Twin Butte Energy Ltd.

ANNUAL INFORMATION FORM

for the year ended December 31, 2007

March 28, 2008

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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.

Unless the context otherwise requires, references herein to "Twin Butte" or the "Corporation" includes E4.

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, 2007.

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.

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.

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. The Corporation undertakes no obligation to update or revise any forward-looking statements except as expressly required by applicable securities laws.

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, of Altarex Corp. and Altarex Inc. to form "Altarex Corp." on May 31, 1997. 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(8) 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) deleting the class of common shares (the "**Pre-Arrangement Shares**") and re-designating 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.

Following the completion of the E4 Arrangement on February 8, 2008, Twin Butte was amalgamated with E4. 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 December 30, 2005, Twin Butte completed the acquisition of a working interest in certain Alberta oil and gas properties from an arm's length vendor, for aggregate consideration of approximately $65,000.

On December 30, 2005, Blueline Energy Limited Partnership and other permitted assignees and arm's length third parties (collectively, the "**Purchasers**") acquired from Sky Energy Corporation and Nova Bancorp Investments Inc. $3,062,072.36 principal amount of Convertible Notes leaving the original noteholders with an aggregate amount of $1,708,912.64. At the time of the transfer, an aggregate of $473,825.28 in interest was paid to the original note holders on the Convertible Notes transferred to the Purchasers.

On December 30, 2005, the Corporation completed a non-brokered private placement of 9,333,310 Non-Voting Shares issued on a "flow-through" basis under the Tax Act and 7,000,000 warrants at a price of $0.43 per unit for gross proceeds of $4,013,323.30. Each warrant (the "**Warrants**") entitled the holder to acquire one Non-Voting Share at an exercise price of $0.43 per share at any time on or before December 31, 2006.

On March 31, 2006, the Corporation converted all of its outstanding Convertible Notes, in the aggregate principal amount of $4,770,985, into an aggregate of 12,323,454 Common Shares. Interest was paid to the holders of the Convertible Notes at the rate of 10% per annum for the period of December 31, 2005 to March 31, 2006.

In preparation for the acquisitions described below, on May 9, 2006 a letter was sent to all of the holders of the Warrants requesting the exercise of such Warrants on or before May 30, 2006. On May 29, 2006, 3,726,641 Non-Voting Shares were issued upon conversion of the Warrants and on May 31, 2006 another 1,267,481 Non-Voting Shares were issued upon conversion of additional Warrants.

On May 31, 2006, Twin Butte issued 8,250,000 warrants ("**Management Warrants**") that were registered in the name of Twin Butte and are 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 at the discretion of Twin Butte prior to December 31, 2006. The Common Shares acquired on exercise of the Management Warrants were held by Twin Butte in trust for the 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**"). Pursuant to the Drilcorp Amalgamation, the former shareholders of Drilcorp received either (i) one-half of one Common Share to a maximum aggregate issuance of 19,641,493 Common Shares; (ii) $0.60 cash; or (iii) a combination of Common Shares and cash, for each common share of Drilcorp. Twin Butte issued an aggregate of 19,641,493 Twin Butte 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**"). Pursuant to the Kerogen Amalgamation, the former shareholders of Kerogen received 3.35 Common Shares for each common share of Kerogen. 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, and the Articles of the Corporation were amended pursuant to the ABCA to reflect the conversion.

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

In July and August 2006, an additional 1,947,509 Common Shares were issued upon the exercise of 1,947,509 Warrants at an exercise price of $0.43 per share for gross proceeds of $837,428.87. In December 2006, the remaining 58,369 Warrants were exercised.

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 May 31, 2007, 876,250 of the Common Shares issued upon exercise of the Management Warrants were transferred to employees of Twin Butte, 392,500 of such Common Shares were legended to the effect that such Common Shares cannot be traded until May 31, 2008.

On June 28, 2007, Twin Butte completed an acquisition of producing assets, undeveloped land and infrastructure in the Leaman/Thunder area of west central Alberta for approximately $28,200,000. "See General Development of the Business – Significant Acquisitions and Recent Developments".

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.

In November and December 2007, an additional 80,000 of the Common Shares issued upon exercise of the Management Warrants were transferred to employees of Twin Butte, 40,000 of such Common Shares were legended to the effect that such Common Shares cannot be traded until May 31, 2008. The remaining Common Shares issued upon exercise of the Management Warrants will be transferred to employees of Twin Butte in 2008.

Significant Acquisitions and Recent Developments

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 June 28, 2007, Twin Butte acquired producing assets, undeveloped land and infrastructure in the Leaman/Thunder area of west central Alberta for approximately $28,200,000 after standard closing adjustments. The assets acquired consisted of approximately 600 BOE/d (90% natural gas) of stable high working interest production and approximately 19,300 net acres of undeveloped land. For a description of the oil and gas properties acquired pursuant to the Leaman/Thunder Acquisition see "Description of Principal Properties – Leaman/Thunder – West Central Alberta".

