



Q3 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 and nine months ended September 30, 2011 and should be read in conjunction with the condensed interim financial statements and accompanying notes for the three and nine months ended September 30, 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 November 21, 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").

The impact of the transition to IFRS is disclosed in the condensed interim financial statements of the Company for the three months ended March 31, 2011. Note 18 to the condensed interim financial statements for the three and nine months ended September 30, 2011 provides reconciliations between the Company's previous CGAAP and its 2010 IFRS.

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 current credit facilities and 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 partner, 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") 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, 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 from (used-in) operations, which is not defined under IFRS or CGAAP 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 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, funds flow 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 or CGAAP as an indication of the Company's performance.

The following table reconciles cash flow used in operating activities to funds flow used in operation in accordance with IFRS:

	Three Months Ended September 30		Nine Months Ended September 30	
	2011	2010	2011	2010
Cash flow used in operating activities	\$ (200,484)	\$ (394,186)	\$ (437,518)	\$ (1,424,578)
Change in non-cash operating working capital	(77,743)	375,606	(218,078)	989,949
Decommissioning expenditures	47,792	---	62,063	---
Funds flow used in operations	\$ (230,435)	\$ (18,580)	\$ (593,533)	\$ (434,629)

Funds flow used-in operations for the three and nine months ended September 30, 2011 of \$230,435 and \$593,533, respectively, was primarily a result of revenues being more than offset by operating and G&A expenses. In the three and nine months ended September 30, 2010 the Company used funds of \$18,580 and \$434,629, respectively.

The Company also considers field netback a key performance measure. However, field netback is not defined under IFRS or CGAAP 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

During the three months ended September 30, 2011 the Company took a major step forward in the development of its heavy oil play in McMullen in northeast Alberta. The Company drilled, completed, equipped and placed on production three vertical test wells at 16-28, 05-28 and 11-28-077-25 W4M. The coring results of all three wells were encouraging with zonal characteristics such as viscosity and pressure meeting or exceeding expectations. All three wells were placed on production in August 2011 and the Company began trucking oil for sale in September 2011. Current production from the three wells is averaging 70 bbls/day. As is the case with most heavy oil wells in the area, continued monitoring of production is required in order to gain a thorough understanding of the Wabasca A oil sands formation.

In order to facilitate further development at McMullen, the Company decided to sell its entire interest in its Cardium oil play at Pembina, Alberta. Excessive cost overruns combined with limited future development (the Company's entire interest was limited to one section) were contributing factors that lead to the decision to sell the property. Net proceeds from the sale were approximately \$1.7 million.

## SELECTED FINANCIAL INFORMATION

	For the three months ended September 30,		
	2011	2010	% Change
Total petroleum and natural gas revenue (\$)	1,182,204	1,110,876	+6
Royalties (\$)	144,289	117,961	+22
Operating, processing, and transportation expenses (\$)	912,349	810,167	+13
Funds flow used-in operations <sup>(1)</sup> (\$)	(230,435)	(18,580)	+1,140
per basic and diluted common share (\$)	---	---	
Weighted average basic shares outstanding	55,690,562	18,627,262	+199
Net loss (\$)	(2,802,144)	(764,924)	+266
per basic and diluted common share (\$)	(0.05)	(0.04)	
Net capital expenditures (dispositions) - cash (\$)	1,462,006	(1,509,568)	
Total assets (\$)	17,846,426	17,140,759	+4
Net debt and working capital deficiency <sup>(2)</sup> (\$)	3,145,267	5,195,863	-39

(1) Funds flow 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 minus current liabilities less effects of commodity contracts.

## SELECTED FINANCIAL INFORMATION

	For the nine months ended September 30,		
	2011	2010	% Change
Total petroleum and natural gas revenue (\$)	4,022,167	3,881,182	+4
Royalties (\$)	401,796	452,934	-11
Operating, processing, and transportation expenses (\$)	2,785,622	2,844,502	-2
Funds flow used-in operations <sup>(1)</sup> (\$)	(593,533)	(434,629)	+37
per basic and diluted common share (\$)	(0.01)	(0.02)	
Weighted average basic shares outstanding	45,221,191	18,449,943	+145
Net loss (\$)	(4,011,878)	(2,721,561)	+47
per basic and diluted common share (\$)	(0.09)	(0.15)	
Net capital expenditures - cash (\$)	4,433,989	801,663	+453
Total assets (\$)	17,846,426	17,140,759	+4
Net debt and working capital deficiency <sup>(2)</sup> (\$)	3,145,267	5,195,863	-39

(1) Funds flow 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 minus current liabilities less effects of commodity contract s.

