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REGISTRANT'S NAME Highpine Oil & Gas Limited

*CURRENT ADDRESS Suite 2200
500 - 4th Avenue S.W.
Calgary, Alberta, T2P 2V6
Canada

**FORMER NAME

**NEW ADDRESS

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No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise. This prospectus constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. These securities have not been and will not be registered under the United States Securities Act of 1933, as amended (the "1933 Act"), or any state securities laws. Accordingly, except as permitted by the Underwriting Agreement (as defined below) and pursuant to an exemption from the registration requirements of the 1933 Act and state securities laws, these securities may not be offered or sold within the United States or to, or for the account or for the benefit of, a U.S. Person (as such term is defined in Regulation S under the 1933 Act) and this prospectus does not constitute an offer to sell or a solicitation of an offer to buy any of these securities within the United States. See "Plan of Distribution – Public Offering".

Initial Public Offering ARLS 12-31-03 **March 24, 2005**

PROSPECTUS

HIGHPINE
OIL & GAS LIMITED

$72,000,000

4,000,000 Common Shares

and

3,455,105 Common Shares Issuable Upon the Exercise of 3,300,000 Special Warrants

This prospectus qualifies the distribution of 4,000,000 common shares ("**Common Shares**") of Highpine Oil & Gas Limited ("**Highpine**" or the "**Corporation**") at a price of $18.00 per Common Share (the "**Offering**"). **There is presently no market through which the Common Shares may be sold and purchasers may not be able to resell the Common Shares purchased under this prospectus.** The Corporation has applied to list the Common Shares distributed under this prospectus on the Toronto Stock Exchange (the "**TSX**"). Listing will be subject to the Corporation fulfilling all of the listing requirements of the TSX. The offering price of the Common Shares offered under this prospectus was determined by negotiation between the Corporation and the Underwriters (as defined below).

Price: $18.00 per Common Share

	Price to the Public	**Underwriters' Fee**	**Net Proceeds to the Corporation (1)**
Per Common Share	$18.00	$0.99 (2)	$17.01
Total Offering	$72,000,000	$3,742,200 (2)	$68,257,800

Notes:

(1) Before deducting expenses of the Offering estimated to be $600,000, which, together with the Underwriters' fee, will be paid from the general funds of the Corporation.

(2) The Underwriters' fee of $0.99 per Common Share is only payable in respect of 3,780,000 of the Common Shares and accordingly, the aggregate commission paid will be $3,742,200.

This prospectus also qualifies the distribution of 3,455,105 Common Shares (issuable for no additional consideration), upon the exercise of 3,300,000 special warrants (the "**Special Warrants**") issued by the Corporation on October 20, 2004 at a price of $9.00 per Special Warrant. The Special Warrants were issued under and are governed by a special warrant indenture, dated as of October 20, 2004 (the "**Special Warrant Indenture**"), between the Corporation and Valiant Trust Company, as trustee (the "**Trustee**").

Tristone Capital Inc., FirstEnergy Capital Corp., BMO Nesbitt Burns Inc., RBC Dominion Securities Inc. and GMP Securities Ltd. (collectively, the "**Underwriters**"), as principals, conditionally offer the Common Shares, subject to prior sale, if, as and when issued by the Corporation and delivered to and accepted by the Underwriters in accordance with the conditions contained in the Underwriting Agreement referred to under "Plan of Distribution – Public Offering" and subject to the approval of certain legal matters relating to the Offering on behalf of the Corporation by Burnet, Duckworth & Palmer LLP and on behalf of the Underwriters by Bennett Jones LLP. Subscriptions for Common Shares will be received subject to rejection or allotment in whole or in part and the right is reserved to close the subscription books at any time without notice.

It is expected that closing of the Offering will occur on or about April 5, 2005 or such other date, not later than April 19, 2005, as the Corporation and the Underwriters may agree. Definitive certificates representing the Common Shares will be available for delivery at closing of the Offering. Subject to applicable laws, the Underwriters may, in connection with the Offering, effect transactions which stabilize or maintain the market price of the Common Shares at levels other than those which might otherwise prevail on the open market. See "Plan of Distribution – Public Offering".