Further information respecting the Leaman/Thunder Acquisition is contained in the Business Acquisition Report of Twin Butte dated September 11, 2007 filed on Sedar at www.sedar.com.

Recent Developments

On February 8, 2008, Twin Butte acquired all of the issued and outstanding common shares of E4 pursuant to the E4 Arrangement. Twin Butte issued 15,663,027 Common Shares to the former shareholders of E4 and assumed bank debt of approximately $19.2 million, including E4's transaction costs. Upon completion of the E4 Arrangement, Paul Starnino, the former President and Chief Executive Officer of E4, and Jim Brown, a former director of E4, were appointed directors of Twin Butte. In addition, Glen Downey, the former Senior Vice President of E4, was appointed Vice President, Exploration of Twin Butte.

The following is a description of the oil and gas properties acquired by the Corporation pursuant to the E4 Arrangement:

Airport – Northeast British Columbia

The Airport property is located in northeast British Columbia, approximately five kilometres west of Fort St. John, British Columbia. At December 31, 2007, E4 maintained an average 82% working interest in 12,152 gross (9,964 net) acres of land and had an interest in 5 gross (5 net) producing gas wells. In addition, E4 also owned a compressor station on the Airport property. At the time of the E4 Arrangement, total production from this area was approximately 300 BOE/d.

Laprise – Northeast British Columbia

The Laprise property is located in northeast British Columbia, approximately 150 kilometres northwest of Fort St. John, British Columbia. At December 31, 2007, E4 had an average 52% working interest in 12,923 gross (6,720 net) acres of land which encompasses the Coplin A and Coplin B pools and held an interest in 7 gross (3.5 net) producing oil wells. At the time of E4 Arrangement, total production from this area was approximately 100 BOE/d.

Provost/Richdale – Central Alberta

The Provost property is located 12 kilometres east of Castor or approximately 150 kilometres east of Red Deer, Alberta. At December 31, 2007, E4 held an average of 65% working interest in approximately 1,511 gross (982 net) acres of land and held an interest in 10 gross (5 net) producing oil wells. Total production from this area at the time of E4 Arrangement was approximately 260 BOE/d. This area is in close proximity to existing Twin Butte operations.

Chain – Central Alberta

The Chain property is located in central Alberta approximately 130 kilometres north of Brooks, Alberta. At December 31, 2007, E4 held an average 43% working interest in over 6,430 gross (2,765 net) acres of land and 12 gross (9 net) producing wells in the Chain area of Alberta. These various working interests, comprising both conventional and coal bed methane rights, are positioned within the fairway of the Horseshoe Canyon coal bed methane development area. Production from this area at the time of the E4 Arrangement was approximately 60 BOE/d.

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.

Growth Strategy

Twin Butte has approximately 143,000 net undeveloped acres of land after the completion of the E4 Arrangement 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 Ft. 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 the Corporation 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's 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 28, 2008, Twin Butte had 21 full-time employees and four 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, 2007. Unless otherwise specified, gross, net acres, well count and production information are as at December 31, 2007.

Oyen – East Central Alberta

The Oyen property is located approximately 375 kilometres southeast of Edmonton, Alberta. The Oyen property produced approximately 512 BOE/d in 2007, representing approximately 30% of Twin Butte's total production volumes in 2007, 17% of which was oil and 83% of which was natural gas. Twin Butte's interests in Oyen consist of working interests, ranging from 35% to 100% and averaging 98%. Twin Butte operates 35 gross (34.3 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 (20,960 net) acres of undeveloped land.

For the year ended December 31, 2007, exploration and development activity on the Oyen property included the drilling of 5 gross (5 net) wells and related facilities expenditures to bring the wells on-stream. Planned exploration and development activity in the Oyen area for 2008 includes the drilling of 2 gross (2 net) wells and facility optimization.

Provost – Central Alberta

The Provost property is located approximately 12 kilometres east of Castor, Alberta or approximately 150 kilometres east of Red Deer, Alberta. The Provost property produced approximately 195 BOE/d in 2007, representing approximately 11% of Twin Butte's total production volumes in 2007, 30% of which was oil and 70% of which was natural gas. Twin Butte's property interests in Provost consist of working interests ranging from 45.5% to 100% and averaging 89%. Twin Butte operates 36 gross (32 net) wells associated with this property. Well depths average 900 metres in this area and target the Viking formation. Production from the area is processed at the 4-21-38-12 W4M Battery and at third party processing facilities.

As at December 31, 2007, the Provost property consisted of 8,960 gross (6,690 net) acres of undeveloped land.

For the year ended December 31, 2007, exploration and development activity on the Provost property included the drilling of 8 gross (6.8 net) wells as well as related facilities expenditures to bring the wells on-stream. Planned exploration and development activity in the Provost area for 2008 includes the drilling of 7 gross (7 net) wells and facility optimization.

