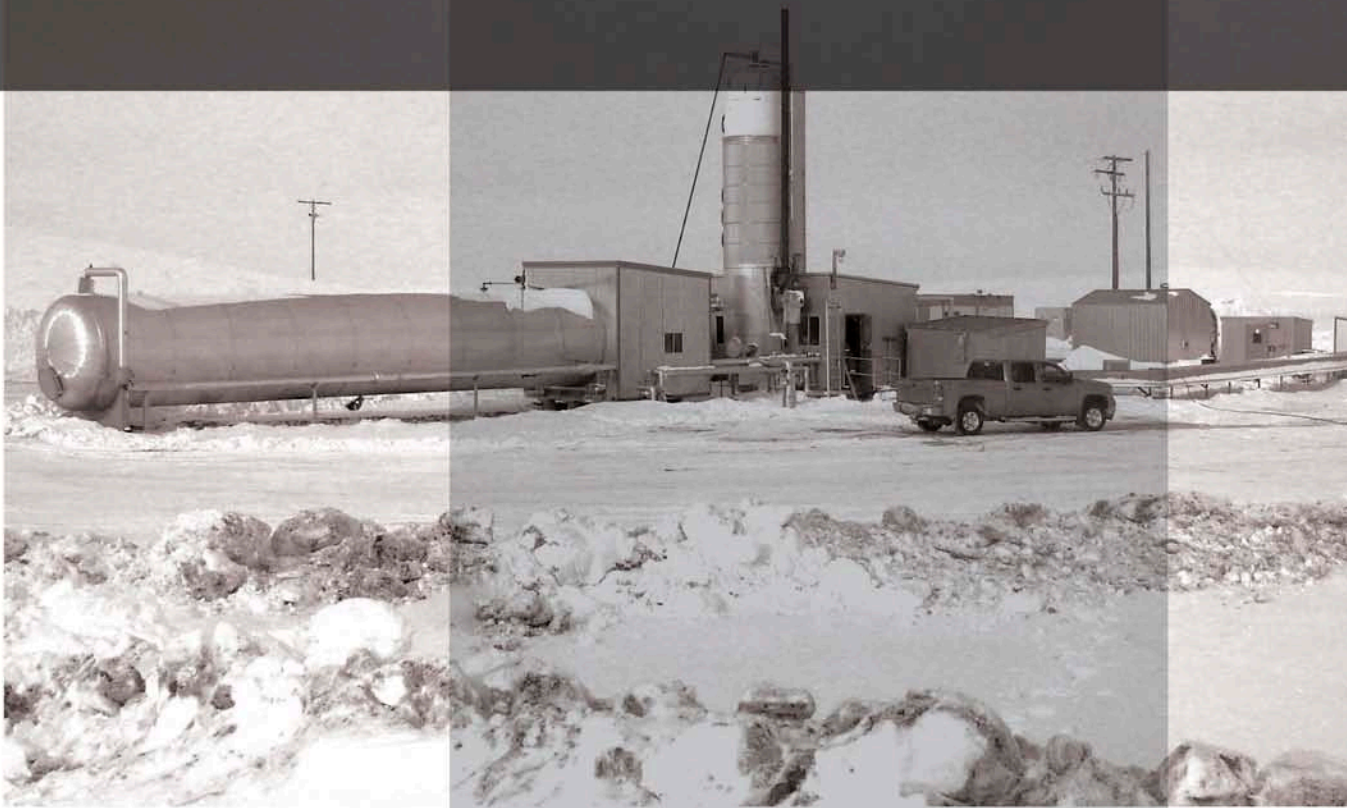


TRAFINA
ENERGY LTD.



**Q3 2010 MANAGEMENT'S
DISCUSSION & ANALYSIS**

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") is a review of the Trafina Energy Ltd. (the "Company" or "Trafina") financial results for the three and nine months ended September 30, 2010 and should be read in conjunction with the interim financial statements and accompanying notes for the three and nine months ended September 30, 2010 and the Company's audited financial statements and MD&A for the year ended December 31, 2009. The discussion provided herein is incremental to the MD&A in respect of the audited financial statements for the year ended December 31, 2009. This MD&A is dated November 17, 2010.

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 equivalency 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 based 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. 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 and access to capital, changes to the Company's lending line of credit and including the ability to raise funds by issuing equity or disposing of assets. Operations 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 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 annual information form for the year ended December 31, 2009 dated April 28, 2010 (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 and in the AIF should not be construed as exhaustive and readers are cautioned not to place undue reliance on these forward-looking statements. Except as required by applicable securities laws, the Company has no obligation to update or revise this forward-looking information.

NON-GAAP MEASURES

The MD&A uses the term "funds flow from (used in) operations", which is not defined under Canadian Generally Accepted Accounting Principles ("GAAP") and should not be considered an alternative to, or more meaningful than, cash flow from (used in) operating activities as determined in accordance with GAAP as an indicator of the Company's performance. Trafina's determination of funds flow from (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 from (used in) operations is a useful supplemental measure as it demonstrates Trafina's ability to generate cash necessary to repay debt or fund future growth through capital investment before changes in non-cash working capital balances. 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 GAAP as an indication of Trafina's performance.

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2010	2009	2010	2009
Cash flow used in operating activities	\$ (394,186)	\$ (444,904)	\$ (1,424,578)	\$ (587,914)
Change in non-cash operating items	375,606	416,332	989,949	695,434
Funds flow from (used in) operations	\$ (18,580)	\$ (28,572)	\$ (434,629)	\$ 107,520

The Company also considers field netback a key performance measure. However, field netback is not defined under 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, a liability settlement, unrealized and realized gains and losses on commodity contracts and other income less royalties and operating expenses. A reconciliation of field netback (non-GAAP) to net loss (GAAP) 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 commodity contracts.