## PRODUCT SALES

	Three Months Ended September 30			Nine Months Ended September 30		
	2011	2010	Change	2011	2010	Change
Natural gas	1,321 mcf/day	1,635 mcf/day	(19) %	1,449 mcf/day	1,823 mcf/day	(21) %
Oil and natural gas liquids	114 bbls/day	96 bbls/day	19 %	121 bbls/day	98 bbls/day	23 %
Total product sales	334 boe/day	369 boe/day	(9) %	363 boe/day	402 boe/day	(10) %

Natural gas product sales declined 19 percent and 21 percent in the three and nine months ended September 30, 2011, respectively, compared to the same periods in 2010. The decline in natural gas product sales was primarily a result of the Company disposing of non-core natural gas weighted properties and natural gas well production declines. Oil and natural gas liquids on the other hand increased 19 percent and 23 percent in the three and nine months ended September 30, 2011, respectively, compared to the three and nine months ended September 30, 2010. The increase in both periods is generally a result of increased well production at the Company's southwest Saskatchewan area and production at the Company's Pembina and McMullen areas.

## BENCHMARK PRICES

	Three Months Ended September 30		Nine Months Ended September 30	
	2011	2010	2011	2010
AECO daily spot price	\$ 3.63/mcf	\$ 3.55/mcf	\$ 3.77/mcf	\$ 4.13/mcf
West Texas Intermediate (WTI)	US\$89.29/bbl	US\$76.06/bbl	US\$95.27/bbl	US\$77.54/bbl
Edmonton Par	\$92.27/bbl	\$74.45/bbl	\$94.26/bbl	\$76.73/bbl
US/CDN \$ average exchange rate	1.02	0.96	1.02	0.97

An increase in natural gas storage levels, a quiet storm season in the Gulf of Mexico and slow global economic recovery were some of the reasons natural gas prices declined from an average price of \$3.97/mcf in the previous quarter to average \$3.63/mcf in the three months ended September 30, 2011. Oil prices took a steep dive in the three months ended September 30, 2011, declining to an average price of US\$89.29/bbl, from an average price of US\$102.55/bbl in the previous quarter. Continued unrest in the Middle East wasn't enough to support strong prices as the United States debt ceiling crisis and worries regarding the European economy put downward pressure on oil pricing.

## COMPANY REALIZED PRICES

	Three Months Ended September 30		Nine Months Ended September 30	
	2011	2010	2011	2010
Natural gas	\$ 3.66/mcf	\$ 3.55/mcf	\$ 3.73/mcf	\$ 4.14/mcf
Oil and natural gas liquids	\$ 70.51/bbl	\$ 65.06/bbl	\$ 76.84/bbl	\$ 68.21/bbl
Total	\$ 38.48/boe	\$ 32.74/boe	\$ 40.59/boe	\$ 35.40/boe

For the three and nine months ended September 30, 2011 natural gas prices correlated closely with the benchmark prices as the Company's realized natural gas sales prices are primarily linked to the daily AECO price. Oil and natural gas liquids realized prices for the three and nine months ended September 30, 2011 increased relative to the oil and natural gas liquids realized prices over the same period in 2010, which also followed the benchmark prices trends. The difference in the Company's realized oil price compared to the Edmonton par or WTI benchmark prices can be defined as the differential price. The differential price to the Edmonton par price in the three and nine months ended September 30, 2011 averaged \$21.76 and \$17.42, respectively. In comparison the differential price to the Edmonton par price in the three and nine months ended September 30, 2010 averaged \$9.39 and \$8.52, respectively. The increase in the differential price in 2011 is primarily a result of a stronger Canadian dollar compared to the US dollar and also the fact that a majority of the Company's oil production in 2011 is classified as heavy oil. In particular, in the three months ended September 30, 2011 the differential widened to \$21.76, mainly as a result of new oil sales from the Company's McMullen oil sands area, which is usually associated with oil quality adjustment charges and diluent blending charges. Diluent blending is necessary to bring the oil to pipeline transportation specifications. As more production is expected from the McMullen area, managing quality adjustment and blending charges will be important.