Jayar – Northwestern Alberta

The Jayar property is located approximately 100 kilometres south of Grande Prairie, Alberta. The Jayar property produced at approximately 622 BOE/d in 2007, representing approximately 37% of Twin Butte's total production volumes in 2007, 35% of which was oil and 65% of which was natural gas. Twin Butte's interests in Jayar consist of working interests ranging from 42.75% to 100% and averaging 89%. Twin Butte operates 33 gross (29 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 1,440 gross (1,173 net) acres of undeveloped land.

For the year ended December 31, 2007, exploration and development activity on the Jayar property included the drilling of 2 gross (1.7 net) wells and related facilities expenditures to bring the wells on-stream. Planned exploration and development activity in the Jayar area for 2008 includes the drilling of 1 gross (0.85 net) horizontal well and facility optimization.

Thunder/Leaman – West Central Alberta

The Thunder/Leaman property is located approximately 75 kilometres west of Edmonton, Alberta. The Thunder/Leaman property was acquired effective June 29, 2007 and as such only contributed volumes for one-half of 2007. Annual production from the property was approximately 315 BOE/d, representing approximately 19% of Twin Butte's total production volumes in 2007, 10% of which was oil and 90% of which was natural gas. Twin Butte's interests in Thunder/Leaman consist of working interests ranging from 46% to 100% and averaging 91%. Twin Butte operates 42 gross (38 net) wells associated with this property. Production from the area is processed at a Twin Butte operated facility and third party facilities.

The Thunder/Leaman property consists of 43,040 gross (26,384 net) acres of undeveloped land.

For the year ended December 31, 2007, exploration and development activity on the Thunder/Leaman property included the drilling of 2 gross (1 net) wells and related facilities expenditures to bring the wells on-stream. Planned exploration and development activity in the Thunder/Leaman area for 2008 includes the drilling of 6 gross (6 net) wells and facility optimization.

Minor Properties

Twin Butte also has a number of minor non-core properties located throughout Alberta. These properties account for approximately 13% 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, 2007, aggregate Twin Butte acreage included 67,143 gross (42,372 net) acres of developed land and 78,768 gross (57,896 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 28, 2008. The effective date of the Statement is December 31, 2007 and the preparation date of the Statement is March 18, 2008.

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, 2007 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.

As the E4 Arrangement was not completed until February 8, 2008 the reserves data summarized below does not include any reserves data with respect to the properties acquired by Twin Butte pursuant to the E4 Arrangement. See "General Development of the Business – Significant Acquisitions and Recent Developments – Recent Developments".

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

The Report of Twin Butte Management and Directors on Oil and Gas Disclosure in accordance with Form 51-101F3 and the Report on Reserves Data by McDaniel & Associates Consultants Ltd. in accordance with Form 51-101F2 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, 2007
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	661.7	621.2	0.0	0.0	16,507.4	13,030.9	209.9	140.5
Proved Developed Non-Producing	0.1	0.1	0.0	0.0	282.5	239.1	3.8	2.5
Proved Undeveloped	236.9	213.2	0.0	0.0	1,976.5	1,432.2	23.3	15.7
Total Proved	898.8	834.5	0.0	0.0	18,766.8	14,702.3	237.0	158.7
Total Probable	542.7	501.0	0.0	0.0	6,981.8	5,465.5	75.6	50.9
Total Proved Plus Probable	1,441.5	1,335.6	0.0	0.0	25,748.6	20,167.8	312.6	209.6

	Net Present Values OF Future Net Revenue ($000's)										
	Before Income Taxes Discounted At (%/year)					After Income Taxes Discounted at (%/year)					Unit Value Before Income Tax Discounted at 10%/year
Reserves Category	**0**	**5**	**10**	**15**	**20**	**0**	**5**	**10**	**15**	**20**	**($/Mcf)($/bbl)**
Proved Developed Producing	102,187	81,703	69,602	61,349	55,241	102,187	81,703	69,602	61,349	55,241	19.21
Proved Developed Non-Producing	176	-187	-373	-469	-517	176	-187	-373	-469	-517	na
Proved Undeveloped	10,374	7,663	5,586	3,968	2,689	10,374	7,663	5,586	3,968	2,689	9.47
Total Proved	112,737	89,180	74,814	64,848	57,413	112,737	89,180	74,814	64,848	57,413	17.55
Total Probable	53,939	33,740	23,958	18,064	14,111	46,985	31,360	22,959	17,586	13,862	13.44
Total Proved Plus Probable	166,676	122,919	98,772	82,912	71,523	159,722	120,540	97,774	82,434	71,274	16.34

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2007
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	247,961	38,785	77,636	13,457	5,346	112,737	0	112,737
Proved Plus Probable	366,043	54,829	120,234	18,636	5,668	166,676	6,954	159,722

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2007
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 Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	30,574	34.02
	Heavy Oil (including solution gas and other by-products)	0	0.00
	Natural Gas (including by-products but excluding solution gas from oil wells)	44,240	2.19
	Total	74,814	17.55
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	40,706	28.24
	Heavy Oil (including solution gas and other by-products)	0	0.00
	Natural Gas (including by-products but excluding solution gas from oil wells)	58,066	2.10
	Total	98,772	16.34

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.