OVERVIEW

- Disposed of various non-core area assets for net proceeds of \$2.6 million.
- Maintained production levels above 400 boepd despite disposing of 30 boepd of producing assets and having 48 boepd of production shut-in for the month of September, 2010 due to a third party transmission line failure.
- Increase oil production in the nine months ended September 30, 2010 by 113 percent over the same period in 2009.
- Reduced operating expenses from \$30.03/boe in the three months ended March 31, 2010 to \$25.95/boe in the nine months ended September 30, 2010.
- Drilled a non-operated Cardium well in Pembina, Alberta in July 2010. After numerous weather-related delays, Trafina announced completion of the well on November 16, 2010 with production expected to come on stream in December. The Company expects to drill up to three follow-up wells in 2011.
- Completed a non-brokered private placement on November 5, 2010 for gross proceeds of \$1.5 million by issuing 3,750,000 shares of the Company at \$0.40 on a flow-through basis (see *Subsequent Events*).
- Received board approval to raise an additional \$1.9 million by issuing units at a price of \$0.30 per unit (see *Subsequent Events*).
- Agreed to purchase strategic lands in north-eastern Alberta, providing access to approximately 37.5 gross sections (28.25 net) of undeveloped land with oil production potential (see *Subsequent Events*).

The first order of business for Trafina in 2010 was to reduce debt levels while maintaining production levels. This was accomplished by disposing of certain non-core assets and bringing on new production from the newly acquired southwest Saskatchewan assets. The second order of business was to take advantage of stabilizing oil prices by transforming from a heavily weighted natural gas producer to a more evenly weighted oil and gas producer, all the while being mindful of rising operating costs. This was achieved by increasing oil production by 113 percent in the nine months ended September 30, 2010, when compared to the same period in 2009 and reducing operating costs to a more moderate \$23.88/boe in the three months ended September 30, 2010. The Company expects its oil production to increase as it awaits the tie-in of its recently completed Cardium well in west Pembina, and prepares to drill a Shaunavon horizontal well in southwest Saskatchewan in late November 2010. The third order of business was to raise sufficient capital to pay for the drilling of the Shaunavon horizontal well and prepare for the possibility of drilling three additional wells at Pembina. To this end, Trafina has succeeded in raising \$1.5 million of flow-through funds and is anticipating raising an additional \$1.9 million by the end of November 2010 (see *Subsequent Events*). Trafina's management believes it is now positioned to take advantage of stronger oil prices by optimizing its current oil producing assets, drilling potentially high impact oil wells and continually evaluating oil based properties, all while managing debt levels.

SELECTED FINANCIAL INFORMATION

	For the three months ended September 30		
	2010	2009	% Change
Total gross petroleum and gas revenue (\$)	1,110,876	803,263	+38
Royalties (\$)	117,960	77,824	+52
Operating, processing, and transportation expenses (\$)	810,167	508,587	+59
Funds flow used in operations ⁽¹⁾ (\$)	18,580	28,572	-35
per basic and diluted common share (\$)	---	---	
Weighted average basic shares outstanding	18,627,262	11,304,641	+65
Loss before income taxes (\$)	(1,048,156)	(999,031)	+5
Net loss(\$)	(789,592)	(763,808)	+3
per basic and diluted common share (\$)	(0.04)	(0.07)	
Net capital expenditures (\$)	1,509,568	309,572	+388
Total assets (\$)	17,911,836	17,050,557	+5
Net debt and working capital deficiency ⁽²⁾ (\$)	(5,195,863)	(3,444,260)	+51

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

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

	For the nine months ended September 30		
	2010	2009	% Change
Total gross petroleum and gas revenue (\$)	3,881,182	2,896,994	+34
Liability settlement gain (\$)	---	533,716	
Royalties (\$)	452,934	319,576	+42
Operating, processing, and transportation expenses (\$)	2,844,502	1,611,341	+77
Funds flow from (used in) operations ⁽¹⁾ (\$)	(434,629)	107,520	
per basic common share (\$)	(0.02)	0.01	
Weighted average basic shares outstanding	18,449,943	11,289,340	+63
Loss before income taxes (\$)	(3,464,536)	(2,336,682)	+48
Net loss (\$)	(2,629,640)	(1,788,600)	+47
per basic and diluted common share (\$)	(0.14)	(0.16)	
Net capital expenditures (\$)	963,663	870,744	+11
Total assets (\$)	17,911,836	17,050,557	+5
Net debt and working capital deficiency ⁽²⁾ (\$)	(5,195,863)	(3,444,260)	+51

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

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

PRODUCTION

	Three Months Ended September 30			Nine Months Ended September 30		
	2010	2009	Change	2010	2009	Change
Natural gas	1,635 mcf/day	2,102 mcf/day	(22) %	1,823 mcf/day	2,166 mcf/day	(16) %
Oil and natural gas liquids	96 bbls/day	42 bbls/day	129 %	98 bbls/day	46 bbls/day	113 %
Total production	369 boe/day	392 boe/day	(6) %	402 boe/day	407 boe/day	(1) %

During the nine months ended September 30, 2010, the Company initiated a process to transform itself from a heavily weighted natural gas producer to a more evenly weighted oil and gas producer. The first step was to dispose of various non-core gas weighted properties in favor of developing its oil play in southwest Saskatchewan. This transformation can be seen in the production results in the nine months ended September 30, 2010. Natural gas production dropped by 16 percent or approximately 60 boepd, mainly due to asset dispositions; however, the lost production was replaced by an increase in oil production of approximately 52 bbls/day. In the three months ended September 30, 2010 production dropped slightly due to a third party transmission line failure. The line has since been repaired and production re-commenced on October 28, 2010. In the third quarter of 2010, 5 (2.5 net) wells were placed on production as a result of the Company completing an emulsion and water disposal project.

