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MANAGEMENT'S RESPONSIBILITY STATEMENT

To the Shareholders of Grand Banks Energy Corporation

The accompanying financial statements and all information contained in the Annual Report are the responsibility of management. The financial statements of the Corporation have been prepared by management in accordance with the accounting policies set out in the accompanying notes to the financial statements. In the opinion of management, the financial statements have been prepared with acceptable limits of materiality and are in accordance with Canadian generally accepted accounting principles ("GAAP") appropriate in the circumstances.

Management maintains systems of control appropriate for the Company's size and operations. Policies and procedures are designed to give reasonable assurance that transactions are properly authorized, assets are safeguarded and financial records properly maintained to provide reliable and timely financial information for the preparation of financial statements.

The Audit Committee of the Corporation's Board of Directors, comprised of non-management Directors, recommends the nomination of the independent auditors and meets with management and the independent auditors to satisfy themselves that management fulfills its responsibilities for financial reporting and control. The Committee reviews the financial statements with the external auditors, considers auditors independence and approves the auditors' fees.

The financial statements have been audited by Deloitte & Touche LLP, independent auditors, and have been approved by the Board of Directors on the recommendation of the Audit Committee.

AR/S
12-31-05

[signed]

EDWARD C. McFEELY
President & Chief Executive Officer

[signed]

DAVID BLAIN, C.A.
Chief Financial Officer

Calgary, Alberta
April 6, 2006

AUDITORS' REPORT

To the Shareholders of Grand Banks Energy Corporation

We have audited the balance sheet of Grand Banks Energy Corporation as at December 31, 2005 and the statement of operations and retained earnings (deficit) and cash flows for the year then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2005 and the results of its operations and its cash flows for the year ended, in accordance with Canadian generally accepted accounting principles.

The comparative financial statements provided herein for the year ended December 31, 2004 were audited by another firm of chartered accountants who rendered an opinion without reservation in their report dated March 11, 2005.

[signed]

Deloitte & Touche LLP
Chartered Accountants

Calgary, Alberta
March 24, 2006

BALANCE SHEETS

As at December 31,	2005	2004
(000s)	*($)*	*($)*
ASSETS		
Current		
Cash and cash equivalents	**5,443**	6,852
Accounts receivable	**3,656**	852
Cash calls receivable	**2,042**	926
Prepaid expenses and advances	**100**	63
Share purchase loans receivable *(Note 8)*	**--**	214
	11,241	8,907
Property and equipment *(Note 3)*	**28,005**	15,740
Future tax asset *(Note 9)*	**3,090**	--
	42,336	24,647
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current		
Accounts payable and accrued liabilities	**9,464**	5,105
Asset retirement obligation *(Note 5)*	**894**	341
	10,358	5,446
Shareholders' Equity		
Equity instruments *(Note 6)*	**29,228**	18,159
Share purchase loans *(Note 8)*	**(48)**	(143)
Contributed surplus *(Note 7)*	**1,790**	1,107
Retained earnings	**1,008**	78
	31,978	19,201
	42,336	24,647

See accompanying notes to the financial statements.

On behalf of the Board of Directors:

[signed]

THOMAS BAMFORD
DIRECTOR

[signed]

W.J. McNAUGHTON
Chairman of the Audit Committee

STATEMENTS OF OPERATIONS AND RETAINED EARNINGS (DEFICIT)

For the Years Ended December 31,	2005	2004
(000s, except per share amounts)	*($)*	*($)*
Revenue		
Crude oil and liquids	**5,327**	1,177
Natural gas	**11,895**	1,120
Royalty income	**28**	114
Processing income	**1**	2
Interest income	**126**	177
	17,377	2,590
Less: royalties	**(4,706)**	(436)
	12,671	2,154
Expenses		
Accretion of asset retirement obligation *(Note 5)*	**67**	22
Depletion and amortization	**10,652**	872
General and administrative	**1,254**	831
Interest	**50**	173
Loss on settlement of asset retirement obligation *(Note 5)*	**98**	--
Production	**2,027**	498
Stock-based compensation (Note 10)	**683**	1,018
	14,831	3,414
Net loss before taxes	**(2,160)**	(1,260)
Future income tax recovery ***(Note 9)***	**3,090**	2,259
Net income for the year	**930**	999
Retained earnings (deficit), beginning of year	**78**	(921)
Retained earnings, end of year	**1,008**	78
Earnings (loss) per share		
Basic and diluted	**0.03**	0.05

See accompanying notes to the financial statements.

STATEMENTS OF CASH FLOWS

For the Years Ended December 31,	2005	2004
(000s)	*($)*	*($)*
Cash flows from operating activities		
Net income for the year	**930**	999
Adjustments for:		
Accretion of asset retirement obligation *(Note 5)*	**67**	22
Asset retirement costs incurred	**(274)**	--
Depletion and amortization	**10,652**	872
Loss on settlement of asset retirement obligation *(Note 5)*	**98**	--
Stock-based compensation	**683**	1,018
Future income tax recovery	**(3,090)**	(2,259)
Funds flow from operations	**9,066**	652
Changes in non-cash operating working capital balances *(Note 14)*	**(637)**	462
	8,429	1,114
Cash flows from financing activities		
Share purchase loans *(Note 8)*	**95**	-
Issue of shares, net	**11,069**	8,782
Change in non-cash working capital	**214**	(214)
	11,378	8,568
Cash flows from investing activities		
Proceeds on disposal of property and equipment	**1,200**	25
Additions to property and equipment	**(23,455)**	(13,126)
Change in non-cash investing working capital *(Note 14)*	**1,039**	2,993
	(21,216)	(10,108)
(Decrease) in cash and cash equivalents	**(1,409)**	(426)
Cash and cash equivalents, beginning of year	**6,852**	7,278
Cash and cash equivalents, end of year	**5,443**	6,852

See accompanying notes to the financial statements.

1. Nature of Operations

Grand Banks Energy Corporation's ("Grand Banks" or "the Corporation") principal business is the exploration, development and production of oil and gas properties. The Corporation was originally incorporated on June 25, 1969 under the British Columbia Companies Act and changed its name from Pacific Amber Resources Ltd. to Grand Banks Energy Corporation in 2003. The Corporation has been continued under the Alberta Business Corporations Act. The Corporation's common voting shares are listed on the TSX Venture Exchange.

2. Summary of Significant Accounting Policies

The financial statements of the Corporation have been prepared by management in accordance with Canadian generally accepted accounting principles. The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates. The financial statements have, in management's opinion, been properly prepared using careful judgement with reasonable limits of materiality and within the framework of the significant accounting policies summarized below.

(a) Property and Equipment

The Corporation accounts for crude oil and natural gas properties in accordance with the Canadian Institute of Chartered Accountants' guideline on full cost accounting in the oil and gas industry. Under this method, all costs associated with the acquisition of, exploration for and the development of natural gas and crude oil reserves, including asset retirement costs, are capitalized.

Costs accumulated within each cost centre are depleted and amortized using the unit-of-production method based on estimated gross (before deduction of royalties) proved reserves. For purposes of this calculation, gas is converted to oil on an energy equivalent basis (six thousand cubic feet of natural gas to one barrel of oil). Capitalized costs subject to depletion are net of equipment salvage values and include estimated future costs to be incurred in developing proved reserves. Proceeds from the disposal of properties are normally deducted from the full cost pool without recognition of gain or loss unless that deduction would result in a change to the rate of depreciation, depletion and amortization of 20% or greater, in which case a gain or loss is recorded.

Costs of acquiring and evaluating unproved properties are initially excluded from depletion calculations. These unevaluated properties are assessed periodically to ascertain whether impairment has occurred. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion calculations.

The Company applies an impairment test ("ceiling test") to determine if capitalized costs are not recoverable and exceed their fair value. The carrying amount of the cost centre is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from proved reserves. If the sum of cash flows is less than the carrying amount, the impairment loss is limited to the amount by which the carrying amount exceeds the sum of the fair value of proved and probable reserves and the costs of unproved properties that have been subject to a separate impairment test and contain no probable reserves.

Expenditures that improve the productive capacity or extend the life of an asset are capitalized. Maintenance and repairs are charged against income.

Office equipment is recorded at cost. Amortization is provided on a declining balance basis over the estimated useful life of the equipment, which varies between 20% and 30%.

2. Summary of Significant Accounting Policies (continued)

(b) Joint Venture Operations

Most of the Corporation's petroleum and natural gas exploration activities are conducted jointly with others. These financial statements reflect only the Corporation's proportionate interest in such activities.

(c) Asset Retirement Obligations

The Corporation recognizes the fair value of a liability for an asset retirement obligation in the period in which it is incurred and records a corresponding increase in the carrying value of the related long-lived asset. The fair value is determined through a review of engineering studies, industry guidelines and management's estimates on a site-by-site basis. The liability is subsequently adjusted for the passage of time and is recognized as an accretion expense in the statement of operations. The liability is also adjusted due to revisions in either the timing or the amount of the original estimated cash flows associated with the liability. The increase in the carrying value of the asset is amortized using the unit-of-production method based on estimated gross proved reserves as determined by independent engineers. Actual expenditures incurred are charged against the accumulated obligation. Any difference between the actual costs incurred upon settlement of the asset retirement obligation and the recorded liability is recognized in the Corporation's earnings in the period in which settlement occurs.

(d) Flow-Through Shares

Expenditure deductions for income tax purposes related to exploratory and development activities funded by flow-through share arrangements are to be renounced to investors in accordance with income tax legislation. Share capital is reduced by the estimated cost of the renounced tax deductions for expenditures renounced.

Effective March 19, 2004, the Corporation adopted the recommendations of the abstract issued by the Emerging Issues Committee ("EIC") 146. For all flow-through offerings after this date, the Corporation will recognize the tax benefit realized for previously unrecognized tax assets as a result of the flow-through offering on its income statement. For previous offerings, the benefit was being recognized through share capital. On May 31, 2005, EIC 146 was further clarified to state that the date of recognition of the related tax liability was the date the Corporation files the renouncement documents with the tax authorities. The Corporation was previously recoding the liability in the period the expenditures were renounced to investors. The Corporation has implemented EIC 146 guidance for all flow-through financings completed after May 31, 2005.

(e) Future Income Taxes

The Corporation uses the liability method of tax allocation in accounting for income taxes. Under this method, future tax assets and liabilities are determined based on differences between the financial reporting and tax bases of assets and liabilities and measured using substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse.

(f) Financial Instruments

The Corporation carries a number of financial instruments as detailed on the balance sheet. It is management's opinion that the Corporation is not exposed to significant interest, currency or credit risks arising from these financial instruments. The fair values of these financial instruments approximate their carrying values, unless otherwise noted.

(g) Measurement Uncertainty

The amounts recorded for depletion and amortization of petroleum and natural gas properties and equipment, the provision for asset retirement obligation and stock-based compensation are based on estimates. The ceiling test is based on estimates of proved and probable reserves, production rates, oil and gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in estimates in future periods could be significant.

2. Summary of Significant Accounting Policies (continued)

(g) Measurement Uncertainty (continued)

The financial statements include accruals based on the terms of existing joint venture agreements. Due to varying interpretations of the definition of terms in these agreements, the accruals made by management in this regard may be significantly different from those determined by the Corporation's joint venture partners. The effect on the financial statements resulting from such adjustments, if any, will be reflected prospectively.

The Corporation is subject to various regulatory and statutory requirements relating to the protection of the environment. These requirements, in addition to contractual agreements and management decisions, result in the accrual of estimated asset retirement obligation costs. Any changes in these estimates will affect future earnings.

Costs attributable to commitments and contingencies are expected to be incurred over an extended period of time and are to be funded primarily from the Corporation's cash provided by operating activities. Although the ultimate impact of these matters on net earnings cannot be determined at this time, it could be material for any one quarter or year.

(h) Cash and Cash Equivalents

Cash and cash equivalents consists of cash on hand, bank balances (including temporary bank overdrafts), term deposits and short term investments with original maturities of three months or less.

(i) Stock-Based Benefit Plan

The Corporation records compensation expense in the financial statements for stock options granted to employees, directors and consultants using the fair value method. Fair values are determined using the Black-Scholes option pricing model. Compensation costs are recognized over the vesting period.

(j) Per Share Amounts

Basic earnings per common share are computed by dividing earnings by the weighted average number of common shares outstanding for the period. Diluted per share amounts reflect the potential dilution that could occur if securities or other contracts to issue common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options and other dilutive instruments.

(k) Revenue Recognition

Revenues associated with the sale of crude oil and natural gas are recorded when the title passes to the customer. Revenues from crude oil and natural gas production from properties in which the Corporation has an interest with other producers are recognized on the basis of the Corporation's net working interest. Alberta Royalty Tax Credits are netted against oil and gas royalties.

(l) Prepaid Expenses and Deposits

Prepaid expenses and deposits include payments for insurance premiums and lease rentals that relate to future periods, and deposits paid to various government agencies and other companies for future crown royalties, well and facility operating costs and office lease payments.

(m) Hedging

Effective January 1, 2004, the Corporation has implemented CICA Accounting Guideline ("AcG-13"), "Hedging Relationships," which is effective for fiscal years beginning on or after July 1, 2003. AcG-13 addresses the identification, designation, documentation and effectiveness of hedging transactions for the purposes of applying hedge accounting. It also established conditions for applying or discontinuing hedge accounting. Under the guideline, hedging transactions must be documented and it must be demonstrated that the derivative instruments are sufficiently effective in order to account for derivatives as hedges. As at December 31, 2005, there were no hedges in place.

2. **Summary of Significant Accounting Policies (continued)**

(n) Share Purchase Financing

The Corporation adopted the new Canadian Institute of Chartered Accountants Emerging Issue Committee No. 132 abstract on Share Purchase Financing. This abstract provides interpretive guidance to the accounting requirements for outstanding share purchase loans receivable. The new guidance requires that share purchase loans receivable should be presented as reductions from shareholders' equity unless there is substantial evidence that the borrower, not the Corporation, is at risk for any decline in the price of the shares, there is reasonable assurance that the Corporation will collect the full amount of the loan in cash and the loan is in accordance with current arm's length market terms and conditions. This standard also requires the loans to be treated in a manner similar to stock-based compensation if the loans are reclassified to equity.

(o) Reclassification

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2004.

3. **Property and Equipment**

	Cost	Accumulated Depletion and Amortization	Net Book Value
(000s)	*($)*	*($)*	*($)*
December 31, 2005			
Furniture and equipment	**97**	**44**	**53**
Petroleum and natural gas properties	**40,823**	**12,871**	**27,952**
	40,920	**12,915**	**28,005**
December 31, 2004			
Furniture and equipment	86	28	58
Petroleum and natural gas properties	17,916	2,234	15,682
	18,002	2,262	15,740

Future development costs relating to proved reserves of $2,885,000 (2004 – $611,000) have been included in the depletion calculation. The Corporation capitalized $178,000 (2004 – $304,000) of general and administrative costs during the year. The Corporation excluded $1,931,000 (2004 – $4,331,000) of undeveloped properties from the depletion calculation as follows:

December 31,	**2005**	2004
(000s)	*($)*	*($)*
Unproven costs		
Land	**1,430**	1,006
Geological and geophysical	**278**	651
Drilling and completion	**223**	2,674
	1,931	4,331

The Corporation performed a ceiling test calculation at December 31, 2005 to assess the recoverable value of its oil and gas properties. The oil and gas future prices are based on the commodity price forecast of the Corporation's independent reserve evaluators. These prices have been adjusted for heating content, quality and transportation parameters specific to the Corporation. The following table summarizes the benchmark prices used in the ceiling test calculation:

3. **Property and Equipment** (continued)

Year	WTI Oil	CDN/US Exchange Rate	AECO Gas
	($US/bbl)	*($)*	*($CDN/mmbtu)*
2006	60.00	0.85	9.85
2007	57.50	0.85	9.00
2008	55.00	0.85	8.00
2009	52.50	0.85	7.50
2010	50.00	0.85	7.00
2011	47.50	0.85	7.14

Escalate thereafter 2.0% per year.

