Twin Butte Energy Ltd.

FOR THE THREE MONTHS ENDED MARCH 31, 2011

Q1 2011

HIGHLIGHTS

Twin Butte Energy Ltd. ("Twin Butte" or the "Company") (TSX: TBE) is pleased to announce its financial and operational results for the three months ended March 31, 2011.

	Three months ended March 31		
	2011	2010	% Change
FINANCIAL *($ thousands, except per share amounts)*			
Petroleum and natural gas sales	**31,728**	25,503	24%
Funds flow (1)	**12,789**	9,724	32%
Per share basic & diluted	**0.10**	0.08	25%
Net (loss)/income	**(2,262)**	3,077	(157)%
Per share basic & diluted	**(0.02)**	0.03	(167)%
Capital expenditures	**17,347**	11,352	53%
Capital dispositions	**(11,500)**	(5,719)	101%
Corporate acquisitions	**–**	–	
Net debt (2)	**80,677**	77,212	(16)%
OPERATING			
Average daily production			
Crude oil (bbl per day)	**4,016**	2,075	94%
Natural gas (Mcf per day)	**19,924**	22,670	-12%
Natural gas liquids (bbl per day)	**271**	287	-6%
Barrels of oil equivalent (boe per day, 6:1)	**7,608**	6,140	24%
Average sales price			
Crude oil ($ per bbl)	**62.41**	68.58	-9%
Natural gas ($ per Mcf)	**4.05**	5.33	-24%
Natural gas liquids ($ per bbl)	**77.88**	70.11	11%
Barrels of oil equivalent ($ per boe, 6:1)	**46.34**	46.14	0%
Operating netback ($ per boe) (3)			
Petroleum and natural gas sales	**46.34**	46.14	0%
Realized gain on financial derivatives	**1.20**	0.48	150%
Royalties	**(8.73)**	(9.51)	-8%
Operating expenses	**(14.73)**	(13.47)	9%
Transportation expenses	**(1.87)**	(1.77)	6%
Operating netback	**22.21**	21.87	2%
Wells drilled			
Gross	**37.0**	25.0	98%
Net	**27.5**	14.5	190%
Success (%)	**96**	100	-4%
COMMON SHARES			
Shares outstanding, end of period	**132,022,950**	128,114,335	3%
Weighted average shares outstanding – diluted	**130,555,111**	122,800,508	6%

(1) Funds flow from operations and funds flow from operations netback are non-IFRS measures that represent the total and the average per boe, respectively, of cash provided by operating activities, before adjusting for changes in non-cash working capital items.

(2) Net debt is a non-IFRS measure representing the total of bank indebtedness and accounts payables, less accounts receivables, less deposits and prepaids.

(3) Operating netback is a non-IFRS measure calculated as the average per boe of the Company's oil and gas sales, less royalties, operating and transportation expenses.

REPORT TO SHAREHOLDERS

CORPORATE

The operational momentum Twin Butte established in 2010 continued in the first quarter of 2011. An active capital program of $17.3 million saw 37 gross (27.5 net) wells drilled with a 96 percent success rate. Corporate production grew to 7,608 boe per day (net of dispositions of 175 boe per day), a 6 percent increase from the fourth quarter of 2010 and liquid weighting increased to a record 56 percent. The Company's ongoing noncore asset disposition program netted $11.5 million on sales of 175 boe per day which when combined with record cash flows and approximately $7.9 million of warrant proceeds maintained a strong balance sheet with net debt at March 31 of $80.7 million. Subsequent to the first quarter an additional $6.7 million of proceeds have been received from the remaining Company warrants that were exercised before the May 9th expiry. The Company's credit facility was recently renewed at $128 million providing continued financial flexibility for future opportunities.

The team at Twin Butte has successfully transitioned the Company to a liquid weighted producer with a multiyear, low risk oil drilling inventory, ensuring reserve and production growth for years. Liquid production continues to grow and liquid weighting is now anticipated to be close to 70 percent by the end of the year.

OPERATIONS

The Company's continued drilling success during the first quarter of 2011 demonstrates the depth and repeatability of the Company's drilling inventory. Twin Butte is in an enviable position in that it has a current inventory of over 400 net oil drilling locations allowing prioritized capital spending to maximize return and minimize payout times. Already in the second quarter an additional 24 gross (13.5 net) wells have been drilled at 100 percent success. Although all wells from the first quarter program are on-stream, spring breakup conditions have prevented approximately half the second quarter wells from being completed and put on-stream.

At Frog Lake in the Eastern Plains of Alberta the Company drilled 35 gross (25.5 net) wells in the first quarter at a 100 percent success rate including the Company's first horizontal heavy oil well. Production from Frog Lake continues to increase recently hitting record production levels of 3,800 boe per day. Post spring breakup, once cased wells are completed, it is anticipated that production will exceed 4,000 boe per day. The Company anticipates this profitable growth to continue for a number of years based on our current sizable drilling inventory of over 320 net locations in this area. In 2011 we anticipate drilling over 140 (92 net) wells in our heavy oil area at and in close proximity to Frog Lake. Our first horizontal well at Frog Lake which has been on production for approximately one month is showing promising results. We anticipate drilling an additional 2 to 3 horizontal wells at Frog Lake over the remainder of 2011 as well as at least 3 horizontal Lloydminster heavy oil wells in a new area south of Frog Lake. With current light to heavy oil differentials considerably narrowed from the first quarter, netbacks exceeding $40 per bbl, recycle ratios greater than 4 times and payouts of less than 10 months are anticipated. With over 900 million barrels of oil in place and a low recovery factor to date of less than two percent, significant recoverable reserve upside potential remains at Frog Lake. Twin Butte has completed preliminary modeling of thermal applications at Frog Lake with results positive enough to warrant additional data acquisition, modeling and costing which will hopefully lead to regulatory work to approve a pilot project for 2012.

At Princess, in South Eastern Alberta, the Company executed an agreement with a senior oil and gas producer whereby Twin Butte can earn up to 30 sections of land prospective for Pekisko oil. The lands are directly adjacent to Twin Butte's current Princess operations where Twin Butte drilled its first Pekisko horizontal oil well in the third quarter of 2010. The well is currently producing in excess of 200 bbls of oil per day after being on-stream for nearly seven months. In the first quarter the Company drilled the first of three commitment wells on the farm in as well as an offset to our 2010 discovery. The offset well encountered oil but too high a water cut to currently produce the well economically. Testing operations on the first earning well were not definitive and will continue post spring breakup. The second commitment well under the farm in agreement is anticipated to be drilled in June.

At Bruce, the site of our successful 2010 Lloydminster light oil horizontal program an application has been submitted for approval of a waterflood scheme which is anticipated to commence by the fourth quarter. The waterflood is anticipated to maximize ultimate reserve recovery and stabilize current production declines. A horizontal well on an analogous play will be drilled in the third quarter.

Twin Butte has recently closed a small acquisition ($2.3 million) of a medium gravity Sparky oil pool with multi-well development potential. Plans are to commence infill and delineation drilling on the pool in the third quarter. In the same area the company anticipates drilling a minimum of two Viking horizontal oil wells in the third quarter. Based on success of the first wells the play could develop into a late year multi-well development. We anticipate reporting more on this new oil growth area later this year.

OUTLOOK

The Company's organic exploration and development program continues to demonstrate potential for continued growth in production and reserves in 2011 and beyond. With over 400 net oil drilling locations Twin Butte believes it can continue the profitable growth in the Company's asset value through the drill bit. Twin Butte has positioned itself in scalable and repeatable play types in core areas that can make a meaningful difference to future corporate growth.

Twin Butte is a value oriented emerging intermediate producer with a significant and growing scalable and repeatable drilling inventory focused on large original oil in place and large original gas in place play types. With a stable low decline production base the Company is well positioned to live within cash flow while providing shareholders with sustainable growth potential over both the short and long term. The 2011 capital plan is highly focused to two core areas in Alberta while providing the flexibility to quickly be accelerated should economic conditions allow. Twin Butte is committed to continually enhance its asset quality while focusing on per share growth.

On behalf of the Board of Directors,

Jim Saunders
President and C.E.O.

May 25, 2011

READER ADVISORY

This MD&A contains non-IFRS financial measures and forward-looking statements and readers are cautioned that the MD&A should be read in conjunction with the Company's disclosure under "Non-IFRS Financial Measures" and "Forward-Looking Statements". Certain information regarding Twin Butte set forth in this news release including management's assessment of the Company's future plans and operations, the effect on the Company and on shareholders of Twin Butte, production increases and future production levels contain forward-looking statements that involve substantial known and unknown risks and uncertainties. These forward-looking statements are subject to numerous risks and uncertainties, certain of which are beyond Twin Butte's control including, without limitation, the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, lack of availability of qualified personnel, stock market volatility, and ability to access sufficient capital from internal and external sources. Twin Butte's actual results, performance or achievements may differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits that Twin Butte will derive there from. Additional information on these and other factors that could affect Twin Butte's results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com), or Twin Butte's website (www.twinbutteenergy.com). Furthermore, the forward-looking statements contained in this news release are made as at the date of this news release and Twin Butte does not undertake any obligation to update publicly or to revise any of the forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Dated as of May 25, 2011

INTRODUCTION

The following Management Discussion and Analysis ("MD&A") is management's assessment of Twin Butte Energy Ltd's. financial and operating results and should be read in conjunction with the message to shareholders and the interim financial statements of the Company for the three months ended March 31, 2011 and 2010 and the audited financial statements and MD&A for the year ended December 31, 2010. The reader is cautioned that the aforementioned audited financial statements and MD&A for the year ended December 31, 2010 are presented using Canadian generally accepted accounting principles ("Canadian GAAP") accounting standards whereas the financial statements for the three months ended March 31, 2011 and the 2010 comparatives have been prepared in accordance with International Financial Reporting Standards ("IFRS"). All references to "Previous GAAP" refer to Canadian GAAP before the adoption of IFRS. This MD&A is presented in Canadian dollars (except where otherwise noted). Additional information relating to the Company, including the Company's Annual Information Form can be found on www.sedar.com.

The Company's principal activity is the acquisition of, exploration for and the development and production of petroleum and natural gas properties in Western Canada.

Transition to International Financial Reporting Standards

The financial statements, MD&A and comparative information have been prepared in Canadian dollars unless otherwise indicated and in accordance with International Financial Reporting Standards ("IFRS") representing generally accepted accounting principles ("GAAP") for publicly accountable enterprises in Canada. The transition date to IFRS was January 1, 2010 and comparative figures for 2010 and Twin Butte's financial position as at January 1, 2010 have been restated to IFRS from the previous Canadian generally accepted accounting principles ("Previous GAAP"). Reconciliations to IFRS from Previous GAAP financial statements including the impact of the transition on the Company's reported financial position and financial performance, including the nature and effect of significant changes in accounting policies from those used in the Company's financial statements for the year ended December 31, 2010, are summarized in note 18 to the unaudited financial statements.

Non-IFRS Measures – Certain measures in this document do not have any standardized meaning as prescribed by non IFRS such as operating netback, funds flow, funds flow from operations, funds flow per share, net debt and capitalization and, therefore, are considered non-IFRS measures. The Management's Discussion and Analysis ("MD&A") contains the term funds flow from operations or funds flow which should not be considered an alternative to, or more meaningful than, cash flow from operating activities as determined in accordance with Previous GAAP as an indicator of the Company's performance. All references to funds flow from operations or funds flow throughout this report are based on cash flow from operating actives before changes in non-cash working capital. The Company also presents funds flow from operations per share whereby per share amounts are calculated using weighted average shares outstanding consistent with the calculation of earnings per share. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this document in order to provide shareholders and potential investors with additional information regarding the Company's liquidity and its ability to generate funds to finance its operations. Management's use of these measures has been disclosed further in this document as these measures are discussed and presented.

Basis of Presentation – The reporting and measurement currency is the Canadian dollar.

boe Presentation – Barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion rate of 6 Mcf: 1 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. All boe conversions in the report are derived by converting gas to oil at the ratio of six thousand cubic feet of gas to one barrel of oil.

FORWARD-LOOKING STATEMENTS

Certain statements contained in this MD&A constitute forward-looking information within the meaning of securities laws. Forward-looking information may relate to our future outlook and anticipated events or results and may include statements regarding the future financial position, business strategy, budgets, projected costs, capital expenditures, financial results, taxes and plans and objectives of or involving Twin Butte. Particularly, statements regarding our future operating results and economic performance are forward-looking statements. In some cases, forward-looking information can be identified by terms such as "may", "will", "should", "expect", "plan", "anticipate", "believe", "intend", "estimate", "predict", "potential", "continue" or other similar expressions concerning matters that are not historical facts.

These statements are based on certain factors and assumptions regarding expected growth, results of operations, performance and business prospects and opportunities. While we consider these assumptions to be reasonable based on information currently available to us, they may prove to be incorrect.

Forward looking-information is also subject to certain factors, including risks and uncertainties that could cause actual results to differ materially from what we currently expect. These factors include risk associated with oil and gas exploration, production, marketing, and transportation such as loss of market, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risk, and competition from other producers and ability to access sufficient capital from internal and external resources.

Other than as required under securities laws, we do not undertake to update this information at any particular time.

All statements, other than statements of historical fact, which address activities, events, or developments that Twin Butte expects or anticipates will or may occur in the future, are forward-looking statements within the meaning of applicable securities laws. These statements are subject to certain risks and uncertainties, and may be based on estimates or assumptions that could cause actual results to differ materially from those anticipated or implied.

Further, the forward-looking statements contained in this MD&A are made as of the date hereof, and the Company does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, as a result of new information, future events or otherwise, except as may be required by applicable securities laws. The Company's forward-looking statements are expressly qualified in their entirety by this cautionary statement. Certain risk factors associated with these forward-looking statements include, but are not limited to, the following:

- Fluctuations in natural gas, condensate, NGL's, and crude oil production levels;
- Twin Butte's inability to successfully market its natural gas, condensate, NGL's, and crude oil;
- Lower than expected market prices for natural gas, condensate, NGL's, and crude oil;
- Adverse changes in foreign currency exchange rates and/or interest rates;
- Uncertainties associated with estimating reserves;
- Competition for capital, asset acquisitions, undeveloped lands, and skilled personnel;
- Operational hazards characteristic of the oil and gas industry such as: geological and drilling problems; and well production, pipeline, and mechanical difficulties;
- Lower than envisaged success in the finding and development of reserves and/or higher than expected costs;
- Adverse changes in general economic conditions in Western Canada, Canada more generally, North America or globally;
- Adverse weather conditions;
- The inability of Twin Butte to obtain financing on favorable terms, or at all;
- Adverse impacts from the actions of competitors;
- Adverse impacts of actions taken and/or policies established by governments or regulatory authorities including changes to tax laws, incentive programs, royalty calculations, and environmental laws and regulations; and

> Reliance on natural gas and NGL processing, pipeline, and storage infrastructure not operated by Twin Butte, the availability of which is essential to Twin Butte's sales and marketing activities.