BENCHMARK PRICES

	Three Months Ended September 30		Nine Months Ended September 30	
	2010	2009	2010	2009
AECO daily spot price	\$ 3.55/mcf	\$2.98/mcf	\$ 4.13/mcf	\$3.79/mcf
West Texas Intermediate (WTI)	US\$76.06/bbl	US\$68.19/bbl	US\$77.54/bbl	US\$56.85/bbl
Edmonton Par	\$74.45/bbl	\$71.70/bbl	\$76.73/bbl	\$62.68/bbl
US/CDN \$ average exchange rate	0.96	0.91	0.97	0.86

After a sharp down-turn in natural gas prices in the three months ended September 30, 2009 due to lower cooling demand as a result of moderate North American temperatures, prices rebounded somewhat in the three months ended September 30, 2010. However, they still remained low as slow recovery projections and continued high natural gas storage levels restricted potential price increases. Oil prices in the three and nine months ended September 30, 2010 recovered slightly from the same period in 2009 as demand exceeded supply.

COMPANY REALIZED PRICES

	Three Months Ended September 30		Nine Months Ended September 30	
	2010	2009	2010	2009
Natural gas	\$ 3.55/mcf	\$ 2.96/mcf	\$ 4.14/mcf	\$ 3.81/mcf
Oil and natural gas liquids	\$ 65.06/bbl	\$ 59.46/bbl	\$ 68.21/bbl	\$ 51.80/bbl
Total	\$ 32.74/boe	\$ 22.24/boe	\$ 35.40/boe	\$ 26.11/boe

The commodity prices realized in the three and nine months ended September 30, 2010 followed the benchmark prices trend, with natural gas and oil and natural gas liquids prices increasing slightly over the same periods in 2009.

PETROLEUM AND NATURAL GAS REVENUE

	Three Months Ended September 30		Nine Months Ended September 30	
	2010	2009	2010	2009
Natural gas	\$ 534,134	\$ 572,501	\$ 2,060,236	\$ 2,253,405
Oil and natural gas liquids	576,742	230,762	1,820,946	643,589
Total petroleum and natural gas revenue	\$ 1,110,876	\$ 803,263	\$ 3,881,182	\$ 2,896,994

Natural gas revenue for the three months ended September 30, 2010 was lower than in the same period in 2009. Lower production due to the Company disposing of natural gas producing assets and a shut down gas transmission line in 2010, was partially offset by higher natural gas prices in the three months ended September 30, 2010. Oil and natural gas liquids revenues in the same period in 2010 were higher than the three months ended September 30, 2009 as a result of an increase in oil production and a slightly higher oil price. A similar situation occurred in the nine months ended September 30, 2010 and 2009 with lower natural gas revenue in 2010, compared to 2009 due to natural gas property dispositions and higher oil and liquids revenues. Higher oil and liquids revenues were a result of increased oil production and increased realized oil prices.

REALIZED GAIN ON COMMODITY CONTRACTS

	Three Months Ended September 30		Nine Months Ended September 30	
	2010	2009	2010	2009
Realized gain on commodity contracts	\$ 163,574	\$ ---	\$ 250,926	\$ ---

A realized gain was recorded in the three and nine months ended September 30, 2010 as a result of the Company entering into favourable gas hedging contracts.

UNREALIZED GAIN (LOSS) ON COMMODITY CONTRACTS

	Three Months Ended September 30		Nine Months Ended September 30	
	2010	2009	2010	2009
Unrealized gain (loss) on commodity contracts	\$ (87,000)	\$ ---	\$ 66,000	\$ ---

In order to smooth out volatile commodity price fluctuations, management entered into two natural gas swap sales, agreeing to sell 500 gigajoules ("GJ") per day at \$5.15 per GJ and an additional 250 GJ per day at \$5.30 per GJ. For the nine months ended September 30, 2010, the Company recorded an unrealized gain of \$66,000 based on future natural gas price projections at September 30, 2010 compared to the Company's contracted rates. For the three months ended September 30, 2010 the Company recorded an unrealized loss of \$87,000 as a result of a decrease in the fair value estimate of the commodity contracts from the fair value estimate as at June 30, 2010.

LIABILITY SETTLEMENT REVENUE

	Three Months Ended September 30		Nine Months Ended September 30	
	2010	2009	2010	2009
Liability settlement	\$ ---	\$ ---	\$ ---	\$ 533,716

On July 29, 2009, the Company signed an agreement with an industry partner to settle an amount owed to the industry partner. This debt was as a result of an over-allocation of revenue in prior periods. The Company had provided for this obligation in its financial statements. As a result of the settlement, the Company reduced its working capital deficit by approximately \$533,000 and recorded an increase in revenue.

OTHER REVENUE

	Three Months Ended September 30		Nine Months Ended September 30	
	2010	2009	2010	2009
Other revenue	\$ 32,820	\$ 50,044	\$ 46,957	\$ 60,428

Other revenue relates to miscellaneous processing and water disposal income from the Company's Kinsella area, which was acquired September 2009.

ROYALTIES

	Three Months Ended September 30				Nine Months Ended September 30			
	2010	Royalty as % of petroleum and natural gas revenue	2009	Royalty as % of petroleum and natural gas revenue	2010	Royalty as % of petroleum and natural gas revenue	2009	Royalty as % of petroleum and natural gas revenue
Total royalties	\$117,960	11%	77,824	10%	\$452,934	12%	\$319,576	11%

Royalty payments as a percentage of petroleum and natural gas revenue were slightly higher in the three and nine months ended September 30, 2010 compared to the same period in 2009. The higher percentage was primarily a result of a Saskatchewan surcharge fee in 2010.

OPERATING EXPENSES

	Three Months Ended September 30				Nine Months Ended September 30			
	2010	\$/boe	2009	\$/boe	2010	\$/boe	2009	\$/boe
Operating expenses	\$810,167	\$23.88	\$508,587	\$14.08	\$2,844,502	\$25.95	\$1,611,341	\$14.52

Operating expenses, including processing and transportation costs, for the three months ended September 30, 2010 were \$810,167 (\$23.88/boe), an increase over the same period in 2009. The increase is attributable to higher operating costs associated with oil production, as oil weighted assets require higher energy costs to extract and separate emulsion. In the nine months ended September 30, 2010, the Company incurred extensive start-up expenses (including numerous one-time charges which were not capitalized) at its newly acquired southwest Saskatchewan properties. Battery site repairs, miscellaneous parts replacements, lease repairs and clean-ups also contributed to an increase in operating expenses. As more wells are placed on production and one-time charges diminish, the Company expects its operating costs on a dollar per boe basis to decrease. In the three and nine months ended September 30, 2009 the Company's production was primarily from stable, low cost, coal bed methane gas (CBM) in the Company's Wetaskiwin area.