The undiscounted value of future net revenues from the Corporation's proved reserves exceeded the carrying value of the oil and gas properties at December 31, 2005.

4. **Bank Indebtedness**

At December 31, 2005, the Corporation had a $5,400,000 (2004 – $750,000) revolving line of credit agreement with a Canadian financial institution. The line was increased to $10,000,000 subsequent to year end. The line of credit bears interest at prime plus 0.25% per annum, secured by the assets of the Corporation, and is due on demand. The effective rate under the increased line was 5.75% (2004 – 5.75%). At December 31, 2005, the Corporation had drawn $Nil (2004 – $Nil) on the line of credit.

5. **Asset Retirement Obligation**

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the obligation associated with the retirement of oil and gas properties:

December 31,	**2005**	2004
(000s)	*($)*	*($)*
Balance, beginning of year	**341**	201
Liabilities incurred in year	**662**	118
Asset retirement costs incurred	**(274)**	--
Loss on settlement of asset retirement obligation	**98**	--
Accretion expense	**67**	22
Balance, end of year	**894**	341

The undiscounted amount of cash flows, required over the estimated reserve life of the underlying assets, to settle the obligation, adjusted for inflation is estimated at $1,354,000 (2004 – $571,000). The obligation was calculated using a credit-adjusted risk free discount rate of 8% and an inflation rate of 2%. It is expected that this obligation will be funded from the Corporation's general resources at the time the costs are incurred with the majority of costs expected to occur between 2009 and 2015. No funds have been set aside to settle this obligation.

6. Equity Instruments

(a) Authorized

The authorized share capital consists of an unlimited number of common shares without nominal or par value.

(b). Issued and Outstanding

	Shares	Amount
(000s)	*(#)*	*($)*
Balance, December 31, 2003	15,637	11,493
Issued on exercise of warrants *(Note 6(g))*	101	105
Flow-through shares issued *(Note 6(i))*	4,500	6,525
Issued for cash *(Note 6(h))*	3,034	2,883
Tax effect of flow-through shares [(1)]	--	(2,259)
Share issue costs	--	(588)
Balance, December 31, 2004	23,272	18,159
Issued on exercise of warrants *(Note 6(g))*	**1,808**	**2,259**
Flow-through shares issued *(Note 6(i))*	**4,670**	**9,190**
Share issue costs	**--**	**(380)**
Balance at December 31, 2005	**29,750**	**29,228**

(1) Calculated at an effective rate of 33.62% on renounced expenditures.

(c) Per Share Amounts

The following table summarizes the calculation of basic net income and diluted net income per share for the years ended December 31, 2005 and 2004:

December 31,	2005	2004
(000s, except per share amounts)	*($)*	*($)*
Net income available to common shareholders	**930**	999
Weighted average number of common shares outstanding – basic	**26,821**	18,801
Dilutive effect of stock options	**449**	206
Dilutive effect of warrants	**1,219**	68
Weighted average number of common shares outstanding – diluted	**28,489**	19,075
Net income per share		
Basic	**0.03**	0.05
Diluted	**0.03**	0.05

(d) Flow-Through Share Information

December 31,	2005	2004
(000s)	*($)*	*($)*
Carried forward from prior year	**5,000**	5,695
Amount of flow-through shares issued	**9,190**	6,525
Expenditures incurred	**(7,450)**	(7,220)
Remaining obligation, end of year	**6,740**	5,000

6. Equity Instruments (continued)

(e) Stock Options

The Option Plan allows directors, employees and consultants to be granted incentive based compensation under the Option Plan while allowing a rolling maximum of 10% of the number of issued and outstanding shares from time-to-time to be granted under the Option Plan. Options may be granted under the Option Plan with no vesting provisions at an exercise price as set by the Board of Directors of the Corporation from time-to-time, subject to the limitations of any stock exchange on which the common shares are listed.

As at December 31, 2005, the Corporation had the following stock options outstanding:

	Share Options	Option Price Per Share Range	Weighted Average Exercise Price
	(#000s)	*($)*	*($)*
Outstanding, December 31, 2003	425	1.00 – 1.15	1.05
Granted	1,625	1.05	1.05
Granted	150	1.15	1.15
Cancelled	(470)	1.00 – 1.15	--
Outstanding, December 31, 2004	1,730	1.00 – 1.15	1.05
Granted	**580**	**1.25**	**1.25**
Outstanding, December 31, 2005	**2,310**	**1.00 – 1.25**	**1.10**

The following table summarizes information about the stock options outstanding at December 31, 2005 and 2004:

	Options Outstanding			Options Currently Exercisable		
Option Price	Share Options	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Shares Options	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price
($)	*(#000s)*	*(Years)*	*($)*	*(#000s)*	*(Years)*	*($)*
2005						
1.00	**195**	**3.2**	**1.00**	**155**	**2.6**	**1.00**
1.05	**1,385**	**4.4**	**1.05**	**923**	**3.9**	**1.05**
1.15	**150**	**4.8**	**1.15**	**100**	**4.3**	**1.15**
1.25	**580**	**5.6**	**1.25**	**194**	**4.6**	**1.25**
	2,310	**4.6**	**1.10**	**1,372**	**3.9**	**1.08**
2004						
1.00	195	3.6	1.00	115	3.0	1.00
1.05	1,385	5.4	1.05	462	4.4	1.05
1.15	150	5.8	1.15	50	4.8	1.15
	1,730	5.2	1.05	627	4.2	1.04

6. Equity Instruments (continued)

(f) Warrants

As at December 31, 2005, the Corporation had the following share purchase warrants outstanding:

Issued	Expiry	Warrant Options	Average Price
		(#000s)	*($)*
Outstanding at December 31, 2003		928	1.23
Issued	Aug. & Sep. 2005	1,517	1.25
Exercised		(84)	1.25
Exercised		(17)	1.00
Outstanding at December 31, 2004	Aug. & Sep. 2005	2,344	1.25
Exercised		**(1,808)**	**1.25**
Expired	**Aug. & Sep. 2005**	**(536)**	**1.25**
Outstanding at December 31, 2005		--	--

The fair value of each warrant was determined at the grant date using the Black-Scholes model assuming a risk-free interest rate of 4.5% and an expected volatility rate of 103%.

For the warrants issued during the year, a value of $Nil (2004 – $683,000) has been assigned.

(g) Issued on Exercise of Warrants

During 2005, the Corporation issued 1,808,000 (2004 – 101,000) common shares at $1.00 to $1.25 per share for cash on the exercise of warrants.

(h) Common Shares Issued for Cash

During 2004, the Corporation closed two private placements for 3,034,267 shares at $0.95 per share. The 2004 issue of common shares included one-half of a share purchase warrant for a term of 18 months with a full purchase warrant exercisable at $1.25 per common share.

(i) Flow-Through Shares Issued

In February 2005, the Corporation issued 3,000,000 flow-through shares at $1.95 per share for gross proceeds of $5,850,000. In December 2005, the Corporation issued 1,670,000 flow-through shares at $2.00 per share for gross proceeds of $3,340,000.

During November 2004, the Corporation issued 4,500,000 flow-through shares at $1.45 per share for gross proceeds of $6,525,000.

7. Contributed Surplus

December 31,	**2005**	2004
(000s)	*($)*	*($)*
Balance, beginning of year	**1,107**	89
Stock compensation costs	**683**	1,018
Balance, end of year	**1,790**	1,107

8. Share Purchase Loans

The Corporation granted loans of $356,000 during 2004 for the purchase of shares to certain employees and a consultant. At December 31, 2005, the total outstanding amount for the loans was $48,000 (2004 – $356,000). At December 31, 2005, the loans had a seven-year term and bear interest at 5.75% per year, require interest only payment for the first year, are due March 31, 2010 and are limited recourse to the shares of the Corporation. In 2004, $214,000 of loans was recorded as an asset. At December 31, 2005, $48,000 (2004 – $143,000) did not meet the conditions for the recognition of an asset and were recorded as a reduction of shareholders' equity. In 2004 these were accounted for in accordance with the Company's stated policy and assumptions for stock-based compensation with an assigned value of $117,000.

9. Income Taxes

(a) The effective tax rate of income tax varies from the statutory rate as follows:

	2005	2004
(000s)	*($)*	*($)*
Combined federal and provincial tax rates	**34.2%**	38.6%
Expected income tax recovery at statutory rate	**(739)**	(486)
Alberta Royalty Tax Credit	**(59)**	(10)
Crown charges	**757**	132
Rate Change	**229**	24
Resource allowance	**(751)**	(73)
Stock-based compensation	**234**	393
Other	**36**	86
Change valuation allowance	**(2,797)**	(2,325)
Actual income tax recovery	**(3,090)**	(2,259)

(b) At December 31, 2005, subject to confirmation by income tax authorities, the Corporation had the following tax pools available to reduce future taxable income:

December 31,	**2005**	2004
(000s)	*($)*	*($)*
Cumulative Canadian development expenses	**8,182**	1,260
Cumulative Canadian exploration expenses	**9,918**	8,219
Cumulative Canadian oil and gas property expenses	**1,532**	1,632
Foreign exploration and development expenses	**8,948**	9,939
Earned depletion	**388**	391
Undepreciated capital cost	**4,773**	1,892
Non-capital losses carried forward for tax purposes expiring between 2006 and 2014	**8,745**	12,749
Undeducted share issue costs carried forward	**958**	966
	43,444	37,048

The tax benefit of these tax pools in excess of carrying value has only been recognized to the extend of the future tax liability triggered by the issue of flow through shares in 2005. A valuation allowance has been recorded for the remainder as the excess does not meet the test of more likely than not realization.

(c) At December 31, 2005, the Corporation had approximately $1,497,000 (2004 – $1,497,000) of capital losses available that have no expiry date and can be used to reduce future capital gains. The tax benefit of these losses has also not been recognized as a future asset as the ultimate realization of the asset value is uncertain.

9. Income Taxes (continued)

(d) Future income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts for income tax purposes. The components of the Corporation's future income tax assets and liabilities are as follows:

December 31,	2005	2004
(000s)	*($)*	*($)*
Nature of temporary differences		
Property and equipment	**4,928**	2,889
Asset retirement obligation	**(301)**	(118)
Unused non-capital tax losses carried forward	**2,955**	4,485
Share issue costs	**305**	334
Unused capital losses carried forward	**126**	130
	8,013	7,720
Valuation allowance	**(4,923)**	(7,720)
Future income tax asset (liability)	**3,090**	--

10. Stock Compensation

The Corporation records stock-based compensation expense for all common share options granted to employees and directors after January 1, 2003. Common share options granted prior to January 1, 2003 did not result in a compensation expense.

The Black-Scholes option valuation method was developed for use in estimating the fair value of traded options that were fully tradable with no vesting restrictions. This option valuation model requires the input of highly subjective assumptions including the expected stock price volatility. Because the Corporation's stock options and performance incentive warrants have characteristics significantly different from those of traded options and because changes in the subjective input assumptions can materially affect the calculated fair value, such value is subject to measurement uncertainty.

The total fair value of share options granted during the year was estimated at $502,000 (2004 - $1,482,000) using the Black-Scholes option pricing model with the following assumptions:

December 31,	2005	2004
Dividend yield	**Nil**	Nil
Expected volatility *(%)*	**76**	93 – 105
Risk free rate of return *(%)*	**4.5**	4.5
Weighted average life *(years)*	**5**	5

11. Financial Instruments

As disclosed in Note 2(f), the Corporation holds various forms of financial instruments. The nature of these instruments and the Corporation's operations expose the Corporation to fair value, interest rate and industry credit risks. The Corporation manages its exposure to these risks by operating in a manner that minimizes its exposure to the extent practical.

(a) Commodity Price Risk

The Corporation will be subject to commodity price risk for the delivery of natural gas and crude oil.

11. Financial Instruments (continued)

(b) Credit Risks

A significant portion of the Corporation's cash is currently held with the same financial institution and, as such, the Corporation is exposed to concentration of credit risk. Substantially all the Corporation's accounts receivable are with customers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks.

12. Related Party Transactions

All related party transactions are in the normal course of operations and have been measured at the agreed to exchange amounts, which is the amount of consideration established and agreed to by the related parties and which is similar to those negotiated with third parties. Except as disclosed elsewhere in the financial statements, the Corporation had the following related party transactions:

(a) The Corporation incurred consulting fees of $193,000 (2004 – $42,000) to companies controlled by a director and/or officers of the Corporation for the period ended December 31, 2005. These officers and/or director did not receive a salary during the period covered by the consulting fees.

(b) The Corporation conducts oil and gas exploration and development activities and related transactions with organizations managed or controlled by directors. These transactions are negotiated and conducted using standard industry agreements and terms.

(c) In February 2004, four directors and officers subscribed for 1,000,000 units at $0.95 per unit in a private placement.

(d) Included in general and administrative expenses is $48,000 (2004- $34,000) paid for directors' fees to independent directors.

(e) In January 2004, a resignation settlement of $132,000 was paid to the former President and Chief Executive Officer.

(f) Included in other income is $8,000 (2004 – $17,000) of interest charged on the share purchase loans (Note 9).

13. Commitments

(a) The Corporation has a commitment for office leases that expire between November 2006 and December 2007 as follows:

2006 – $150,000
2007 – $ 86,000

(b) The Corporation has entered into employment agreements with its executive officers. In addition to defining the terms of employment, the agreements entitle these executives to compensation on a change of management or control, or for termination without cause. The Corporation has agreed to indemnify certain individuals, who have acted at the Corporation's request to be officers or directors of the Corporation.

(c) At December 31, 2005, the Corporation had farm-in obligations for five wells in 2006 and two wells in 2007. The most significant of these obligations is for the well at Harley, which is currently being drilled. Grand Banks is the operator and has 16.67% in this well.

14. Statement of Cash Flows

(a) Changes in non-cash working capital balances are comprised of the following:

December 31,	2005	2004
(000s)	*($)*	*($)*
Accounts receivable	**(2,804)**	(641)
Cash calls receivable	**(1,116)**	(766)
Prepaid expenses and advances	**(37)**	(54)
Share purchase loans	**214**	(214)
Accounts payable and accrued liabilities	**4,359**	4,916
	616	3,241
Less amounts related to investing activities	**1,039**	2,993
Less amounts related to financing activities	**214**	(214)
	(637)	462

(b) In 2005, the cash interest paid was $188,000 (2004 – $3,000).

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") should be read in conjunction with the audited financial statements of Grand Banks and accompanying notes for the year ended December 31, 2005. In this MD&A, production and reserves information are commonly reported in units of barrels of oil equivalent ("boe"). For purposes of computing such units, natural gas is converted to equivalent barrels of oil using a conversion factor of six thousand cubic feet to one barrel of oil. This conversion ratio of 6:1 is based on an energy equivalent wellhead value for the individual products. Such disclosures of boes may be misleading, particularly if used in isolation. Readers should be aware that historical results are not necessarily indicative of future performance.

This MD&A and the annual financial statements and accompanying notes have been prepared by management and approved by the Audit Committee of the Board of Directors of Grand Banks and include information to April 6, 2006.

The quarterly financial statements have not been reviewed or audited on behalf of the shareholders by the Corporation's independent external auditors.

All financial measures presented in this Annual Report are expressed in Canadian dollars unless otherwise indicated.

Highlights

Grand Banks Energy Corporation ("Grand Banks" or the "Corporation") recorded average sales of natural gas, crude oil and liquids during the year ended December 31, 2005 of 898 boe/d versus 152 boe/d produced a year ago. This 491% increase came by way of the drill bit. Most of the funds used to finance this drilling were raised through flow-through equity financings, which require that the funds raised be earmarked for exploratory projects. While Grand Banks has drilled a number of successful high deliverability exploratory wells, its growth in reserves has not matched production growth because of limited pool size and competitive drainage. Therefore, the challenge for the Corporation has been to acquire land and prospects with the potential for the development of significant reserves and production to allay declines from existing wells and to build a foundation for continued growth. To accomplish this, Grand Banks has acquired over 20,000 net acres of land in the Williston Basin, a light oil prone area located in southeastern Saskatchewan and Manitoba.

