Celtic Exploration Ltd.

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2004

MARCH 31, 2005

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GLOSSARY OF ABBREVIATIONS

AECO-C	Alberta Energy Company "C" Meter Station of the Nova Pipeline System
API	American Petroleum Institute
ARTC	Alberta Royalty Tax Credit
Bbl	Barrels
Bbl/d	Barrels per day
BOE	Barrel of oil equivalent (6 Mcf = 1Bbl)
BOE/d	Barrels of oil equivalent per day
CICA	Canadian Institute of Chartered Accountants
GJ	Gigajoules
GJ/d	Gigajoules per day
Mbbl	Thousand Barrels
Mboe	Thousands of barrels of oil equivalent
Mcf	Thousand cubic feet
Mmcf	Million cubic feet
Mmcf/d	Million cubic feet per day
Mmbtu	Millions of British thermal units
NGLs	Natural gas liquids
OPEC	Organization of Petroleum Exporting Countries
stb	Standard stock tank barrel
WTI	West Texas Intermediate
M$	Thousands of dollars
MM$	Millions of dollars

CONVERSION OF UNITS

1 acre	0.4 hectares
2.5 acres	1 hectare
1 bbl	0.159 cubic metres
6.29 bbls	1 cubic metre
1 foot	0.3048 metres
3.281 feet	1 metre
1 mcf	28.2 cubic metres
0.035 mcf	1 cubic metre
1 mile	1.61 kilometres
0.62 miles	1 kilometre
1 mmbtu	1.054 GJ
0.949 mmbtu	1 GJ

In this Annual Information Form where amounts are expressed on a barrel of oil equivalent basis, natural gas volumes have been converted to oil equivalence at six thousand cubic feet per barrel. The term BOE may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet per barrel is based on an energy equivalency conversion method primarily applicable at 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 these forward-looking statements.

In particular, this Annual Information Form and the documents incorporated by reference contain forward-looking statements pertaining to the following:

- the quantity of reserves;
- oil and natural gas production levels;
- capital expenditure programs;
- projections of market prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the Corporation’s ability to raise capital and to continually add to reserves through acquisitions and development; and
- treatment under government regulatory 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:

- volatility in market prices for oil and natural gas;
- liabilities and risks inherent in oil and natural gas operations;
- uncertainties associated with estimating reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions; and
- geological, technical, drilling and processing problems.

CORPORATE STRUCTURE

Name, Address and Incorporation

Celtic Exploration Ltd., (the "**Corporation**" or "**Celtic**"), was incorporated under the *Business Corporations Act* (Alberta) (the "**ABCA**") on April 16, 2002 as Desco Exploration Ltd. On September 30, 2002, the Corporation filed Articles of Amendment to change its name from "Desco Exploration Ltd" to "Celtic Exploration Ltd.".

The Corporation does not have any subsidiaries.

The head office of Celtic is located at Suite 500, 505 – 3rd Street S.W., Calgary, Alberta, T2P 3E6 and the registered office is located at 1000, 400 - 3rd Avenue S.W., Calgary, Alberta T2P 4H2.

GENERAL DEVELOPMENT OF THE BUSINESS

History of the Corporation

The Corporation became a reporting issuer as a capital pool company in the Province of Alberta on June 18, 2002 by obtaining a receipt for a prospectus from the Alberta Securities Commission. Pursuant to this prospectus the Corporation raised $250,000 (before costs of issue) by issuing 1.0 million common shares in the capital of the Corporation ("**Common Shares**") at a price of $0.25 per share. The proceeds of the offering were used to identify and evaluate assets or businesses for a prospective qualifying transaction ("**Qualifying Transaction**") within the meaning of the TSX Venture Exchange ("**TSX-V**") Policy 2.4 (the "**Policy**"). The offering closed on June 27, 2002 and the Corporation's Common Shares were listed on the TSX-V on July 8, 2002.

On September 30, 2002, the Corporation acquired certain producing oil and gas interests located at Princess, Alberta, from Jarrod Oils Ltd., a private corporation, controlled by Eldon A. McIntyre, a director of Celtic. This acquisition was effective as of August 1, 2002. The purchase price was $4.1 million, before adjustments, and was paid by the issuance of 2.6 million Common Shares at a price of $1.00 per share and by $1.5 million in cash. This acquisition constituted the Qualifying Transaction of the Corporation within the meaning of the Policy and upon the issuance of the TSX-V Final Exchange Bulletin in this matter on October 4, 2002, Celtic was no longer a capital pool company. This transaction added approximately 205 BOE/d of production, 94% of which was oil and NGLs and 6% of which was natural gas. In summary, the transaction revised Celtic's balance sheet to improve financial flexibility, provided initial cash flow, diversified the asset base and increased Celtic's prospect inventory.

On September 30, 2002, the Corporation filed Articles of Amendment to change its name from "Desco Exploration Ltd." to "Celtic Exploration Ltd.".

On September 30, 2002, the Corporation completed a private placement of 2.0 million Common Shares at a price of $1.00 per share raising gross proceeds of $2.0 million and a private placement of 3.0 million Common Shares, issued as "flow-through shares" within the meaning of the *Income Tax Act* (Canada) raising gross proceeds of $3.0 million. The proceeds were used to complete the Qualifying Transaction and to carry out the Corporation's exploration and development program.

On November 13, 2002, Celtic completed a private placement of 4.0 million Common Shares at a price of $3.00 per share raising gross proceeds of $12.0 million. The proceeds of the offering were used to finance Celtic's acquisition program and its exploration and development program.

On December 16, 2002, Celtic acquired 100% of the issued and outstanding shares of Dorchester Energy Inc. ("**DEI**"), a TSX-V listed corporation, for a purchase price of $11.5 million payable by way of $0.70 per share in cash or 0.233 of a Celtic Common Share, for each of the 16.1 million common shares of DEI. DEI shareholders elected to receive 1.8 million Celtic Common Shares, at a deemed price of $3.00 per share and $5.8 million in cash. Celtic also assumed from DEI $6.2 million of debt, net of working capital. On December 16, 2002, in a related transaction, Celtic also acquired 100% of the issued and outstanding shares of Denim Energy Corp. ("**Denim**") from twelve individual vendors for a purchase price of $3.7 million, which was paid in cash and by the issuance of 0.4 million Celtic Common Shares at a price of $3.00 per share. On December 16, 2002, in a further related transaction, Celtic also completed the purchase of certain oil and gas interests located in the Richdale area, Alberta, from seven corporate vendors, for a purchase price of $1.0 million which was paid in cash and by the issuance of 0.1 million Celtic Common Shares at a price of $3.00 per share.

As at December 16, 2002, DEI was producing approximately 720 BOE/d from five principal properties in Alberta, of which 58% was natural gas and the balance was oil and NGLs. As at December 16, 2002, Denim was producing approximately 154 BOE/d from three properties in Alberta of which approximately 85% was natural gas and the remainder was oil and NGL's. Production from the Richdale area, Alberta assets, purchased from the seven corporate vendors, as at December 16, 2002 was approximately 66 BOE/d of which 90% was natural gas.

On December 31, 2002 DEI was dissolved and all of its rights, property, assets and undertaking were assigned, transferred and conveyed to and all of its obligations and liabilities were undertaken and assumed by Celtic. On December 31, 2002 Denim was also dissolved and all of its rights, property, assets and undertaking were assigned to and all of its obligations and liabilities were undertaken and assumed by Celtic.

In May 2003, Celtic completed a private placement of 4.0 million Common Shares at a price of $3.95 per share raising gross proceeds of $17.8 million. The proceeds were used to finance Celtic's development, exploration and acquisition activities.

In July 2003, Celtic completed the acquisition, in two transactions, of certain oil and gas assets located in the Alderson, Bow Island and Drumheller areas in Southern Alberta, the Ashmont area in Eastern Alberta and in the Utikuma area in Northern Alberta. The effective date of each purchase was March 1, 2003 and the aggregate adjusted purchase price was $18.8 million. Production from the properties acquired was approximately 740 BOE/d, comprised of approximately 517 Bbls/d of light oil and approximately 1.34 Mmcf/d of natural gas.

On July 14, 2003, the Corporation's Common Shares were listed and commenced trading on the Toronto Stock Exchange.

In September 2003, Celtic completed, in two transactions, the acquisition of a 100% working interest in oil and gas assets located in the Fox Creek area, Alberta. The effective dates for the transactions were July 1, 2003 and August 1, 2003 and the aggregate adjusted purchase price was $4.3 million. At the time of the purchases the property was producing approximately 200 BOE/d of 48°API oil and natural gas.

In September 2003, Celtic completed a private placement of 2.5 million Common Shares at a price of $6.25 per share for gross proceeds of $15.6 million. The proceeds were used to finance Celtic's development, exploration and acquisition activities.

In April 2004, Celtic closed a property acquisition in the Morse River area, Alberta for an adjusted purchase price of $3.2 million. A 79.98% working interest was purchased in the Morse River Unit with net production of about 120 barrels of 41^0 API oil. Morse River is located approximately 50 miles from the Fox Creek property and is producing out of the same horizon as Celtic's Fox Creek area property.

Trends

The oil and gas industry is facing a number of trends that could affect Celtic's business, financial condition and/or operating results.

There is a continued trend to volatility of commodity prices. It appears that natural gas prices have entered an era of extreme volatility. With the supply and demand balance for natural gas being tight, the market is experiencing a great deal of elasticity in pricing due to a number of factors, including weather, drilling activity, production declines, storage levels, fuel switching and North American demand. Oil prices are dependent on the world economy and the reaction of OPEC to demand. Oil prices continue to remain volatile as a result of the political uncertainty and unrest around the world, potentially impacting supply.

During recent years, there has been active consolidation within the oil and gas sector, as a result of large U.S. based companies and Canadian oil and gas income trusts completing the acquisition of production and reserves. Though this trend towards consolidation began primarily with senior oil and gas producers, it moved down to the junior level. In addition, recent volatility in commodity pricing has led to uncertainty regarding valuations based on recent and near-term cash flows.