Additional information relating to Twin Butte, including Twin Butte's financial statements can be found on SEDAR at www.sedar.com or the Company's website at www.twinbutteenergy.com.

PETROLEUM AND NATURAL GAS SALES

Twin Butte realized the following production volumes, commodity prices and sales:

	Three months ended March 31	
	2011	2010
Average Twin Butte Realized Commodity Prices (1)		
Heavy oil ($ per bbl)	**58.97**	64.48
Light & Medium oil ($ per bbl)	**76.56**	77.21
Natural gas ($ per Mcf)	**4.05**	5.33
Natural gas liquids ($ per bbl)	**77.88**	70.11
Barrels of oil equivalent ($ per boe, 6:1)	**46.34**	46.14
(1) The average selling prices reported are before realized derivative instrument gains/losses and transportation charges.		
Benchmark Pricing		
WTI crude oil (US$ per bbl)	**94.25**	78.71
WTI crude oil (Cdn$ per bbl)	**88.54**	81.86
AECO natural gas (Cdn$ per Mcf) (2)	**3.79**	4.95
Exchange rate – (US$/ Cdn$)	**1.01**	0.96
(2) The AECO natural gas price reported is the average daily spot price.		
Sales		
$000's		
Heavy oil	**17,148**	8,159
Light & Medium oil	**5,410**	4,649
Natural gas	**7,270**	10,882
Natural gas liquids	**1,900**	1,813
Total petroleum and natural gas sales	**31,728**	25,503
Average Daily Production		
Heavy oil (bbl/day)	**3,231**	1,406
Light & medium oil (bbl/day)	**785**	669
Natural gas liquids (bbl/day)	**271**	287
Natural gas (Mcf/day)	**19,924**	22,670
Total (boe/d)	**7,608**	6,140
% oil and gas liquids	**56%**	38%

Sales for the three months ended March 31, 2011 were $31.7 million, as compared to $25.5 million for the three months ended March 31, 2010 representing an increase of $6.2 million or 24%. This increase in revenue is attributed primarily to a year over year increase in production of 24%. Production grew from 6,140 boe/d in the three months ended March 31, 2010 to 7,608 boe/d for the three months ended March 31, 2011. The increase in production came mainly from internal growth in our Frog Lake area and the asset acquisition of additional Frog Lake properties in Q4 2010. The average realized commodity price before derivative instruments remained flat during the quarter at $46.34 per boe in 2011 from $46.14 in the first three months of 2010.

The Company's weighting to oil and liquids for the first quarter of 2011 was 56% compared to a weighting of 38% for the first quarter of 2010. The weighting has changed mainly due to the Company's drilling program which has increased the percentage of oil production in the Company and has been one of the major factors in seeing total sales per boe stay relatively flat despite lower gas & oil pricing from the comparative periods. We anticipate the oil/gas weighting ratio will continue to increase through the year.

ROYALTIES

	Three months ended March 31	
($ 000's)	**2011**	2010
Royalty Breakdown		
Heavy Oil	**3,947**	2,145
Light & Medium oil	**1,347**	821
Natural Gas	**139**	1,509
NGL's	**548**	779
Total Royalties	**5,981**	5,254
% of Revenue	**19%**	21%
per Boe	**$ 8.73**	$ 9.51

Royalties for the three months ended March 31, 2011 were $6.0 million, as compared to $5.3 million for the three months ended March 31, 2010. Royalties on an absolute basis increased as a result of increased production volumes and sales as a result of our drilling success and strategic acquisitions. Liquids production comprised 56% of volumes for the first quarter 2011 as compared to 38% in 2010. As a percentage of sales, the average royalty rate for the first quarter of 2011 was 19% compared to 21% for the comparative period of 2010. The rate has decreased as the Company's gas royalties have been reduced significantly. Oil and liquids royalty rates were approximately 24% for the first quarter of 2011 while gas royalties were approximately 2%, (which also includes prior period corrections) as a result of the lower realized pricing.

On March 11, 2010, the Alberta Government announced additional modifications to the province's Crown royalty framework. The changes included:

- The current maximum 5.0% royalty rate for the first twelve months of production up to a maximum of 50,000 bbls of oil or 500,000 Mcf of natural gas became a permanent element of the calculation effective January 1, 2011;
- The maximum royalty rate for crude oil wells was reduced to 40% from the previous 50% rate. This change was effective January 1, 2011;
- The maximum royalty rate for natural gas wells was reduced to 36% from the previous 50% rate. This change was effective January 1, 2011.

On May 27, 2010, the Alberta government released the new royalty curves associated with the changes announced on March 11, 2010, which determine royalty rates at certain commodity price levels, and revised the natural gas deep drilling credit to wells deeper than 2,000 metres, compared to 2,500 metres previously. The deep drilling credit is $625 per metre for metres below 2,000 metres to 3,500 metres. The drilling credits are treated as a reduction in capital spending.

On March 23, 2011 the above modification's were approved by the Alberta Government with a May 1, 2010 effective date for the New Well Royalty Regulation.

OPERATING & TRANSPORTATION EXPENSES

Operating expenses were $10.1 million or $14.73 per boe for the quarter ended March 31, 2011 as compared to $7.4 million or $13.47 per boe for the three months ended March 31, 2010. The increase on an absolute dollar basis is mainly attributable to the production from our drilling program. The Company has been implementing various initiatives, mainly at Frog Lake area, to reduce operating costs and we anticipate starting to see results, which should result in further efficiencies over the next 6-9 months.

The operating costs will be reduced in the following manner. In the Frog Lake area, the Company has commissioned for operations in April a salt water disposal well that was drilled in late 2010, in order to save on 3rd party disposal fees. The Company, as part of an ongoing fuel gas system installation, has tied in all wells drilled to the end of 2010 at Frog Lake to use fuel gas produced from the field, replacing propane. Finally, specific chemicals are being added to break up emulsion for lower processing and trucking charges.

Operating & Transportation Expense	Three months ended March 31,			
(000's except per boe amounts)	**2011**	**$ per boe**	2010	$ per boe
Operating expenses	**10,089**	**14.73**	7,444	13.47
Transportation	**1,278**	**1.87**	976	1.77
Total	**11,367**	**16.60**	8,420	15.24

Transportation expenses for the three months ended March 31, 2011 were $1.3 million or $1.87 per boe compared to $1.0 million or $1.77 per boe in the prior year comparative quarter. The increase on an absolute basis is mainly attributable to the production growth from our drilling program, while on a boe basis the cost has increased slightly mainly due to the heavier oil weighting.

On a combined basis for the quarter we have higher operating and transportation costs of $16.60 per boe as compared to $15.24 per boe for the comparable period of 2010. This increase of 9% is due to higher fuel and operating costs from the cold weather in the first quarter and inflationary pressures in the oil and gas sector.

GENERAL AND ADMINISTRATIVE ("G&A") EXPENSES

	Three months ended March 31	
$ 000's	**2011**	2010
G&A expenses	**2,735**	2,371
Recoveries	**(527)**	(415)
Capitalized G&A expenses	**(613)**	(452)
Total net G&A expenses	**1,595**	1,504
Total net G&A expenses ($/boe)	**$ 2.33**	$ 2.72

General and administrative expenses, net of recoveries and capitalized G&A, were $1.6 million or $2.33 per boe for the current quarter as compared to $1.5 million or $2.72 per boe in the prior year comparative quarter.

While total G&A costs have increased for the quarter comparatives due to the additional staff and costs of running the larger operation, on a per barrel basis we have seen a decline of 14% from $2.72 to $2.33 per boe. We anticipate G&A on a BOE basis to average between $2.00 and $2.25 per boe for the balance of the year as production increases up.

SHARE-BASED PAYMENT EXPENSE

Share-based Payments	Three months ended March 31,			
(000's except per boe amounts)	**2011**	**$ per boe**	2010	$ per boe
Total	**193**	**0.28**	69	0.14

During the three month period ended March 31, 2011, the Company expensed $0.2 million in stock based compensation as compared to $0.1 million in the three month period ended March 31, 2010.

The Company granted 345,000 stock options in the first quarter of 2011 as compared to 85,000 stock option grants in the first quarter of 2010. Total options forfeited were 352,083 in the quarter vs. 223,000 last year.

FINANCE EXPENSE

Finance expenses	Three months ended March 31,			
(000's except per boe amounts)	**2011**	**$ per boe**	2010	$ per boe
Accretion on decommissioning provision	**264**	**0.38**	236	0.43
Interest and bank charges	**750**	**1.09**	864	1.56
Total	**1,014**	**1.47**	1,100	1.99

For the three months ended March 31, 2011, interest and bank charges were $0.7 million as compared to $0.9 million in the three month period ended March 31, 2010. Lower interest costs in the 2011 period compared to the 2010 period are due primarily to lower interest rates.

The Company's current interest charge on bank borrowings is bank prime of 3.0% plus a margin of 1.00% for a total effective rate of 4.00%. This compares to last year's effective rate of 4.75%

DERIVATIVE ACTIVITIES

During 2010 and 2011, the Company has entered into fixed price swap for natural gas and crude oil and fixed/floating interest rate swap transactions. As part of our financial management strategy, Twin Butte has adopted a commodity price and interest rate risk management program. The purpose of the program is to reduce volatility in the financial results and to stabilize and hedge future cash flow against the unpredictable commodity price environment, with an emphasis on protecting downside risk.

Entering into derivative instruments is looked upon as a way for the Company to reduce go forward price risk by increasing the predictability of a portion of the Company's future revenue stream. However, there are risks that our counterparty becomes illiquid or the Company may not have the actual sales volumes to offset the hedge position. To reduce these risks the Company deals with a major Canadian bank as our counterparty on derivative instruments and limits the volumes hedged to approximately 50% or less of forecasted sales volumes.

The Company has recognized a realized gain on financial derivatives in the amount of $0.8 million ($1.20 per boe) for the three month period ended March 31, 2011 as compared to a $0.3 million ($0.48 per boe) realized gain for the prior year comparative period. The realized gain on financial derivatives for the three month period ended March 31, 2010 amounted to a gain of $0.4 million for natural gas sales price derivatives, and a loss of $0.1 million for crude oil sales price derivatives.

As at March 31, 2011, the Company has recognized a net unrealized financial derivatives liability in the amount of $11.8 million. The Company has recognized an unrealized loss on financial derivatives in the amount of $9.1 million for the three month period ended March 31, 2011 as compared to a $4.1 million unrealized gain for the prior year comparative period.

Financial Derivatives	Three months ended March 31,			
(000's except per boe amounts)	**2011**	**$ per boe**	2010	$ per boe
Realized gain (loss)	**821**	**1.20**	265	0.48
Unrealized gain (loss)	**(9,090)**	**(13.28)**	4,069	7.37
Gain (loss) on derivatives	**(8,269)**	**(12.08)**	4,334	7.85

The Company has been able to utilize Twin Butte's oil production to enhance our natural gas price for 2011 year through the use of an enhanced swap, where we sold forward calls on oil production for 2011 and 2012 at prices above our budgeted pricing, and use this value to enhance the swap price we have and will receive on natural gas sales through 2011 to well above the strip price. This increased gas price provides additional certainty to cash flow which is then recycled into an increased capital program.

The following is a summary of derivatives in effect as at March 31, 2011 and their related fair market values (unrealized gain (loss) positions):

Crude Oil Sales Price Derivatives

Daily barrel ("bbl") quantity	Remaining term of contract	Fixed price per bbl ($CDN)	Fixed call price per bbl WTI ($US)	Fixed price per bbl (WTI)	Fair market value $ 000's
200	April 1 to December 31, 2011	88.00			(933)
200	April 1 to December 31, 2011	89.40			(857)
300	April 1 to December 31, 2011	92.04			(1,069)
300	April 1 to December 31, 2011	95.05			(822)
300	April 1 to December 31, 2011	98.05			(577)
300	January 1 to December 31, 2012	100.45			(437)
1000	April 1 to December 31, 2011		95.00		(4,216)
1000	January 1 to December 31, 2012		100.00		(5,726)
Crude oil fair value position					(14,637)

As at March 31, 2011 the marked-to-market value of the Company's crude oil sales price derivative was a liability of $14.6 million. Subsequent to the first quarter the Company has entered into an additional fixed price swap on 500 bbl for calendar 2012 at $US 106.81/bbl.

Natural Gas Sales Price Derivatives

Daily giga-joule ("GJ") quantity	Remaining term of contract	Fixed price per per GJ (AECO Monthly)	Fixed price per GJ (AECO) Daily	Fixed call price per GJ (AECO Monthly)	Fair Market value $ 000's
1,500	April 1 to October 31, 2011		$5.90		$716
3,000	April 1 to December 31, 2011			$7.00	($2)
4,500	April 1 to October 31, 2011		$5.90		$2,147
Natural gas fair value position					$2,861

As at March 31, 2011 the marked-to-market value of the Company's natural gas sales price derivative contracts was an asset of approximately $2.9 million.

Gain/Loss on Dispositions

The company disposed of two small properties for net cash proceeds of $11.5 million producing a gain of $2.6 million. This compares to last year's dispositions proceeds $5.6 million and a loss of $0.7 million on those dispositions.

DEPLETION & DEPRECIATION

For the three month period ended March 31, 2011, depletion and depreciation of capital assets was $8.8 million or $12.78 per boe compared to $7.2 million or $13.09 per boe for the three month period ended March 31, 2010. Depletion for the three months ended March 31, 2011 compared to the prior year comparative period has increased as a result of a higher production. It has however, decreased slightly on a per boe basis.

INCOME TAXES

Deferred tax recovery amounted to $0.7 million for the three month period ended March 31, 2011 compared to a deferred tax expense in the amount of $1.6 million for the three month period ended March 31, 2010. This was mainly due to the large unrealized derivative instrument losses booked in the first quarter.

The Company has existing tax losses and pools of approximately $317 million.

FUNDS FLOW FROM OPERATIONS, AND NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

Funds flow from operations for the three month period ended March 31, 2011 was $12.8 million, an increase of 31% from first quarter 2010 funds flow of $9.7 million. This represents $0.10 per diluted share compared to $0.08 per diluted share same quarter last year and $0.10 in the fourth quarter 2010. The increase in funds flow is due primarily to the 24% increase in production to 7,608 boe/d from 6,140 boe/d, along with a slight improvement in average commodity pricing.

