Fabi, P. Eng.
Vice-President, Engineering

(Signed) Craig Hruska
Director and Chairman of the Reserves Committee

(Signed) Paul Starnino
Director and Member of the Reserves Committee

March 27, 2009

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.