The consolidation of the oil and gas industry continues and recent transactions indicate that Canadian royalty income trusts are the dominant consolidator. Royalty income trusts have had a significant impact on the oil and gas industry, including emerging junior companies. As a result of natural decline rates and a relatively low cost of capital, Celtic anticipates that royalty income trusts will continue to be active asset gatherers.

Celtic anticipates a modest reduction in commodity prices in the near term. With regard to both oil and natural gas, Celtic believes that current prices are unsustainable and will likely trend lower. These trends in commodity pricing mean that companies who have built a solid financial foundation, like Celtic, are likely to benefit from the opportunities that always arise as the industry heads into a less buoyant portion of the cycle.

General

Celtic is engaged in the exploration for, and the development and production of, oil and natural gas. Celtic's current activities are focused in southern Alberta in the Bantry/Princess, Bow Island, Michichi, Richdale and Drumheller areas. In east central Alberta in the Ashmont and Redwater areas, in west central Alberta in the Chime/Kakwa, Fox Creek and Morse River / Swan Hills areas and in northern Alberta, in the Otter/Ogston, Utikuma Lake and McLeans Creek areas.

Stated Business Objective

The business plan of Celtic is to create sustainable and profitable growth as a participant in the oil and gas industry in Western Canada. To accomplish this, Celtic has been and will continue to pursue an integrated two-pronged growth strategy. On the one hand, Celtic will continue to identify and acquire strategic acquisitions of oil and natural gas properties where it believes further exploitation, development and exploration opportunities exist. In addition, Celtic implements a full cycle exploration program. The Corporation therefore pursues exploration and development drilling together with focused acquisitions both within its existing geographical project areas in the Western Canada Sedimentary Basin and in other areas of Alberta, Saskatchewan and British Columbia which present opportunities which are of interest to its management. Since commencing active oil and gas operations in the fall of 2002, the Corporation has successfully adhered to its two-pronged growth strategy. Firstly, the Corporation has completed corporate and asset acquisitions for an aggregate purchase price in excess of $54 million. Subsequent to completing each of these acquisitions, the Corporation has actively carried out exploitation and development drilling operations to further enhance the value of the acquired assets. Secondly, and at the same time, the Corporation has accumulated assets through its full cycle exploration program including conducting seismic operations, acquiring land and drilling exploration wells.

Celtic plans to pursue the internal and external generation of exploration plays that have low, medium and high risk and multi-zone hydrocarbon potential and plans to maintain a balance between exploration, exploitation and development drilling for oil and gas reserves over the course of the next five years, although management of Celtic will also consider asset and corporate acquisition opportunities that meet its business parameters. While Celtic believes that it will have the skills and resources necessary to achieve its stated objectives, participation in the exploration for and development of oil and natural gas has a number of inherent risks.

Management of Celtic has extensive industry experience in producing areas of Western Canada in addition to its knowledge of its existing properties and management will have the capability to expand the scope of Celtic's activities as opportunities arise.

In addition to specific acquisition criteria including risk profile, technical upside, reserve life and asset quality that will be evaluated by the management of Celtic, in circumstances where Celtic seeks to acquire assets with proven and probable reserves, prior to the investment decision being finalized, Celtic may obtain an independent engineering report (whether from the vendor of such assets or otherwise) relating to such proven and probable reserves.

Corporate Strategy

Celtic's strategy is to focus on acquisitions of oil and gas assets, to develop a broad inventory of both exploration and development opportunities to mitigate risk on capital investment, to augment acquisition opportunities with drilling activity and to increase critical mass and investigate opportunities to establish new core areas.

Business Risks

The business of exploring for, developing and producing oil and natural gas reserves is inherently risky. There is substantial risk that the manpower and capital employed do not result in the finding of new reserves in economic quantities. There is a risk that the sale of Celtic's reserves may be delayed indefinitely due to processing constraints, lack of pipeline capacity or lack of markets. The price Celtic receives for its oil and gas production fluctuates continuously and, for the most part, is beyond our control. Celtic is also subject to the risks associated with owning oil and gas properties, including environmental risks such as the pollution of air, land and water. In all areas of the business, Celtic competes against entities that may have greater technical and financial resources. Celtic's growth is dependent upon external sources of financing which may not be available on acceptable terms.

Celtic mitigates these risks by hiring highly qualified personnel, either directly as employees or indirectly when contracting for services. Celtic's philosophy of focusing in a limited number of geographical areas allows it to develop a high level of technical and managerial expertise in each area. To control the cost and pace of development, Celtic acquires high working interests in each prospect and operates wherever possible. Celtic may enter into commodity price and interest rate hedging strategies to add a degree of certainty to cash flow. The Corporation diversifies its oil and gas market portfolio among various marketers and among a variety of contracts with respect to pricing and term. In the field, Celtic adheres to sound operational standards, which meet or exceed recognized levels. Finally, all levels of the Corporation's operations are adequately insured.

Seasonal Considerations

Certain properties in the Otter/Ogston region of northern Alberta and the Kakwa/Chime area of west central Alberta are accessible only during winter months. The majority of the Corporation's properties are accessible year round, except during spring break-up. Major facilities through which Celtic's production is processed may temporarily be shut down for a short period of time during the year to conduct repair and maintenance operations.

Future Commitments

The Corporation may, from time to time, enter into fixed price contracts and derivative financial instruments with respect to oil and gas sales, in order to secure a certain amount of cash flow to protect a level of capital spending. Celtic currently has the following fixed price commitments to sell oil and gas production in place. For the term from December 1, 2004 to March 31, 2005, Celtic has agreed to sell, based on physical deliveries, 4,000 GJ/d of natural gas at a fixed price of $9.19 per GJ. In the first quarter of 2005, Celtic entered into an agreement for the term from April 1, 2005 to October 31, 2005, to sell, based on physical deliveries, 4,000 GJ/d of natural gas at a fixed price of $7.00 per GJ. In addition, for the term from April 1, 2005 to December 31, 2005, Celtic has entered into a financial derivative contract to sell 1,000 Bbl/d of oil, pursuant to the WTI index and Bank of Canada noon rate at $63.88 per Bbl.

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. As at December 31, 2004, Celtic recorded a provision on its balance sheet of $3.3 million for asset retirement obligations for future site restoration, reclamation and abandonment costs. 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. No assurance can be given that the application of environmental laws to the business and operations of Celtic 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 Celtic's financial condition, results of operations or prospects. See "*INDUSTRY CONDITIONS* - *Environmental Regulation*".

Employees

At December 31, 2004, the Corporation had 24 employees and 6 contract personnel at the head office. At the Corporation's field operations, the Corporation had 4 employees and 11 contractors.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Petroleum and Natural Gas Reserves

Sproule Associates Limited ("**Sproule**"), independent petroleum engineers of Calgary, Alberta, prepared a report entitled "Evaluation of the PNG Reserves of Celtic Exploration Ltd. (As of December 31, 2004)" ("the **Sproule Report**"), effective December 31, 2004, evaluating the proved and probable crude oil, natural gas and NGL reserves attributable to Celtic's interest in 100% of its properties and the present value of estimated future cash flow from such reserves, based on both constant price and cost assumptions and on forecast price and cost assumptions. The reserves information was prepared and is presented in accordance with the requirements of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* (**"NI 51-101"**).

In preparing the Sproule Report, Sproule obtained information from Celtic, 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 with the Sproule Report is based, was obtained from public records, other operators and from Sproule'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 Sproule as represented.

The following tables, based on the Sproule Report, show the estimated share of Celtic's oil, natural gas and NGL reserves in its properties and the present value of estimated future net revenue for these reserves, after provision for the ARTC and Alberta gas cost allowance, using both constant price and cost assumptions and forecast price and cost assumption as indicated. **All evaluations of the present worth of estimated future net revenue in the Sproule Report are stated after provision for estimated future capital expenditures and future site restoration and reclamation costs, both before and after income taxes, but prior to indirect costs and do not necessarily represent the fair market value of the reserves.**

Throughout the following summary tables differences may arise due to rounding.

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 in Form 51-101F2 containing certain information estimated using forecast prices and costs based on December 31, 2004 pricing assumptions
Appendix B:	Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3

Definitions used for reserve categories in the Sproule Report are attached as Appendix C hereto.

The following table summarizes Celtic's oil and gas reserves as of December 31, 2004 based on constant price and cost assumptions:

SUMMARY OF OIL AND GAS RESERVES
as of December 31, 2004

CONSTANT PRICES AND COSTS

	Reserves									
	Light and Medium Oil		**Heavy Oil**		**Natural Gas (non-associated & associated)**		**Natural Gas (solution)**		**Natural Gas Liquids**	
Reserves Category	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mmcf)**	**Net (Mmcf)**	**Gross (Mmcf)**	**Net (Mmcf)**	**Gross (Mbbl)**	**Net (Mbbl)**
PROVED										
Developed Producing	3,422.7	2,969.7	50.6	49.3	10,830	8,936	3,676	2,904	379.5	285.5
Developed Non-Producing	131.6	121.0	52.0	49.7	424	339	24	23	12.4	9.8
Undeveloped	184.9	148.8	0.0	0.0	2,232	1,718	76	51	51.5	35.5
TOTAL PROVED	**3,739.2**	**3,239.5**	**102.6**	**99.0**	**13,487**	**10,994**	**3,776**	**2,978**	**443.4**	**330.9**
Probable	2,090.2	1,747.4	147.6	142.8	6,559	5,301	2,286	1,705	316.0	225.6
TOTAL PROVED PLUS PROBABLE	**5,829.3**	**4,986.9**	**250.2**	**241.8**	**20,045**	**16,295**	**6,062**	**4,683**	**759.4**	**556.5**

The following tables summarize the undiscounted value and the present value, discounted at 5%, 10%, 15% and 20%, of Celtic's estimated future net revenue based on constant price and cost assumptions as of December 31, 2004:

SUMMARY OF NET PRESENT VALUES OF
FUTURE NET REVENUE
as of December 31, 2004

CONSTANT PRICES AND COSTS

	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	**0 (M$)**	**5 (M$)**	**10 (M$)**	**15 (M$)**	**20 (M$)**	**0 (M$)**	**5 (M$)**	**10 (M$)**	**15 (M$)**	**20 (M$)**
PROVED										
Developed Producing	162,028	132,980	113,855	100,313	90,196	133,665	109,789	94,281	83,335	75,157
Developed Non-Producing	6,500	5,656	5,010	4,500	4,088	4,351	3,753	3,296	2,936	2,647
Undeveloped	14,287	12,177	10,608	9,394	8,424	9,375	7,821	6,671	5,785	5,080
TOTAL PROVED	**182,814**	**150,814**	**129,472**	**114,206**	**102,708**	**147,391**	**121,363**	**104,247**	**92,056**	**82,884**
Probable	99,628	69,750	53,364	43,055	35,975	65,746	45,792	34,833	27,932	23,191
TOTAL PROVED PLUS PROBABLE	**282,443**	**220,564**	**182,837**	**157,261**	**138,683**	**213,137**	**167,155**	**139,080**	**119,988**	**106,075**

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) as of December 31, 2004 CONSTANT PRICES AND COSTS								
Reserves Category	**Revenue (M$)**	**Royalties (M$)**	**Operating Costs (M$)**	**Develop-ment Costs (M$)**	**Well Abandon -ment Costs (M$)**	**Future Net Revenue Before Income Taxes (M$)**	**Income Taxes (M$)**	**Future Net Revenue After Income Taxes (M$)**
Proved Reserves	304,313	45,869	67,562	4,820	3,247	182,814	35,423	147,391
Proved Plus Probable Reserves	474,498	75,921	104,716	8,024	3,395	282,443	69,306	213,137

NET PRESENT VALUE OF FUTURE NET REVENUE BY PRODUCTION GROUP as of December 31, 2004 CONSTANT PRICES AND COSTS		
RESERVES CATEGORY	**PRODUCTION GROUP**	**FUTURE NET REVENUE BEFORE INCOME TAXES & ARTC (discounted at 10%/year) (M$)**
Proved Reserves	Light and Medium Oil (including solution gas and associated by-products)	80,354
	Heavy Oil (including solution gas and associated by-products)	668
	Natural Gas (including associated by-products)	46,204
Proved Plus Probable Reserves	Light and Medium Oil (including solution gas and associated by-products)	116,010
	Heavy Oil (including solution gas and associated by-products)	1,564
	Natural Gas (including associated by-products)	62,337

The following table summarizes Celtic's oil and gas reserves as of December 31, 2004 based on forecast price and cost assumptions:

SUMMARY OF OIL AND GAS RESERVES
as of December 31, 2004

FORECAST PRICES AND COSTS

	Reserves									
	Light and Medium Oil		**Heavy Oil**		**Natural Gas (non-associated & associated)**		**Natural Gas (solution)**		**Natural Gas Liquids**	
Reserves Category	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mmcf)**	**Net (Mmcf)**	**Gross (Mmcf)**	**Net (Mmcf)**	**Gross (Mbbl)**	**Net (Mbbl)**
PROVED										
Developed Producing	3,365.4	2,929.6	51.2	49.5	10,801	8,914	3,598	2,841	376.5	283.5
Developed Non-Producing	129.9	120.2	54.3	50.9	424	339	24	23	12.4	9.8
Undeveloped	184.3	148.1	0.0	0.0	2,239	1,724	76	51	51.5	35.5
TOTAL PROVED	**3,679.6**	**3,197.9**	**105.5**	**100.4**	**13,464**	**10,977**	**3,698**	**2,915**	**440.4**	**328.8**
Probable	2,048.4	1,727.7	152.1	145.4	6,538	5,277	2,172	1,607	313.2	223.6
TOTAL PROVED PLUS PROBABLE	**5,728.0**	**4,925.6**	**257.6**	**245.8**	**20,002**	**16,254**	**5,870**	**4,522**	**753.6**	**552.5**

The following tables summarize the undiscounted value and the present value, discounted at 5%, 10%, 15% and 20%, of Celtic's estimated future net revenue based on forecast price and cost assumptions as of December 31, 2004:

SUMMARY OF NET PRESENT VALUES OF
FUTURE NET REVENUE
as of December 31, 2004

FORECAST PRICES AND COSTS

	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					**AFTER INCOME TAXES DISCOUNTED AT (%/year)**				
RESERVES CATEGORY	**0 (MM$)**	**5 (MM$)**	**10 (MM$)**	**15 (MM$)**	**20 (MM$)**	**0 (MM$)**	**5 (MM$)**	**10 (MM$)**	**15 (MM$)**	**20 (MM$)**
PROVED										
Developed Producing	141,100	119,293	104,581	93,943	85,840	119,783	100,712	88,133	79,114	72,273
Developed Non-Producing	6,093	5,415	4,879	4,445	4,087	4,084	3,595	3,212	2,903	2,649
Undeveloped	12,926	11,205	9,903	8,879	8,050	8,475	7,179	6,206	5,446	4,835
TOTAL PROVED	**160,119**	**135,913**	**119,363**	**107,266**	**97,978**	**132,342**	**111,487**	**97,550**	**87,463**	**79,757**
Probable	81,470	57,897	45,047	36,950	31,351	53,666	37,897	29,286	23,854	20,097
TOTAL PROVED PLUS PROBABLE	**241,589**	**193,810**	**164,410**	**144,216**	**129,329**	**186,007**	**149,384**	**126,836**	**111,317**	**99,853**

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) as of December 31, 2004 FORECAST PRICES AND COSTS								
Reserves Category	**Revenue (M$)**	**Royalties (M$)**	**Operating Costs (M$)**	**Develop-ment Costs (M$)**	**Well Abandon-ment Costs (M$)**	**Future Net Revenue Before Income Taxes (M$)**	**Income Taxes (M$)**	**Future Net Revenue After Income Taxes (M$)**
Proved Reserves	282,970	41,241	72,948	4,830	3,832	160,119	27,777	132,342
Proved Plus Probable Reserves	437,586	66,789	116,864	8,052	4,293	241,589	55,581	186,007

FUTURE NET REVENUE BY PRODUCTION GROUP as of December 31, 2004 FORECAST PRICES AND COSTS		
RESERVES CATEGORY	**PRODUCTION GROUP**	**FUTURE NET REVENUE BEFORE INCOME TAXES & ARTC (discounted at 10%/Year) (M$)**
Proved Reserves	Light and Medium Oil (including solution gas and associated by-products	74,649
	Heavy Oil (including solution gas and associated by-products)	1,129
	Natural Gas (including associated by-products)	41,339
Proved Plus Probable Reserves	Light and Medium Oil (including solution gas and associated by-products)	104,535
	Heavy Oil (including solution gas and associated by-products)	2,294
	Natural Gas (including associated by-products)	54,656

PRICING ASSUMPTIONS

Constant Prices and Costs - December 31, 2004

Sproule employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2004 in estimating Celtic's reserves data using constant prices and costs.

SUMMARY OF PRICING ASSUMPTIONS
as of December 31, 2004

CONSTANT PRICES AND COSTS

Year	OIL[1]				NATURAL GAS[1]		NATURAL GAS LIQUIDS			Exchange Rate[2] ($US/$Cdn)
	WTI Cushing Oklahoma ($US/stb)	Hardisty Bow River 24.9 ° API ($Cdn/stb)	Edmonton Par Price 40° API ($Cdn/stb)	Cromer Medium 29.3 ° API ($Cdn/stb)	AECO Gas Price ($Cdn/Mcf)	Alberta Reference Plantgate ($Cdn/Mcf)	Edmonton Propane ($Cdn/Bbl)	Edmonton Butanes ($Cdn/Bbl)	Edmonton Pentanes Plus ($Cdn/Bbl)	
2004 (Year End)	44.04	24.15	46.51	32.10	6.78	6.65	36.11	39.78	51.80	0.832

Notes:
(1) This summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer.
(2) The exchange rate used to generate the benchmark reference prices in this table.

Forecast Prices and Costs - December 31, 2004

Sproule employed the following pricing, exchange rate and inflation rate assumptions in estimating Celtic's reserves data using forecast prices and costs as of December 31, 2004.

FORECAST PRICES USED IN PREPARING RESERVES DATA
Sproule Associates Limited
Price Forecast
Effective December 31, 2004

Year	Light Oil			Heavy & Medium Oil		Natural Gas Liquids and Sulphur			
	WTI Cushing Oklahoma ($US/Bbl)	Edmonton Par Price 40° API ($Bbl)	Alberta Royalty Par Price ($Bbl)	Hardisty Lloyd-blend 22.3° API ($Bbl)	Hardisty Bow River 24.9° API ($Bbl)	Edmonton Propane ($Bbl)	Edmonton Butantes ($Bbl)	Edmonton Pentanes Plus ($Bbl)	Plantgate Sulphur ($/Mlt)
Historical									
2000	30.30	44.03	43.03	32.59	34.49	31.34	34.83	46.27	14.14
2001	25.94	39.06	38.06	23.46	25.04	29.87	27.93	42.46	-2.26
2002	26.09	40.12	39.12	30.59	31.85	20.36	25.39	40.80	12.71
2003	31.14	43.23	42.23	31.16	33.00	32.97	34.55	44.16	41.32
2004	41.41	52.91	50.91	36.17	38.00	35.95	41.38	53.90	39.88
Forecast									
2005	44.29	51.25	48.75	33.19	36.26	32.09	38.20	52.49	30.00
2006	41.60	48.03	45.50	33.46	34.89	30.07	34.01	49.19	20.30
2007	37.09	42.64	40.07	29.91	32.11	26.70	30.20	43.67	15.45
2008	33.46	38.31	35.69	26.74	30.68	23.98	27.13	39.23	15.69
2009	31.84	36.36	33.71	25.32	29.08	22.76	25.75	37.24	15.92
2010	32.32	36.91	34.22	25.84	29.60	23.11	26.13	37.80	16.16
2011	32.80	37.47	34.73	26.37	30.13	23.46	26.53	38.37	16.40
2012	33.30	38.03	35.26	26.91	30.67	23.81	26.93	38.95	16.65
2013	33.79	38.61	35.79	27.45	31.21	24.17	27.34	39.54	16.90
2014	34.30	39.19	36.33	28.00	31.76	24.53	27.75	40.14	17.15
2015	34.82	39.78	36.88	28.57	32.33	24.90	28.17	40.74	17.41
Escalation rate of 1.5% thereafter									

