TERRAENERGY CORP

Annual Information Form

For the Year Ended December 31, 2009

March 25, 2010

TABLE OF CONTENTS

THE CORPORATION **1**

Intercorporate Relationships 1

GENERAL DEVELOPMENT OF THE BUSINESS **1**

Business of the Corporation 1
Corporate Strategy 1
History of the Corporation 2
Recent Developments 3
Environmental Matters 5
Employees 5
Competitive Conditions 5

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION **5**

Petroleum and Natural Gas Reserves 5

RESERVE REPORT PRICING ASSUMPTIONS **9**

Forecast Prices and Costs Employed by GLJ - December 31, 2009 9

RECONCILIATION OF CHANGES IN RESERVES **10**

Reserves Reconciliation 10

ADDITIONAL INFORMATION RELATING TO RESERVES DATA **10**

Undeveloped Reserves 10
Proved Undeveloped Reserves 10
Probable Undeveloped Reserves 11
Significant Factors or Uncertainties Affecting Reserves Data 12

OTHER OIL AND GAS INFORMATION **13**

Oil and Gas Assets 13
Properties with No Attributed Reserves 16
Income Tax Horizon 17
Exploration and Development Activities 18
Production Estimates 18
Production History 19
Netback History 19
Production Volume by Field 20

RISK FACTORS **20**

Uncertain Discovery of Viable Commercial Prospects 20
Volatility of Oil and Natural Gas Contracts 21
Exploration, Development and Production Risks 21
Prices, Markets and Marketing of Crude Oil and Natural Gas 21
Global Economic Conditions 22
Capital Markets 22
Royalty Regime 22
Substantial Capital Requirements; Liquidity 23
Competition 23
Shortage of Supplies and Equipment 23

Interruption from Severe Weather 23
Dependence on Third-Party Pipelines 23
Operating Hazards and Uninsured Risks 24
Restoration, Safety and Environmental Risks 24
Expiration of Licenses and Leases 24
Title 24
Environmental Risks 24
Reserve Estimates 25
Operational Dependence 25
Reserve Replacement 26
Reliance on Key Employees 26
Corporate Matters 26
Management of Growth 26
Permits and Licences 26
Additional Funding Requirements 26
Variations in Foreign Exchange Rates 27
Issuance of Debt 27
Financial Instruments 27
Availability of Drilling Equipment and Access Restrictions 27
Aboriginal Claims 27
Seasonality 28
Third Party Credit Risk 28
Alternatives to and Changing Demand for Petroleum Products 28
Emission Regulation 28

INDUSTRY CONDITIONS 28

Canadian Government Regulation 28
Pricing and Marketing – Oil 29
Pricing and Marketing – Natural Gas 29
The North American Free Trade Agreement 29
Provincial Royalties and Incentives 29
Land Tenure 32
Environmental Regulation 33

DIVIDENDS OR DISTRIBUTIONS 34

DESCRIPTION OF SHARE CAPITAL 34

Common Shares 34
Preferred Shares 35

MARKET FOR SECURITIES 35

Price Range and Volume of Trading of Common Shares 35

PRIOR SALES 35

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER 36

DIRECTORS AND OFFICERS 36

CEASE TRADE ORDERS, BANKRUPTCIES, PENALTIES OR SANCTIONS 38

AUDIT COMMITTEE INFORMATION 38

LEGAL PROCEEDINGS 39

REGULATORY ACTIONS 40

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS 40
TRANSFER AGENT AND REGISTRAR 40
MATERIAL CONTRACTS 40
INTERESTS OF EXPERTS 40
CONFLICTS 40
ADDITIONAL INFORMATION 41
APPENDIX A FORM 51-101F2 42
APPENDIX B FORM 51-101F3 44
APPENDIX C DEFINITIONS USED FOR RESERVE CATEGORIES 46
APPENDIX D AUDIT COMMITTEE CHARTER 48

ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
bbl	barrels	mcf	thousand cubic feet
mbbl	thousand barrels	mmcf	million cubic feet
mmbbl	million barrels	mcf/d	thousand cubic feet per day
bbl/d	barrels of oil per day	mmcf/d	million cubic feet per day
API	American Petroleum Institute	mmbtu	million British thermal units
NGLs	natural gas liquids	GJ	gigajoule
stb	standard stock tank barrel	GJ/d	gigajoules per day
mstb	thousand standard stock tank barrels	H_2S	hydrogen sulfide

Other

boe	barrel of oil equivalent converting six mcf of natural gas to one barrel of oil (6:1)
boe/d	barrels of oil equivalent per day
km	kilometre
mboe	thousand of barrels of oil equivalent
M$	thousands of dollars
MM$	millions of dollars
NPV	net present value
OPEC	Organization of Petroleum Exporting Countries

In this Annual Information Form the calculation of barrels of oil equivalent (boe) is calculated at a conversion rate of 6,000 cubic feet (mcf) of natural gas for one barrel (bbl) of oil based on an energy equivalency conversion method. Boes may be misleading particularly if used in isolation. A boe conversion ratio of 6 mcf : 1 bbl is based on an energy equivalency conversion method primarily applicable to the burner tip and does not represent a value equivalency at the wellhead.

CURRENCY

In this Annual Information Form, unless otherwise noted, all dollar amounts are expressed in Canadian dollars.

FORWARD-LOOKING STATEMENTS

Certain statements contained in this Annual Information Form and in certain documents incorporated by reference into this Annual Information Form, constitute forward-looking statements. These statements relate to future events or the Corporation's future performance. All statements other than statements of historical fact may be forward-looking statements. 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. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Corporation believes that the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form or as of the date specified in the documents incorporated by reference into this Annual Information Form, as the case may be. The Corporation does not intend, and does not assume any obligation, to update or revise these forward-looking statements except as required pursuant to applicable securities laws.

Forward-looking information and statements are included throughout this Annual Information Form (and the documents incorporated by reference herein) including under the headings "General Development of the

Business", "Statement of Reserves Data and Other Oil and Gas Information", "Additional Information Relating to Reserves Data", "Other Oil and Gas Information", "Risk Factors" and "Industry Conditions" and include, but are not limited to, statements pertaining to the following:

- the use of the net proceeds of the Financing;
- any estimate of present value or future cash flow;
  drilling inventory, drilling plans and timing of drilling, re-completion and tie-in of wells;
- plans for facilities construction and completion and the timing and method of funding thereof;
- productive capacity of wells, anticipated or expected production rates and anticipated dates of commencement of production;
- drilling, completion and facilities costs;
- results of various projects of Terra Energy;
- timing of receipt of regulatory approvals;
- effect of production increases on operating costs per boe;
- ability to lower cost structure in certain projects of Terra Energy;
- growth expectations within Terra Energy;
- timing of development of undeveloped reserves;
- the tax horizon and taxability of Terra Energy;
- supply and demand for oil, natural gas liquids and natural gas;
- the performance and characteristics of Terra Energy's oil and natural gas properties;
- Terra Energy's acquisition strategy, the criteria to be considered in connection therewith and the benefits to be derived there from;
- the impact of Canadian federal and provincial governmental regulation on Terra Energy relative to other oil and gas issuers of similar size;
- realization of the anticipated benefits of acquisitions and dispositions;
- weighting of production between different commodities;
- the quantity and quality of the oil and natural gas reserves;
- projections of commodity prices and costs;
- expectations regarding the Corporation's ability to raise capital and continually add reserves through acquisition and development;
- expected levels of royalty rates, operating costs, general and administrative costs, costs of services and other costs and expenses;
- capital expenditure programs and the timing and method of financing thereof; and
- treatment under government regulation and taxation regimes.

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 Annual Information Form:

- general economic and business conditions in Canada, the United States and globally;
- the ability of management of the Corporation to execute its business plan;
- fluctuations in the price of oil and natural gas, interest and exchange rates;
- the risks of the oil and gas industry both domestically and internationally, such as operational risks in exploring for, developing and producing crude oil and natural gas and market demand;
- actions taken by governmental authorities, including increases in taxes and changes in government regulations and incentive programs;
- geological, technical, drilling and processing problems;
- risks and uncertainties involving geology of oil and gas deposits;
- risks inherent in marketing operations, including credit risk;
- the ability to enter into or renew leases;
- the uncertainty of estimates and projections relating to production, costs and expenses;
- potential delays or changes in plans with respect to exploration or development projects or capital expenditures;
- availability of sufficient financial resources to fund the Corporation's capital expenditures;

- uncertainty of finding reserves, developing and marketing those reserves;
- unanticipated operating events, which could reduce production or cause production to be shut in or delayed;
- failure to realize the anticipated benefits of acquisitions and incorrect assessments of the value of acquisitions;
- ability to locate satisfactory properties for acquisition or participation;
- shut-ins of connected wells resulting from extreme weather conditions;
- insufficient storage or transportation capacity;
- hazards such as fire, explosion, blowouts, cratering and spills, each of which could result in substantial damage to wells, production facilities, other property and the environment or in personal injury;
- encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations;
- the ability to add production and reserves through development and exploration activities;
- the possibility that government policies or laws, including laws and regulations related to the environment, may change or governmental approvals may be delayed or withheld;
- uncertainty in amounts and timing of royalty payments;
- uncertainties inherent in estimating quantities of oil and natural gas reserves and cash flows to be derived therefrom;
- failure to obtain industry partner and other third party consents and approvals, as and when required;
- stock market volatility and market valuations;
- competition for, among other things, capital, acquisition of reserves, undeveloped land and skilled personnel;
- competition for and inability to retain drilling rigs and other services; and
- the other factors considered under “Risk Factors” in this Annual Information Form and other risk factors identified in other documents incorporated herein by reference.

These factors should not be considered exhaustive. 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 Annual Information Form, 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 information has been provided in this Annual Information Form 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.

The forward-looking statements contained in this Annual Information Form and the documents incorporated by reference herein are expressly qualified by this cautionary statement.

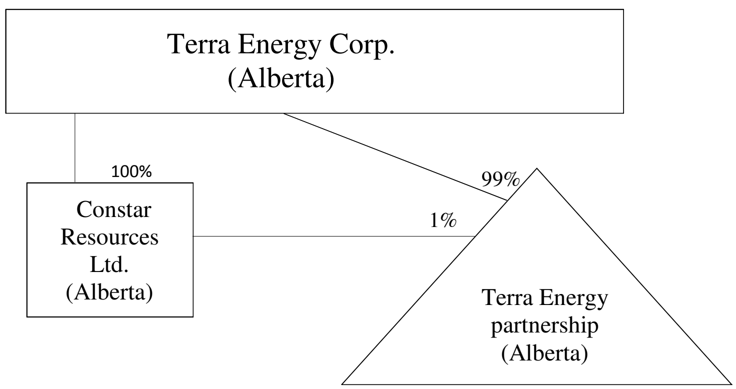
THE CORPORATION

Terra Energy Corp. ("**Terra Energy**" or the "**Corporation**") was amalgamated pursuant to the Alberta *Business Corporations Act* ("**ABCA**") on January 30, 2004 (the "**Terra Energy Amalgamation**"). One of the amalgamating predecessor corporations, Rhodes Resources Corp. ("**Rhodes**"), was continued under the ABCA on November 1, 2002. The other amalgamating corporations, Terrapet Energy Corp. ("**Terrapet**") and Terra Energy Corp., were incorporated pursuant to the ABCA.

The head and registered office of the Corporation is located at Suite 970, 333-7th Ave S.W., Calgary, Alberta T2P 2Z1.

Intercorporate Relationships

The following diagram sets forth the names of the significant subsidiaries of the Corporation, the percentage of voting securities owned by the Corporation and the jurisdiction of incorporation or continuance of each subsidiary as of the date hereof. Terra Energy and Constar Resources Ltd., an Alberta Corporation, are partners in the Terra Energy partnership, a general partnership which carries on oil and gas exploration, development and production activities utilizing the assets of the partners.



GENERAL DEVELOPMENT OF THE BUSINESS

Business of the Corporation

The Corporation is an oil and gas exploration, development and production company operating primarily in the Western Canadian Sedimentary Basin.

Corporate Strategy

Terra Energy expects to grow through a combination of low-risk exploitation and high-impact exploration drilling. Terra Energy will, however, consider additional growth opportunities through business combinations, the acquisition of oil and gas properties, acquisition of undeveloped lands and through additional development and exploratory drilling. Growth will be funded through cash flow, increased debt, equity offerings and/or asset rationalizations.

History of the Corporation

2007

The Corporation's focus in 2007 was primarily on infrastructure with approximately 50% of its Capital program being applied to infrastructure and the remainder being divided between drilling, completions, land acquisition and seismic.