During 2005, Grand Banks participated in 36 wells (21.3 net). The Corporation operated 18 of these wells (16.0 net) of which 18 (13.3 net) were cased as oil wells, 5 (1.5 net) cased as gas wells and 13 (6.5 net) were dry holes for an average 64% (69% net) success rate. By December 31, 2005, 14 oil wells (10 net) and 1 gas well (0.5 net) had been successfully brought on production along with all wells drilled during 2004. During the first quarter of 2006, all 3 of the 2005 oil wells (3 net) were brought on production with 2 (0.4 net) of the remaining successful gas wells expected to come on-stream during the second quarter of 2006.

The Corporation will continue with its strategy for growth through the drill bit. The progress that has been made over the past year, which emphasizes more lower risk development drilling, is expected to steadily increase corporate reserves. As reserves are added in a cost effective manner, depletion will decline and profitability will increase. Grand Banks will continue to devote a portion of its budget to high impact exploratory projects, financed primarily with the proceeds of flow-through financings. This strategy is particularly well suited to Grand Banks because the tax pools renounced to investors in flow-through shares are offset by corporate tax pools in excess of $40,000,000.

Financial and Operational Results

The following table summarizes the results for the years ended December 31, 2005, 2004 and 2003:

	2005	2004	Change		2003
				(%)	
Sales Volumes					
Natural gas *(mcf/d)*	**3,834**	457	3,377	739	263
Crude oil and liquids *(bbls/d)*	**258**	68	190	279	41
Royalty income *(boe/d)*	**2**	8	(6)	(75)	--
Average boe/d *(6:1)*	**898**	152	746	491	85
Product Prices					
Natural gas *($/mcf)*	**8.50**	6.70	1.80	27	6.76
Crude oil and liquids *($/bbl)*	**56.63**	47.17	9.46	20	35.40
(000s)	*($)*	*($)*	*($)*	*(%)*	*($)*
Financial Results					
Gross revenues	**17,377**	2,590	14,787	571	1,241
Loss before income taxes	**(2,160)**	(1,260)	(900)	(71)	(926)
Net income (loss)	**930**	999	(69)	(7)	(926)
Per share – basic	**0.03**	0.05	(0.02)	(40)	(0.10)
Per share – diluted	**0.03**	0.05	(0.02)	(40)	(0.10)
Funds generated from operations	**9,066**	652	8,414	1,290	(342)
Per share – basic	**0.34**	0.03	0.31	1,033	(0.04)
Per share – diluted	**0.32**	0.03	0.29	967	(0.04)
Additions to property and equipment, net of proceeds	**22,255**	13,101	9,154	70	1,174
Total assets	**42,336**	24,647	17,689	72	11,051
Working capital	**1,777**	3,802	(2,025)	(53)	7,470
Asset retirement obligation	**894**	341	553	162	201
Flow-through share obligations	**6,740**	5,000	1,740	35	5,695
	($/boe)	*($/boe)*	*($/boe)*	*(%)*	*($/boe)*
Netback Analysis					
Oil and gas revenue *(6:1)*	**52.61**	43.31	9.30	21	38.74
Royalty expense	**14.35**	7.83	6.52	83	5.87
Operating costs	**6.18**	8.94	(2.76)	(31)	9.44
Netback	**32.08**	26.54	5.54	21	23.43

Annual Results

Sales Volumes

Total sales volumes increased to 898 boe/d in 2005 from 152 boe/d in 2004. The 746 boe/d improvement was due to a 3,377 mcf/d increase in natural gas volumes and a 190 bbls/d increase in crude oil and liquids volumes. Growth in natural gas volumes was primarily due to new wells in the Virginia Hills (421 boe/d), Blueberry (88 boe/d), Kakwa (66 boe/d) and Berland River (28 boe/d) areas of Alberta. The increases in crude oil and liquid volumes were primarily as a result of new wells at Kingsford (95 boe/d) in Saskatchewan and Sinclair (22 boe/d) in Manitoba. All of the Corporation's sales volumes consisted of natural gas and light to medium gravity crude oil, with no heavy oil.

Gross Revenues

Total gross revenues increased to $17,377,000 from $2,590,000. This $14,787,000 or 571% year-over-year improvement was due to increased production volumes combined with higher prices for the Corporation's products. Natural gas revenues totaled $11,895,000, up $10,775,000 or 962% from $1,120,000 in 2004, due to a 739% increase in natural gas volumes and a 27% improvement in product prices. Crude oil and liquids revenues were $5,327,000 in 2005 compared with $1,177,000 a year ago. The $4,150,000 or 353% increase was due to a 279% rise in crude oil and liquids volumes combined with a 20% increase in prices. For the year ended December 31, 2005, interest income totaled $126,000 versus $177,000 in 2004 due to lower average cash balances earning interest. The Corporation has not hedged any of its production.

Land Holdings

	2005			2004		
	Gross	Net	Average Interest	Gross	Net	Average Interest
	(acres)	*(acres)*	*(%)*	*(acres)*	*(acres)*	*(%)*
Developed lands	**25,761**	**7,792**	**30**	20,150	4,158	21
Undeveloped lands	**63,246**	**27,266**	**43**	41,713	15,188	36
Total lands	**89,007**	**35,058**	**39**	61,863	19,346	31

Drilling Activity

	Exploration		Development		Total	
	Gross	Net	Gross	Net	Gross	Net
	(#)	*(#)*	*(#)*	*(#)*	*(#)*	*(#)*
2005						
Natural gas	**2.0**	**0.7**	**3.0**	**0.8**	**5.0**	**1.5**
Crude oil and liquids	**2.0**	**1.2**	**16.0**	**12.1**	**18.0**	**13.3**
Dry and abandoned	**12.0**	**5.7**	**1.0**	**0.8**	**13.0**	**6.5**
Total wells	**16.0**	**7.6**	**20.0**	**13.7**	**36.0**	**21.3**
Success rate *(%)*	**25**	**25**	**95**	**94**	**64**	**69**
2004						
Natural gas	7.0	2.3	3.0	0.9	10.0	3.2
Crude oil and liquids	2.0	1.5	1.0	0.3	3.0	1.8
Dry and abandoned	5.0	3.0	0.0	0.0	5.0	3.0
Total wells	14.0	6.8	4.0	1.2	18.0	8.0
Success rate *(%)*	64	56	100	100	72	63

Royalty Expense

Royalty costs, net of Alberta Royalty Tax Credit ("ARTC") were $4,706,000 or 27% of production revenues compared with $436,000 or 19% in 2004. The amount of royalties increased due to higher sales volumes and prices, while the increase in royalty rate, net of ARTC, was due to a new well with Crown and gross overriding royalties combined with reaching the maximum ARTC rebate.

Production Expenses

Production expenses totaled $2,027,000 or $6.18/boe for 2005 compared with $498,000 or $8.94/boe a year ago. The $1,529,000 increase was a result of higher production volumes. The reduction in unit operating costs resulted from higher productivity of new wells added during the year.

Accretion of Asset Retirement Obligation

The accretion of asset retirement obligations totaled $67,000 in 2005 compared with $22,000 in 2004. This $45,000 or 205% increase was due to an increase in the total number of estimated wells to be abandoned and reclaimed in the future.

Depletion and Depreciation

For the year ended December 31, 2005, depletion and depreciation totaled $10,652,000 or $32.49/boe compared with $872,000 or $15.65/boe in 2004. The $9,780,000 increase in depletion costs was due to a 491% jump in production volumes and a 105% increase in the depletion rate that was a result of higher finding and development costs for proved reserves. Probable reserves and unevaluated property costs are not included in the depletion calculation.

Loss on Settlement of Asset Retirement Obligation

The Corporation recorded a loss on reclamation costs of $98,000 as actual reclamation costs exceeded the provision for reclamation of two wells in Alberta.

Interest

Interest expense decreased to $50,000 in 2005 from $173,000 in 2004, a reduction of $123,000 or 71%. The decrease in interest costs was due to a reduction of $138,000 in charges relating to flow-through share funds not spent before February 28, 2005, which was partially offset by an increase of $15,000 in line of credit fees. The interest on flow-through shares relates to amounts renounced and not spent until the following year under the "look back" rule. The Corporation spent its flow-through obligations in 2005 more quickly than in 2004.

General and Administrative Costs

General and administrative expenses for 2005 and 2004 are summarized as follows:

December 31,	**2005**	2004	Change	
(000s)	*($)*	*($)*	*($)*	*(%)*
Consulting fees	**440**	341	99	29
Directors' fees	**48**	34	14	41
Filing and transfer fees	**55**	45	10	22
Legal and audit	**70**	37	33	89
Other	**263**	75	188	251
Rent and office	**171**	130	41	32
Salaries and benefits	**632**	542	90	17
Overhead recovered	**(247)**	(69)	(178)	(258)
Overhead capitalized	**(178)**	(304)	126	41
	1,254	831	423	51
Costs per boe	**3.82**	14.92	(11.10)	(74)

Year-over-year general and administrative costs increased $423,000 or 51% due primarily to expanded operations resulting in higher consulting fees, other costs and reduced overhead capitalized partially offset by increased recoveries from operations. Other costs include a provision for bad debts of $107,000 and increased technical information costs of $43,000. Overhead recoveries increased due to more operated capital projects. The decrease in capitalized overhead was primarily as a result of higher overhead recovered. The decline in the cost per boe was attributable to higher production volumes partially offset by increased general and administrative costs.

Stock-Based Compensation

Stock-based compensation costs were $683,000 in 2005 compared with $1,018,000 in 2004, a decrease of $335,000 or 33%. During 2005, the Corporation issued 580,000 stock options compared with 1,775,000 issued in 2004. The average option cost was $0.87 in 2005 versus $0.84 in 2004. Stock-based compensation costs are amortized over the vesting period, which is up to two years from the date of grant.

Income Tax

The Corporation recorded a future income tax recovery of $3,090,000 in 2005 compared with $2,259,000 a year ago. Grand Banks records a future income tax recovery and a future tax asset for flow-through shares issued in each of the periods when it is determined the future tax asset relating to flow-through shares issued is likely to be realized by meeting the spending requirements of the flow-through shares. The Corporation then records the renouncement of flow-through share costs, as a reduction of the future tax asset and share capital, when the renouncement forms are filed, which is usually in the first quarter of the year following issue. At December 31, 2005, the Corporation had approximately $43,000,000 (2004 – $37,000,000) in tax pools available for future deduction. At December 31, 2005 and 2004, no future tax asset was recognized for these pools as they did not meet the test of more likely than not realization.

Net Income

Grand Banks recorded net income of $930,000 or $0.03 per share for 2005 compared with $999,000 or $0.05 per share in 2004.

Liquidity and Capital Resources

At December 31, 2005, the Corporation had working capital of $1,777,000 versus $3,802,000 at December 31, 2004. During 2005, the Corporation had funds generated from operations of $9,066,000 (see "Non-GAAP Measures"). Grand Banks currently has a $10,000,000 line of credit available at the bank's prime rate plus 0.25%, which was not drawn at December 31, 2005. The Corporation has not declared any dividends. Grand Banks expects it has sufficient capital resources to meet its planned activities during the first half of 2006. The Corporation had a $6,740,000 flow-through spending obligation at December 31, 2005, which it believes will be met by the December 31, 2006 deadline.

Financing Activities

The Corporation closed a private placement in March 2005 raising $5,850,000 through the issuance of 3,000,000 flow-through common shares. During 2005, there were 1,808,000 share purchase warrants exercised for proceeds of $2,259,000. No warrants were outstanding at December 31, 2005. In December 2005, Grand Banks closed a private placement totaling $3,340,000 for 1,670,000 flow-through common shares. At December 31, 2005, there was $47,500 in share purchase loans outstanding. Subsequent to year-end, the Corporation applied for and was granted an increase in its line of credit from $5,400,000 to $10,000,000.

Investing Activities

Additions to property and equipment net of dispositions totaled $22,255,000 in 2005 compared with $13,101,000 in 2004, an increase of $9,154,000 or 70%. The details of the spending changes are summarized in the following table:

December 31,	**2005**	2004	Change	
(000s)	*($)*	*($)*	*($)*	*(%)*
Land	**1,300**	1,129	171	15
Geological and geophysical	**804**	1,317	(513)	(39)
Drilling and completion	**18,320**	9,105	9,215	101
Equipment and gathering	**2,842**	1,226	1,616	132
G&A capitalized	**178**	304	(126)	(41)
Office equipment	**11**	45	(34)	(76)
	23,455	13,126	10,329	79
Proceeds of disposition	**(1,200)**	(25)	(1,175)	--
Additions to property and equipment, net of proceeds	**22,255**	13,101	9,154	70

The increase in capital spending was primarily due to an increase in the number of wells drilled during 2005.

Financial Instruments

Grand Banks has not entered into any commodity or financial instrument hedges, however, it does carry various forms of financial instruments, all of which are recognized in the Corporation's financial statements. Unless otherwise indicated in the financial statements, it is management's opinion that the Corporation is not exposed to excessive interest, currency or credit risks arising from these financial instruments. The fair values of these financial instruments approximate their carrying values, unless otherwise indicated. The Corporation has no unrecognized gains or losses on its financial instruments.

Obligations

	Payments Due By Period				
	Total	Less Than 1 Year	1 – 3 Years	4 – 5 Years	After 5 Years
(000s)	*($)*	*($)*	*($)*	*($)*	*($)*
Office lease	236	150	86	--	--
Flow-through shares	6,740	6,740	--	--	--
Operating leases	60	60	--	--	--
Lease rentals land	485	101	182	141	61
Asset retirement	1,354	264	108	90	892
Total contractual obligations	8,875	7,315	376	231	953

At December 31, 2005, the Corporation had farm-in obligations for five wells in 2006 and two wells in 2007 that are not included in the preceding table. The most significant of these obligations is for the well at Harley, which is currently being drilled. Grand Banks is the operator and has a 16.67% working interest in this well. These farm-in obligations are expected to meet some of the flow-through share obligations outlined in the preceding table.

The Corporation had no outstanding bank debt at December 31, 2005.

Transactions with Related Parties

All related party transactions are in the normal course of operations and have been measured at the agreed to exchange amounts, which is the amount of consideration established and agreed to by the related parties and which is similar to those negotiated with third parties.

(a) Consulting fees of $193,000 (2004 – $42,000) to companies controlled by a director and/or officers of the Corporation for the period ended December 31, 2005. This director and/or officers did not receive a salary during the period covered by the consulting fees.

(b) The Corporation conducts oil and gas exploration and development activities and related transactions with organizations managed or controlled by directors. These transactions are negotiated and conducted using standard industry agreements and terms.

(c) In February 2004, four directors and officers subscribed for 1,000,000 units at $0.95 per unit in a private placement.

(d) Included in general and administrative expenses is $48,000 (2004 – $34,000) relating to directors' fees paid to independent directors.

(e) In January 2004, a resignation settlement of $132,000 was paid to the Corporation's former President and Chief Executive Officer.

(f) Included in other income is $8,000 (2004 – $17,000) of interest charged on the share purchase loans, as reflected in Note 8 to the financial statements.

Fourth Quarter Results

Sales Volumes

Daily sales volumes averaged 970 boe/d in the fourth quarter of 2005 compared with 238 boe/d in the same period of 2004, an increase of 732 boe/d or 308%. Natural gas volumes were 2,690 mcf/d in the 2005 three-month period versus 904 mcf/d in 2004. This 1,786 mcf/d (295 boe/d) increase was primarily due to new wells at Virginia Hills (286 boe/d) and Kakwa (89 boe/d). Crude oil and liquid volumes rose 441 bbls/d or 544% to 522 bbls/d compared with 81 bbls/d in the fourth quarter of 2004 primarily as a result of new wells at Kingsford (328 bbls/d), Sinclair (46 boe/d) and Bittern Lake (22 boe/d). All of the Corporation's sales volumes consisted of natural gas and light to medium gravity crude oil, with no heavy oil.