(c) **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									
2008	90.00	89.00	64.70	55.30	6.81	48.30	61.90	2.0	1.000
2009	86.70	85.70	62.30	53.20	7.39	48.40	59.60	2.0	1.000
2010	83.20	82.20	59.70	50.50	7.39	47.00	57.20	2.0	1.000
2011	79.60	78.50	57.00	48.70	7.39	45.60	54.60	2.0	1.000
2012	78.50	77.40	56.20	48.00	7.49	45.40	53.90	2.0	1.000
2013	77.30	76.20	55.30	47.20	7.70	45.40	53.00	2.0	1.000
2014	78.80	77.70	56.40	48.10	7.97	46.40	54.10	2.0	1.000
2015	80.40	79.30	57.50	49.10	8.23	47.60	55.20	2.0	1.000
2016	82.00	80.80	58.70	50.10	8.44	48.70	56.20	2.0	1.000
2017	83.70	82.50	59.90	51.10	8.70	49.90	57.40	2.0	1.000
2018	85.30	84.10	61.10	52.10	8.92	50.90	58.50	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, 2006	715.3	452.0	1,167.3	0.0	0.0	0.0	8,676.9	5,490.4	14,167.3	152.6	107.2	259.8
Discoveries	26.3	10.7	37.0	0.0	0.0	0.0	878.0	895.1	1,773.1	0.4	1.8	2.2
Extensions and Improved Recovery	212.3	181.5	393.8	0.0	0.0	0.0	2,434.2	300.5	2,734.7	28.5	-19.0	9.5
Technical Revisions	-17.6	-135.0	-152.6	0.0	0.0	0.0	1,745.2	-1,744.5	0.6	-22.7	-46.8	-69.5
Acquisitions (1)	111.1	39.7	150.8	0.0	0.0	0.0	7,827.4	2,040.3	9,867.7	105.9	32.4	138.3
Dispositions	-20.4	-6.2	-26.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Production	-128.2	0.0	-128.2	0.0	0.0	0.0	-2,794.8	0.0	-2,794.8	-27.7	0.0	-27.7
December 31, 2007 (2)	898.8	542.7	1,441.5	0.0	0.0	0.0	18,766.8	6,981.8	25,748.6	237.0	75.6	312.6

Notes:

(1) Reflects the acquisitions of Leaman/Thunder Acquisition. See "General Development of the Business – Significant Acquisitions and Recent Developments ".
(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)
2007	236.9	0.0	1,976.9	23.3	589.7
2006	76.1	0.0	139.0	0.4	99.7
2005	-	-	-	-	-
Prior to 2005	-	-	-	-	-

In 2007, proved undeveloped reserves were primarily attributed to drilling locations in the Jayar and Bulwark areas. As of the date of this Annual Information Form, all of the locations are expected to be drilled in the next two years.

Probable Undeveloped Reserves

Year	Light and Medium Oil	Heavy Oil	Natural Gas	Natural Gas Liquids	BOE
	(Mbbl)	(Mbbl)	(MMcf)	(Mbbl)	(MBOE)
2007	154.9	0.0	2071.7	14.5	514.7
2006	224.5	0.0	1494.6	30.2	503.8
2005	-	-	-	-	-
Prior to 2005	-	-	-	-	-

In 2007, the majority of the probable undeveloped reserves were attributed to drilling locations in the Jayar and Bulwark areas. As of the date of this Annual Information Form, all of the wells are expected to be drilled in the next two 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
2008	12,693	17,873
2009	696	696
2010	0	0
2011	0	0
2012	0	0
2013	0	0
Thereafter	68	67
Total	13,457	18,636

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, 2007.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	72	58.5	8	6.3	67	48	62	42
Saskatchewan	-	-	-	-	-	-	1	1
Total	72	58.5	8	6.3	67	48	63	43

Properties with no Attributable Reserves

The following table sets out the Corporation's developed and undeveloped land holdings as at December 31, 2007.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	66,503	41,733	78,769	57,896	145,272	99,629
Saskatchewan	640	640	0	0	640	640
Total	67,143	42,373	78,769	57,896	145,912	100,269

The Corporation expects that rights to explore, develop and/or exploit 2,037 net acres of its undeveloped land holdings will expire by December 31, 2008. 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, 2007 the Corporation had 73 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 $5,668,000 (undiscounted) and $2,625,000 (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)
2008	441
2009	531
2010	111
Thereafter	4,263
Total Undiscounted	5,346
Total Discounted at 10%	2,793

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 $160 million of tax pools will be available as at December 31, 2007, 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, 2007:

	000's
Exploration, drilling and completions	10,167
Development, equipping and facilities	6,504
Net Property acquisitions (Proved Properties)	27,671
Property acquisitions (Unproved Properties)	1,633
Geological and geophysical	895
Other	789
Total	47,659