The Tower to Septimus pipeline project commenced flowing gas on April 30, 2007 and added approximately 500 boe/d of production from the Tower field. The East Boudreau pipeline project commenced flowing gas on September 12, 2007 and added approximately 830 boe/d. The Tower dehydration and compression facility was constructed by Terra Energy in the fourth quarter of 2007. The Corporation owns 100% of this facility. The facility commenced processing gas on December 20, 2007 and added approximately an additional 500 boe/d of incremental production from Tower.

The completion of these projects allowed Terra Energy to bring on much of its "behind pipe" production. Quarterly average production rates for 2007 were: Q1 - 2,476 boe/d, Q2 – 3,005 boe/d, Q3 – 3,706, and Q4 –3857 boe/d.

Credit Facility

In May of 2007, Terra Energy renewed and expanded its credit facility from $55,000,000 to $65,000,000 with a syndicate of senior lenders. In December of 2007, the credit facility was expanded to $70,000,000. The increases were in line with increased production.

2008

Terra Energy completed a major infrastructure project with the construction of a 25.4 kilometer, 8" gathering pipeline to connect its Eight Mile and Sunrise Fields to its Tower Dehydration and Compression Facility.

On May 13, 2008, the Corporation sold approximately 110 sections of Montney petroleum and natural gas rights for net proceeds received of $66.5 million. Under full cost accounting, the sale of undeveloped petroleum and natural gas property uses a deemed cost of disposition, which resulted in a gain of $15.1 million. The sales were focused on and limited to the Montney formation in approximately 110 gross sections of land, leaving those mineral rights held by the Corporation in formations, both above and below the Montney, unaffected by the sale process. At the time of such sale, Terra Energy did not have any production from the Montney formation at Fort St. John, leaving the Corporation's production base untouched.

In November 2008, the installation of a second compressor expanded the design capacity of the Tower facility to approximately 20 mmcf per day. The production from Tower, Eight Mile and Sunrise fields has raised the production to 5,132 boe/d during Q4 2008.

2009

On June 17, 2009, the Corporation, though its wholly-owned subsidiary 1475136 Alberta Ltd., acquired all the outstanding shares of Tecton Energy Canada ULC with the issuance of 2,580,645 common shares of the Corporation at a value of $1.47 per share and $4.1 million of cash. The value of the common shares issued is based upon the volume weighted average market price over a period before and after the date the terms of the business combination are announced. The acquisition was accounted for using the purchase method of accounting where the Corporation is identified as the acquirer.

On July 15, 2009, the Corporation completed the acquisition (the "**Peace River Arch Asset Acquisition**") of certain high quality, long-life oil and gas assets located in the Peace River Arch regions of northeast British Columbia and northwest Alberta for approximately $76.6 million (the "**Peace River Arch Assets**"). The Peace

River Arch Assets included approximately 2,200 boe/d of production, 77,600 gross (46,000 net) acres of undeveloped land and several "oil targeted" development prospects. Fields associated with the Peace River Arch Assets include Stoddart, Eagle, Boundary, Bonanza, Cecil and Worsley, among others. The Peace River Arch Asset Acquisition served to further consolidate the Corporation's existing position in its core area of Fort St. John in British Columbia while significantly expanding the Corporation's footprint into the more oil-prone regions of the Peace River Arch in Alberta. A business acquisition report of the Corporation dated August 11, 2009 with respect to the Peace River Arch Asset Acquisition the Corporations' profile was filed through the Internet on the Corporation's profile on the System for Electronic Document Analysis and Retrieval (SEDAR) website at www.sedar.com.

In connection with the Peace River Arch Asset Acquisition, the Corporation completed a bought deal subscription receipt on the financing for gross proceeds of $20,300,000 by issuing 14,000,000 subscription receipts ("**Subscription Receipts**") of the Corporation at a price of $1.45 per Subscription Receipt which were exchanged for 14,000,000 Common Shares and 7,000,000 Common Share purchase warrants ("**Warrants**"). Each whole Warrant is exercisable into one Common Share at a price of $1.90 and expires on July 7, 2011.

In July 2009, the Corporation completed the expansion of its credit facility to $90,000,000 with its existing syndicate of lenders. In connection with the Boundary Lake Unit Sale (as defined below), the Corporation's credit facility was reduced from $90,000,000 to $80,000,000.

On December 15, 2009, the Corporation completed the sale of its non-operated interests in Boundary Lake Units 1 and 2 for gross proceeds of approximately $24,000,000, subject to post closing adjustments (the "**Boundary Lake Unit Sale**"). Under the terms of the Boundary Lake Unit Sale, Terra Energy sold its 2.3515% unit interest in Boundary Lake Unit 1 and its 4.7129% unit interest in Boundary Lake Unit 2. Unit interest production related to the sale was approximately 140 boe/d with proved plus probable reserves of approximately 1,600,000 boe resulting in deal metrics of more than $171,000 per flowing boe and $14.41 per boe of proved plus probable reserves.

Recent Developments

On February 10, 2010, the Corporation entered into a farm-in and option agreement with a large producer (the "**Farm-in Agreement**"), whereby Terra Energy has committed to drill two test wells and will have the option to drill a third test well, all with a view towards earning a 100% interest in 13 sections of prospective land within the Montney Fairway in northeast British Columbia.

The first test well is required to be spud on or before July 30, 2010. The second test well must be spud on or before September 30, 2010. The test wells will primarily be targeting the Montney formation and other deeper formations, but may also have secondary targets. Each of the two initial test wells is planned to be a simple vertical drill, but the Farm-in Agreement does allow for the conversion of one vertical drill into a horizontal drill, thereby satisfying the earning requirement for drilling the third test well (the option well). Under the terms of the Farm-in Agreement, the farmor will retain a non-convertible 10% gross overriding royalty on production from the earned lands. The farm-in lands and the option lands are all adjacent to or in close proximity to other lands of the Corporation in the Wilder and Altares/Farrell Creek areas.

On February 16, 2010, the Corporation completed an asset exchange (the "**Asset Arrangement**") pursuant to an asset exchange agreement (the "**Asset Exchange Agreement**") whereby Terra Energy and its counterparty, a large producer, negotiated and executed a formal asset exchange agreement and completed the assignment and conveyance of assets. The Asset Arrangement involved an exchange of oil and gas assets, with cash forming no part of the consideration. The effective date of the Asset Arrangement was November 1, 2009.

In accordance with the terms of the Asset Exchange Agreement, Terra Energy acquired approximately 91 gross (66 net) sections of land located in several key areas of high activity in northeast British Columbia, including Altares/Farrell Creek, Wilder/Monias, Groundbirch and Inga/Fireweed. The lands acquired by the Corporation are in close proximity to the Corporation's existing core area of operations. In addition to the Montney Fairway, Terra Energy acquired certain additional lands in northeastern British Columbia having identified potential for multi-frac horizontal development.

Upon completion of the Asset Arrangement, Terra Energy is one of the largest holders of prospective Montney rights in British Columbia, with approximately 122 gross (100 net) sections within the prospective Montney Fairway.

In consideration for the assets acquired under the Asset Arrangement, Terra Energy assigned and conveyed to the counterparty all of its rights and interests in a specified resource play which has been under development by the Corporation for more than two years. This specified resource play consists of "tight" siltstones and shales which encase a porous and laterally-continuous sandstone "body" of approximately two metres in thickness. The sandstone body and adjacent shales and siltstones are charged with natural gas. Accordingly, the rights and interests assigned by Terra Energy under the Asset Exchange Agreement were limited to only a designated geological interval of approximately 35 meters in thickness (embodying the entire resource play), extending across approximately 77 gross (69 net) sections of land. Terra Energy retained the balance of its rights and interests to all other geological units owned by Terra Energy in these 77 sections of land. The rights and interests assigned by Terra Energy did not include any wells or tangible assets, and were comprised entirely of petroleum and natural gas rights. At the effective date of the Asset Arrangement, the assets assigned by the Corporation under the Asset Arrangement were not contributing to the Corporation's overall production base or cash flow.

Terra Energy has entered into an option to purchase (the "**Option**") pursuant to which Terra Energy has the option to acquire various interests in both unitized and non-unitized oil and gas properties located within the Corporation's existing core operating areas. The Option involves approximately 2,000 boe/d of liquids rich production for total cash consideration of approximately $115 million. The Option is subject to customary title and environmental due diligence, various representations, warranties, conditions, approvals and closing adjustments. Unless extended by the parties, the Option will expire March 31, 2010.

On March 3, 2010, the Corporation announced its capital expenditure plan and budget for the financial year ended December 31, 2010 ("**2010 Capex Plan**"). The 2010 Capex Plan contemplates a minimum of $65,000,000 of capital expenditures targeting: (i) a strategic push into the Montney Fairway in northeast British Columbia, by advancing the level of geotechnical/engineering science, on a "field-by-field" basis, in respect of each block or field of prospective undeveloped Montney land, to the "decision-point" stage for major commercial development and proving-up significant reserves in the process; and (ii) drilling projects designed to maintain production or increase it beyond the current base level of 7,100 boe/d which includes advancing work on other non-conventional plays on the Corporation's existing land base (including plays targeting "oily" reservoirs), shifting the balance in the commodity mix of the Corporation's conventional operations closer towards 50:50 (oil:gas) weighting over time, maximizing the use of Alberta drilling incentive credits and benefitting from the British Columbia temporary gas royalty program.

On March 24, 2010, the Corporation closed a "bought-deal" financing for gross proceeds of $22.5 million (the "**Financing**"), with a syndicate of underwriters by issuing an aggregate of 5 million Common Shares at a price of $1.80 per share for gross proceeds of $9,000,000 and 6.25 million Common Shares were issued on a "flow-through" basis under the *Income Tax Act* (Canada) ("**Flow-Through Shares**") at a price of $2.16 per share for gross proceeds of $13,500,000.

The net proceeds of the Financing will be used by the Company to temporarily reduce indebtedness under the Company's credit facility as at the date of the closing of the Financing, which will be subsequently redrawn and applied as needed to fund the 2010 Capex Plan, in the case of proceeds from the issuance of the Flow-Through Shares, the incurring of Canadian exploration expenses before December 31, 2011, and for general corporate purposes.

Environmental Matters

The oil and gas industry is subject to environmental regulations pursuant to applicable legislation. Such legislation provides for restrictions and prohibitions on release or emission of various substances produced in association with certain oil and gas industry operations, and requires that well and facility sites be abandoned and reclaimed to the satisfaction of environmental authorities. Terra Energy recorded an estimated provision on its balance sheet of $10.1 million for reserve and abandonment site restoration as at December 31, 2009. The Corporation maintains an insurance program consistent with industry practice to protect against losses due to accidental destruction of assets, well blowouts, pollution and other operating accidents or disruptions. The Corporation also has operational and emergency response procedures and safety and environmental programs in place to reduce potential loss exposure. See "*INDUSTRY CONDITIONS – ENVIRONMENTAL REGULATION*".

Employees

At December 31, 2009, Terra Energy's work force consisted of 35 employees. Field operations are provided by a combination of independent contractors and full-time staff. As at March 25, 2010, Terra Energy's head office work force consisted of 36 employees and our Fort St. John field office consisted of 3 employees.

Competitive Conditions

The oil and natural gas industry is intensely competitive in all its phases. Terra Energy competes with numerous other participants in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Terra Energy's competitors include resource companies which have greater financial resources, staff and facilities than those of Terra Energy. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. Terra Energy believes that its competitive position is equivalent to that of other oil and gas issuers of similar size and at a similar stage of development. See "*RISK FACTORS - COMPETITION*".

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Petroleum and Natural Gas Reserves

GLJ Petroleum Consultants Ltd. ("**GLJ**"), independent petroleum engineers of Calgary, Alberta prepared a Reserves Assessment and Evaluation of Canadian Oil and Gas Properties - Corporate Summary and Property Reports and a corporate evaluation dated February 23, 2010 of Terra's oil and gas reserves (the "**GLJ Report**") which evaluation is effective December 31, 2009. **The GLJ Report is in respect of Terra's core oil and gas properties.** In preparing its report, GLJ obtained basic information from Terra, which included land data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts, financial data and future operating plans. Other engineering, geological or economic data required to conduct the evaluation and upon which the GLJ Report is based, was obtained from public records, other operators and from GLJ's non-confidential files. The extent and character of ownership and the accuracy of all factual data supplied for the independent evaluation, from all sources, was accepted by GLJ as represented.