Gross Revenues

Gross revenues were $5,653,000 in the 2005 fourth quarter compared with $993,000 in 2004, up $4,660,000 or 469% due to a 308% increase in sales volumes and a 45% improvement in average product prices. Natural gas and crude oil and liquids prices all increased due to favourable spot market conditions. Natural gas prices averaged $11.60/mcf in the fourth quarter of 2005 compared with $6.75/mcf in the corresponding period of 2004. Crude oil and liquids prices averaged $57.34/bbl in the 2005 three-month period compared with $48.71/bbl in 2004. The Corporation has not hedged any of its production.

Royalty Expense

Fourth quarter royalty costs, net of ARTC, were $1,547,000 or 28% of production revenues compared with $220,000 or 24% in 2004. Total royalties, net of ARTC, rose $1,327,000 or 603% due to increased revenues and higher royalty rates. The increase in royalty rates was due to a new well with Crown and gross overriding royalties combined with reaching the ARTC maximum rebate.

Production Expenses

Production expenses totaled $628,000 or $7.04/boe in the fourth quarter of 2005 compared with $219,000 or $9.98/boe for the same period in 2004. The $409,000 or 187% rise in expenses resulted from increased production volumes partially offset by lower unit operating costs. The reduction in unit operating costs related to the higher productivity of the new wells.

Accretion of Asset Retirement Obligation

The accretion of asset retirement obligations increased $11,000 or 157% to $18,000 for the 2005 fourth quarter from $7,000 for the same period in 2004 due to an increase in the total number of wells to be abandoned and reclaimed.

Depletion and Depreciation

Depletion and depreciation was $2,629,000 in the 2005 three-month period or $29.46/boe compared with $371,000 or $16.91/boe a year ago. The $2,258,000 or 609% increase in depletion costs was due to 308% higher volumes combined with a 74% increase in the depletion rate per boe, which resulted from higher finding and development costs for proved reserves. Probable reserves and unevaluated property costs are not included in the depletion calculation.

Loss on Settlement of Asset Retirement Obligation

The Corporation recorded a loss on asset retirement costs of $22,000 as actual reclamation costs exceeded the provision for reclamation at two wells in Alberta.

Interest

Interest expense decreased $27,000 in the fourth quarter of 2005 to a recovery of $6,000 compared with $21,000 in the same period of 2004. The Corporation had no remaining interest bearing flow-through spending obligations in the fourth quarter of 2005. New flow-through obligations incurred through the issue of flow-through shares in 2005 are not subject to interest charges until 2006.

General and Administrative Costs

General and administrative expenses for the fourth quarters of 2005 and 2004 are summarized as follows:

December 31,	**2005**	2004	Change	
(000s)	*($)*	*($)*	*($)*	*(%)*
Consulting fees	**130**	101	29	29
Directors' fees	**12**	12	--	--
Filing and transfer fees	**12**	6	6	100
Legal and audit	**19**	11	8	73
Other	**148**	22	126	573
Rent and office	**42**	34	8	24
Salaries and benefits	**226**	160	66	41
Overhead recovered	**(128)**	(61)	(67)	(110)
Overhead capitalized	**3**	(36)	39	108
	464	249	215	86
Costs per boe	**5.20**	11.35	(6.15)	(54)

The year-over-year decline in general and administrative costs per boe was due to higher production volumes. General and administrative costs increased in the fourth quarter of 2005 due primarily to expanded operations, which increased consulting fees, salaries and benefits and other costs. Overhead recoveries increased as a result of more operated capital projects, while overhead capitalized decreased due to higher overhead recoveries from operations.

Stock-Based Compensation

Stock-based compensation costs totaled $167,000 in the fourth quarter of 2005 compared with $866,000 in 2004. The Corporation issued 580,000 stock options in the 2005 three-month period versus 1,775,000 in 2005. Stock-based compensation costs are amortized over the vesting period, which is up to two years from the date of grant.

Income Tax

The Corporation recorded a future income tax recovery of $1,123,000 in the fourth quarter of 2005 compared with $2,259,000 a year ago. The Corporation records a tax recovery and a future tax asset for flow-through shares issued in each of the periods when it is determined the future tax asset relating to flow-through shares issued is likely to be realized by meeting the spending requirements of the flow-through shares. The Corporation then records the renouncement of flow-through share costs, as a reduction of the future tax asset and share capital, when the renouncement forms are filed, which is usually in the first quarter of the year following issue. At December 31, 2005, the Corporation had approximately $43,000,000 (2004 – $37,000,000) in tax pools available for future deduction. No future tax asset was recognized for these pools at December 31, 2005 and 2004 as they did not meet the test of more likely than not realization.

Net Income

Grand Banks recorded a net income of $1,307,000 or $0.04 per share for the fourth quarter of 2005 compared with $1,299,000 or $0.06 per share the prior year.

Summary of Quarterly Results

Eight-Quarter Comparison

The quarterly results are prepared without audit or review by the Corporation's independent auditors. The following table summarizes the Corporation's financial and operating highlights for the past eight quarters. Sales volumes are the average for the period shown, net to the Corporation, before the deduction of royalties.

Three Months Ended	Mar.31, 2004	Jun.30, 2004	Sep.30, 2004	Dec.31, 2004	**Mar.31, 2005**	**Jun.30, 2005**	**Sep.30, 2005**	**Dec.31, 2005**
Sales Volumes								
Natural gas *(mcf/d)*	270	286	362	904	**2,224**	**5,653**	**4,755**	**2,690**
Crude oil and liquids *(bbls/d)*	60	62	70	81	**98**	**180**	**227**	**522**
Royalty income *(boe/d)*	10	6	8	7	**4**	**1**	**1**	**--**
Average boe/d *(6:1)*	115	116	139	238	**473**	**1,123**	**1,021**	**970**
Product Prices								
Natural gas *($/mcf)*	6.70	7.21	6.20	6.75	**7.02**	**7.37**	**8.74**	**11.60**
Crude oil and liquids *($/bbl)*	42.22	45.04	51.47	48.71	**52.79**	**51.82**	**60.38**	**57.34**
Oil equivalent *($/boe)*	39.86	44.25	44.35	43.29	**41.97**	**45.48**	**54.23**	**63.01**
(000s, except per share amounts)	*($)*	*($)*	*($)*	*($)*	*($)*	*($)*	*($)*	*($)*
Financial Results								
Gross revenues	477	513	606	993	**1,921**	**4,685**	**5,117**	**5,653**
Net income (loss)	(180)	(70)	(50)	1,299	**(282)**	**1,018**	**(1,113)**	**1,307**
Per share – basic	(0.01)	(0.00)	(0.00)	0.06	**(0.01)**	**0.04**	**(0.04)**	**0.04**
Per share – diluted	(0.01)	(0.00)	(0.00)	0.06	**(0.01)**	**0.04**	**(0.04)**	**0.04**
Funds generated from operations	27	135	206	284	**856**	**2,681**	**2,532**	**2,997**
Additions to property and equipment, net of proceeds	816	1,097	1,957	9,257	**6,673**	**2,020**	**5,291**	**8,270**
Total assets	13,489	13,665	14,395	24,647	**30,934**	**31,492**	**34,713**	**42,336**
Working capital	9,101	8,139	6,388	3,802	**3,805**	**4,499**	**3,745**	**1,777**
Flow-through share obligation	5,183	4,893	3,786	5,000	**7,350**	**6,350**	**5,350**	**6,740**
Asset retirement obligation	241	260	297	341	**477**	**827**	**832**	**894**

Sales Volumes

Sales volumes were relatively flat for the first three quarters of 2004. In the fourth quarter of 2004, sales volumes increased 71% from the third quarter of 2004 due primarily to production from new wells in the Blueberry, Bonanza and Berland River areas of Alberta. In the first quarter of 2005, the daily average boe/d rate increased 99% from the fourth quarter of 2004 due to natural gas production from new wells in the Bittern Lake, Pouce Coupe and Virginia Hills areas of Alberta and additional crude oil production from a new well in each of Saskatchewan and Manitoba. The 137% increase in 2005 second quarter sales volumes over the first quarter of 2005 was primarily due to the full quarter effect of the Virginia Hills well. During the third quarter of 2005, natural gas sales volume declines from Virginia Hills were largely offset by increased crude oil and liquids sales volumes from new wells in Saskatchewan and Manitoba. During the fourth quarter of 2005, total sales volumes dropped modestly as natural gas volume declines at Virginia Hills exceeded new oil sales volumes for Kingsford and Sinclair.

Gross Revenues

Total gross revenues, on a quarterly basis, increased from $477,000 in the first quarter of 2004 to $5,653,000 in the fourth quarter of 2005. The increases in gross sales revenues were directly related to the sales volumes from the wells previously discussed combined with product price changes. All of the Corporation's natural gas, crude oil and liquids were sold at spot prices, which are subject to world and North America supply and demand fundamentals.

Net Income (Loss)

The Corporation recorded net losses ranging between $50,000 and $180,000 from the first quarter of 2004 until the third quarter of 2004, as sales volumes were insufficient to generate enough revenue to cover fixed costs. The Corporation recorded a net income of $1,229,000 in the fourth quarter of 2004 as stock-based compensation costs of $866,000 were more than offset by a future income tax recovery related to flow-through shares of $2,259,000.

In the first quarter of 2005, the Corporation recorded a net loss of $282,000 as increased revenues from higher sales volumes were more than offset by increased depletion expense and stock-based compensation costs. The increase in depletion expense was due to higher sales volumes and an increased depletion rate. No future income tax recoveries were recorded in the first quarter of 2005. The Corporation recorded a net income of $1,018,000 in the second quarter of 2005 as higher sales volumes and revenues combined with recording a future tax benefit of $1,967,000 more than offset increased depletion expense. In the third quarter of 2005, the Corporation recorded a net loss of $1,113,000 as increased revenues from higher product prices were more than offset by a continuation of the high depletion costs. No future income tax recovery was recorded in the third quarter of 2005. During the 2005 fourth quarter, net income improved to $1,307,000 due to recording a future tax recovery of $1,123,000 relating to the issue of flow-through shares and a lower depletion rate.

Additions to Property and Equipment

Additions to property and equipment (capital spending) increased gradually from $816,000 in the first quarter of 2004 to $1,957,000 in the third quarter of 2004 as the Corporation expanded operations and increased its drilling and completion activity. The increase in capital spending during the fourth quarter of 2004 to $9,257,000 was primarily due to the extensive drilling, completions and tie-in programs from expanded operations that began in early 2004. Capital spending declined to $6,673,000 in the first quarter of 2005. During the second quarter of 2005, capital spending fell to $2,020,000 as wet weather delayed projects for the entire industry, including Grand Banks. Capital spending increased again to $5,291,000 in the third quarter of 2005 as delayed projects were completed. The Corporation spent $8,270,000 in the fourth quarter of 2005 as it drilled new vertical and horizontal oil wells in Saskatchewan and Manitoba.

Working Capital

The Corporation replenished working capital by raising new equity in the first and fourth quarters of 2004 for gross proceeds of $2,883,000 and $6,525,000, respectively. During the first and fourth quarters of 2005, the Corporation raised additional equity capital for gross proceeds of $5,850,000 and $3,340,000, respectively.

Working capital at December 31, 2005 was $1,777,000, while funds generated from operations for the fourth quarter of 2005 were $3,000,000. The Corporation currently has unused lines of credit totaling $10,000,000.

Flow-Through Obligation

The remaining flow-through obligation represented the amount of flow-through shares issued in excess of qualifying capital expenditures. In 2005, all flow-through obligations from flow-through shares issued in 2004 were met. During 2005, the Corporation issued flow-through shares totaling $9,190,000. At December 31, 2005, $6,740,000 of these obligations remained. It is the Corporation's belief that this spending will be met by December 31, 2006 as required.

Asset Retirement Obligation

The asset retirement obligations grew from $241,000 in the first quarter of 2004 to $894,000 in the fourth quarter of 2005 as the Corporation continued to drill wells that are required to be abandoned and reclaimed at some point in the future. The asset retirement obligation represents the present value of future abandonment and reclamation cost for the Corporation's interest in the wells.

Other Items

Outstanding Shares, Options and Warrants

The following table is a summary of the Corporation's share capital structure:

As at	December 31, 2005	April 6, 2006
(000s)	*(#)*	*(#)*
Common shares outstanding	**29,750**	**29,790**
Options outstanding	**2,310**	**2,965**
Fully diluted	**32,060**	**32,755**

Stock Options	Shares	Weighted Average Exercise Price	Weighted Average Term
	(#000s)	*($)*	*(Years)*
Options outstanding, December 31, 2004	1,730	1.05	5.2
Options outstanding, December 31, 2005	**2,310**	**1.10**	**4.6**
Options vested, December 31, 2005	**1,372**	**1.08**	**3.9**

Warrants	Expiry	Warrants	Average Price
		(#000s)	*($)*
Warrants outstanding, December 31, 2004	Aug. & Sep. 2005	2,344	1.25
Exercised		**(1,808)**	**1.25**
Expired		**(536)**	**1.25**
Warrants outstanding, December 31, 2005		**--**	**--**

Accounting Policy Changes

There were no accounting policy changes in 2005.

Critical Accounting Estimates

Management is required to make judgements, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Corporation.

Reserve estimates have a significant impact on income or loss, as they are a key component in the calculation of depletion and depreciation and site restoration costs. A change in the reserve quantity estimates will result in a corresponding change in depletion, depreciation and site restoration costs. In addition, if capitalized costs are determined to be in excess of the calculated ceiling, which is based on reserve quantities and values, the excess must be written off as an expense. The reserves and estimated future net cash flow from the assets of Grand Banks have been independently evaluated by Paddock Lindstrom & Associates Ltd.

Future site restoration costs are estimated and amortized over the life of reserves. These costs were estimated by management using industry standard guidelines. A change in estimated future site restoration costs will change the amortization of site restoration costs included in depletion and depreciation expense.

Non-GAAP Measures

Funds generated from operations is not a recognized measure under Canadian generally accepted accounting principles ("GAAP"). Management believes that funds generated from operations is a useful measure of financial performance. For the purposes of funds generated from operations calculations, the following table reconciles the non-GAAP financial measures "funds generated from operations" to "net income," the most comparable measure calculated in accordance with GAAP:

	Three Months Ended December 31,		Years Ended December 31,	
	2005	2004	**2005**	2004
(000s)	*($)*	*($)*	*($)*	*($)*
Net income	**1,307**	1,299	**930**	999
Adjustments for:				
Accretion of asset retirement obligation	**18**	7	**67**	22
Assets retirement costs	**(23)**	--	**(274)**	--
Depletion and amortization	**2,629**	371	**10,652**	872
Loss on settlement of asset retirement obligation	**22**	--	**98**	--
Stock-based compensation	**167**	866	**683**	1,018
Future income tax (recovery)	**(1,123)**	(2,259)	**(3,090)**	(2,259)
Funds generated from operations	**2,997**	284	**9,066**	652

Netback is the average per unit of volume for oil and gas revenues less royalties and production costs incurred. Netback is expressed in terms of dollars per boe and is calculated in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities.

Disclosure Controls

As of December 31, 2005, the Corporation's management evaluated the effectiveness of the design and operation of its disclosure controls and procedures ("Disclosure Controls"), as defined under rules adopted by the Canadian Securities Administrators. This evaluation was performed under the supervision of, and with the participation of, the President and Chief Executive Officer and Chief Financial Officer.

Disclosure Controls are procedures designed to ensure that information required to be disclosed in documents filed with securities regulatory authorities is recorded, processed, summarized and reported on a timely basis, and is accumulated and communicated to the Corporation's management, including the President and Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure.

The Corporation's management, including the President and Chief Executive Officer and Chief Financial Officer, does not expect that the Corporation's Disclosure Controls will prevent or detect all error and all fraud. Because of the inherent limitations in all controls systems, an evaluation of controls can provide only reasonable, not absolute, assurance that all control issues and instances of fraud or error, if any, within the Corporation have been detected.