Despite higher revenues the Company posted a net loss and comprehensive loss of $2.3 million for the three month period ended March 31, 2011, equating to a basic and diluted net loss per share of $0.02, compared to a net income and comprehensive income of $4.0 million for the three month period ended March 31, 2010, equating to a basic and diluted net income per share of $0.03.

Funds flow from operations calculation *($000's)*	**Three Months ended March 31, 2011**	Three Months ended March 31, 2010
Cash flow from operating activities	**20,756**	7,985
Less: change in non-cash working capital	**(7,967)**	1,739
Funds flow from operations	**12,789**	9,724

The net loss and comprehensive loss of $2.3 million for the three month period ended March 31, 2011 includes non-cash items including depletion and depreciation of $8.8 million, deferred tax recovery of $0.7 million, unrealized loss on derivative instruments of $9.1 million, share-based payments of $0.2 million, and gain of $2.6 million on sale of property. The largest change from the prior year is the valuation of unrealized derivative contracts, which fluctuate with forward commodity pricing.

The following table summarizes netbacks for the past nine quarters on a barrel of oil equivalent basis:

($ per boe)	**Q1 2011**	Q4 2010	Q3 2010	Q2 2010	Q1 2010	Q4 2009(1)	Q3 2009(1)	Q2 2009(1)	Q1 2009(1)
Petroleum and natural gas sales	**46.34**	44.18	39.21	40.44	46.14	42.24	31.99	32.07	35.58
Royalties	**(8.73)**	(8.47)	(7.97)	(8.72)	(9.51)	(7.27)	(3.55)	(0.55)	(4.99)
Realized gain (loss) on financial derivatives	**1.20**	2.51	3.18	2.56	0.48	0.38	2.92	1.58	7.14
Operating expenses	**(14.73)**	(13.79)	(12.93)	(14.34)	(13.47)	(12.94)	(12.99)	(13.70)	(13.39)
Transportation expenses	**(1.87)**	(1.65)	(1.58)	(1.42)	(1.77)	(1.58)	(2.41)	(2.32)	(2.66)
Operating netback(2)	**22.21**	22.78	19.91	18.52	21.87	20.83	15.96	17.08	21.68
General and administrative expenses	**(2.33)**	(1.87)	(2.34)	(2.69)	(2.72)	(3.63)	(3.42)	(5.15)	(3.93)
Interest expense	**(1.09)**	(1.36)	(0.69)	(1.43)	(1.56)	(2.52)	(1.62)	(1.59)	(1.40)
Funds flow from operations (3)	**18.79**	19.55	16.88	14.40	17.59	14.68	10.92	10.34	16.35

(1) The quarters in 2009 includes the Previous GAAP results.

(2) Operating netback is a non-IFRS measure calculated as the average per boe of the Company's oil and gas sales, less royalties, operating and transportation expenses.

(3) Funds flow from operations is a non-IFRS measure that represents the total of funds provided by operating activities, before adjusting for changes in non-cash working capital items.

QUARTERLY FINANCIAL SUMMARY

The following table highlights Twin Butte's performance for each of the past nine quarters:

($ thousands, except per share amounts)	**Q1 2011**	Q4 2010	Q3 2010	Q2 2010	Q1 2010	Q4 2009	Q3 2009	Q2 2009	Q1 2009
Average production (boe/d)	**7,608**	7,161	6,481	6,489	6,140	5,699	2,894	2,864	2,936
Petroleum and natural gas sales	**31,728**	29,111	23,382	23,880	25,503	22,150	8,519	8,359	9,396
Operating netback (per boe)	**22.21**	22.78	19.91	18.52	21.87	20.83	15.96	17.08	21.68
Funds flow from operations	**12,789**	13,551	10,275	9,242	9,724	7,714	2,906	2,691	4,319
Per share basic & diluted	**0.10**	0.10	0.08	0.06	0.08	0.08	0.05	0.06	0.09
Net income (loss)	**(2,262)**	(53)	(2,249)	(446)	3,989	(961)	(3,542)	(3,328)	(4,858)
Per share basic & diluted	**(0.02)**	(0.00)	(0.02)	(0.00)	0.03	(0.01)	(0.06)	(0.07)	(0.10)
Corporate acquisitions	**–**	21,109	–	–	–	120,539	10,624	–	–
Capital expenditures (net of dispositions)	**5,847**	12,340	11,765	5,309	5,633	(1,437)	2,042	-9,022	5,412
Total assets	**338,478**	337,685	306,658	300,118	302,632	308,640	177,407	169,448	183,687
Net debt excluding financial derivatives	**80,677**	96,026	76,238	74,366	77,212	102,911	42,114	39,889	51,390

CAPITAL EXPENDITURES

During the first quarter of 2011, the Company invested $17.3 million on capital activity, less proceeds of $11.5 million from property dispositions, for net capital activity of $6.0 million. Property dispositions were completed in areas that were assessed as non-core in an effort to focus the Company's capital investment in core growth areas, and to reduce the Company's net debt. The Company's capital expenditures for the first quarter were focused predominantly in the heavy oil core area of Frog Lake, drilling 34 (23.5 net) oil wells in that area, of the 37 (27.5 net) total wells drilled in the first quarter. In addition, the Company drilled two horizontal oil wells at Jenner, and one vertical oil well at Earlie.

The following tables summarize capital expenditures, drilling results and undeveloped land positions for 2010 and 2009.

	Three months ended March 31	
($ 000's)	**2011**	2010
Land acquisition	**220**	99
Geological and geophysical	**574**	697
Drilling and completions	**11,803**	7,123
Equipping and facilities	**3,991**	2,980
Other	**759**	447
Gross Capital	**17,347**	11,346
Property dispositions	**(11,500)**	(5,713)
Total net capital expenditures	**5,847**	5,633

Drilling Results

Three months ended March 31	**2011**		2010	
	Gross	**Net**	Gross	Net
Crude oil	**36**	**25.5**	24	13.5
Natural gas	**–**	**–**	1	1.0
Dry and abandoned	**1**	**1.0**	–	–
Service	**–**	**–**	–	–
Total	**37**	**26.5**	25	14.5
Success rate (%)		**96%**		100%

Undeveloped Land

The Company's undeveloped land position has been reduced by a combination of drilling, dispositions and expiries in the past 12 months.

Three months ended March 31	**2011**	2010
Gross Acres	**326,526**	346,292
Net Acres	**238,915**	254,612

LIQUIDITY AND CAPITAL RESOURCES

The Company evaluates its ability to carry on business as a going concern on a quarterly basis. The key indicator is whether the funds flow, which is after interest and G&A expenses, will be sufficient to cover all obligations. In addition, the Company budgets to use funds flow from operating activities to fund the majority of the capital program to sustain or grow production net of declines. Funds derived from cash flow and asset dispositions may be used to apply to the Company's debt facility or fund the capital expenditure program.

In order to support the Company's business plan, Twin Butte's strategy is to fund the majority of its capital expenditure program with funds flow from operations. In order to maintain the Company's net debt at current or lower levels, Twin Butte plans to limit 2011 capital expenditures to approximately funds flow and proceeds from non-core property dispositions, which should continue to provide the Company a significant undrawn portion on the Company's credit facility borrowing.

As at March 31, 2011, the Company had a credit facility with a syndicate of two Canadian chartered banks in the amount of $128.0 million which was renewed subsequent to the quarter end in April, 2011. The credit facility is composed of a $128.0 million demand revolving operating credit facility. The Company's credit facility is subject to semi-annual review by the bank, with the next semi-annual credit facility review scheduled for October 2011. The facility is a borrowing base facility that is determined based on, among other things, the Company's current reserve report, results of operations, current and forecasted commodity prices and the current economic environment.

The credit facility provides that advances may be made by way of direct advances, bankers' acceptance, or standby letters of credit/guarantees. Direct advances bear interest at the bank's prime lending rate plus an applicable margin. The applicable margin charged by the bank is dependent on the Company's debt to cash flow ratio from the quarterly results two quarters earlier. The bankers' acceptances bear interest at the applicable bankers' acceptance rate plus a stamping fee, based on the Company's debt to trailing cash flow ratio. The credit facility is secured by a demand debenture and a general security agreement covering all assets of the Company.

The Company's bank indebtedness does not have a specific maturity date as it is a demand facility. This means that the lender has the ability to demand repayment of all outstanding indebtedness or a portion thereof at any time. If that were to occur the Company would be required to source alternate credit facilities or sell assets to repay the indebtedness. The Company reduces this risk by complying with the covenants of the banking syndicate and maintaining an undrawn balance on the facility. The covenants require maintaining a current ratio of not less than 1.0:1.0.

On an ongoing basis the Company will review its capital expenditures to ensure that funds flow and or access to credit facilities is available to fund these capital expenditures. The Company has the flexibility to adjust capital expenditures based on funds flow to manage debt levels.

At March 31, 2011, the Company had $70.2 million drawn on its credit facility and total net debt of $80.7 million. The Company has $57.8 million undrawn line on its credit facility. Twin Butte has met all of its covenants pertaining to this loan agreement and was not required to make any repayments.

The Company confirms there are no off balance sheet financing arrangements.

SHARE CAPITAL

In the first quarter of 2011 there were 5,260,072 warrants exercised for 3,682,049 Twin Butte shares at $2.14 per share for total cash of $7.9 million. Subsequent to March 31, 2011 and up to the expiry date an additional 4,489,700 warrants for 3,142,789

Twin Butte shares were exercised. 1,250,228 warrants were not exercised and expired on May 10, 2011. Also 143,233 options were exercised for $0.1 million proceeds.

On February 2, 2010 the Company closed a bought deal equity financing of 18,400,000 Common Shares at a price of $1.25 per share, for gross proceeds of $23,000,000 ($21,593,767 net of issue costs).

As of May 25, 2011 the Company has 135,187,406 Common Shares, and 8,578,834 stock options outstanding.

CONTRACTUAL OBLIGATIONS AND CONTINGENCIES

The Company had other commitments and guarantees in the normal course of business, consisting of an office space lease and equipment rentals which are not considered material.

The Company is involved in legal claims associated with the normal course of operations. The Company has completed an assessment and has determined that a contingent liability is not required in the financial statements.

RELATED PARTY TRANSACTIONS

During the three month period ended March 31, 2011 the Company incurred costs totaling $1.4 million (March 31, 2010 - $0.4 million) for services rendered by a company in which an officer and director of Twin Butte is a director. These costs were incurred in the normal course of business and recorded at the exchange amount. As at March 31, 2011, the Company had $0.9 million included in accounts payable and accrued liabilities related to these transactions (March 31, 2010 - $0.4 million).

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with IFRS requires Management to make certain judgments and estimates. Changes in these judgments and estimates could have a material impact on the Company's financial results and financial condition.

Management relies on the estimate of reserves as prepared by the Company's independent qualified reserves evaluator. The process of estimating reserves is critical to several accounting estimates and is complex and 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 and production activities becomes available and as economic conditions impact crude oil and natural gas prices, operating expense, royalty burden changes, and future development costs. Reserve estimates impact net income through depletion and impairment of petroleum and natural gas properties. The reserve estimates are also used to assess the borrowing base for the Company's credit facilities. Revision or changes in the reserve estimates can have either a positive or a negative impact on net income and the borrowing base of the Company.

Management's process of determining the provision for deferred income taxes, the provision for decommissioning liability costs and related accretion expense, and the fair values assigned to any acquired assets and liabilities in a business combination is based on estimates. These estimates are significant and can include proved and probable reserves, future production rates, future petroleum and natural gas prices, future costs, future interest rates, future tax rates and other relevant assumptions. Revisions or changes in any of these estimates can have either a positive or a negative impact on asset and liability values and net income.

In accordance with IFRS, derivative assets and liabilities are recorded at their fair values at the reporting date, with gains and losses recognized directly into comprehensive income in the same period. The fair value of derivatives outstanding is an estimate based on pricing models, estimates, assumptions and market data available at that time. As such, the recognized amounts are non-cash items and the actual gains or losses realized on eventual cash settlement can vary materially due to subsequent fluctuations in commodity prices and foreign exchange rates as compared to the valuation assumptions.

The fair value of stock options is based on estimates using the Black-Scholes option pricing model and is recorded as share-based payments expense in the financial statements.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

Canadian publicly accountable enterprises have implemented International Financial Reporting Standards ("IFRS") for the fiscal years beginning on or after January 1, 2011. The transition date to IFRS was January 1, 2010 and comparative figures for

2010 and Twin Butte's financial position as at January 1, 2010 have been restated to IFRS from the previous Canadian generally accepted accounting principles ("Previous GAAP"). Reconciliations to IFRS from Previous GAAP financial statements including the impact of the transition on the Company's reported financial position and financial performance, including the nature and effect of significant changes in accounting policies from those used in the Company's financial statements for the year ended December 31, 2010, are summarized in note 18 to the unaudited financial statements. The following discussion explains the significant differences between IFRS and the Previous GAAP followed by the Company.

a) Property and equipment

Under Previous GAAP, the Company, like many Canadian oil and gas reporting issuers, applied the "full cost" concept in accounting for its oil and gas assets. Under full cost, capital expenditures were maintained in a single cost centre for each country, and the cost centre was subject to a single depletion and depreciation calculation and impairment test. Under IFRS, the Company makes a much more detailed assessment of its oil and gas assets that impact depletion and impairment calculations. Included in this assessment is an ongoing appraisal of exploration and evaluation expenditures ("E&E"). Under Canadian GAAP, it was only necessary to track costs associated with unproved properties that would be excluded from depletion and depreciation calculations. Under IFRS, a company may choose to account for E&E under its previous GAAP and capitalize such costs without recording depreciation expense until the technical feasibility and commercial viability of the project is determined, at which time the costs are moved to development properties or expensed accordingly. Twin Butte capitalizes E&E costs except for costs incurred before the acquisition of rights to explore in a separate asset account, and to moves these costs into property and equipment when technically feasible and commercially viable. As at transition on January 1, 2010, $26.8 million was reclassified from property, plant and equipment to exploration and evaluation assets.