FIELD NETBACK ⁽¹⁾

	Three Months Ended September 30				Nine Months Ended September 30			
	2010	\$/boe	2009	\$/boe	2010	\$/boe	2009	\$/boe
Petroleum and natural gas revenue	\$1,110,876	\$32.74	\$803,263	\$22.24	\$3,881,182	\$35.40	\$2,896,994	\$26.11
Realized gain on commodity contract	163,574	4.82	---	---	250,926	2.29	---	---
Unrealized gain (loss) on commodity contract	(87,000)	2.56	---	---	66,000	0.60	---	---
Liability settlement gain	---	---	---	---	---	---	533,716	4.81
Other revenue	32,820	0.97	50,044	1.39	46,957	0.43	60,428	0.54
Royalty	(117,960)	3.48	(77,824)	2.16	(452,934)	4.13	(319,576)	2.88
Operating expenses	(810,167)	23.88	(508,587)	14.08	(2,844,502)	25.95	(1,611,341)	14.52
Field netback ⁽¹⁾	\$292,143	\$8.61	\$266,896	\$7.39	\$947,629	\$8.64	\$1,560,221	\$14.06
Sales volumes (boe)	33,933		36,111		109,629		110,958	

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

When comparing the three months ended September 30, 2010 with the same period in 2009, higher revenues as a result of higher commodity prices and a net gain on the Company's commodity contracts were partially offset by higher royalty and operating expenses, resulted in a slightly higher field netback. However, field netback for the nine months ended September 30, 2010 was lower than field netback for the nine months ended September 30, 2009. When compared to 2009, higher revenue and a net gain in commodity contracts in 2010 were offset by higher royalties and operating expenses. Also no liability settlement was recorded in the nine months ended September 30, 2010.

GENERAL AND ADMINISTRATIVE ("G&A") EXPENSE

	Three Months Ended September 30		Nine Months Ended September 30	
	2010	2009	2010	2009
G&A	\$ 359,122	\$ 257,667	\$ 1,211,056	\$ 916,978
G&A per boe	\$ 10.58	\$ 7.14	\$ 11.05	\$ 8.26

General and administrative expenses for the three months ended September 30, 2010 were 40 percent higher than for the same period in 2009. Increased G&A expenses are mainly attributable to costs relating to salaries, consulting fees, legal fees and fees relating to acquisition evaluations. General and administrative expenses also increased by \$294,078 in the nine months ended September 30, 2010 compared to the nine months ended September 30, 2009. The increase is mainly attributable to an increase in third party engineering services, and consulting and legal fees resulting from the Company's active asset acquisition and divestiture program.

DEPLETION, DEPRECIATION, AND ACCRETION

For the three and nine months ended September 30, 2010, depletion, depreciation and accretion expense was \$895,291 (\$26.38/boe) and \$2,935,495 (\$26.78/boe), respectively. For the three and nine months ended September 30, 2009, depletion, depreciation and accretion expense was \$923,485 (\$25.57/boe) and \$2,809,082 (\$25.32/boe), respectively. The Company's depletion calculation uses the unit-of-production method in its computation.

STOCK BASED COMPENSATION EXPENSE

Stock based compensation expense totaled \$160,412 for the nine months ended September 30, 2010, compared to \$102,369 for the nine months ended September 30, 2009. The increase in stock based compensation expense relates to 730,000 stock options granted since September, 2009. Stock based compensation expense totaled \$47,285 for the three months ended September 30, 2010, compared to \$46,974 for the three months ended September 30, 2009. At September 30, 2010 1,790,000 stock options were outstanding.

INTEREST EXPENSE

Interest expense for the three and nine months ended September 30, 2010 was \$38,601 and \$105,202, respectively, and interest expense for the three and nine months ended September 30, 2009 was \$37,801 and \$68,474, respectively. Higher interest charges in 2010 when compared to 2009 are a result of an increase in debt leverage in 2010 and interest charges relating to the Company's liability settlement, and accrued interest charges due to the Canada Revenue Agency for outstanding flow-through share obligations after February 2010. At September 30, 2010 the Company had fulfilled all remaining flow-through share spending obligations of \$740,000.

INCOME TAXES

For the three months ended September 30, 2010, the Company recorded a future income tax reduction of \$258,564. For the nine months ended September 30, 2010, the Company recorded a future income tax reduction of \$834,896. For the three and nine months ended September 30, 2009, the Company recorded a future income tax reduction of \$235,223 and \$417,808, respectively. Trafina's tax horizon depends on factors such as production, commodity prices, the tax classification of wells drilled as well as the diversified nature of other capital expenditures incurred throughout the year.

NET LOSS

	Three Months Ended September 30		Nine Months Ended September 30	
	2010	2009	2010	2009
Net loss	\$ 789,592	\$ 763,808	\$ 2,629,640	\$ 1,788,600

The Company recorded net losses in the three months ended September 30, 2010 and September 30, 2009. Petroleum and natural gas revenues were more than offset by high depletion, depreciation and accretion expenses and high operating costs.