Year	Natural Gas					Operating Cost Inflation Rate (%/Yr)	Exchange Rate ($US/$Cdn)
	Alberta Gas Reference Price Plantgate	Alberta AECO-C Spot	Aggregator Plantgate	Alliance Pipeline	Henry Hub Price ($US/MMBtu)		
Historical							
2000	4.50	5.07	4.58	-	3.89	1.5	0.674
2001	5.40	6.23	5.20	5.48	4.27	2.0	0.646
2002	3.88	4.04	3.78	3.65	3.22	2.7	0.637
2003	6.12	6.66	5.95	6.28	5.39	2.5	0.716
2004	6.57	6.87	6.44	6.54	6.14	2.5	0.770
Forecast							
2005	6.76	6.97	6.72	6.67	6.74	2.5	0.840
2006	6.45	6.66	6.43	6.36	6.48	2.5	0.840
2007	6.00	6.21	5.97	5.92	6.08	2.5	0.840
2008	5.55	5.73	5.53	5.48	5.70	2.5	0.840
2009	5.21	5.37	5.19	5.17	5.41	1.5	0.840
2010	5.31	5.47	5.29	5.29	5.49	1.5	0.840
2011	5.38	5.57	5.38	5.39	5.58	1.5	0.840
2012	5.48	5.67	5.48	5.49	5.66	1.5	0.840
2013	5.58	5.77	5.58	5.59	5.75	1.5	0.840
2014	5.68	5.87	5.68	5.69	5.83	1.5	0.840
2015	5.79	5.98	5.79	5.80	5.92	1.5	0.840
Escalation rate of 1.5% thereafter							

Celtic's weighted average realized sales prices for the year ended December 31, 2004 were $48.71/Bbl for oil and NGLs and $6.97/Mcf for natural gas.

RECONCILIATION OF CHANGES IN RESERVES AND FUTURE NET REVENUE

Reserves Reconciliation

The following table sets forth a reconciliation of Celtic's total net proved, probable and proved plus probable reserves as at December 31, 2004 against such reserves as at December 31, 2003 based on forecast price and cost assumptions.

FACTORS	LIGHT AND MEDIUM OIL[1]			HEAVY OIL			ASSOCIATED AND NON-ASSOCIATED GAS[2]			BOE		
	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (Mmcf)	Net Probable (Mmcf)	Net Proved Plus Probable (Mmcf)	Net Proved (Mboe)	Net Probable (Mboe)	Net Proved Plus Probable (Mboe)
December 31, 2003	2,947	1,116	4,063	0	0	0	10,806	4,275	15,081	4,748	1,829	6,576
Acquisitions[4]	367	169	535	0	0	0	336	197	533	422	202	624
Discoveries	405	323	728	0	0	0	3,699	2,586	6,284	1,022	754	1,776
Dispositions	(63)	0	(63)	0	0	0	(274)	(51)	(325)	(109)	(9)	(118)
Extensions	504	293	797	107	145	253	1,348	401	1,749	836	505	1,341
Improved Recovery	531	239	589	0	0	0	782	526	1,308	481	326	807
Technical Revisions[3]	(292)	(188)	(480)	0	0	0	(531)	(1,050)	(1,580)	(380)	(363)	(743)
Economic Factors	0	0	0	0	0	0	0	0	0	0	0	0
Net Production	(691)	0	(691)	(7)	0	(7)	(2,273)	0	(2,273)	(1,076)	0	(1,076)
December 31, 2004	3,527	1,952	5,478	100	145	246	13,892	6,884	20,776	5,942	3,244	9,187

Notes:

(1) Includes NGLs.
(2) Includes solution gas.
(3) Technical revisions to reserve volumes for December 31, 2003.

Future Net Revenue Reconciliation

The following table sets forth a reconciliation of Celtic's estimate of future net revenue discounted at 10%, attributable to net proved reserves as evaluated on the Sproule Report using constant prices and costs.

Period and Factor	2004 (M$)
December 31, 2003[1]	79,569
Sales and Transfers of Oil and Gas Produced, Net of Production Costs and Royalties[2]	(39,149)
Net Change in Prices, Production Costs and Royalties Related to Future Production[3]	351
Changes in Previously Estimated Future Development Costs Incurred During the Period[4]	(1,119)
Changes in Estimated Future Development Costs[5]	(3,921)
Changes Resulting from Extensions and Improved Recoveries	29,633
Changes Resulting from Discoveries	24,921
Changes Resulting from Acquisitions	11,608
Changes Resulting from Dispositions	(1,893)
Net Change Resulting from Revisions in Quantity Estimates	(8,283)
Accretion of Discount	14,693
Net Change in Income Taxes Incurred During the Period and Changes in Future Income Tax	(2,673)
Other[6]	510
December 31, 2004[1]	104,247

Notes:

(1) After income tax present value of future net revenue discounted @ 10%, includes ARTC.
(2) Corporation actual before income tax, excluding G&A.
(3) The impact of changes in price and other economic factors on future net revenue.
(4) Change in previously estimated development costs incurred during 2004.
(5) Change in estimated future development costs.
(6) Change in value of ARTC.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

The following discussion generally describes the basis on which Celtic 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 Celtic 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.

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.

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is complex. It required 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. Celtic's reserves are evaluated by Sproule, an independent engineering firm.

Estimates made are reviewed and revised, either upward to 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. Celtic'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 both constant prices and costs and forecast prices and costs) and proved plus probable reserves (using forecast prices and costs only).

	Constant Prices and Costs	**Forecast Prices and Costs**	
Year	**Proved Reserves (M$)**	**Proved Reserves (M$)**	**Proved Plus Probable Reserves (M$)**
2005	4,453	4,453	7,510
2006	367	377	377
2007	0	0	66
2008	0	0	0
2009	0	0	0
Remaining Years	0	0	99
Total Undiscounted	4,820	4,830	8,052
Total Discounted at 10% per year	4,716	4,724	7,801

The Corporation has established a $60 million capital program to fund its exploration and development activities for 2005. The Corporation's capital program does not include any new acquisition opportunities, which would likely be financed through debt or equity financings.

Celtic estimates that its internally generated cash flow will be sufficient to fund the future development costs disclosed above. Celtic typically has available three sources of funding to finance its capital expenditure program; internally generated cash flow from operating activities, debt financing when appropriate and new equity issues, if available on favourable terms.

OTHER OIL AND GAS INFORMATION

Oil and Gas Properties and Wells

Celtic has four core areas; Northern Alberta, West Central Alberta, East Central Alberta and Southern Alberta, all of which are the subject of the Sproule Report. The term "net", when used to describe the Corporation's share of production, means the total of the Corporation's working interest share before deducting royalties owned by others.

Northern Alberta

Otter/Ogston: The Corporation has interests in 14,080 gross (9,600 net) acres in this area which is located 100 kilometres north east of Peace River, Alberta.

Utikuma Lake: The Corporation has interests in 9,600 gross (4,564 net) acres in this area which is located 110 kilometres south east of Peace River, Alberta.

West Central Alberta

Chime/Kakwa: The Corporation has interests in 59,680 gross (13,203 net) acres in this area which is located 95 kilometres south of Grande Prairie, Alberta.

Fox Creek: The Corporation has interests in 9,280 gross (5,360 net) acres in this area which is located 10 kilometres east of Fox Creek, Alberta.

Morse River/Swam Halls: The Corporation has interests in 23,040 gross (22,167 net) acres in this area which is located in close proximity to Swan Hills, Alberta.

East Central Alberta

Ashmont: The Corporation holds interests in 35,360 gross (32,522 net) acres in this area which is located 45 kilometres north west of St. Paul, Alberta.

Redwater/Skaro: The Corporation holds interests in 4,800 gross (4,688 net) acres in this area which is located 15 kilometres east of Redwater, Alberta.

Southern Alberta

Bantry/Princess: The Corporation has interests in 5,098 gross (4,299 net) acres in this area which is located 50 miles north west of Medicine Hat, Alberta.

Bow Island: The Corporation has interests in 7,156 gross (2,715 net) acres in this area which is located 25 miles west of Medicine Hat, Alberta.

Drumheller/Twinning: The Corporation has interests in 5,920 gross (1,473 net) acres in this area which is located 55 miles north east of Calgary, Alberta.

Michichi: The Corporation has interests in 17,760 gross (10,254 net) acres in this area which is located 15 miles north east of Drumheller, Alberta.

Richdale: The Corporation has interests in 5,600 gross (4,839 net) acres in this area which is located 50 miles north east of Drumheller, Alberta.

Wells

As at December 31, 2004, the Corporation had an interest in 234 gross (136 net) producing and 101 gross (48.6 net) non-producing oil and natural gas wells and 21 gross (14.7 net) service wells as follows.

	PRODUCING				NON-PRODUCING				SERVICE WELLS	
	Oil		Natural Gas		Oil		Natural Gas			
Location	Gross(1)	Net(2)	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	134	85.5	100	50.5	35	20.6	62	27.4	21	14.7
Saskatchewan	0	0.0	0	0.0	2	0.4	2	0.2	0	0.0
TOTAL	134	85.5	100	50.5	37	21.0	64	27.6	21	14.7

Notes:

(1) "Gross" wells means the number of wells in which Celtic 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 Celtic's percentage working interest therein.

(3) In addition, Celtic has an interest is 465 gross (6.4 net) producing oil and natural gas wells and 216 gross (6.0 net) non-producing wells in the Bellshill Lake Ellerslie Unit and the Leduc Woodbend D-2 and D-3 Units, all of which are located in Alberta.