Under Previous GAAP the Company did not recognize gains or losses on the disposal of oil and gas properties unless such dispositions would change the depletion rate by 20% or more while IFRS requires such recognition. This results in a change to the carrying value and a gain or loss on sale of property, plant and equipment.

b) Depletion and depreciation

For Previous GAAP purposes, the full cost method of accounting for oil and gas properties requires a single calculation of depletion and depreciation of the carrying value of PP&E based on proved reserves. However, IFRS requires an allocation of the amount recognized as PP&E to each significant identified component and each component depleted separately, utilizing an appropriate method of depletion. This component depletion of PP&E results in an increased number of calculations of depreciation expense and impacts the amount of depletion expense recognized. IFRS also permits the option of using either proved or proved and probable reserves in the depletion calculation. Twin Butte has utilized proved and probable reserves to calculate depletion expense as we believe it represents a better approximation of useful life and depletion of reserves.

c) Impairment of Assets

Under Canadian GAAP, impairment calculations are prepared according to a two-step test generally conducted at a country level and are not subsequently reversed. Under IFRS, impairment testing is completed at an individual asset group or "Cash Generating Unit" level ("CGU") when indicators suggest there may be impairment. A CGU is defined as the smallest group of assets that produce independent cash flows. Impairment of assets at a CGU level use a one-step approach for testing and measuring asset impairment, with asset carrying values compared to the higher of "Value in Use" and "Fair Value less Costs to Sell". The IFRS methodology may result in the possibility of more frequent impairments in the carrying value of PP&E. However, under IFRS previous impairment losses must be reversed where circumstances change such that the previously recognized impairment has been reduced. The company did not have any impairments at either January 1, 2010 or December 31, 2011.

d) Decommissioning Liabilities

Both Canadian GAAP and IFRS require a company to provide for a liability related to decommissioning PP&E. Both methodologies are similar and we have determined there to be no significant difference for Twin Butte, other than a difference related to discount rates. Canadian GAAP requires that the decommissioning liability be discounted at a credit-adjusted risk-free rate while IFRS requires that the decommissioning liability be discounted at an appropriate rate with either the cash flows or rate adjusted for risks. Twin Butte has selected to use the risk-free rate for discounting purposes as we believe this accurately represents a market-based rate for such a liability and at transition date the decommission liability was increased $8.7 million and charged to deficit.

e) Share-based Payments

Under Previous GAAP, the Company accounted for stock-based compensation plans on a straight-line basis over the term of the vesting period. Under IFRS each tranche in an award is considered a separate grant with different vesting date and fair value. Each grant is separately accounted for using applicable assumptions for those specific dates and different fair values and accounted for using graded vesting recognition of expense.

Under Previous GAAP, forfeitures of awards are recognized as they occur. The calculation of share-based compensation under IFRS reflects an estimate of the number of awards expected to vest, which is revised if subsequent information indicates that actual forfeitures are likely to differ from the estimate. As a result, the Company adjusted its expense for share-based awards by $0.1 for the twelve months ending December 31, 2010 and recognized the corresponding adjustment to contributed surplus.

f) Flow-through shares

Flow-through shares are a Canadian tax incentive which is the subject of specific guidance under Previous GAAP, however there is no specific guidance under IFRS. Under Canadian GAAP, when flowthrough shares are issued they are recorded at face value. The related future tax liability is established for the tax effect of the difference between the tax basis and the book basis of the assets when renounced and is recorded as a reduction of share capital. There is no income statement effect associated with the issuance of these shares.

Twin Butte has adopted a policy under IFRS where the proceeds from the offering are to be allocated between the sale of the shares and the sale of the tax benefit. The allocation is made based on the difference between the quoted market price of the existing shares and the amount an investor pays for the flow through shares. A liability is established for this difference that is reversed upon renunciation of the tax benefit. The difference between this liability and the deferred tax liability is recorded as an income tax expense. This has resulted in a re-classification between deficit and share capital at January 1, 2010 of $1.5 million.

g) Deferred Income Taxes

Deferred income tax calculated according to IFRS is substantially similar to Previous GAAP and arises from differences between the accounting and tax bases of assets and liabilities. To the extent that assets and liabilities have changed from transition to IFRS, the amount of deferred income tax liability has been impacted. Additionally, under Previous GAAP deferred income tax liabilities were required to be disclosed as either current or long-term. Under IFRS, all deferred income tax liabilities are considered to be noncurrent liabilities.

h) First Time Adoption of International Financial Reporting Standards

IFRS 1 provides the framework for the first time adoption of IFRS and specifies that an entity shall apply the principles under IFRS retrospectively. IFRS 1 also specifies that the adjustments that arise on retrospective conversion to IFRS from other GAAP should be directly recognized in retained earnings. Certain optional exemptions and mandatory exceptions to retrospective application are provided under IFRS 1. The Company has taken the following exemptions:

> Companies using full-cost accounting are allowed to measure their oil and gas assets at the amount determined under the Previous GAAP at the date of transition. This amount is pro-rated to the underlying assets based upon the value of proved and probable reserves values at transition date, discounted at 10%.

> Companies using the full cost book value as deemed cost exemption are allowed to measure the liabilities for decommissioning, restoration and similar liabilities at the date of transition and recognize directly in deficit any difference between that amount and the carrying amount determined under Previous GAAP.

> IFRS 3 Business Combinations has not been applied to acquisitions of subsidiaries or of interests in associates and joint ventures that occurred before January 1, 2010.

> IFRS 2 Share-based Payment has not been applied to any equity instruments that were granted on or before November 7, 2002, nor has it been applied to equity instruments granted after November 7, 2002 that vested before January 1, 2010.

> IAS 17 Leases has been applied as of transition date rather than at the lease's inception date.

> IAS 23 Borrowing Costs will not be applied before January 1, 2010.

i) New standards and interpretations not yet adopted

IFRS 11 - Joint Arrangements
IFRS 11 requires a venturer to classify its interest in a joint arrangement as a joint venture or joint operation. Joint ventures will be accounted for using the equity method of accounting whereas for a joint operation the venturer will recognize its share of the assets, liabilities, revenue and expenses of the joint operation. Under existing IFRS, entities have the choice to proportionately consolidate or equity account for interests in joint ventures. IFRS 11 supersedes IAS 31, Interests in Joint Ventures, and SIC-13, Jointly Controlled Entities—Non-monetary Contributions by Venturers. The Company has yet to assess the full impact of IFRS 11.

IFRS 13 - Fair Value Measurement
IFRS 13 is a comprehensive standard for fair value measurement and disclosure requirements for use across all IFRS standards. The new standard clarifies that fair value is the price that would be received to sell an asset, or paid to transfer a liability in an orderly transaction between market participants, at the measurement date. It also establishes disclosures about fair value measurement. Under existing IFRS, guidance on measuring and disclosing fair value is dispersed among the specific standards requiring fair value measurements and in many cases does not reflect a clear measurement basis or consistent disclosures. The Company has yet to assess the full impact of IFRS 13.

Standards issued but not yet effective up to the date of issuance of the Company's financial statements are listed below. This listing is of standards and interpretations issued which the Company reasonably expects to be applicable at a future date. The Company intends to adopt those standards when they become effective.

Standards issued but not yet effective up to the date of issuance of the Company's financial statements are listed below. This listing is of standards and interpretations issued which the Company reasonably expects to be applicable at a future date. The Company intends to adopt those standards when they become effective.

IFRS 9 Financial Instruments: Classification and Measurement
IFRS 9 was issued in November 2009. This standard is the first step in the process to replace IAS 39 Financial Instruments:

Recognition and Measurement. IFRS 9 introduces new requirements for classifying and measuring assets and liabilities, which may affect the Company's accounting for its financial assets. The standard is not applicable until January 1, 2013 but is available for early adoption. The Company has yet to assess the full impact of IFRS 9.

j) Internal Controls

In accordance with the Company's approach to certification of internal controls required under Canadian Securities Administrators' National instrument 52-109 and SOX 302 and 404, all entity level, information technology, disclosures and business process controls will require updating and testing to reflect changes arising from our conversion to IFRS. Upon review, we have determined there to be minimal updating of processes, controls and documentation required.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Disclosure controls and procedures have been designed to provide reasonable assurance that information required to be disclosed by the Company is recorded, processed, summarized and reported within the time periods specified under the Canadian securities law.

Twin Butte's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation, that the disclosure controls and procedures as of the end of March 31, 2011, are effective and provide reasonable assurance that material information related to the Company is made known to them by others within Twin Butte.

Twin Butte's Chief Executive Officer and Chief Financial Officer are responsible for establishing and maintaining internal controls over financial reporting ("ICFR"). They have, as at the quarter ended March 31, 2011, designed ICFR or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The control framework Twin Butte's officers used to design the ICFR is the Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations.

Twin Butte's Chief Executive Officer and Chief Financial Officer are required to disclose any change in the internal controls over financial reporting that occurred during our most recent interim period that has materially affected, or is reasonably likely to affect, the Company's internal controls over financial reporting. No material changes in the internal controls were identified during the period ended March 31, 2011 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

It should be noted that a control system, including Twin Butte's disclosure and internal controls and procedures, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

BALANCE SHEET

(unaudited) (Cdn $ thousands)

As at	*Note*	**March 31, 2011**	December 31, 2010	January 1, 2010
			Note 18	*Note 18*
ASSETS				
Current Assets				
Accounts receivable		**$ 21,396**	$ 27,358	$ 20,759
Deposits and prepaids expenses		**2,443**	2,453	3,182
Derivative assets	*5*	**2,863**	3,947	–
		26,702	33,758	23,941
Non-Current assets				
Deferred taxes	*15*	**5,180**	4,494	4,582
Exploration and evaluation	*7*	**20,117**	19,897	26,791
Property and equipment	*6, 8*	**286,479**	287,561	255,729
		$ 338,478	$ 345,710	$ 311,043
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current Liabilities				
Accounts payable and accrued liabilities		**$ 34,322**	$ 27,779	$ 29,713
Bank indebtedness	*9*	**70,194**	97,705	96,342
Derivative liabilities	*5*	**10,017**	3,293	1,224
		114,533	128,777	127,279
Non-Current liabilities				
Other liabilities		**249**	354	796
Derivative liabilities	*5*	**4,622**	3,340	–
Decommissioning provision	*10*	**30,017**	30,274	23,581
		149,421	162,745	151,656
Shareholders' Equity				
Share capital	*11*	**220,035**	211,538	189,504
Warrants	*11*	**476**	912	912
Contributed surplus	*11*	**5,416**	5,124	4,261
Deficit		**(36,870)**	(34,609)	(35,290)
		189,057	182,965	159,387
		$ 338,478	$ 345,710	$ 311,043

Commitments and contingencies *17*

The accompanying notes are an integral part of these interim financial statements.

STATEMENT OF INCOME (LOSS) AND COMPREHENSIVE INCOME

		Three Months Ended March 31,	
(unaudited) (Cdn$ thousands except per share amounts)	*Note*	**2011**	2010
			Note 18
Petroleum and natural gas sales		**$ 31,728**	$ 25,503
Royalties		**(5,981)**	(5,254)
Revenues		**$ 25,747**	$ 20,249
Expenses			
Operating		**10,089**	7,444
Transportation		**1,278**	976
General and administrative	*12*	**1,595**	1,504
Share-based payments		**193**	69
(Gain) loss on derivatives	*5*	**8,269**	(4,335)
(Gain) loss on divestitures		**(2,590)**	721
Depletion and depreciation		**8,846**	7,231
		27,680	13,610
Operating Income before finance expense and income taxes		**(1,933)**	6,639
Finance expense	*13*	**1,014**	1,100
Income before income taxes		**(2,947)**	5,539
Deferred tax expense (recovery)	*15*	**(685)**	1,550
INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)		**(2,262)**	3,989
Income (loss) per share $			
Basic & Diluted		**(0.02)**	0.03

The accompanying notes are an integral part of these interim financial statements.

STATEMENT OF CASH FLOWS

		Three Months Ended March 31,	
(Cdn$ thousands) (unaudited)	*Note*	**2011**	2010
			Note 20
Cash provided by(used in):			
OPERATING ACTIVITIES:			
Net income (loss)		**$ (2,262)**	$ 3,989
Items not involving cash:			
Depletion and depreciation		**8,846**	7,231
Deferred tax expense (recovery)		**(685)**	1,550
Loss on derivatives - unrealized	*5*	**9,090**	(4,069)
Finance expenses	*13*	**1,014**	1,100
Interest paid		**(749)**	(865)
Share-based payments		**193**	69
Gain (loss) on sale of divestitures	*8*	**(2,590)**	720
Expenditures on decommissioning liability		**(68)**	(2)
		12,789	9,724
Changes in non-cash working capital	*14*	**7,967**	(1,739)
		20,756	7,985
FINANCING ACTIVITIES			
Change in bank indebtedness		**(27,511)**	(30,738)
Issuance of share capital	*11*	**7,881**	23,000
Issuance of share capital on exercise of stock options	*11*	**132**	–
Share issue costs		**–**	(1,406)
		(19,498)	(9,144)
INVESTING ACTIVITIES			
Expenditures on property and equipment		**(12,758)**	(4,559)
Proceeds on dispositions of property and equipment		**11,500**	5,718
		(1,258)	1,159
Increase in cash		**$ –**	$ –
Cash and cash equivalents, beginning and end of period		**$ –**	$ –

The accompanying notes are an integral part of these interim financial statements.

STATEMENTS OF CHANGES IN SHAREHOLDERS EQUITY

	Three Months Ended March 31,	
(Cdn$ thousands) (unaudited)	**2011**	2010
		Note 20
Share capital		
Balance, beginning of year	**$ 211,538**	$ 189,504
Common shares issued under bought deal financing	**–**	23,000
Share issue costs	**–**	(1,012)
Common shares issued under option plan	**179**	–
Warrants exercised	**8,318**	–
Balance, end of period	**$ 220,035**	$ 211,492
Warrants		
Balance, beginning of year	**$ 912**	$ 912
Warrants exercised	**(436)**	–
Balance, end of period	**$ 476**	$ 912
Contributed surplus		
Balance, beginning of year	**$ 5,124**	$ 4,261
Share-based payments for options exercised	**(47)**	(35)
Share-based payments for options granted	**339**	105
Balance, end of period	**$ 5,416**	$ 4,331
Deficit		
Balance, beginning of year	**$ (34,609)**	$ (35,290)
Net income (loss) & comprehensive income (loss)	**(2,262)**	3,989
Balance, end of period	**$ (36,870)**	$ (31,300)

See accompanying notes to the unaudited interim financial statements

NOTES TO INTERIM FINANCIAL STATEMENTS

March 31, 2011 (unaudited)

All tabular amounts are in thousands of Canadian dollars except as otherwise indicated.

NOTE 1. BUSINESS AND STRUCTURE OF TWIN BUTTE

Twin Butte Energy Ltd. ("Twin Butte" or "the company") is a growth oriented junior oil and natural gas exploration, development and production Company with properties located in Western Canada. Twin Butte is domiciled and incorporated in Canada under the Business Corporation's Act (Alberta). Twin Butte's head office address is 410, 396 – 11th Avenue SW, Calgary, Alberta, Canada. The Company's primary listing is on the Toronto Stock Exchange under the symbol (TBE).

