Terra Energy Corp.
Management's Discussion & Analysis
For the Three and Nine Months Ended September 30, 2011

This Management's Discussion and Analysis ("MD&A") of financial condition and results of operations of Terra Energy Corp. ("Terra Energy" or the "Corporation") is dated November 10, 2011. It should be read in conjunction with the unaudited condensed consolidated financial statements and the corresponding notes for the three and nine months ended September 30, 2011 and September 30, 2010 and with the audited year end consolidated financial statements of the Corporation for the years ended December 31, 2010 and December 31, 2009.

Terra Energy's Board of Directors and Audit Committee have reviewed and approved the September 30, 2011unaudited condensed consolidated financial statements and related MD&A.

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

Petroleum and natural gas volumes are converted to an equivalent measurement basis referred to as a "barrel of oil equivalent" ("boe") using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil ("6:1"). The 6:1 conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Readers are cautioned that boe figures may be misleading, particularly if used in isolation.

The continuous disclosure materials of the Corporation, including its annual MD&A and audited financial statements, Information Circular and Proxy Statement, Annual Information Form, material change reports and press releases issued by the Corporation are available through the SEDAR system at www.sedar.com.

CORPORATE HISTORY

Terra Energy is a publicly traded Corporation, amalgamated under the Business Corporations Act of Alberta, and formed as a result of the amalgamation of Terra Energy Corp., Terrapet Energy Corp., and Rhodes Resources Corp. on January 30, 2004. This MD&A along with the associated financial statements referenced above includes the accounts of the Corporation and its wholly-owned subsidiaries, including Constar Resources Ltd., and Terra Energy Partnership, a general partnership between Terra Energy Corp. and Constar Resources Ltd.

The Corporation's principal business is the exploration, development and production of petroleum and natural gas in Western Canada.

BASIS OF PRESENTATION

The condensed consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). The Corporation adopted IFRS effective January 1, 2011. Unless otherwise noted, 2010 comparative information has been prepared in accordance with IFRS. Previously, the Corporation prepared its interim and annual consolidated financial statements in accordance with Canadian generally accepted accounting principles ("GAAP"). The Corporation's significant accounting policies under IFRS are outlined in Note 2 of the condensed consolidated financial statements. Note 15 provides reconciliations of the effects of transition to IFRS from Canadian GAAP on reported financial position, financial performance and cash flows of the Corporation.

SELECTED QUARTERLY INFORMATION

($ in thousands, except per share amounts)	**2011 Q3**	2011 Q2	2011 Q1	2010 Q4[(1)]	2010 Q3[(1)]	2010 Q2[(1)]	2010 Q1[(1)]	2009 Q4[(1)]	2009 Q3[(1)]
Gross Revenue	**16,976**	18,751	18,342	18,752	17,580	19,280	24,245	20,998	13,584
Cash Flow from Operations	**6,115**	7,923	3,996	3,057	2,859	6,946	10,750	8,327	6,418
Net Income (Loss)	**(1,701)**	3,420	(1,474)	(2,255)	(1,712)	216	1,731	4,404	(2,347)
Per Share (Basic)	**(0.02)**	0.03	(0.01)	(0.03)	(0.02)	-	0.02	0.05	(0.03)
Per Share (Diluted)	**(0.02)**	0.03	(0.01)	(0.03)	(0.02)	-	0.02	0.05	(0.03)
Total Assets	**291,800**	288,895	293,043	294,042	292,957	251,092	241,572	222,481	240,140
Long-term Financing	**86,710**	89,504	86,206	85,074	84,472	58,118	37,703	54,390	81,451
Working Capital Surplus (Deficiency)	**(9,308)**	(6,312)	(12,365)	(14,235)	(12,880)	(3,520)	(15,182)	(2,601)	731
Operating:									
Average Daily Production (boe/d)	**6,053**	5,993	6,456	7,073	6,581	6,531	7,187	6,361	6,117
Average Revenue Prices									
Crude Oil (bbl)	**84.42**	95.82	81.98	76.34	70.92	72.38	72.72	69.58	65.90
Natural Gas Liquids (bbl)	**58.47**	62.95	59.90	43.81	40.11	47.11	46.21	43.14	25.77
Natural Gas (Mcf)	**3.72**	3.99	3.78	3.67	3.69	4.08	5.13	4.79	2.98

(1) *IFRS transition date was January 1, 2011, therefore 2010 comparative information has not been restated under IFRS.*

Gross revenue and cash flow from operations have fluctuated over the quarters in line with commodity price volatility and fluctuating production volumes. Total assets have grown over the quarters as a result of exploration and drilling activities, as well as certain asset acquisitions that occurred in the the third quarter of 2010. Long-term financing has increased in relation to the acquisition over the quarters.

FINANCIAL MEASURES

This MD&A provides certain financial measures that do not have a standardized meaning prescribed by IFRS and previous GAAP. These financial measures may not be comparable to similar measures presented by other issuers. The terms “cash flow from operations”, “operating netback”, “working capital” and “net debt” are not recognized under IFRS or previously under GAAP. The Corporation uses these measures to help evaluate its performance, leverage, and liquidity as well as to assess potential acquisitions.

Cash flow from operations is an important financial measure as it demonstrates the Corporation’s ability to generate funds necessary to repay debt and to fund future growth through capital investment. Cash flow from operations should not be considered an alternative to, or more meaningful than, cash flow from operating activities as an indicator of the Corporation’s performance. All references to cash flow from operations throughout this MD&A are based on cash flow from operating activities before changes in non-cash working capital. The Corporation also presents cash flow from operations per share whereby the per share amounts are calculated using weighted average shares outstanding consistent with the calculation of net income per share, which per share amount is calculated under IFRS and is more fully described in the notes to the financial statements.

Operating netback is an important financial measure as it demonstrates profitability relative to current commodity prices. Operating netback is calculated as revenues less royalties and operating expenses. There is no IFRS measure that is reasonably comparable to operating netback.

Net debt and working capital are both important financial measures as they are used to assess liquidity and general financial strength. Working capital is calculated as current assets less current liabilities. Net debt is calculated as the sum of working capital and long-term financing excluding the mark-to-market adjustment of financial instruments and the estimate of the current portion of decommissioning obligations. There is no IFRS measure that is reasonably comparable to working capital or net debt.

Discovered Petroleum Initially-in-Place ("DPIIP") (equivalent to discovered resources) is defined in the COGE Handbook as that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of DPIIP includes production, reserves, and contingent resources; the remainder is unrecoverable. A recovery project cannot be defined for this volume of DPIIP at this time. There is no certainty that it will be commercially viable to produce any portion of the resources.

Undiscovered Petroleum Initially-In-Place ("UDPIIP") (equivalent to undiscovered resources) is defined in the COGE Handbook as that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered. The recoverable portion of UDPIIP is referred to as "prospective resources," the remainder as "unrecoverable." A recovery project cannot be defined for this volume of UDPIIP at this time. There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

There is no certainty that it will be economically viable or technically feasible to produce any portion of this DPIIP and UDPIIP. Resources do not constitute, and should not be confused with, reserves. This estimate of remaining recoverable resources (unrisked) includes contingent resources that have not been adjusted for risk based on the chance of development. It is not an estimate of volumes that may be recovered. Actual recovery may be less.

FORWARD-LOOKING ADVISORY

This MD&A contains certain statements or disclosures relating to Terra Energy that are based on the expectations of its Management, as well as assumptions made by and information currently available to Terra Energy which may constitute forward-looking statements or information ("forward-looking statements") under applicable securities laws. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. All such statements and disclosures, other than those of historical fact, which address activities, events, outcomes, results or developments that the Corporation anticipates or expects may, or will occur in the future (in whole or in part) should be considered forward-looking statements. Information presented in such statements or disclosures, may, among other things, relate to: the anticipated benefits and enhanced shareholder value resulting from operations; the success of the Corporation's growth strategy; sources of income; forecasts of capital expenditures and the sources of the financing thereof; expectations regarding the ability of the Corporation to raise capital, movements in currency exchange rates, anticipated income taxes, the Corporation's business outlook, plans and objectives of Management for future operations' forecast business results and anticipated financial performance. Many factors could cause the performance or achievements of Terra Energy to be materially different from any future results, performance or achievements that may be expressed or implied by such forward-looking statements.

In particular, such forward-looking statements include:

(a) Under the heading "Liquidity and Capital Resources" the statement that:

   i. On a go forward basis, the Corporation's intent is to restrict its conventional development activity to available cash flow.

   ii. Future development of this resource will require contributions of additional capital to the Corporation.

   iii. The Corporation is actively seeking out private equity, farm-out opportunities, and possible joint ventures as various alternative methods of funding future development.

(b) Under the heading "Commitments and Contingencies" the statement that:

   i. The Corporation does not currently believe that the outcome of adverse decisions in any proceedings related to these matters, or any amount which it may be required to pay, would have a material adverse impact on its financial position, results of operations or liquidity.

(c) Under the heading "Outlook" the Corporation stated that:

   i. The Corporation would take a prudent approach to capital investment and operational spending with a focus on targeting oil and liquids rich opportunities, all with a view towards shifting the Corporation's overall commodity mix towards oil.

ii. The Corporation will allow our significant Montney assets in British Columbia to carry themselves, by securing development capital in the form of private equity, joint ventures and partnerships.

iii. Terra Energy has successfully drilled a vertical well into the Doig formation resulting in a test rate of over 100 bbls/day of oil and associated gas of 150 boe/d. The results from this well reflect the potential for developing this area utilizing unconventional techniques, including horizontal drilling and multi-stage fracking. Terra Energy intends to license at least four horizontal locations in the area for potential resource style oil development.

iv. The Corporation is fortunate to have an abundance of prospective natural gas properties. These natural gas properties give rise both to new drilling opportunities and low risk recompletion opportunities.

v. In the greater Peace River area, Terra Energy is targeting the Belloy formation and has drilled two very successful wells into this formation.

vi. Terra Energy is successfully fighting off declines as we pave the way towards more oil and liquids rich opportunities. All of this is being managed within cash flow at a time when natural gas prices are low.

vii. Interest in the unconventional Montney gas play in British Columbia has only increased as LNG export on the west coast moves closer to becoming a reality. Accordingly, as we continue to seek capital to develop these major Montney assets, Terra Energy will expand efforts to secure funding by targeting alternative forms of capital, including capital from Asia and Europe in the form of more conventional joint venture deals being announced by industry peers and will also consider the outright sale of the Montney assets to strategic players. Terra will continue to update the investment community as any major new developments may occur.

viii. Terra Energy engaged Macquarie Capital Markets Canada Ltd. with a view to marketing certain specified assets located in west-central Alberta. In the event of a successful sale transaction, the Corporation would utilize the proceeds both to pay down bank debt and to advance its two key strategies, namely a shift towards oil/liquids and the advancement of the Montney assets in British Columbia.