Properties With No Attributed Reserves

The following table sets forth the gross and net acres of unproved properties held by the Corporation 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 - UNDEVELOPED LAND (acres)		
LOCATION	**Gross[1]**	**Net[2]**	**Net Area to Expire in 2005**
Alberta	198,918	117,983	14,080
British Columbia	4,815	2,820	-
Saskatchewan	802	401	-
TOTAL	**204,535**	**121,204**	**14,080**

Notes:
(1) ”Gross Acres” are the total acres in which Celtic has or had an interest.
(2) “Net Acres” is the aggregate of the total acres in which Celtic has or had an interest multiplied by Celtic’s working interest percentage held therein.

There are no costs or work commitments associated with Celtic's non-producing properties except for annual lease rental payments.

Forward Contracts

Celtic may use certain financial instruments to hedge its exposure to commodity price fluctuations on a portion of its crude oil and natural gas production. (See “*General Development* of the Business - Future Commitments”).

Additional Information Concerning Abandonment and Reclamation Costs

Celtic estimates the costs associated with well abandonment and reclamation based on its previous experience, current regulations, costs, technology and industry standards area by area. Celtic expects to incur abandonment and reclamation costs on 356 gross wells (199.3 net wells), together with 12.4 net unitized wells comprising currently producing, non-producing and service wells. Celtic’s share of the expected total abandonment and reclamation costs for wells with assigned reserves, non-producing and service wells and facilities, net of salvage value are summarized, without discount and using a discount rate of 10%, in the following table:

	Constant Pricing (M$)		Forecast Pricing (M$)			
Category	**Proved NPV 0%**	**Proved NPV 10%**	**Proved 0%**	**Proved 10%**	**Proved plus Probable 0%**	**Proved plus Probable NPV 10%**
Wells with reserves assigned[1]	3,247	1,564	3,832	1,823	4,293	1,542
Wells with no reserves assigned and Facilities[2]	2,892	1,393	3,413	1,624	3,657	1,314
Total abandonment and reclamation cost provision	6,139	2,957	7,245	3,447	7,950	2,856
Portion forecast to be paid during the next three years	648	556	662	566	499	425

Notes:
(1) Abandonment and reclamation costs were estimated by Sproule and included in the Sproule Report for all wells assigned reserves.
(2) Celtic has estimated the timing and the costs associated with the abandonment and reclamation for wells with no reserves assigned and for facilities. This represents the total abandonment and reclamation costs that were not deducted in computing future net revenue.

Tax Horizon

At the end of 2004, Celtic had estimated income tax deductions of approximately $76.4 million available to reduce future taxable income. Celtic does not expect to incur current income taxes in 2005. The Corporation could, if sufficient income tax deductions are not generated by future business operations, incur income taxes in 2006.

Costs Incurred

The following table summarizes Celtic's property acquisition costs, exploration costs and development costs (before property dispositions) incurred during the financial year ended December 31, 2004.

Property Acquisitions and Capital Expenditures	
Nature of cost	**Amount ($M)**
Property Acquisition Costs	
Proved	3,517
Unproved	100
Exploration Costs	19,015
Development Costs	35,460
Total	58,092

Exploration and Development Activities

The following table summaries the results of exploration and development activities during the financial year ended December 31, 2004.

Wells	Gross	Net
Development		
Gas	10	7.8
Oil	19	13.4
Coal Bed Methane	-	-
Unsuccessful	5	4.3
Exploratory		
Gas	8	4.9
Oil	9	5.1
Coal Bed Methane	14	4.3
Unsuccessful	2	1.7
Total	67	41.5

Celtic's initial plans for 2005 include a $60 million capital expenditure program, funded from cash flow from operating activities and bank debt.

Production Estimates

The following table discloses the estimated average daily production before the deduction of royalties of Celtic for 2005 by product type associated with the first year of the future net revenue estimates reported in the Sproule Report effective December 31, 2004, based on forecast prices and costs.

Corporation	Light and Medium Oil (Bbl/d)	Heavy Oil (Bbl/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbl/d)	Combined (BOE/d)
Proved					
Developed producing	1,843	34	8,310	173	3,435
Developed non-producing	113	18	378	5	199
Undeveloped	215	-	1,605	30	512
Total Proved	2,171	52	10,293	208	4,146
Probable	368	3	1,959	76	774
Total proved plus probable	2,539	55	12,252	284	4,920

The following table discloses the estimated average daily production before deduction of royalties for 2005 for Celtic's Fox Creek area property, being in excess of 20% of the estimated production set forth in the immediately preceding table.

Fox Creek	Light and Medium Crude Oil (Bbl/d)	Heavy Oil (Bbl/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbl/d)	Combined (BOE/d)
Proved					
Developed producing	416	0	1,145	80	687
Developed non-producing	0	0	0	0	0
Undeveloped	0	0	0	0	0
Total Proved	416	0	1,145	80	687
Probable	229	0	633	44	378
Total proved plus probable	645	0	1,778	124	1,065

Production History

The following table summarizes Celtic's average daily production before deduction of royalties, for the periods indicated.

	2004				
Product	**Year**	**Q4**	**Q3**	**Q2**	**Q1**
Oil and NGLs (Bbl/d)	2,283	2,142	2,396	2,314	2,281
Natural gas (Mcf/d)	7,952	8,292	8,086	7,372	8,054
Total (BOE/d)	3,608	3,524	3,744	3,543	3,623

Netback History

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

	2004				
Category	**Year**	**Q4**	**Q3**	**Q2**	**Q1**
Selling prices					
Oil & NGLs ($/Bbl)	48.71	53.08	53.06	45.79	42.89
Natural gas ($/Mcf)	6.97	7.13	6.91	7.29	6.57
Royalties					
Oil & NGLs ($/Bbl)	(8.17)	(8.98)	(8.65)	(8.01)	(7.05)
Natural gas ($/Mcf)	(1.36)	(1.40)	(1.30)	(1.32)	(1.44)
Transportation and selling expenses					
Oil & NGLs ($Bbl)	(0.46)	(0.67)	(0.30)	(0.52)	(0.38)
Natural Gas ($/mcf)	(0.19)	(0.20)	(0.19)	(0.25)	(0.14)
Production expenses(1)					
Oil & NGLs ($/Bbl)	(8.28)	(8.85)	(9.66)	(7.25)	(7.31)
Natural gas ($/Mcf)	(1.31)	(1.05)	(1.30)	(1.72)	(1.22)
Operating netbacks					
Oil & NGLs ($/Bbl)	31.88	34.66	34.58	30.08	28.19
Natural gas ($/Mcf)	4.11	4.48	4.12	4.00	3.77

Note:

(1) Production expenses include petroleum 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 important field, and in total, Celtic's production volumes for the financial year ended December 31, 2004 for each product type.

Field	Light and Medium Oil (Bbls/d)	Heavy Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	BOE (BOE/d)	%
Southern Alberta						
Princess/Bantry	252	-	271	3	300	9%
Michichi/Drumheller	58	-	1,091	12	252	7%
Bow Island/Grand Forks	232	15	95	-	263	7%
Richdale	2	-	1,228	7	213	6%
Joffre	88	-	285	13	149	4%
Other	123	2	971	10	296	9%
Total	755	17	3,941	45	1,473	41%
East Central Alberta						
Ashmont	-	-	1,272	-	212	6%
Redwater/Skaro	-	-	365	-	61	2%
Other	72	-	229	6	116	3%
Total	72	-	1,866	6	389	11%
West Central Alberta						
Fox Creek	509	-	1,458	108	860	24%
Morse River / Swan Hills	135	-	-	-	135	4%
Kakwa/Chime	-	-	659	11	121	3%
Total	644	-	2,117	119	1,116	31%
Northern Alberta						
Utikuma	318	-	28	4	327	9%
Otter/Ogston/ Red Earth	194	-	-	-	194	5%
McLeans Creek	109	-	-	-	109	3%
Total	621	-	28	4	630	17%
TOTAL	2,092	17	7,952	174	3,608	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 Celtic.

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 Celtic 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.

Insurance

Celtic's involvement in the exploration for and development of oil and gas properties may result in Celtic becoming subject to liability for pollution, blow-outs, property damage, personal injury and other hazards. Although Celtic will obtain insurance in accordance with industry standards to address such risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not, in all circumstances be insurable or, in certain circumstances, Celtic may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or for other reasons. The payment of such uninsured liabilities would reduce the funds available to Celtic. The occurrence of a significant event that Celtic is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on Celtic's financial position, results of operations or prospects.

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 Celtic. 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 Celtic's oil and gas production. Celtic might also elect not to produce from certain wells at lower prices. All these factor could result in a material decrease in Celtic's future net production revenue, causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings available to Celtic will be in part determined by the borrowing base of Celtic. A sustained material decline in prices from historical average prices could reduce Celtic's future borrowing base, therefore reducing the bank credit available to Celtic, and could require that a portion of any existing bank debt of Celtic be repaid.

In addition to establishing markets for its oil and natural gas, Celtic 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 Celtic will be affected by numerous factors beyond its control. Celtic will be affected by the differential between the price paid by refiners for light quality oil and the grades of oil produced by Celtic. The ability of Celtic to market natural gas may depend upon its ability to acquire space on pipelines which deliver natural gas to commercial markets. Celtic 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. Celtic has limited direct experience in the marketing of oil and natural gas.

Substantial Capital Requirements; Liquidity

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

Celtic will actively compete for reserve acquisitions, exploration leases, licences and concessions and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial resources than Celtic. Celtic's competitors will include major integrated oil and natural gas companies and numerous other independent oil and natural gas companies and individual producers and operators.

The oil and gas industry is highly competitive. Celtic's competitors for the acquisition, exploration, production and development of oil and natural gas properties, and for capital to finance such activities include companies that have greater financial and personal resources available to them than Celtic.

Certain of Celtic's customers and potential customers may themselves explore for oil and natural gas and the results of such exploration efforts could affect Celtic's ability to sell or supply oil or gas to these customers in the future. Celtic's ability to successfully bid on and acquire additional property rights, to discover reserves to participate in drilling opportunities and to identify and enter into commercial arrangements with customers will be dependent upon developing and maintaining close working relationships with its future industry partners and joint operators and its ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment.