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, 2007:

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Natural Gas	7.0	6.3	2.0	1.0
Oil	3.0	2.5	6.0	5.0
Service	0	0	0	0
Dry	0	0	0	0
Total	10.0	8.8	8.0	6.0

Production Estimates

The following table sets out the volume of the Corporation's production estimated for the year ended December 31, 2008 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				
Jayar	198	2,645	58	697
Oyen	81	2,392	1	480
Thunder/Leaman	36	3,499	38	657
Other Properties	137	834	2	278
Total Proved	451	9,371	99	2,112
PROVED PLUS PROBABLE				
Jayar	208	2,730	60	723
Oyen	85	2,598	1	519
Thunder/Leaman	36	3,683	39	689
Other Properties	152	1,011	3	323
Total Proved Plus Probable	481	10,023	102	2,254

Note:

(1) Numbers may not add due to rounding.

The Corporation's Jayar field is the only field which accounts for 20% or more of the Corporation's estimated 2008 production in the December 31, 2007 McDaniel Report.

Production History

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

	Quarter Ended 2007			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**
Average Daily Production (1)				
Light and Medium Crude Oil (bbl/d)	390	382	327	305
Gas (Mcf/d)	9,022	9,483	6,347	5,720
NGLs (bbl/d)	113	79	60	51
Combined (BOE/d)	2,006	2,042	1,445	1,309
Average Price Received				
Light and Medium Crude Oil ($/bbl)	79.04	77.21	70.12	63.86
Gas ($/Mcf)	6.67	5.54	7.46	7.74
NGLs ($/bbl)	74.28	70.40	65.20	53.25
Combined ($/BOE)	49.55	42.91	51.38	50.76
Royalties Paid				
Combined ($/BOE)	9.99	9.08	10.52	9.55

	Quarter Ended 2007			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**
Operating Expenses (includes transport) ($/BOE)				
Combined ($/BOE)	15.43	14.33	13.27	14.42
Netback Received ($/BOE) (2)	24.13	19.50	27.59	26.79

Notes:

(1) Before deduction of royalties.
(2) 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, 2007:

	Light and Medium Crude Oil (bbl/d)	**Gas (Mcf/d)**	**NGLS (bbl/d)**	**BOE (BOE/d)**
Jayar	168	2,387	52	618
Thunder/Leaman	18	1,673	19	316
Other Alberta	165	3,597	5	769
Total	351	7,657	76	1,703

Substantially all of Twin Butte's crude oil production for the year ended December 31, 2007 was 100% light and medium quality crude oil (25° API or greater).

For the year ended December 31, 2007, approximately 62% of Twin Butte's gross revenue was derived from natural gas production, 31% was derived from crude oil production and the remaining 7% 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 2008:

Commodity Contract	Period	Volume	Price
Oil swap	Jan 1 - Dec 31, 2008	100 bbl/d	$US 70.65 WTI
Oil swap	Jan 1 - Dec 31, 2008	60 bbl/d	$US 87.25 WTI
Oil swap	Jan 1 - Mar 31, 2008	60 bbl/d	$US 91.15 WTI
Oil collar	Jan 1 - Mar 31, 2008	50 bbl/d	$US 88.00 – 100.50 WTI
Oil collar	Apr 1 - Dec 31, 2008	100 bbl/d	$US 90.00 – 120.00 WTI
Gas swap	Jan 1 - Dec 31, 2008	2,000 GJs/d	$6.50 AECO
Gas swap	Jan 1 - Dec 31, 2008	1,000 GJs/d	$6.64 AECO
Gas swap	Apr 1 - Oct 31, 2008	2,500 GJs/d	$6.45 AECO
Gas swap	Apr 1 - Oct 31, 2008	1,000 GJs/d	$7.075 AECO

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 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 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, 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 negotiations between the mineral 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 22.1% effective January 1, 2007 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 five steps: 19.5% on January 1, 2008, 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. Currently, the amount of royalties that are payable is influenced by the oil production, density of the oil, and the vintage of the oil. Originally, the vintage classified oil as "new oil" and "old oil" depending on when the oil pools were discovered. If the pool was discovered prior to March 31, 1974 it is considered "old oil", if it was discovered after March 31, 1974 and before September 1, 1992, it is considered "new oil". The Alberta government introduced in 1992 a Third Tier Royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 1, 1992. The new oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 30%. The old oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 35%.

The royalty reserved to the Crown in respect of natural gas production, subject to various incentives, is between 15% and 30%, in the case of new natural gas, and between 15% and 35%, in the case of old natural gas, depending upon a prescribed or corporate average reference price. Natural gas produced from qualifying intervals in eligible gas wells spudded or deepened to a depth below 2,500 metres is also subject to a royalty exemption, the amount of which depends on the depth of the well.

Oil sands projects are subject to a specific regulation made effective July 1, 1997, and expiring June 30, 2009, which, among other things, determines the Crown's share of crude and processed oil sands products.