(d) Under the heading "Critical Accounting Estimates - Proved Oil and Natural Gas Reserves" the statements that:

i. On an undiscounted basis, the future development costs associated with proved reserves is approximately $43.2 million compared to $383.7 million in expected cash flow. Estimated future development costs for probable reserves is $56.0 million compared to $331.5 million in expected cash flow.

ii. In either event, estimated future development costs will be funded from the unutilized portion of the Corporation's credit facility or from cash flow from operations.

iii. The cost of funding estimated future development costs will not make the development of a property uneconomic or have an impact on disclosed reserves or future cash flow from the production of proved reserves.

(e) Under the heading "Critical Accounting Estimates - Litigation" the statement that:

i. The Corporation does not currently believe that the outcome of adverse decisions in any pending or threatened proceeding related to these and other matters or any amount which it may be required to pay by reason thereof, would have a material adverse effect on its financial position or results of operations.

(f) Under the heading "Critical Accounting Estimates - Share Based Compensation and Share Purchase Warrants" the statement that:

i. The assumptions used could differ from actual fair value of the stock options at any time.

(g) Under the heading "Income Taxes" the statement that:

i. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded.

(h) Under the heading "Risk Factors Relating to Oil and Natural Gas Exploration, Development and Production - Uncertain Discovery of Viable Commercial Prospects" the statement that:

i. The Corporation's future success may be dependent upon its ability to economically locate commercially viable oil or natural gas deposits.

ii. The inability to successfully locate and drill wells that will economically produce commercial quantities of oil and natural gas could have a material adverse effect on the Corporation's business and financial position.

(i) Under the heading "Risk Factors Relating to Oil and Natural Gas Exploration, Development and Production - Global Economic Conditions" the statement that:

i. The expectations for natural gas prices for 2011 continue to be bearish and will result in constrained cash flow levels for the Corporation. In order to manage through these uncertain times, the Corporation will continue to take a prudent approach to capital investment and operational spending.

ii. The Corporation will continue to utilize hedging strategies to protect and enhance cash flow.

(j) Under the heading "British Columbia Royalty Regime" the statement that:

i. The Alberta royalty regime and drilling credit program and the British Columbia royalty regime may have an impact on decisions that the Corporation will make in determining where to focus its drilling activities in the future.

(k) Under the heading "Risk Factors Relating to Oil and Natural Gas Exploration, Development and Production - Prices, Markets and Marketing of Crude Oil and Natural Gas" the statement that:

i. Terra Energy might also elect not to produce from certain wells at lower prices. All these factors could result in a material decrease in Terra Energy's future net production revenue, causing a reduction in its oil and natural gas acquisition and development activities.

ii. Terra Energy will also likely be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities and related to operational problems with such pipelines and facilities and extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and the management of other aspects of the oil and natural gas business.

(l) Under the heading "Risk Factors Relating to Oil and Natural Gas Exploration, Development and Production - Substantial Capital Requirements; Liquidity" the statement that:

i. Terra Energy anticipates that it will make substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future.

ii. If Terra Energy's future revenues or reserves decline, Terra Energy may have limited ability to expend the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to Terra Energy.

iii. Moreover, future activities may require Terra Energy to alter its capitalization significantly. The inability of Terra Energy to access sufficient capital for its operations could have material adverse effect on Terra Energy's financial condition, results of operations or prospects.

(m) Under the heading "Risk Factors Relating to Oil and Natural Gas Exploration, Development and Production - Capital Markets" the statement that:

i. Based on current funds available and expected funds generated from operations, Terra Energy believes it has sufficient funds available to fund its projected capital expenditures.

The Corporation's actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this MD&A:

(a) general economic conditions in Canada, the United States and globally;

(b) industry conditions, including fluctuations in the price of oil and natural gas;

(c) governmental regulation of the oil and natural gas industry, including environmental regulation;

(d) fluctuation in foreign exchange or interest rates;

(e) liabilities inherent in oil and natural gas operations;

(f) geological, technical, drilling and processing problems;

(g) unanticipated operating events which can reduce production or cause production to be shut in or delayed;

(h) failure to realize the anticipated benefits of acquisitions;

(i) failure to obtain industry partner and other third party consents and approvals, when required;

(j) stock market volatility and market valuations;

(k) competition for, among other things, capital, acquisitions of reserves, undeveloped land and skilled personnel;

(l) competition for, and inability to, retain drilling rigs and other services;

(m) rights to surface access; and

(n) the need to obtain required approvals from regulatory authorities; and the other factors considered under "Risk Factors" in this MD&A and other risk factors identified in the Corporation's Annual Information Form and other documents incorporated herein by reference.

Statements relating to "reserves" or "resources" are by their nature forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described can be profitably produced in the future. With respect to forward-looking statements contained or incorporated by reference in this MD&A, Terra Energy has made assumptions regarding: future exchange rates; energy markets and the price of oil and natural gas; the impact of increasing competition; condition in general economic and financial markets; availability of drilling and related equipment; availability of skilled labour; availability of prospective drilling rights; current technology; cash flow; commodity prices; production rates; effects of regulation and tax laws by governmental agencies; future operating costs and the Corporation's ability to obtain financing on acceptable terms. In addition, forward-looking statements in documents incorporated by reference herein may be based on additional assumptions as disclosed in such documents. Readers are cautioned that the foregoing list of factors is not exhaustive.

The above summary of assumptions and risks related to forward-looking statements has been provided in this MD&A and the documents incorporated by reference herein in order to provide readers with a more complete perspective on Terra Energy's future operations. Readers are cautioned that this information may not be appropriate for other purposes. These forward-looking statements speak only as of the date of this MD&A or as of the date specified in the documents incorporated by reference, as the case may be. The Corporation does not intend and does not undertake to update or revise these forward-looking statements except as required pursuant to applicable securities laws.

The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement.

REPORTING CONTROLS

The Corporation's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") are responsible for establishing and maintaining disclosure controls and procedures ("DC&P") and internal controls over financial reporting ("ICFR"), as those terms are defined in National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings.

The CEO and CFO have designed, or caused to be designed under their supervision, DC&P to provide reasonable assurance that material information relating to the Corporation is made known to the CEO and CFO on a timely basis and that information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by the Corporation under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation. The CEO and CFO have evaluated, or caused to be evaluated under their supervision, the effectiveness of Terra Energy's DC&P and have concluded that Terra Energy's DC&P are effective as at September 30, 2011, based on that evaluation.

Internal control over financial reporting is a process designed to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized and to facilitate the preparation of relevant, reliable and timely information. The CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of the Corporation's financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Corporation's internal controls over financial reporting as at the nine months ended September 30, 2011, and concluded that the Corporation's internal controls over financial reporting are effective for the foregoing purpose. The Corporation's CEO and CFO are required to cause the Corporation to disclose any change in the Corporation's internal controls over financial reporting that occurred during the nine months ended September 30, 2011, that has materially affected, or is reasonably likely to materially affect, the Corporation's internal controls over financial reporting. No material changes in the Corporation's internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Corporation's internal controls over financial reporting.

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

RESULTS OF OPERATIONS

Production

	Three months ended September 30			Nine months ended September 30		
	2011 Average	2010 Average	Growth %	**2011 Average**	2010 Average	Growth %
Oil (bbl/d)	**482**	595	(19.0)	**554**	654	(15.4)
Natural Gas (Mcf/d)	**30,221**	31,653	(4.5)	**30,422**	31,460	(3.3)
Liquids (bbl/d)	**535**	712	(24.9)	**586**	867	(32.4)
Combined boe/d	**6,053**	6,581	(8.0)	**6,210**	6,764	(8.2)

Production decreased in the third quarter of 2011 by 8.0% compared to the same period in 2010 due to anticipated production declines. Similarly the production for the nine month period ended September 30, 2011, declined by 8.2% over the comparable period of 2010.

Operations

	Three months ended September 30				Nine months ended September 30			
(in thousands, except per share and boe amounts)	**2011 $**	2010 $	**2011 ($/boe)**	2010 ($/boe)	**2011 $**	2010 $	**2011 ($/boe)**	2010 ($/boe)
Revenue Before Royalties	**16,976**	17,580	**30.48**	29.04	**54,070**	61,105	**31.89**	33.09
Royalties	**(2,278)**	(2,686)	**(4.09)**	(4.44)	**(7,822)**	(9,993)	**(4.61)**	(5.41)
Revenue After Royalties	**14,698**	14,894	**26.39**	24.60	**46,248**	51,112	**27.28**	27.68
Production Expenses	**(8,657)**	(7,854)	**(15.54)**	(12.97)	**(25,716)**	(19,883)	**(15.17)**	(10.77)
Operating Netback	**6,041**	7,040	**10.85**	11.63	**20,532**	31,229	**12.11**	16.91
Gain on Disposal of Other Assets	**-**	83	**-**	0.14	**250**	347	**0.15**	0.19
General & Administrative Expenses	**(2,148)**	(2,471)	**(3.86)**	(4.08)	**(6,699)**	(6,947)	**(3.95)**	(3.76)
Financing Costs	**(1,153)**	(864)	**(2.07)**	(1.42)	**(3,652)**	(2,362)	**(2.15)**	(1.28)
Realized Gain (Loss) Derivative Instruments	**3,115**	(1,157)	**5.59**	(1.91)	**6,561**	(1,832)	**3.87**	(0.99)
Unrealized Gain (Loss) Derivative Instruments	**(13)**	940	**(0.02)**	1.55	**672**	154	**0.40**	0.08
Realized Foreign Exchange Gain	**190**	220	**0.34**	0.36	**794**	397	**0.47**	0.22
Unrealized Foreign Exchange Gain (Loss)	**224**	664	**0.40**	1.10	**393**	128	**0.23**	0.07
Non-cash Expenses	**(5,894)**	(6,411)	**(10.58)**	(10.59)	**(17,781)**	(20,203)	**(10.49)**	(10.94)
Loss Before Income Taxes and Other Income	**362**	(1,956)	**0.65**	(3.22)	**1,070**	911	**0.64**	0.50
Income Tax (Expense) Recovery	**(2,063)**	244	**(3.70)**	0.40	**(825)**	(676)	**(0.49)**	(0.36)
Net Income	**(1,701)**	(1,712)	**(3.05)**	(2.82)	**245**	235	**0.15**	0.14
Per Share - Basic	**(0.02)**	(0.02)			**-**	-		
Per Share - Diluted	**(0.02)**	(0.02)			**-**	-		

Revenue

	Three months ended September 30				Nine months ended September 30			
(in thousands)	**2011 $**	2010 $	**2011 ($/boe)**	2010 ($/boe)	**2011 $**	2010 $	**2011 ($/boe)**	2010 ($/boe)
Gross Revenue	**16,976**	**17,580**	**30.48**	**29.04**	**54,070**	61,105	**31.89**	33.09
Realized Gain (Loss) on Financial Derivative Contracts	**3,115**	(1,157)	**5.59**	(1.91)	**6,561**	(1,832)	**3.87**	(0.99)
Unrealized Gain (Loss) on Financial Derivative Contracts	**(13)**	940	**(0.02)**	1.55	**672**	154	**0.40**	0.08
Revenue Before Royalties	**20,078**	17,363	**36.05**	28.68	**61,303**	59,427	**36.16**	32.18

Third Quarter

Gross revenue decreased by 3.4% to $16,976,000 for the three month period ended September 30, 2011, compared to $17,580,000 for the comparable period of 2010, resulting from anticipated production declines that were partially offset by increased product pricing. For the third quarter, the Corporation realized a gain of $3,115,000 from financial derivative contracts compared to a loss of $1,157,000 for the comparable period of 2010.

