



Q1 2011 MANAGEMENT'S
DISCUSSION & ANALYSIS

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") is a review of Trafina Energy Ltd's (the "Company" or "Trafina") financial results for the three months ended March 31, 2011 and should be read in conjunction with the condensed interim financial statements and accompanying notes for the three months ended March 31, 2011 and the Company's audited financial statements and MD&A for the year ended December 31, 2010. The discussion provided herein is incremental to the MD&A in respect of the audited financial statements for the year ended December 31, 2010. This MD&A is dated June 22, 2011.

As of January 1, 2011, the Company prepares its financial statements in accordance with International Financial Reporting Standards ("IFRS"), IFRS 1 – First time adoption of IFRS ("IFRS 1") and International Accounting Standard 34 – Interim Financial Reporting, as issued by the International Accounting Standards Board. Previously, the Company's financial statements were prepared in accordance with Canadian Generally Accepted Accounting Principles ("CGAAP"). Reconciliations between CGAAP and IFRS financial information can be found in the condensed interim financial statements for the three months ended March 31, 2011.

All references to dollar values refer to Canadian dollars, unless otherwise stated.

In this MD&A, reserves and production are commonly stated in barrels of oil equivalent (boe) on the basis that six thousand cubic feet (Mcf) of natural gas is equivalent to one barrel of oil (Bbl). **Boes may be misleading, particularly if used in isolation.** A boe conversion ratio of 6 Mcf to 1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent an equivalency of value at the wellhead.

FORWARD-LOOKING STATEMENTS

Certain information set forth in this MD&A contains forward-looking information. Such information is frequently characterized by words such as "plan", "expect", "project", "intend", "believe", "anticipate", "estimate" or other similar words, or statements that certain events or conditions "may" or "will" occur. Forward-looking information is not based on historical facts but rather on management's expectations regarding the Company's future growth, results of operations, production, future capital and other expenditures (including the amount, nature and sources of funding thereof) and anticipated financial condition and liquidity throughout 2011. Readers are cautioned that assumptions used in the preparation of forward looking statements may prove to be incorrect. Events or circumstances may cause actual results to differ materially from those predicted, as a result of numerous known and unknown risks, uncertainties, and other factors, many of which are beyond the control of the Company. These risks include, but are not limited to: credit risks associated with collection of outstanding accounts receivable, access to capital, such as changes to the Company's credit facilities, the ability to raise funds by issuing equity or disposing of assets. Operational risks include commodity price and exchange rate fluctuations, which ultimately affect the Company's realized oil and natural gas revenue and future production mix and operating expenses, which will have an effect on funds flow from operating activities. Industry related risks include, but are not limited to: operational risks in exploration, development and production of oil and natural gas and production risks associated with sour hydrocarbons, dependence on third-party owned and operated production facilities, availability of skilled personnel and services, failure to obtain industry partners, regulatory and other third-party consents and approvals, delays or changes in plans, risks associated with the uncertainty of reserve estimates, health, safety and environmental risks and the uncertainty of estimates and projections of current production, operating costs, capital expenses and abandonment estimates. Reference is made to Trafina's revised annual information form for the year ended December 31, 2010 dated April 8, 2011 (the "AIF") and its short form prospectus dated April 12, 2011 (the "Prospectus") for a description of additional risks that could affect the Company's future results and could cause results to differ materially from those expressed in the Company's forward looking statements. The risks outlined above, elsewhere in this MD&A, in the prospectus and in the AIF should not be construed as exhaustive. Readers are cautioned not to place undue reliance on these forward-looking statements. Except as required by applicable securities laws, the Company undertakes no obligation to update or revise any forward-looking statements.

NON-IFRS MEASURES

The MD&A uses the term "funds flow used-in operations", which is not defined under CGAAP or IFRS and should not be considered an alternative to, or more meaningful than, cash flow from (used in) operating activities as determined in accordance with IFRS as an indicator of the Company's performance. The Company's determination of funds flow used-in operations may not be comparable to that reported by other companies. 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. Management believes that in addition to cash flow from operating activities, funds flow used-in operations is a useful supplemental measure as it demonstrates the Company's ability to generate cash necessary to repay debt or fund future growth through capital investment before changes in non-cash working capital balances and decommissioning expenditures. Investors are cautioned, however, that the measure should not be construed as an alternative to cash flow from (used in) operating activities determined in accordance with IFRS and CGAAP as an indication of the Company's performance.

The following table reconciles cash flow from (used in) operating activities to funds flow used in operations:

	Three Months Ended March 31	
	2011	2010
Cash flow from (used in) operating activities	\$ 238,131	\$ (949,445)
Change in non-cash operating working capital	(469,476)	606,432
Decommissioning expenditures	14,271	---
Funds flow used-in operations	\$ (217,074)	\$ (343,013)

The Company also considers field netback a key performance measure. However, field netback is not defined under IFRS or Canadian GAAP and, therefore, may not be comparable with the calculation of similar measures by other companies. Field netback is comprised of the Company's revenue from petroleum and natural gas sales, including realized commodity gains and losses and other income less royalties and operating expenses. A reconciliation of field netback (non-GAAP) to net loss under IFRS is presented under the *Netback Analysis* section of this MD&A. In addition, the Company presents "Net debt and working capital deficiency", which consists of current liabilities less current assets and excludes the effect of unrealized gains or losses on commodity contracts.

OVERVIEW

After a busy three months ended December 31, 2010, when the Company purchased 15 sections of undeveloped lands in McMullen in northeastern Alberta, the Company focused on executing its plan to drill at least four vertical oil wells at McMullen by the summer of 2011. In January of this year the Company began construction of an all-weather access road and construction of five well sites. As of the date of this MD&A the Company has completed the access road and the five well sites and is poised to commence its first phase vertical well drilling program. In April 2011, in order to fund a portion of the Company's 2011 capital program (including the initial vertical drilling program at McMullen), the Company raised gross proceeds of \$9.0 million and in June 2011 the Company negotiated a revised credit facilities agreement with its current lender.