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 ("**ARTC**") was to be eliminated, effective January 1, 2007. The programs affected by this announcement are: (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 being introduced is the Innovative Energy Technologies Program (the "**IETP**") which is intended to promote 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 will be the one to decide which projects qualify and the level of support that will be provided. The deadline for the IETP's third round of applications was May 31, 2007. The successful applicants have not yet been announced and it appears, based on the previous two rounds, that the selection process can take at least 8 months. The technical information gathered from this program is to be made public once a two-year confidentiality period expires.

On October 25, 2007, the Alberta government released a report entitled "The New Royalty Framework" (the "**NRF**") containing the government's proposals for Alberta's new royalty regime that is scheduled to be effective on January 1, 2009. The proposed NRF includes new royalty formulas for conventional oil and natural gas that will operate on sliding scales that are determined by commodity prices and well productivity; in addition to the policy of "shallow rights reversion". The Alberta government is intending to implement this policy in order to maximize the development of currently undeveloped resources which is consistent with the government's objective of maximizing recovery of known gas resources, while increasing royalty revenues. The policy's 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. It appears that leaseholders will get a grace period before the shallower zones are reverted to the Crown, which is still to be determined. Substantial legislative, regulatory and systems updates will be introduced before changes become fully effective in January 2009. See "Risk Factors – New Alberta Royalty Regime".

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 11,450 m^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 of up to $30 million annually 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.

- 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.

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 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 gas sector. Among the changes to be implemented are: (i) a new 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) a new 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.

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", "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. The royalty/tax will be payable on associated natural gas produced from an oil well that exceeds approximately 65 thousand cubic metres in a month.

- 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.

In 1975, the Government of Saskatchewan introduced a Royalty Tax Rebate ("**RTR**") as a response to the federal government 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 five years since the federal government had the initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income.

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* (Saskatchewan) and the *Oil and Gas Conservation Regulations*, 1985. The program includes a security deposit, which has two purposes: (i) preventing the individual 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 property. 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, 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. 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. Industries can either choose one of these options or a combination thereof. The Corporation will be committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and an expense nature as a result of the increasingly stringent laws relating to the protection of the environment, and will be taking such steps as required to ensure compliance with the EPEA and similar legislation in other jurisdictions in which it operates. The Corporation believes that it is in material compliance with applicable environmental laws and regulations. The Corporation also believes that 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.

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 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 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, on February 19, 2008 the provincial Government announced that starting on July 1, 2008, provided the legislation is approved; a revenue-neutral carbon tax will be applied to all fossil fuels used in the Province. The tax would be phased in, and the initial rate would be based on CO_{2e} 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 would receive otherwise.

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Protocol**"). The 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 remains uncertain whether the Kyoto target of 6% below 1990 emission levels will be enforced in Canada. The Federal Government has introduced legislation aimed at reducing greenhouse gas emissions using an "intensity based" approach, the specifics of which have yet to be determined. 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. On January 31, 2008, the Government of Canada and the Province of Alberta released 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; (iii) allocating new funding into projects through competitive process; and (ii) targeting research to lower the cost of technology.

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 of Canada'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 industries. The Updated Action Plan is intended to force industry to reduce greenhouse gas emissions and 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. The Updated Action Plan provides for: (i) mandatory reductions of 18% from the 2006 baseline starting in 2010 and by an addition 2% in subsequent years for existing facilities; (ii) new facilities built between 2004 and 2011 will have mandatory emissions standards based upon clean fuel standards (natural gas) with a 2% reduction below the third years intensity levels; and (iii) oil sands plants built in 2012 and later which use heavier hydrocarbons and upgraders and in situ production will have mandatory standards in 2018 based carbon capture and storage or other green technologies intensity. For the upstream oil and gas industry the Updated Action Plan also provides for a company threshold of 10,000 boe/day and facility threshold of 3,000 tonnes of $C0_2$.

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. As details of the implementation of this legislation have not yet been announced, the effect on the Corporation's operations cannot be determined 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' ability to adjust supply to world demand and weather. Crude oil prices have been kept high by political events causing disruptions in the supply of oil and concern over potential supply disruptions triggered by unrest in the Middle East and more recently have been impacted by weather and increased storage levels. Political events trigger large fluctuations in price levels.

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. In recent times, the Canadian dollar has increased materially in value against the United States dollar. Such material increases in the value of the Canadian dollar may negatively impact production revenues from Canadian producers and further increases in the value of the Canadian dollar would exacerbate this negative impact. Such increases may also negatively impact the future value of such entities' reserves as determined by independent evaluators.

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 North American economy. The capital market volatility in Canada has also been affected by uncertainties surrounding the economic impact that the 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 October 25, 2007 proposal of the Alberta government relating to the NRF. The impact of the NRF 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 announcement by the Alberta government also negatively impacts investor sentiment to invest in the province of Alberta. 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.

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 may explore for and produce 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 that could have a material adverse effect upon its financial condition. 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 could have a material adverse effect on the Corporation.