NOTE 2. BASIS OF PREPARATION

(a) Basis of preparation and adoption of IFRS

The Company prepares its financial statements in accordance with Canadian generally accepted accounting principles as set out in the Handbook of the Canadian Institute of Chartered Accountants ("CICA Handbook"). In 2010, the CICA Handbook was revised to incorporate International Financial Reporting Standards, and require publicly accountable enterprises to apply such standards effective for years beginning on or after January 1, 2011. Accordingly, the Company has commenced reporting on this basis in these interim financial statements. In the financial statements, the term "Previous GAAP" refers to Canadian GAAP before the adoption of IFRS

These interim condensed financial statements have been prepared in accordance with IFRS applicable to the preparation of interim financial statements, including IAS 34 and IFRS 1. Subject to certain transition elections disclosed in note 18, the Company has consistently applied the same accounting policies in its opening IFRS Balance Sheet at January 1, 2010 and throughout all periods presented, as if these policies had always been in effect. Note 18 discloses the impact of the transition to IFRS on the Company's reported financial position, financial performance and cash flows, including the nature and effect of significant changes in accounting policies from those used in the Company's financial statements for the year ended December 31, 2010.

The policies applied in these condensed interim financial statements are based on IFRS issued and outstanding as of May 25, 2011, the date the Board of Directors approved the statements. Any subsequent changes to IFRS that are given effect in the Company's annual consolidated financial statements for the year ending December 31, 2011 could result in restatement of these interim consolidated financial statements, including the transition adjustments recognized on change-over to IFRS.

The condensed interim financial statements should be read in conjunction with the Company's Canadian GAAP annual financial statements for the year ended December 31, 2010. Note 18 discloses IFRS information for the year ended December 31, 2010 not provided in the 2010 annual financial statements.

(b) Basis of measurement

The financial statements have been prepared under the historical cost convention, except for derivative instruments, which are measured at fair value. The methods used to measure fair values of derivative instruments are discussed in note 5.

(c) Functional and presentation currency

These financial statements are presented in Canadian dollars, which is the Company's functional currency.

NOTE 3. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies set out below have been applied consistently to all years presented in these financial statements, and have been applied consistently by the Company, excluding optional exemptions taken by the Company on transition to IFRS (note 18).

(a) Cash and cash equivalents

Cash consists of balances held with banks, and other short-term highly liquid investments with original maturities of three months or less from inception.

(b) Financial instruments

The Company's financial instruments consist of financial assets, financial liabilities, and derivative instruments. All financial instruments are initially recognized at fair value on the balance sheet. Measurement of financial instruments subsequent to the initial recognition, as well as resulting gains and losses, are based on how each financial instrument was initially classified. The Company has classified each identified financial instrument into the following categories: fair value through profit or loss, loans and receivables, held to maturity investments, available for sale financial assets, and other financial liabilities. Fair value through profit or loss financial instruments are measured at fair value with gains and losses recognized in income immediately. Available for sale financial assets are measured at fair value with gains and losses, other than impairment losses, recognized in other comprehensive income and transferred to income when the asset is derecognized. Loans and receivables, held to maturity investments and other financial liabilities are recognized at amortized cost using the effective interest method and impairment losses are recorded in income when incurred.

Derivative instruments executed by the Company to manage market risk associated with volatile commodity prices are classified as fair value through profit or loss and recorded on the balance sheet at fair value as derivative assets and liabilities. Gains and losses on these derivative instruments are recorded as gains and losses on derivatives in the statement of income in the period they occur.

Gains and losses on derivative instruments are comprised of cash receipts and payments associated with periodic settlement that occurs over the life of the instrument, and non-cash gains and losses associated with changes in the fair values of the instruments, which are remeasured at each reporting date and recorded on the balance sheet. Transaction costs attributed to the acquisition or issue of a derivative instrument is expensed immediately. For other financial instruments, transaction costs are added to the fair value initially recognized for financial asset or liability.

(c) Share capital

Equity instruments issued by the Company are recorded at the proceeds received, with direct issue costs as a deduction there from, net of any associated tax benefit.

(d) Jointly controlled assets

A significant portion of the Company's oil and natural gas activities involve jointly controlled assets. The consolidated financial statements include the Company's share of these jointly controlled assets and a proportionate share of the relevant revenue and related costs.

(e) Property and equipment and exploration and evaluation assets

(i) Recognition and measurement

The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of the decommissioning provision, and for qualifying assets, borrowing costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

(ii) Exploration and evaluation expenditures

Pre-license costs are recognized in the statement of income as incurred. All exploratory costs incurred subsequent to acquiring the right to explore for oil and natural gas are capitalized. Such costs can typically include costs to acquire land rights in areas with no proved or probable reserves assigned, geological and geophysical costs, and exploration wells.

Exploration and evaluation costs initially are capitalized as either tangible or intangible exploration or evaluation assets according to the nature of the assets acquired. The costs are accumulated in areas by well, field or exploration area pending determination of technical feasibility and commercial viability. Exploration and evaluation assets are assessed for impairment if sufficient data exists to determine technical feasibility and commercial viability, and facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, exploration and evaluation assets are allocated to cash-generating units.

The technical feasibility and commercial viability of extracting a mineral resource from exploration and evaluation assets is considered when proved and probable reserves are determined to exist. A review of each exploration license or field is carried out, at least annually, to ascertain whether proved and probable reserves have been discovered. Upon determination of proved and probable reserves, exploration and evaluation assets attributable to those reserves are first tested for impairment and then reclassified from exploration and evaluation assets to development and production assets within property and equipment. If the well or exploration project did not encounter potentially economic oil and gas quantities, the costs are expensed and reported in exploration and evaluation expense in the period incurred.

(iii) Development and production expenditures

Items of property and equipment, which include petroleum and natural gas development and production assets, are measured at cost (including directly attributable general and administrative costs) less accumulated depletion and depreciation and accumulated impairment losses. Costs include lease acquisition, drilling and completion, production facilities, decommissioning costs, geological and geophysical costs and directly attributable costs related to development and production activities, net of any government incentive programs.

When significant parts of an item of property and equipment, including oil and natural gas properties, have different useful lives, they are accounted for as separate items (major components). Gains and losses on disposal of an item of property and equipment, including oil and natural gas properties, are determined by comparing the proceeds from disposal with the carrying amount of property and equipment and are recognized net within in the statement of income (loss) and comprehensive income (loss).

(iv) Subsequent costs

Costs incurred subsequent to development and production that are significant are recognized as oil and gas assets only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in income as incurred. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved and probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property and equipment are recognized in income as incurred.

(v) Depletion and depreciation

The net carrying value of oil and gas properties is depleted using the unit of production method by reference to the ratio of production in the period to the related proved and probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. Future development costs are estimated taking into account the level of development required to produce the reserves. These estimates are reviewed by independent reserve engineers at least annually. Major development projects are not depleted until production commences.

Turnarounds are capitalized and amortized over the period to the next inspection. Other inspection and maintenance programs are expensed as incurred.

The expected useful lives of property and equipment are reviewed on an annual basis and, if necessary, changes in useful lives are accounted for prospectively.

The Company records furniture and equipment at cost and provides depreciation on the declining balance method at a rate of 20% per annum which is designed to amortize the cost of the assets over their estimated useful lives. The Company records leasehold improvements at cost and provides depreciation on the straight-line method over the term of the lease. Leased assets are depreciated over the shorter of the lease term and their useful lives unless it is reasonably certain that the Company will obtain ownership by the end of the lease term. Depreciation methods, useful lives and residual values are reviewed at each financial year end.

(f) Asset swaps

Exchanges of development and production assets are measured at fair value unless the exchange transaction lacks commercial substance or the fair value of neither the asset received nor the asset given up is reliably measurable. The cost of the acquired asset is measured at the fair value of the asset given up, unless the fair value of the asset received is more clearly evident. Where fair value is not used, the cost of the acquired asset is measured at the carrying amount of the amount given up. Any gain or loss on derecognition of the asset given up is recognized in statement of income (loss) and income (loss). For exchanges or parts of exchanges that involve only exploration and evaluation assets, the exchange is accounted for at carrying value.

(g) Leased assets

Leases in which a significant portion of the risks and rewards of ownership are retained by the lessor are classified as operating leases. Payments made under the operating leases are charged to income on a straight-line basis over the period of the lease.

(h) Impairment

(i) Financial assets

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset. An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate. Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics. All impairment losses are recognized in income. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in the income (loss) statement.

(ii) Non-financial assets

The carrying amounts of the Company's non-financial assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. Exploration and evaluation assets are assessed for impairment when they are reclassified to property and equipment, as oil and natural gas interests, and also if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or "CGU"). The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell.

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved and probable reserves. Fair value less cost to sell is assessed utilizing market valuation based on an arm's length transaction between active participants. In the absence of any such transactions, fair value less cost to sell is estimated by discounting the expected after-tax cash flows of the cash generating unit at an after-tax discount rate that reflects the risk of the properties in the cash generating unit. The discounted cash flow calculation is then increased by a tax-shield calculation, which is an estimate of the amount that a prospective buyer of the cash generating unit would be entitled. The carrying value of the cash generating unit is reduced by the deferred tax liability associated with its property and equipment.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses recognized in prior years are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been objective change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or depletion, if no impairment loss had been recognized.

(i) Share based payments

The Company's compensation program currently consists of three primary components: (i) annual base salary (ii) discretionary short-term incentive cash bonus; (iii) and periodic grants of long-term incentives in the form of stock options ('equity-settled transactions'). Awards of options are made from time to time to participants at varying levels consistent with the individual's position and level of responsibility.

The Company follows the fair value method of valuing stock option grants. Under this method, compensation costs attributable to share options granted to employees, officers and directors of the Company are measured at fair value at the date of grant and expensed over the vesting period. In determining the fair value of the options granted, the Black-Scholes model is used and assumptions regarding interest rates, underlying volatility and expected life of the options are made.

A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options that vest. Upon the exercise of the stock options, consideration paid together with the amount in contributed surplus is recorded as an increase to share capital.

(j) Decommissioning provision

A decommissioning liability is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Decommissioning liabilities are determined by discounting the expected future cash flows at a risk-free rate.

(k) Revenue

Revenue from the sale of oil and natural gas is recorded when the significant risks and rewards of ownership of the product is transferred to the buyer which is usually when legal title passes to the external party. For natural gas, this is generally at the time product enters the pipeline. For crude oil, this is generally at the time the product reaches a trucking terminal. For natural gas liquids, this is generally at the time the product is processed through a gas plant. Revenue is measured net of discounts, customs duties and royalties. With respect to the latter, the entity is acting as a collection agent on behalf of others.

Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

(l) Finance expense

Finance expense comprises interest expense on borrowings and accretion of the discount on the decommissioning provision.

(m) Borrowing costs capitalized

Borrowing costs incurred for the construction of qualifying assets are capitalized during the period of time that is required to complete and prepare the assets for their intended use or sale. The Company considers a qualifying asset to be any significant construction project expected to take more than twelve months to complete. The capitalization rate used to determine the amount of borrowing costs to be capitalized is the weighted average interest rate applicable to the Company's outstanding general and specific borrowings during the period.

(n) Income tax

Income tax expense comprises current and deferred income tax. Income tax expense is recognized in income or loss except to the extent that it relates to items recognized directly in shareholders' equity.

Current income tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to income tax payable in respect of previous years. Deferred income tax is recognized using the liability method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred income tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination, and at the time of the transaction, affects neither accounting income nor taxable income. Deferred income tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date.

A deferred income tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred income tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

(o) Net income (loss) per share

Basic net income (loss) per share is calculated by dividing the net income (loss) of the Company by the weighted average number of common shares outstanding during the period. Diluted net income (loss) per share is determined by adjusting the net income attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments such as options granted to employees.

(p) New standards and interpretations not yet adopted

Standards issued but not yet effective up to the date of issuance of the Company's financial statements are listed below. This listing is of standards and interpretations issued which the Company reasonably expects to be applicable at a future date. The Company intends to adopt those standards when they become effective.

IFRS 11 - Joint Arrangements
IFRS 11 requires a venturer to classify its interest in a joint arrangement as a joint venture or joint operation. Joint ventures will be accounted for using the equity method of accounting whereas for a joint operation the venturer will recognize its share of the assets, liabilities, revenue and expenses of the joint operation. Under existing IFRS, entities have the choice to proportionately consolidate or equity account for interests in joint ventures. IFRS 11 supersedes IAS 31, Interests in Joint Ventures, and SIC-13, Jointly Controlled Entities—Non-monetary Contributions by Venturers. The Company has yet to assess the full impact of IFRS 11.

IFRS 13 - Fair Value Measurement
IFRS 13 is a comprehensive standard for fair value measurement and disclosure requirements for use across all IFRS standards. The new standard clarifies that fair value is the price that would be received to sell an asset, or paid to transfer a liability in an orderly transaction between market participants, at the measurement date. It also establishes disclosures about fair value measurement. Under existing IFRS, guidance on measuring and disclosing fair value is dispersed among the specific standards requiring fair value measurements and in many cases does not reflect a clear measurement basis or consistent disclosures. The Company has yet to assess the full impact of IFRS 13.

IFRS 9 Financial Instruments: Classification and Measurement
IFRS 9 was issued in November 2009. This standard is the first step in the process to replace IAS 39 Financial Instruments: Recognition and Measurement. IFRS 9 introduces new requirements for classifying and measuring financial assets and liabilities, which may affect the Company's accounting for its financial assets. The standard is not applicable until January 1, 2013 but is available for early adoption. The Company has yet to assess the full impact of IFRS 9.

NOTE 4. SIGNIFICANT ACCOUNTING JUDGMENTS, ESTIMATES AND ASSUMPTIONS

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates, and differences could be material. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Estimates and assumptions

Information about significant areas of estimation uncertainty in applying accounting policies that have the most significant effect on the amounts recognized in the financial statements is included in the following notes:

- Note 5 – valuation of financial instruments;
- Note 8 – valuation of property and equipment;
- Note 10 – measurement of decommissioning provision; and
- Note 11 – measurement of share-based compensation.

Judgements

In the process of applying the Company's accounting policies, management has made the following judgements, apart from those involving estimates, which may have the most significant effect on the amounts recognized in the financial statements.

(a) Exploration and evaluation assets

The decision to transfer assets from exploration and evaluation to property and equipment is based on the estimated proved and probable reserves used in the determination of an area's technical feasibility and commercial viability.

(b) Reserves base

The oil and gas development and production properties are depreciated on a unit of production ("UOP") basis at a rate calculated by reference to proved and probable reserves determined in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" and incorporate the estimated future cost of developing and extracting those reserves. Proved plus probable reserves are determined using estimates of oil and natural gas in place, recovery factors and future prices. Future development costs are estimated using assumptions as to number of wells required to produce the reserves, the cost of such wells and associated production facilities and other capital costs.