Based on the evaluation of Disclosure Controls, the President and Chief Executive Officer and Chief Financial Officer have concluded that, subject to the inherent limitations noted above, the Corporation's Disclosure Controls are effective in ensuring that material information relating to the Corporation is made known to the Corporation's management on a timely basis by others and is included as appropriate in this MD&A.

Forward-Looking Statements

This Annual Report contains forward-looking or outlook information with respect to Grand Banks. The use of any of the words "anticipate," "continue," "estimate," "expect," "may," "will," "project," "should," "believe," "outlook," and similar expressions are intended to identify forward-looking statements. 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 the Corporation's forward-looking statements. Consequently, all of the forward-looking statements make in this Annual Report are qualified by these cautionary statements and there can be no assurance that actual results or developments anticipated by the Corporation will be realized, or that they will have the expected consequences or effects on the Corporation or its business or operations. The Corporation assumes no obligation to update publicly any such forward-looking statements, whether as a result of new information, future events or otherwise.

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

- Volatility in market prices for oil and natural gas.
- Risks inherent in the Corporation's operations.
- Geological, technical, drilling and processing problems.
- General economic conditions.
- Industry conditions, including fluctuation in the price of oil and natural gas.
- Governmental regulations.
- Fluctuation in foreign exchange and interest rates.
- Unanticipated events that can reduce production or cause production to be shut-in or delayed.
- Failure to obtain industry partners and other third party consents and approvals, when required.
- The need to obtain required approvals from regulatory authorities.
- The other factors discussed in the "Operational and Other Business Risks" section of this MD&A.

Operational and Other Business Risks

Need to Replace and Grow Reserves

The future oil and natural gas production of Grand Banks, and therefore future cash flows, are highly dependent upon ongoing success in exploring its current and future undeveloped land base, exploiting the current producing properties and acquiring or discovering additional reserves. Without reserve additions through exploration, acquisition or development activities, reserves and production will decline over time as reserves are depleted.

The business of discovering, developing or acquiring reserves is capital intensive. To the extent cash flows from operations are insufficient and external sources of capital become limited or unavailable, the ability of Grand Banks to make the necessary capital investments to maintain and expand its oil and natural gas reserves may be impaired.

There can be no assurance that the Corporation will be able to find and develop or acquire additional reserves to replace and grow production at acceptable costs.

Exploration, Development and Production Risks

Oil and natural gas exploration involves a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that expenditures made on future exploration by Grand Banks will result in new discoveries of oil and 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, 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.

The long-term commercial success of Grand Banks depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. No assurance can be given that the Corporation will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participation are identified, Grand Banks may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic.

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 diligent well supervision and effective maintenance operations can contribute to maximizing production rate 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.

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, blowouts, 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.

Reserve Estimates

The production forecast and recoverable estimates contained in the Corporation's engineering report are only estimates, and the actual production and ultimate recoverable reserves from the properties may be greater or less than the independent estimates of Paddock Lindstrom & Associates Ltd. ("Paddock Lindstrom").

There are numerous uncertainties inherent in estimating quantities of reserves and cash flows to be derived therefrom, including many factors that are beyond the control of Grand Banks. The reserve and cash flow information set forth herein represent estimates only. The reserves and estimated future net cash flow from the assets of Grand Banks have been independently evaluated by Paddock Lindstrom. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditure, marketability of production, future prices of oil and natural gas, operating costs and royalties and other government levies that may be imposed over the producing life of the reserves.

These assumptions were based on price forecasts in use at the date the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of the Corporation. Actual production and cash flows derived therefrom will vary from these evaluations, and such variations could be material. The foregoing evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluations.

Volatility of Oil and Natural Gas Prices

The operational results and financial condition of Grand Banks will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect of the operations, proved reserves and financial conditions of Grand Banks and could result in a reduction of the net production revenue of the Corporation causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings that might be made available to the Corporation are typically determined in part by the borrowing base of the reserves of Grand Banks. A sustained material decline in prices from historical average prices could reduce the borrowing base of the Corporation, therefore reducing the bank credit available to Grand Banks and possibly requiring that a portion of such bank debt be repaid.

Grand Banks uses the full cost method of accounting for oil and natural gas properties. Under this accounting method, capitalized costs are reviewed on a quarterly basis for impairment to ensure that the carrying amount of these costs is recoverable based on expected future cash flows.

Operational Hazards and Other Uncertainties

Oil and natural gas exploration operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts and oil spills, each of which could result in substantial damage to oil and natural gas wells, production faculties, other property and the environment or in personal injury.

In accordance with industry practice, Grand Banks is not fully insured against all of these risks, nor are all such risks insurable. Although Grand Banks maintains liability insurance, where available, in an amount that it considers adequate and consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event Grand Banks could incur significant costs that could have a material adverse affect upon its financial condition. Business interruption insurance may also be purchased for selected facilities, to the extent that such insurance is available. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations.

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for such equipment or access restrictions may affect the availability and/or cost of such equipment to Grand Banks and may delay exploration and development activities. To the extent Grand Banks is not the operator of its oil and gas properties, the Corporation will be dependent on other operators for timing of activities related to non-operating properties and will be largely unable to direct or control the activities of the operators.

Although property title reviews are completed according to industry standards prior to the purchase of most oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the claim of Grand Banks, which could result in the reduction of the revenue received by the Corporation.

Competition

There is strong competition relating to all aspects of the oil and natural gas industry. Grand Banks actively competes for capital, skilled personnel, undeveloped land, reserve acquisitions, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity, and in all other aspects of its operations with a substantial number of other organizations, many of which may have greater technical and financial resources than Grand Banks.

Key Personnel

The success of Grand Banks depends in large measure on certain key personnel. The loss of the services of such key personnel could have a material adverse affect on the Corporation. Grand Banks does not have key person insurance in effect for management. The contributions of these individuals to the immediate operations of Grand Banks are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business.

Environmental Risks

The oil and natural gas industry is subject to environmental regulations pursuant to a variety of international conventions and Canadian federal, provincial and municipal laws, regulations and guidelines. A breach of such regulations may result in the imposition of fines or issuances of clean-up orders in respect of Grand Banks or its assets. Such regulations may be changed to impose higher standards and potentially more costly obligations on the Corporation. There can be no assurance that future environmental costs will not have a material adverse affect on Grand Banks.

Other Information

Additional information regarding Grand Banks Energy Corporation's reserves and other data is available on the Corporation's website at www.grandbanksenergy.com and on the Canadian Securities Administrators' System for Electronic Document Analysis and Retrieval ("SEDAR") at www.sedar.com.

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FORM 52-109FT1

CERTIFICATION OF ANNUAL FILINGS

I, EDWARD C. MCFEELY, PRESIDENT AND CEO OF GRAND BANKS ENERGY CORPORATION certify that:

1. I have reviewed the annual filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*) of Grand Banks Energy Corporation (the issuer) for the period ending December 31, 2005;

2. Based on my knowledge, the annual filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the annual filings;

3. Based on my knowledge, the annual financial statements together with the other financial information included in the annual filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the annual filings;

4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures for the issuer, and we have:

    (a) designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the annual filings are being prepared; and

    (b) evaluated the effectiveness of the issuer's disclosure controls and procedures as of the end of the period covered by the annual filings and have caused the issuer to disclose in the annual MD&A our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by the annual filings based on such evaluation.

Date: April 10, 2006

"signed Edward C. McFeely"
Edward C. McFeely
President & CEO

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CORPORATE FINANCE

FORM 52-109FT1

CERTIFICATION OF ANNUAL FILINGS

I, DAVID BLAIN, CHIEF FINANCIAL OFFICER OF GRAND BANKS ENERGY CORPORATION certify that:

1. I have reviewed the annual filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*) of Grand Banks Energy Corporation (the issuer) for the period ending December 31, 2005;

2. Based on my knowledge, the annual filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the annual filings;

3. Based on my knowledge, the annual financial statements together with the other financial information included in the annual filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the annual filings;

4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures for the issuer, and we have:

   (a) designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the annual filings are being prepared; and

   (b) evaluated the effectiveness of the issuer's disclosure controls and procedures as of the end of the period covered by the annual filings and have caused the issuer to disclose in the annual MD&A our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by the annual filings based on such evaluation.

Date: April 10, 2006

<u>*"signed David Blain"*</u>
David Blain
Chief Financial Officer

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GRAND BANKS ENERGY CORPORATION
REPORT ON RESERVE DATA AND OTHER INFORMATION (NI 51-101F1)
As of December 31, 2005
(CAD $000's)

DISCLOSURE OF RESERVES DATA

The oil and natural gas reserves data set forth below is based on an evaluation by Paddock Lindstrom & Associates Ltd. ("PLA"), a qualified, independent reserves evaluator firm engaged by the Board of Directors to evaluate the Company's oil and natural gas reserves. The following information with an effective date of December 31, 2005 comes from the PLA Report dated February 28, 2006. The reserves data conforms to the requirements of NI 51-101.

It should not be assumed that the estimates of future net revenues presented in the tables below represent fair market values of the reserves. There is no assurance that the constant prices and costs assumptions and forecast process and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas liquids and natural gas reserves may be greater than or less than the estimates provided herein.

DEFINITIONS AND NOTES

Mbbl –	One Thousand Barrels of oil
Mcf –	One Thousand cubic feet of gas
MMcf –	Millions of cubic feet of gas
BOE –	Barrels of oil equivalent have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel oil (6:1). BOEs may be misleading, particularly if used in isolation. A BOE conversion of 6 Mcf: 1 Bbl is based on an approximate energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
Mboe –	One Thousand Barrels of oil equivalent converted at 6:1
CAD $000's –	All monetary amounts are Canadian dollars expressed in thousands (except the per unit amounts)
Rounding -	Numbers may not add due to rounding

"**Gross**" means:
(a) in relation to our interest in production and reserves, our interest (operating and nonoperating) before deduction of royalties and without including any royalty interest to us;
(b) in relation to wells, the total number of wells in which we have an interest; and
(c) in relation to properties, the total area of properties in which we have an interest.

"**Net**" means:
(a) in relation to our interest in production and reserves, our interest (operating and nonoperating) after deduction of royalty obligations, plus our royalty interest in production or reserves;
(b) in relation to wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and
(c) in relation to our interest in a property, the total area in which we have an interest multiplied by the working interest we owned.

RESERVES DATA (CONSTANT PRICES AND COSTS)

NI 51-101 Table 1 - Constant

Grand Banks Energy Corporation

Summary of Oil and Gas Reserves

Constant Prices and Costs - December 31, 2005 Prices

Effective December 31, 2005

Volumes In Imperial Units

	Oil Light and Medium		Natural Gas Solution		Natural Gas Assoc. & Non-Assoc.		Natural Gas Coalbed Methane		Natural Gas Total Gas		Natural Gas Liquids		BOE	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Reserves Category	(MStb)	(MStb)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MStb)	(MStb)	(MStb)	(MStb)
Proved Developed Producing	505.6	435.6	54.2	36.8	1,194.4	837.1	0.0	0.0	1,248.6	874.0	17.9	11.2	731.6	592.4
Proved Developed Non-Producing	78.2	66.7	205.4	172.6	334.3	253.8	0.0	0.0	539.7	426.4	4.2	2.8	172.4	140.6
Proved Undeveloped	67.3	62.2	16.3	13.9	0.0	0.0	29.7	22.3	46.0	36.1	0.0	0.0	74.9	68.3
Total Proved	651.1	564.5	275.9	223.3	1,528.8	1,090.9	29.7	22.3	1,834.4	1,336.5	22.2	14.0	979.0	801.3
Probable Additional	742.2	661.9	179.8	147.7	1,097.1	817.0	5.9	4.5	1,282.9	969.1	14.8	9.7	970.8	833.2
Total Proved + Probable	1,393.3	1,226.4	455.7	371.0	2,625.9	1,907.9	35.6	26.7	3,117.2	2,305.6	37.0	23.8	1,949.8	1,634.4

Volumes In Metric Units

	Oil Light and Medium		Natural Gas Solution		Natural Gas Assoc. & Non-Assoc.		Natural Gas Coalbed Methane		Natural Gas Total Gas		Natural Gas Liquids	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Reserves Category	(E3M3)	(E3M3)	(E6M3)	(E6M3)	(E6M3)	(E6M3)	(E6M3)	(E6M3)	(E6M3)	(E6M3)	(E3M3)	(E3M3)
Proved Developed Producing	80.4	69.2	1.5	1.0	33.7	23.6	0.0	0.0	35.2	24.6	2.8	1.8
Proved Developed Non-Producing	12.4	10.6	5.8	4.9	9.4	7.2	0.0	0.0	15.2	12.0	0.7	0.4
Proved Undeveloped	10.7	9.9	0.5	0.4	0.0	0.0	0.8	0.6	1.3	1.0	0.0	0.0
Total Proved	103.5	89.8	7.8	6.3	43.1	30.7	0.8	0.6	51.7	37.7	3.5	2.2
Probable Additional	118.0	105.2	5.1	4.2	30.9	23.0	0.2	0.1	36.1	27.3	2.4	1.5
Total Proved + Probable	221.5	195.0	12.8	10.5	74.0	53.8	1.0	0.8	87.8	65.0	5.9	3.8

NI 51-101 Table 2 - Constant
Grand Banks Energy Corporation
Summary of Net Present Values of Future Net Revenue
Including Alberta Royalty Tax Credit
Effective December 31, 2005

	Before Income Taxes				
	0%	5%	10%	15%	20%
Reserves Category	**(M$)**	**(M$)**	**(M$)**	**(M$)**	**(M$)**
Proved Developed Producing	26,972.3	23,882.9	21,570.2	19,767.9	18,321.4
Proved Developed Non-Producing	5,869.0	4,265.0	3,222.5	2,506.4	1,991.0
Proved Undeveloped	2,561.4	2,005.1	1,609.0	1,313.6	1,085.3
Total Proved	35,402.7	30,153.1	26,401.6	23,587.9	21,397.7
Probable Additional	35,053.6	25,577.1	19,672.2	15,675.3	12,803.9
Total Proved + Probable	70,456.4	55,730.2	46,073.9	39,263.1	34,201.7

	After Income Taxes				
	0%	5%	10%	15%	20%
Reserves Category	**(M$)**	**(M$)**	**(M$)**	**(M$)**	**(M$)**
Proved Developed Producing	26,972.3	23,882.9	21,570.2	19,767.9	18,321.4
Proved Developed Non-Producing	5,869.0	4,265.0	3,222.5	2,506.4	1,991.0
Proved Undeveloped	2,561.4	2,005.1	1,609.0	1,313.6	1,085.3
Total Proved	35,402.7	30,153.1	26,401.6	23,587.9	21,397.8
Probable Additional	25,098.4	18,458.6	14,342.0	11,544.9	9,517.7
Total Proved + Probable	60,501.1	48,611.7	40,743.6	35,132.8	30,915.4

NI 51-101 Table 3 - Constant

Grand Banks Energy Corporation

Total Future Net Revenue (Undiscounted)

Constant Prices and Costs - December 31, 2005 Prices

Effective December 31, 2005

Reserves Category	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Development Costs (M$)	Well Abandonment Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
Proved Developed Producing	43,525.1	7,788.5	8,283.3	0.0	481.1	26,972.3	0.0	26,972.3
Proved Developed Non-Producing	9,858.6	1,511.6	633.5	1,807.2	37.5	5,869.0	0.0	5,869.0
Proved Undeveloped	4,715.3	402.9	633.8	1,078.3	38.9	2,561.4	0.0	2,561.4
Total Proved	58,099.1	9,702.9	9,550.6	2,885.5	557.6	35,402.7	0.0	35,402.7
Probable Additional	60,518.5	8,353.0	9,360.4	7,387.7	363.6	35,053.6	9,955.2	25,098.4
Total Proved + Probable	118,617.6	18,055.9	18,910.9	10,273.2	921.2	70,456.4	9,955.2	60,501.1