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 will have 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 will therefore depend 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 will manage 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 will depend 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 will compete 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 will 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 intended business, financial condition and results of operations. 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.

New Alberta Royalty Regime

On October 25, 2007, the Alberta government released a report entitled "The New Royalty Framework" containing the government's proposals for Alberta's new royalty regime which is scheduled to be effective on January 1, 2009. Given that the NRF has only recently been announced, it is not possible at this time to determine the full impact of the NRF on the Corporation's financial condition and operations.

The Corporation cannot provide any assurance that the NRF will be implemented in the form proposed. If changes are made to the NRF before it is implemented by the Alberta government, such changes could result in the implementation of a new royalty regime that impacts the Corporation in a materially different manner, and that is more adverse to the Corporation, than the NRF as currently proposed. See "Industry Conditions".

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 likely subject the Corporation to possible future legislation regulating emissions of greenhouse gases, such as the government of Canada's proposed *Clean Air Act* of 2006, the new regulatory framework announced on March 10, 2008, and Alberta's recently enacted *Climate Change and Emissions Management Act*. The direct or indirect costs of these regulations may adversely affect the expected business of the Corporation. 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 adversely affect the Corporation's financial condition, results of operations or 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 either the nature of those requirements or the impact on the Corporation and its operations and financial condition. See "Industry Conditions – Environmental Regulation".

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 the Organization of Petroleum Exporting Countries, 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, borrowing capacity, revenues, profitability and cash flows from operations.

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.

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. Such material increases in the value of the Canadian dollar have negatively impacted the Corporation's production revenues. Further material increases in the value of the Canadian dollar would exacerbate this negative impact. This increase in the exchange rate for the Canadian dollar and 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. 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 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.

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. To the extent the Corporation is not the operator of its oil and gas properties, the Corporation will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

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 could result in a reduction of the revenue received by the Corporation.

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. All such estimates are to some degree speculative, and classifications of reserves are only attempts to define the degree of speculation involved. 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, blowouts, 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, could have a material adverse effect on the Corporation.

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 could have a material adverse effect on the Corporation. The Corporation will not have insurance to protect against the risk from terrorism.

Dilution

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

Management of Growth

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

Dividends

To date, 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.

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 this could have an adverse effect on the Corporation and its operations.

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 could have a material adverse effect on the Corporation and its cash flow from operations. 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 could have a material adverse affect on the Corporation. The Corporation does not have any key person insurance in effect for the Corporation. The contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

DIVIDENDS

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

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**
2007			
January	3.90	3.00	382,948
February	3.70	2.95	350,979
March	3.10	2.75	424,655
April	3.45	2.85	440,087
May (1)	3.50	3.10	361,785
June	3.55	3.05	133,920
July	3.20	2.15	2,291,927
August	2.69	1.90	267,065
September	2.84	2.40	652,056
October	2.60	2.40	586,384
November	2.57	2.40	4,525,989
December	2.50	2.20	1,145,682
2008			
January	2.25	2.02	359,852
February	2.75	2.02	1,421,959
March (1 - 27)	2.49	2.21	1,936,249

Note:

(1) On May 28, 2007, the Common Shares were consolidated on the basis of one post-consolidated Common Share for each five pre-consolidated Common Shares. The high and low sales prices and the trading volumes reported above for months prior to that date have been re-calculated to give effect to the consolidation.

PRIOR SALES

There is no class of securities of Twin Butte that is outstanding but not listed or quoted on a marketplace.

ESCROWED SECURITIES

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	825,000	1.9%

Note:

(1) The 825,000 Common Shares are releasable from escrow on May 31, 2008

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
Jim Saunders [(2)(4)] Alberta, Canada	Chairman and Director	Chairman of Twin Butte since September 2006; 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).
R. James Brown [(2)] Alberta, Canada	Director	Vice President and Chief Financial Officer of Fording Canadian Coal Trust, Fording (GP) ULC and Elk Valley Coal since October 2005; 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).
Ron Cawston Alberta, Canada	President, Chief Executive Officer and Director	President and Chief Executive Officer of Twin Butte since May 15, 2006; and prior thereto Executive Vice President and Chief Operating Officer of Kerogen 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
Paul Colborne [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 the Board of Scollard Energy Inc. (oil and gas company) since December 2007; and prior thereto, President and CEO since January 2004; and prior thereto, President of Addison Energy Inc. (oil and gas company).
Ken Mullen [2][3] Alberta, Canada	Director	President and Chief Executive Officer of Savanna Energy Services Corp. (oilfield services company).
Paul Starnino [4] Alberta, Canada	Director	Independent businessman since February 8, 2008; prior thereto, President and Chief Executive Officer of E4 since August 2005; prior thereto, President and Chief Executive Officer of P3 Energy Ltd. (oil and gas company) since January 2005; and prior thereto, President and Chief Executive Officer of E3 Energy Inc. (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) (and Crossfield Gas Corp. prior thereto).
Brian Dunn Alberta, Canada	Vice President, Engineering and Corporate Development	Vice President, Engineering and Corporate Development of Twin Butte since July 2006; prior thereto Senior Analyst, Engineering with the Ross Smith Energy Group since March 2004; and prior thereto, Vice President, Engineering with Waterous & Co.
Glenn A. Downey Alberta, Canada	Vice President, Exploration	Vice President, Exploration of Twin Butte since February 8, 2008; prior thereto, Senior Vice President of E4 since August 2005; prior thereto, Senior Vice President of P3 Energy Ltd. (oil and gas company) since January 2005; and prior thereto, Senior Vice President of E3 Energy Inc. (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, Mr. Cawston has been a director of Twin Butte since June 2, 2006, 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.