Production from certain wells drilled during the current year, are awaiting completion of facility infrastructure to enable production commencement.

The combined product price for the third quarter of 2011 was 5% higher than the comparable period of 2010. Natural gas prices for the third quarter of 2011 were 0.8% higher than the comparable period of 2010, while oil and natural gas liquids prices rose by 45.8%. The combined price for the third quarter increased by 5% to $30.48 per boe compared to the comparable quarter of 2010.

Nine Months

Similarly, gross revenues for the nine month period ended September 30, 2011 decreased by 12% to $54,070,000 from $61,105,000 primarily as a result of production declines of 8.2% and revenues that were impacted by a turnaround at the McMahon facility.

Gas commodity prices for the period were down by 10.8% to $3.84 per mcf compared to $4.31 per mcf. Natural gas liquid prices increased by 30.8% from the comparable period of 2010. The combined price for the period decreased by 3.6% to $31.89 per boe from $33.09 per boe for the comparable period of 2010.

Below is a breakdown of gross revenue prices realized by the Corporation:

	Three months ended September 30			Nine months ended September 30		
	2011	2010	% Growth	**2011**	2010	% Growth
Crude Oil ($/bbl)	**84.42**	70.92	19.0	**89.74**	72.05	24.5
Natural Gas Liquids ($/bbl)	**58.47**	40.11	45.8	**58.63**	44.82	30.8
Natural Gas ($/Mcf)	**3.72**	3.69	0.8	**3.84**	4.31	(10.8)

Derivative Contracts

At period ends, in accordance with IFRS, the Corporation is required to calculate and reflect a "mark-to-market" value of its financial instruments on the balance sheet. Furthermore, during each period end, the prior period's mark-to-market is reversed and a new mark-to-market adjustment is calculated with the difference being recorded to unrealized gain (loss) on financial instruments on the statement of operations. The periodic cash settlement of these various financial instruments is recorded in realized gain (loss) on financial instruments on the statement of operations.

Third Quarter

For the three months ended September 30, 2011, the Corporation's Condensed Consolidated Statement of Operations and Comprehensive Income (Loss) recorded a realized gain of $3,115,000 from the settlement of financial instruments reflected in the consolidated statement of operations.

The Corporation's Condensed Consolidated Statement of Operations and Comprehensive Income (Loss) reflect an unrealized loss on financial instruments of $13,000 due to the reversal of the June 30, 2011, mark-to-market asset of $685,000 and a new mark-to-market asset of $672,000 at September 30, 2011.

Nine Months

For the nine months ended September 30, 2011, the Condensed Corporation's Consolidated Statement of Operations and Comprehensive Income (Loss) recorded a realized gain of $6,561,000 from the settlement of financial instruments reflected in the consolidated statement of operations.

The Corporation's Condensed Consolidated Statements of Operations reflect an unrealized gain of $672,000 on commodity contracts. This is the result of a new mark-to-market asset of $672,000 at September 30, 2011.

For the nine month period ended September 30, 2011, the Corporation's Condensed Consolidated Statements of Financial Position reflect a risk management contract asset of $1,465,000 resulting from an unrealized gain on commodity contracts of $672,000 and an unrealized gain on foreign exchange contracts of $793,000.

The unrealized gains on derivative and foreign exchange contracts are non-cash items and, as a result, do not affect the Corporation's cash flow from operations.

Royalties

	Three months ended September 30				Nine months ended September 30			
(in thousands)	**2011 $**	2010 $	**2011 ($/boe)**	2010 ($/boe)	**2011 $**	2010 $	**2011 ($/boe)**	2010 ($/boe)
Charge for the Period	**2,278**	2,686	**4.09**	4.44	**7,822**	9,993	**4.61**	5.41
Royalties as a Percentage of Gross Revenue	**13.4%**	15.3%			**14.5%**	16.4%		

Third Quarter

Royalties decreased by 15% to $2,278,000 for the three month period ended September 30, 2011, compared to $2,686,000 for the three month period ended September 30, 2010, primarily as a result of the Corporation's decreased product prices in the third quarter.

Royalties as a percentage of gross revenues decreased to 13.4% compared to 15.3% for the same period ended September 30, 2010. Royalties on a per unit of production basis decreased by 8% to $4.09 for the three month period ended September 30, 2011, compared to $4.44 for the same period ended September 30, 2010.

Nine Months

For the nine month period ended September 30, 2011, royalties decreased by 22% to $7,822,000 from $9,993,000, primarily resulting from gas commodity price reductions of 10.8% and overall production declines of 8%.

Royalties as a percentage of gross revenues decreased to 14.5% in 2011, compared to 16.4% in 2010 benefiting from the royalty rate reduction program on British Columbia wells. Gas commodity prices for the period were down by 10.8 % to $3.84 per mcf compared to $4.31 per mcf at September 30, 2010. Natural gas liquids rose by 30.8% from the comparable period of 2010.

Production Expenses

	Three months ended September 30				Nine months ended September 30			
(in thousands)	**2011 $**	2010 $	**2011 ($/boe)**	2010 ($/boe)	**2011 $**	2010 $	**2011 ($/boe)**	2010 ($/boe)
Production Expenses	**8,657**	7,854	**15.54**	12.97	**25,716**	19,883	**15.17**	10.77

Third Quarter

Production expenses increased by 10% to $8,657,000 for the three month period ended September 30, 2011, compared to $7,854,000 for the same period ended September 30, 2010, reflecting decrease in third party processing fees and a higher fixed component of operating costs related to reduced production volumes. Production expenses on a per unit of production basis increased 20% to $15.54 in 2011 compared to $12.97 in 2010 resulting from production declines, loss of third party processing fee income and higher costs associated with oil producing properties.

Nine Months

For the nine month period ended September 30, 2011, production expenses increased 29% to $25,716,000 in 2011 compared to $19,883,000 in 2010, reflecting a decrease in third party processing income, a higher fixed component of operating costs related to reduced production volumes and increased operating costs associated with oil properties acquired in September 2010. Production expenses on a per unit of production basis increased 41% to $15.17 in 2011 compared to $10.77 in 2010 resulting from production declines, loss of third party processing fee income and higher costs associated with oil producing properties.

General and Administrative Expenses

	Three months ended September 30				Nine months ended September 30			
(in thousands)	**2011 $**	2010 $	**2011 ($/boe)**	2010 ($/boe)	**2011 $**	2010 $	**2011 ($/boe)**	2010 ($/boe)
General and Administrative Expenses	**2,148**	2,471	**3.86**	4.08	**6,699**	6,947	**3.95**	3.76

Third Quarter

General and administrative expenses decreased 13% to $2,148,000 for the three month period ended September 30, 2011, compared to $2,471,000 for the same period ended September 30, 2010. General and administrative expenses on a per unit of production basis decreased 5.4% to $3.86 for the three month period ended September 30, 2011, compared to $4.08 for the same period ended September 30, 2010.

Nine Months

For the nine month period ended September 30, 2011, general and administrative expenses decreased 3.5% to $6,699,000 compared to $6,947,000 for the same period ended September 30, 2010. General and administrative expenses on a per unit of production basis increased 5.1% to $3.95 for the nine months period ended September 30, 2011 compared to $3.76 for the same period ended September 30, 2010, related to a reduction in the production base.

Finance Costs

	Three months ended September 30				Nine months ended September 30			
($ in thousands)	**2011 $**	2010 $	**2011 ($/boe)**	2010 ($/boe)	**2011 $**	2010 $	**2011 ($/boe)**	2010 ($/boe)
Interest Expense	1,010	698	1.81	1.15	3,154	1,821	1.86	0.99
Accretion Expense	143	166	0.26	0.27	498	541	0.29	0.29
Total Finance Costs	1,153	864	2.07	1.42	3,652	2,362	2.15	1.28

Third Quarter

Finance costs increased by 33% to $1,153,000 for the three month period ended September 30, 2011, compared to $864,000 for the same period ended September 30, 2010, due to an increase in long-term financing in relation to the acquisition of oil and natural gas assets.

Nine Months

Similarly for the nine month period ended September 30, 2011, finance costs increased by 54.6% to $3,652,000 compared to $2,362,000 for the same period in 2010 due to an increase in the long-term financing in relation to the acquisition of oil and natural gas assets.

Foreign Exchange Gain

	Three months ended September 30				Nine months ended September 30			
($ in thousands)	**2011 $**	2010 $	**2011 ($/boe)**	2010 ($/boe)	**2011 $**	2010 $	**2011 ($/boe)**	2010 ($/boe)
Realized Foreign Exchange Gain	**190**	220	**0.34**	0.36	**794**	397	**0.47**	0.22
Unrealized Foreign Exchange Gain	**224**	664	**0.40**	1.10	**393**	128	**0.23**	0.07
	414	884	**0.74**	1.46	**1,187**	525	**0.70**	0.29

Third Quarter

For the three month period ended September 30, 2011, a realized gain of $190,000 was recognized on a U.S. Dollar Average Rate Range Bonus Accumulator Contract held by the Corporation. The unrealized foreign exchange gain of $224,000 represents the mark-to-market value of the U.S. Dollar Average Rate Range Bonus Accumulator contracts held by the Corporation of $793,000 offset by the reversal of the June 30, 2011, unrealized mark-to-market gain of $569,000.

Nine Months

For the nine month period ended September 30, 2011, a realized gain of $794,000 was recognized on a U.S. Dollar Average Rate Range Bonus Accumulator Contract held by the Corporation. The unrealized foreign exchange gain of $393,000 represents the mark-to-market value of the U.S. Dollar Average Rate Range Bonus Accumulator contracts held by the Corporation of $793,000 offset by the reversal of the December 31, 2010 unrealized mark-to-market gain of $400,000.

Other Non-cash Expenses

	Three months ended September 30				Nine months ended September 30			
($ in thousands)	**2011 $**	2010 $	**2011 ($/boe)**	2010 ($/boe)	**2011 $**	2010 $	**2011 ($/boe)**	2010 ($/boe)
Depletion, Depreciation and Amortization	**5,840**	6,186	**10.48**	10.22	**16,878**	18,658	**9.96**	10.10
Share-based Compensation	**54**	225	**0.10**	0.37	**903**	1,545	**0.53**	0.84
Other Non-cash Expenses	**5,894**	6,411	**10.58**	10.59	**17,781**	20,203	**10.49**	10.94

Third Quarter

Other non-cash expenses decreased 8% to $5,894,000 for the three month period ended September 30, 2011, compared to $6,411,000 for the same period ended September 30, 2010. Depletion, depreciation and amortization decreased by $346,000 due to lower production volumes. Share-based compensation declined by $171,000 in the current period compared to the prior period. On a per unit of production basis, non-cash expenses remained relatively unchanged at $10.58 for the three month period ended September 30, 2011 and September 30, 2010.