Net loss increased three percent in the three months ended September 30, 2010, when compared to the same period in 2009. The primary reasons for the increase were higher royalty, operating and G&A costs. Net losses were also recorded in the nine months ended September 30, 2010 and September 30, 2009 as a result of revenues being offset by high depletion, depreciation and accretion expense and higher operating costs. Net loss increased 47 percent in the nine months ended September 30, 2010, when compared to the same period in 2009. Higher overall expenses and no impact of a liability settlement, offset by a net gain from commodity contracts and a higher future tax reduction were the main reasons for a higher net loss in 2010. 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 FROM (USED IN) OPERATIONS

	Three Months Ended September 30		Nine Months Ended September 30	
	2010	2009	2010	2009
Net loss	\$ (789,592)	\$ (763,808)	\$ (2,629,640)	\$ (1,788,600)
Add back items not involving cash:				
Depletion, depreciation and accretion	895,291	923,485	2,935,495	2,809,082
Future income tax reduction	(258,564)	(235,223)	(834,896)	(417,808)
Stock-based compensation	47,285	46,974	160,412	102,369
Unrealized (gain) loss on commodity contract	87,000	---	(66,000)	---
Liability settlement	---	---	---	(533,716)
Abandonments	---	---	---	(63,807)
Funds flow from (used in) operations ⁽¹⁾	\$ (18,580)	\$ (28,572)	\$ (434,629)	\$ 107,520
Funds flow from (used in) operations per share –basic ⁽¹⁾	\$ ---	\$ ---	\$ (0.02)	\$ 0.01

(1) See “NON-GAAP MEASURES” in this MD&A.

For the three months ended September 30, 2010 and September 30, 2009 the Company used funds of \$18,580 and \$28,572, respectively, in its operations as a result of low revenue and high operating expenses. In the nine months ended September 30, 2010 the Company used funds in operations of \$434,629, mainly as a result of low revenues and high operating costs primarily associated with start-up costs in southwest Saskatchewan. For the nine months ended September 30, 2009 funds flow from operations was \$107,520. Funds were generated mainly due to lower operating and G&A costs.

NETBACK ANALYSIS

The following table reconciles field netback (non-GAAP) to funds flow from (used in) operations (non-GAAP) to net loss (GAAP) for the three and nine months ended September 30, 2010 and September 30, 2009:

	Three Months Ended September 30		Nine Months Ended September 30	
	2010	2009	2010	2009
Petroleum and natural gas revenue	\$ 1,110,876	\$ 803,263	\$ 3,881,182	\$ 2,896,994
Realized gain on commodity contract	163,574	---	250,926	---
Unrealized gain (loss) on commodity contract	(87,000)	---	66,000	---
Liability settlement revenue	---	---	---	533,716
Other revenue	32,820	50,044	46,957	60,428
Royalties	(117,960)	(77,824)	(452,934)	(319,576)
Operating expenses	(810,167)	(508,587)	(2,844,502)	(1,611,341)
Field netback ⁽¹⁾	292,143	266,896	947,629	1,560,221
General and administrative	(359,122)	(257,667)	(1,211,056)	(916,978)
Interest	(38,601)	(37,801)	(105,202)	(68,474)

Current tax	---	---	---	130,274
Unrealized (gain) loss on commodity contract	87,000	---	(66,000)	---
Abandonments	---	---	---	(63,807)
Liability settlement revenue	---	---	---	(533,716)
Funds flow from (used-in) operations ⁽¹⁾	(18,580)	(28,572)	(434,629)	107,520
Depletion, depreciation and accretion	(895,291)	(923,485)	(2,935,495)	(2,809,082)
Future income tax reduction	258,564	235,223	834,896	417,808
Stock-based compensation	(47,285)	(46,974)	(160,412)	(102,369)
Unrealized gain (loss) on commodity contract	(87,000)	---	66,000	---
Abandonments	---	---	---	63,807
Liability settlement revenue	---	---	---	533,716
Net loss	\$ (789,592)	\$ (763,808)	\$ (2,629,640)	\$ (1,788,600)

(1) See NON-GAAP MEASURES.

LIQUIDITY AND CAPITAL RESOURCES

At September 30, 2010, the Company had net debt and working capital deficiency of \$5,195,863, which excludes the fair value of commodity contracts. At September 30, 2009 the Company had a net debt and working capital deficiency of \$3,444,260. The primary reason for the difference is that 2009 includes the liability settlement adjustment and lower operating and administrative costs.

In the nine months ended September 30, 2010, the Company's main focus was to prudently manage its debt levels. This was accomplished by disposing of non-core properties for net proceeds of \$2.6 million in the nine months ended September 30, 2010. A further reduction of the Company's debt level will be achieved by issuing common equity (see *Subsequent Events*).

Funds acquired from non-core property dispositions and issuances of securities will enable the Company to focus on further development activities in its core areas of Rangeview/Divide in southwest Saskatchewan and Ronalane and Pembina in Alberta. The Company is also continually evaluating under-valued oil and gas assets and/or corporate asset acquisitions in an attempt to increase its asset base. It is anticipated that in order to meet all of these objectives additional funds will be required.

BANK DEBT

At September 30, 2010 the Company had credit facilities consisting of a \$4,500,000 revolving operating demand facility, with interest charged on advances under the facility at the bank's prime rate plus 1.50 percent and a \$1,250,000 acquisition and development demand facility, with interest charged on advances at the bank's prime rate plus 2.00 percent. The facilities are secured by a \$50,000,000 fixed and floating charge debenture on all assets. The revolving operating demand facility requires maintenance of a 1:1 working capital ratio covenant.

At September 30, 2010, the Company had drawn a total of \$3,813,553 on its available facilities with \$2,743,553 drawn on its revolving operating demand credit facility and \$1,070,000 drawn on its acquisition and development facility. Principal repayments relating to the acquisition and demand facility amount to \$30,000 per month and commenced September 1, 2010. Repayments will increase to \$55,000 per month starting January 1, 2011. At September 30, 2010, the Company was in compliance with its working capital covenant.

Subsequent to quarter end, the bank completed a scheduled review of the Company's assets and revised the revolving operating demand facility lending value to \$4,000,000 million. The Company's acquisition and development demand facility lending value remained at \$1,250,000. The next review date is scheduled for January 2011.

EQUITY

Changes to equity of the Company for the nine months ended September 30, 2010 were as follows:

Property purchase

As part of the consideration for acquiring certain assets in February 2010, the Company issued 324,000 special warrants convertible into Class A common shares of the Company. The release of these special warrants was subject to the Company obtaining approval of the transfer of certain well licenses by the Alberta Energy Resources Conservation Board ("ERCB"). In May 2010 the Company received the necessary ERCB approvals and converted the special warrants to 324,000 Class A common shares.