A summary of primary activity for the three months ended March 31, 2011 are as follows:

- In January 2011 commenced construction of an all access road at McMullen allowing the Company to prepare for drilling a minimum of four vertical evaluation wells
- Road and lease construction was completed June, 2011
- On March 18, 2011 acquired an additional 18 sections of land in McMullen, bringing the total to 33 sections
- Subsequent to the first quarter of 2011 completed a public offering raising gross proceeds of \$9.0 million in April 2011

SELECTED FINANCIAL INFORMATION

	For the three months ended March 31,		
	2011	2010	% Change
Total gross oil and gas revenue (\$)	1,537,110	1,494,636	+3
Royalties (\$)	140,177	205,263	-32
Operating, processing, and transportation expenses (\$)	1,063,145	1,144,843	-7
Funds flow used-in operations ⁽¹⁾ (\$)	(217,074)	(343,013)	+37
per basic and diluted common share (\$)	(0.01)	(0.02)	
Weighted average basic shares outstanding	29,941,262	18,294,595	+64
Loss before income taxes (\$)	(1,066,238)	(1,569,619)	+32
Net loss (\$)	(936,238)	(1,314,104)	+29
per basic and diluted common share (\$)	(0.03)	(0.07)	
Net capital expenditures (dispositions) (\$)	2,001,759	(144,011)	---
Total assets (\$)	18,985,901	17,446,435	+9
Net debt and working capital deficiency ⁽²⁾ (\$)	(8,427,247)	(4,158,567)	-103

(1) Funds flow from (used in) operations is a Non-IFRS Measure. See "Non-IFRS Measures" in this MD&A.

(2) Net debt and working capital deficiency consists of current assets and current liabilities less commodity contract liabilities.

PRODUCTION

	Three Months Ended March 31		
	2011	2010	Change
Natural gas	1,564 mcf/day	1,961 mcf/day	(20)%
Oil and natural gas liquids	152 bbls/day	97 bbls/day	57%
Total production	412 boe/day	424 boe/day	(3)%

Natural gas production declined 20 percent in the first three months ended March 31, 2011, compared to the same period in 2010. The main reason for the reduction was the disposition of various non-core natural gas producing areas in the second half of 2010. In March 2010, the Company began its transformation to a more oil focused exploration company and continued this strategy throughout 2010 and into 2011. As a result, oil and natural gas liquids production increased 57 percent in the three months ended March 31, 2011, compared to the three months ended March 31, 2010. Successful oil drilling in southwest Saskatchewan and Pembina, Alberta in the last quarter of 2010 was the main reason for continued evenly weighted oil and natural gas production.

BENCHMARK PRICES

	Three Months Ended March 31	
	2011	2010
AECO daily spot price	\$ 3.70/mcf	\$ 4.95/mcf
West Texas Intermediate (WTI)	US\$ 93.98/bbl	US\$ 78.68/bbl
Edmonton Par	\$ 88.51/bbl	\$ 80.31/bbl
US/CDN \$ average exchange rate	1.01	0.96

The slow economy recovery globally, coupled with continued high natural gas storage levels, restricted any potential natural gas price increase during 2010 and kept prices low throughout 2010. This downward pressure continued into the three months ended March 31, 2011 with natural gas prices averaging \$3.70/mcf. Oil prices began climbing in 2010 as a reaction to continued and escalating North African and Middle East unrest. In the three months ended March 31, 2011 Edmonton par oil prices averaged \$88.51/bbl, compared to an average of \$80.31/bbl in the three months ended March 31, 2010.

COMPANY REALIZED PRICES

	Three Months Ended March 31	
	2011	2010
Natural gas	\$ 3.74/mcf	\$ 4.93/mcf
Realized gain (loss) on commodity contract-natural gas	\$ 0.05/mcf	\$ 0.12/mcf
Oil and natural gas liquids	\$ 74.24/bbl	\$ 71.73/bbl
Realized gain (loss) on commodity contract-oil	\$ (1.22)/bbl	\$ ---
Total	\$ 41.55/boe	\$ 39.21/boe

Natural gas prices for the three months ended March 31, 2011 followed the benchmark prices trend, with prices averaging \$3.74/mcf. Oil and natural gas liquids prices for the three months ended March 31, 2011 increased but the differential to the Edmonton par widened slightly, mainly due to the majority of oil production being heavier.

REVENUE

	Three Months Ended March 31	
	2011	2010
Natural gas	\$ 523,451	\$ 870,810
Oil and natural gas liquids	1,013,659	623,826
Total petroleum and natural gas revenue	\$ 1,537,110	\$ 1,494,636

Revenue for the three months ended March 31, 2011 was \$1,537,110, which was slightly higher than the same period in 2010. Lower natural gas revenues as a result of non-core natural gas property sales was partially offset by an increase in oil and natural gas liquids revenues, a result of the Company focusing on oil exploration. Consequently, oil and natural gas liquids revenue increased sixty two percent in the three months ended March 31, 2011, compared to the three months ended March 31, 2010.

REALIZED GAIN (LOSS) ON COMMODITY CONTRACTS

	Three Months Ended March 31	
	2011	2010
Realized gain on commodity contracts- natural gas	\$ 7,657	\$ 20,892
Realized loss on commodity contracts- oil	(16,373)	---
Total	\$ (8,716)	\$ 20,892

For the three months ended March 31, 2011 the Company recorded a net loss on commodity contracts as a result of an increase in oil prices. In the three months ended March 31, 2010 the Company realized a gain on its commodity contracts as natural gas prices remained low.