Proved and probable reserves are estimated using independent reserve engineer reports and represent the estimated quantities of oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is ninety percent likely that the actual remaining quantities recovered will exceed the estimated proved reserves. 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 and probable reserves.

(c) Depletion of oil and gas assets

Oil and gas properties are depleted using the UOP method over proved plus probable reserves. The calculation of the UOP rate of depletion could be impacted to the extent that actual production in the future is different from current forecast production based on proved plus probable reserves. This would generally result from significant changes in any of the factors or assumptions used in estimating reserves.

(d) Determination of cash generating units

Oil and gas properties are grouped into cash generating units for purposes of impairment testing. Management has evaluated the oil and gas properties of the Company, and grouped the properties into cash generating units on the basis of their ability to generate independent cash in flows, similar reserve characteristics, geographical location, and shared infrastructure.

(e) Impairment indicators and calculation of impairment

At each reporting date, Twin Butte assesses whether or not there are circumstances that indicate a possibility that the carrying values of exploration and evaluation assets and property and equipment are not recoverable, or impaired. Such circumstances include incidents of physical damage, deterioration of commodity prices, changes in the regulatory environment, or a reduction in estimates of proved and probable reserves. When management judges that circumstances clearly indicate impairment, property and equipment and exploration and evaluation assets are tested for impairment by comparing the carrying values to their recoverable amounts. The recoverable amounts of cash generating units are determined based on the higher of value-in-use calculations and fair values less costs to sell. These calculations require the use of estimates and assumptions, including the discount rate applied.

(f) Decommissioning provision

Decommissioning costs will be incurred by the Company at the end of the operating life of the Company's facilities and properties. The ultimate decommissioning liability is uncertain and can vary in response to many factors including changes to relevant legal requirements, the emergence of new restoration techniques, experience at other production sites, or changes in the risk-free discount rate. The expected timing and amount of expenditure can also change in response to changes in reserves or changes in laws and regulations or their interpretation. As a result, there could be significant adjustments to the provisions established which would affect future financial results.

(g) Income taxes

The Company recognizes deferred income tax assets to the extent that it is probable that taxable profit will be available to allow the benefit of that deferred income tax asset to be utilized. Assessing the recoverability of deferred income tax assets requires the Company to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecast cash flows from operations and the application of existing tax laws. To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Company to realize the deferred income tax assets recorded at the reporting date could be impacted. Additionally, future changes in tax laws in the jurisdictions in which the Company operates could limit the ability of the Company to obtain tax deductions in future periods.

(h) Contingencies

By their nature, contingencies will only be resolved when one or more future events occur or fail to occur. The assessment of contingencies inherently involves the exercise of significant judgment and estimates of the outcome of future events.

NOTE 5. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Financial instruments of the Company include accounts receivables, deposits, accounts payable and accrued liabilities, bank indebtedness, other liabilities and derivative assets and liabilities. Accounts receivables and deposits are classified as loans and receivables and measured at amortized cost. Accounts payable and accrued liabilities, bank indebtedness and other liabilities are all classified as other liabilities and similarly measured at amortized cost. As at March 31, 2011, there were no significant differences between the carrying amounts reported on the Balance Sheet and the estimated fair values of these financial instruments due to the short terms to maturity and the floating interest rate on the bank indebtedness.

	As at March 31, 2011		As at December 31, 2010	
	Carrying Amount	**Estimated Fair Value**	Carrying Amount	Estimated Fair Value
Financial Assets				
Derivative assets	**$ 2,863**	**$ 2,863**	$ 3,947	$ 3,947
Accounts receivable	**21,396**	**21,396**	27,358	27,358
Deposits	**1,322**	**1,322**	1,372	1,372
Financial Liabilities				
Derivative liabilities	**$ 14,639**	**$ 14,639**	$ 6,633	$ 6,633
Accounts payable and accrued liabilities	**34,322**	**34,322**	27,779	27,779
Bank indebtedness	**70,194**	**70,194**	97,705	97,705
Other liabilities	**249**	**249**	354	354

Fair value is determined following a three level hierarchy:

Level 1: Quoted prices in active markets for identical assets and liabilities. The Company does not have any financial assets or liabilities that require level 1 inputs.

Level 2: Inputs other than quoted prices included within Level 1 that are observable, either directly or indirectly. Such inputs can be corroborated with other observable inputs for substantially the complete term of the contract. Twin Butte uses Level 2 inputs in the determination of the fair value of derivative assets and liabilities.

Level 3: Under this level, fair value is determined using inputs that are not observable. Twin Butte has no assets or liabilities that use level 3 inputs.

Twin Butte has an established strategy to manage the risk associated with changes in commodity prices by entering into derivatives, which are recorded at fair value as derivative assets and liabilities with gains and losses recognized through income (loss). As the fair value of the contracts varies with commodity prices, they give rise to financial assets and liabilities. The fair values of the derivatives are determined by a Level 2 valuation model, where pricing inputs other than quoted prices in an active market are used. These pricing inputs include quoted forward prices for commodities, foreign exchange rates, volatility and risk-free rate discounting, all of which can be observed or corroborated in the marketplace. The actual gains and losses realized on eventual cash settlement can vary materially due to subsequent fluctuations in commodity prices and foreign exchange rates as compared to the valuation assumptions. The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production, and financing activities such as:

- credit risk;
- liquidity risk;
- price and currency risk; and
- interest rate risk.

(a) Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Company's receivables from joint venture partners and oil and natural gas marketers. The maximum exposure to credit risk is as follows:

	March 31, 2011	Dec 31, 2010	Jan 1, 2010
Accounts receivable	**$ 21,396**	$ 27,358	$ 20,759
Deposits	**1,322**	1,372	2,305
Derivative assets	**2,861**	3,946	–
	$ 25,579	$ 32,676	$ 23,064

Accounts receivable, deposits, and derivative assets are subject to credit risk exposure and the carrying values reflect management's assessment of the associated maximum exposure to such credit risk. Twin Butte mitigates such credit risk by closely monitoring significant counterparties and dealing with a broad selection of partners that diversify risk within the sector. The Company's deposits are primarily due from the Alberta Provincial government and are viewed by Management as having minimal associated credit risk. To the extent that Twin Butte enters derivatives to manage commodity price risk, it may be subject to credit risk associated with counterparties with which it contracts.

Credit risk is mitigated by entering into contracts with only stable, creditworthy parties and through frequent reviews of exposures to individual entities. In addition, the Company only enters into derivative contracts with major national banks and international energy firms to further mitigate associated credit risk.

Substantially all of the Company's accounts receivables are due from customers and joint operation partners concentrated in the Canadian oil and gas industry. As such, trade and other receivables are subject to normal industry credit risks. As at March 31, 2011, $2.6 million or 12% of trade and other receivables are outstanding for 90 days or more (December 31, 2010 - $3.4 million or 13% of trade and other receivables). The Company believes that the entire balance is collectible, and in some instances we have the ability to mitigate risk through withholding production or offsetting payables with the same parties. Management has provided for an allowance for doubtful accounts of $0.4 million at March 31, 2011 (December 31, 2010 - $0.4 million).

(b) Liquidity risk

The Company is subject to liquidity risk attributed from accounts payable and other accrued liabilities, bank indebtedness, other liabilities, and derivative liabilities. Accounts payable and other accrued liabilities, and derivative liabilities are primarily due within one year of the balance sheet date and Twin Butte does not anticipate any problems in satisfying the obligations from cash provided by operating activities and the existing credit facility. The Company's bank indebtedness is subject to a $128 million credit facility agreement. Although the credit facility is a source of liquidity risk, the facility also mitigates liquidity risk by enabling Twin Butte to manage interim cash flow fluctuations.

The demand revolving credit facility contains standard commercial covenants for facilities of this nature. The only financial covenant is a requirement for Twin Butte to maintain a current ratio of not less than 1.0:1.0, and such ratio is to be tested at the end of each fiscal quarter. Current ratio is defined as the ratio of (i) current assets, excluding financial derivatives, plus any undrawn availability under the credit facility to (ii) current liabilities, excluding financial derivatives and the drawn portion of the credit facility. The Company is in compliance with its financial covenants.

The Company's bank indebtedness does not have specific maturity dates. It is governed by a credit facility agreement with a syndicate of financial institutions (note 9). Under the terms of the agreement, the facility is reviewed semi-annually, with the next review scheduled in October 2011.

(c) Price and currency risk

Twin Butte's derivative assets and liabilities are subject to both price and currency risks as their fair values are based on assumptions including forward commodity prices and foreign exchange rates. The Company may use derivative financial instruments from time to time to hedge its exposure to commodity prices, foreign exchange and interest rate fluctuations. The mark to market valuations of these contracts is presented in the Company's financial statements. These valuations are based on forward looking estimates including, but not limited to, volatility, interest rates and commodity prices.

To the extent that Twin Butte enters derivatives to manage commodity price risk, it may be subject to liquidity risk as derivative liabilities become due. While the Company has elected not to follow hedge accounting, derivative instruments are not entered for speculative purposes and management closely monitors existing commodity risk exposures. As such, liquidity risk is mitigated since any losses actually realized are offset by increased cash flows realized from the higher commodity price environment.

The timing of cash outflows relating to the derivative liabilities as at March 31, 2011 are as follows:

Derivative Position

	March 31, 2011	December 31, 2010
Derivatives		
Current asset	**$ 2,863**	$ 3,947
Non-current asset	**–**	–
Current liability	**(10,017)**	(3,293)
Non-current liability	**(4,622)**	(3,340)
Net derivative liability position	**$ (11,776)**	$ (2,686)

The timing of cash outflows relating to the derivative liabilities as at March 31, 2011 are as follows:

Crude Oil Sales Price Derivatives

Daily barrel ("bbl") quantity	Remaining term of contract	Fixed price per bbl ($CAD)	Fixed call price per bbl WTI ($US)	Fair market value $ 000's
200	April 1 to December 31, 2011	88.00		(933)
200	April 1 to December 31, 2011	89.40		(857)
300	April 1 to December 31, 2011	92.04		(1,069)
300	April 1 to December 31, 2011	95.05		(822)
300	April 1 to December 31, 2011	98.05		(577)
300	January 1 to December 31, 2012	100.45		(437)
1000	April 1 to December 31, 2011		95.00	(4,216)
1000	January 1 to December 31, 2012		100.00	(5,726)
Crude oil fair value position				(14,637)

Natural Gas Sales Price Derivatives

Daily giga-joule ("GJ") quantity	Remaining term of contract	Fixed price per GJ (AECO Daily)	Fixed call price per GJ (AECO Monthly)	Fair Market value $ 000's
1,500	April 1 to October 31, 2011	$ 5.90		716
3,000	April 1 to December 31, 2011		$ 7.00	(2)
4,500	April 1 to October 31, 2011	$ 5.90		2,147
Natural gas fair value position				2,861

(d) Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The interest charged on the outstanding bank indebtedness fluctuates with the interest rates posted by the lenders. The Company is exposed to interest rate risk and has not entered into any mitigating interest rate hedges or swaps. Had the borrowing rate been 100 basis points higher throughout the three months ended March 31, 2011, net loss would have increased by $0.1 million (March 31, 2010 - $0.2 million) based on the average debt balance outstanding during the period.

(e) Capital management

The Company's objective when managing capital is to maintain a flexible capital structure which will allow it to execute on its capital investment program, which includes investing in oil and gas activities which may or may not be successful. Therefore the Company continually strives to balance the proportion of debt and equity in its capital structure to take into account the level of risk being incurred in its capital expenditures. The Company manages its capital structure and makes adjustments relative to changes in economic conditions and the Company's risk profile. In order to maintain the capital structure, the Company may from time to time issue shares and adjust its capital spending to manage current and projected debt levels. The Company monitors its bank debt level and working capital in order to assess capital and operating efficiency.

In the management of capital, the Company includes working capital and total net debt (defined as the sum of current assets and current liabilities including bank indebtedness and other liabilities less financial derivatives, a non IFRS measure) in the definition of capital. The Company's share capital is not subject to external restrictions; however, its credit facility value is based primarily on its petroleum and natural gas reserves and there are covenants Twin Butte must comply with (note 11). The Company was in compliance with all of its financial covenants at each reporting period.

The balance of share capital and total net debt as defined above at March 31, 2011, and December 31, 2010:

	March 31, 2011	Dec 31, 2010
Bank indebtedness	**70,194**	97,705
Working capital deficit [(1)]	**10,483**	(421)
Net debt	**80,677**	98,126
Shareholders Equity	**189,057**	182,965
Net Debt to Equity	**0.43**	0.54

(1) Working capital deficit is a non-IFRS measure that includes trade and other receivables, prepaid expenses and deposits, trade and other other accounts payable.

As at March 31, 2011 the Company had $70.2 million outstanding on its credit facility of $128.0 million, and a working capital deficit of $10.5 million, resulting in $80.7 million in net debt.

The credit facility is subject to a borrowing base review performed on a periodic basis by the banking syndicate, based primarily on reserves and using commodity prices estimated by the lenders, as well as other factors. In April 2011, the revolving credit facility was maintained at $128.0 million. A decrease to the borrowing base could lead to a reduction in the credit facility which may require repayment to the lenders. The next semi-annual borrowing base review is scheduled for October 2011.

The Company manages its capital structure and makes adjustments by continually monitoring its business conditions, including: the current economic conditions; the risk characteristics of the underlying assets; the depth of its investment opportunities, forecasted investment levels; the past efficiencies of our investments; the efficiencies of the forecasted investments and the desired pace of investment; current and forecasted total debt levels; current and forecasted petroleum and natural gas prices and other factors that influence petroleum and natural gas prices and cash flow from operating activities (before changes in non-cash working capital) such as foreign exchange and basis differential.

In order to maintain or adjust the capital structure, the Company will consider: its forecasted debt to forecasted cash flow from operating activities (before changes in non-cash working capital) ratio while attempting to finance an acceptable investment program including incremental investment and acquisition opportunities; the current level of bank credit available from the Company's bank; the level of bank credit that may be obtainable from its bank as a result of crude oil and natural gas reserve growth; the availability of other sources of debt with different characteristics than the existing bank debt; the sale of assets; limiting the size of the investment program and new common equity if available on favorable terms.

The Company's capital management objectives, policies and processes have remained unchanged during the reporting periods.