Title

Title to oil and natural gas interests is often not capable of conclusive determination without incurring substantial expense. In accordance with industry practice, Celtic 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 Celtic 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 foreign governments and third parties and may require Celtic to incur costs to remedy such discharge. No assurance can be given that the application of environmental laws to the business and operations of Celtic 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 Celtic's financial condition, results of operations or prospects.

Reserve Estimates

The reserve reports for its oil and gas properties contain estimates of Celtic's oil and gas reserves and the estimated future net reserves therefrom that rely upon various assumptions, including assumptions as to oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil and gas reserves is complex, requiring significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. As a result, such estimates are inherently imprecise. Actual future production, oil and gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves may vary substantially from those estimated in the respective reserve reports. Any significant variance in these assumptions could materially affect the estimated quantities and present value of reserves set forth in the Sproule Report. In addition, such reserves may be subject to downward or upward revisions based upon production history, results of future exploration and development, prevailing oil and gas prices and other factors, many of which are beyond the control of Celtic. Actual production, revenues, taxes, development expenditures and operating expenses with respect to reserves will likely vary from the estimates used and such variances may be material.

The present value of future net reserves referred to in the Sproule Report should not be construed as the current market value of the estimated oil and gas reserves attributable to Celtic's properties. The estimated discounted future net cash flows from proved reserves are generally based on prices and costs as of the date of the estimate, whereas actual future prices and costs may be materially higher or lower. Actual future net cash flows will be affected by increases or decreases in consumption by oil and gas purchasers and changes in governmental regulations or taxation. The timing of actual future net cash flows from proved reserves, and thus their actual present value, will be affected by the timing of both the production and the incurrence of expenses in connection with development and production of oil and gas properties.

Reserve Replacement

Celtic's future oil and natural gas reserves, production, and cash flows to be derived therefrom are highly dependent on Celtic successfully acquiring or discovering new reserves. Without the continual addition of new reserves, any existing reserves Celtic may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Celtic's reserves will depend not only on Celtic'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 Celtic's future exploration and development efforts will result in the discovery and development of additional commercial accumulations of oil and natural gas.

Reliance on Operators and Key Employees

To the extent Celtic is not the operator of its oil and gas properties, Celtic will be dependent on such operators for the timing of activities related to such properties and will largely be unable to direct or control the activities of the operators. In addition, the success of Celtic will be largely dependent upon the performance of its management and key employees. Celtic 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 Celtic.

Corporate Matters

To date, Celtic has not paid any dividends on its 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 Celtic 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 Celtic 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.

Permits and Licenses

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

Additional Funding Requirements

Celtic's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, Celtic 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 Celtic to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If Celtic's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect Celtic's ability to expend the necessary capital to replace its reserves or to maintain its production. If Celtic'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 be available on favourable terms. Any equity financing may result in a change of control of Celtic or holders of Common Shares suffering further dilution.

Issuance of Debt

From time to time Celtic 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 Celtic's debt levels above industry standards. Neither Celtic's articles nor its bylaws limit the amount of indebtedness that Celtic may incur. The level of Celtic's indebtedness from time to time could impair Celtic's ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise. Celtic's ability to meet its debt service obligations will depend on Celtic's future operations which are subject to prevailing industry conditions and other factors, many of which are beyond the control of Celtic. As certain of the indebtedness of Celtic bears interest at rates which fluctuate with prevailing interest rates, increases in such rates would increase Celtic's interest payment obligations and could have a material adverse effect on Celtic's financial condition and results of operations. Further, Celtic's indebtedness is secured by substantially all of Celtic's assets. In the event of a violation by Celtic of any of its loan covenants or any other default by Celtic 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 Celtic'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.

Availability of Drilling Equipment and Access Restrictions

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

Kyoto Protocol

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". Celtic's exploration and production facilities and other operations and activities will emit a small amount of greenhouse gases which may subject Celtic to legislation regulating emissions of greenhouse gases. The Government of Canada has put forward a Climate Change Plan for Canada which suggests further legislation will set greenhouse gases emission reduction requirements for the various industrial activities, including oil and gas exploration and production. Future federal legislation, together with provincial emission reduction requirements, such as those proposed in Alberta's Bill 32: Climate Change and Emissions Management, may require the reduction of emissions or emissions intensity with Celtic's operations and facilities. The direct or indirect costs of these regulations may adversely affect the business of Celtic.

INDUSTRY CONDITIONS

Canadian Government Regulation

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada, Alberta and Saskatchewan, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these controls or regulations will affect the operations of Celtic in a manner materially different than they would affect other oil and gas companies of similar size. All current legislation is a matter of public record and Celtic is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing – Oil and Natural Gas

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Such price depends in part on oil quality, prices of competing oils, distance to market, the value of refined products and the supply/demand balance. 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 licence from the NEB and the issue of such licence requires the approval of the Governor in Council.

The price of natural gas is determined by negotiation between buyers and seller. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. 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 two years or for a term of two to 20 years (in quantities of not more than 30,000 cubic metres per 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 a larger quantity requires an exporter to obtain an export licence from the NEB and the issue of such licence requires the approval of the Governor in Council.

The governments of British Columbia, Alberta and Saskatchewan also regulate the volume of natural gas which may be removed from those provinces for consumption elsewhere based on such factors as reserve ability, transportation arrangements and market considerations.

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 prorationing of capacity on the interprovincial pipeline systems continues to limit oil exports.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico become effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada - U.S. Free Trade Agreement. Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period; (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 border restrictions and export taxes. The agreement also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements, which is important for Canadian natural gas exports.

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 crude oil, NGL, sulphur 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, although production from such lands is subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The royalty rate payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date 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.

In the Province of Alberta, a producer of oil or natural gas is entitled to a credit against the royalties payable to the Crown by virtue of the Alberta royalty tax credit ("**ARTC**") program. The ARTC program is based on a price sensitive formula and the ARTC rate varies between 75% at prices at and below $100 per cubic metre ($15.90 per Bbl) and 25% at prices at and above $210 per cubic metre ($33.39 per Bbl). The ARTC rate is applied to a maximum of $2,000,000 of Alberta Crown royalties payable for each producer or associated group of producers. Crown royalties on production from producing properties acquired from a corporation claiming maximum entitlement to ARTC will generally not be eligible for ARTC. The rate will be established quarterly based on the average "par price", as determined by the Alberta Department of Energy for the previous quarterly period.

On December 22, 1997, the Alberta government announced that it would be conducting a review of the ARTC program with the objective of setting out better targeted objectives for a smaller program and to deal with administrative difficulties. On August 30, 1999, the Alberta government announced that it would not be reducing the size of the program but that it would introduce new rules to reduce the number of persons who qualify for the program. The new rules will preclude companies that pay less than $10,000 in royalties per year and non-corporate entities from qualifying for the program. Such rules will not presently preclude Celtic from being eligible for the ARTC program.

Crude oil and natural gas royalty holidays for specific wells and royalty reductions reduce the amount of Crown royalties paid by Celtic to the provincial governments. In general, the ARTC program provides a rebate on Alberta Crown royalties paid in respect of eligible producing properties.

On March 3, 2003 the Department of Finance (Canada) released a technical paper entitled "Improving the Income Taxation of the Resource Sector in Canada" (the "**Technical Paper**"). The new structure for federal taxation of resource income proposed by the Technical Paper contains the following initiatives applicable to the oil and gas industry to be phased in over a five year period: (i) a reduction of the federal statutory corporate income tax rate on income earned from resource activities from 28 to 21% beginning with a one percentage point reduction effective January 1, 2003, and (ii) a deduction for federal income tax purposes of actual provincial and other Crown royalties and mining taxes paid and the elimination of the 25% resource allowance. The Technical Paper also proposes that the percentage of ARTC that the Company will be required to include in federal taxable income will be 5% in 2003; 12.5% in 2004; 17.5% in 2005; 32.5% in 2006; 50% in 2007; 60% in 2008; 70% in 2009; 80% in 2010; 90% in 2011, and 100% in 2012 and beyond.

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.

The new fiscal regime in Saskatchewan provides new royalty and tax structures, a new system of volume incentives, and a reduced Corporation Capital Tax Surcharge rate. Other components are a new royalty/tax regime for gas produced from new oil wells and changes that benefit horizontal and deep oil wells. The "fourth tier" Crown royalty rate and freehold production tax structure is production and price sensitive and applies to: conventional oil wells (vertical and horizontal) and gas wells with a finished drilling date on or after October 1, 2002; incremental oil produced from new or expanded waterflood projects with a commencement date on or after October 1, 2001; and, natural gas produced from gas wells with a finished drilling date on or after October 1, 2002. The price sensitive parameters for the new "fourth tier" royalty structures provide: a base rate of 5% and marginal rate of 30% for both oil and gas; a base price of $100 per cubic metre for oil and $50 per thousand cubic metres for gas; and, a reference well production rate of 250 cubic metres of oil per month and 250 thousand cubic metres of gas per month.

The freehold production tax rates are now determined by subtracting a production tax factor of 12.5 percentage points (an increase in the previous 10 percentage point freehold production tax factor) from the corresponding Crown royalty rates. Further, the Corporation Capital Tax Surcharge rate has been decreased to 2.0% from 3.6% for: all oil and gas that is produced from oil wells or gas wells with a finished drilling date on or after October 1, 2002; and, incremental oil related to new or waterflood projects having a commencement date on or after October 1, 2002. In conjunction with the "fourth tier" royalty/tax structures, the government of Saskatchewan introduced 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. The incentive volumes are applicable to various well types and are subject a maximum royalty rate of 2.5% and a freehold production tax rate of 0%. Re-entry and short section horizontal oil well royalty/tax categories have been eliminated. 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. The definition of “deep oil well” has also been expanded.

The new Crown royalty and freehold production tax regime applies to associated natural gas (gas produced from oil wells) that is gathered for use or sale and is produced from: oil wells with a finished drilling date on or after October 1, 2002; and, 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. Effectively, a royalty/tax will be payable on associated natural gas produced from an oil well that exceeds approximately 65 thousand cubic metres in a month.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominately by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences 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 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 gas industry currently subject to environmental regulation pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release of emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability for pollution damage and the imposition for material fines and penalties.