## PETROLEUM AND NATURAL GAS REVENUE

	Three Months Ended September 30		Nine Months Ended September 30	
	2011	2010	2011	2010
Natural gas	\$ 444,297	\$ 534,134	\$ 1,475,948	\$ 2,060,236
Oil and natural gas liquids	737,907	576,742	2,546,219	1,820,946
Total petroleum and natural gas revenue	\$ 1,182,204	\$ 1,110,876	\$ 4,022,167	\$ 3,881,182

A decline in natural gas sales for the three and nine months ended September 30, 2011 compared to the three and nine months ended September 30, 2010 as a result of the disposition of non-core natural gas weighted properties and natural gas well production declines was the primary reason for lower natural gas revenue. Oil and natural gas liquids revenue for the three and nine months ended September 30, 2011 were higher than oil and natural gas liquids revenue in the same period in 2010, mainly due to higher oil product sales and higher realized oil prices. In general, the Company began to see the benefits of a move to oil production as petroleum and natural gas liquids revenues increased in the three and nine months ended September 30, 2011 compared to the same period in 2010.

## REALIZED GAIN (LOSS) ON COMMODITY CONTRACTS

	Three Months Ended September 30		Nine Months Ended September 30	
	2011	2010	2011	2010
Realized gain on commodity contracts – natural gas	\$ 36,448	\$ 163,574	\$ 61,254	\$ 250,926
Realized gain (loss) on commodity contracts – oil	7,399	---	(50,687)	---
Total gain on commodity contracts	\$ 43,847	\$ 163,574	\$ 10,567	\$ 250,926

A continued low natural gas price resulted in the Company realizing a gain on its natural gas commodity contracts in the three and nine months ended September 30, 2011 and 2010. The Company recorded an oil commodity contracts gain in the three months ended September 30, 2011 as oil prices declined from the previous quarter. Overall, oil prices remained high compared to the Company's oil commodity contracts in the nine months ended September 30, 2011 giving rise to a realized loss on its oil commodity contracts. The Company did not enter into any oil commodity contracts in the nine months ended September 30, 2010.

**UNREALIZED GAIN (LOSS) ON COMMODITY CONTRACTS**

	Three Months Ended September 30		Nine Months Ended September 30	
	2011	2010	2011	2010
Unrealized gain (loss) on commodity contracts	\$105,770	\$(87,000)	\$ 230,359	\$ 66,000

The following table outlines the Company's outstanding commodity sales contracts and estimated fair value as at September 30, 2011:

Type	Daily Volume	Duration	Price	Estimated fair value
Fixed-Gas	300 GJ/day	October 1, 2011 to December 31, 2011	\$3.85/GJ	\$14,600
Fixed-Gas	300 GJ/day	October 1, 2011 to December 31, 2011	\$4.41/GJ	\$35,100
Collar-Oil	50 bbl/day	October 1, 2011 to December 31, 2011	Floor \$75.00 WTI Cdn Ceiling \$90.00 WTI Cdn	\$(205)
Collar-Oil	50 bbl/day	October 1, 2011 to December 31, 2011	Floor \$90.00 WTI US Ceiling \$108.90 WTI US	\$61,275
Total				110,770

**OTHER**

	Three Months Ended September 30		Nine Months Ended September 30	
	2011	2010	2011	2010
Other revenue	\$ 11,741	\$ 32,820	\$ 54,367	\$ 46,957

Other revenue relates to gas processing, water disposal and interest revenue.

**ROYALTIES**

	Three Months Ended September 30				Nine Months Ended September 30			
	2011	Royalty as % of revenue	2010	Royalty as % of revenue	2011	Royalty as % of revenue	2010	Royalty as % of revenue
Royalties	\$ 144,289	12%	\$ 117,961	11%	\$ 401,796	10%	\$ 452,934	12%

Royalty payments as a percentage of revenue were higher in the three months ended September 30, 2011 compared to the same period in 2010. The higher percentage is primarily as a result of favorable Alberta Crown natural gas custom processing and gas cost allowance reimbursements in 2010 compared to 2011. Royalties as a percentage of revenue in the nine months ended September 30, 2011 were lower compared to the same period in 2010 as a result of lower royalty rates on the Company's Cardium horizontal well at Pembina, Alberta, and overall lower rates in 2011 due to the disposition of properties in 2010 associated with higher freehold royalty rates.