NOTE 6. ACQUISITION EXPENDITURES

Property asset acquisition

On December 1, 2010, the Company purchased producing petroleum and natural gas assets in Western Alberta, for total consideration of $20.7 million. The purpose of the acquisition was to increase oil exposure and increase the Frog Lake area lands. The purchase was paid for in cash and was recognized as a business combination in accordance with IFRS 3 Business Combinations, as the acquired assets met the definition of a business. The acquisition has been accounted for using the acquisition method, and the purchase price was allocated to the net assets acquired as follows:

Assets Acquired

	Total
Petroleum and natural gas properties	$ 23,564
Decommissioning provision	(2,822)
Total net assets acquired	$ 20,742

Consideration

		Total
Cash	$	20,742
Total purchase price	$	20,742

NOTE 7. EXPLORATION AND EVALUATION ASSETS

Balance at January 1, 2010	$	26,791
Additions		872
Transferred to property, plant and equipment		(55)
Dispositions		(1,440)
Exploration and evaluation expense		(6,271)
Balance at December 31, 2010	$	19,897
Additions		220
Balance at March 31, 2011	**$**	**20,117**

NOTE 8. PROPERTY AND EQUIPMENT

	Oil & gas properties	Office equipment	Total
Cost:			
Balance at January 1, 2010	$ 255,658	$ 219	$ 255,877
Additions	72,240	–	72,240
Changes in decommissioning provision	2,083	–	2,083
Disposals	(10,739)	–	(10,739)
Balance at December 31, 2010	319,242	219	319,461
Additions	16,674	–	16,674
Disposals	(8,910)	–	(8,910)
Balance at March 31, 2011	**$ 327,006**	**$ 219**	**$ 327,225**
Accumulated depletion, depreciation and impairment losses:			
Balance at January 1, 2010	–	148	148
Depletion and depreciation for the period	31,695	57	31,752
Balance at December 31, 2010	31,695	205	31,900
Depletion and depreciation for the period	8,835	11	8,846
Balance at March 31, 2011	**$ 40,530**	**$ 216**	**$ 40,746**
Carrying Value			
January 1, 2010	$ 255,658	$ 71	$ 255,729
December 31, 2010	$ 287,547	$ 14	$ 287,561
March 31, 2011	**$ 286,476**	**$ 3**	**$ 286,479**

The Company has capitalized $0.7 million of general and administrative expenses directly related to exploration and development activities for the three month period ended March 31, 2011 ($2.1 million December 31, 2010).

Future development costs on proved plus probable undeveloped reserves of $157.0 million as at March 31, 2011 are included in the calculation of depletion ($157.0 million – December 31, 2010).

During the three month period ended March 31, 2011, Twin Butte completed the sale of a combination of non-core properties in Alberta for net proceeds of $11.5 million ($12.3 million – December 31, 2010). A $2.6 million gain was recognized on these transactions ($1.5 million gain December 31, 2010).

An impairment test calculation was performed on property and equipment at January 1, 2010, the date of transition to IFRS as required by IFRS 1, First-time Adoption of International Financial Reporting Standards ("IFRS 1"). The carrying value of Twin Butte's property and equipment was compared to its recoverable value. No impairment provision was required at January 1, 2010. The fair value of oil and natural gas interests (included in property and equipment) is estimated with reference to the discounted cash flows expected to be derived from oil and natural gas production based on externally prepared reserve reports. The discount rate is specific to the asset with reference to general market conditions, being 10% at January 1, 2010.

NOTE 9. BANK INDEBTEDNESS

As at March 31, 2011, the Company had a $128 million demand revolving credit facility with a syndicate of two Canadian chartered banks. The credit facility provides that advances may be made by way of direct advances, bankers' acceptances, or standby letters of credit/guarantees. Interest rates on the demand revolving operating credit facility fluctuate based on the revised pricing grid and range from bank prime plus 0.50% to bank prime plus 2.5%, depending upon the Company's prior quarter debt to cash flow ratio of between less than one times to greater than three times. A debt to cash flow ratio of less than one times has interest payable at the bank's prime lending rate plus 0.50%. A debt to cash flow ratio greater than three times has interest payable at the bank's prime lending rate plus 2.5%. The credit facility is secured by a demand debenture and a general security agreement covering all assets of the Company.

The facility is a borrowing base facility that is determined based on, among other things, the Company's current reserve report, results of operations, current and forecasted commodity prices and the current economic environment. The Company's credit facility was reviewed and approved subsequent to the end of the quarter in April 2011. The Company's next semi-annual credit facility review is scheduled for October 2011.

NOTE 10. DECOMMISSIONING PROVISION

Decommissioning obligations are based on the Company's net ownership in wells and facilities, and management's best estimate of future costs to abandon and reclaim those wells and facilities as well as an estimate of the future timing of the costs to be incurred.

The Company has estimated the present value of its total decommissioning provision to be $30.0 million at March 31, 2011, based on a total future liability of $37.8 million. Payments to settle the obligations occur over the operating lives of the underlying assets, estimated to be from 2 to 19 years with the majority of the costs to be incurred after 2018. A risk free rate of 3.5% was used, reduced from 4% in 2010, and an inflation rate of 2% was used to calculate the present value of the decommissioning provision.

Changes to the decommissioning provision are as follows:

	Three months ended 31–Mar–11	Year Ended 31–Dec–10
Decommissioning provision, beginning of period	**$ 30,274**	$ 23,581
Liabilities incurred	**819**	1,775
Liabilities settled	**(68)**	(540)
Acquisitions	**–**	2,962
Dispositions	**(1,107)**	(833)
Effect of the change in risk free rate	**–**	2053
Revisions in estimated cash outflows	**(165)**	305
Accretion of decommissioning provision	**264**	971
Decommissioning provision, end of period	**$ 30,017**	$ 30,274

NOTE 11. SHAREHOLDERS EQUITY

Authorized

An unlimited number of voting Common Shares and an unlimited number of Preferred Shares.

	Number of Shares	Share capital $
Balance at January 1, 2010	109,715	189,504
Common shares issued	18,400	23,000
Share issued costs	–	1,023
Common shares issued under option plan	83	57
Balance at December 31, 2010	128,198	211,538
Exercised warrants	3,682	8,318
Common shares issued under option plan	143	179
Balance at March 31, 2011	**132,023**	**220,035**

Issue of Common Shares & Warrants

In the first quarter of 2011, 5,260,072 warrants were exercised for 3,682,049 Twin Butte shares at $2.14 per share for total cash consideration of $7.9 million. Subsequent to March 31, 2011 and up to the expiry date an additional 4,489,700 warrants for 3,142,789 Twin Butte shares were exercised for proceeds of $6.7 million. 1,250,228 warrants were not exercised and expired on May 10, 2011 (Nil – December 31, 2010).

During the quarter ended March 31, 2011, 143,233 options were exercised for proceeds of $0.1 million.

On February 2, 2010 the Company closed a bought deal equity financing of 18,400,000 Common Shares at a price of $1.25 per share, for gross proceeds of $23.0 million ($21.6 million net of issue costs).

Stock Options and Share-based payments

The Company has a stock option plan under which options to purchase Common Shares may be granted to officers, directors, employees and consultants. The Board has approved a policy of reserving up to 10% of the outstanding Common Shares for issuance to eligible participants. The reserved amount is 13,202,295 (12,819,767 – December 31, 2010). As at March 31, 2011 there were 8,410,501 (8,560,817 – December 31, 2010) Common Shares reserved for issuance under the plan. All options awarded have a maximum term of five years and vest in equal one-third increments on each anniversary of the grant.

Stock options are measured at fair value on the date of the grant using a Black-Scholes option pricing model, and the resulting share-based payment expense is recognized on a graded-vesting basis over the related vesting period. Twin Butte recorded share-based payment expense of $0.2 million for the three months ended March 31, 2011 (three months ended March 31, 2010 - $0.1 million). A 50% forfeiture rate was used to estimate the Company's share-based payment expense for the three months ended March 31, 2011 (December 31, 2010: 50%).

The following table sets forth a reconciliation of stock option plan activity through to March 31, 2011:

	Number of Options	Weighted Average Exercise Price
Outstanding at January 1, 2010	4,020,000	$ 0.94
Granted	5,921,150	1.54
Exercised	(83,333)	0.62
Forfeited	(1,297,000)	1.18
Outstanding at December 31, 2010	8,560,817	$ 1.33
Granted	345,000	2.52
Exercised	(143,233)	0.92
Forfeited	(352,083)	1.47
Outstanding at March 31, 2011	**8,410,501**	**$ 1.38**

There were 1,428,101 options exercisable as at March 31, 2011 (1,378,005 – December 31, 2010) at an average exercise price of $1.38 per share ($0.95 – December 31, 2010).

	March 31, 2011			December 31, 2010		
Exercise Price	**Number of Options Outstanding**	**Weighted Average Exercise Price $**	**Weighted Average Years to Expiry**	Number of Options Outstanding	Weighted Average Exercise Price $	Weighted Average Years to Expiry
$0.42 – 0.91	**1,225,100**	**0.69**	**3.08**	1,275,000	0.68	3.32
$0.93 – 1.24	**1,692,001**	**1.02**	**3.01**	1,808,667	1.02	3.29
$1.31 – 1.51	**3,249,000**	**1.35**	**4.11**	3,476,500	1.34	4.35
$1.97 – 2.62	**2,244,400**	**2.06**	**4.65**	2,000,650	1.98	4.86
	8,410,501	**1.38**	**3.88**	8,560,817	1.33	4.09

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with assumptions and resulting values for grants as follows. In 2010 and 2011, the volatility was measured at the standard deviation of continuously compounded share returns based on statistical analysis of daily share of Twin Butte.

	Options Granted in Three Months Ended March 31, 2011	Options Granted in Year 2010
Expected volatility	**71%**	70%
Risk free rate of return	**1.86%**	2.00%
Expected stock option life	**3 years**	3 years
Dividend yield rate	**0.0%**	0.0%
Weighted average fair value of stock option grants	**$ 1.17**	$ 0.59

Net Income (Loss) Per Share

The following table sets forth the details of the denominator used for the computation of basic and diluted net income (loss) per share:

	Three months ended March 31	
	2011	2010
Net income (loss) for the period	**$ (2,262)**	$ 3,889
Weighted average number of basic shares (000's)	**130,555**	121,572
Effect of dilutive securities:		
Employee stock options (000's)	**–**	1,228
	130,555	122,801
Net income (loss) per share basic & diluted ($)	**(0.02)**	0.03

All of the issued stock options were excluded from the calculation of diluted weighted average shares outstanding for the three months ended March 31, 2011 as to include them would be anti-dilutive as a result of a loss position.

NOTE 12. GENERAL & ADMINISTRATION ("G&A") EXPENSES

	Three months ended March 31	
	2011	2010
Staff salaries and benefits	**$ 1,528**	$ 1,158
Rent and Insurance	**183**	227
Office and other costs	**1,024**	986
Capitalized G&A and overhead recoveries	**(1,140)**	(867)
	$ 1,595	$ 1,504

NOTE 13. FINANCE EXPENSE

	Three months ended March 31	
	2011	2010
Accretion on decommissioning provision	**$ 264**	$ 236
Interest and bank charges	**750**	864
Total	**$ 1,014**	$ 1,100

NOTE 14. SUPPLEMENTAL CASH FLOW INFORMATION

	Three months ended March 31	
	2011	2010
Changes in non-cash working capital:		
Accounts receivables	**$ 5,962**	$ 5,841
Prepaid expenses and deposits	**10**	85
Accounts payables	**6,543**	(871)
	$ 12,515	$ 5,055
Changes in non-cash working capital relating to:		
Operating activities	**$ 7,967**	$ (1,739)
Investing activities	**4,548**	6,793
Financing activities	**–**	–
	$ 12,515	$ 5,055

NOTE 15. INCOME TAX EXPENSE

Income tax expense is recognized based on management's best estimate of the weighted average annual income tax rate expected for the full financial year. The estimated average annual rate used for the three months ended March 31, 2011 was 25% (March 31, 2010 – 28%)

NOTE 16. RELATED PARTY TRANSACTIONS

During the three month period ended March 31, 2011, the Company incurred costs totaling $1.4 million ($0.4 million – March 31, 2010) for oilfield services rendered by a company in which an officer and director of Twin Butte is a director. These costs were incurred in the normal course of business. As at March 31, 2011, the Company had $0.9 million ($0.4 million – March 31, 2010) included in accounts payable and accrued liabilities related to these transactions.

NOTE 17. COMMITMENTS AND CONTINGENCIES

The Company is committed to future minimum payments,(total of $43,000 until October 2013) for natural gas transmission and processing, operating leases on compression equipment and future premiums on financial derivatives.

As at March 31, 2011, the Company had contractual obligations and commitments for base office rent as follows:

	Office Rent
2011	871,040
2012	763,517

The Company is involved in legal claims associated with the normal course of operations. The Company has completed an assessment and has not recorded a legal provision.

NOTE 18. EXPLANATIONS OF TRANSITION TO IFRS

As stated in note 2 (a), these are the Company's first financial statements prepared in accordance with IFRS. The Company has adopted IFRS effective January 1, 2011. The Company's financial statements for the year ending December 31, 2011 will be the first annual financial statements that comply with IFRS. Accordingly, the Company will make an unreserved statement of compliance with IFRS beginning with its 2011 annual financial statements. The Company's transition date is January 1, 2010 (the "transition date") and the Company has prepared its opening IFRS balance sheet at that date.

The accounting policies set out in note 3 have been applied in preparing the financial statements for the period ended March 31, 2011, the comparative information presented in these financial statements for the period ended March 31, 2010 and December 31, 2010 and the preparation of an opening IFRS balance sheet at January 1, 2010. The Company will ultimately prepare its opening balance sheet and financial statements for 2010 and 2011 by applying existing IFRS effective as at December 31, 2011. Accordingly, the opening balance sheet and financial statements for 2010 and 2011 may differ from these financial statements.

In preparing its opening IFRS balance sheet, the Company has adjusted amounts reported previously in financial statements prepared in accordance with Previous GAAP. An explanation of how the transition from Previous GAAP to IFRS has affected the Company's financial position, financial performance and cash flows is set out in the following tables and the notes that accompany the tables.