Nine Months

For the nine month period ended September 30, 2011, non cash expenses dropped 12% to $17,781,000 compared to $20,203,000 in 2010. On a per unit of production basis, non cash expenses decreased by 4% to $10.49 for the nine month period ended September 30, 2011, compared to $10.94 for the same period ended September 30, 2010. Depletion, depreciation and amortization decreased by 10% to $16,878,000 from $18,658,000 as a result of a decline in production volumes. Stock based compensation decreased by 42% to $903,000 in the current period compared to $1,545,000 largely due to decrease in the issuance of additional stock options.

Income Taxes

	Three months ended September 30				Nine months ended September 30			
($ in thousands)	**2011 $**	2010 $	**2011 ($/boe)**	2010 ($/boe)	**2011 $**	2010 $	**2011 ($/boe)**	2010 ($/boe)
Current Income Tax	**-**	4	**-**	0.01	**-**	4	**-**	-
Deferred Income Tax Expense (Recovery)	**2,063**	(248)	**3.70**	(0.41)	**825**	672	**0.49**	0.36
Income Tax Expense (Recovery)	**2,063**	(244)	**3.70**	(0.40)	**825**	676	**0.49**	0.36

Third Quarter

Income tax expense of $2,063,000 for the three month period ended September 30, 2011, was recorded compared to a recovery of $244,000 for the same period ended September 30, 2010. The increase in income tax expense is consistent with the increase in the deferred income associated with Terra Energy partnership. On a per unit of production basis, the deferred income tax expense was $3.70 for the three month period ended September 30, 2011, compared to an recovery of $0.40 for the same period ended September 30, 2010.

Nine Months

Income tax expense of $825,000 for the nine month period ended September 30, 2011 was recorded compared to an expense of $676,000 for the same period ended September 30, 2010. On a per unit of production basis, the deferred income tax expense was $0.49 for the nine month period ended September 30, 2011, compared to a expense of $0.36 for the same period ended September 30, 2010.

LIQUIDITY AND CAPITAL RESOURCES

The Corporation defines liquidity as it's ability to generate cash and to meet existing known and reasonably likely future cash requirements. Cash flow from operations is a measure of the Corporation's ability to generate cash in order to meet these requirements. The Corporation has funded its capital programs through cash flow and bank borrowings. Acquisitions have been funded through a combination of debt and, if required, equity. Cash flow from operations for the nine months ended September 30, 2011, has decreased 39% to $14,852,000 from $24,262,000 for the same period in 2010. This decrease reflects the decrease in natural gas commodity prices and decreased production volumes compared to the same period last year.

The current economic environment has made access to debt and equity markets more difficult. The cost of capital has increased while the availability of capital has decreased. In 2010, the Corporation utilized leveraging capabilities to acquire assets in a low price environment at metrics below the cost of developing existing assets. At September 30, 2011, the Corporation had $8,944,000 in unutilized credit facility and $14,852,000 in cash flow from operations. On a go forward basis, the Corporation's intent is to restrict its conventional development activity to available cash flow. On November 1, 2010, the Corporation announced the results of its Initial Independent Resource Assessment in which the Corporation reported a "best estimate" of DPIIP, net to the Corporation, of 5.48 trillion cubic feet ("Tcf"). Future development of this resource will require contributions of additional capital to the Corporation. The Corporation is actively seeking out private equity, farm-out opportunities, and possible joint ventures as various alternative methods of funding future development.

Cash Flow from Operations

Cash flow from operations ("cash flow"), representing cash generated from operating activities before changes in non-cash working capital items, and is not a recognized measure under IFRS. Management utilizes cash flow as a key measure to assess the ability of the Corporation to finance operating activities and capital expenditures. Additionally, cash flow has been described and presented in order to provide shareholders and potential investors with information regarding the Corporation's liquidity and its ability to generate funds to finance its operations. This performance indicator may not be comparable to similar measures used by other companies.

The following table presents a reconciliation of cash flow from operations to Cash flow - operating activities for the periods noted:

	Three months ended September 30		Nine months ended September 30	
($ in thousands)	**2011**	2010	**2011**	2010
Non-IFRS Cash Flow from Operations	**6,115**	2,859	**17,783**	20,556
Change in Non-cash Working Capital	**5,221**	3,638	**(2,931)**	3,706
IFRS Cash flow - Operating Activities	**11,336**	6,497	**14,852**	24,262

Third Quarter

For the three month period ended September 30, 2011, the Corporation generated cash flow from operations of $11,336,000, an increase of 75% compared to $6,497,000 for the three month period ended September 30, 2010. The increase is due primarily to the realization of certain commodity derivative instruments.

Nine Months

For the nine month period ended September 30, 2011, the Corporation generated cash flow from operations of $14,852,000, a decrease of 39% compared to $24,262,000 for the nine month period ended September 30, 2010. The primary driver for the decrease of cash flow from operations was decrease in commodity prices and decrease in production volumes when compared to the nine month period in the prior year.

Sensitivity Analysis

The following table indicates the relative annual effect of changes in certain key variables to the Corporation's pre-tax cash flow:

Changes to Annual Cash Flow from Operations	Change	$ Change
Price per Barrel of Oil (U.S.$ WTI)	+/- U.S.$1.00	233,000
Price per Mcf of Natural Gas (CAD$ AECO)	+/- CAD$0.10	1,140,000
Interest Rate on Debt	+/- 1.00%	867,000

Capital expenditures, net debt and working capital are measures of the known and reasonably likely future cash requirements.

($ in thousands)	**September 30, 2011**	December 31, 2010	% Growth
Working Capital Deficiency	**9,308**	14,235	(34.6)
Current Portion of Decommissioning Obligations	**(30)**	(200)	(85.0)
Long-term Debt	**86,710**	85,074	1.9
Net Debt including Risk Management Contracts	**95,988**	99,109	(3.1)
Risk Management Contracts - Included in Current Assets	**1,465**	400	266.3
Net Debt	**97,453**	99,509	(2.1)

The working capital deficiency at September 30, 2011, was $9,308,000 compared to a deficiency of $14,235,000 at December 31, 2010. The decrease in the working capital deficiency was driven by a decrease in current liabilities resulting from lower exploration and development activity in the third quarter of 2011. A working capital deficiency is a normal event in the oil and gas industry with liquidity being maintained by drawing from the unutilized credit facility as needed and then repaying it periodically through production revenues.

Net debt at September 30, 2011, was $97,453,000 compared to $99,509,000 at December 31, 2010. At September 30, 2011, the Corporation was drawn $89,359,000 against its credit facility compared to $88,585,000 at December 31, 2010.

Terra Energy's long-term financing consists of a $100.0 million 364 day revolving bank syndicated credit facility with a one year term-out provision. If the credit facility is not renewed at maturity, the Corporation has the ability to repay any amounts outstanding on the credit facility one year from maturity. As a result of this one year repayment feature, the Corporation has classified its bank credit facility as a long-term financial obligation.

Property Acquisition

On September 1, 2010, the Corporation completed the acquisition of certain oil and natural gas assets, including 100% of the Square Creek gas field and 80,000 net acres of undeveloped land. The assets were acquired for consideration of $25.9 million and 3,664,444 common shares of the Corporation for total consideration of approximately $30.8 million. The effective date of the transaction was September 1, 2010. Decommissioning liabilities associated with the properties acquired were $1,259,904.

Capital Expenditures

Third Quarter

Capital expenditures decreased by 53% to $6,529,000 before property acquisitions for the three month period ended September 30, 2011, compared to $13,911,000 for the same period ended last year. Terra Energy financed its capital expenditures for the period through cash flow from operations. Capital expenditures in the future are largely discretionary and will be contingent upon management's assessment of the financial condition of the Corporation and the current economic climate and its impact on access to capital and debt markets.

Nine Months

For the nine months ended September 30, 2011, capital expenditures decreased by 61% to $17,381,000 before property acquisitions compared to $44,014,000 for the same period ended last year. During the nine months ended September 30, 2010, the Corporation completed an asset exchange arrangement involving the exchange of oil and gas assets, with cash forming no part of the consideration. Under the terms of the arrangement, the Corporation acquired approximately 170 gross (70 net) sections of land located in several key areas of high activity in northeast British Columbia. In consideration for the assets acquired, the Corporation assigned and conveyed to the counterparty all of its rights and interest in a specified resource play which has been under development by the Corporation for more than two years.

For the three and nine month period ended September 30, 2011, capital expenditures incurred by the Corporation are broken down as follows:

	Three months ended September 30		Nine months ended September 30	
($ in thousands)	**2011**	2010	**2011**	2010
Exploration	**5,721**	9,335	**5,894**	16,172
Development	**-**	2,968	**8,382**	15,314
Undeveloped Land	**502**	629	**539**	8,869
Geological / Geotechnical	**40**	771	**93**	2,273
Facilities	**-**	280	**1,520**	537
Other Assets	**266**	(72)	**953**	849
Total Capital Expenditures	**6,529**	13,911	**17,381**	44,014
Property Acquisitions	**-**	25,892	**-**	37,220
Property Dispositions	**-**	-	**(1,548)**	-
Net Capital Expenditures	**6,529**	39,803	**15,833**	81,234

Capital Resources

The Corporation's share capital is as follows:

	September 30, 2011		December 31, 2010	
	No. of Shares	**Amount**	No. of Shares	Amount
(amounts in thousands)	**#**	**$**	#	$
Common Shares	**101,852**	**116,397**	101,964	116,494

As at September 30, 2011, the Corporation had purchased 176,200 of its common shares for a total cost of $209,210 at an average price of $1.19 per common share. Share capital was reduced by $201,310 and the excess of $7,900 was charged to retained earnings.

For the year ended December 31, 2010, the Corporation purchased 1,197,900 of its common shares for total costs of $1,786,777, at an average price of $1.49 per common share. Share capital was reduced by $1,255,978 and the excess of $530,799 was charged to retained earnings.

Of the purchased shares for the period, none were being held for cancellation at September 30, 2011, (December 31, 2010 - 106,100).

At September 30, 2011, there were no common share purchase warrants outstanding. During the quarter 7 million unexercised common share purchase warrants expired.