NI 51-101 Table 4
Grand Banks Energy Corporation
Net present Value of Future Net Revenue By Production Group
Constant Prices and Costs - December 31, 2005 Prices
Effective December 31, 2005

	Future Net Revenue Before Income Taxes (Discounted at 10%) (M$)
Total Proved	
Light and Medium Crude Oil (including solution gas and other by-products)	18,521.5
Heavy Oil (including solution gas and other by-products)	0.0
Associated and Non-Associated gas (including by-products)	6,935.3
Coalbed Methane gas	76.6
Other Revenue	868.3
Total	26,401.6
Total Proved + Probable	
Light and Medium Crude Oil (including solution gas and other by-products)	33,284.9
Heavy Oil (including solution gas and other by-products)	0.0
Associated and Non-Associated gas (including by-products)	11,359.2
Coalbed Methane gas	99.5
Other Revenue	1,330.2
Total	46,073.9

NI 51-101 Table 4A - Constant

Grand Banks Energy Corporation

Oil and Gas Reserves and Net Present Values By Production Group

Constant Prices and Costs - December 31, 2005 Prices

Effective December 31, 2005

	Reserves										
	Oil		Gas		Natural Gas Liquids		Net Present Value Before Tax				
	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
Light and Medium Oil											
Proved Developed Producing	505.6	435.6	54.2	36.8	2.5	1.8	18,998.4	16,901.5	15,279.1	13,991.7	12,947.7
Proved Developed Non-Producing	78.2	66.7	205.4	172.6	0.0	0.0	3,962.8	2,582.0	1,716.5	1,144.3	748.1
Proved Undeveloped	67.3	62.2	16.3	13.9	0.0	0.0	2,442.7	1,906.0	1,525.9	1,243.8	1,026.7
Total Proved	651.1	564.5	275.9	223.3	2.5	1.8	25,403.9	21,389.5	18,521.5	16,379.7	14,722.5
Probable Additional	742.2	661.9	179.8	147.7	1.0	0.7	27,476.1	19,618.2	14,763.4	11,502.9	9,175.4
Total Proved + Probable	1,393.3	1,226.4	455.7	371.0	3.6	2.5	52,880.0	41,007.6	33,284.9	27,882.6	23,897.9
Heavy Oil											
Proved Developed Producing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Proved Developed Non-Producing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Proved Undeveloped	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Proved	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Probable Additional	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Proved + Probable	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Associated and Non-Associated Gas											
Proved Developed Producing	0.0	0.0	1,194.4	837.1	15.4	9.5	7,053.6	6,156.3	5,536.7	5,077.3	4,719.5
Proved Developed Non-Producing	0.0	0.0	334.3	253.8	4.2	2.8	1,776.3	1,565.6	1,398.6	1,263.0	1,150.8
Proved Undeveloped	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Proved	0.0	0.0	1,528.8	1,090.9	19.6	12.3	8,829.9	7,721.9	6,935.3	6,340.3	5,870.4
Probable Additional	0.0	0.0	1,097.1	817.0	13.8	9.0	6,832.9	5,369.8	4,423.9	3,761.9	3,273.5
Total Proved + Probable	0.0	0.0	2,625.9	1,907.9	33.4	21.3	15,662.8	13,091.7	11,359.2	10,102.2	9,143.9
Coalbed Methane											
Proved Developed Producing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Proved Developed Non-Producing	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Proved Undeveloped	0.0	0.0	29.7	22.3	0.0	0.0	110.4	91.8	76.6	63.9	53.3
Total Proved	0.0	0.0	29.7	22.3	0.0	0.0	110.4	91.8	76.6	63.9	53.3
Probable Additional	0.0	0.0	5.9	4.5	0.0	0.0	36.6	28.7	22.9	18.6	15.3
Total Proved + Probable	0.0	0.0	35.6	26.7	0.0	0.0	147.0	120.5	99.5	82.5	68.6

NI 51-101 TABLE 5 - CONSTANT

GRAND BANKS ENERGY CORPORATION
CONSTANT PRICE ASSUMPTIONS
BASED ON DECEMBER 31, 2005 POSTINGS
EFFECTIVE DATE DECEMBER 31, 2005

		AECO C				
Edmonton	Hardisty	Natural Gas	Pentanes Plus			
40° API	25° API	Price	(Condensate)	Butane	Propane	Sulphur
$Cdn/bbl	$Cdn/bbl	$Cdn/MMBtu	$Cdn/bbl	$Cdn/bbl	$Cdn/bbl	$Cdn/lt
$68.05	$37.34	$9.47	$71.07	$54.03	$44.34	$30.00

Average product prices for 2005 were $56.63 per barrel of oil and $8.50 per Mcf of natural gas.

NI 51-101 Table 1 - Forecast
Grand Banks Energy Corporation
Summary of Oil and Gas Reserves
Forecast Prices and Costs - PLA December 31, 2005 Prices
Effective December 31, 2005

Volumes In Imperial Units

	Oil		Natural Gas											
	Light and Medium		Solution		Assoc. & Non-Assoc.		Coalbed Methane		Total Gas		Natural Gas Liquids		BOE	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Reserves Category	(MStb)	(MStb)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MStb)	(MStb)	(MStb)	(MStb)
Proved Developed Producing	510.9	439.6	56.0	40.4	1,184.8	863.3	0.0	0.0	1,240.8	903.7	17.8	11.3	735.5	601.5
Proved Developed Non-Producing	78.2	66.7	205.4	172.6	334.3	260.4	0.0	0.0	539.7	433.0	4.2	2.8	172.4	141.7
Proved Undeveloped	67.3	62.2	16.3	13.9	0.0	0.0	29.7	22.6	46.0	36.5	0.0	0.0	74.9	68.3
Total Proved	656.3	568.5	277.7	226.8	1,519.2	1,123.7	29.7	22.6	1,826.6	1,373.2	22.1	14.1	982.8	811.5
Probable Additional	744.7	663.8	180.7	149.3	1,095.9	840.1	5.9	4.5	1,282.5	993.9	14.8	9.8	973.2	839.3
Total Proved + Probable	1,401.0	1,232.3	458.4	376.1	2,615.0	1,963.9	35.6	27.2	3,109.1	2,367.1	36.9	23.9	1,956.0	1,650.8

Volumes In Metric Units

	Oil		Natural Gas									
	Light and Medium		Solution		Assoc. & Non-Assoc.		Coalbed Methane		Total Gas		Natural Gas Liquids	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Reserves Category	(E3M3)	(E3M3)	(E6M3)	(E6M3)	(E6M3)	(E6M3)	(E6M3)	(E6M3)	(E6M3)	(E6M3)	(E3M3)	(E3M3)
Proved Developed Producing	81.2	69.9	1.6	1.1	33.4	24.3	0.0	0.0	35.0	25.5	2.8	1.8
Proved Developed Non-Producing	12.4	10.6	5.8	4.9	9.4	7.3	0.0	0.0	15.2	12.2	0.7	0.4
Proved Undeveloped	10.7	9.9	0.5	0.4	0.0	0.0	0.8	0.6	1.3	1.0	0.0	0.0
Total Proved	104.3	90.4	7.8	6.4	42.8	31.7	0.8	0.6	51.5	38.7	3.5	2.2
Probable Additional	118.4	105.5	5.1	4.2	30.9	23.7	0.2	0.1	36.1	28.0	2.3	1.6
Total Proved + Probable	222.7	195.9	12.9	10.6	73.7	55.3	1.0	0.8	87.6	66.7	5.9	3.8

NI 51-101 Table 2 - Forecast
Grand Banks Energy Corporation
Summary of Net Present Values of Future Net Revenue
Including Alberta Royalty Tax Credit
Effective December 31, 2005

	Before Income Taxes				
	0%	5%	10%	15%	20%
Reserves Category	**(M$)**	**(M$)**	**(M$)**	**(M$)**	**(M$)**
Proved Developed Producing	24,550.7	22,173.8	20,358.6	18,914.6	17,732.6
Proved Developed Non-Producing	4,851.1	3,674.6	2,869.6	2,293.7	1,865.7
Proved Undeveloped	2,138.5	1,706.0	1,388.0	1,145.2	954.1
Total Proved	31,540.3	27,554.4	24,616.2	22,353.5	20,552.3
Probable Additional	28,693.2	21,342.7	16,658.7	13,432.2	11,080.6
Total Proved + Probable	60,233.5	48,897.0	41,275.0	35,785.7	31,633.0

	After Income Taxes				
	0%	5%	10%	15%	20%
Reserves Category	**(M$)**	**(M$)**	**(M$)**	**(M$)**	**(M$)**
Proved Developed Producing	24,550.7	22,173.8	20,358.6	18,914.6	17,732.6
Proved Developed Non-Producing	4,851.1	3,674.6	2,869.6	2,293.7	1,865.7
Proved Undeveloped	2,138.5	1,706.0	1,388.0	1,145.2	954.1
Total Proved	31,540.3	27,554.4	24,616.2	22,353.5	20,552.3
Probable Additional	22,432.9	16,733.5	13,128.3	10,644.7	8,826.6
Total Proved + Probable	53,973.2	44,287.9	37,744.5	32,998.2	29,379.0

NI 51-101 Table 3 - Forecast
Grand Banks Energy Corporation
Total Future Net Revenue (Undiscounted)
Forecast Prices and Costs - PLA December 31, 2005 Prices
Effective December 31, 2005

Reserves Category	**Revenue (M$)**	**Royalties (M$)**	**Operating Costs (M$)**	**Development Costs (M$)**	**Well Abandonment Costs (M$)**	**Future Net Revenue Before Income Taxes (M$)**	**Income Taxes (M$)**	**Future Net Revenue After Income Taxes (M$)**
Proved Developed Producing	41,344.0	7,223.7	9,031.3	0.0	538.4	24,550.7	0.0	24,550.7
Proved Developed Non-Producing	9,081.8	1,349.6	1,010.2	1,807.2	64.0	4,851.1	0.0	4,851.1
Proved Undeveloped	4,364.2	369.3	728.9	1,078.3	49.2	2,138.5	0.0	2,138.5
Total Proved	54,790.1	8,942.5	10,770.4	2,885.5	651.6	31,540.3	0.0	31,540.3
Probable Additional	55,613.3	7,488.7	11,531.0	7,388.4	511.8	28,693.2	6,260.3	22,432.9
Total Proved + Probable	110,403.4	16,431.3	22,301.4	10,273.9	1,163.3	60,233.5	6,260.3	53,973.2

NI 51-101 Table 4

Grand Banks Energy Corporation

Net present Value of Future Net Revenue By Production Group

Forecast Prices and Costs - PLA December 31, 2005 Prices

Effective December 31, 2005

	Future Net Revenue Before Income Taxes (Discounted at 10%) (M$)
Total Proved	
Light and Medium Crude Oil (including solution gas and other by-products)	16,823.3
Heavy Oil (including solution gas and other by-products)	0.0
Associated and Non-Associated gas (including by-products)	6,952.2
Coalbed Methane gas	65.3
Other Revenue	775.3
Total	24,616.2
Total Proved + Probable	
Light and Medium Crude Oil (including solution gas and other by-products)	29,211.4
Heavy Oil (including solution gas and other by-products)	0.0
Associated and Non-Associated gas (including by-products)	10,834.6
Coalbed Methane gas	82.2
Other Revenue	1,146.8
Total	41,275.0

NI 51-101 TABLE 5 - FORECAST

PADDOCK LINDSTROM & ASSOCIATES LTD.
FORECAST PRICES AND COSTS ASSUMPTIONS

December 31, 2005

YEAR	WTI @ CUSHING $US/BBL	CDN/US EXCHANGE RATE	WTI @ CUSHING $C/BBL	EDM REF PRICE $C/BBL	HARDISTY 25 API $C/BBL	HEAVY 12 API $C/BBL	CROMER 29 API $C/BBL	CONDEN-SATE $C/BBL	BUTANE $C/BBL	PROPANE $C/BBL	ETHANE $C/BBL	SULPHUR $/LT
2006	60.00	0.850	70.59	69.57	46.57	36.57	64.70	69.57	48.70	41.74	33.47	30.00
2007	57.50	0.850	67.65	66.61	47.61	38.61	61.94	66.61	46.62	39.96	30.24	25.00
2008	55.00	0.850	64.71	63.64	50.64	42.64	59.19	63.64	44.55	38.19	26.43	20.00
2009	52.50	0.850	61.76	60.68	47.68	39.68	56.43	60.68	42.48	36.41	24.43	20.40
2010	50.00	0.850	58.82	57.72	44.46	36.46	53.68	57.72	40.40	34.63	22.44	20.81
2011	47.50	0.850	55.88	54.76	41.23	33.23	50.92	54.76	38.33	32.85	22.88	21.22
2012	48.45	0.850	57.00	55.85	42.06	34.06	51.94	55.85	39.10	33.51	23.34	21.65
2013	49.42	0.850	58.14	56.97	42.90	34.90	52.98	56.97	39.88	34.18	23.81	22.08
2014	50.41	0.850	59.30	58.11	43.75	35.75	54.04	58.11	40.68	34.86	24.29	22.52
2015	51.42	0.850	60.49	59.27	44.63	36.63	55.12	59.27	41.49	35.56	24.77	22.97
2016	52.44	0.850	61.70	60.46	45.52	37.52	56.22	60.46	42.32	36.27	25.27	23.43
2017	53.49	0.850	62.93	61.66	46.43	38.43	57.35	61.66	43.17	37.00	25.77	23.90
2018	54.56	0.850	64.19	62.90	47.36	39.36	58.49	62.90	44.03	37.74	26.29	24.38
2019	55.65	0.850	65.48	64.16	48.31	40.31	59.66	64.16	44.91	38.49	26.81	24.87
2020	56.77	0.850	66.78	65.44	49.27	41.27	60.86	65.44	45.81	39.26	27.35	25.36
2021	57.90	0.850	68.12	66.75	50.26	42.26	62.08	66.75	46.72	40.05	27.90	25.87
2022	59.06	0.850	69.48	68.08	51.27	43.27	63.32	68.08	47.66	40.85	28.45	26.39
2023	60.24	0.850	70.87	69.44	52.29	44.29	64.58	69.44	48.61	41.67	29.02	26.92

YEAR	HENRY HUB $US/MMBTU	AECO C C$/MMBTU	ALBERTA 1 YR FIRM C$/MMBTU	ALBERTA SPOT C$/MMBTU	AGGRE-GATOR C$/MMBTU	ALLIANCE C$/MMBTU	ALBERTA AGRP C$/MMBTU	SASK SPOT C$/MMBTU	SASK PROVGAS C$/MMBTU	SUMAS SPOT C$/MMBTU	BC STN 2 C$/MMBTU	BC CANWEST WELLHEAD C$/MMBTU
2006	9.85	10.54	10.36	10.36	10.26	10.11	10.30	10.36	10.36	11.09	10.52	9.81
2007	9.00	9.52	9.33	9.33	9.33	9.08	9.30	9.38	9.38	10.08	9.50	8.78
2008	8.00	8.32	8.13	8.13	8.13	7.87	8.13	8.23	8.23	8.89	8.30	7.57
2009	7.50	7.71	7.52	7.52	7.52	7.25	7.52	7.62	7.62	8.29	7.69	6.94
2010	7.00	7.10	6.90	6.90	6.90	6.63	6.90	7.00	7.00	7.69	7.08	6.31
2011	7.14	7.24	7.04	7.04	7.04	6.77	7.04	7.14	7.14	7.85	7.23	6.44
2012	7.28	7.39	7.18	7.18	7.18	6.90	7.18	7.28	7.28	8.00	7.37	6.57
2013	7.43	7.53	7.33	7.33	7.33	7.04	7.33	7.43	7.43	8.17	7.52	6.70
2014	7.58	7.68	7.47	7.47	7.47	7.18	7.47	7.57	7.57	8.33	7.67	6.83
2015	7.73	7.84	7.62	7.62	7.62	7.32	7.62	7.72	7.72	8.49	7.82	6.97
2016	7.88	7.99	7.77	7.77	7.77	7.47	7.77	7.87	7.87	8.66	7.98	7.11
2017	8.04	8.15	7.93	7.93	7.93	7.62	7.93	8.03	8.03	8.84	8.14	7.25
2018	8.20	8.32	8.09	8.09	8.09	7.77	8.09	8.19	8.19	9.01	8.30	7.40
2019	8.37	8.48	8.25	8.25	8.25	7.93	8.25	8.35	8.35	9.20	8.47	7.55
2020	8.53	8.65	8.42	8.42	8.42	8.09	8.42	8.52	8.52	9.38	8.63	7.70
2021	8.70	8.83	8.58	8.58	8.58	8.25	8.58	8.68	8.68	9.57	8.81	7.85
2022	8.88	9.00	8.76	8.76	8.76	8.41	8.76	8.86	8.86	9.76	8.98	8.01
2023	9.06	9.18	8.93	8.93	8.93	8.58	8.93	9.03	9.03	9.95	9.16	8.17