UNREALIZED GAIN (LOSS) ON COMMODITY CONTRACTS

	Three Months Ended March 31	
	2011	2010
Unrealized gain (loss) on commodity contracts	\$ (133,438)	\$ 282,000

For the three months ended March 31, 2011 and March 31, 2010, the Company recorded an unrealized loss of \$133,438 and an unrealized gain of \$282,000, respectively, primarily as a result of the difference between future commodity price projections at March 31, 2011 and March 31, 2010, compared to the Company's contracted rates. The unrealized loss for the three months ended March 31, 2011 was primarily a result of higher than contracted future oil prices, partially offset by slightly lower than contracted future gas prices.

The following table outlines the Company's outstanding commodity sales contracts as at March 31, 2011:

Type	Daily Volume	Duration	Price
Fixed-Gas	300 GJ/day	April 1, 2011 to December 31, 2011	\$3.85/GJ
Fixed-Gas	300 GJ/day	May 1, 2011 to December 31, 2011	\$4.41/GJ
Collar-Oil	50 bbl/day	April 1, 2011 to December 31, 2011	Floor \$75.00 WTI Cdn Ceiling \$90.00 WTI Cdn
Collar-Oil	50 bbl/day	May 1, 2011 to December 31, 2011	Floor \$90.00 WTI US Ceiling \$108.90 WTI US

OTHER

	Three Months Ended March 31	
	2011	2010
Other revenue (expense)	\$ 30,345	\$ (22,488)

Other revenue relates to miscellaneous processing and interest revenue.

ROYALTIES

	Three Months Ended March 31			
	2011	Royalty as percent of petroleum & natural gas revenue	2010	Royalty as percent of petroleum & natural gas revenue
Total royalties	\$ 140,177	9	\$ 205,263	14

Royalty payments as a percentage of revenue were lower in the first three months ended March 31, 2011, compared to the same period in 2010. The main reason for lower royalty payments was a combination of lower royalty rates on the Company's Cardium horizontal well at Pembina, Alberta and favorable Alberta Crown natural gas custom processing and cost allowance reimbursements.

OPERATING EXPENSES

	Three Months Ended March 31			
	2011	\$/boe	2010	\$/boe
Operating expenses	\$ 1,063,145	\$ 28.74	\$ 1,144,843	\$ 30.03

Operating expenses, including processing and transportation costs, for the three months ended March 31, 2011 were \$1,063,145 (\$28.74/boe), which on a dollar per boe basis decreased 4 percent over the same period in 2010. In the three months ended March 31, 2011, the Company incurred higher than expected costs for snow removal in southwest Saskatchewan, in addition to costs for down-hole well repairs in Saskatchewan and central Alberta. The three months ended March 31, 2011 also included an increase of approximately \$20,000 in transportation costs, compared to the three months ended March 31, 2010, a result of increased oil production.

FIELD NETBACK ⁽¹⁾

	Three Months Ended March 31			
	2011	\$/boe	2010	\$/boe
Petroleum and natural gas revenue	\$ 1,537,110	\$ 41.55	\$ 1,494,636	\$ 39.21
Realized gain (loss) on commodity contract	(8,716)	0.24	20,892	0.55
Other revenue (expense)	30,345	0.82	(22,488)	0.59
Royalties	(140,177)	3.79	(205,263)	5.38
Operating expenses	(1,063,145)	28.74	(1,144,843)	30.03
Field netback ⁽¹⁾	\$ 355,417	\$ 9.60	\$ 142,934	\$ 3.75
Sales volumes (boe)	36,996		38,118	

(1) See "NON-IFRS MEASURES" in this MD&A.

The Company's average field netback per boe for the three months ended March 31, 2011 increased to \$9.60/boe, compared to the three months ended March 31, 2010, which realized an average field netback of \$3.75/boe. Slightly higher revenue as a result of an increase in oil production and higher oil prices and slightly lower royalty payments and operating costs, partially offset by a realized commodity loss, resulted in a higher netback.

GENERAL AND ADMINISTRATIVE ("G&A") EXPENSE

	Three Months Ended March 31	
	2011	2010
G&A gross	\$ 572,550	\$ 512,508
G&A overhead recovery	(45,636)	(59,554)
G&A net	\$ 526,914	\$ 452,954
G&A per boe	\$ 14.24	\$ 11.88

General and administrative expenses for the three months ended March 31, 2011 were 16 percent higher than for the same period in 2010. Increased G&A expenses are mainly attributable to an increase in salaries and an increase in reporting costs.

SHARE BASED COMPENSATION EXPENSE

Share based compensation expense totaled \$23,273 for the three months ended March 31, 2011, compared to \$67,967 for the three months ended March 31, 2010. The decrease in share based compensation expense in 2011 relates to the new reporting standards under IFRS, whereby a greater portion of expense is recognized up front on the initial grant date. There were no new options granted in the three months ended March 31, 2011, compared to 170,000 stock options granted in the three months ended March 31, 2010. Share based compensation expense for the three months ended March 31, 2010 was restated for the effect of adopting IFRS.

FINANCING EXPENSE

	Three Months Ended March 31	
	2011	2010
Interest expense	\$ 45,577	\$ 32,993
Accretion expense	33,303	25,660
Total financing expense	\$ 78,880	\$ 58,653

Interest expense for the three months ended March 31, 2011 is a result of bank borrowings and was slightly higher than the interest expense for the three months ended March 31, 2010, primarily due to higher debt levels. Accretion expense represents the change in the time value of the Company's decommissioning obligation. The accretion expense for the three months ended March 31, 2011 is slightly higher than the accretion expense for the three months ended March 31, 2010 mainly as a result of new obligations associated with new wells drilled.