The following tables set forth certain information relating to the oil and natural gas reserves of the Corporation's properties and the present value of the estimated future net cash flow associated with such reserves as at December 31, 2009 which numbers may vary slightly from those presented in the GLJ Report, due to rounding. Also due to rounding, certain columns may not add exactly. The information set forth below is derived from the GLJ Report which reports have been prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("**NI 51-101**"). **All evaluations and reviews of future net cash flow are stated prior to any provision for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. The estimated future net revenue from the production of disclosed oil and gas reserves does not represent the fair market value of the**

Corporation's reserves. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGLs and natural gas reserves may be greater than or less than the estimates provided herein.

In accordance with the requirements of NI 51-101, attached hereto are the following appendices:

Appendix A: *Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor in Form 51-101F2.*

Appendix B: *Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3.*

Appendix C: *Definitions used for reserve categories in the GLJ Report.*

SUMMARY OF OIL AND GAS RESERVES
as of December 31, 2009

FORECAST PRICES AND COSTS

RESERVES

RESERVES CATEGORY	OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL OIL EQUIVALENT	
	Gross before Royalty (mbbl)	Net after Royalty (mbbl)	Gross before Royalty (mbbl)	Net after Royalty (mbbl)	Gross before Royalty (mmcf)	Net after Royalty (mmcf)	Gross before Royalty (mbbl)	Net after Royalty (mbbl)	Gross before Royalty (mbbl)	Net after Royalty (mbbl)
Proved Developed Producing	1,562	1,254	25	23	50,995	40,644	1,599	1,233	11,685	9,284
Developed Non-Producing	211	164	14	14	9,627	7,626	234	185	2,063	1,633
Proved Undeveloped	0	0	300	209	9,074	7,253	270	219	2,083	1,637
Total Proved	1,773	1,418	338	246	69,696	55,523	2,103	1,636	15,831	12,554
Probable	539	450	110	76	38,518	30,586	953	734	8,021	6,358
Total Proved Plus Probable	2,311	1,868	449	322	108,214	86,109	3,056	2,370	23,852	18,912

SUMMARY NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2009

FORECAST PRICES AND COSTS

RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT (%YEAR)					AFTER INCOME TAXES DISCOUNTED AT (%YEAR)					UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/YEAR
	0	5	10	15	20	0	5	10	15	20	
	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	$/boe
Proved Developed	287,404	219,282	179,688	153,790	135,449	241,923	185,125	152,226	130,730	115,505	19.36
Producing Developed	39,327	29,201	23,007	18,785	15,708	29,289	21,361	16,523	13,235	10,847	14.09
Non-Producing Undeveloped	53,139	42,283	35,538	30,924	27,546	39,280	30,990	25,838	22,316	19,744	21.70
Total Proved	379,871	290,766	238,233	203,498	178,703	310,491	237,477	194,587	166,281	146,096	18.98
Probable	205,423	115,197	75,551	54,117	40,928	153,862	85,279	55,032	38,629	28,519	11.88
Total Proved Plus Probable	585,294	405,963	313,784	257,615	219,630	464,353	322,756	249,619	204,911	174,616	16.59

TOTAL FUTURE NET REVENUE

(UNDISCOUNTED)
as of December 31, 2009

FORECAST PRICES AND COSTS

Reserves Category	**Revenue (M$)**	**Royalties (M$)**	**Operating Costs (M$)**	**Capital Development Costs (M$)**	**Well Abandonment Costs (M$)**	**Future Net Revenue Before Income Taxes (M$)**	**Income Taxes (M$)**	**Future Net Revenue After Income Taxes (M$)**
Proved Reserves	880,987	175,210	298,507	21,256	6,144	379,871	69,379	310,491
Probable	498,592	96,600	162,195	32,336	2,038	205,423	51,561	153,862
Proved Plus Probable Reserves	1,379,580	271,810	460,702	53,591	8,183	585,294	120,941	464,353

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2009

FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES & ARTC (discounted at 10%/year) (M$)	UNIT VALUE BEFORE INCOME TAXES (discounted at 10% year) ($/BOE)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	53,276	29.95
	Heavy Oil (including by-products but excluding solution gas	11,128	35.46
	Natural Gas (including by-products but excluding solution gas from oil wells)	173,466	16.62
	Non-conventional Oil and Gas Activities	354	13.32
	Total	238,224	18.98
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	63,898	27.26
	Heavy Oil (including by-products but excluding solution gas	13,306	32.32
	Natural Gas (including by-products but excluding solution gas from oil wells)	236,132	14.65
	Non-conventional Oil and Gas Activities	440	11.20
	Total	313,775	16.59

RESERVE REPORT PRICING ASSUMPTIONS

Forecast Prices and Costs Employed by GLJ - December 31, 2009

GLJ employed the following pricing, exchange rate and inflation rate assumptions in estimating Terra Energy's reserves data using forecast prices and costs as of December 31, 2009.

FORECAST PRICES USED IN PREPARING RESERVES DATA
GLJ Petroleum Consultants

Crude Oil and Natural Gas Liquids

Price Forecast
Effective December 31, 2009

Year	WTI Crude Oil $US/bbl	Brent Crude Oil $US/bbl	Edmonton Light Crude Oil $C/bbl	Alberta Lloyd Blend Medium Crude Oil $C/ bbl	Alberta Heavy Crude Oil $C/ bbl	Sask Cromer Medium Crude Oil $C/ bbl	Ethane's $C/ bbl	Edmonton Propane $C/ bbl	Edmonton Butanes $C/ bbl	Edmonton Pentaines Plus $C/ bbl	Inflation %	US/CAN Exchange Rate $US/$CAN
	(1)	(2)	(3)	(4)	(5)	(6)						
Forecast												
2010	$80.00	$78.50	$83.26	$70.36	$64.99	$76.60	$20.02	$52.46	$64.11	$84.93	2	$0.950
2011	$83.00	$81.50	$86.42	$71.30	$65.24	$78.64	$22.88	$54.45	$66.54	$88.15	2	$0.950
2012	$86.00	$84.50	$89.58	$72.11	$65.33	$80.62	$23.24	$56.43	$68.98	$91.37	2	$0.950
2013	$89.00	$87.50	$92.74	$72.80	$65.26	$82.54	$23.43	$58.42	$71.41	$94.59	2	$0.950
2014	$92.00	$90.50	$95.90	$75.28	$67.52	$85.35	$23.79	$60.42	$73.84	$97.82	2	$0.950
2015	$93.84	$92.34	$97.84	$76.80	$68.90	$87.07	$24.15	$61.64	$75.33	$99.79	2	$0.950
2016	$95.72	$94.22	$99.81	$78.35	$70.32	$88.83	$25.06	$62.88	$76.85	$101.81	2	$0.950
2017	$97.64	$96.14	$101.83	$79.93	$71.76	$90.63	$26.88	$64.15	$78.41	$103.86	2	$0.950
2018	$99.59	$98.09	$103.89	$81.55	$73.22	$92.46	$28.84	$65.45	$79.99	$105.96	2	$0.950
2019	$101.58	$100.08	$105.98	$83.19	$74.72	$94.32	$29.46	$66.77	$81.60	$108.10	2	$0.950
Thereafter	2.0%/y	2.0%/y	2.0%/y	2.0%/y	2.0%/y	2.0%/y	2.0%/y	2.0%/y	2.0%/y	2.0%/y	2.0%/y	

(1) West Texas Intermediate at Cushing Oklahoma
(2) North Sea Brent Blend
(3) Edmonton Light Sweet 40 degrees API, 0.3% sulphur
(4) Lloyd Blend Medium at Hardisty Alberta
(5) Heavy crude oil 12 degrees API at Hardisty Alberta
(6) Midale Cromer crude oil 29 degrees API, 2.0% sulphur

FORECAST PRICES USED IN PREPARING RESERVES DATA
GLJ Petroleum Consultants

Natural Gas and Sulphur
Price Forecast
Effective December 31, 2009

Year	NYMEX Futures Contract $US/mmbtu	Alberta AECO Spot Price $C/mmbtu	Alberta Average Plantgate $C/mmbtu	Alberta Aggregator Plantgate $C/mmbtu	Sask. Prov. Gas SaskEnergy $C/mmbtu	Sask. Spot Sales Plantgate $C/mmbtu	British Columbia Westcoast Station 2 $C/mmbtu	British Columbia Spot Plantgate $C/mcf
			(1)					
Forecast								
2010	$6.00	$5.96	$5.75	$5.51	$5.68	$5.88	$5.76	$5.56
2011	$7.00	$6.79	$6.58	$6.30	$6.48	$6.71	$6.59	$6.38
2012	$7.10	$6.89	$6.68	$6.40	$6.58	$6.81	$6.69	$6.49
2013	$7.15	$6.95	$6.73	$6.45	$6.63	$6.87	$6.75	$6.54
2014	$7.30	$7.05	$6.84	$6.55	$6.73	$6.97	$6.85	$6.64
2015	$7.50	$7.16	$6.94	$6.65	$6.83	$7.08	$6.96	$6.75
2016	$7.75	$7.42	$7.20	$6.90	$7.09	$7.34	$7.22	$7.01
2017	$8.25	$7.95	$7.72	$7.41	$7.59	$7.87	$7.75	$7.53
2018	$8.79	$8.52	$8.29	$7.95	$8.14	$8.44	$8.32	$8.10
2019	$8.96	$8.69	$8.47	$8.12	$8.31	$8.61	$8.49	$8.28
Thereafter	2.0%/y	2.0%/y	2.0%/y	2.0%/y	2.0%/y	2.0%/y	2.0%/y	2.0%/y

(1) This forecast also applies to direct sales contracts and the Alberta gas reference price used in the crown royalty calculations.

Terra Energy's weighted average realized sales prices for the year ended December 31, 2009 were $64.57/bbl for crude oil, $4.14/mcf for natural gas and $31.39/bbl for natural gas liquids.

RECONCILIATION OF CHANGES IN RESERVES

Reserves Reconciliation

The following table sets forth a reconciliation of Terra Energy's total net proved, probable and proved plus probable reserves as at December 31, 2009 against such reserves as at December 31, 2008 based on forecast price and cost assumptions.

	LIGHT , MEDIUM AND HEAVY OIL			ASSOCIATED AND NON-ASSOCIATED GAS			NATURAL GAS LIQUIDS			BOE		
Factors	**Gross Proved (mbbl)**	**Gross Probable (mbbl)**	**Gross Proved Plus Probable (mbbl)**	**Gross Proved (mmcf)**	**Gross Probable (mmcf)**	**Gross Proved Plus Probable (mmcf)**	**Gross Proved (mbbl)**	**Gross Probable (mbbl)**	**Gross Proved Plus Probable (mbbl)**	**Gross Proved (mbbl)**	**Gross Probable (mbbl)**	**Gross Proved Plus Probable (mbbl)**
Dec. 31, 2008	653	312	965	56,998	29,680	86,678	2,287	1,071	3,358	12,440	6,329	18,769
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	335	109	444	8,984	(735)	8,249	200	(3)	197	2,033	(17)	2,016
Infill Drilling	-	-	-	-	-	-	-	-		-	-	-
Technical Revisions	2	(66)	(64)	(2,668)	(1,829)	(4,496)	(512)	(235)	(747)	(954)	(604)	(1,558)
Acquisitions	1,299	286	1,585	22,310	14,452	36,762	603	219	823	5,620	2,914	8,534
Dispositions	-	-	-	(4,592)	(2,603)	(7,196)	(153)	(91)	(243)	(918)	(525)	(1,443)
Economic Factors	(10)	8	(2)	(1,110)	(447)	(1,557)	(44)	(9)	(53)	(239)	(76)	(313)
Production	(168)	-	(168)	(10,226)	-	(10,226)	(279)	-	(279)	(2,151)	-	(2,151)
Dec. 31, 2009	2,111	649	2,760	69,696	38,518	108,214	2,103	953	3,056	15,831	8,021	23,852

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

The following discussion generally describes the basis on which Terra Energy attributes proved and probable undeveloped reserves and its plans for developing those undeveloped reserves.

Proved Undeveloped Reserves

Proved undeveloped reserves are generally those reserves related to wells that have been tested and not yet tied-in, wells drilled near the end of the fiscal year or wells further away from Terra Energy gathering systems. In addition, such reserves may relate to planned infill drilling locations. The majority of these reserves are planned to be on stream within a two year timeframe.

The majority of Terra Energy's proved undeveloped reserves are in the Corporation's core area of Fort St. John B.C. and newly acquired areas of Balsam and Cecil in Alberta.