The Special Warrants were sold to investors pursuant to prospectus exemptions under applicable securities legislation pursuant to an agency agreement dated effective as of September 21, 2004 (the "**Agency Agreement**") between Highpine and FirstEnergy Capital Corp. and Tristone Capital Inc. (collectively, the "**Special Warrant Agents**"). The gross proceeds received by the Corporation from the sale of the Special Warrants were $29,700,000. The Special Warrant Agents received a fee equal to 5.5% of the gross proceeds from the sale of the Special Warrants, for an aggregate fee of $1,633,500. No commission or fee will be payable to the Special Warrant Agents or otherwise by the Corporation in connection with the distribution of the Common Shares upon exercise of the Special Warrants. The issue price of $9.00 per Special Warrant was determined by negotiation between the Corporation and the Special Warrant Agents. See "Plan of Distribution – Special Warrant Offering".

Each Special Warrant entitles the holder thereof to acquire 1.047 Common Shares (subject to adjustment as provided for pursuant to the terms of the Special Warrant Indenture) at no additional cost, at any time until 4:30 p.m. (Calgary time) (the "**Expiry Time**") on that date which is five business days following the date (the "**Clearance Date**") upon which a receipt for the final version of this prospectus is issued by each of the securities commissions in the provinces of Alberta, British Columbia and Ontario (individually, a "**Filing Province**" and collectively, the "**Filing Provinces**"). Any Special Warrants not exercised prior to the Expiry Time shall be deemed, by their terms, to have been exercised immediately prior to the Expiry Time without any further action on the part of the holder. See "Plan of Distribution – Special Warrant Offering".

If a receipt for the final version of this prospectus has not been obtained dated on or prior to 4:30 p.m. (Calgary time) on October 20, 2005 (the "**Clearance Deadline**") from the securities commissions in each of the Filing Provinces, then each holder of Special Warrants in a Filing Province in which such a receipt has not been so obtained (or, in the case of holders of Special Warrants resident outside of the Filing Provinces, if a receipt has not been obtained in the Province of Alberta) shall be entitled to receive, upon exercise or deemed exercise of the Special Warrants at any time after the Clearance Deadline, 1.152 Common Shares for each of such holder's Special Warrants (in lieu of the 1.047 Common Shares that each Special Warrant was previously exercisable for) subject to adjustment in certain events without the payment of any additional consideration. Definitive certificates for the Common Shares issuable upon exercise of the Special Warrants will be available for delivery within five business days from the exercise of the Special Warrants. See "Plan of Distribution – Special Warrant Offering".

RBC Dominion Securities Inc., one of the Underwriters, is a wholly owned subsidiary of a Canadian chartered bank that is a lender to Highpine and to which Highpine is presently indebted. Consequently, Highpine may be considered to be a "connected issuer" of RBC Dominion Securities Inc. under applicable Canadian securities laws. Highpine will initially use the net proceeds of the Offering to repay a portion of its indebtedness to such bank. See "Relationship Between Highpine's Banker and an Underwriter" and "Use of Proceeds".

An investment in and ownership of the Common Shares should be considered speculative due to the nature of the Corporation's involvement in the exploration for, and the acquisition, development and production of, oil and natural gas reserves. The Corporation's business is subject to the risks normally encountered in the oil and natural gas industry. There is currently no market through which the Common Shares or the Special Warrants may be sold and purchasers may not be able to resell the Common Shares purchased under this prospectus. See "Risk Factors".

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ELIGIBILITY FOR INVESTMENT

In the opinion of Burnet, Duckworth & Palmer LLP and Bennett Jones LLP (collectively, "**Counsel**"), subject to the provisions of any particular plan, provided the Common Shares are listed on a prescribed stock exchange (which includes the TSX) at the relevant time, the Common Shares, when issued, will be qualified investments, within the meaning of the Tax Act, for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans and registered education savings plans and will not constitute "foreign property" under the Tax Act and the regulations thereunder for persons subject to tax under Part XI of the Tax Act.

In the opinion of Counsel, subject to compliance with the prudent investment standards and the general investment provisions of the following statutes (and, where applicable, the regulations thereunder) and, in certain cases, subject to the satisfaction of additional requirements relating to investment or lending policies, procedures or goals and, in certain circumstances, the filing of such policies, procedures and goals, the Common Shares offered hereunder are not, at the date hereof, precluded as investments under or by the following statutes:

Insurance Companies Act (Canada);
Trust and Loan Companies Act (Canada);
Pension Benefits Standards Act, 1985 (Canada);
Cooperative Credit Associations Act (Canada);
Financial Institutions Act (British Columbia);
Pension Benefits Standards Act (British Columbia);
Loan and Trust Corporations Act (Alberta);
Insurance Act (Alberta);
Employment Pension Plans Act (Alberta);
Alberta Heritage Savings Trust Fund Act (Alberta);
The Pension Benefits Act, 1992 (Saskatchewan);
The Trustee Act (Manitoba);
The Insurance Act (Manitoba);
The Pension Benefits Act (Manitoba);
Pension Benefits Act (Ontario);
Loan and Trust Corporations Act (Ontario);
Trustee Act (Ontario);
An Act respecting insurance (Québec)
(for an insurer, as defined therein, incorporated under the laws of the Province of Québec, other than guarantee fund corporations);
An Act respecting trust companies and savings companies (Québec)
(for a trust company, as defined therein, investing its own funds and funds received as deposits and a savings company, as defined therein, investing its own funds); and
Supplemental Pension Plans Act (Québec).