Note: All prices escalated at 2% per year after 2023
All costs escalated at 2% per year from 2006
First year forecast is for 12 months

NI 51-101 Table 6

Grand Banks Energy Corporation

Reconciliation of Company Net Reserves by Principal Product Type

Opening: 2004-12-31 Forecast Prices and Costs - PLA January 1 2005 Prices

Closing: 2005-12-31 Forecast Prices and Costs - PLA December 31, 2005 Prices

	Light & Medium Oil			Heavy Oil			Associated & Non-Associated Gas			Coalbed Methane		
	Net Proved	Net Probable	Net Proved + Probable	Net Proved	Net Probable	Net Proved + Probable	Net Proved	Net Probable	Net Proved + Probable	Net Proved	Net Probable	Net Proved + Probable
	Mstb	Mstb	Mstb	Mstb	Mstb	Mstb	MMcf	MMcf	MMcf	MMcf	MMcf	MMcf
Opening Balance	93.7	75.2	168.9	0.0	0.0	0.0	2,440.5	920.5	3,360.9	0.0	0.0	0.0
Extensions	57.7	308.6	366.3	0.0	0.0	0.0	102.9	89.6	192.5	0.0	0.0	0.0
Improved Recovery	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Technical Revisions	-30.5	-0.5	-31.0	0.0	0.0	0.0	-834.6	-463.2	-1,297.8	0.0	0.0	0.0
Discoveries	489.9	250.1	739.9	0.0	0.0	0.0	488.2	309.9	798.1	22.6	4.5	27.2
Acquisitions	14.2	30.2	44.4	0.0	0.0	0.0	92.3	85.9	178.3	0.0	0.0	0.0
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0	-255.4	-102.0	-357.4	0.0	0.0	0.0
Economic Factors	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Production	-56.4	0.0	-56.4	0.0	0.0	0.0	-910.1	0.0	-910.1	0.0	0.0	0.0
Closing Balance	568.6	663.6	1,232.1	0.0	0.0	0.0	1,123.7	840.1	1,963.9	22.6	4.5	27.2

NI 51-101 Table 6A
Grand Banks Energy Corporation
Reconciliation of Company Net Reserves by Principal Product Type

Opening: 2004-12-31 Forecast Prices and Costs - PLA January 1 2005 Prices
Closing: 2005-12-31 Forecast Prices and Costs - PLA December 31, 2005 Prices

	Light & Medium Oil			Heavy Oil			Associated & Non-Associated Gas			Coalbed Methane			Total		
	Net Proved	Net Probable	Net Proved + Probable	Net Proved	Net Probable	Net Proved + Probable	Net Proved	Net Probable	Net Proved + Probable	Net Proved	Net Probable	Net Proved + Probable	Net Proved	Net Probable	Net Proved + Probable
OIL	Mstb	Mstb	Mstb	Mstb	Mstb	Mstb	Mstb	Mstb	Mstb	Mstb	Mstb	Mstb	Mstb	Mstb	Mstb
Opening Balance	93.7	75.2	168.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	93.7	75.2	168.9
Extensions	57.7	308.6	366.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	57.7	308.6	366.3
Improved Recovery	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Technical Revisions	-30.5	-0.5	-31.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-30.5	-0.5	-31.0
Discoveries	489.9	250.1	739.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	489.9	250.1	739.9
Acquisitions	14.2	30.2	44.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.2	30.2	44.4
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Production	-56.4	0.0	-56.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-56.4	0.0	-56.4
Closing Balance	568.5	663.6	1,232.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	568.5	663.6	1,232.1
GAS	MMcf	MMcf	MMcf	MMcf	MMcf	MMcf	MMcf	MMcf	MMcf	MMcf	MMcf	MMcf	MMcf	MMcf	MMcf
Opening Balance	62.9	46.9	109.7	0.0	0.0	0.0	2,440.5	920.5	3,360.9	0.0	0.0	0.0	2,503.3	967.3	3,470.6
Extensions	21.3	31.1	52.4	0.0	0.0	0.0	102.9	89.6	192.5	0.0	0.0	0.0	124.2	120.7	244.8
Improved Recovery	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Technical Revisions	-17.9	-21.5	-39.3	0.0	0.0	0.0	-834.6	-463.2	-1,297.8	0.0	0.0	0.0	-852.5	-484.7	-1,337.2
Discoveries	179.8	90.9	270.7	0.0	0.0	0.0	488.2	309.9	798.1	22.6	4.5	27.2	690.7	405.3	1,096.0
Acquisitions	7.4	2.3	9.7	0.0	0.0	0.0	92.3	85.9	178.3	0.0	0.0	0.0	99.7	88.2	187.9
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0	-255.4	-102.0	-357.4	0.0	0.0	0.0	-255.4	-102.0	-357.4
Economic Factors	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Production	-26.7	0.0	-26.7	0.0	0.0	0.0	-910.1	0.0	-910.1	0.0	0.0	0.0	-936.8	0.0	-936.8
Closing Balance	226.8	149.7	376.5	0.0	0.0	0.0	1,123.7	840.8	1,964.5	22.6	4.5	27.2	1,373.2	995.0	2,368.2
NGL	Mstb	Mstb	Mstb	Mstb	Mstb	Mstb	Mstb	Mstb	Mstb	Mstb	Mstb	Mstb	Mstb	Mstb	Mstb
Opening Balance	2.6	1.1	3.7	0.0	0.0	0.0	27.4	12.8	40.2	0.0	0.0	0.0	30.1	13.9	43.9
Extensions	0.2	-0.2	0.0	0.0	0.0	0.0	1.7	0.3	2.0	0.0	0.0	0.0	1.9	0.1	2.0
Improved Recovery	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Technical Revisions	-0.5	-0.1	-0.6	0.0	0.0	0.0	-5.7	-7.9	-13.6	0.0	0.0	0.0	-6.2	-8.0	-14.2
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0	4.2	3.6	7.8	0.0	0.0	0.0	4.2	3.6	7.8
Acquisitions	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.4	0.6	0.0	0.0	0.0	0.2	0.4	0.6
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0	-0.5	-0.2	-0.8	0.0	0.0	0.0	-0.5	-0.2	-0.8
Economic Factors	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Production	-0.6	0.0	-0.6	0.0	0.0	0.0	-14.9	0.0	-14.9	0.0	0.0	0.0	-15.5	0.0	-15.5
Closing Balance	1.8	0.7	2.5	0.0	0.0	0.0	12.3	9.1	21.4	0.0	0.0	0.0	14.1	9.8	23.9
BOEs	MBOE	MBOE	MBOE	MBOE	MBOE	MBOE	MBOE	MBOE	MBOE	MBOE	MBOE	MBOE	MBOE	MBOE	MBOE
Opening Balance	106.8	84.1	190.9	0.0	0.0	0.0	434.2	166.2	600.4	0.0	0.0	0.0	540.9	250.3	791.3
Extensions	61.4	313.6	375.0	0.0	0.0	0.0	18.9	15.2	34.1	0.0	0.0	0.0	80.3	328.8	409.1
Improved Recovery	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Technical Revisions	-33.9	-4.2	-38.1	0.0	0.0	0.0	-144.8	-85.1	-229.9	0.0	0.0	0.0	-178.8	-89.3	-268.0
Discoveries	519.8	265.2	785.1	0.0	0.0	0.0	85.5	55.3	140.8	3.8	0.8	4.5	609.1	321.3	930.4
Acquisitions	15.4	30.6	46.0	0.0	0.0	0.0	15.6	14.8	30.3	0.0	0.0	0.0	31.0	45.3	76.4
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0	-43.1	-17.2	-60.3	0.0	0.0	0.0	-43.1	-17.2	-60.3
Economic Factors	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Production	-61.4	0.0	-61.4	0.0	0.0	0.0	-166.6	0.0	-166.6	0.0	0.0	0.0	-228.0	0.0	-228.0
Closing Balance	608.1	689.3	1,297.3	0.0	0.0	0.0	199.6	149.2	348.9	3.8	0.8	4.5	811.5	839.3	1,650.7

NI 51-101 TABLE 7
GRAND BANKS ENERGY CORPORATION
RECONCILIATION OF CHANGES IN NET PRESENT VALUES OF FUTURE NET REVENUE
DISCOUNTED AT 10% PER YEAR
TOTAL PROVED RESERVES
CONSTANT PRICES AND COSTS - DECEMBER 31, 2005 POSTINGS

		2005 (M$)
Estimated Future Net Revenue at Beginning of Year		
	December 31, 2004 Opening Balance (After Credits and Before Income Tax)	15,021
Sales and Transfers of Oil and Gas Produced, Net of Production Costs and Royalties		
	Predicted 2005 cash flow including Capital Spent (10%)	-6,025
Net Changes in Prices, Production Costs and Royalties Related to Future Production		
	Changes in Prices	5,761
	Changes in Royalty	-2,111
	Changes in Estimated Operating Costs	-866
	Changes in Estimated Abandonment Costs	21
	Changes in Proc./Gath. & Plant Income	0
Changes in Estimated Future Development Costs		
	Changes in Estimated Capital Costs	-151
Extensions and Improved Recovery Discoveries		
	Additions, Extensions and Discoveries	18,349
Acquisitions of Reserves		
	PW of Changes in WI (Int. Acq'd or Disp.)	771
Dispositions of Reserves		
	PW of Changes in WI (Int. Acq'd or Disp.)	-1,438
Net Change Resulting from Revisions in Quantity Estimates		
	Revision of Quantity Estimates	-5,396
Accretion of Discount		1,502
Net Change in Royalty Tax Credits		95
Net Change In Income Tax		0
Timing and Miscellaneous Changes		
	Misc Changes	867
Estimated Future Net Revenue at End of Year		
	December 31, 2005 Corporate Evaluation (After Credits and Before Income Tax)	26,402
Actual Income Tax Calculated for December 31, 2005 Corporate Evaluation		0
Estimated Future Net Revenue at End of Year		
	December 31, 2005 Corporate Evaluation (After Credits and After Income Tax)	26,402

NI 51-101 TABLE 9-A
GRAND BANKS ENERGY CORPORATION
TOTAL PROVED RESERVES
PRODUCTION AND CASH FLOW FORECASTS
CAPITAL SCHEDULE
FORECAST PRICES AND COSTS - PLA DECEMBER 31, 2005 PRICES
EFFECTIVE DATE: DECEMBER 31, 2005

	CAPITAL COSTS	
	UNDISCOUNTED M$	DISCOUNTED @ 10% M$
2006	2885	2837
2007	0	0
2008	0	0
2009	0	0
2010	0	0
2011	0	0
2012	0	0
2013	0	0
2014	0	0
2015	0	0
SUB.	2885	2837
REM.	0	0
TOTAL	2885	2837

NI 51-101 TABLE 9-B
GRAND BANKS ENERGY CORPORATION
TOTAL PROVED PLUS PROBABLE RESERVES
PRODUCTION AND CASH FLOW FORECASTS
CAPITAL SCHEDULE
FORECAST PRICES AND COSTS - PLA DECEMBER 31, 2005 PRICES
EFFECTIVE DATE: DECEMBER 31, 2005

	CAPITAL COSTS	
	UNDISCOUNTED M$	DISCOUNTED @ 10% M$
2006	10216	9873
2007	58	50
2008	0	0
2009	0	0
2010	0	0
2011	0	0
2012	0	0
2013	0	0
2014	0	0
2015	0	0
SUB.	10274	9923
REM.	0	0
TOTAL	10274	9923

NI 51-101 TABLE 9-C
GRAND BANKS ENERGY CORPORATION
TOTAL PROVED RESERVES
PRODUCTION AND CASH FLOW FORECASTS
CAPITAL SCHEDULE
CONSTANT PRICES AND COSTS - DECEMBER 31, 2005 PRICES
EFFECTIVE DATE: DECEMBER 31, 2005

	CAPITAL COSTS	
	UNDISCOUNTED M$	DISCOUNTED @ 10% M$
2006	2885	2837
2007	0	0
2008	0	0
2009	0	0
2010	0	0
2011	0	0
2012	0	0
2013	0	0
2014	0	0
2015	0	0
SUB.	2885	2837
REM.	0	0
TOTAL	2885	2837

NI 51-101 TABLE 9-D
GRAND BANKS ENERGY CORPORATION
TOTAL PROVED PLUS PROBABLE RESERVES
PRODUCTION AND CASH FLOW FORECASTS
CAPITAL SCHEDULE
CONSTANT PRICES AND COSTS - DECEMBER 31, 2005 PRICES
EFFECTIVE DATE: DECEMBER 31, 2005

	CAPITAL COSTS	
	UNDISCOUNTED M$	DISCOUNTED @ 10% M$
2006	10216	9873
2007	58	50
2008	0	0
2009	0	0
2010	0	0
2011	0	0
2012	0	0
2013	0	0
2014	0	0
2015	0	0
SUB.	10273	9922
REM.	0	0
TOTAL	10273	9922

NI 51-101 TABLE 10-A
GRAND BANKS ENERGY CORPORATION
TOTAL PROVED RESERVES
PRODUCTION AND CASH FLOW FORECASTS
ABANDONMENTS SCHEDULE
FORECAST PRICES AND COSTS - PLA DECEMBER 31, 2005 PRICES
EFFECTIVE DATE: DECEMBER 31, 2005

ABANDONMENT COSTS

	UNDISCOUNTED M$	DISCOUNTED @ 10% M$
2006	14	13
2007	34	30
2008	7	5
2009	127	91
2010	40	26
2011	29	17
2012	79	42
2013	30	15
2014	0	0
2015	48	19
SUB.	409	260
REM.	243	62
TOTAL	652	322

NI 51-101 TABLE 10-B
GRAND BANKS ENERGY CORPORATION
TOTAL PROVED PLUS PROBABLE RESERVES
PRODUCTION AND CASH FLOW FORECASTS
ABANDONMENTS SCHEDULE
FORECAST PRICES AND COSTS - PLA DECEMBER 31, 2005 PRICES
EFFECTIVE DATE: DECEMBER 31, 2005

ABANDONMENT COSTS

	UNDISCOUNTED M$	DISCOUNTED @ 10% M$
2006	0	0
2007	49	42
2008	7	5
2009	22	16
2010	106	69
2011	63	37
2012	73	39
2013	38	18
2014	47	21
2015	110	44
SUB.	514	292
REM.	650	128
TOTAL	1163	420

NI 51-101 TABLE 10-C
GRAND BANKS ENERGY CORPORATION
TOTAL PROVED RESERVES
PRODUCTION AND CASH FLOW FORECASTS
ABANDONMENTS SCHEDULE
CONSTANT PRICES AND COSTS - DECEMBER 31, 2005 PRICES
EFFECTIVE DATE: DECEMBER 31, 2005

	ABANDONMENT COSTS	
	UNDISCOUNTED M$	DISCOUNTED @ 10% M$
2006	38	36
2007	34	30
2008	7	5
2009	96	69
2010	37	24
2011	26	16
2012	70	38
2013	26	13
2014	0	0
2015	40	16
SUB.	375	247
REM.	183	47
TOTAL	558	294

NI 51-101 TABLE 10-D
GRAND BANKS ENERGY CORPORATION
TOTAL PROVED PLUS PROBABLE RESERVES
PRODUCTION AND CASH FLOW FORECASTS
ABANDONMENTS SCHEDULE
CONSTANT PRICES AND COSTS - DECEMBER 31, 2005 PRICES
EFFECTIVE DATE: DECEMBER 31, 2005

	ABANDONMENT COSTS	
	UNDISCOUNTED M$	DISCOUNTED @ 10% M$
2006	24	23
2007	48	42
2008	7	5
2009	21	15
2010	73	48
2011	57	34
2012	65	35
2013	33	16
2014	40	18
2015	92	37
SUB.	460	272
REM.	461	94
TOTAL	921	365

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Proved Undeveloped Reserves

Undeveloped reserves are attributed by PLA in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

OTHER OIL AND GAS INFORMATION

Principal Properties

The following is a description of the Company's principal oil and natural gas properties as at December 31, 2005. Reserve amounts are stated at December 31, 2005 and are based on forecast prices and costs assumptions as evaluated in the PLA Report.