DEPLETION AND DEPRECIATION

For the three months ended March 31, 2011 and March 31, 2010, depletion and depreciation expense was \$659,150 (\$17.82/boe) and \$672,901 (\$17.65/boe), respectively. Under IFRS the Company calculates depletion and depreciation expense on proved plus probable reserves on an area or commodity basis. Previously under CGAAP, the Company's depletion and depreciation was calculated on proved reserves and on a full cost pool basis. For the three months ended March 31, 2010 depletion and depreciation was adjusted for the effect of adopting IFRS.

IMPAIRMENT OF PROPERTY AND EQUIPMENT

For the purpose of impairment testing, assets are grouped together into Cash Generating Units ("CGUs"). A CGU's recoverable amount is the higher of its fair value less costs to sell and its value in use. Value in use is determined by estimated the present value of the future net cash flows expected to be derived from the continued use of the asset or cash generating unit. Fair value less costs to sell is determined to be the amount for which the asset could be sold in an arm's length transaction. Fair value less costs to sell can be determined by using an observable market or by using discounted future net cash flows of proved and probable reserves using forecasted prices and costs. An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount.

The Company did not test for impairment for the three months ended March 31, 2011 as there were no indicators of impairment. For the three months ended March 31, 2010 and year ended December 31, 2010 the Company recognized impairments of \$805,307 and \$3,504,697, respectively. In the three months ended March 31, 2010 the Company impaired certain gas properties due to a decline in gas prices and production and further impaired its gas properties at September 30, 2010 and December 31, 2010 due to declining gas prices. At December 31, 2010 the Company tested the E&E assets for impairment and concluded that certain seismic data and future development of the underlying area was not part of the Company's future plans and impaired the asset by \$115,000.

GAIN ON PROPERTY DIVESTMENT

Under CGAAP dispositions were recorded to the full cost pool and no gains or losses were reported unless the resulting disposition changed the depletion rate by 20 percent or greater. Under IFRS, proceeds from a divestiture are deducted from the carrying value of the asset and a gain or loss is recognized in earnings. In the three months ended March 31, 2010 a gain of \$63,229 was recorded as a result of property dispositions. No gains or losses were reported in the three months ended March 31, 2011.

INCOME TAXES

Deferred income taxes arise from differences between the accounting and tax bases of the Company's assets and liabilities. For the three months ended March 31, 2011 the Company recorded a deferred income tax reduction of \$130,000. The reduction was a result of the Company fulfilling its 2010 flow through obligation. For the three months ended March 31, 2010 the Company recorded a deferred income tax reduction of \$255,515 as a result of a valuation allowance. For the three months ended March 31, 2010 deferred income taxes were restated for the effect of adopting IFRS.

NET LOSS

	Three Months Ended March 31	
	2011	2010
Net loss	\$ 936,238	\$ 1,314,104

For the three months ended March 31, 2011, the Company recorded a net loss of \$936,238, compared to a net loss of \$1,314,104 reported in the three months ended March 31, 2010. Higher revenues in the first three months of 2011, in addition to lower royalties, operating and share based compensation expenses, were partially offset by an unrealized loss, higher general and administrative expenses and financing expenses.

Comprehensive loss consists of net loss and other comprehensive loss ("OCL"). Because the Company does not have any OCL, the Company's net loss and comprehensive loss are the same.

FUNDS FLOW USED-IN OPERATIONS⁽¹⁾

	Three Months Ended March 31	
	2011	2010
Cash flow from (used in) operating activities	238,131	(949,445)
Change in non-cash operating working capital	(469,476)	606,432
Decommissioning expenditures	14,271	---
Funds flow used-in operations ⁽¹⁾	\$ (217,074)	\$ (343,013)
Funds flow used-in operations per share –basic	\$ (0.01)	\$ (0.02)

(1) See "NON-IFRS MEASURES" in this MD&A.

Funds flow used-in operations for the three months ended March 31, 2011 of \$217,074 was primarily a result of revenues being more than offset by operating and G&A expenses. In the three months ended March 31, 2010 the Company's funds flow used-in operations was \$343,013.

NETBACK ANALYSIS

The following table reconciles field netback (non-IFRS) to funds flow used-in operations (non-IFRS) to net loss for the three months ended March 31, 2011 and March 31, 2010:

	Three Months Ended March 31	
	2011	2010
Petroleum and natural gas revenue	\$ 1,537,110	\$ 1,494,636
Realized gain (loss) on commodity contract	(8,716)	20,892
Other revenue (expense)	30,345	(22,488)
Royalties	(140,177)	(205,263)
Operating expenses	(1,063,145)	(1,144,843)
Field netback ⁽¹⁾	355,417	142,934
General and administrative	(526,914)	(452,954)
Financing expense - interest	(45,577)	(32,993)
Funds flow used-in operations ⁽¹⁾	(217,074)	(343,013)
Depletion and depreciation	(659,150)	(672,901)
Deferred income tax reduction	130,000	255,515
Share based compensation	(23,273)	(67,967)
Unrealized gain (loss) on commodity contract	(133,438)	282,000
Finance expenses – accretion	(33,303)	(25,660)
Impairment of property and equipment	---	(805,307)
Gain on property divestment	---	63,229
Net loss	\$ (936,238)	\$ (1,314,104)

(1) See "NON-IFRS MEASURES" in this MD&A.

LIQUIDITY AND CAPITAL RESOURCES

At March 31, 2011, the Company had drawn a total of \$4.2 million on its available facilities with \$3.9 million drawn on its revolving operating demand credit facility and \$0.3 million drawn on its acquisition and development facility.

At March 31, 2011 the Company had a working capital deficiency of \$8.4 million, excluding the fair value of its commodity contracts. The Company was in violation of its working capital ratio covenant as at March 31, 2011; however, as a result of completing a public financing and receiving approximately \$9.0 million of gross proceeds subsequent to the end of the quarter, the Company's lender waived the violation.