COMMITMENTS AND CONTINGENCIES

In the normal course of business, the Corporation enters into various obligations that will impact the Corporation's future operations and liability. The principal commitments of the Corporation are as follows:

($ in thousands)	Total	Current within 1 year	Within 1 to 3 years	Within 4 to 5 years
Bank Overdraft	2,649	2,649	-	-
Accounts Payable and Accrued Liabilities	17,860	17,860	-	-
Office Lease	1,981	867	1,044	70
Long-term Financing (1)	86,710	-	86,710	-
Gathering and Processing Contracts	15,606	5,483	9,845	278
Finance Lease Obligation	729	729	-	-
Total	125,535	27,588	97,599	348

(1) Excludes any interest related costs.

The Corporation had outstanding letters of credit to various parties for a total of $505,744 (December 31, 2010 - $505,744). The amounts expire at various dates during 2011.

The Corporation is involved in various claims and litigations arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Corporation's favour, the Corporation does not currently believe that the outcome of adverse decisions in any proceedings related to these matters, or any amount which it may be required to pay, would have a material adverse impact on its financial position, results of operations or liquidity.

The Corporation is required to incur qualifying exploration expenditures by December 31, 2011, of approximately $13,500,000 as a result of flow-through shares issued in March, 2010. At September 30, 2011, the Corporation had incurred $12,829,244.

OFF-BALANCE SHEET ARRANGEMENTS AND FINANCIAL INSTRUMENTS

From time to time, the Corporation is party to certain derivative instruments, including crude oil and natural gas contracts. The Corporation enters into these contracts to manage commodity price risk in future earnings and cash flow. These contracts reduce the Corporation's exposure to the fluctuations in petroleum and natural gas revenues by locking in fixed forward prices on a portion of the Corporation's crude oil and natural gas production.

At September 30, 2011, the Corporation had the following derivative commodity contracts outstanding:

Natural Gas			
Contract type	Price	Volumes per day	Contract term
Financial	Sell $4.00	5,000 GJ	April 1, 2011 to March 31, 2012
Financial	Sell $4.00	5,000 GJ	April 1, 2011 to March 31, 2012
Financial – Basis Swap	$(0.52) USD	912,500 MMBtu	January 1, 2013 to December 31, 2013
Financial – Basis Swap	$(0.55) USD	2,737,500 MMBtu	January 1, 2013 to December 31, 2013
Financial – Basis Swap	$(0.55) USD	2,737,500 MMBtu	January 1, 2014 to December 31, 2014
Financial – Basis Swap	$(0.55) USD	2,737,500 MMBtu	January 1, 2015 to December 31, 2015

The mark-to-market adjustment of these contracts has been recognized as an asset of $672,075 at September 30, 2011 (2010 liability - nil). A $0.10 decrease in the natural gas price would result in an increase of $1,095,000 to the mark-to-market adjustment.

At September 30, 2011, the Corporation had the following foreign Canadian Dollar/U.S. Dollar exchange option contracts outstanding:

Option Payout Range CAD/U.S. Dollar	U.S. Dollar Notional Amount	Daily Payout Amount	Contract Term
$0.95 to $1.135	$5,000,000	CAD $5,000	September 2010 - December 2011
$0.95 to $1.135	$5,000,000	CAD $5,000	January 2012 - May 2012

For each valuation day in which the exchange rate is within the option payout range, the Corporation will receive $5,000 per day. For each valuation day in which the exchange rate is equal to or greater than the target level of $1.135, the Corporation will sell U.S. $5,000,000 at that rate financially settled in CAD against the monthly average for value spot. If the exchange rate is below the $0.95 level on a valuation day, there is no exchange of funds. The mark-to-market adjustment of these contracts has been recognized as an asset of $792,943 at September 30, 2011.

RELATED PARTY TRANSACTIONS

The Corporation entered into transactions with the following related party:

Borden Ladner Gervais LLP - a Director is a partner with the law firm

	Three months ended September 30		Nine months ended September 30	
($ in thousands)	**2011**	2010	**2011**	2010
Expenses				
Legal Consulting - Borden Ladner Gervais LLP	**78**	102	**233**	482
Other				
Recorded as Part of Oil and Natural Gas Properties - Borden Ladner Gervais LLP	**-**	-		87

The above transactions are in the normal course of operations and have been valued at the exchange amounts agreed by the related party.

SUBSEQUENT EVENTS

a) Subsequent to September 30, 2011, the Corporation entered into the following financial commodity contracts:

Oil			
Contract Type	Price	Volumes per Day	Contract Term
Financial	$90.40 CAD	1,000 bbls	January 2012 to December 2012
Financial	$93.10 CAD	1,000 bbls	December 2012
Financial	$92.95 CAD	1,000 bbls	January 2013 to December 2013

OUTLOOK

Early in 2011, Terra Energy announced two key strategies for calendar 2011. On the one hand, the Corporation would take a prudent approach to capital investment and operational spending, with a focus on targeting oil and liquids rich opportunities, all with a view towards shifting the Corporation's overall commodity mix towards oil. The other strategy was to allow our significant Montney assets in British Columbia to carry themselves, by securing development capital in the form of private equity, joint ventures and partnerships.

Operationally, the Corporation has been successful in both targeting and finding new oil. Terra has drilled, completed and proved up (on a 100% working interest basis) a brand new Triassic oil pool in northeast British Columbia. This test well brought on 70 bbls/d of light oil production from a single vertical well. Additionally, this test well has given rise to at least four or more follow-up development/step-out locations to be licensed. In the Valhalla area of west-central Alberta, Terra Energy has successfully drilled a vertical well into the Doig formation resulting in a test rate of over 100 bbls/day of oil and associated gas of 150 boe/d. This oil well is currently awaiting tie-in. The results from this well reflect the potential for developing this area utilizing unconventional techniques, including horizontal drilling and multi- stage fracing. Industry partners have demonstrated successful results from the same formation directly north of Terra Energy's lands utilizing horizontal drilling and multi-stage fracking. Terra Energy intends to license four or more horizontal locations in the area for potential resource style oil development.

At the same time, the Corporation is fortunate to have an abundance of prospective natural gas properties. These natural gas properties give rise both to new drilling opportunities and low risk recompletion opportunities. In the greater Peace River area, Terra Energy is targeting the Belloy formation and has drilled two very successful wells into this formation. In the Hamelin Creek area of west-central Alberta, Terra Energy has been active in recompleting existing wells with a high level of success. These recompletion operations result in extraordinarily low F&D costs for any reserves which are proved up.

Overall, Terra Energy is successfully fighting off declines as we pave the way towards more oil and liquids rich opportunities. All of this is being managed within cash flow at a time when natural gas prices are low.

During the summer months, Terra has endeavoured to secure private equity funding to advance its unconventional Montney gas play in northeastern British Columbia. The volatility in global financial markets and the state of the natural gas market in North America have resulted in the process taking longer than originally anticipated, and have prevented Terra Energy from reporting a private equity deal to this date. At the same time, interest in the unconventional Montney gas play in British Columbia has only increased as LNG export on the west coast moves closer to becoming a reality. Another major development in the unconventional Montney play in British Columbia is the recent success being demonstrated on offsetting lands in the Montney condensate play. Accordingly, as we continue to seek capital to develop these major Montney assets, Terra Energy will expand efforts to secure funding by targeting alternative forms of capital, including capital from Asia and Europe in the form of more conventional joint venture deals being announced by industry peers and will also consider the outright sale of the Montney assets to strategic players. Terra Energy will continue to update the investment community as any major new developments may occur.

More recently, Terra Energy engaged Macquarie Capital Markets Canada Ltd. with a view to marketing certain specified assets located in west-central Alberta, in the Karr, North Ante Creek, Peoria and Sturgeon lake areas. These assets are non-core to Terra Energy and have no production or reserves currently attributed to them. Terra Energy owns 100% of approximately 140,000 acres or approximately 218 sections in the aforementioned four areas. Included in this marketing process will be Terra Energy's Duvernay assets. Terra Energy's Duvernay assets are located in the Karr and North Ante Creek areas, where Terra Energy holds approximately 79 net sections (approximately 50,000 net acres) of Duvernay rights. The Duvernay is an emerging liquids-rich resource play that has attracted the attention of numerous major industry players as it is widely believed to be the next significant resource play in Western Canada. Terra Energy's Duvernay assets are predominantly located in two large contiguous blocks in a geologically prospective area of the Duvernay. In the event of a successful sale transaction, the Corporation would utilize the proceeds both to pay down bank debt and to advance its two key strategies, namely a shift towards oil/liquids and the advancement of the Montney assets in British Columbia.

CHANGES IN ACCOUNTING POLICIES

The condensed interim consolidated financial statements and comparative information have been prepared in accordance with IFRS. The Corporation adopted IFRS on January 1, 2010. Previously, the Corporation prepared its condensed consolidated financial statements in accordance with GAAP. The Corporation has provided IFRS accounting policies and prepared reconciliations between GAAP and IFRS in Note 2 and Note 16 of its September 30, 2011, interim consolidated financial statements. The following table provides a summary reconciliation of the 2010 net income under GAAP and IFRS to illustrate the impact on adoption. The adoption of IFRS did not have an impact on the Corporation's operations.

Summary of Net Income

($ in thousands)	2010	Q4 2010	Q3 2010	Q2 2010	Q1 2010
Net Income (Loss) - Canadian GAAP	(8,712)	(3,233)	(3,733)	(1,741)	(5)
General and Administrative	(519)	(60)	(153)	(108)	(197)
Depletion, Depreciation and Amortization	10,262	2,677	2,791	2,404	2,390
Finance Costs	305	173	78	80	(26)
Share-based Compensation	151	23	26	39	62
Income Taxes	(3,507)	(1,835)	(721)	(458)	(493)
Net Income (Loss) - IFRS	(2,020)	(2,255)	(1,712)	216	1,731

Exploration and Evaluation

Exploration and evaluation ("E&E") assets are those expenditures for an area or project which technical feasibility and commercial viability have not yet been determined. Such expenditures include costs of acquiring licenses, seismic, exploratory drilling and completion costs. E&E assets are not amortized. When technical feasibility and commercial viability are determined, the costs are transferred to property, plant and equipment. At the date of transition, the Corporation's E&E balance was $21.8 million, entirely related to undeveloped land. Exploration and evaluation assets will be subject to impairment testing if technical feasibility and commercial viability cannot be established.

Property, Plant and Equipment

Development expenditures include costs incurred subsequent to the determination of technical feasibility and commercial viability and are categorized as property, plant and equipment.

Under GAAP, with respect to dispositions, there was no recognition of a gain or loss unless the disposition would result in a change to the depletion rate of 20% or greater, in which case a gain or loss would be recorded. Under IFRS, a disposition of property, plant and equipment will generally result in the recognition of a gain or loss in income regardless of the amount of the transaction.

Under IFRS, the Corporation is required to recognize and measure an impairment loss if the carrying value of property, plant and equipment exceeds the recoverable amount of any individual cash generating unit ("CGU"). Under IFRS, the recoverable amount is the higher of fair value less cost to sell and value in use. The Corporation has two CGUs and did not record any impairment loss as a result of the accounting policy change.