British Columbia

In Sunrise, which represents approximately 66% of the total proved undeveloped reserves of the Corporation, Terra Energy has budgeted for the drilling of two 100% infill development wells and two 25% non operated wells. Both of the 100% wells were drilled prior to year end and were placed on production in the beginning of 2010.

Alberta

In Cecil (which represents approximately 13% of the total proved undeveloped reserve value of the Corporation), Terra Energy drilled a successful well in Q4 2009, which was subsequently placed on production on January 1, 2010.

In Balsam (which represents approximately 18% of the total proved undeveloped reserve value of the Corporation), Terra Energy drilled a successful well in Q1 2010. The well has been completed, and is expected to be tied-in and equipped with facilities for production by the end of Q1 2010.

The following table sets forth the volumes of gross proved undeveloped reserves that were first attributed in each of Terra Energy's three most recent financial years and before that, in the aggregate:

PROVED UNDEVELOPED RESERVES								
	Light and Medium Crude Oil		Heavy Crude Oil		Natural Gas		Natural Gas Liquids	
	1st Attributed	Cumulative at year end	1st attributed	Cumulative at year end	1st attributed	Cumulative at year end	1st attributed	Cumulative at year end
31-Dec	(mboe)	(mboe)	(mboe)	(mboe)	(mmcf)	(mmcf)	(mboe)	(mboe)
Prior to 2007	90	95	0	0	10,034	16,915	72	87
2007	0	0	0	0	810	3,555	9	119
2008	0	0	0	0	5,183	6,146	125	168
2009	0	0	300	300	3,890	9,065	92	270

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Probable Undeveloped Reserves

Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. The majority of these reserves are planned to be on stream within a two year timeframe.

The majority of Terra Energy's probable undeveloped reserves are related to drilling locations identified by GLJ and Terra Energy as locations which are highly prospective for natural gas and / or crude oil discoveries.

In Altares, which represents approximately 32 of the probable undeveloped reserve value of the Corporation, Terra Energy intends to drill two follow up horizontal Montney locations offset a vertical well which has already been completed and tested.

In Tower, which represents approximately 5% of the probable undeveloped reserve value of the Corporation, Terra Energy intends to drill one follow-up location in 2010 as have been identified by GLJ as a probable location. Drilling is expected to commence in Q3 2010 with an expected on stream date of Q4 2010, subject to regulatory and land owner approvals.

In Sunrise, which represents approximately 13% of the probable undeveloped reserve value of the Corporation, Terra Energy intends to drill one follow up location in 2010 as have been identified by GLJ as a probable location. This location is scheduled to be drilled in Q3 2010 with an expected on stream date of Q4 2010, subject to regulatory and land owner approvals.

In Boudreau, which represents approximately 17.0% of the probable undeveloped reserve value of the Corporation, Terra Energy has identified two drilling locations which are considered to be development drilling locations. Upon drilling the two locations in Boudreau, Terra Energy has adequate infrastructure in place to tie-in any new natural gas and oil volumes which the Corporation may discover.

In Monias, which represents 5% of the probable undeveloped reserve value of the Corporation, Terra Energy has identified an offset horizontal drilling location to a producing Montney gas well. This well is scheduled to be drilled and on stream in 2010.

The remaining probable undeveloped reserves relate to reserves associated with small working interest drilling locations, producing wells which may, depending on economics and actual well production results, produce additional reserves above and beyond the existing proved reserves.

The following table sets forth the volumes of probable undeveloped reserves that were first attributed in each of Terra Energy's three most recent financial years and, before that, in the aggregate:

PROBABLE UNDEVELOPED RESERVES								
	Light and Medium Crude Oil		Heavy Crude Oil		Natural Gas		Natural Gas Liquids	
	1st Attributed	Cumulative at year end	1st attributed	Cumulative at year end	1st attributed	Cumulative at year end	1st attributed	Cumulative at year end
31-Dec	(mboe)	(mboe)	(mboe)	(mboe)	(mmcf)	(mmcf)	(mboe)	(mboe)
Prior to 2007	118	192	0	0	15,160	26,630	150	228
2007	0	84	0	0	5,623	11,583	107	368
2008	0	84	0	0	7,318	12,546	165	392
2009	0	84	100	100	10,705	18,918	101	377

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, commodity prices and economic conditions. Terra Energy's reserves are evaluated by GLJ which is an independent engineering firm.

Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, commodity prices, economic conditions and governmental restrictions. Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. Terra Energy's actual production, revenues, taxes, development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material.

Future Development Costs

The following table outlines development costs deducted in the estimation of future net revenue attributable to proved reserves (using forecast prices and costs) and proved plus probable reserves (using forecast prices and costs) to those properties evaluated in the GLJ Report.

	Forecast Prices and Costs	
	Proved Reserves (M$)	**Proved Plus Probable Reserves (M$)**
2010	10,139	23,779
2011	4,755	19,046
2012	0	1,615
2013	1,486	2,786
Remaining Years	4,876	6,365
Total Undiscounted	21,256	53,591
Total Discounted at 10% per year	16,924	44,781

OTHER OIL AND GAS INFORMATION

Oil and Gas Assets

The following discussion outlines the Corporation's important properties, plants, facilities and installations:

Boudreau (B.C.)

The Boudreau 14-13-84-21 W6M sour oil / gas facility is located approximately 25 km west of Fort St. John and was constructed by Terra Energy in the 4th quarter of 2004. The Corporation owns 100% of this facility. The Boudreau facility has compression, dehydration, oil / water separation and water disposal handling. The oil is trucked from the facility and the gas is compressed and delivered to the Spectra raw gas gathering system for processing at the Spectra McMahon Gas Plant. In 2006, Terra Energy constructed a "line-loop" pipeline connecting the Corporation's underutilized Red Creek facility to the new natural gas discovery wells in Boudreau. With the completion of the pipeline, the majority of Terra Energy's Boudreau production is processed at the Red Creek facility.

Eagle (B.C.)

Terra Energy operates and has a 40.16% ownership interest in a 2.9 mmcf/d gas facility located at 6-19-85-18 W6M in the Eagle area. The facility consists of desiccant dehydration and compression facilities. The facility is located approximately 13 km north of Fort St. John.

Red Creek (B.C.)

The Red Creek 3-10-85-21 W6M facility is located approximately 35 km west of Fort St. John and is equipped with compression, dehydration, oil separation and water injection. In 2005, a new 4 inch pipeline was constructed to tie-in two new Baldonnel development wells to the underutilized Red Creek facility. Additional drilling added four additional Baldonnel wells. In December 2005, a new 815 horsepower compressor was added to handle this new and future production from the area south of Red Creek. The compressor is capable of handling 8 mmcf/d and with additional pipeline capacity up to 10 mmcf/d. The existing low pressure compressor continues to handle the solution gas and low pressure gas from the Red Creek field. In September 2007, a 19.5 km gathering line connecting the East Boudreau gas field to Red Creek was commissioned. The Corporation owns 100% of this facility.

Stoddart (B.C.)

The Stoddart Facility at 14-26-85-20W5 is located approximately 25 km north-west of Fort St. John. The facility consists of an oil battery and gas compression. The battery is pipeline connected to an oil pipeline and the natural gas is delivered to the Spectra raw gas gathering system for delivery to the Spectra McMahon Gas facility.

Tower (B.C.)

The Tower 9-28-81-17 W6M sour dehydration and compression facility is located approximately 24 km south-east of Fort St. John and was constructed by Terra Energy in the 4th quarter of 2007. The Corporation owns 100% of this facility. Initially, four wells (eight productive zones) were tied into the facility. Addition wells were tied in from the North Eight Mile and Sunrise areas in 2008 with completion of a 25.4 km 8 inch gathering pipeline.

The Tower facility had initially installed capacity of 14 mmcf/d and was enlarged to 20 mmcf/d with the addition of a second compressor in November 2008. The facility has compression, dehydration, separation facilities and tankage for field condensate and water. The facility is connected to the Spectra “South Peace Pipeline” and delivers gas to the Spectra McMahon Gas facility. Terra Energy has a five year firm service agreement with Spectra.

The Tower facility is also connected to the Septimus and Wilder fields via a six inch 38 km pipeline. It allows excess production in the Tower area to be delivered to the Terra Energy operated Wilder Facility. If the Wilder Facility becomes full, the pipeline may be reversed and gas from the Septimus and Wilder areas may be delivered to the Tower facility.

The Sunrise portion of the 8 inch gathering pipeline is also connected to a third party gathering system and facility located at West Doe. Approximately 3.25 mmcf/d of firm capacity sour processing is contracted at the West Doe facility.

Wilder (B.C.)

The Wilder 10-34-82-20 W6M gas facility is located 20 km southeast of Fort St. John and is equipped with compression and dehydration. A 17 km pipeline was constructed in the first quarter of 2006 to tie-in wells located at Septimus that are completed in the Halfway and Boundary Lake formations. In the first half of 2007, a 19 km pipeline was constructed from the Tower area to Septimus to interconnect the Tower, Septimus and Wilder fields. The Wilder facility has capacity of approximately 10 mmcf/d and is owned 100% by the Corporation. This facility processes Terra Energy owned production plus third party gas and is in a key area for additional third party processing from the Montney resource play.

Stoddart 4-24 and North Pine 11-2 (B.C.)

Terra Energy acquired two facilities in the Stoddart/North Pine area in 2009 as part of the Peace River Arch Assets. The Stoddart 4-24 facility has a 200 hp screw booster compressor, a 768 hp recip compressor and dehydration for processing of gas for sales to Spectra’s raw gas gathering system. The North Pine 11-2 facility has a 1,545 hp recip compressor and dehydration for processing of gas for sales to Spectra’s raw gas gathering system. The Corporation owns 94.7% of the Stoddart 4-24 facility, 41.9% of the North Pine 11-2 facility and operates both on behalf of the working interest partners.

North Boundary/Hill (AB)

The North Boundary 10-19-86-11W6 gas facility is located 72 km northeast of Fort St. John and is equipped with an amine and dehydration facility. The facility has an approximate capacity of 3 mmcf/d and is licenced for a maximum of 1 tonne/day of sulfur emissions. The facility is connected to an existing third party facility for dewpoint control and sales metering to the Nova Gas Transmission system. The Corporation owns 65.625% of the facility and operates it on behalf of the working interest partners. This facility was acquired in 2009 as part of the Peace River Arch Assets.

Worsley (AB)

The Worsley 16-36-86-10W6 sweet gas facility is located 90 km northeast of Fort St. John and is equipped with a 6 mmcf/d compressor and a 5 mmcf/d refrigeration unit for gas treatment and sales to Nova Gas Transmission. There is a second decommissioned 7 mmcf/d refrigeration package located on site. This facility processes both owned production and some third party gas and is owned 100% by the Corporation. This facility was acquired in 2009 as part of the Peace River Arch Assets.

Cecil Battery (AB) The Cecil 8-6-85-8W6 battery is located 100 km east of Fort St. John and is equipped with 2000 bbls of oil separation and storage capacity, a 3000 bbl/d water injection system and a 100 hp solution gas compressor. Solution gas is gathered to the Devon operated 16-4-85-8W6 Cecil facility for further processing. The Corporation owns 90% of the facility and operates it on behalf of the working interest partners. This facility was acquired in 2009 as part of the Peace River Arch Assets.

Dimsdale (AB)

The Dimsdale facility is located 15 km west of Grande Prairie, Alberta and is equipped with separation and metering facilities and compression. The gas is tied into the Wembley gas plant where the gas is processed and shipped to sales. This infrastructure will be utilized with production obtained from the two new wells Terra Energy drilled in 2005.

Wells

As at December 31, 2009, the Corporation had an interest in 223 gross (96 net) producing and 322 gross (177 net) non-producing oil, natural gas and other wells as follows:

	PRODUCING				**NON-PRODUCING**					
	Oil		**Natural Gas**		**Oil**		**Natural Gas**		**Other**	
Wells	**Gross**[1]	**Net**[2]	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
B.C.	21	14.7	56	36.9	29	21.4	51	34.6	49	37.7
Alberta	84	14.6	59	29.4	56	19.1	57	27.2	73	35.8
Sask.	3	0	0	0	6	0.8	0	0	1	0.1
TOTAL WELLS	108	29	115	66	91	41	108	62	123	74

Notes:
(1) "Gross" wells means the number of wells in which Terra Energy has a working interest.
(2) "Net" wells means the aggregate number of wells obtained by multiplying each gross well by Terra Energy's percentage working interest therein.

Properties with No Attributed Reserves

The following table sets forth the gross and net acres of unproved properties held by the Corporation as at December 31, 2009 and the net area of unproved property for which the Corporation expects its rights to explore, develop and exploit to expire during the next year.