Capital expenditures forecasted for the remainder of 2011 include drilling at least two Pembina Cardium wells and the drilling of four vertical evaluation wells in the McMullen area. If certain geological criteria are met, the wells will be completed, equipped and placed on production. The Company will require additional capital to complete its 2011 capital program as currently planned. Potential additional sources of financing include an increase in bank lending amounts (assuming successful results from the Company's drilling program), debt and equity financings and dispositions. There is no assurance that financings will be available on terms acceptable to the Company.

BANK DEBT

In June, 2011 the Company renewed its credit facilities agreement with a Canadian chartered bank. The new facilities consist of a \$4.0 million revolving operating demand facility, with interest charged on advances under the facility at the bank's prime rate plus 1.50%. The facility also includes a \$1.8 million acquisition and development demand facility, with interest charged on advances at the bank's prime rate plus 2.00%. The facilities are secured by a \$50 million fixed and floating charge debenture on all assets. The next review date is scheduled on or before October 1, 2011. The facilities include a working capital ratio covenant, which is not to fall below 1:1.

As the available credit facilities are based on the bank's assessment of the Company's reserves, development prospects and future commodity prices, there can be no assurance that the amount of available credit facility will not decrease at the next review date.

EQUITY

Stock option exercise

In January, an executive officer of the Company exercised 100,000 stock options at \$0.30 and was issued 30,000 Class A common shares for gross proceeds to the Company of \$30,000.

Flow through shares

As a result of completing private placement financings in November and December 2010, the Company was required to incur \$2.0 million on eligible flow-through expenditures prior to December 31, 2011. The Company incurred \$1.1 million in qualified expenditures by the end of December, 2010, resulting in a remaining obligation of \$0.9 million of qualified expenditures to be incurred prior to December 31, 2011. As at March 31, 2011 the Company fulfilled its flow through spending obligation.

Equity financing

On April 21, 2011 the Company announced that it had completed a public offering of units for gross proceeds of approximately \$9 million (the "Offering"). At closing, the Company issued 25,715,000 units (comprised of 25,715,000 Class A common shares ("Common Shares") and 25,715,000 Common Share purchase warrants ("Share Purchase Warrants")) at a price of \$0.35 per unit. Each Share Purchase Warrant issued pursuant to the Offering will entitle the holder thereof to acquire one Common Share at a price of \$0.45 per share on or before October 21, 2012 (the "Expiry Date").

Private Placement Warrants

On March 7, 2011 the Company announced the acceleration of the expiry of the 6,334,000 warrants to April 15, 2011. The remaining 2,513,335 warrants expire on June 3, 2011. Subsequent to March 31, 2011, none of the 6,334,000 warrants were exercised prior to April 15, 2011 and have expired, and 14,300 warrants of the 2,513,335 warrants that expire on June 3, 2011 were exercised for proceeds of \$6,435. The foregoing warrants were issued by the Company on a private placement basis.

OUTSTANDING EQUITY DATA

Trafina is authorized to issue an unlimited number of Class A voting common shares, an unlimited number of Class B non-voting common shares and an unlimited number of preferred shares. As at June 22, 2011, 55,690,562 Class A voting common shares were issued and outstanding. There are nil Class B non-voting common shares and nil preferred shares outstanding. As at June 22, 2011, 25,715,000 share purchase warrants were issued and outstanding, with an exercise price of \$0.45 per common share and 2,095,000 stock options were outstanding, with an average exercise price of \$0.38 per common share.

CAPITAL EXPENDITURES

The following table summarizes capital expenditures for the three months ended March 31, 2011 and March 31, 2010.

	Three months ended March 31	
	2011	2010
Property dispositions	\$ ---	\$ (1,533,892)
Property acquisitions	---	383,660
Land	197,645	---
Drilling, completions and recompletions	1,689,285	609,582
Equipping and facilities	102,455	340,288
Other	7,534	56,351
Total net capital expenditures, cash	\$ 1,996,919	\$ (144,011)
Share based compensation	4,840	---
Total net capital expenditures	\$ 2,001,759	\$ (144,011)

For the three months ended March 31, 2011, the Company purchased additional land at McMullen and southwest Saskatchewan for approximately \$0.2 million. The Company also spent approximately \$1.4 million building an all-weather access road and well-site leases at McMullen. An additional \$0.3 million was spent on drilling one (0.50 net) test well at Twin Lakes with the potential to earn a 25 percent working interest in 13 sections adjacent to the McMullen area. The participation agreement requires that an additional well is drilled by June 2012. The Company is not obligated to drill the second well. The remaining capital expenditures were a result of equipping two wells at southwest Saskatchewan for \$0.1 million.

For the three months ended March 31, 2010, Trafina disposed of three non-core area properties for net proceeds of \$1.5 million. During the same period, the Company also incurred expenditures of \$0.3 million related to purchase of the southwest Saskatchewan assets on January 15, 2010 from a private oil and gas corporation in exchange for debt owing to the Company. Other capital expenditures for the three months ended March 31, 2010 consisted of \$0.5 million to complete a test well in the Pembina area of Alberta for Ellerslie gas. Several minor recompletions were performed along with various surveying related costs which amounted to \$0.1 million. The Company also spent \$0.3 million on equipping and tie-in projects at Wetaskiwin, Ronalane and southwest Saskatchewan.

CONTRACTUAL OBLIGATIONS

Trafina has an office lease arrangement terminating August 30, 2014. The Company's total remaining rent obligation is as follows:

2011	\$100,502
2012	\$146,000
2013	\$158,000
2014	\$112,000

OFF BALANCE SHEET TRANSACTIONS

There were no off balance sheet transactions entered into during the period, nor are there any outstanding as of June 22, 2011.