## OPERATING EXPENSES

	Three Months Ended September 30				Nine Months Ended September 30			
	2011	\$/boe	2010	\$/boe	2011	\$/boe	2010	\$/boe
Operating expenses	\$ 912,349	\$ 29.69	\$ 810,167	\$ 23.88	\$2,785,622	\$ 28.11	\$2,844,502	\$ 25.95

Operating expenses, including processing and transportation costs, for the three months ended September 30, 2011 were \$912,349 (\$29.69/boe), which on a dollar per boe basis increased 24 percent over the same period in 2010 (\$810,167; \$23.88/boe). The increase on a boe basis was mainly due to a combination of lower product sales and well repair costs at southwest Saskatchewan for the three months ended September 30, 2011. Operating expenses, including processing and transportation costs, for the nine months ended September 30, 2011 were \$2,785,622 (\$28.11/boe), which on a dollar per boe basis increased eight percent over the same period in 2010 (\$2,844,502; \$25.95/boe). The increase on a boe basis was mainly a result of fixed costs incurred in southwest Saskatchewan due to a delay in repair work as a result of wet lease conditions and higher than expected costs for snow removal. The Company also incurred additional costs for down-hole well repairs in west central Alberta for the nine months ended September 30, 2011.

## FIELD NETBACK<sup>(1)</sup>

	Three Months Ended September 30				Nine Months Ended September 30			
	2011	\$/boe	2010	\$/boe	2011	\$/boe	2010	\$/boe
Petroleum and natural gas revenue	\$182,204	\$ 38.47	\$1,110,876	\$32.74	\$4,022,167	\$ 40.59	\$3,881,182	\$35.40
Realized gain on commodity contracts	43,847	1.43	163,574	4.82	10,567	0.11	250,926	2.29
Other revenue	11,741	0.38	32,820	0.97	54,367	0.55	46,957	0.43
Royalties	(144,289)	4.70	(117,961)	3.48	(401,796)	4.05	(452,934)	4.13
Operating expenses	(912,349)	29.69	(810,167)	23.88	(2,785,622)	28.11	(2,844,502)	25.95
Field netback <sup>(1)</sup>	\$181,154	\$5.89	\$379,142	\$8.61	\$899,683	\$9.09	\$881,629	\$8.64
Sales volumes (boe)	30,728		33,933		99,099		109,629	

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

The Company's average field netback per boe for the three months ended September 30, 2011 decreased to \$5.89/boe compared to the three months ended September 30, 2010, when the average field netback was \$8.61/boe. The main reason for the decrease was higher operating costs. Also higher royalty payments and lower gains on commodity contracts, partially offset by higher revenue as a result of higher oil prices and oil sales contributed to a lower field netback in the three months ended September 30, 2011. The Company's average field netback per boe for the nine months ended September 30, 2011 increased slightly to \$9.09/boe, compared to the nine months ended September 30, 2010, which realized an average field netback of \$8.64/boe. Higher revenue in the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010 as a result of higher oil prices and higher oil production was slightly offset by a larger gain on commodity contracts realized in the nine months ended September 30, 2010, compared to the nine months ended September 30, 2011.

## GENERAL AND ADMINISTRATIVE (“G&A”) EXPENSE

	Three Months Ended September 30		Nine Months Ended September 30	
	2011	2010	2011	2010
G&A gross	\$ 462,111	\$ 397,243	\$ 1,573,081	\$ 1,342,947
G&A overhead recovery	(55,232)	(38,121)	(144,293)	(131,891)
G&A net	406,879	359,122	1,428,788	1,211,056
G&A per boe	\$ 13.24	\$ 10.58	\$ 14.42	\$ 11.05

General and administrative expenses for the three months ended September 30, 2011 were approximately \$48,000 (13 percent) higher than for the same period in 2010. Increased G&A expenses are mainly attributable to an increase in salaries. G&A expenses for the nine months ended September 30, 2011 were \$217,732 (18 percent) higher than for the nine months ended September 30, 2010. The increase in G&A costs for this period was primarily due to an increase in salaries, reporting costs and IFRS conversion costs, offset slightly by less activity associated with asset acquisition transactions.

## SHARE BASED COMPENSATION EXPENSE

Share based compensation expense totaled \$30,048 for the three months ended September 30, 2011, compared to \$28,022 for the three months ended September 30, 2010. For the nine months ended September 30, 2011 and 2010 share based compensation expense totaled \$230,456 and \$124,011, respectively. The small increase in share based compensation expense for the nine months ended September 30, 2011 relates to the timing and amount of stock options granted during the period. The Company granted approximately 1.5 million stock options in the nine months ended September 30, 2011 compared to the Company granting approximately 0.6 million stock options in the nine months ended September 30, 2010.