All the properties described below are located in Western Canada and are within the Canadian provinces of Alberta, Saskatchewan and Manitoba. The properties identified below represent 78 per cent of the total proved plus probable reserves assigned by PLA in the PLA Report.

	Production and Reserves		
Property	2005 Production (BOE/d)	Proved Reserves (MBOE)	Proved Plus Probable Reserves (MBOE)
Kingsford, Saskatchewan	95	487	806
Sinclair, Manitoba	24	115.3	487.2
Wood River, Alberta	6	43.7	149.5
Virginia Hills, Alberta	421	25.2	29.1
Berland River West, Alberta	43	42.7	61.5

Kingsford

The Kingsford property is located in Saskatchewan. The Company is the operator and owns an average land interest of 59 % percent. During 2005, net production from the area averaged 95 BOE/d. PLA has assigned net proved reserves of 487 MBOE and proved plus probable reserves of 806 MBOE which represents 41 % of the total proved plus probable reserves.

Sinclair

The Sinclair property is located in Manitoba. The Company is the operator and owns an average land interest of 93 % percent. During 2005, net production from the area averaged 24 BOE/d (production commenced January 2005). PLA has assigned net proved reserves of 115.4 MBOE and proved plus probable reserves of 487.2 MBOE which represents 25 % of the total proved plus probable reserves.

Wood River

The Wood River property is located in Alberta. This property is operated by the Company in some wells and another company in others. The Company owns an average land interest of approximately 21 % percent. During 2005, net production from the area averaged 6 BOE/d (most production came on in December 2005). PLA has assigned net proved reserves of 43.7 MBOE and proved plus probable reserves of 149.5 MBOE which represents 8 % of the total proved plus probable reserves

Virginia Hills

The Virginia Hills property is located in Alberta. The Company is the operator and owns an average land interest of 89 % percent. During 2005, net production from the area averaged 421 BOE/d (production commenced in March 2005). PLA has assigned net proved reserves of 25.2 MBOE and proved plus probable reserves of 29.1 MBOE which represents 1.5 % of the total proved plus probable reserves.

Berland River West

The Berland River West property is located in Alberta. This property is operated by another company. The Company owns an average land interest of 9.375% percent. During 2005, net production from the area averaged 43 BOE/d. PLA has assigned net proved reserves of 42.7 MBOE and proved plus probable reserves of 61.5 MBOE which represents 3 % of the total proved plus probable reserves.

Oil and Gas Wells

All wells in which the Company has an interest are located in Canada. The following table sets forth the number and status of oil and natural wells in which the Company had a working interest as at December 31, 2005.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
Province	Gross	Net	Gross	Net	Gross	Net	Gross	Net
British Columbia	0	0	0	0	0	0	1	0.1
Alberta	7	1.3	3	1.2	19	6.0	13	2.6
Saskatchewan	21	6.1	7	2.3	0	0	0	0
Manitoba	5	5.0	2	2.0	0	0	0	0
Total	33	12.4	12	17.5	19	6	14	1.7

Properties with No Attributed Reserves

The following table sets out the Company's undeveloped land holdings as at December 31, 2005.

	Acres	
	Gross	Net
Alberta	28,342	6,706
British Columbia	14,190	1,518
Manitoba	16,959	15,680
Saskatchewan	3,755	3,362
	63,246	27,266

Forward Contracts

The Company has not entered into financial or physical hedges in respect of commodity prices or foreign exchanges rates at this time.

Additional Information Concerning Abandonment and Reclamation Costs

The Company has sufficient resources to meet these obligations. The December 31, 2005 Reserve Report has included estimated abandonment costs but it does not include $514,000 (December 31, 2004, $259,000) of undiscounted costs related to the eventual site reclamation of the properties.

Tax Horizon

Grand Banks Energy Corporation has approximately $43 million of tax pools available for future deduction. The Company does not expect to pay income taxes at any time in the foreseeable future based on the estimated net futures revenues based on the PLA Report effective December 31, 2005.

Capital Expenditures

The following table summarizes capital expenditures related to the Company's activities for the year ended December 31, 2005.

	2005 ($' 000)
Land Costs	$ 1,300
Geological and Geophysical Costs	805
Drilling and Completion Costs	18,320
Equipment and Gathering Costs	2,842
Capitalized G&A Costs	178
Office Equipment Costs	11
Total	$ 23,456

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells that the Company participated in during the year ended December 31, 2005.

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Oil	2.0	1.2	16.0	12.1
Natural gas	2.0	0.7	3.0	0.8
Dry	12.0	5.7	1.0	0.8
Total	16.0	7.6	20.0	13.7

Production Estimates

The following table sets out the volume of the Company's production estimated for the year ended December 31, 2006 which is the first year of the estimate of future net revenue disclosed in the tables contained herein.

Forecast Production Estimates - 2006	Light and Medium Oil		Natural Gas		Natural Gas Liquids		BOE	
Reserves Category	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	(bbl/d)	*(bbl/d)*	*(Mcf/d)*	*(Mcf/d)*	*(bbl/d)*	*(bbl/d)*	*(BOE/d)*	*(BOE/d)*
Proved Developed Producing	409	348	1393	939	18	11	659	515
Proved Developed Non-Producing	36	34	399	309	3	2	65	51
Total Proved	445	382	1792	1248	21	13	724	566
Probable Additional	173	154	360	262	6	4	279	239
Total Proved plus Probable	618	536	2152	1510	27	17	1003	805

The production estimates shown above include the following significant properties.

Forecast Production Estimates - 2006 Significant properties (included above)	Light and Medium Oil		Natural Gas		Natural Gas Liquids		BOE	
Reserves Category	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	(bbl/d)	*(bbl/d)*	*(Mcf/d)*	*(Mcf/d)*	*(bbl/d)*	*(bbl/d)*	*(BOE/d)*	*(BOE/d)*
Total Proved								
Kingsford	279	234	0	0	0	0	279	234
Virginia Hills	0	0	361	222	8.5	5	69	42
Total Proved plus Probable								
Kingsford	354	297	132	111	0	0	376	316
Virginia Hills	0	0	406	248	9.5	5.6	77	47

Production History

The following table summarizes certain information in respect of the Company's production, product prices received, royalties paid, operating expenses and the resulting netback for the periods indicated below:

BOE at (6:1)	Quarter Ended 2005 Mar. 31	June 30	Sept. 30	Dec. 31	Year Ended 2005
Average Daily Production					
Light, Medium Oil and NG Liquids (bbl/d)	98	180	227	522	258
Natural Gas (Mcf/d)	2224	5653	4755	2690	3834
Royalty Production (BOE/d)	4	1	1	0	2
Combined (BOE/d)	473	1123	1021	970	898
Average Production Prices Received					
Light, Medium Oil and NG Liquids ($/bbl)	$52.79	$51.82	$60.38	$57.34	$56.63
Natural Gas ($/Mcf)	$7.02	$7.37	$8.74	$11.60	$8.50
Combined ($/BOE)	$41.97	$45.48	$54.23	$63.01	$52.61
Royalties Paid					
Combined ($/BOE)	$10.59	$11.88	$15.91	$17.34	$14.35
Operating Costs					
Combined ($/BOE)	$7.84	$4.73	$6.21	$7.04	$6.18
Netback Received					
Combined ($/BOE)	$25.91	$28.87	$32.11	$38.63	$32.08

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REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR AND AUDITOR
FORM 51-101F2

Terms to which a meaning is ascribed in National Instrument 51-101 have the same meaning herein.

To the Board of Directors of Grand Banks Energy Corporation (the "Company"):

1. We have evaluated and audited the Company's reserves data as at December 31, 2005. The reserves data consist of the following:

   (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2005 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, 2005 using constant prices and costs; and
   (ii) the related estimated future net revenue.

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

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

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

4. The following table sets forth the estimated future net revenue, (before the deduction of income taxes), attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated and audited by us for the year ended December 31, 2005, and identifies the respective portions thereof that we have evaluated and audited and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation/Audit Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue ($thousands - before taxes, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
Paddock Lindstrom & Associates Ltd.	February 28, 2006	Canada	nil	41,275.0	nil	41,275.0

5. In our opinion, the reserves data respectively evaluated and audited by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

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

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

Executed as to our report referred to above:

Paddock Lindstrom & Associates Ltd.
Calgary, Alberta, Canada

Execution Date: February 28, 2006

L.K. Lindstrom, P.Eng.
President

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REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA
AND OTHER INFORMATION (NI 51-101 F3)

Management of Grand Banks Energy Corporation (the Company) is 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 consists of the following:

(a) (i) proved and probable oil and gas reserves estimated as at December 31, 2005 using forecast prices and costs; and
(ii) the related estimated future net revenue; and

(b) (i) proved oil and gas reserves quantities, estimated as at December 31, 2005 using constant prices and costs; and
(ii) the related standardized measure of discounted future net cash flows from oil and gas reserve quantities.

An independent qualified evaluator has evaluated the Company's reserves data. The report of the independent qualified reserve evaluator is presented below.

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 evaluator;
(b) met with the independent qualified evaluator to determine whether any restrictions affected the ability of the independent qualified evaluator to report without reservation; and
(c) Reviewed the reserves data with management and the independent qualified 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 filings with securities regulatory authorities of the reserves 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 "Edward C. McFeely"

Edward C. McFeely
President & Chief Executive Officer

Signed "Thomas Bamford"

Thomas Bamford P.Eng.
Director & Chairman Reserves Committee

Signed " Keith Wilford"

Keith Wilford P.Eng.
Vice President Operations

Signed "Kenneth Hayes"

Kenneth Hayes P.Geo.
Director & Member of the Reserves Committee

GRAND BANKS ENERGY CORPORATION

For Immediate Release ("GBE" – TSX-V)

Grand Banks Announces 2005 Results

Calgary, Alberta – April 10, 2006

Grand Banks Energy Corporation (the 'Company') is pleased to announce its financial and operating results for the year ended December 31, 2005.

Highlights:

- Increased average sales volumes to 898 boe per day or 491%
- Increased undeveloped landholdings to approximately 27,000 net acres
- Increased corporate proved plus probable reserves to 1.956 million boe

	Year ended December 31		
	2005	2004	% Change
Average Sales Volumes:			
Natural gas – mcf/day	3,834	457	739
Crude oil & liquids – bbls/day	258	68	279
Sales volumes – boe/day	898	152	491
Financial Results (Canadian $000's)			
Gross revenues	$ 17,377	$ 2,590	571
Net Income	$ 930	$ 999	(7)
Funds generated from operations	$ 9,066	$ 652	1,290
Capital expenditures	$ 22,255	$ 13,101	70
Working capital	$ 1,777	$ 3,802	(53)
Flow-through share obligations	$ 6,740	$ 5,000	35
Total assets	$ 42,336	$ 24,647	72

Grand Banks has undergone very significant growth in production volumes for 2005. Successful drilling has increased average corporate production to 898 boe/day in 2005 compared to 152 boe/day in 2004. Natural gas volumes averaged 3,834 mcf/day compared to 457 mcf/day in 2004 primarily from positive drilling results in Alberta. Crude oil and liquids volumes averaged 258 bbls/day in 2005 compared to an average of 68 bbls/day in 2004 due to new wells at Kingsford in Saskatchewan and Sinclair in Manitoba.

Grand Banks has increased its undeveloped landholdings to over 27,000 net acres, of which 20,000 net acres are located in the Williston Basin, a light oil prone area located in southeast Saskatchewan and Manitoba.

Operationally, in March, 2006, Grand Banks and its partners have abandoned the deeper portion of the previously announced Brazeau area Nisku exploratory test. However, discussions are underway on a completion program to test two up-hole gas-bearing zones identified during drilling. Field work is nearly complete at Kingsford, Saskatchewan where 6 new wells have been flow-lined into an upgraded central battery facility and tied into a sales pipeline. Minimal production disruptions are anticipated over spring breakup. In Sinclair, Manitoba, Grand Banks has 13 (12.8 net) wells on production at approximately 120 bopd. Road bans are now in place, and many of these wells will be shut in until bans are lifted in about six weeks. The winter drilling program on the Sinclair Bakken/Three Forks play has identified areas of substantial development potential upon the extensive land holdings Grand Banks has in the area. License applications are being submitted for our second quarter drilling program where we intend to drill a number of horizontal wells.

On our southeast Saskatchewan Joint Venture lands, we are preparing two horizontal wells targeting light oil within the Middle Bakken resource play fairway offsetting a competitor's production in the Stoughton area. These wells will be drilled as soon as weather permits. Drilling operations are ongoing and ahead of schedule at the Grand Banks et al Tower Creek 2-21-55-27W5M location, a 5,000 meter Leduc test located near Hinton, Alberta, where Grand Banks holds a 16.67% working interest. This 3D seismically defined prospect has the potential to add over 500 boe/d of net sales volumes to Grand Banks Energy Corporation, if successful, based on analogous wells.

For a copy of Grand Bank's 2005 financial statements, management discussion and analysis and reserve filing please visit www.sedar.com.

Grand Banks is listed on the TSX-Venture Exchange under the Symbol GBE.

For further information please contact:

Grand Banks Energy Corporation
1600, 444 – 5th Avenue S.W.
Calgary, Alberta T2P 2T8
Phone: (403) 262-8666
Fax: (403) 262-8796

E.C. (Ted) McFeely
Chairman, President and Chief Executive Officer

FORWARD LOOKING STATEMENTS

This press release contains forward-looking statements including expectations of future production. These statements are based on current expectations that involve a number of risks and uncertainties, which could cause actual results to differ from those anticipated

BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

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GLOBAL corporate compliance

April 11, 2006

Alberta Securities Commission
British Columbia Securities Commission

TSX Venture Exchange

Attention: Continuous Disclosure

Dear Sirs:

Re: Grand Banks Energy Corporation

On behalf of our above captioned client, we wish to confirm the following dates regarding their upcoming meeting:

MEETING TYPE	Annual General
DATE OF MEETING	June 6, 2006
MEETING LOCATION	Calgary, AB
CLASS OF SECURITIES ENTITLED TO RECEIVE NOTICE	Common
CLASS OF SECURITIES ENTITLED TO VOTE	Common
CUSIP NO	38522T-105
RECORD DATE FOR NOTICE	May 2, 2006
RECORD DATE FOR VOTING	May 2, 2006
BENEFICIAL OWNERSHIP DETERMINATION DATE	May 2, 2006
MATERIAL MAIL DATE	May 10, 2006

Yours truly,
GLOBAL CORPORATE COMPLIANCE INC.

"Brenda Davis"

Brenda Davis
Associate

cc Grand Banks Energy Corporation
Computershare Trust Company of Canada (for your information only)