TRANSACTIONS WITH RELATED PARTIES

A law firm of which the corporate secretary of the Company is a partner provides general and corporate legal services to the Company. For the three months ended March 31, 2011, fees for legal services billed from this related party were approximately \$70,000 (March 31, 2010 - \$43,000), of which \$70,000 is included in accounts payable and accrued liabilities at March 31, 2011 (March 31, 2010 - \$43,000). These services are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

SUBSEQUENT EVENTS

On April 21, 2011 the Company completed the Offering for gross proceeds of \$9 million. At closing, the Company issued 25,715,000 units (comprised of 25,715,000 Common Shares and 25,715,000 Share Purchase Warrants at a price of \$0.35 per unit. Each Share Purchase Warrant issued pursuant to the Offering will entitle the holder thereof to acquire one Common Share at a price of \$0.45 per share on or before October 21, 2012.

In June 2011 Trafina signed a purchase and sale agreement to sell certain non-core working interests to a third party for gross proceeds of approximately \$0.5 million. The sale is expected to close on or before June 30, 2011. As at June 1, 2011 production from the assets was approximately 35 boepd.

HISTORICAL QUARTERLY FINANCIAL INFORMATION

Outlined below is a table of selected historical quarterly financial information over the last eight quarters. The adoption of IFRS at January 1, 2010 requires restatement of the Company's opening balance sheet as at January 1, 2010 and all quarterly periods in 2010. As a result of the transition period, all quarterly periods in 2009 have not been restated and are stated in accordance with CGAAP.

	2011	2010				2009		
	IFRS	IFRS		IFRS		CGAAP		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Production (boe/day)	412	393	369	413	424	398	392	403
Petroleum and natural gas revenue (\$)	1,537,110	1,285,780	1,110,876	1,275,670	1,494,636	1,225,710	803,263	913,483
Revenue (\$/boe)	41.55	35.56	32.74	33.99	39.21	34.25	22.24	24.91
G&A (\$)	526,914	492,319	359,122	398,980	452,954	421,242	257,667	279,805
Funds flow from (used-in) operations (\$) ⁽¹⁾	(217,074)	(455,696)	(18,580)	(73,035)	(343,013)	9,501	(28,572)	60,826
Funds flow per basic and diluted common share (\$)	(0.01)	(0.02)	---	---	(0.02)	---	---	0.01
Net loss (\$)	(936,238)	(3,896,593)	(764,924)	(642,533)	(1,314,104)	(870,969)	(763,808)	(341,010)
Net loss per basic and diluted common share (\$)	(0.03)	(0.16)	(0.04)	(0.03)	(0.07)	(0.06)	(0.07)	(0.03)
Capital expenditures (\$)	2,001,759	4,458,105	1,509,568	(401,894)	(144,011)	2,484,314	309,572	333,882
Net debt and working capital deficiency (\$) ⁽¹⁾	(8,427,247)	(6,228,982)	(5,195,863)	(3,667,818)	(4,158,567)	(3,911,476)	(3,444,260)	(2,896,332)

(1) See *NON-IFRS MEASURES* in this MD&A.

In the last three quarters of 2009 the Company generated funds flow from operations in all quarters except Q3 when the Company used funds flow, primarily as a result of low natural gas prices. In the year ended December 31, 2010 the Company used funds from operations in all quarters. In Q1 2010 the Company used funds flow in its operations, primarily as a result of start-up and repair charges at its southwest Saskatchewan properties. In Q2 2010 repair costs at southwest Saskatchewan somewhat diminished and reduced funds flow used in operations to \$73,035. In Q3 2010 funds were used as a result of shut in production due to repairs on a non-operated gas transmission line at Wetaskiwin in the month of September. In Q4 2010 funds flow was used in operations due to high operating expenses and high G&A costs. In the first quarter of 2011 the Company recorded funds flow used in operations of \$217,074 as a result of high operating and G&A costs. The Company's net loss for the second quarter of 2009 decreased to a net loss of \$341,010, primarily a result of recording a \$533,000 liability settlement gain. A continual decline in natural gas prices resulted in a net loss for the third quarter of \$763,808. In the fourth quarter of 2009, the Company's net loss increased to \$870,969 mainly as a result of higher depletion, depreciation and accretion expenses. Q1 2010 net loss was \$1,314,104, primarily due to the aforementioned start-up operating expenses at southwest Saskatchewan and an impairment of property and equipment expense. The Q2 2010 net loss was mainly due to lower commodity prices and higher expenses. In Q3 2010 a net loss of \$764,924 was recorded, primarily as a result of low revenues and a net gain on commodity contracts, offset by high depletion and depreciation, operating and G&A expenses. A net loss in Q4 2010 of \$3,896,593 was a result of higher revenues offset by high operating, G&A, depletion and depreciation and an impairment of property and equipment. In the first quarter of 2011 the Company recorded a net loss of \$936,238, primarily a result of revenues being offset by an unrealized gain on commodity contracts and high operating expenses.

CRITICAL ACCOUNTING ESTIMATES

The following describes accounting estimates that are critical to the financial statements:

Derivatives

The fair value of commodity contracts are based on published market prices as at the balance sheet date and may differ from what will eventually be realized. Changes in the fair value of the commodity contracts are recognized in profit or loss. The actual gains and losses realized on eventual cash settlement can vary due to subsequent fluctuations in commodity prices.

Oil and Gas Reserves

Reserves and resources are used in the units of production calculation for depreciation, depletion and amortization and the impairment analysis which affect net income. There are numerous uncertainties inherent in estimating oil and gas reserves. Estimating reserves is very complex, requiring many judgments based on geological, geophysical, engineering and economic data. Changes in these judgments could have a material impact on the estimated reserves. These estimates may change, having either a negative or positive effect on net earnings as further information becomes available and as the economic environment changes.