## FINANCING EXPENSE

	Three Months Ended September 30		Nine Months Ended September 30	
	2011	2010	2011	2010
Interest expense	\$ 4,710	\$ 38,600	\$ 64,428	\$ 105,202
Accretion expense	27,167	32,317	94,078	96,290
Finance expense	\$ 31,877	\$ 70,917	\$ 158,506	\$ 201,492

Interest expense for the three months ended September 30, 2011 was lower than for the same period in 2010. The reduction in interest expense was a result of the Company using less debt and instead using proceeds from a public financing which closed on April 21, 2011. The aforementioned public financing also had an effect on lowering interest payments in the nine months ended September 30, 2011 compared to interest payments in the nine months ended September 30, 2010. Accretion expense represents the change in the time value of the Company's decommissioning obligation. The accretion expense for the three months ended September 30, 2011 and 2010 and accretion expense for the nine months ended September 30, 2011 and 2010 were substantially similar when comparing each period.

## DEPLETION AND DEPRECIATION

For the three months ended September 30, 2011 and 2010, depletion and depreciation expense was \$470,238 (\$15.30/boe) and \$567,781 (\$16.73/boe), respectively. For the nine months ended September 30, 2011 and 2010, depletion and depreciation expense was \$1,678,048 (\$16.93/boe) and \$1,857,479 (\$16.94/boe), respectively. The Company calculates depletion and depreciation expense on a proved plus probable reserves basis.

## IMPAIRMENT OF PROPERTY AND EQUIPMENT

For the purpose of impairment testing, assets are grouped together into cash generating units (“CGUs”). A CGUs 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 CGU. 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.

For the nine months ended September 30, 2011 the Company recorded an impairment of \$1,340,000 on a CGU due to a decline in well performance. For the nine months ended September 30, 2010 the Company recognized impairments of \$1,005,115 due to a decline in gas prices and production on certain gas properties.

## LOSS / GAIN ON PROPERTY ACQUISITION / DIVESTMENT

For the three and nine months ended September 30, 2011 the Company recorded a net loss on property acquisition and divestment of \$810,026 and \$436,122, respectively. When disposing of property or equipment, proceeds are deducted from the carrying value of the asset and any associated decommissioning liabilities resulting in recognition of a gain or loss. In the three months ended September 30, 2011 the Company disposed of various producing and non-producing non-core assets. After reversing the carrying value of the assets and removing the associated decommissioning liabilities the Company recorded a net loss of \$810,026. In the nine months ended September 30, 2011 the Company recorded a loss on property acquisition and divestment of \$436,122 as a result of the aforementioned transactions, offset by gain on property divestment of \$373,904. In the three and nine months ended September 30, 2010 the Company recorded gains on property dispositions of \$142,855 and \$423,576, respectively.

## 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 September 30, 2011 the Company recorded no deferred income tax and recorded a deferred income tax reduction of \$130,000 in the nine months ended September 30, 2011. The reduction was a result of the Company fulfilling its 2010 flow through obligation. For the three and nine months ended September 30, 2010 the Company recorded a deferred income tax reduction of \$25,729 and \$306,387, respectively, as a result of a valuation allowance.

## NET LOSS

	Three Months Ended September 30		Nine Months Ended September 30	
	2011	2010	2011	2010
Net loss	\$ 2,802,144	\$ 764,924	\$ 4,011,878	\$ 2,721,561

For the three months ended September 30, 2011 the Company recorded a net loss of \$2,802,144, compared to a net loss of \$764,924 reported in the three months ended September 30, 2010. A higher net loss in the three months ended September 30, 2011 was mainly a result of higher revenue offset by higher depletion and depreciation costs, an impairment of property and equipment and a recognized loss on disposition of property. For the nine months ended September 30, 2011 the Company recorded a net loss of \$4,011,878, compared to a net loss of \$2,721,561 reported in the nine months ended September 30, 2010. A higher net loss in the nine months ended September 30, 2011 was primarily a result of higher revenue, the recording of a larger unrealized commodity contract gain, lower finance expenses and depletion and depreciation costs, offset slightly by higher G&A, share-based costs, a recognized loss on disposition of property, a higher impairment of property and equipment and a lower deferred income tax reduction.

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.