	UNPROVED PROPERTIES (acres)		
LOCATION	**Gross[(1)]**	**Net[(2)]**	**Net Area to Expire by December 31, 2010**
Alberta	289,838	260,680	20,438
Saskatchewan	1,913	1,750	1,284
British Columbia	331,151	233,127	48,214
TOTAL	622,902	495,557	69,936

Notes:

(1) "Gross Acres" are the total acres in which Terra Energy has or had an interest.

(2) "Net Acres" is the aggregate of the total acres in which Terra Energy has or had an interest multiplied by Terra Energy's working interest percentage held therein.

There are no costs or work commitments associated with Terra Energy's non-producing properties except for ongoing Crown lease commitments.

The undeveloped land holdings of the Corporation were evaluated as at December 31, 2009 by Seaton-Jordan & Associates Ltd. ("**Seaton-Jordan**"). The estimated value of Terra Energy's net undeveloped land holdings is approximately $72.1 million as at December 31, 2009. This valuation represents an increase of 146% over last year's valuation of undeveloped land prepared by Seaton-Jordan.

Additional Information Concerning Abandonment and Reclamation Costs

Terra Energy estimates well abandonment and reclamation costs for surface leases, wells and facilities based on its previous experience, current regulations, costs, technology and industry standards area by area. Such costs are included in the GLJ Report as deductions in arriving at future net revenue. The expected total abandonment costs for wells and facilities are summarized in the net of estimated salvage value calculated without discount and using a discount rate of 10% is as follows:

TERRA ENERGY RESERVES

	Forecast (M$) Pricing			
	Proved NPV 0%	**Proved NPV 10%**	**Proved Plus Probable NPV 0%**	**Proved Plus Probable NPV 10%**
Wells with reserves assigned	6,144	2,215	8,183	2,196
Wells & Facilities with no reserves assigned	7,500	2,608	7,500	2,608
Total abandonment and reclamation cost provision(1)(2)	13,644	4,823	15,683	4,804
Portion forecast to be paid during the next three years	1,354	1,309	1,259	1,230

Notes:
(1) Abandonment and disconnect costs were estimated by GLJ and are included in the GLJ Report for wells assigned reserves.
(2) The Corporation has estimated the timing and costs associated with the abandonment and reclamation for wells with no reserves assigned. These costs were not included in the GLJ Report.

Income Tax Horizon

At December 31, 2009, Terra Energy had estimated income tax deductions of approximately $147.7 million available to reduce future taxable income. Terra Energy does not expect to incur material current income taxes for the year ended December 31, 2010.

The following table summarizes Terra Energy's property acquisition costs, exploration costs and development costs incurred during the financial year ended December 31, 2009.

	$
Exploration	5,807,931
Development	7,719,106
Undeveloped Land	6,104,027
Geological / Geotechnical	585,357
Facilities	6,353,086
Other Assets	1,661,100
Total Capital Expenditures	28,230,607
Net Property Acquisitions	51,290,536
Total Capital Expenditures	79,521,143

Exploration and Development Activities

The following table summarizes the results of exploration and development activities during the financial year ended December 31, 2009.

	Gross[(1)]	Net[(2)]
Development Wells		
Gas	5.0	4.1
Oil	1.0	0.5
Standing	1.0	0.6
Dry	-	-
Exploratory Wells		
Gas	1.0	0.8
Oil	-	-
Standing	-	-
Dry	-	-
Total Wells	8.0	6.0

Notes:

(1) "Gross" wells means the number of wells in which Terra Energy has a working interest or a royalty interest that may be convertible to a working interest.

(2) "Net" wells means the aggregate number of wells obtained by multiplying each gross well by Terra Energy's percentage working interest therein.

Production Estimates

The following discloses the estimated average daily production of Terra Energy through fiscal 2010 by product type associated with the first year of the future net revenue estimates reported in the GLJ Report effective December 31, 2009.

	Light and Medium Crude Oil (bbl/d)	Heavy Oil (bbl/d)	Natural Gas (mcf/d)	Natural Gas Liquids (bbl/d)	Combined BOE (boe/d)
Proved					
Developed producing					
Sunrise	0	0	5,279	182	1,062
Other	648	8	20,522	613	4,689
Total	648	8	25,801	795	5,751
Developed non-producing					
Sunrise	0		32	1	6
Other	50	8	1,710	25	368
Total	50	8	1,742	26	375
Proved undeveloped					
Sunrise	0	0	4,055	140	816
Other	0	143	1,843	36	487
Total	0	143	5,898	176	1,303
Total Proved	699	159	33,441	998	7,429
Probable					
Sunrise	0	0	263	9	53
Other	8	0	3,721	98	726
Total	8	0	3,984	107	779
Total proved plus probable	707	159	37,425	1,105	8,208

Production History

The following table summarizes Terra Energy's average daily sales production volumes before deduction of royalties, for the periods indicated.

	2009				
	Year ended December 31, 2009	**Q4 Oct. - Dec.**	**Q3 July - Sept.**	**Q2 April - June**	**Q1 Jan. - March**
Oil (bbl/d)	460	778	691	186	176
Natural Gas Liquids (bbl/d)	775	728	618	700	1,058
Natural gas (mcf/d)	28,263	29,132	28,840	27,156	27,900
Total (boe/d)	5,946	6,361	6,117	5,412	5,884

Netback History

The following table sets forth information respecting average net product prices received, royalties paid, operating expenses and netbacks received by the Corporation in respect of the Corporation's production of crude oil and natural gas for the periods indicated.

	2009				
	Year ended December 31, 2009	**Q4 Oct. - Dec.**	**Q3 July - Sept.**	**Q2 April - June**	**Q1 Jan. - March**
Selling prices					
Oil ($/bbl)	64.57	69.58	65.90	61.91	39.37
Natural gas ($/mcf)	4.14	4.79	2.98	3.60	5.21
Natural gas liquids ($/bbl)	31.39	43.14	25.77	32.24	25.97
Royalties					
Oil ($/bbl)	14.29	17.95	21.39	5.93	3.43
Natural gas ($/mcf)	0.61	0.54	0.26	0.52	1.14
Natural gas liquids ($/bbl)	8.34	14.79	9.14	5.30	5.67
Production expenses(1)					
Oil ($/bbl)	8.99	11.50	7.21	7.42	9.58
Natural gas ($/mcf)	1.50	1.92	1.20	1.24	1.60
Natural gas liquids ($/bbl)	8.99	11.50	7.21	7.42	9.58
Field netbacks					
Oil ($/bbl)	41.29	40.13	37.30	48.56	26.36
Natural gas ($/mcf)	2.03	2.33	1.52	1.84	2.47
Natural gas liquids ($/bbl)	14.06	16.85	9.42	19.52	10.72

Note:

(1) Operating expenses include mineral and surface lease rentals, property taxes and expenses related to the operation and maintenance of wells, production facilities and gathering systems.

Production Volume by Field

The following table discloses for each significant field, and in total, Terra Energy's sales production volumes for the financial year ended December 31, 2009 for each product type.

Field	Light and Medium Crude Oil (bbls/d)	Natural Gas (mcf/d)	Natural Gas Liquids (bbls/d)	BOE (boe/d)	%
Boudreau, British Columbia	24	5,006	121	979	16%
Sunrise, British Columbia	2	9,422	310	1,882	33%
Tower, British Columbia	-	4,041	120	793	13%
Other	434	9,794	224	2,292	38%
Total	460	28,263	775	5,946	100%

RISK FACTORS

The business of exploring for, developing and producing oil and natural gas reserves is inherently risky. Oil and natural gas operations involve many risks which even a combination of experience and knowledge and careful evaluation may not be able to overcome. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by Terra Energy.

Uncertain Discovery of Viable Commercial Prospects

The Corporation's future success may be dependent upon its ability to economically locate commercially viable oil or gas deposits. The Corporation can make no representations, warranties or guaranties 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 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 gas could have a material adverse effect on the Corporation's business and financial position. The Corporation'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 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.

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 gas prices. Oil and 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 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 Terra Energy 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 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.

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 Terra Energy's oil and 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 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. Terra Energy has limited direct experience in the marketing of oil and natural gas.

Global Economic Conditions

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions began in 2008, continued in 2009 and still currently persist causing a loss of confidence in the broader U.S. and global credit and financial markets and which has resulted in the collapse of, and government intervention in, major banks, financial institutions and insurers and 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 the credit and capital markets. These factors may continue to negatively impacted 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 and the ongoing global credit and liquidity concerns.

Capital Markets

Continued global economic volatility may result in Terra Energy, along with all other oil and gas entities, to have restricted access to capital, bank debt and equity, and could 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 only 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 expenses 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.

Royalty Regime

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on well productivity, geographical location, field discovery data and the type or quality of the petroleum product produced.

The royalty regime in British Columbia, Alberta and any other jurisdictions in which the Corporation's oil and natural gas assets are located may be subject to further review and changes which could adversely impact Terra Energy's financial condition and operations.

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.

Competition

The Corporation engages in the highly competitive industry of exploration for and production of oil and gas. The Corporation competes directly and indirectly with major and independent oil and gas companies in its exploration for and development of desirable oil and gas properties. Many companies and individuals are engaged in the business of acquiring interests in and developing oil and 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 labor 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

In fiscal 2009, 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 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 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, 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

Our 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 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 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. 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 "*INDUSTRY CONDITIONS – ENVIRONMENTAL REGULATION*". Terra Energy is in material compliance with current 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 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, the independent reserves evaluator, has used 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 Report, and such variations could be material. The GLJ 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 Report will be reduced to the extent that such activities do not achieve the level of success assumed in the GLJ Report. The GLJ Report is effective as of a specific effective date and has not been updated and thus does not reflect changes in the Corporation's resources since that date.

Operational Dependence

Other companies operate some of the assets in which Terra Energy has an interest. As a result, Terra Energy will have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect Terra Energy's financial performance. Terra Energy's return on assets operated by others will therefore depend upon a number of factors that may be outside of Terra Energy's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

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 Key Employees

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, Terra Energy 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.

Certain of the directors and officers of Terra Energy are also directors and officers of other oil and gas companies involved in oil and 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 ABCA.

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. The inability of the Corporation to deal with this growth could have a material adverse impact on its business, operations and prospects.

Permits and Licences

The operations of Terra Energy may require licences and permits from various governmental authorities. There can be no assurance that Terra Energy will be able to obtain all necessary licences 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 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 affect 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 gas prices are quoted in United States 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 increased materially in value against the United States dollar. Such material increases in the value of the Canadian dollar have negatively impacted Terra Energy's operating entities production revenues in the past. Further material increases in the value of the Canadian dollar would exacerbate this negative impact. Future increases in the exchange rate for the Canadian dollar and future Canadian/United States 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 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 materially 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 its oil and 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 United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States 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 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 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 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.

INDUSTRY CONDITIONS

Canadian Government Regulation

The oil and natural gas industry is subject to extensive controls and regulations imposed by various levels of government. Outlined below are some of the more significant aspects of the relevant legislation and regulations. It is not expected that any of such controls and regulations will affect the operations of the Corporation in a manner materially different than they will affect other oil and gas companies of similar size.

Pricing and Marketing – Oil

Producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Such price depends on oil quality, price of competing oils, distance to market and the value of refined products. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export license from the NEB and the issuance of such license requires the approval of the Governor in Council.

Pricing and Marketing – Natural Gas

The price of natural gas sold in intra-provincial and inter-provincial trade is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the government of Canada. The price received by the Corporation depends, in part, on the prices of competing natural gas and other substitute fuels, access to downstream transportation, distance to markets, length of the contract term, weather conditions, the supply and demand balance and other contractual terms. Exporters are free to negotiate prices with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than 2 years or for a term of 2 to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export license from the NEB and the issuance of such license requires the approval of the Governor in Council.

The government of Alberta also regulates the volume of natural gas which may be removed from the province for consumption elsewhere.

The lack of firm pipeline capacity continues to limit the ability to produce and market natural gas production although pipeline expansions are ongoing. In addition, the pro-rationing of capacity on the interprovincial pipeline systems continues to limit oil exports.

The North American Free Trade Agreement

On January 1, 1994, the North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico became effective. NAFTA carries forward most of the material energy terms contained in the Canada-U.S. Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports to the U.S or Mexico will be allowed provided that the restrictions are otherwise justified under certain provisions of the General Agreement on Tariffs and Trade and then only if any export restrictions do not: (i) reduce the proportion of the energy resource exported relative to the total supply of energy resource (based upon the proportion prevailing in the most recent 36 months); (ii) impose an export price higher than the domestic price; or (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory boarder restrictions and export taxes. The agreement also contemplates clearer disciplines on regulators to avoid discriminatory actions and to minimize disruption of contractual arrangements.