Depreciation and Depletion

Depletion of petroleum and natural gas properties is provided using the unit-of-production method based on production volumes before royalties in relation to total estimated proved and probable reserves as determined annually by independent qualified reserve engineers in accordance with National Instrument 51-101 and the Canadian Oil and Gas Evaluation Handbook. Natural gas reserves and production are converted at the energy equivalent of six thousand cubic feet to one barrel of oil.

Calculations for depletion and depreciation of production equipment are based on total capitalized costs plus estimated future development costs of proved and probable undeveloped reserves less the estimated net realizable value of production equipment and facilities after the proved reserves are fully produced. The costs of acquiring and evaluating unproved properties are excluded from depletion calculations.

Recoverability of Asset Carrying Values

The Company assesses its oil and gas properties, including exploration and evaluation assets, for possible impairment if there are events or changes in circumstances that indicate that carrying values of the assets may not be recoverable, or at least at every reporting date.

The assessment of any impairment of property, plant and equipment is dependent upon estimates of recoverable amount that take into account factors such as reserves, economic and market conditions, timing of cash flows, the useful lives of assets and their related salvage values.

Decommissioning Obligations

Provisions for decommissioning obligations associated with the Company's drilling operations are based on current legal and constructive requirements, technology, price levels and expected plans for remediation. Actual costs and cash outflows can differ from estimates because of changes in laws and regulations, public expectations, prices, discover and analysis of site conditions and changes in clean up technology.

Share-based Compensation

The fair value of stock options granted is measured using a Black Scholes model. Measurement inputs include share price on measurement date, exercise price of the option, expected volatility, expected life of the options, expected dividends and the risk-free rate. The Company estimates volatility based on historical share price excluding specific time frames in which volatility was affected by specific transactions that are not considered to be indicative of the Company's expected share price volatility. The expected life of the options is based on historical experience and general option holder behaviour.

Income Taxes

Related assets and liabilities are recognized for the estimated tax consequences between amounts included in the financial statements and their tax base using substantively enacted future income tax rates. Timing of future revenue streams and future capital spending changes can affect the timing of any temporary differences, and accordingly affect the amount of the deferred income tax asset or liability calculated at a point in time. These differences could materially impact earnings.

ACCOUNTING POLICY CHANGES

The following explains the significant differences between the Company's CGAAP accounting policies and those applied by the Company under IFRS.

Petroleum and natural gas expenditures

The most significant changes to the Company's accounting policies relate to the accounting for petroleum and natural gas expenditures. Under CGAAP, the Company followed the Canadian Institute of Chartered Accountants ("CICA") guideline on full cost accounting in which all costs directly associated with the acquisition of, the exploration for, and the development of crude oil, natural gas liquids and natural gas reserves were capitalized on a cost centre basis. Costs accumulated within the cost centre were depleted using the unit-of-production method based on proved reserves determined using estimated future prices and costs. Upon transition to IFRS the Company was required to adopt new accounting policies for petroleum and natural gas expenditures.

The Company adopted the IFRS 1 exemption whereby the Company deemed its January 1, 2010 property and equipment ("P&E") costs to be equal to its previous CGAAP historical P&E net book value and separate the P&E into three categories; pre-exploration costs, exploration and evaluation ("E&E") assets and development and production ("D&P") assets. The Company did not identify any pre-exploration costs. The Company identified and reclassified amounts that fit the definition of E&E assets and also removed expenditures relating to office furniture and equipment. The remaining net expenditures were allocated to D&P assets on a pro rata basis using reserve value metrics from its proved plus probable Company interest reserves.

(i) E&E

E&E assets as at January 1, 2010 of \$1.4 million were reclassified from P&E to E&E assets on the Company's Balance Sheet as at January 1, 2010. Under CGAAP the Company would capitalize all expenditures associated with unproved properties. Under IFRS E&E expenditures can only be capitalized once the legal right to explore has been obtained. Once technical feasibility and commercial viability of the E&E assets has been determined the costs are then transferred from E&E assets to P&E and are subject to an impairment test.

(ii) P&E

After removing E&E assets and minor office and equipment costs as at January 1, 2010, the remaining costs were allocated to P&E assets on a pro rata basis using reserve value metrics from its proved plus probable Company interest reserves. The company's opening allocation was as follows:

E&E	\$1.4 million
P&E	\$16.1 million

The P&E assets were then classified into cash generating units ("CGUs"), which are defined as 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 CGUs are tested for impairment.

(iii) Impairment

IFRS requires an asset impairment test to be conducted on transition date and when indicators of impairment are present. Under CGAAP impairment of long-lived assets is assessed on the basis of an asset's estimated undiscounted future cash flows compared with the asset's carrying amount and if impairment is indicated, discounted cash flows are prepared to quantify the amount of impairment. The Company did not record any impairment under CGAAP.

The resulting D&P assets were rolled down into CGUs and tested for impairment. The impairment test resulted in the following impairment write downs:

Cash Generating Unit	Impairment on Transition
Wetaskiwin, coal bed methane	\$ 691,000
Wetaskiwin, natural gas	292,000
Wetaskiwin, oil	57,000
Misc properties	165,000
Sold properties in 2010	785,000
Total	\$ 1,990,000

The Company used the greater of its value in use and its fair value less costs to sell. The impairment amount was recorded to the January 1, 2010 deficit.

Under IFRS impairments that were previously recognized are reversed when there has been a subsequent increase in the recoverable amount. In the case of an impairment reversal, the carrying amount of the asset or CGU is limited to the original carrying amount less depreciation, depletion and amortization as if no impairment had been recognized for the asset or CGU for prior periods.