(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.

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

There are no material legal proceedings to which the Corporation is a party or in respect of which any of its property is the subject, nor are any such proceedings known to the Corporation to be contemplated.

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, 2007 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, 2007 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 James Saunders. 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 is currently Vice President and Chief Financial Officer of Elk Valley Coal Partnership and Fording Canadian Coal Trust, positions he was appointed to in October 2005. He has 28 years of experience in the oil and gas industry, the past ten years as Chief Financial Officer with High Point Resources Inc., Dorset Exploration Ltd., Richland Petroleum Inc., and Terraquest Energy Inc. Mr. Brown is a director of Culane Energy Inc. and Calgary Handi-Bus Association. He is a member of Financial Executives International Canada, and has served as President of both Calgary and Regina chapters. 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 is 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 Plain Energy Services Ltd. Prior to joining Plain 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.
Jim Saunders Calgary, Alberta	Yes	Yes	Mr. Saunders is currently the Chairman of Twin Butte. Prior thereto, he was the Chairman and Chief Executive Officer of Prairie Schooner Petroleum Ltd. from September 2004 until September 2006. He is currently a director of Orleans Energy Ltd. and Savanna Energy Services Corp. Prior thereto, he was the President and Chief Executive Officer of Great Northern Exploration Ltd. and held that position since June 2004. Mr. Saunders was the President of Ionic Energy Inc. from June 1997 until April 2001. Mr. Saunders received his Professional Engineering designation from APEGGA in 1983. Mr. Saunders holds a Bachelor of Science in Engineering, which he obtained from the University of New Brunswick in 1982.

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, 2007	$85,000	Audit of financial statements and review of interim financial statements
Fiscal Year Ended December 31, 2006	$78,000	Audit of financial statements and review of interim financial statements
Audit – Related Fees		
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 Leaman/Thunder Acquisition and due diligence related to private placements
Fiscal Year Ended December 31, 2006	$Nil	Not applicable
Tax Fees		
Fiscal Year Ended December 31, 2007	$4,000	Review of tax returns
Fiscal Year Ended December 31, 2006	$Nil	Not applicable
All Other Fees		
Fiscal Year Ended December 31, 2007	$Nil	Not applicable
Fiscal Year Ended December 31, 2006	$Nil	Not applicable

ADDITIONAL INFORMATION

Additional information relating to Twin Butte may be found on SEDAR at www.sedar.com and also on Twin Butte's website at www.twinbuttenergy.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 April 5, 2007 relating to the annual meeting of shareholders held on May 15, 2007.

Additional information is also provided in Twin Butte's financial statements and management's discussion and analysis for the year ended December 31, 2007, 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 Acquisitions and Recent Developments – Recent Developments";

"**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.

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

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

"**McDaniel Report**" means the March 18, 2008 report prepared by McDaniel, evaluating the crude oil, natural gas and NGL reserves of Twin Butte, as at December 31, 2007, 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;

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

"**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, and unless the context otherwise requires, includes E4.

ABBREVIATIONS

Crude Oil and Natural Gas Liquids

bbl	one barrel
bbl	barrels
bbl/d	barrels per day
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)
MBOE	one thousand barrels of oil equivalent
MMBOE	one million barrels of oil equivalent
BOE/d	barrels of oil equivalent per day
NGL	natural gas liquids
stb	standard stock tank barrel

Natural Gas

Mcf	one thousand cubic feet
MMcf	one million cubic feet
Bcf	one billion cubic feet
Mcf/d	one thousand cubic feet per day
MMcf/d	one million cubic feet per day
GJ	gigajoule
GJs/d	gigajoules per day
Btu	British thermal unit
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 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, 2007, 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) Ron Cawston
Ron Cawston
President and Chief Executive Officer

(Signed) Brian Dunn
Brian Dunn
Vice-President, Engineering and Corporate Development

(Signed) James Saunders
James Saunders
Director and Chairman of the Reserves Committee

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

March 28, 2008

SCHEDULE "B"

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, 2007. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2007, 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, 2007, 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, 2007, prepared March 18, 2008	Canada	-	98,772	-	98,772

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 28, 2008.

Per: (Signed) C. B. Kowalski
C. B. Kowalski, P.Eng.

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.