## NETBACK ANALYSIS

The following table reconciles field netback (non-IFRS) to funds flow used-in operations (non-IFRS) to net loss for the three and nine months ended September 30, 2011 and 2010:

	Three Months Ended September 30		Nine Months Ended September 30	
	2011	2010	2011	2010
Petroleum and natural gas revenue	\$ 1,182,204	\$ 1,110,876	\$ 4,022,167	\$ 3,881,182
Realized gain (loss) on commodity contracts	43,847	163,574	10,567	250,926
Other revenue	11,741	32,820	54,367	46,957
Royalties	(144,289)	(117,961)	(401,796)	(452,934)
Operating expenses	(912,349)	(810,167)	(2,785,622)	(2,844,502)
Field netback <sup>(1)</sup>	181,154	379,142	899,683	881,629
General and Administrative	(406,879)	(359,122)	(1,428,788)	(1,211,056)
Interest	(4,710)	(38,600)	(64,428)	(105,202)
Funds flow used-in operations <sup>(1)</sup>	(230,435)	(18,580)	(593,533)	(434,629)
Depletion and depreciation	(470,238)	(567,781)	(1,678,048)	(1,857,479)
Deferred income taxes	---	25,729	130,000	306,387

Share based compensation	(30,048)	(28,022)	(230,456)	(124,011)
Unrealized gain (loss) on commodity contract	105,770	(87,000)	230,359	66,000
Finance expense - accretion	(27,167)	(32,316)	(94,078)	(96,290)
Impairment of property and equipment	(1,340,000)	(199,808)	(1,340,000)	(1,005,115)
Gain (loss) on property divestment	(810,026)	142,855	(436,122)	423,576
Net loss	\$ (2,802,144)	\$ (764,924)	\$ (4,011,878)	\$ (2,721,561)

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

## LIQUIDITY AND CAPITAL RESOURCES

At September 30, 2011 the Company had a working capital deficiency of \$3.15 million, excluding the fair value of its commodity contracts. The Company's maximum available lending amount on its revolving operating demand facility is \$3.5 million.

Capital expenditures forecasted for the remainder of 2011 include the drilling, completing and production testing of one vertical test well on its McMullen lands. In order for the Company to pay for current operations and drill one vertical well at McMullen additional funds are required. Potential additional sources of funding include access to additional bank lending amounts, dispositions of assets and equity financings. There is no assurance that additional capital will be available on terms acceptable to the Company or at all.

## BANK DEBT

At September 30, 2011, the Company had drawn \$978,224 on its available facilities and had a working capital deficiency of approximately \$3.1 million, excluding the fair value of its commodity contracts.

In October, 2011 the Company renewed its credit facilities agreement with its lender consisting of a \$3.5 million revolving operating demand facility, with interest charged on advances under the facility at the bank's prime rate plus 1.50% and a \$3.5 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 January 1, 2012. The renewed credit facilities agreement includes a working capital ratio covenant, which is not to fall below 1:1. The Company was compliant with its banking covenant.

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

### Equity financing

On April 21, 2011 the Company 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 entitles 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"). Costs associated with the financing including commissions and legal and reporting fees were \$0.8 million.

Set forth below is the use of the proceeds of the offering.

Disclosed Use of Proceeds	How Net Proceeds Were Used
Proceeds of the offering will be used to pay down the Company's bank debt, settle a portion of its working capital deficiency and fund a portion of its remaining capital expenditure program.	The Company received net proceeds of approximately \$8.2 million and immediately settled its outstanding bank debt. The settlement of the bank debt allowed the Company to reduce some of its outstanding working capital deficiency. Temporarily reducing its working capital deficiency allowed the Company to utilize its available credit facilities to fund its on-going capital expenditure program.

### Stock option exercise

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

### Private placement warrants

On March 7, 2011 the Company announced the acceleration of the expiry of 6,334,000 warrants issued on November 30, 2010 and December 2, 2010 to April 15, 2011. The remaining 2,513,335 warrants issued December 3, 2009 expired on June 3, 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 expired on June 3, 2011 were exercised for proceeds of \$6,435.

### 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. As at March 31, 2011 the Company had fulfilled its flow-through spending obligation.

### Stock options

The Company has an employee stock option plan under which employees, consultants, officers and directors are eligible to receive options to purchase Common Shares of the Company. For stock options granted, one third of the options vest on the day following the date of grant, one third on the day following the first anniversary date of the grant and the remaining options vest on the day following the second anniversary date of the grant. On June 30, 2011 the Company issued 1,490,000 stock options to directors, officers, employees and consultants of the Company with an exercise price of \$0.35 per Common Share.