Provincial Royalties and Incentives

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on well productivity, geographical location, field discovery data and the type or quality of the petroleum product produced.

From time to time the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. Oil and gas royalty rates vary from province to province.

On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" (the "**NRF**") containing the government's proposals for Alberta's new royalty regime which became effective on January 1, 2009 and is applicable to all conventional oil and natural gas wells in Alberta.

On November 19, 2008 and November 24, 2008 the Government of Alberta announced details of an optional five-year transitional royalty program that applies to conventional oil and natural gas wells drilled to measured depths between 1,000 and 3,500 meters between November 19, 2008 and January 1, 2014. For each such well, the Corporation can make a onetime election to produce the well under the transitional royalty program or the NRF. As of January 1, 2014, all production subject to the transitional program will revert to the NRF.

Subsequent to the October 2007 and November 2008 announcements, the Government of Alberta launched a study of the competitiveness of the conventional oil and gas business in Alberta. The Government of Alberta has indicated that such study is to be completed in September 2009.

On March 3, 2009, the Government of Alberta announced new incentive programs to encourage additional activity in the province's conventional oil and gas sectors. These new incentives included a royalty credit of $200 per meter drilled on new conventional oil and natural gas wells and a royalty reduction that provided a maximum five percent royalty rate for all new wells that begin producing conventional oil and natural gas between April 1, 2009 and March 31, 2010, for up to 12 months production or the first 50,000 barrels of oil or 500,000 mcf of natural gas produced from a new well.

On March 11, 2010, the Government of Alberta announced that the following will become permanent features of the royalty structure, effective with the January 2011 production month:

- Permanent 5% front-end royalty
    - The current incentive program rate of 5% on new natural gas and conventional oil wells will become a permanent feature of the royalty system, with the current time and volume limits.

- Lower Maximum Rates
    - The maximum royalty rate for conventional oil will be reduced at higher price levels from 50% to 40% to provide better risk-reward balance to investors.
    - Recognizing the fundamental changes to the North American supply/demand balance and increased competition from other jurisdictions, the maximum royalty rate for conventional and unconventional natural gas will be reduced at higher price levels from 50% to 36%.

- Implementation/Transition
    - All royalty curves will be finalized and announced by May 31, 2010 and be effective for all production January 1, 2011.
    - The transitional royalty framework for oil and gas introduced in November 2008 will continue until its original announced expiration on December 31, 2013. Effective January 1, 2011, no new wells will be allowed to select the transitional royalty rates. Wells that have already selected the transitional royalty rates will have the option to stay with those rates or switch to the new rates effective January 1, 2011.
    - The drilling royalty credit will continue until expiry on March 31, 2011 and all other programs will continue as designed.

As part of the recognition of the significant changes in the North American natural gas market, the Government of Alberta will continue to analyze various components of natural gas royalties. The conclusion of this analysis will be included in the final royalty curve revisions to be announced on May 31, 2010.

The general oil and gas royalty structure in British Columbia is based on a sliding scale. As the price the producer receives for the gas goes up, so do the royalties that producer pays to the Province. However, the majority of gas produced in the province is also subject to a hard cap on the percentage of royalties paid. Parts 10 and 11 of the *Petroleum and Natural Gas Act* (the "**PNG Act**"), contain the primary legislative provisions for royalties and freehold production taxes on oil and gas in British Columbia. The Crown receives a royalty on any oil and gas production from Crown Land "permitted, licensed or leased" under the PNG Act. Authority is given to prescribe by Regulation the royalty rate, who must pay it, when it must be paid, as well as penalties for late or non-payment, and any other related considerations. The calculation of royalties payable for different classes of petroleum and natural gas and most of the practices and procedures to be followed are set out in the Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation. Natural gas is divided into ten categories, each with different royalty rates, which vary depending on the type of gas it is, whether it is freehold or Crown reserve and whether it is conservation or non-conservation gas. The results of failing to pay the royalties due can be significant, ranging from the imposition of penalties and interest to the Minister outright cancelling a permit, licence or lease pursuant to Section 135 of the PNG Act. The government has developed a number of royalty credit programs for certain types of drilling and wells. These include: the Summer Royalty Program; the Low Productivity Program; the Deep Royalty Program; the Deep Discovery Royalty Program; the Deep Re-Entry Royalty Program; the Marginal Royalty Program; the Ultra-Marginal Royalty Program; the Coalbed Methane Royalty Program; the Infrastructure Royalty Program; and the recently created Net Profit Royalty Program. Some of these credits, including the Deep Well Program, Summer Program and Coalbed Methane Program, result in a dollar amount being deducted from the royalty amount owed. Others, such as the Low Productivity, Coalbed Methane, Marginal and Ultra-Marginal Royalty programs, result in a reduction of the percentage of royalties owed on each cubic metre of gas. The Infrastructure and Net Profit Royalty programs are designed to compensate producers for specific construction or drilling projects that must be approved in advance.

Under the British Columbia royalty regime, a temporary 2% 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% gas royalty, for a 12 month period, provided they commence continuous production before December 31, 2010.

Effective October 1, 2002, the government of Saskatchewan revised its fiscal regime for the oil and gas industry by introducing a number of major changes affecting the Crown royalty and freehold production tax structures and the Corporation Capital Tax Surcharge rate applicable to production from new oil and gas exploration and development activity. The changes were implemented to stimulate increased exploration and development activity in the province.

In Saskatchewan, the amount payable as a royalty in respect of oil depends on the vintage of the oil, the type of oil, the quantity of oil produced in a month, and the value of the oil. For Crown royalty and freehold production tax purposes, crude oil is considered "heavy oil", "southwest designated oil", or "non heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil" introduced October 1, 2002, "third tier oil", "new oil" and "old oil") of oil production are applicable to each of the three crude oil types. The Crown royalty and freehold production tax structure for crude oil is price sensitive and varies between the base royalty rates of 5% for all "fourth tier oil" to 20% for "old oil". Marginal royalty rates are 30% for all "fourth tier oil" to 45% for "old oil".

The amount payable as a royalty in respect of natural gas is determined by a sliding scale based on a reference price (which is the greater of the amount obtained by the producer and a prescribed minimum price), the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non associated natural gas. The royalty and production tax classifications of gas production are "fourth tier gas" introduced October 1, 2002, "third tier gas", "new gas", and "old gas". The Crown royalty and freehold production tax for gas is price sensitive and varies between the base royalty rate of 5% for "fourth tier gas" and 20% for "old gas". The marginal royalty rates are between 30% for "fourth tier gas" and 45% for "old gas".

On October 1, 2002, the following changes were made to the royalty and tax regime in Saskatchewan:

A new Crown royalty and freehold production tax regime applicable to associated natural gas (gas produced from oil wells) that is gathered for use or sale and is produced from: (a) oil wells with a finished drilling date on or after October 1, 2002, and (b) oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas oil production ratio in any month of more than 3,500 cubic metres of gas for every cubic metre of oil. The royalty/tax will be payable on associated natural gas produced from an oil well that exceeds approximately 65,000 cubic metres in a month. The associated natural gas royalty/tax regime will apply to gas produced from oil wells affected by concurrent production approvals after October 1, 2002 if the oil wells meet (a) or (b) above.

A modified system of incentive volumes and maximum royalty/tax rates applicable to the initial production from oil wells and gas wells with a finished drilling date on or after October 1, 2002, was introduced. The incentive volumes are applicable to various well types and are subject to a maximum royalty rate of 2.5% and a freehold production tax rate of zero per cent.

The elimination of the re entry and short section horizontal oil well royalty/tax categories. All horizontal oil wells with a finished drilling date on or after October 1, 2002, will receive the "fourth tier" royalty/ tax rates and new incentive volumes.

A horizontal oil well, with a finished drilling date on or after October 1, 2002, that is a non deep oil well qualifies for a 6,000 cubic metre incentive volume.

A horizontal oil well, with a finished drilling date on or after October 1, 2002, that is a deep oil well qualifies for a 16,000 cubic metre incentive volume.

In 1975, the Government of Saskatchewan introduced a Royalty Tax Rebate ("**RTR**") as a response to the Government of Canada disallowing Crown royalties and similar taxes as a deductible business expense for income tax purposes. As of January 1, 2007, the remaining balance of any unused RTR will be limited in its carry forward to seven years since the Government of Canada's initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income. Saskatchewan's RTR will be wound down as a result of the Government of Canada's plan to reintroduce full deductibility of provincial resource royalties for corporate income tax purposes.

On June 19, 2007, the Government of Saskatchewan introduced the Orphan Well and Facility Liability Management Program pursuant to the amendment of the Oil and Gas Conservation Act and the Oil and Gas Conservation Regulations, 1985. The program includes a security deposit, which has two purposes: (i) preventing any person with insufficient financial capability from acquiring oil and gas wells or facilities; and (ii) in the case of a bankrupt company, the funds cover the decommissioning and reclaiming of orphan properties. An additional change introduced is the mandatory licensing of all upstream oil and gas facilities in Saskatchewan.

Land Tenure

Crude oil and natural gas located in the western provinces are owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licenses and permits for varying terms from two years and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

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*, 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**"). 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 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 2010 onwards, which is intended to form the basis for a future emissions reduction system. 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 B.C. approximately 73% towards meeting its goal of reducing greenhouse gas emissions in the province by 33% by 2020. 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 with an interim goal to reduce flaring by half by 2011, 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.

DIVIDENDS OR DISTRIBUTIONS

Since its incorporation, Terra Energy has not paid any dividends or made any distributions on its common shares. Dividends or distributions on its common shares will be paid solely at the discretion of Terra Energy's board of directors after taking into account the financial condition of Terra Energy and the economic environment in which it is operating. No dividends or distributions are expected to be paid in the foreseeable future.

DESCRIPTION OF SHARE CAPITAL

The authorized capital of Terra Energy consists of an unlimited number of common shares and an unlimited number of preferred shares issuable in series, of which, as at December 31, 2009, 87,989,178 common shares were issued and outstanding. No preferred shares are presently issued and outstanding. Terra Energy's stock option plan was approved by shareholders on June 24, 2009 and authorizes the Corporation to issue up to 10 percent of issued and outstanding common shares to directors, officers, employees and to consultants of the Corporation. At December 31, 2009, options to purchase 8,062,200 common shares of the Corporation were outstanding.

The following is a summary of the rights, privileges, restrictions and conditions attaching to the common shares and the preferred shares of Terra Energy.

Common Shares

The common shares of Terra Energy rank junior to the preferred shares. Holders of common shares are entitled to one vote per share at meetings of shareholders of Terra Energy, to receive dividends if, as and when declared by the board of directors of Terra Energy and to receive pro rata the remaining property and assets of Terra Energy upon its dissolution or winding-up, subject to the rights of shares having priority over the common shares.

Preferred Shares

The preferred shares of Terra Energy are issuable in series and will have such rights, restrictions, conditions and limitations as the board of directors of Terra Energy may from time to time determine. The preferred shares shall rank senior to the common shares with respect to the payment of dividends or distribution of assets or return of capital of Terra Energy in the event of a dissolution, liquidation or winding up of Terra Energy. No preferred shares are presently issued and outstanding.

MARKET FOR SECURITIES

Price Range and Volume of Trading of Common Shares

The common shares of the Corporation are listed and posted for trading on the Toronto Stock Exchange and trade under the symbol "TT". The common shares of the Corporation commenced trading on the Toronto Stock Exchange on June 1, 2009. Prior thereto, the common shares of the Corporation were listed on the TSX Venture Exchange. The following sets forth the price range and trading volume of the Corporation's common shares on the Toronto Stock Exchange or the TSX Venture Exchange, as applicable, as reported by sources Terra Energy believes to be reliable for the periods indicated.

Period	$ High	$ Low	Volume Traded
2009			
January	1.13	0.86	1,480,921
February	1.40	1.00	1,779,179
March	1.60	1.14	1,180,740
April	1.70	1.25	1,100,849
May	1.90	1.48	1,153,604
June	1.65	1.31	1,379,211
July	1.37	1.07	817,561
August	1.35	1.10	658,455
September	1.58	1.15	1,383,460
October	1.64	1.32	1,396,169
November	1.54	1.36	1,490,524
December	1.55	1.39	1,438,579
2010			
January	1.74	1.45	1,315,531
February	1.78	1.50	2,385,748
March 1 to 24	1.81	1.58	2,143,100

PRIOR SALES

The following table sets forth, for each class of securities of the Corporation that is outstanding but not listed or quoted on a marketplace, the price at which securities of the class have been issued during the financial year ended December 31, 2009 and the number of securities of the class issued at that price and the date on which the securities were issued.