The Company evaluates its CGUs for impairment when indicators of impairment are present. In the three months ended March 31, 2010 the Company impaired certain gas properties due to a decline in gas prices and production and further impaired its gas properties at September 30, 2010 and December 31, 2010 due to declining gas prices. At December 31, 2010 the Company tested the E&E assets for impairment and concluded that certain seismic data and future development of the underlying area was not part of the Company's future plans and impaired the asset by \$115,000. The Company recorded impairments for the three months ended March 31, 2010 and year ended December 31, 2010 of \$805,307 and \$3,504,697, respectively.

Impairments in 2010 were as follows:

Cash Generating Unit	Year ended December 31, 2010	Three months ended December 31, 2010	Three months ended September 30, 2010	Three months ended March 31, 2010
Wetaskiwin, coal bed methane	\$ 1,465,603	\$ 885,606	\$ 108,480	\$ 471,517
Wetaskiwin, natural gas	855,903	430,785	91,328	333,790
Kinsella/Ronalane	1,068,191	1,068,191	---	---
E&E assets	115,000	115,000	---	---
Total	\$ 3,504,697	\$ 2,499,582	\$ 199,808	\$ 805,307

(iv) Depletion

Under CGAAP depletion was calculated using total proved reserves and used a full cost pool concept. Under IFRS a corporation has a choice regarding its depletion base and depletion is calculated based on individual components and not a full cost pool. The Company has adopted the policy of depleting its development and producing assets using a proved plus probable reserves base and calculates depletion at an area or commodity level. As a result of using a proved plus probable reserve base and depleting at an area level, accumulated depletion decreased by \$321,547 for the three months ended March 31, 2010 and decreased by \$1,193,298 for the year ended December 31, 2010.

Decommissioning obligations:

The Company elected to use an exemption that allowed it to use IAS 37 *Decommissioning Liabilities* to record an abandonment liability and any changes to the CGAAP amount at January 1, 2010 will be recorded to opening deficit. An increase in the decommissioning obligation at January 1, 2010 was primarily a result of using a risk free rate, compared to using a credit adjusted risk free rate under CGAAP. As a result of applying this exemption, the Company's decommissioning obligation increased by \$1,102,809. As a result of using a risk free rate to calculate the net present value of decommissioning obligations instead of a credit adjust risk free rate the Company's decommissioning obligation for the three months ended March 31, 2010 and the year ended December 31, 2010 increased by \$516,775 and \$577,138, respectively. The resultant increase in the Company's decommissioning obligation also increased property and equipment for the three months ended March 31, 2010 and December 31, 2010 by \$689,148 and \$1,290,779. The change in the discount rates used also had an effect on accretion expense resulting in accretion expense decreasing by \$28,366 and \$144,548 in the three months ended March 31, 2010 and the year ended December 31, 2010, respectively.

Flow-through share obligation / share capital:

Under CGAAP proceeds received from the issuance of flow-through shares were credited to share capital and the associated deferred tax liability was recognized when the Company renounced the eligible tax pools. Under IFRS a liability is set up to account for a premium between the underlying share price at the time an agreement is entered into, compared to the flow-through share unit price. The liability is reduced as qualifying flow-through expenditures are made. An analysis was made of all of the Company's flow-through issuances to December 31, 2009. For flow-through issuances completed in 2009 a liability of approximately \$58,474 was recorded with an offsetting entry to share capital. For flow-through issuances completed prior to 2009, an entry was made to reduce share capital for \$489,982 and deficit to adjust for previous flow-through tax adjustments. The Company's flow-through obligation at January 1, 2010 was reduced by \$7,602 for the three months ended March 31, 2011 as the Company incurred qualifying flow-through expenditures. A revised flow-through obligation of \$322,500 was recorded at December 31, 2010 as a result of the Company raising approximately \$2.0 million of flow-through shares. A corresponding adjustment was made to share capital for the year ended December 31, 2010. The flow-through obligation was partially offset due to the Company incurring a portion of eligible costs prior to year end.

Deferred income tax:

Deferred income taxes have been adjusted to reflect the tax effect arising from the differences between IFRS and CGAAP. Upon transition to IFRS, as a result of adjustments to P&E and decommissioning obligation the Company's deferred income tax liability was reduced by \$786,991. As a result of temporary differences between CGAAP and IFRS relating to flow-through shares and the recording of an entry to remove a deferred tax asset as it was determined that it wasn't probable that future taxable profits will be available against which the temporary difference can be utilized, in the three months ended March 31, 2010 and year ended December 31, 2010, deferred income taxes were reduced to nil and share capital increased by \$190,277 as previously recorded under CGAAP.

Contributed surplus:

The Company elected an exemption that allowed it to apply IFRS2 (share-based payments) to any unvested options outstanding as at December 31, 2009. Differences to CGAAP include the fact that each award is treated as a separate award under IFRS and IFRS uses a graded vesting method in the calculation instead of each award treated as a single award and calculated using a straight-line method as under CGAAP. Recalculating stock based compensation on outstanding options as at December 31, 2009 resulted in an increase in contributed surplus of \$101,336, with a corresponding entry to deficit. Using a graded method for calculating share based compensation under IFRS resulted in an increase to contributed surplus for the three months ended March 31, 2010 of \$2,125 and a decrease to contributed surplus for the year ended December 31, 2010 of \$18,599 and corresponding entries were made to share based compensation.

NEW STANDARDS

Effective January 1, 2013 the Company will be required to adopt IFRS 9, "Financial Instruments", which is the result of the first phase of the IASB's project to replace IAS 39, "Financial Instruments: Recognition and Measurement". The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value.

ADDITIONAL INFORMATION

Additional information relating to the Company is filed on SEDAR at www.sedar.com or on the Company's website at www.trafinaenergy.com. Information can also be obtained by contacting the Company at Trafina Energy Ltd., 2210, 530-8th Avenue S.W., Calgary, Alberta T2P 3S8.