Environmental legislation in the Province of Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (the “**EPEA**”), which came into force on September 1, 1993. The EPEA imposes stricter environmental standards, requires more stringent compliance, reporting and monitoring obligations and significantly increases penalties. Celtic is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and expense nature as a result of the increasingly stringent laws relating to the protection of the environmental and will be taking such steps as required to ensure compliance with the EPEA and similar legislation in other jurisdictions in which it operates. Celtic believes that it is in material compliance with applicable environmental laws and regulations. Celtic also believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

Dividends

Celtic has not declared or paid any dividends since its incorporation and does not foresee the declaration or payment of dividends in the near future. Any decision to pay dividends on its shares will be made by the board of directors on the basis of Celtic's earnings, financial requirements and other conditions existing at such future time.

MANAGEMENT’S DISCUSSION AND ANALYSIS

The section “Management’s Discussion and Analysis” on pages 18 through 41 of the Corporation’s Annual Report for the year ended December 31, 2004 is incorporated herein by reference.

DESCRIPTION OF SHARE CAPITAL

General Description of Share Capital

Celtic is authorized to issue an unlimited number of Common Shares without nominal or par value, of which, as at March 20, 2005, 25,886,563 Common Shares are issued and outstanding as fully paid and non-assessable. In addition, 1,916,335 Common Shares are reserved for options to be granted to directors, officers, employees and consultants of Celtic. Celtic is also authorized to issue and unlimited number of preferred shares ("**Preferred Shares**"), without nominal or par value. To date, no Preferred Shares have been issued.

Common Shares

The holders of Celtic's Common Shares are entitled to dividends as and when declared by the board of directors of Celtic, to one vote per share at meetings of shareholders of Celtic and, upon liquidation, to receive such assets of Celtic are distributable to the holders of the Common Shares.

Preferred Shares

The Preferred Shares may be issued from time to time in one or more series, each series consisting of a number of Preferred Shares as determined by the board of directors of Celtic who may also fix the designations, rights, privileges, restrictions and conditions attaching to the shares of each series of Preferred Shares. There are no Preferred Shares issued and outstanding as at the date hereof.

The Preferred Shares of each series shall, with respect to payment of dividends and distributions of assets in the event of liquidation, dissolution or winding-up of Celtic, whether voluntary, or any other distribution of the assets of Celtic among its shareholders for the purpose of winding-up its affairs, rank equally with the Preferred Shares of every other series and shall be entitled to preference over the Common Shares, and the shares of any other class ranking junior to the Preferred Shares.

MARKET FOR SECURITIES

Price Range and Volume of Trading of Common Shares

The following table sets forth the reported high and low sales prices (which are not necessarily the closing prices) and the trading volumes for the common shares of Celtic on the Toronto Stock Exchange (and, prior to July 14, 2003, on the TSX Venture Exchange, and its predecessor) as reported by sources Celtic believes to be reliable for the periods indicated:

Date	Price Range ($)			Trading Volume
	High	**Low**	**Close**	
2003				
October	6.30	5.55	6.00	2,022,101
November	6.25	5.85	6.25	539,427
December	8.00	6.00	8.00	544,750
2004				
January	8.15	7.27	7.40	1,114,656
February	7.95	6.70	7.79	425,760
March	7.99	7.01	7.45	970,774
April	8.50	7.36	8.36	1,135,830
May	8.50	7.95	8.00	1,007,586
June	8.12	7.11	7.75	516,934
July	8.25	7.60	8.00	653,041
August	8.25	7.70	7.80	716,724
September	8.98	7.75	8.80	704,828
October	9.25	8.65	8.95	1,041,691
November	9.80	8.40	9.65	971,721
December	9.95	8.55	9.30	809,741

Date	Price Range ($)			Trading Volume
	High	Low	Close	
2005				
January	10.74	9.00	10.60	1,092,897
February	12.45	10.75	12.29	1,129,822
March 1 - 20	12.44	9.50	11.20	998,599

DIRECTORS AND OFFICERS

The following table sets forth the name, municipality of residence, office of the Corporation, and principal occupation for the past five years of each of the directors and executive officers of Celtic. The term of office of each director will expire at the end of the next annual meeting of shareholders of Celtic.

Name and Country of Residence	Number of Common Shares Beneficially Owned	Offices with the Corporation	Principal Occupation During the Past Five Years
David J. Wilson(2)(4) Alberta, Canada	4,663,532	President and Chief Executive Officer and Director since September 2002	President and Chief Executive Officer of Celtic. Prior thereto President of Vintage petroleum Canada, Inc. from May, 2001 to May 2002 and President and Chief Executive Officer of Genesis Exploration Ltd. from 1992 to May 2001.
Sadiq H. Lalani Alberta, Canada	15,000	Vice President, Finance and Chief Financial Officer since October 2002	Vice President, Finance and Chief Financial Officer of Celtic. Prior thereto Vice President, Finance and Chief Financial Officer for True Energy Inc. from November 2001 to October 2002 and prior to that was Senior Vice President and Chief Financial Officer for Triumph Energy Corporation from April 1996 to May 2001.
William C. Guinan(2)(3) Alberta, Canada	240,667	Corporate Secretary and Director since April 2002	Partner, Borden Ladner Gervais LLP, a law firm.
Robert J. Dales(1)(2)(3)(4) Alberta, Canada	554,167	Director since April 2002	President, Valhalla Ventures Inc. a private Alberta investment company, from January 1999 to the present.
Eldon A. McIntyre(1)(4) Alberta, Canada	2,785,833	Director since September 2002	President, Jarrod Oils Ltd., a private Saskatchewan company engaged in oil and gas exploration and production, from the late 1970's to the present.
Neil G. Sinclair(1)(3) British Columbia, Canada	815,667	Director since April 2002	President, Sinson Investments Ltd., a private British Columbia company engaged in property development, from 1973 to the present.
Alan G. Franks Alberta, Canada	Nil	Vice President, Operations since December 2002	Vice President, Operations of Celtic. Prior thereto Project Manager, Facilities of Canadian Natural Resources Limited. from May 2001 to December 2002 and Manager, Operations of Cirque Energy Corp. and Cirque Energy (UK) Limited from 1998 to May 2001.
Michael R. Shea Alberta, Canada	Nil	Vice President, Land since December 2002	Vice President, Land of Celtic. Prior thereto land consultant to NCE Resources Group from September 2001 to December 2002 and prior to that was President and Chief Executive Officer of Canadian Mustang Energy Inc. from April 1999 to June 2001.

Name and Country of Residence	Number of Common Shares Beneficially Owned	Offices with the Corporation	Principal Occupation During the Past Five Years
David C. Morgenstern Alberta, Canada	200	Vice President, Exploration since December 2004	Vice President, Exploration of Celtic. Prior thereto Senior Exploration Geologist for Vintage Petroleum Canada Inc. from July 2001 to December 2004 and President and Chief Operating Officer for Symmetry Resources Inc. from June 1996 to February 2000.

Notes:

(1) Member of the Audit Committee. Celtic is required, pursuant to the ABCA, to have an audit committee of the board of directors.

(2) Member of the Corporate Governance Committee.

(3) Member of the Compensation Committee.

(4) Member of the Reserves Committee.

As at March 20, 2004, the directors and officers of the Corporation, as a group, owned directly or indirectly 9,075,066 Common Shares or approximately 35.1% of the issued and outstanding Common Shares. The information as to the Common Shares, not being within the knowledge of the Corporation, has been furnished by the respective directors and officers of the Corporation individually.

AUDIT COMMITTEE

Under Multilateral Instrument 52-110 *Audit Committee*, the Corporation is required to include in its Annual Information Form the disclosure required under From 52-110F1 with respect to its audit committee, including the text of its audit committee charter, the composition of the audit committee and the fees paid to the external auditor. This information is provided in Appendix D attached hereto.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

The management of the Corporation is not aware of any material interest, direct or indirect, or of any informed person of the Corporation, any proposed directors of the Corporation or any associate or affiliate of an informed person or proposed director, in any transaction since the commencement of the last fiscal year, or in any proposed transaction since the beginning of the Corporation's most recently completed financial year end being the year ended December 31, 2004 or in any proposed transaction which has materially affected or would materially affect the Corporation.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares of Celtic is Valiant Trust Company at its principal offices in Calgary, Alberta.

INTEREST OF EXPERTS

Certain information incorporated into this Annual Information Form has been taken from the Sproule Report which report has been prepared by Sproule. See "Statement of Reserves Data and Other Oil and Gas Information." No personal or company whose profession or business gives authority to a statement made by such person or company and who is named in this Annual Information Form as having prepared or certified a part of this Annual Information Form, or a report or valuation described in this Annual Information Form, has received or shall receive a direct or indirect interest in the property of Celtic or of any associate or affiliate of Celtic. As at the date hereof, the principals of Sproule do not beneficially own, directly or indirectly, any of the Common Shares of Celtic.

CONFLICTS OF INTEREST

There are potential conflicts of interest to which the directors and officers of Celtic will be subject in connection with the operations of Celtic. In particular, certain of the directors and officers of Celtic 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 Celtic or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of Celtic. 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

The Corporation, upon request to the secretary of the Corporation, will provide to any person or company:

(a) when the securities of the Corporation are in the course of a distribution under a preliminary short form prospectus or a short form prospectus,

- (i) one copy of the AIF of the Corporation, together with one copy of any document, or the pertinent pages of any document, incorporated by reference in the AIF,

- (ii) one copy of the comparative financial statements of the Corporation for its most recently completed financial year for which financial statements have been filed together with the accompanying report of the auditor and one copy of the most recent interim financial statements of the Corporation that have been filed, if any, for any period after the end of its most recently completed financial year,

- (iii) one copy of the information circular of the Corporation in respect of its most recent annual meeting of shareholders that involved the election of directors or one copy of any annual filing prepared instead of that information circular, as appropriate, and

- (iv) one copy of any other documents that are incorporated by reference into the preliminary short form prospectus or the short for prospectus and are not required to be provided under clauses (a)(i), (ii) or (iii) above; or

(b) at any other time, one copy of any documents referred to in clauses (a)(i), (ii) and (iii) above, provided that the Corporation may require the payment of a reasonable charge if the request is made by a person or company who is not a security holder of the Corporation.