Class of Securities	Issue Price or Exercise Price	Number of Securities Issued	Date of Issue
Subscription Receipts	1.45	14,000,000	July 7, 2010
Warrants	1.90	7,000,000	July 15, 2010
Stock Options	1.33	1,150,000	February 13, 2009
Stock Options	1.34	450,000	February 28, 2009

Class of Securities	Issue Price or Exercise Price	Number of Securities Issued	Date of Issue
Stock Options	1.38	250,000	June 19, 2009
Stock Options	1.35	150,000	June 24, 2009
Stock Options	1.36	40,000	June 29, 2009
Stock Options	1.37	1,140,000	September 24, 2009
Stock Options	1.54	360,000	October 30, 2009
Stock Options	1.39	298,000	November 17, 2009

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

There are no shares in escrow or subject to contractual restriction on transfer at the time of this report.

DIRECTORS AND OFFICERS

The following table sets forth the name, province and country of residence of the directors and officers, the offices held by each in the Corporation, the period served as director and the principal occupation of each during the past five years. The term of office of each director will expire at the end of the next annual meeting of shareholders of the Corporation.

Name and Province and Country of Residence	Director or Officer Since	Principal Occupation During the Last Five Years
Ted S. Anderson(1)(3)(10) Alberta, Canada	Director since January 30, 2004	Mr. Anderson is the Manager of Special Projects for Pioneer Land Services since 2000. From 1978 through 2000, Mr. Anderson was President of Pioneer Land Services Ltd.
Ralph G. Evans(1)(3)(4) Alberta, Canada	Director since January 30, 2004	Mr. Evans is a professional engineer and has been the principal of R.G. Evans Consulting Inc. since 1996. Mr. Evans was employed for over 29 years with the Energy Resources Conservation Board and its predecessor regulatory body the Alberta Energy & Utilities Board in various positions including as a Board member.
Colin P. MacDonald(2)(4) Alberta, Canada	Director since January 30, 2004	Mr. MacDonald is a partner in the Calgary offices of Borden Ladner Gervais LLP, a Canadian law firm.
Cas H. Morel(2)(3)(4) Alberta, Canada	Promoter President, Chief Executive Officer, Chairman and Director since January 30, 2004	Mr. Morel is the President, Chief Executive Officer and a director of Terra Energy since January 30, 2004 and has been the President and a director of Terra Capital Corp. (a private holding and management services company) since 1996. Mr. Morel was also President, Chief Executive Officer and a director of each of Rhodes Resources Corp. from October 31, 2002 to January 30, 2004 and Terrapet Energy Corp. from November 7, 1995 to January 30, 2004, prior to their amalgamation to form Terra Energy Corp.
Robert D. Penner(1)(2)(5) Alberta, Canada	Director since April 21, 2005 Lead Director	Mr. Penner is a Chartered Accountant and is currently an independent businessman. From 1965 until his retirement in 2004, Mr. Penner worked with KPMG LLP, Chartered Accountants and its predecessor as a senior tax partner.
Tony Sabelli Alberta, Canada	Director since May 15, 2007; Executive Vice President Alberta and Saskatchewan Operations since September 7, 2009	Mr. Sabelli joined Terra Energy as the Executive Vice President Alberta and Saskatchewan Operations on September 7, 2009. Prior thereto Mr. Sabelli was the founder of and Vice President, Operations with a private oil and gas producer. Prior to that, Mr. Sabelli was Vice President, Operations with Red Sky Energy Ltd. from April 2005 to April 2006. Mr. Sabelli held various positions at Canadian Natural Resources Limited from January 1993 to March 2005, including a position as the General Manager of Drilling and Completions.
James F. Wong(2) Alberta, Canada	Director since January 13, 2010	Mr. Wong is Professional Engineer and has been an Energy Business Consultant since 1999. From 1996 to September 1999, Mr. Wong was the Managing Director Fracmaster (China) Limited.

Name and Province and Country of Residence	Director or Officer Since	Principal Occupation During the Last Five Years
Tim A. Beatty Alberta, Canada	Executive Vice President BC Operations since September 7, 2009	Mr. Beatty was appointed Executive Vice President BC Operations on September 7, 2009. Mr. Beatty has employed with Terra Energy since January 1, 2004, currently in the position of Executive Vice President BC Operations since September 7, 2009; prior to that Vice President, Capital Projects since 2007 and prior thereto as Vice President, Drilling and Completions since 2004. Prior thereto he was the Vice President, Operations of Terra Capital Corp. since July 2002.
John M. Behr Alberta, Canada	Vice President, Exploration since September 23, 2005	Mr. Behr is the Vice President, Exploration of Terra Energy since September 2005 and prior thereto was the Chief Geophysicist of Terra Energy from February to September of 2006. From March 2004 to February 2005, he was Senior Geophysicist of the Fort Saint John Exploration group at Dominion Exploration Canada. Prior thereto, Mr. Behr was Principal Geophysicist in the Deep Basin and Foothills Group at El Paso Oil and Gas Canada Inc. from August 2002 until March 2005.
Jan M. Campbell Alberta, Canada	Corporate Secretary since May 15, 2007	Ms. Campbell is the President of Comply Inc., a consulting firm which provides corporate secretarial services, since December 2005. From September 1997 to November 2005, Ms. Campbell was the Corporate Secretary to Precision Drilling Corporation, a predecessor to Precision Drilling Trust, a publicly traded income trust listed on the TSX and the New York Stock Exchange. Ms. Campbell is not an employee of Terra Energy, but rather serves as a consultant and as an officer on a part-time basis.
Graham V. Collins Alberta, Canada	Vice President Production Alberta and Saskatchewan since September 7, 2009	Mr. Collins was appointed Vice President Production Alberta and Saskatchewan of Terra Energy on September 7, 2009. Prior to that, Mr. Collins was the Manager of Production for Terra Energy since March 2005. Prior thereto, Mr. Collins was a Senior Engineer for Hunt Oil from September 2004 to March 2005.
Bud K. Love Alberta, Canada	Vice President, Finance and Chief Financial Officer since January 30, 2004	Mr. Love is the Vice President, Finance and Chief Financial Officer of Terra Energy since January 30, 2004. Mr. Love was the Vice President, Finance and Chief Financial Officer of Rhodes Resources Corp. from October 31, 2002 to January 30, 2004 and Vice President, Finance and Chief Financial Officer of Terrapet Energy Corp. from May 1998 to January 30, 2004, prior to their amalgamation to form Terra Energy Corp. From 1993 to February 2004, Mr. Love was the principal and founder of BKL & Associates, a full service accounting firm.
Gord J. Oliver Alberta, Canada	Vice President Exploitation B.C. since September 7, 2009	Mr. Oliver was appointed Vice President Exploitation B.C. of Terra Energy on September 7, 2009. Prior to that, Mr. Oliver was the Manager Exploitation for Terra Energy since March 2005. Prior thereto, Mr. Oliver was the Vice President Business Development for Efficient Energy Corp. from June 2002 to December 2004.

Notes:

(1) Audit Committee member.
(2) Corporate Governance, Compensation and Nominating Committee member.
(3) Engineering Reserves Committee member.
(4) Environmental and Safety Committee member.
(5) Mr. Penner is a director of Storm Cat Energy Corporation ("**Storm Cat**"). In November 2008, the U.S. subsidiaries of Storm Cat filed for a voluntary petition for reorganization under Chapter 11 of the United States Bankruptcy Code and Storm Cat was subsequently delisted from the Toronto Stock Exchange and the NYSE Alternext U.S. LLC (formerly, the American Stock Exchange), which delistings remain in effect as of the date hereof. In April 2009, pursuant to an order of the Ontario Securities Commission, the securities of Storm Cat were cease traded for a failure to file audited annual financial statements, management's discussion and analysis and an annual information form, all for the year ended December 31, 2008 and such order remains in effect as of the date hereof.

As at March 25, 2010, the directors and officers of the Corporation, as a group, owned, directly or indirectly, or controlled or directed 25,359,251 common shares of the Corporation or approximately 25.6% of the issued and outstanding common shares. The information as to shares beneficially owned, directly or indirectly or over which control or direction is exercised, is based upon information furnished to the Corporation by the respective individuals indicated.

CEASE TRADE ORDERS, BANKRUPTCIES, PENALTIES OR SANCTIONS

Except as set forth herein, to the knowledge of management of the Corporation, none of the directors or executive officers of the Corporation (nor any personal holding company of any of such persons) is, as of the date of this Annual Information Form, or was within ten years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including the Corporation), that was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, an "**Order**") that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer or was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

Except as set forth herein, to the knowledge of management of the Corporation, none of the directors or executive officers of the Corporation (nor any personal holding company of any of such persons), or securityholder holding a sufficient number of our securities to affect materially the control of the Corporation is, as of the date of this Annual Information Form, or has been within the ten years before the date of this Annual Information Form, a director or executive officer of any company (including the Corporation) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or has, within the ten years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

To the knowledge of management of the Corporation, no director or executive officer of the Corporation (nor any personal holding company of any such persons), or shareholder holding a sufficient number of securities to affect materially the control of the Corporation, has been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority or been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision in respect of the securities of the Corporation.

AUDIT COMMITTEE INFORMATION

Audit Committee Charter

The audit committee of Terra Energy ("**Audit Committee**") is responsible for reviewing Terra Energy's financial reporting procedures, internal controls and the performance of the external auditors. The Audit Committee Charter of Terra Energy is set forth as Appendix D of this Annual Information Form.

Composition of the Audit Committee

The current members of the Audit Committee are Robert D. Penner (Chairman), Ted S. Anderson and Ralph G. Evans. The Audit Committee is a standing committee appointed by the board of directors of Terra Energy to assist the board of directors of Terra Energy in fulfilling its oversight responsibilities with respect to the financial reporting by Terra Energy. Each member of the Audit Committee is independent as defined under Multilateral Instrument 52-110 *Audit Committees* ("**MI 52-110**") and none received any compensation, directly or indirectly, from Terra Energy other than for services as a member of the board of directors of Terra Energy and its committees, as applicable. All members of the Audit Committee are financially literate as defined in MI 52-110.

Relevant Education and Experience of Members of the Audit Committee

Robert D. Penner (Chairman)

Mr. Penner is a Chartered Accountant and is currently an independent businessman. From 1965 until his retirement in 2004, Mr. Penner worked with KPMG LLP, Chartered Accountants and its predecessor as a senior tax partner.

Ted. S. Anderson

Mr. Anderson has over 30 years of land management experience. From 1978 through to 2000, Mr. Anderson was the President of Pioneer Land Services Ltd., and is now the Manager of Special Projects for Pioneer Land Services. Mr. Anderson graduated from the University of Alberta with a B.Sc. in Agriculture.

Ralph G. Evans

Mr. Evans is a professional engineer and has been the principal of R.G. Evans Consulting Inc. since 1996. Mr. Evans was employed for over 29 years with the Energy Resources Conservation Board and its predecessor regulatory body the Alberta Energy & Utilities Board in various positions including as a Board member.

Pre-Approval Policies and Procedures

The Audit Committee has delegated to the Chairman of the Audit Committee (or such other member of the Audit Committee who may be delegated authority), the authority to act on behalf of the Audit Committee between meetings of the Audit Committee with respect to the pre-approval of audit and permitted non-audited services provided by Deloitte & Touche LLP. The Audit Committee is required to be notified of any non-approved services over and above audit and tax. The Chairman reports on any such pre-approval at the next meeting of the Audit Committee.

Auditor Service Fees

The following table provides information about fees billed to Terra Energy and its affiliates for professional services rendered by Deloitte & Touche LLP, the Corporation's external auditor, during the fiscal year ended December 31, 2009:

Type of service provided (all figures in Cdn $)	**Year-ended December 31, 2009**	**Year-Ended December 31, 2008**
Audit fees (including quarterly reviews)	$152,110	$177,020
Audit-related fees	26,924	-
Tax fees	2,650	-
Going public fees: these services included both reviews and tax advice	-	-
All other fees	13,025	2,100
Total	**$194,709**	$179,120

LEGAL PROCEEDINGS

To the knowledge of the management of Terra Energy, Terra Energy is not a party to, nor are any of Terra Energy's properties subject to any material legal proceedings. However, the Corporation is subject to non-material legal proceedings as described in Note 16 to the audited financial statements of the Corporation for the year ended December 31, 2009 (the "**2009 Financial Statements**"), which financial statements can be found on SEDAR at www.sedar.com and such information is incorporated herein by reference.