## 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 November 21, 2011 the Company had the following issued and outstanding equity:

Class A voting common shares issued and outstanding (trading on the TSX-Venture exchange under the symbol TFA.A)	55,690,562
Share Purchase Warrants (trading on the TSX-Venture exchange under the symbol TFA.WT.A: exercise price of \$0.45)	25,715,000
Stock options (weighted average exercise price of \$0.37)	3,585,000

## CAPITAL EXPENDITURES

The following table summarizes capital expenditures for the three and nine months ended September 30, 2011 and 2010.

	Three months ended September 30		Nine months ended September 30	
	2011	2010	2011	2010
Property dispositions	\$ (1,726,324)	\$ (23,671)	\$ (2,176,622)	\$ (2,605,215)
Property acquisitions	---	21,081	---	602,564
Land	550	---	221,268	---
Road construction, drilling, completions and recompletions	1,698,939	595,385	4,419,425	1,378,201
Equipping and facilities	1,488,841	867,508	1,936,842	1,434,678
Other	---	49,265	33,076	153,436
Total net capital expenditures, cash	\$ 1,462,006	\$ 1,509,568	\$ 4,433,989	\$ 963,663

For the three months ended September 30, 2011, the Company received proceeds of \$1.7 million from selling its entire interest in the Company's Cardium oil play at Pembina, Alberta and selling a minor undeveloped land position. Most of the Company's focus is primarily on developing its McMullen area. During the three months ended September 30, 2011 the Company drilled, completed, equipped and placed on production three vertical test wells for approximately \$3.1 million. Additional costs were as a result of equipment modifications at southwest Saskatchewan. For the nine months ended September 30, 2011 the Company incurred costs of approximately \$2.2 million to construct an all-weather access road and prepare well sites, in part, to drill, complete and equip the aforementioned vertical test wells. The Company also spent \$0.5 million at southwest Saskatchewan equipping various wells and recompleting one well. The remaining expenditures related to 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 be drilled by June 2012. However, the Company is not obligated to drill the second well. The Company also disposed of various non-core assets for net proceeds of \$0.45 million. During the three months ended September 30, 2010, the majority of capital expenditures were associated with drilling a Pembina Cardium well and a pipeline tie-in project at Ronalane. The Company also disposed of non-core area assets and incurred additional costs associated with its southwest Saskatchewan properties. For the nine months ended September 30, 2010 the Company disposed of several non-core area properties for net proceeds of \$2.6 million and acquired assets for \$0.6 million, with costs incurred in the first nine months of the year to realize on the acquisition of approximately \$337,000. The remaining expenditures in the nine months ended September 30, 2010 were a result of equipping wells in southwest Saskatchewan and Brownfield Alberta, the aforementioned drilling of the Pembina well and a pipeline construction project in southern Alberta.

### CONTRACTUAL OBLIGATIONS

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

2011 (remaining)	\$33,500
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 November 21, 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 nine months ended September 30, 2011, fees for legal services billed from this related party were approximately \$245,000 (September 30, 2010 - \$157,000), of which \$19,700 is included in accounts payable at September 30, 2011 (September 30, 2010 - \$22,500). These services are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

### SUBSEQUENT EVENTS

The Company signed a binding letter of intent which grants a Gross Overriding Royalty (GORR) to an Alberta corporation that was instrumental in the Company acquiring the initial McMullen lands in northeast, Alberta. The GORR is restricted to two of the 33 sections of land at McMullen and replaces a 20 percent right to participate in the two sections. The letter agreement provides for payment to the corporation of a 2.5 percent GORR, less applicable deductions applicable to production of this type. The parties expect to enter into a formal agreement prior to the end of November 2011. When this transaction is completed, the Company will retain a 100 percent ownership in the McMullen lands and reserves.

### 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, Q4 data in 2009 have not been restated and are stated in accordance with CGAAP.

	2011 IFRS			2010 IFRS			2009 CGAAP	
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Production (boe/day)	334	343	412	393	369	413	424	398
Petroleum and natural gas revenue (\$)	1,182,204	1,302,854	1,537,110	1,285,780	1,110,876	1,275,670	1,494,636	1,225,710
Revenue (\$/boe)	38.47	41.74	41.55	35.56	32.74	33.99	39.21	34.25
G&A (\$)	406,879	494,996	526,914	492,319	359,122	398,980	452,954	421,242
Funds flow from (used-in) operations (\$) <sup>(1)</sup>	(230,435)	(146,024)	(217,074)	(455,696)	(18,580)	(73,035)	(343,013)	9,501
Funds flow per basic and diluted common share (\$)		---	(0.01)	(0.02)	---	---	(0.02)	---
Net loss (\$)	(2,802,144)	(273,497)	(936,238)	(3,896,593)	(764,924)	(642,533)	(1,314,104)	(870,969)
Net loss per basic and diluted common share (\$)	(0.05)	(0.01)	(0.03)	(0.16)	(0.04)	(0.03)	(0.07)	(0.06)
Capital expenditures (dispositions)-cash (\$)	1,462,006	975,064	1,996,919	4,445,515	1,509,568	(563,895)	(144,011)	2,484,314
Net debt and working capital deficiency (\$) <sup>(1)</sup>	(3,145,267)	(1,354,826)	(8,427,247)	(6,228,982)	(5,195,863)	(3,667,818)	(4,158,567)	(3,911,476)