Depletion, Depreciation and Amortization

Oil and natural gas properties, including pipelines are depleted using the unit of production method by reference to the ratio of production in a year to the related proved and probable reserves at a major area level. Under GAAP, only proved reserves were used. This change has resulted in lower depletion expense. Facility costs are depreciated over 10 years.

Decommissioning Liabilities

Under GAAP, asset retirement obligation was measured as the estimated fair value of the retirement and decommissioning expenditures expected to be incurred. Existing liabilities were not re-measured using current discount rates. Under IFRS, decommissioning liability is the best estimate of expenditures expected to be required to settle the present obligation at the end of the period. If there are uncertainties surrounding the amount recognized as a provision then the obligation is estimated by weighting all possible outcomes by their associated probabilities. The discount rate used for decommissioning liability is a risk free rate as the estimated provision is adjusted to reflect risks specific to the liability. Under GAAP, the Corporation used a credit-adjusted risk free rate. As a result, the Corporation's decommissioning liability increased at transition by $5.1 million. At December 31, 2010, the Corporation's decommissioning liabilities increased by $7.6 million. Under IFRS, the unwinding of the discount rate is charged as financing cost versus accretion expense under GAAP.

Share-based Compensation

IFRS 2, *Share-based Payments*, requires options given to employees to be fair valued using a model such as the Black-Scholes model. IFRS also requires the use of an estimated forfeiture rate. Under GAAP, the Corporation used the actual forfeiture rate in calculating fair value.

Flow-through Shares

Flow-through shares are a unique Canadian tax incentive which is the subject of specific guidance under GAAP. The premium paid for the flow-through shares in excess of the market value of the shares without the flow-through features at the time of issue is credited to share capital. When the renouncement is made share capital is reduced and a future income tax liability is recognized. Under IFRS, the flow-through share premium is recorded as other liability at the time of flow-through share issuance.

The liability is reversed and tax expense and future tax liability recorded upon renunciation of flow-through shares. At the January 1, 2010 transition date, share capital increased by $8.7 million as a result of flow-through shares issued prior to the transition date. In March 2010, the Corporation issued flow-through shares and under IFRS recorded a liability of $2.3 million.

Income Taxes

Future income taxes have been adjusted to reflect the tax effect arising from the differences between GAAP and IFRS.

CRITICAL ACCOUNTING ESTIMATES

In preparing financial statements in accordance with IFRS, management undertakes certain judgments and estimates. Changes in these judgments and estimates could have a material impact on the financial results and condition. The following discussion outlines accounting policies and practices that are critical to determining the Corporation's financial results.

Proved Oil and Natural Gas Reserves

Under the Canadian Securities Administrators' National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" (NI 51-101), "proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable (it is likely that the actual remaining quantities recovered will exceed the estimated proved reserves). In accordance with this definition, the level of certainty targeted by the reporting Corporation should result in at least a

90% probability that the quantities actually recovered will equal or exceed the estimated reserves. In the case of "probable" reserves, which are obviously less certain to be recovered than proved reserves, NI 51-101 states that it must be equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. With respect to the consideration of certainty, in order to report reserves as proved plus probable, the reporting Corporation must believe that there is at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

The oil and natural gas reserve estimates are made using all available geological, reservoir and historical production data. Estimates are reviewed and revised as appropriate. Revisions may occur as a result of changes in prices, costs, fiscal regimes, reservoir performance or a change in the Corporation's plans.

On an undiscounted basis, the future development costs associated with proved reserves is approximately $43.2 million compared to $383.7 million in expected cash flow. Estimated future development costs for probable reserves is $56.0 million compared to $331.5 million in expected cash flow. In either event, estimated future development costs will be funded from the Corporation's unutilized credit facility or from cash flow from operations. The cost of funding estimated future development costs will not make the development of a property uneconomic or have an impact on disclosed reserves or future cash flow from the production of proved reserves. Further information regarding the Corporation's reserves is contained in its Annual Information Form dated March 25, 2011 and filed on SEDAR at www.sedar.com.

Estimate of Recoverability

At each reporting period, the Corporation compares the carrying value of petroleum and natural gas properties to estimated future cash flow from the production of proved and probable reserves. If the future cash flows are lower than the carrying costs, the properties are written down to their fair value. Fair value is estimated using present value calculations, which incorporates risks and other uncertainties as well as the future value of reserves when determining estimated cash flows. These estimates are subject to measurement uncertainty and the impact on the financial statements could be material. As at September 30, 2011, there was no impairment of the Corporation's assets.

Decommissioning Obligation

The Corporation recognizes liabilities for the estimated reclamation and abandonment obligations on the balance sheet by increasing oil and natural gas properties offset by a liability of an equal amount. Estimates are required to determine the future obligation. The asset and liability are initially measured at fair value, being the discounted future value of the liability, and then capitalized as part of the cost of the asset and subsequently amortized over the life of the asset. The liability then accretes until the retirement obligation is settled.

Litigation

The Corporation is involved in various claims and litigation arising from the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Corporation's favour, the Corporation does not currently believe that the outcome of adverse decisions in any pending or threatened proceeding related to these and other matters or any amount which it may be required to pay by reason thereof, would have a material adverse effect on its financial position or results of operations.

Depletion, Depreciation and Amortization Expense

The Corporation uses the unit of production method based on proved plus probable reserves to determine depletion, depreciation and amortization expense. Changes in estimated proved or probable reserves or future development costs have a direct impact on depletion, depreciation and amortization expense.

Share-Based Compensation and Share Purchase Warrants

To determine the charge for share-based compensation, the Corporation calculates the fair value of the options granted and share purchase warrants issued using assumptions regarding the life of the option, dividend yields, interest rates, potential forfeiture rates and volatility. The assumptions used could differ from actual fair value of the stock options at any time.

Income Taxes

The determination of the Corporation's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment despite the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded.

Financial Instruments

The Corporation's results are impacted by external market risks associated with fluctuations in commodity prices, operational and safety and environmental risks. The Corporation partially mitigates its exposure to market risks through the use of various financial instruments and physical contracts. The Corporation does not utilize derivative instruments for speculative purposes.

RISK FACTORS RELATING TO OIL AND NATURAL GAS EXPLORATION, DEVELOPMENT AND PRODUCTION

Uncertain Discovery of Viable Commercial Prospects

The Corporation's future success may be dependent upon its ability to economically locate commercially viable oil or natural gas deposits. The Corporation can make no representations, warranties or guarantees that it will be able to consistently identify viable prospects, or that such prospects will be commercially exploitable. An inability of the Corporation to consistently identify and exploit commercially viable hydrocarbon deposits would have a material and adverse effect on the Corporation's business and financial position. Exploratory drilling is subject to numerous risks, including the risk that no commercially productive oil and natural gas reservoirs will be encountered. The cost of drilling, completing and operating wells is often uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including unexpected formation and drilling conditions, pressure or other irregularities in formations, blowouts, equipment failures or accidents, as well as weather conditions, compliance with governmental requirements and/or shortages or delays in the delivery of equipment. The inability to successfully locate and drill wells that will economically produce commercial quantities of oil and natural gas could have a material adverse effect on the Corporation's business and financial position. Terra Energy's properties are in various stages of exploration and development.

Whether the Corporation ultimately drills a property may depend on a number of factors including funding, the receipt of additional seismic data or reprocessing of existing data, material changes in oil or natural gas prices, the costs and availability of drilling equipment, success or failure of wells drilled in similar formations or which would use the same production facilities, changes in estimates of costs to drill or complete wells, the Corporation's ability to attract industry partners to acquire a portion of its working interest to reduce exposure to drilling and completion costs, decisions of the Corporation's joint working interest owners, and/or restrictions under provincial regulators.

Global Economic Conditions

Recent market events and conditions, including disruptions in the international credit markets and other financial systems, the deterioration of global economic conditions, and the increase in North American natural gas supply estimates have caused significant volatility to commodity prices. These conditions began in 2008, continued in 2009 and 2010, and still currently persist causing a loss of confidence in the broader U.S. and global credit and financial markets. This has resulted in the collapse of, and government intervention in, major banks, financial institutions and insurers thereby creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments to address the global financial crisis, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions continue to cause uncertainty both in the credit and capital markets. These factors may continue to negatively impact corporate valuations and may impact the performance of the global economy going forward. Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, OPEC actions, civil unrest in various commodity producing countries and the ongoing global credit and liquidity concerns.

The expectations for natural gas prices for 2011, continue to be bearish and will result in constrained cash flow levels for the Corporation. In order to manage through these uncertain times, the Corporation will continue to take a prudent approach to capital investment and operational spending. The Corporation is utilizing its hedging program to reduce cash flow volatility and currently has approximately 30% of its gas production hedged at $4.00 per GJ from April 1, 2011 through March 31, 2012 as well as an oil hedge for approximately 35% of its oil production from September, 2011 to June 2013. The Corporation has taken advantage of recent volatility in oil pricing to crystallize gain of $1.7 million. The Corporation will continue to utilize hedging strategies to protect and enhance cash flow.

Volatility of Oil and Natural Gas Contracts

The ultimate profitability, cash flow and future growth of the Corporation will be affected by changes in prevailing oil and natural gas prices. Oil and natural gas prices have been subject to wide fluctuations in recent years in response to changes in the supply and demand for oil and natural gas, market uncertainty, competition, regulatory developments and other factors which are beyond the control of the Corporation. It is impossible to predict future oil and natural gas price movements with any certainty. An extended or substantial decline in oil and natural gas prices would have a material adverse effect on: (i) the Corporation's access to capital, and (ii) the Corporation's financial position and results of operations.

Exploration, Development and Production Risks

Oil and natural gas exploration involves a high degree of risk and there is no assurance that expenditures made on exploration by the Corporation will result in new discoveries of oil or natural gas in commercial quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over pressured zones and tools lost in the hole, and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While close well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

British Columbia Royalty Regime

Under the British Columbia royalty regime, a temporary 2% natural gas royalty program was introduced effective September 1, 2009, whereby all natural gas wells with a spud date after August 31, 2009, and before July 1, 2010, are eligible for the 2% natural gas royalty, for a 12 month period, provided they commenced continuous production before December 31, 2010.

The Corporation's assets are located primarily in British Columbia, however, with the acquisition of the Peace River Arch assets in July 2009, the Corporation has increased exposure to the Alberta royalty regime. The Alberta royalty regime and drilling credit program and the British Columbia royalty regime may have an impact on decisions that the Corporation will make in determining where to focus its drilling activities in the future.

Alberta Royalty Regime

Under the Alberta royalty regime, the Government implemented "The New Royalty Framework" (the "NRF") on October 25, 2007, with an effective date of January 1, 2009. On November 19, 2008, in response to the significant reduction in activity and the global economic crisis, the Government of Alberta announced that for wells that commenced drilling after this date, companies can elect, on a well by well basis, to either have the NRF apply to the production from that well or have the old, pre-NRF rates apply for new wells between 1,000 and 3,500 metres in depth. This five-year transitional royalty system is designed to help stimulate drilling in Alberta.