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements contained in this prospectus constitute forward-looking statements. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe" 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 such forward-looking statements. The Corporation believes that the expectations reflected in these forward-looking statements are based on reasonable assumptions but no assurance can be given that these expectations will prove to be correct and the forward-looking statements included in this prospectus should not be unduly relied upon. These statements speak only as of the date of this prospectus.

In particular, this prospectus contains forward-looking statements pertaining to the following:

- oil and natural gas production levels and the sources of their growth;
- capital expenditure programs;
- the estimated quantity of oil and natural gas reserves and recovery rates;
- projections of commodity prices and costs;
- supply and demand for oil and natural gas;
- planned construction and expansion of facilities;
- drilling plans;
- reserve life;
- plans for and results of exploration and development activities;
- expectations regarding the Corporation's ability to raise capital and to continually add to reserves through acquisitions, exploration and development; and
- treatment under governmental regulatory regimes and tax laws.

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 prospectus:

- general economic, market and business conditions;
- volatility in market prices for oil and natural gas;
- risks inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems;
- actions by governmental authorities, including increases in taxes;
- the availability of capital on acceptable terms;
- fluctuations in foreign exchange or interest rates and stock market volatility; and
- the other factors discussed under "Risk Factors" in this prospectus.

These factors should not be construed as exhaustive. The Corporation undertakes no obligation to update or revise any forward-looking statements except as required by applicable securities laws.

CERTAIN TAX CONSIDERATIONS

Prospective investors should be aware that the purchase of Common Shares has tax consequences which are not described in this prospectus. Accordingly, prospective investors are advised to consult their own tax advisors with respect to the tax aspects of investing in the Common Shares.

SUMMARY OF THE PROSPECTUS

The following is a summary of the principal features of this distribution and should be read together with the more detailed information and financial data and statements contained elsewhere in this prospectus. Reference is made to the Glossary for the definitions of certain terms with initial capital letters used in this prospectus and in this summary.

Highpine Oil & Gas Limited

Business

Highpine is an Alberta-based oil and natural gas corporation with an aggressive activity plan for future growth. Founded in April 1998, Highpine is engaged in the exploration for, and the acquisition, development and production of, natural gas and crude oil in western Canada. Highpine's business plan contemplates that the Corporation will pursue exploration, development and exploitation drilling, complemented with focused acquisitions. See "Highpine's Business".

Management and Directors

Highpine's directors and senior officers are as set out in the following table.

Name	Positions Held
A. Gordon Stollery	Chairman, President and Chief Executive Officer and Director
John A. Brussa	Director
Richard G. Carl	Director
Andrew Krusen	Director
Hank B. Swartout	Director
Greg N. Baum	Executive Vice President and Chief Operating Officer
Harry D. Cupric	Vice President, Finance and Chief Financial Officer
Vince L. Farkas	Vice President, Operations and Engineering
Wayne Gray	Vice President, Land
Doug McArthur	Vice President and Chief Geologist
Fred D. Davidson	Corporate Secretary

See "Directors and Officers"

The Offering

Offering

4,000,000 Common Shares.

Amount

$72,000,000

Price

$18.00 per Common Share.

Qualification for Distribution of Additional Securities

In addition to qualifying the distribution of 4,000,000 Common Shares in connection with the Offering, this prospectus also qualifies the distribution of 3,455,105 Common Shares to be issued, without additional consideration, upon the exercise of 3,300,000 previously issued Special Warrants of the Corporation. See "Plan of Distribution – Special Warrant Offering".

Closing

On or about April 5, 2005, and in any event not later than April 19, 2005. See "Plan of Distribution – Public Offering".