Stock Options

The Company has an employee stock option plan under which employees, consultants and directors are eligible to receive options to purchase Class A 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 January 21, 2010, the Board of Directors of Trafina approved the issuance of 170,000 stock options to employees and consultants of the Company with an exercise price of \$0.46 per common share. Also in January, a director of the Company exercised 30,000 stock options at a price of \$0.30 per share and was issued 30,000 Class A common shares for gross proceeds of \$9,000. At September 30, 2010, stock options to purchase 1.79 million Class A common shares were outstanding, with an average exercise price of \$0.37 per common share.

Flow-through Shares

In February 2010, the Company renounced \$0.74 million of flow-through obligations as a result of the issuance of 1.9 million Class A common shares issued on a flow-through basis in December 2009, pursuant to the *Income Tax Act* (Canada). As a result, a future income tax liability and corresponding reduction of share capital of \$190,277 was recorded in the six months ended June 30, 2010. At September 30, 2010 the Company had fulfilled its flow-through spending obligation.

Outstanding share 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. At November 17, 2010, 22,527,262 Class A common shares were issued and outstanding (see *Subsequent Events*). There are nil Class B common shares and nil preferred shares outstanding.

CAPITAL EXPENDITURES

The following table summarizes capital expenditures for the three and nine months ended September 30, 2010 and September 30, 2009.

	Three months ended September 30		Nine months ended September 30	
	2010	2009	2010	2009
Property dispositions	\$ (23,671)	\$ ---	\$ (2,605,215)	\$ ---
Property acquisitions	21,081	104,893	602,564	116,997
Drilling, completions and recompletions	595,385	16,726	1,378,201	274,207
Equipping and facilities	867,508	149,042	1,434,678	667,733
Non-operated joint interest partner 2008 accrual adjustment	---	---	---	(246,469)
Other	49,265	16,800	153,436	36,165
Total capital expenditures, net	\$ 1,509,568	\$ 309,572	\$ 963,663	\$ 870,744

During the three months ended September 30, 2010, the majority of capital expenditures were associated with drilling a much anticipated Pembina Cardium well and a pipeline tie-in project at Ronalane. The Company also disposed of non-core area assets for \$23,671 and incurred additional costs associated with its southwest Saskatchewan properties of \$23,671. 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. Assets acquired consisted of a central Alberta property which was paid for using cash and the issuance of Class A common shares of the Company. Total consideration for the property was approximately \$265,000. Additional acquisition costs were associated with the acquisition of assets in Saskatchewan from a private oil and gas corporation that were exchanged for amounts owing to the Company on January 15, 2010. Costs incurred in the first nine months of the year to realize on the acquisition were 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 the pipeline construction project in southern Alberta. In the nine months ended September 30, 2009, the Company also incurred expenditures to complete and equip wells in its Wetaskiwin area, in addition to acquiring a 50 percent interest in certain assets in Alberta.

CONTRACTUAL OBLIGATIONS

At September 30, 2010, the Company had the following contractual obligations:

Financial sales contracts

The following contracts were in place at September 30, 2010:

Type	Daily Volume	Duration	Price
Fixed- Gas	500 GJ/day	October 1, 2010 to October 31, 2010	\$5.15/GJ
Fixed - Gas	250 GJ/day	October 1, 2010 to October 31, 2010	\$5.30/GJ

On November 1, 2010, the Company entered into the following financial sales contracts:

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

Flow-through

As a result of completing a private placement financing on November 5, 2010 (*see Subsequent Events*), the Company is required to incur \$1.5 million on eligible flow-through expenditures to be incurred by December 31, 2011. The qualified expenditures will be funded by cash flow from operating activities, bank debt and funds raised as a result of issuing equity.

Office rent

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

2010	\$ 31,000
2011	\$134,000
2012-2014	\$416,000

The Company expects to fulfill these obligations from funds flow and bank debt.

OFF BALANCE SHEET TRANSACTIONS

There were no off balance sheet transactions entered into during the period, and none are outstanding as of November 18, 2010.

TRANSACTIONS WITH RELATED PARTIES

A law firm of which the Company's corporate secretary is a partner provides general and corporate legal services to the Company. For the nine months ended September 30, 2010, fees for legal services billed from this related party were approximately \$157,000 (December 31, 2009, \$108,000), of which \$22,000 is included in accounts payable and accrued liabilities at September 30, 2010 (December 31, 2009, \$24,000). These services are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

SUBSEQUENT EVENTS

Management team:

On October 1, 2010 the Company announced that its board of directors had approved the appointment of Mr. Edward Marcinew as Vice President, Exploration. Mr. Marcinew has 27 years of experience in the oil and gas industry and has been serving the Company as a geological consultant. In connection with his appointment, Mr. Marcinew was granted options to acquire 70,000 Class A common shares at a price of \$0.33 per share. These options have an expiry date of October 1, 2015 and are subject to the provisions of the Company's stock option plan. On November 5, 2010 Mr. Marcinew purchased 150,000 shares of the Company's common shares at a price of \$0.30 per share on a private placement basis for gross proceeds of \$45,000.

Capital financings:

On November 5, 2010 the Company completed a non-brokered private placement of Class A common shares issued on a flow-through basis resulting in gross proceeds of \$1.5 million. At closing, the Company issued 3,750,000 flow-through shares at a price of \$0.40 per share. Directors and senior officers of the Company directly and indirectly purchased an aggregate of 550,000 flow-through shares pursuant to the private placement. The Company paid a finder's fee of \$24,000 to an arm's-length party in the connection with the subscriptions of certain subscribers who participated in the private placement. Gross proceeds from the sale will be used to incur eligible exploration expenditures that will be renounced to subscribers as Canadian exploration expenses effective on or before December 31, 2010.