REGULATORY ACTIONS

To the knowledge of the Corporation, there were no (i) penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority during the Corporation's last financial year, (ii) penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision, or (iii) settlement agreements the Corporation entered into before a court relating to securities legislation or with a securities regulatory authority during the last financial year.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

The management of the Corporation is not aware of any material interests, direct or indirect, of any directors or executive officers of the Corporation, any person or company which beneficially owns or controls or directs, directly or indirectly, more than 10% of the outstanding common shares of the Corporation, or any known associate or affiliate of such persons, in any transaction within the last three financial years of the Corporation, or during the current financial year which has materially affected or is reasonably expected to materially affect the Corporation.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the common shares of Terra Energy is Computershare Trust Company of Canada at its principal offices in Calgary, Alberta and Toronto, Ontario.

MATERIAL CONTRACTS

Terra Energy has not entered into any material contracts, except for contracts entered into in the ordinary course of business.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report, valuation or opinion described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by Terra Energy during, or related to, the year ended December 31, 2009 other than GLJ, Terra Energy's independent qualified reserves evaluator, and Deloitte & Touche LLP, Terra Energy's auditor. To Terra Energy's knowledge, none of the principals of GLJ had any registered or beneficial interests, direct or indirect, in any securities or other property of Terra Energy or of Terra Energy's associates or affiliates either at the time they prepared the statement, report, valuation or opinion prepared by it, at any time thereafter or to be received by them. Deloitte & Touche LLP, Terra Energy's auditor, is independent in accordance with the auditor's rules of professional conduct in Canada.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of Terra Energy or any associate or affiliate of Terra Energy.

CONFLICTS

There are potential conflicts of interest to which the directors and officers of Terra Energy will be subject in connection with the operations of Terra Energy. In particular, certain of the directors and officers of Terra Energy are involved in managerial or director positions with other oil and gas companies whose operations may, from time to time, be in direct competition with those of Terra Energy or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of Terra Energy. See "*DIRECTORS AND OFFICERS*". Conflicts, if any, will be subject to the procedures and remedies available under the ABCA. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the ABCA.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remunerations, principal holders of the Corporation's securities, options to purchase securities and interests of insiders in material transactions is contained in the Corporation's management information circular relating to its most recent annual meeting of shareholders of the Corporation. Additional financial information is contained in the Corporation's comparative financial statements and management's discussion and analysis for the year ended December 31, 2009. Additional information relating to the Corporation may be found on SEDAR at www.sedar.com.

Additional copies of this Annual Information Form, the materials listed in the preceding paragraph, any interim financial statements which have been issued by the Corporation and any other document incorporated herein by reference will be available upon request by contacting the Corporation at its offices at Suite 970, 333 – 7th Avenue S.W., Calgary, Alberta T2P 2Z1, Phone: (403) 699-7777 or Fax: (403) 264-7189.

APPENDIX A
FORM 51-101F2
REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

Report on Reserves Data

To the board of directors of Terra Energy Corp. (the "**Company**"):

1. We have reviewed the Company's reserves data as at December 31, 2009. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2009, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2009 and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

			Net Present Value of Future Net Revenue (before income taxes, 10% discount rate $M)			
Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	Corporate Summary February 23, 2010	Canada	-	$313,784	-	**$313,784**

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 23, 2010

(signed) *"Myron J. Hladyshevsky"*

Myron J. Hladyshevsky, P.Eng.
Vice-President

APPENDIX B
FORM 51-101F3
REPORT OF
MANAGEMENT AND DIRECTORS
ON OIL AND GAS DISCLOSURE

This is the form referred to in item 3 of section 2.1 of National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). This form does not apply in British Columbia.

Terms to which a meaning is ascribed in NI 51-101 have the same meaning in this form.[1]

The report referred to in item 3 of section 2.1 of NI 51-101 shall in all material respects be as follows:

Report of Management and Directors on Reserves Data and Other Information

Management of Terra Energy Corp. (the "**Company**") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2009, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The reports of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The board of directors of the Company has:

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has approved:

(d) the content and filing with securities regulatory authorities of Form 51-101F1 reserves data and other oil and gas information;

(e) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(f) the content and filing of this report.

[1] For the convenience of readers, Appendix 1 to Companion Policy 51-101CP sets out the meanings of certain terms in sections 1 and 2 of this Form or in NI 51-101, Form 51-101F1, Form 51-101F2 or the Companion Policy.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(signed) *"Cas H. Morel"*
Cas H. Morel
President and Chief Executive Officer

(signed) *"Bud K. Love"*
Bud K. Love
Vice President, Finance and Chief Financial Officer

(signed) *"Ralph G. Evans"*
Ralph G. Evans
Director

(signed) *"Theodore S. Anderson"*
Theodore S. Anderson
Director

March 25, 2010

APPENDIX C
DEFINITIONS USED FOR RESERVE CATEGORIES

The following reserves definitions are set out by the Canadian Securities Administrators in National Instrument 51-101 (NI 51-101; in Part 2 of Appendix 1 to Companion Policy 51-101CP) with reference to the COGE Handbook.

Reserve Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

analysis of drilling, geological, geophysical, and engineering data;
the use of established technology;
specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

Reserves are classified according to the degree of certainty associated with the estimates.

Proved Reserves

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.

Probable Reserves

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Possible Reserves

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.
Other criteria that must also be met for the categorization of reserves are provided in Section 5.5 of the COGE Handbook.

Development and Production Status

Each of the reserves categories (proved, probable, and possible) may be divided into developed and undeveloped categories.

Developed Reserves

Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

Developed Producing Reserves

Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

Developed Non-Producing Reserves

Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

Undeveloped Reserves

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserves entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves estimates are presented). Reported Reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves;
- at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with *reserves* estimates and the effect of aggregation is provided in Section 5.5.3 of the *COGE Handbook*.

Incorporation of these guidelines means that total corporate proved reserves reflect a conservative estimated and proved plus probable reserves reflect a current "best estimate" of the oil and gas quantities which will be recovered.

APPENDIX D

AUDIT COMMITTEE CHARTER

PURPOSE

The primary function of the Committee is to assist the Board of Directors (the "Board") in fulfilling its oversight responsibilities by reviewing:

1. the financial information that will be provided to the shareholders and others;
2. the systems of internal controls, management and the Board have established; and
3. all audit processes.

Primary responsibility for the financial reporting information systems, risk management and is overseen by the Board.

COMPOSITION

1. The Committee shall be composed of a minimum of three directors, all of whom shall be independent as that term is defined in Multilateral Instrument 52-110, Audit Committees ("MI 52-110") (attached hereto as Schedule "A").
2. Members shall be appointed by the Board on an annual basis, shall serve one-year terms and may serve consecutive terms, which are encouraged to ensure continuity of experience.
3. The Chair of the Committee shall be appointed by the Board for a one-year term, and may serve any number of consecutive terms.
4. All members of the Committee shall be financially literate. Financial literacy is the ability to read and understand a balance sheet, income statement and cash flow statement that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Corporation's financial statements.
5. The Chair shall, in consultation with management and the external auditor and internal auditor (if any), establish the agenda for the meetings and ensure that properly prepared agenda materials are circulated to the members with sufficient time for study prior to the meeting. The external auditor will also receive notice of all meetings of the Committee. The Committee may employ a list of prepared questions and considerations as a portion of its review and assessment process.
6. The Committees shall meet at least four times per year and may call special meetings as required. A quorum at meetings of the Committee shall be its Chair and one of its other members. The Committee may hold its meetings, and members of the Committee may attend meetings, by telephone conference if this is deemed appropriate.
7. The minutes of the Committee meetings shall accurately record the decisions reached and shall be distributed to Committee members with copies to the Board, the Chief Executive Officer, the Chief Financial Officer and the external auditor.
8. The Committee reviews, prior to their presentation to the Board and their release, all material financial information required by securities regulations.
9. The Committee enquires about potential claims, assessments and other contingent liabilities.
10. The Committee periodically reviews with management, depreciation and amortization policies, loss provisions and other accounting policies for appropriateness and consistency.

AUTHORITY

1. The Committee is appointed by the Board pursuant to provisions of the Business Corporations Act (Alberta) and the bylaws of the Corporation.
2. Primary responsibility for the Corporation's financial reporting; accounting systems and internal controls is vested in senior management and is overseen by the Board. The Committee is a standing committee of the Board established to assist it in fulfilling its responsibilities in this regard. The Committee shall have responsibility for overseeing management reporting on internal controls. While it is management's responsibility to design and implement an effective system of internal control, it is the responsibility of the Committee to ensure that management has done so.
3. The Committee shall have unrestricted access to the Corporation's personnel and documents and will be provided with the resources necessary to carry out its responsibilities.
4. The Committee shall have direct communication channels with the internal auditors (if any) and the external auditors to discuss and review specific issues as appropriate.
5. The Committee shall have the sole authority to retain (or terminate) advisors or consultants as it determines necessary to assist the Committee in discharging its functions hereunder. The Committee shall be provided with the necessary funding to compensate the advisors or consultants retained by the Committee.

RELATIONSHIP WITH EXTERNAL AUDITORS

1. An external auditor must report directly to the Committee.
2. The Committee is directly responsible for overseeing the work of the external auditor engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the issuer, including the resolution of disagreements between management and the external auditor regarding financial reporting.
3. The Committee shall implement structure and procedures to ensure that it meets with the external auditor on a regular basis in the absence of management.

ACCOUNTING SYSTEMS, INTERNAL CONTROLS AND PROCEDURES

1. The Committee shall obtain reasonable assurance from discussions with and/or reports from management, and reports from external auditors that accounting systems are reliable and that the prescribed internal controls are operating effectively for the Corporation and its subsidiaries and affiliates.
2. The Committee shall review to ensure to its satisfaction that adequate procedures are in place for the review of the Corporation's disclosure of financial information extracted or derived from the Corporation's financial statements and will periodically assess the adequacy of those procedures.
3. The Committee shall review with the external auditor the quality and not just the acceptability of the Corporation's accounting principles and direct the external auditor's examinations to particular areas.
4. The Committee will review control weaknesses identified by the external auditor's, together with management's response and review with external auditors their view of the qualifications and performance of the key financial and accounting executives.
5. In order to preserve the independence of the external auditor, the Committee will:

   a) recommend to the Board the external auditor to be nominated for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Corporation;

   b) recommend to the Board the compensation of the external auditor's engagement; and

c) review and pre-approve any engagements for non-audit services to be provided by the external auditors or its affiliates, together with estimated fees, and consider the impact, if any, on the independence of the external auditor.

6. The Committee will review with management and with the external auditor any proposed changes in major accounting policies, the presentation and impact of significant risks and uncertainties, and key estimates and judgements of management that may be material to financial reporting.
7. The Committee shall establish procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters and the confidential anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.
8. The Committee shall establish a periodic review procedure to ensure that the external auditor complies with the Canadian Public Accountability Regime under Multilateral Instrument 52-108, Auditor Oversight.
9. The Committee shall review and approve the Corporation's hiring polices regarding partners, employees and former partners and employees of the present and former external auditor of the Corporation.

STATUTORY AND REGULATORY RESPONSIBILITIES

1. Annual Financial Information – review the annual audited financial statements, including Letter to Shareholders and related press releases and recommend their approval to the Board, after discussing matters such as the selection of accounting policies (and changes thereto), major accounting judgments, accruals and estimates with management and the external auditor.
2. Annual Report – review the management discussion and analysis ("MD & A") section and all other relevant sections of the annual report to ensure consistency of all financial information included in the annual report.
3. Interim Financial Statements – review the quarterly interim financial statements, including the Letter to Shareholders and related press releases and recommend their approval to the Board.
4. Earnings Guidance/Forecasts – review forecasted financial information and forward looking statements.
5. In addition, the Committee must review the Corporation's financial statements, MD & A and earnings press releases before the Corporation publicly discloses this information.

REPORTING

1. The Committee will report, through the Chairperson of the Committee, to the Board following each meeting on the major discussions and decisions made by the Committee, and report annually to the Board on the Committee's responsibilities and how it has discharged them.
2. In addition, the Committee will review and reassess these Terms of Reference annually and recommended any proposed changes to the Corporate Governance and Compensation Committee.

OTHER RESPONSIBILITIES

1. Investigating fraud, illegal acts or conflicts of interest.
2. Discussing selected issues with corporate counsel or the outside auditor or management.