Use of Proceeds

The net proceeds to the Corporation from the sale of the Common Shares hereunder are estimated to be $67,657,800 after deducting the Underwriters' fee of $3,742,200 and the estimated expenses of the Offering of $600,000. The net proceeds of the Offering will be used by the Corporation to temporarily reduce bank indebtedness which will be redrawn and applied to fund the Corporation's ongoing exploration and development activities, and for general working capital purposes. In particular, the net proceeds will be used, together with cash flow

	and bank debt, to fund the Corporation's 2005 capital program, which contemplates aggregate expenditures of approximately $60 million. See "Use of Proceeds" and "Highpine's Business – Business Plan and Growth Strategies".
Eligibility for Investment	In the opinion of Counsel, subject to the provisions of any particular plan, provided the Common Shares are listed on a prescribed stock exchange (which includes the TSX) at the relevant time, the Common Shares, when issued, will be qualified investments, within the meaning of the Tax Act, for trusts governed by registered retirement savings plans, registered retirement income funds and registered education savings plans, and will not constitute "foreign property" under the Tax Act and the regulations thereunder for persons subject to tax under Part XI of the Tax Act. In the opinion of Counsel, based on the legislation in effect on the date of this prospectus, the Common Shares are eligible investments as set forth under the heading "Eligibility for Investment".

Summary Financial and Operational Information

Summary Financial Information

The following is a summary of selected financial information of the Corporation as at and for the periods indicated and should be read in conjunction with the financial statements of the Corporation and the notes to such financial statements included in this prospectus. See "Consolidated Financial Statements of Highpine Oil & Gas Limited".

	Nine Months Ended September 30, 2004	Years Ended December 31,		
		2003	2002	2001
	(unaudited)	(audited)	(audited)	(audited)
	$	$	$	$
Revenues, net of royalties	21,617,000	13,817,000	5,221,000	2,429,000
Operating expenses	4,603,000	2,294,000	1,367,000	935,000
Cash flow from operations (1)	13,518,000	11,616,000	3,130,000	889,000
Per Equity Share (basis)	0.90	0.80	0.24	0.07
Per Equity Share (diluted)	0.89	0.80	0.24	0.07
Net earnings	2,129,000	19,108,000	1,056,000	59,000
Per Equity Share (basis)	0.14	1.32	0.08	0.00
Per Equity Share (diluted)	0.14	1.31	0.08	0.00
Total assets	138,941,000	44,041,000	23,697,000	12,645,000
Working capital (deficiency), excluding current bank debt	(13,581,000)	5,258,000	(633,000)	3,015,000
Bank debt	46,729,000	–	–	–
Shareholders' equity	47,538,000	34,385,000	15,086,000	10,847,000

Note:

(1) "Cash flow from operations" is not a recognized measure under GAAP. See "Non-GAAP Measures".

Summary Production Information

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

	Nine Months Ended September 30, 2004	Years Ended December 31,		
		2003	2002	2001
Crude oil and NGL (bbls/d)	1,471	443	301	237
Natural gas (mcf/d)	6,301	4,281	1,809	545
Oil equivalent (boe/d)	2,521	1,157	603	328

See "Highpine's Business – Production History".

The following table summarizes Highpine's developed and undeveloped landholdings (in acres) as at January 14, 2005.

	Undeveloped	Developed	Total
Gross [(1)]	196,304	69,847	266,151
Net [(1)]	90,605	16,263	106,868

Note:
(1) "Gross" means the total number of acres in which Highpine has an interest and "Net" means the aggregate of the percentage working interests of Highpine in the Gross acres.

See "Highpine's Business – Landholdings".

Oil and Natural Gas Reserves

The tables below summarize Highpine's crude oil, NGL and natural gas reserves and the estimated present worth of future net cash flows associated with such reserves, as at December 31, 2004, as evaluated by Paddock in the Paddock Report (based on constant and forecast price assumptions) in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101 and the COGE Handbook. **All evaluations of future net cash flows are stated before and after the provision for income taxes and prior to indirect costs and after deduction of royalties, estimated future capital expenditures and well abandonment costs and after giving effect to ARTC. It should not be assumed that the present values of estimated future net cash flows shown below is representative of the fair market value of the crude oil, NGL and natural gas reserves. *There is no assurance that the price and cost assumptions used in estimating such future net cash flow will be consistent with actual prices and costs and variances could be material.* The recovery and reserve estimates of Highpine's crude oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGL and natural gas reserves may be greater than or less than the estimates provided herein.** See "Highpine's Business – Oil and Natural Gas Reserves."