(a) Reconciliation of equity from Canadian GAAP to IFRS

At the date of IFRS transition – January 1, 2010:

BALANCE SHEET *(unaudited)*

As at *(Cdn $ thousands)*	*Notes*	Previous GAAP December 31, 2009	IFRS adjustments	IFRS January 1, 2010
ASSETS				
Current Assets				
Accounts receivable		$ 20,759	$ –	$ 20,759
Deposits and prepaids expenses		3,182	–	3,182
		23,941		23,941
Deferred taxes	*a,h*	2,401	2,181	4,582
Exploration and evaluation assets	*a,c*	–	26,791	26,791
Property and equipment	*a,b,d,e*	282,521	(26,791)	255,729
		$ 308,863	$ 2,181	$ 311,043
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current Liabilities				
Accounts payable and accrued liabilities		$ 29,713	$ –	$ 29,713
Bank indebtedness		96,342	–	96,342
Derivative liabilities		1,224	–	1,224
		127,279		127,279
Other liabilities		796	–	796
Decommissioning provision	*a,f*	14,856	8,725	23,581
		142,931	8,725	151,656
Shareholders' Equity				
Share capital	*a*	188,006	1,498	189,504
Warrants		912	–	912
Contributed surplus	*a*	4,185	77	4,261
Deficit	*a*	(27,171)	(8,119)	(35,290)
		165,932	(6,544)	159,387
		$ 308,863	$ 2,181	$ 311,044

As at December 31, 2010:

BALANCE SHEET *(unaudited)*

As at *(Cdn $ thousands)*	*Notes*	Previous GAAP December 31, 2010	IFRS adjustments	IFRS December 31, 2010
ASSETS				
Current Assets				
Accounts receivable		$ 27,358	$ –	$ 27,358
Deposits and prepaids expenses		2,453	–	2,453
Derivative assets		3,947	–	3,947
		33,758	–	33,758
Deferred taxes	*h*	2,944	1,550	4,494
Exploration and evaluation assets	*c*	–	19,897	19,897
Property and equipment	*b,d,e*	300,983	(13,422)	287,561
		$ 337,685	$ 8,025	$ 345,710
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current Liabilities				
Accounts payable and accrued liabilities		$ 27,779	$ –	$ 27,779
Bank indebtedness		97,705	–	97,705
Derivative liabilities		3,293	–	3,293
		128,777	–	128,777
Other liabilities		354	–	354
Derivative liabilities		3,340	–	3,340
Decommissioning provision	*f*	17,592	12,682	30,274
		150,063	12,682	162,745
Shareholders' Equity				
Share capital	*a*	210,039	1,499	211,538
Warrants		912	–	912
Contributed surplus	*g*	4,989	135	5,124
Deficit		(28,318)	(6,291)	(34,609)
		187,622	(4,657)	182,965
		$ 337,685	$ 8,025	$ 345,710

As at March 31, 2010:

BALANCE SHEET *(unaudited)*

As at *(Cdn $ thousands)*	*Notes*	Previous GAAP March 31, 2010	IFRS adjustments	IFRS March 31, 2010
ASSETS				
Current Assets				
Accounts receivable		$ 14,918	$ –	$ 14,918
Deposits and prepaids expenses		3,096	–	3,096
Derivative Assets		3,833	–	3,833
		21,847	–	21,847
Deferred taxes	*h*	1,547	1,881	3,428
Exploration and Evaluation assets	*c*	–	26,738	26,738
Property and equipment	*b,d*	279,236	(25,246)	253,990
		$ 302,631	$ 3,373	$ 306,003
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current Liabilities				
Accounts payable and accrued liabilities		$ 28,926	$ –	$ 28,926
Bank indebtedness		65,604	–	65,604
Derivative liabilities		987	–	987
		95,517	–	95,517
Other liabilities		696	–	696
Derivative liabilities		–	–	–
Decommissioning provision	*f*	15,346	9,009	24,355
		111,559	9,009	120,568
Shareholders' Equity				
Share capital	*a*	209,993	1,499	211,492
Warrants		912	–	912
Contributed surplus	*g*	4,260	71	4,331
Deficit		(24,094)	(7,206)	(31,300)
		191,071	(5,636)	185,435
		$ 302,630	$ 3,373	$ 306,003

Reconciliation of total comprehensive income for the three months ended March 31, 2010

STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

	Note	Three Months Ended March 31,				
(Cdn$ thousands) (unaudited)			Previous GAAP		Effect of transition to IFRS	IFRS
Petroleum and natural gas sales		$	25,503	$	–	$ 25,503
Royalties			(5,254)		–	(5,254)
Revenues		$	20,249	$	–	$ 20,249
Expenses						
Operating			7,444		–	7,444
Transportation			976		–	976
General and administrative			1,504		–	1,504
Share-based payments	*g*		75		(6)	69
(Gain) loss on derivatives			(4,335)		–	(4,335)
(Gain) loss on divestitures			–		721	721
Depletion and depreciation	*d*		9,396		(2,165)	7,231
			15,060		(1,450)	13,610
Operating Income before finance expense and income taxes			5,189		1,450	6,639
Finance expense	*i*		864		236	1,100
Income before income taxes			4,325		1,214	5,539
Deferred tax expense	*h*		1,248		302	1,550
INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)			3,077		912	3,989
Income (loss) per share $						
Basic & Diluted			0.03		–	0.03

Reconciliation of total comprehensive income for the year ended December 31, 2010

STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

	Note	Twelve Months Ended December 31,		
(Cdn$ thousands) (unaudited)		Previous GAAP	Effect of transition to IFRS	IFRS
Petroleum and natural gas sales		$ 101,876	$ –	$ 101,876
Royalties		(20,734)	–	(20,734)
Revenues		$ 81,142	$ –	$ 81,142
Expenses				
Operating		32,709	–	32,709
Transportation		3,842	–	3,842
General and administrative		5,719	–	5,719
Share-based payments	*g*	809	58	867
Gain (loss) on derivatives		(3,862)	–	(3,862)
(Gain) loss on divestitures		–	(1,533)	(1,533)
Exploration and evaluation	*c*	–	6,313	6,313
Depletion and depreciation	*d*	39,965	(8,269)	31,696
		79,182	(3,431)	75,751
Operating Income before finance expense and income taxes		1,960		5,391
Finance expense	*i*	3,255	971	4,226
Income before income taxes		(1,295)		1,165
Deferred tax expense (recovery)	*h*	(147)	630	483
INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)		(1,148)	(1,830)	682
Income (loss) per share $				
Basic & Diluted		(0.01)		0.01

NOTES TO RECONCILIATION

(a) Elected exemptions from full retrospective application

In preparing these financial statements in accordance with IFRS 1 First-time Adoption of International Financial Reporting Standards ("IFRS 1"), the Company has applied certain of the optional exemptions from full retrospective application of IFRS. The optional exemptions are described below.

(i) Business combinations

The Company has applied the business combinations exemption in IFRS 1 to not apply IFRS 3 retrospectively to past business combinations. Accordingly, the Company has not restated business combinations that took place prior to January 1, 2010.

(ii) Share-based payments

The Company elected to apply the share-based payment exemption to awards that vested prior to January 1, 2010. Awards that were unvested at the date of transition to IFRS, being the unvested stock options, were restated retroactively. This resulted in a $0.1 million adjustment to deficit and contributed surplus at the date of transition.

(iii) Decommissioning provisions

The Company elected to apply IFRS relating to decommissioning provisions as at the date of transition to IFRS. The Company restated its decommissioning provision in accordance with IFRS at January 1, 2010. Under Previous GAAP asset retirement obligations were discounted at a credit adjusted risk free rate of 8%. Under IFRS, the estimated cash flow to abandon and remediate the wells and facilities has been risk adjusted therefore the provision is discounted at a weighted average risk free rate of 4.0%. This resulted in a $8.7 million increase to decommissioning provision and a corresponding increase to deficit at the date of transition (the deferred tax effect of the adjustment was $2.2 million).

(iv) Oil and gas property cost basis

The Company followed a 'full cost' approach under the Previous GAAP which is a policy no longer permitted upon transition to IFRS. The Company has elected to apply the first-time adoption exemption for full cost oil and gas entities where the carrying value of oil and gas assets at the date of transition to IFRS is measured on a deemed costs basis. Exploration and evaluation assets are reclassified from the Previous GAAP full cost pool to intangible exploration and evaluation assets at the amount that was recorded under Previous GAAP. The remaining full cost pool has been allocated to producing and development oil and gas properties using proved and probable reserve values discounted at 10%. This resulted in a $26.8 million recognition of exploration and evaluation assets with a corresponding decrease in oil and gas properties.

b) Property and Equipment – For the purpose of impairment testing, Twin Butte's property and equipment assets were allocated to its CGU's unlike under Previous GAAP where all oil and natural gas assets are accumulated into one cost centre by country. The deemed cost of Twin Butte's oil and natural gas assets were allocated to its defined CGUs based on Twin Butte's total proved plus probable reserve values discounted at 10% as at January 1, 2010, in accordance with IFRS 1. These CGUs were aligned within the major geographic regions in which Twin Butte operates and could change in the future as a result of significant acquisition and disposition activity.

(c) Exploration and Evaluation ("E&E") expenditures – Upon transition to IFRS, Twin Butte reclassified all E&E expenditures that were included in the property and equipment assets balance on the balance sheet. This consisted of the carrying amount for Twin Butte's land which did not have proved or probable reserves attributed directly to related exploration properties. E&E assets will not be depleted, and will be assessed for impairment when indicators of impairment exist. Management identified and reclassified the following amounts from property and equipment assets to E&E in the balance sheet prepared under IFRS as at January 1, 2010 ($26.8 million), March 31, 2010 ($26.8 million) and December 31, 2010 ($19.9 million). For the year ended December 31, 2010, $6.3 million was expensed relating to lease expiries.

(d) Depletion expense – Twin Butte has chosen to calculate its depletion using the UOP method over proved plus probable reserves, as compared to using only proved reserves under Previous GAAP. As a result, the depletion expense decreased as compared to its current calculation under Previous GAAP. March 31,2010 depletion was lower by $2.2 million and the year December 31, 2010, depletion was reduced by $8.3 million. Accretion expense has been removed and added to Finance costs of $0.2 million for the three months March 31, 2010 and $1.2 million for the year ended December 31, 2010.

(e) Impairment of PP&E assets – Under IFRS, an impairment test of PP&E is performed at the CGU level as opposed to the entire PP&E balance, which is currently required under Previous GAAP through the full cost ceiling test. Twin Butte is required to recognize an impairment loss if the carrying amount of a CGU exceeds the higher of its fair value less cost to sell and value in use. Under a two step approach, Canadian GAAP, estimated future cash flows used to assess whether an impairment has occurred are not discounted. Twin Butte did not have an impairment at transition or during the year 2010.

(f) Decommissioning provision – Under IFRS, Twin Butte remeasured its liability for decommissioning provision using the risk-free rate of interest. IFRS requires that asset decommissioning provision be re-measured each reporting period for changes in the discount rate with a corresponding adjustment to the cost of property, plant and equipment. At January 1, 2010 Twin Butte's total of its decommissioning provision increased by $8.7 million to $23.6 million as the liability was revalued to reflect the estimated risk free rate of interest of 4.0% as compared to the credit adjusted risk-free rate of 8.0% used previously under Canadian GAAP. At December 31, 2010 the risk-free rate was further reduced to 3.5% and increased an additional $2.1 million decommissioning provision.

(g) Share-based payments – Under Previous GAAP, the Company accounted for stock-based compensation plans on a straight-line basis over the term of the vesting period. Under IFRS each tranche in an award is considered a separate grant with different vesting date and fair value. Each grant is separately accounted for using applicable assumptions for those specific dates and different fair values and accounted for using graded vesting recognition of expense. Under

Previous GAAP, forfeitures of awards are recognized as they occur. The calculation of share-based compensation under IFRS reflects an estimate of the number of awards expected to vest, which is revised if subsequent information indicates that actual forfeitures are likely to differ from the estimate. As a result, the Company adjusted its expense for share-based awards by $0.1 for the twelve months ending December 31, 2010 and recognized the corresponding adjustment to contributed surplus.

(h) Deferred income tax calculated according to IFRS is substantially similar to Previous GAAP and arises from differences between the accounting and tax bases of assets and liabilities. To the extent that assets and liabilities have changed from transition to IFRS, the amount of deferred income tax asset would be impacted. Twin Butte recorded an overall increase of $2.2 million to its deferred tax asset upon transition to IFRS with the offset to opening deficit. The adjustments discussed above have also impacted deferred tax expense recognized in the statement of income (loss) in the three months ended March 31, 2010 by $0.3 million (year ended December 31, 2010 - $0.6 million).

(i) Finance expenses

Under IFRS, interest expenses and accretion expense are included as finance expenses. These individual amounts for Previous GAAP have been reclassified for IFRS.

(j) Adjustments to the statement of cash flows

The transition from Previous GAAP to IFRS had no significant impact on cash flows generated by the Company.

(k) Flow-through shares

Flow-through shares are a Canadian tax incentive which is the subject of specific guidance under Previous GAAP, however there is no specific guidance under IFRS. Under Previous GAAP, when flowthrough shares are issued they are recorded at face value. The related future tax liability is established for the tax effect of the difference between the tax basis and the book basis of the assets when renounced and is recorded as a reduction of share capital. There is no income statement effect associated with the issuance of these shares.

Twin Butte has adopted a policy under IFRS where the proceeds from the offering are to be allocated between the sale of the shares and the sale of the tax benefit. The allocation is made based on the difference between the quoted market price of the existing shares and the amount an investor pays for the flow through shares. A liability is established for this difference that is reversed upon renunciation of the tax benefit. The difference between this liability and the deferred tax liability is recorded as an income tax expense. This has resulted in a re-classification between deficit and share capital at January 1, 2010 of $1.5 million.

NOTE 19. SUBSEQUENT EVENTS

Crude Oil Sales Price Derivative Contract

Subsequent to March 31, 2011 the Company entered into the following crude oil sale price derivative:

Daily barrel (bbl) quantity	Term of contract	Fixed Price per bbl (WTI)
500	January 1, 2012 to December 31, 2012	$106.81 US

Also, subsequent to March 31, 2011 and up to the expiry date an additional 4,489,700 warrants for 3,142,789 Twin Butte shares were exercised. 1,250,228 warrants were not exercised and expired on May 10, 2011.

CORPORATE INFORMATION

OFFICERS

Jim Saunders
President and Chief Executive Officer

Bob Bowman
Vice President, Operations

Neil Cathcart
Vice President, Exploration

Mike Fabi
Vice President, Engineering

Bruce W. Hall
Chief Operating Officer

Colin Ogilvy
Vice President, Land

R. Alan Steele
Vice President, Finance & CFO

BOARD OF DIRECTORS

David Fitzpatrick (1) (3)
Chairman of the Board

Jim Brown (1) (2) (3)

John Brussa

Jim Saunders

Warren Steckley (1) (2) (3)

William A. (Bill) Tricket (2)

Member of:

(1) Audit Committee
(2) Reserves Committee
(3) Compensation, Nominating and Governance Committee

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National Bank of Canada, Calgary, AB

ATB Financial, Calgary AB

SOLICITORS

Burnet, Duckworth & Palmer LLP,
Calgary, AB

ENGINEERS

McDaniel & Associates Consultants Ltd. Calgary, AB

REGISTRAR & TRANSFER AGENT

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