On March 3, 2009, the Government of Alberta announced a three-point incentive program to stimulate new and continued economic activity in Alberta which included a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program.

On June 25, 2009, the Government announced that the drilling royalty credit for qualifying wells and the new well incentive program would be extended by one year to March, 2011.

On March 11, 2010, the Government of Alberta announced a plan to modify the current royalty framework for natural gas and conventional oil for all production effective January 1, 2011. Under the modified royalty framework, the maximum royalty rate will be reduced from the current levels of 50% to 40% for conventional oil and from 50% to 36% for natural gas, effective January 1, 2011. Royalty curves were finalized and announced on May 27, 2010.

There were no changes announced in Alberta's most recent budget delivered February 25, 2011.

Prices, Markets and Marketing of Crude Oil and Natural Gas

Oil and natural gas are commodities whose prices are determined based on world demand, supply and other factors, all of which are beyond the control of Terra Energy. World prices for oil and natural gas have fluctuated widely in recent years. Any material decline in prices will result in a reduction of net production revenue. Certain wells or other projects may become uneconomic as a result of a decline in world oil prices and natural gas prices, leading to a reduction in the future volume of the Corporation's oil and natural gas production. Terra Energy might also elect not to produce from certain wells at lower prices. All these factors could result in a material decrease in Terra Energy's future net production revenue, causing a reduction in its oil and natural gas acquisition and development activities. In addition, bank borrowings available to Terra Energy will be in part determined by the borrowing base of Terra Energy. A sustained material decline in prices from historical average prices could reduce Terra Energy's future borrowing base, therefore reducing the bank credit available to Terra Energy, and could require that a portion of any existing bank debt of Terra Energy be repaid.

In addition to establishing markets for its oil and natural gas, Terra Energy must also successfully market its oil and natural gas to prospective buyers. The marketability and price of oil and natural gas which may be acquired or discovered by Terra Energy will be affected by numerous factors beyond its control. Terra Energy will be affected by the differential between the price paid by refiners for light quality oil and the grades of oil produced by Terra Energy.

The ability of Terra Energy to market natural gas may depend upon its ability to acquire space on pipelines which deliver natural gas to commercial markets. Terra Energy will also likely be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities and related to operational problems with such pipelines and facilities and extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and the management of other aspects of the oil and natural gas business.

Substantial Capital Requirements; Liquidity

Terra Energy anticipates that it will make substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If Terra Energy's future revenues or reserves decline, Terra Energy may have limited ability to expend the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to Terra Energy. Moreover, future activities may require Terra Energy to alter its capitalization significantly. The inability of Terra Energy to access sufficient capital for its operations could have material adverse effect on Terra Energy's financial condition, results of operations or prospects.

Capital Markets

As a result of the weakened global economic conditions and certain natural gas pricing environment, Terra Energy, along with many industry peers, may have restricted access to capital, bank debt and equity, and is likely to face increased borrowing costs. Although Terra Energy's business and asset base have not changed, the lending capacity of all financial institutions has diminished and risk premiums have increased. As future capital expenditures will be financed out of funds generated from operations, borrowings and possible future equity sales, Terra Energy's ability to do so is dependent on, among other factors, the overall state of capital markets and investor appetite for investments in the energy industry and Terra Energy's securities in particular.

To the extent that external sources of capital become limited or unavailable or available on onerous terms, Terra Energy's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be materially and adversely affected as a result.

Based on current funds available and expected funds generated from operations, Terra Energy believes it has sufficient funds available to fund its projected capital expenditures. However, if funds generated from operations are lower than expected or capital costs for these projects exceed current estimates, or if Terra Energy incurs major unanticipated expense related to development or maintenance of its existing properties, it may be required to seek additional capital to maintain its capital expenditures at planned levels. Failure to obtain any financing necessary for Terra Energy's capital expenditure plans may result in a delay in development or production on Terra Energy's properties.

Competition

The Corporation engages in the highly competitive industry of exploration for and production of oil and natural gas. The Corporation competes directly and indirectly with major and independent oil and natural gas companies in its exploration for and development of desirable oil and natural gas properties. Many companies and individuals are engaged in the business of acquiring interests in and developing oil and natural gas properties in Canada, and the industry is not dominated by any single competitor or a small number of competitors. Many of such competitors have substantially greater financial, technical, sales, marketing and other resources, as well as greater historical market acceptance than does the Corporation. The Corporation will compete with numerous industry participants for the acquisition of land and rights to prospects, and for the equipment and labour required to operate and develop such prospects. Competition could materially and adversely affect the Corporation’s business, operating results and financial condition. Such competitive disadvantages could adversely affect the Corporation’s ability to participate in projects with favorable rates of return.

Shortage of Supplies and Equipment

The Corporation’s ability to conduct operations in a timely and cost effective manner is subject to the availability of natural gas and crude oil field supplies, rigs, equipment and service crews. Although none are expected currently, any shortage of certain types of supplies and equipment could result in delays in our operations as well as in higher operating and capital costs.

Interruption from Severe Weather

The Corporation’s operations are conducted principally in the central region of Alberta, northeastern British Columbia and Saskatchewan. The weather in these areas can be extreme and can cause interruption or delays in our drilling and construction operations.

Dependence on Third Party Pipelines

Substantially all of Terra Energy’s sales of natural gas production were through deliveries to local third party gathering systems to processing plants. In addition, the Corporation relies on access to interprovincial pipelines for the sale and distribution of substantially all of our natural gas. As a result, a curtailment of our sale of natural gas by pipelines or by third party gathering systems, an impairment of our ability to transport natural gas on interprovincial pipelines or a material increase in the rates charged to us for the transportation of natural gas by reason of a change in federal or provincial regulations or for any other reason, could have a material adverse effect upon us. In such event, we would have to obtain other transportation arrangements. There can be no assurance that we would have economical transportation alternatives or that it would be feasible for us to construct pipelines. In the event such circumstances were to occur, our netbacks from the affected wells would be suspended until, and if, such circumstances could be resolved.

Operating Hazards and Uninsured Risks

The oil and natural gas business involves a variety of operating risks, including fire, explosion, pipe failure, casing collapse, abnormally pressured formations, adverse weather conditions, governmental and political actions, premature reservoir declines and environmental hazards such as oil spills, natural gas leaks and discharges of toxic gases. The occurrence of any of these events with respect to any property operated or owned (in whole or in part) by us could have a material adverse impact on us. The Corporation and the operators of our properties, maintain insurance in accordance with customary industry practices and in amounts that we believe to be reasonable. However, insurance coverage is not always economically feasible and is not obtained to cover all types of operational risks. The occurrence of a significant event that is not insured or insured fully could have a material adverse effect on our financial condition.

Restoration, Safety and Environmental Risks

The Corporation's operations are in Alberta, British Columbia and Saskatchewan. Certain laws and regulations exist that require companies engaged in petroleum activities to obtain necessary safety and environmental permits to operate. Such legislation may restrict or delay us from conducting operations in certain geographical areas. Further, such laws and regulations may impose liabilities on us for remedial and clean-up costs, personal injuries related to safety and environmental damages, such liabilities are collectively referred to as "asset retirement obligations".

Expiration of Licenses and Leases

The Corporation's properties are held in the form of licenses and leases and working interests in licenses and leases. If the Corporation or the holder of the license or lease fails to meet the specific requirement of a license or lease, the license or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each license or lease will be met. The termination or expiration of the Corporation's licenses or leases or the working interests relating to a license or lease may have a material adverse effect on the Corporation's results of operations and business.

Title

Title to oil and natural gas interests is often not capable of conclusive determination without incurring substantial expense. In accordance with industry practice, Terra Energy will conduct such title reviews in connection with its principal properties as it believes are commensurate with the value of such properties. However, no absolute assurances can be given that title defects do not exist. If title defects do exist, it is possible that Terra Energy may lose all or a portion of its right title and interest in and to the properties to which the title defects relate.

Environmental Risks

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of international conventions and federal, provincial and municipal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require Terra Energy to incur costs to remedy such discharge. In recent months, the industry has been subject to greater focus of the environmental impact of drilling and completion techniques relating to the exploration of natural gas. Changes to the regulatory requirements for drilling and completion techniques could have a material impact on the ability of the Corporation to drill and complete natural gas wells. Implementation of strategies with respect to climate change and reducing greenhouse gases whether to meet the limits required by the Kyoto Protocol or as otherwise determined by federal or provincial governments could have a material impact on the nature of oil and natural gas operations, including those of Terra Energy (see "Environmental Regulation"). Terra Energy is in material compliance with environmental laws. No assurance can be given that the application of environmental laws to the business and operations of Terra Energy will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect Terra Energy's financial condition, results of operations or prospects.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities in oil, natural gas and natural gas liquids reserves and cash flows to be derived therefrom, including many factors beyond the Corporation's control. The reserve and associated cash flow information set forth herein represents estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom prepared by different engineers, or by the same engineers at different times, may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material. Further, the evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluation.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, GLJ Petroleum Consultants Ltd. ("GLJ"), the independent reserves evaluator, has prepared a reserves report effective December 31, 2010, (the "GLJ Reserves Report") using forecast price and cost estimates in calculating reserve quantities included herein.

Actual future net revenue will be affected by other factors such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs. Actual production and revenues derived therefrom will vary from the estimates contained in the GLJ Reserves Report, and such variations could be material. The GLJ Reserves Report is based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom, contained in the GLJ Reserves Report, will be reduced to the extent that such activities do not achieve the level of success assumed in the GLJ Reserves Report. The GLJ Reserves Report is effective as of a specific effective date and has not been updated and thus does not reflect changes in the Corporation's reserves since that date.

Reserve Replacement

Terra Energy's future oil and natural gas reserves, production, and cash flows to be derived therefrom are highly dependent on Terra Energy successfully acquiring or discovering new reserves. Without the continual addition of new reserves, any existing reserves Terra Energy may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Terra Energy's reserves will depend not only on Terra Energy's ability to develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. There can be no assurance that Terra Energy's future exploration and development efforts will result in the discovery and development of additional commercial accumulations of oil and natural gas.

Reliance on Operators and Key Employees

To the extent Terra Energy is not the operator of all of its oil and natural gas properties, Terra Energy will be dependent on such operators for the timing of activities related to such properties and will largely be unable to direct or control the activities of the operators. In addition, the success of Terra Energy will be largely dependent upon the performance of its management and key employees. Terra Energy does not have any key man insurance policies, and therefore there is a risk that the death or departure of any member of management or any key employee could have a material adverse effect on Terra Energy.

Corporate Matters

To date, the Corporation has not paid any dividends on its outstanding common shares and does not anticipate the payment of any dividends on its common shares for the foreseeable future.

Management of Growth

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

Permits and Licenses

The operations of Terra Energy may require licenses and permits from various governmental authorities. There can be no assurance that Terra Energy will be able to obtain all necessary licenses and permits that may be required to carry out exploration and development at its properties.