In addition, on November 5, 2010 the board of directors of the Company approved a non-brokered private placement of up to \$1,900,200 of units at a price of \$0.30 per unit, with each unit consisting of one Class A common share and one Class A common share purchase warrant ("Warrant"). No new control persons will be created as a result of this private placement. Each Warrant will entitle the holder thereof to acquire one Common Share at a price of \$0.45 per share on or before the date that is the second anniversary of the Closing Date (the "Expiry Date"). If at any time after the Closing Date and before the Expiry Date the 20 day volume weighted average trading price ("VWAP") of the Common Shares is greater than \$0.50 per share, the Corporation shall be entitled, upon 30 days prior written notice to all holders of the Warrants, to require all of the then outstanding Warrants to be exercised by a date to be specified by the Corporation (the "VWAP Conversion Date"). All Warrants that remain unexercised following the VWAP Conversion Date shall immediately expire and all rights of holders of such Warrants terminated without any compensation to any such holder. The VWAP is calculated by dividing the total value by the total volume of Common Shares traded for the relevant period. Closing of the private placement is expected to occur on or before November 30, 2010 and is subject to the approval of the TSX Venture Exchange.

Property purchase and participation agreement:

On November 17, 2010 the Company entered into a definitive agreement to purchase an undivided 100 percent working interest in approximately 37.5 gross sections (28.25 net) of undeveloped lands in north-eastern Alberta. In addition to the land purchase, the Company has entered into a participation agreement with the same third party to earn a 25 percent working interest in an additional 13 gross sections of land in the same area by drilling one well at a 100 percent working interest or two wells at a 50 percent working interest. Drilling of the well or wells are expected to commence in early 2011. Closing is anticipated to occur on or about November 30, 2010.

HISTORICAL QUARTERLY FINANCIAL INFORMATION

Outlined below is a table of historical quarterly financial information over the last eight quarters:

	2010			2009				2008
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Production (boepd)	369	413	424	389	392	403	423	420
Petroleum and natural gas revenue (\$)	1,110,876	1,275,671	1,515,528	1,225,710	803,263	913,483	1,180,249	1,651,810
Revenue (\$/boe)	32.74	33.99	39.21	34.25	62.69	24.91	31.19	42.75
G&A (\$)	359,122	398,980	452,954	421,242	257,667	279,805	379,506	386,265
Funds flow from (used in) operations (\$) ⁽¹⁾	(18,580)	(73,035)	(343,013)	9,501	(28,572)	60,826	75,266	423,868
Funds flow per basic and diluted common share	\$(0.00)	\$(0.00)	\$(0.02)	--	--	\$0.01	\$0.01	\$0.05
Net loss (\$)	(789,592)	(935,108)	(904,940)	(870,969)	(763,808)	(341,010)	(683,782)	(400,307)
Net loss per basic and diluted common share	\$(0.04)	\$(0.05)	\$(0.05)	\$(0.06)	\$(0.07)	\$(0.03)	\$(0.06)	\$(0.05)
Capital expenditures (\$)	1,509,568	(401,894)	(144,011)	2,484,314	309,572	333,882	227,289	1,228,271
Net debt and working capital deficiency (\$) ⁽¹⁾	(5,195,863)	(3,667,818)	(4,158,567)	(3,911,476)	(3,444,260)	(2,896,332)	(3,712,758)	(3,631,929)

(1) See NON-GAAP MEASURES.

Beginning in Q4 2008, the Company consistently generated funds flow from operations until Q3 2009 when the Company used funds flow, primarily as a result of low natural gas prices. In Q1 2010 the Company also 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 diminished dramatically and reduced funds flow used in operations to \$73,035. In Q3 2010 funds flow used was again reduced and positive funds flow would have occurred had a non-operated gas transmission line at Wetaskiwin not been down for the month of September (see *Production*). In the first quarter of 2009, the Company had a net loss of \$683,782 primarily as a result of lower commodity prices and higher depletion expense. 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 saw a net loss of \$904,940, primarily due to the aforementioned start-up operating expenses at southwest Saskatchewan. The Q2 2010 net loss was mainly due to lower commodity prices and higher expenses. In Q3 2010 a net loss of \$789,592 was recorded, primarily as a result of low revenues and a net gain on commodity contracts, offset by high depletion, depreciation and accretion, operating and G&A expenses.

FINANCIAL INSTRUMENTS

The Company has certain financial instruments, including accounts receivable, commodity contracts, accounts payable and accrued liabilities, liability settlement and bank debt, and is exposed to risks such as credit risk, liquidity risk and market risk. The Company manages its exposure to these risks by operating in a manner that minimizes its exposure to the extent practical.

The carrying amount of the Company's accounts receivable, accounts payable and accrued liabilities and liability settlement approximate their fair values due to short terms to maturity. Bank debts bear interest at a floating market rate and accordingly the fair value approximates the carrying value. The carrying value of the Company's liability settlement is calculated using an interest rate agreed upon between two non related parties dealing at arm's length, thus the carrying value approximates the fair value.

The Company adopted the amendments to CICA Handbook section 3862 – "Financial Instruments" for its financial assets and liabilities effective December 31, 2009. These amendments outline a hierarchy of methods used to determine the fair value of financial instruments at the balance sheet date. As at September 30, 2010, the only financial instrument that required disclosure of fair value according to the new three-level hierarchy was the commodity contracts (derivative financial instruments), which are recorded at fair value and are considered level 2. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the market place.

Credit Risk

Credit risk is generally related to the collection of the Company's accounts receivable from petroleum and natural gas purchasers and joint interest partners. At September 30, 2010, approximately 33 percent of the Company's accounts receivable trade balance was from various petroleum and natural gas purchasers and has subsequently been received. A further 21 percent of the Company's accounts receivables as at September 30, 2010 have been received to date. The remaining 46 percent of the account receivable trade balance is due from joint interest partners. At September 30, 2010, approximately \$300,000 (year end December 31, 2009 - \$217,500) of receivables were outstanding for more than 90 days.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they are due. The Company manages liquidity by ensuring, as far as possible, that it will have sufficient liquidity under both normal and stressed conditions. Trafina's management prepares a yearly budget, revised cash flow forecasts and monthly sales reconciliations. As noted earlier, in order to mitigate the Company's liquidity risk, Trafina disposed of certain non-core properties in the nine months ended September 30, 2010 and funds received were used to pay down debt.