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

In Q4 2009 the Company generated funds flow from operations. 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 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 three quarters of 2011 the Company recorded funds flow used in operations as a result of revenues being more than offset by higher operating and G&A costs. In Q4 2009, the Company's net loss was \$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. In Q2 2011 the Company recorded a lower net loss primarily due to the Company recording lower operating and G&A costs and the Company recording higher revenues due to increased oil prices. In Q3 2011 the Company's net loss increased to \$2,802,144 as a result of revenues being offset by high operating expenses and loss on property dispositions.

## CRITICAL ACCOUNTING ESTIMATES

A summary of the Company's significant accounting policies is contained in note 3 of the Company's condensed IFRS interim financial statements for the three months ended March 31, 2011. These accounting policies are subject to estimates and key judgments about future events. The following is a discussion of the accounting estimates that are critical to the financial statements.

### Commodity contracts

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, discovery 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.

## **INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)**

On January 1, 2011, the Company adopted IFRS for financial reporting purposes, using a transition date of January 1, 2010. The interim financial statements for the three and nine months ended September 30, 2011 and related notes have been prepared under IFRS in accordance with International Accounting Standard ("IAS") 34, Interim Financial Reporting. Previously, the Company prepared its interim and annual financial statements in accordance with CGAAP. As such, 2010 comparative results included in this MD&A have been adjusted to conform to IFRS. The adoption of IFRS has not had a material impact on the Company's operations, strategic decisions, or overall cash flows.

The impact of the transition to IFRS is disclosed in note 18 of the condensed interim financial statements of the Company for the three months ended March 31, 2011. Note 18 to the condensed interim financial statements for the three and nine months ended September 30, 2011 provides reconciliations between the Company's 2010 CGAAP results and its 2010 IFRS results.

## **NEW ACCOUNTING STANDARDS**

The following new standards may be applicable to the Company and will become effective for future periods. The Company has not yet adopted any of the 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.

IFRS 10, "Consolidated Financial Statements", will replace portions of IAS 27 "Consolidation and Separate Financial Statements" and interpretation SIC-12 "Consolidation – Special Purpose Entities." The key features of IFRS 10 include consolidation using single control model, definition of control, considerations on power and continuous reassessment. IFRS 10 is effective for annual periods beginning on or after January 1, 2013.

IFRS 11, “Joint Arrangements” will replace IAS 31, “Interest in Joint Ventures”. The new standard redefines joint operations and joint ventures. Joint operations are required to be proportionately consolidated and joint ventures to be equity accounted. Under IAS 31, joint ventures could be proportionately accounted. IFRS 11 is effective for annual periods beginning on or after January 1, 2013.

IFRS 12, “Disclosure of Interests in Other Entities”, outlines the required disclosures for interests in subsidiaries and joint arrangements. The new disclosure provides information for users to evaluate the nature, risks and financial effects associated with an entity’s interests in subsidiaries and joint arrangements. IFRS 12 is effective for annual periods beginning on or after January 1, 2013.

IFRS 13, “Fair Value Measurement”, establishes a common definition of fair value and a framework for measuring fair value under IFRS. The standard also enhances the disclosures required for fair value measurements. IFRS 13 applies when other IFRSs require or permit fair value measurements. IFRS 13 is effective for annual periods beginning on or after January 1, 2013.

## **ADDITIONAL INFORMATION**

Additional information relating to the Company including the Company’s AIF is filed on SEDAR at [www.sedar.com](http://www.sedar.com) or on the Company’s website at [www.trafinaenergy.com](http://www.trafinaenergy.com). Information can also be obtained by contacting the Company at Trafina Energy Ltd., 2210, 530-8<sup>th</sup> Avenue S.W., Calgary, Alberta T2P 3S8.