Additional information including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities, options to purchase securities and interest of insiders in material transaction, if applicable, is contained in the Corporation's information circular for its most recent annual meeting of shareholders that involved the election of directors, and that additional financial information is provided in the Corporation's comparative financial statements for its most recently completed financial year. Additional information relating to the Corporation may be found on SEDAR at www.sedar.com.

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 Celtic Exploration Ltd. (the “Company”):

2. We have evaluated the Company’s Reserves Data as at December 31, 2004. The reserves data consist of the following:

   (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2004 using forecast prices and costs; and

   (ii) the related estimated future net revenue; and

   (b) (i) proved oil and gas reserve quantities were estimated as at December 31, 2004 using constant prices and costs; and

   (ii) the related estimated future net revenue (included as a separate report).

3. 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).

4. 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 presented in the COGE Handbook.

5. The following table sets forth the estimated future net revenue attributed to proved plus probable reserves, estimated using forecast prices and costs on a before tax basis and calculated using a discount rate of 10%, included in the reserves data of the Company evaluated by us as of December 31, 2004, and identifies the respective portions thereof that we have evaluated and reported on to the Company’s management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country)	Net Present Value of Future Net Revenue (10% Discount Rate)			
			Audited (M$)	Evaluated (M$)	Reviewed (M$)	Total (M$)
Sproule	Evaluation of the P&NG Reserves of Celtic Exploration Ltd., as of December 31, 2004 prepared December 2004 to January 2005	Canada				
Total			**Nil**	**164,410**	**Nil**	**164,410**

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

7. We have no responsibility to update the report referred to in paragraph 4 for events and circumstances occurring after its preparation date.

8. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
February 9, 2005

(signed)
Cameron P. Six, P. Eng.
Project Leader

(signed)
Harry J. Helwerda, P. Eng.
Vice-President, Engineering, Canada and U.S.

(signed)
Wesley J. Waddell, P. Geol.
Associate

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"). The form does not apply in British Columbia.

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

2. 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 Celtic Exploration Ltd. (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 consist of the following:

(a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2004 using forecast prices and costs; and

(ii) the related estimated future net revenue; and

(b) (i) proved oil and gas reserves estimated as at December 31, 2004, using constant prices and costs; and

(ii) the related estimated future net revenue.

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

The Reserves Committee of 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 Reserves Committee of 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, on the recommendation of the Reserves Committee, approved

(a) the content and filing with securities regulatory authorities of the reserve data and other oil and gas information;

(b) the filing of the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

(signed)
David J. Wilson
President and Chief Executive Officer

(signed)
William C. Guinan
Corporate Secretary

(signed)
Robert J. Dales
Director

(signed)
Eldon A. McIntyre
Director

Dated this 1st day of March, 2005.

APPENDIX C

DEFINITIONS USED FOR RESERVE CATEGORIES

The following definitions form the bases of the classification of reserves and values presented in the Sproule Report. They have been prepared by the Standing Committee on Reserves Definitions of the Petroleum Society of the CIM ("CIM"), incorporated in the Society of Petroleum Evaluation Engineers ("SPEE") Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and specified by National Instrument 51-101 ("NI 51-101").

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recovered 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; and
- a remaining reserve life of 50 years.

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

1. **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.

2. **Probable Reserves**

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

3. **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. Possible reserves have not been considered in this report.

Other criteria that must also be met for categorization of reserves are provided in Section 5.5 of the COGE Handbook.

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

4. **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.

5. **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.

6. **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.

7. **Undeveloped Reserves**

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., 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.

8. **Levels of Certainty for Reported Reserves**

The qualitative certainty levels contained in the definitions in Sections 1, 2 and 3 are applicable to individual reserves entitles, which refer to the lowest level at which reserves estimates are made, and to reported reserves, which refers to the highest level sum of individual entity estimates for which reserve estimates are made.

Reported total reserves estimated by deterministic or probabilistic methods, whether comprised of a single reserves entity or an aggregate estimate for multiple entities, should target the following levels of certainty under a specific set of economic conditions:

a. There is a 90% probability that at least the estimated proved reserves will be recovered.

b. There is a 50% probability that at least the sum of the estimated proved reserves plus probable reserves will be recovered.

c. There is a 10% probability that at least the sum of the estimated proved reserves plus probable reserves plus possible reserves will be recovered.

A quantitative measure of the probability associated with a reserves estimate is generated only when a probabilistic estimate is conducted. The majority of reserves estimates will be performed using deterministic methods that do not provide a 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. Whether deterministic or probabilistic methods are used, evaluators are expressing their professional judgement as to what are reasonable estimates.

9. **Pipeline Gas Reserves** are gas reserves remaining after deducting surface losses due to process shrinkage and raw gas used as lease fuel.

10. **Remaining Recoverable Reserves** are the total remaining recoverable reserves associated with the acreage in which the Company has an interest.

11. **Company Gross Reserves** are the Company's working interest share of the remaining reserves, before deduction of any royalties.

12. **Company Net Reserves** are the gross remaining reserves of the properties in which the Company has an interest, less all Crown, freehold, and overriding royalties and interest owned by others.

13. **Net Production Revenue** is income derived from the sale of net reserves of oil, pipeline gas, and gas by-products, less all capital and operating costs.

14. **Fair Market Value** is defined as the price at which a purchaser seeking an economic and commercial return on investment would be willing to buy, and a vendor would be willing to sell, where neither is under compulsion to buy or sell and both are competent and have reasonable knowledge of the facts.

15. **Barrels of Oil Equivalent (BOE) Reserves** - BOE is the sum of the oil reserves, plus the gas reserves divided by a factor of 6, plus the natural gas liquid reserves, all expressed in barrels or thousands of barrels.

APPENDIX D

1. The Audit Committee's Charter

The following is the text of the Audit Committee's Charter.

I. 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 internal controls of the Corporation is vested in management and is overseen by the Board.

II. COMPOSITION AND PROCESS

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").
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 Committee 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.

III. 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.

IV. 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 structures and procedures to ensure that it meets with the external auditor on a regular basis in the absence of management.

V. 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 auditors, 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 for the external auditors' 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 judgments 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 policies regarding partners, employees and former partners and employees of the present and former external auditor of the Corporation.

VI. 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.

VII. 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.

VIII. OTHER RESPONSIBILITIES

1. Investigating fraud, illegal acts or conflicts of interest.

2. Discussing selected issues with corporate counsel or the outside auditor or management.

2. Composition of the Audit Committee

During the year ended December 31, 2004 the Audit Committee of the Corporation was composed of the following individuals:

Robert Dales	Independent(1)	Financially literate(2)
Eldon McIntyre	Independent(1)	Financially literate(2)
Neil Sinclair	Independent(1)	Financially literate(2)

(1) A member of an audit committee is independent if the member has no direct or indirect material relationship with the Corporation which could, in the view of the Board, reasonably interfere with the exercise of a member's independent judgment.

(2) An individual is financially literate if he has the ability to read and understand a set of financial statements that present a breadth 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.

3. Relevant Education and Experience

Mr. Dales, the Chairman of the Audit Committee, holds an MBA. He also has over 10 years of public issuer experience, both as an officer and a director.

Mr. McIntyre has been President of an active private corporation, with significant oil and gas operations, for over 25 years. He also has over 12 years of public issuer experience, both as an officer and a director.

Mr. Sinclair holds a BA and MBA. He has also been President of an active private corporation, with significant real estate operations, for over 25 years.

4. Reliance on Certain Exemptions

At no time since the commencement of the Corporation's most recently completed financial year has the Corporation relied on any exemption from MI 52-110, other than in Section 2.4 of MI 52-110 (De Minimis Non-audit Services), or an exemption from MI 52-110, in whole or in part, granted under Part 8 of MI 52-110.

5. Reliance on the Exemption in Subsection 3.3(2) or Section 3.6

At no time since the commencement of the Corporation's most recently completed financial year has the Corporation relied on the exemptions in Sections 3.3(2) or 3.6 of MI 52-110.

6. Reliance on Section 3.8

At no time since the commencement of the Corporation's most recently completed financial year has the Corporation relied on Section 3.8 of MI 52-110.

7. Audit Committee Oversight

At no time since the commencement of the Corporation's most recently completed financial year was a recommendation of the Audit Committee to nominate or compensate an external auditor not adopted by the Board.

8. Pre-Approval Policies and Procedures

The Audit Committee of the Corporation has adopted specific policies and procedures for the engagement of non-audit services entitled "Procedures for Approval of Audit and Non-Audit Services by the External Auditors" (the "**Procedure**"). Under the Procedure, the auditors may not act in any capacity where they function as management, audit their own work or serve in an advocacy role on behalf of the Corporation. Various audit related services provided by the auditors have been pre-approved. Management is required, however, to obtain pre-approval of the Audit Committee for services where engagement fees are expected to exceed $25,000. Where fees for a particular engagement are expected to be less than or equal to $25,000 the Chairman of the Audit Committee is to be notified expeditiously of the commencement of such services. If an engagement with the auditors for a particular service is contemplated that is neither expressed forbidden under the Procedure nor covered under the range of services provided for therein, such an engagement must be pre-approved. The Audit Committee has delegated the authority to effect such pre-approval to the Chairman of the Audit Committee. Pre-approved non-audit services shall be provided pursuant to an engagement letter signed by the auditors which shall set out the particular non-audit services to be provided. At every regularly scheduled meeting of the Audit Committee, management is required to report on all new pre-approved engagements of the auditors since the last such report.

9. External Auditor Service Fees (By Category)

The aggregate fees billed by the Corporation's external auditors in each of the last two fiscal years are as follows:

Financial Period Ending December 31	Audit Fees(1)	Audit Related Fees	Tax Fees(2)	All Other Fees
2004	$51,408	Nil	$6,500	Nil
2003	$55,987	Nil	$7,200	Nil

Notes:
(1) The aggregate audit fees billed.
(2) The aggregate fees billed for professional services rendered for tax compliance, tax advice and tax planning.