The following are the contractual maturities of financial liabilities as at September 30, 2010:

Financial liability	Less than 1 year	1 to 2 years
Accounts payable and accrued liabilities	\$ 2,675,704	\$ ---
Liability settlement	277,778	---
Bank debts	3,813,553	---
Total	\$ 6,767,035	\$ ---

It is expected that the Company's bank facilities will be renewed and as a result payment of bank debt will not be required.

Market Risk

Market risk is the risk that changes in market prices, such as foreign exchange rates, commodity prices and interest rates will affect the Company's net earnings or the value of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing returns.

Foreign currency exchange rate risk

Foreign currency exchange rate risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in foreign exchange rates. Although all of the Company's petroleum and natural gas sales are denominated in Canadian dollars, the underlying market prices in Canada for petroleum and natural gas are impacted by changes in the exchange rate between the Canadian and United States dollar. The Company has no forward exchange rate contracts in place during the nine months ended September 30, 2010.

Commodity price risk

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for petroleum and natural gas are impacted not only by the relationship between the Canadian and United States dollar as outlined above, but also by world economic events that dictate the level of supply and demand. The Company attempts to mitigate commodity price risk through the use of financial derivatives sales contracts. In 2009 management entered into a financial swap sales contract to sell 500 gigajoules (“GJ”) per day of natural gas production at \$5.15 per GJ, which ended October 31, 2010. In 2010 management entered into an additional financial swap sales contract to sell an additional 250 GJ per day of natural gas production at \$5.30 per GJ commencing April 1, 2010 and ending October 31, 2010. At September 30, 2010 the Company recorded a commodity contracts asset of \$42,000 based on the fair value of the contracts at that time. An unrealized gain on commodity contracts of \$66,000 was recognized in the nine months ended September 30, 2010 and a realized gain of \$250,926 was recognized over the same period. For the three months ended September 30, 2010 the Company recorded an unrealized loss on commodity contracts of \$87,000 and a realized gain of \$163,574.

Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. At September 30, 2010, the Company had bank debt of \$3,813,553 and any future cash draws against this facility will further expose the Company to changes in interest rates on its bank debt which bears a floating rate of interest. The Company had no interest rate swap or financial contracts in place during the nine months ended September 30, 2010. A 1.0 percent change in the prime rate over the nine months ended September 30, 2010 would have impacted net loss by approximately \$15,100.

BUSINESS RISKS

Although economic conditions have improved slightly in 2010, Trafina expects to see an unsettled economy for the remainder of 2010 and as a result, faces many risks associated with its business. For a list of risk factors, see the Company’s AIF filed on SEDAR at www.sedar.com.

INTERNATIONAL FINANCIAL REPORTING STANDARDS (“IFRS”)

The CICA Accounting Standards Board adopted a strategic plan for the direction of accounting standards in Canada. As part of that plan, accounting standards in Canada for public companies are expected to converge with International Financial Reporting Standards for financial periods beginning on January 1, 2011. As a result of this transition for 2011, Trafina will also be expected to disclose comparative 2010 results. This will require Trafina to restate its 2010 results to conform to IFRS standards.

Since the release of the Company’s audited financial statements and MD&A for the year ended December 31, 2009, the company has completed a high level analysis of its financial records in order to determine the areas that will be materially impacted by the transition. The Company began its analysis by focusing on its balance sheet at December 31, 2009, in particular property and equipment, asset retirement obligations and contributed surplus.

IFRS-1 is a standard under IFRS that includes mandatory and optional exemptions that a Corporation may elect to help in its transition to IFRS. The elections are only available to Corporations that are transitioning to IFRS for the first time and is only applicable to the opening balance sheet of the Corporation. The Company is still assessing its election choices; however, the following are IFRS-1 exemptions that the Company anticipates to elect and anticipated changes to its opening balance sheet at January 1, 2010. The following choices and anticipated changes are not exhaustive and remain subject to further analysis and change.

Property and equipment (“P&E”):

The Company has elected to use the deemed cost full cost exemption under IFRS-1. This election enables the Company to use the balance sheet carrying amount of its P&E at December 31, 2009 prepared under Canadian GAAP. P&E amounts will then be allocated to various categories at a cash generating unit level based on the Company’s reserve volumes or reserve values. The Company anticipates that it will use reserve values to allocate certain P&E amounts. Currently the Company expects to have between seven and nine cash generating units. Once P&E assets are allocated the Company is required to perform an impairment test on each cash generating unit. The Company anticipates that certain cash generating units might be impaired.

Asset retirement obligations (“ARO”):

ARO under IFRS is referred to as Decommissioning Liabilities and is referenced under IAS-37 – “Provisions, Contingent Liabilities and Contingent Assets”. Under IFRS-1 the Company has elected to use an exemption that allows the Company to measure decommissioning liabilities as at the date of transition to IFRS in accordance with IAS-37 and recognize any transitional differences to Canadian GAAP in Retained Earnings. It is expected that changes to the ARO amount on the balance sheet will primarily be as a result of a change in the discount rate used in the calculation - under Canadian GAAP the Company uses a credit-adjusted risk free rate in its ARO calculation, while under IFRS the calculation only requires a risk free rate.

Contributed surplus (“share-based payments”):

The Company has chosen an election under IFRS-1, which allows the Company to apply IFRS-2 – “Share-based payments” to any unvested options outstanding as at December 31, 2009. At December 31, 2009 the Company has 983,000 unvested options outstanding. A major difference to Canadian GAAP includes the fact that each award is treated as a separate award under IFRS and uses a graded vesting method in the calculation instead of each award treated as a single award under Canadian GAAP and calculated using a straight-line method.

The Company is continually evaluating the impact on the change-over to IFRS reporting and remains in consultation with its auditors.

ADDITIONAL INFORMATION

Additional information relating to the Company, including the Company’s AIF, is filed on SEDAR at www.sedar.com and 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.