Additional Funding Requirements

Terra Energy's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, Terra Energy may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause Terra Energy to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If Terra Energy's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will effect Terra Energy's ability to expend the necessary capital to replace its reserves or to maintain its production. If Terra Energy's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available on favourable terms. Any equity financing may result in a change of control of Terra Energy or holders of its common shares suffering further dilution.

Variations in Foreign Exchange Rates

World oil and natural gas prices are quoted in U.S. dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has fluctuated materially in value against the U.S. dollar. Such fluctuations in the value of the Canadian dollar have materially impacted Terra Energy's operating entities production revenues. Further material fluctuations in the value of the Canadian dollar could exacerbate this impact. This fluctuation in the exchange rate for the Canadian dollar and future Canadian/U.S. exchange rates could accordingly impact the future value of Terra Energy's reserves as determined by independent evaluators.

Issuance of Debt

From time to time Terra Energy may enter into transactions to acquire assets or the shares of other corporations. These transactions may be financed partially or wholly with debt, which may increase Terra Energy's debt levels above industry standards. Neither Terra Energy's articles nor its bylaws limit the amount of indebtedness that Terra Energy may incur. The level of Terra Energy's indebtedness from time to time could impair Terra Energy's ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise. Terra Energy's ability to meet its debt service obligations will depend on Terra Energy's future operations which are subject to prevailing industry conditions and other factors, many of which are beyond the control of Terra Energy. As certain of the indebtedness of Terra Energy bears interest at rates which fluctuate with prevailing interest rates, increases in such rates would increase Terra Energy's interest payment obligations and could have a material adverse effect on Terra Energy's financial condition and results of operations. Further, Terra Energy's indebtedness is secured by substantially all of Terra Energy's assets. In the event of a violation by Terra Energy of any of its loan covenants or any other default by Terra Energy on its obligations relating to its indebtedness, the lender could declare such indebtedness to be immediately due and payable and, in certain cases, foreclose on Terra Energy's assets. In addition, oil and natural gas operations are subject to the risks of exploration, development and production of oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, cratering, sour gas releases, fires and spills. Losses resulting from the occurrence of any of these risks could have a material adverse effect on future results of operations, liquidity and financial condition.

Financial Instruments

From time to time the Corporation may enter into agreements to receive fixed prices on a portion of its oil or natural gas production to offset the risk of revenue losses if commodity prices decline, however, if commodity prices increase beyond the levels set in such agreements, the Corporation will not benefit from such increases. Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to U.S. dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the U.S. dollar; however, if the Canadian dollar declines in value compared to the U.S. dollar, the Corporation will not benefit from its fluctuating exchange rate.

Availability of Drilling Equipment and Access Restrictions

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to Terra Energy and may delay exploration and development activities.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. The Corporation is not aware that any claims have been made in respect of its property and assets; however, if a claim arose and was successful this could have an adverse effect on the Corporation and its operations.

Seasonality

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. There can be no assurance that these seasonal factors will not adversely affect the timing and scope of the Corporation's exploration and development activities, which could in turn have a material adverse impact on the Corporation's business, operations and prospects.

Third Party Credit Risk

The Corporation is, or may be exposed to, third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Corporation, such failures could have a material adverse effect on the Corporation and its cash flow from operations. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

Alternatives to and Changing Demand for Petroleum Products

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices could reduce the demand for crude oil and other liquid hydrocarbons. The Corporation cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Corporation's business, financial condition, results of operations and cash flows.

Emission Regulation

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". The Government of Canada is in the process of developing future regulatory requirements that are expected to set greenhouse gas emission reduction requirements for various industrial activities, including oil and gas exploration and production. Terra Energy's exploration and production facilities and other operations and activities emit a small amount of greenhouse gases which will likely subject Terra Energy to federal law regulating emissions of greenhouse gases if and when such requirements come into force. Future federal legislation, together with provincial emission reduction requirements, such as those contained in Alberta's Climate Change and Emissions Management Act, British Columbia's Greenhouse Gas Reduction (Cap and Trade) Act, and proposed in Saskatchewan's Bill 126: Management and Reduction of Greenhouse Gases Act, may require the reduction of emissions or emissions intensity with Terra Energy's operations and facilities. The direct or indirect costs of these regulations may adversely affect the business of Terra Energy.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions and regulation on the storage and transportation of various substances produced or utilized in association with certain oil and gas industry operations and can affect the location and operation of wells and facilities and the extent to which exploration and development is permitted. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. As well, applicable environmental laws may impose remediation obligations with respect to property designated as a contaminated site upon certain responsible persons, which include persons responsible for the substance causing the contamination, persons who caused the release of the substance and any past or present owner, tenant or other person in possession of the site. Compliance with such legislation can require significant expenditures and a breach of such legislation may result in the suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, the imposition of fines and penalties or the issuance of clean-up orders.

Applicable provincial environmental laws in British Columbia, Alberta and Saskatchewan are primarily found in the Environmental Management Act, Environmental Protection and Enhancement Act and the Environmental Management and Protection Act, 2002, respectively. Environmental standards and compliance for releases, clean-up and reporting in each province are strict, and there is a range of enforcement actions available, with often severe penalties. All of these provinces review energy projects through environmental assessment processes which may be held in conjunction with a federal assessment. These review processes involve public participation.

Environmental legislation in Alberta has been consolidated into the Environmental Protection and Enhancement Act (Alberta) (the "EPEA"), which came into force on September 1, 1993, and the Oil and Gas Conservation Act (Alberta) (the "OGCA"). The EPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations, and significantly increased penalties. In 2006, the Alberta Government enacted regulations pursuant to the EPEA to specifically target sulphur oxide and nitrous oxide emissions from industrial operations including the oil and gas industry. In addition, the reduction emission guidelines outlined in the Climate Change and Emissions Management Amendment Act came into effect on July 1, 2007 ("CCEMAA"). Under this legislation, Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12%. Industries have three options to choose from in order to meet the reduction requirements outlined in this legislation, namely, (i) making improvement to operations that result in reductions; (ii) purchasing emission credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emissions; or (iii) contributing to the Climate Change and Emissions Management Fund. Industries can either choose one of these options or a combination thereof. Pursuant to CCEMAA and the Specified Gas Emitters Regulation, companies were obliged to reduce their emission intensity by 12% by March 31, 2008. It is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

On January 24, 2008, the Alberta Government announced a new climate change action plan that will cut Alberta's projected 400 million tonnes of emissions in half by 2050. This plan is based on three areas: (i) carbon capture and storage, which will be mandatory for in situ oil sand facilities that use heavy fuels for steam generation; (ii) energy conservation and efficiency; and (iii) greening production through increased investment in clean energy technology, including supporting research on new oil sands extraction processes, as well as the funding of projects that reduce the cost of separating carbon dioxide from other emissions supporting carbon capture and storage. In addition to this action plan, the Provincial Energy Strategy unveiled on December 11, 2008 is expected to, among other things, support the upgrading, refining and petrochemical clusters existing in the Province of Alberta, market Alberta's energy internationally, review the emission targets and carbon charges applied to large facilities, and promote the innovation of energy technology by encouraging investment in research and development.

Environmental legislation in British Columbia has largely been consolidated into the Environmental Management Act (British Columbia) (the "EMA") and the Oil and Gas Activities Act (British Columbia) (the "OGAA"). The OGAA came into force on October 4, 2010, consolidating the numerous statutes and regulations that formerly governed the rights and responsibilities of the petroleum and natural gas industry in the province. The Environmental Protection and Management Regulation, created under the OGAA, imposes a number of obligations the petroleum and natural gas industry must meet with respect to wildlife, old-growth management areas, and water quality in streams, wetlands, lakes and aquifers. In addition, the Province has passed several pieces of legislation addressing greenhouse gas emissions, such as the Carbon Tax Act, Greenhouse Gas Reduction Targets Act, and Greenhouse Gas Reduction (Cap and Trade) Act, although not all provisions of the Greenhouse Gas Reduction (Cap and Trade) Act are currently in force. British Columbia facilities emitting more than 10,000 tonnes of greenhouse gases a year must record and report their emission levels from January 1, 2010, onwards, which is intended to form the basis for a future emissions reduction system.

In support of British Columbia's emissions reduction system, the provincial government published consultation papers for proposed regulations under the Greenhouse Gas Reduction (Cap and Trade) Act on October 22, 2010. The consultation papers contemplate an emission credits trading regime applicable to facilities in British Columbia that emit greater than 25,000 tonnes of greenhouse gases annually. Covered facilities would be required to meet compliance obligation through emission allowances, obtained by a combination of free distribution and auction, as well as emissions reduction units from offset projects or recognized compliance units from other jurisdictions.

It is reasonably likely that the trend towards stricter standards in environmental legislation and regulation in British Columbia will continue. In addition, the Government of British Columbia has outlined strategies and initiatives in a Climate Action Plan (released June 2008) which are intended to take British Columbia approximately 73% towards meeting its goal of reducing greenhouse gas emissions in the province by 33% of 2007 emission levels by 2020. British Columbia's greenhouse gas emission reduction targets were subsequently confirmed and expanded in the Clean Energy Act, which included a target of 80% reduction of emissions from 2007 levels by 2050. The Province's current Energy Plan (released February 2007) sets targets for zero net greenhouse gas emissions from electricity generation, the elimination of routine flaring at oil and gas producing wells and production facilities by 2016, new investments in innovation, and other measures aimed at clean energy leadership.

Federal environmental laws such as the Canadian Environmental Protection Act, 1999 and the Fisheries Act also apply in a variety of circumstances.

Climate change is an issue that is increasingly subject to government regulation. Although Canada has ratified the Kyoto Protocol and despite legislation to this end introduced by opposition parties in Parliament, it remains uncertain whether the targets in the Kyoto Protocol will be enforced in Canada. Alberta, British Columbia and the federal Government have all introduced climate change action plans that include various means of achieving emissions or emissions intensity reductions, which may include direct reductions, emissions trading, carbon capture and storage, technology fund contributions, taxes on greenhouse gas emissions and credit for early action. Coordination between these plans has not yet been developed and remains a source of uncertainty. Given the evolving regulatory schemes related to climate change and the control of greenhouse gases and resulting requirements, it is not currently possible to predict the final form these requirements will take or the impact on Terra Energy and its operations and financial condition at this time.

Conflicts of Interest

Directors and officers of Terra Energy may also be directors and officers of other oil and natural gas companies involved in oil and natural gas exploration and development, and conflicts of interest may arise between their duties as officers and directors of Terra Energy and as officers and directors of such other companies. Such conflicts must be disclosed in accordance with, and are subject to such other procedures and remedies as apply under the Alberta Business Corporations Act.

Dilution

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

Project Risks

Terra Energy will manage a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. Terra Energy's ability to execute projects and market oil and natural gas will depend upon numerous factors beyond Terra Energy's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies, including environmental regulations.

Because of these factors, Terra Energy could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.