Summary of Crude Oil, NGL and Natural Gas Reserves and Net Present Values of Estimated Future Net Revenue as of December 31, 2004 Based on Constant Price Assumptions

	Reserves							
	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids	
Reserves Category	Gross (mbbl)	Net (mbbl)	Gross (mbbl)	Net (mbbl)	Gross (mmcf)	Net (mmcf)	Gross (mbbl)	Net (mbbl)
Proved								
Developed Producing	1,463	1,129	680	581	12,420	9,944	518	390
Developed Non-Producing	1,171	870	95	80	4,397	3,514	312	235
Total Developed	2,634	1,999	775	662	16,817	13,458	830	625
Undeveloped	867	621	-	-	1,136	887	79	62
Total Proved	3,501	2,620	775	662	17,953	14,345	909	687
Probable	2,246	1,682	152	131	7,942	6,284	294	222
Total Proved Plus Probable	5,747	4,302	927	793	25,895	20,629	1,203	909

	Net Present Values of Future Net Revenue									
	Before Income Taxes Discounted at (%/year)					After Income Taxes Discounted at (%/year)				
Reserves Category	0	5	10	15	20	0	5	10	15	20
	(Thousands of Dollars)									
Proved										
Developed Producing	113,314	94,330	81,512	72,252	65,231	89,448	73,792	63,378	55,930	50,320
Developed Non-Producing	58,443	46,498	38,655	33,102	28,959	42,651	33,507	27,623	23,511	20,473
Total Developed	171,757	140,829	120,167	105,354	94,190	132,099	107,299	91,001	79,441	70,793
Undeveloped	23,590	18,016	14,282	11,601	9,588	11,793	8,591	6,404	4,815	3,612
Total Proved	195,347	158,845	134,449	116,956	103,778	143,892	115,890	97,405	84,255	74,404
Probable	104,270	73,208	55,733	44,674	37,106	69,485	48,337	36,525	29,076	23,990
Total Proved Plus Probable	299,617	232,053	190,182	161,630	140,884	213,377	164,227	133,930	113,331	98,395

Summary of Crude Oil, NGL and Natural Gas Reserves and Net Present Values of Estimated Future Net Revenue as of December 31, 2004 Based on Forecast Price Assumptions

	Reserves							
	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids	
Reserves Category	Gross (mbbl)	Net (mbbl)	Gross (mbbl)	Net (mbbl)	Gross (mmcf)	Net (mmcf)	Gross (mbbl)	Net (mbbl)
Proved								
Developed Producing	1,462	1,143	680	582	12,423	9,948	518	393
Developed Non-Producing	1,171	900	95	80	4,390	3,520	312	239
Total Developed	2,633	2,043	775	662	16,813	13,468	830	632
Undeveloped	867	642	-	-	1,136	890	80	63
Total Proved	3,500	2,685	775	662	17,949	14,358	910	695
Probable	2,239	1,751	144	125	7,954	6,300	292	224
Total Proved Plus Probable	5,739	4,436	919	787	25,903	20,658	1,202	919

	Net Present Values of Future Net Revenue									
	Before Income Taxes Discounted at (%/year)					After Income Taxes Discounted at (%/year)				
Reserves Category	0	5	10	15	20	0	5	10	15	20
	(Thousands of Dollars)									
Proved										
Developed Producing	97,087	82,927	73,085	65,800	60,157	78,217	66,007	57,664	51,568	46,893
Developed Non-Producing	51,245	41,264	34,678	29,985	26,460	34,438	27,246	22,632	19,400	17,000
Total Developed	148,332	124,191	107,763	95,785	86,617	112,655	93,252	80,296	70,968	63,893
Undeveloped	20,603	15,760	12,507	10,171	8,413	13,502	9,970	7,604	5,911	4,642
Total Proved	168,935	139,951	120,270	105,956	95,031	126,157	103,222	87,900	76,879	68,534
Probable	90,611	64,092	49,198	39,761	33,281	60,395	42,269	32,173	25,802	21,440
Total Proved Plus Probable	259,545	204,042	169,468	145,717	128,312	186,552	145,491	120,073	102,681	89,974

Summary of Risk Factors

Prospective investors should carefully consider the information set forth under the heading "Risk Factors" and other information set forth herein before deciding to invest in the Common Shares.

An investment in and ownership of Common Shares should be considered speculative due to the nature of the Corporation's involvement in the exploration for, and the acquisition, development and production of, oil and natural gas reserves. The Corporation's business is subject to the risks normally encountered in the oil and natural gas industry such as: the marketability of, and prices for, oil and natural gas; competition with companies having greater resources; acquisition, exploration and production risks; the need for capital; fluctuations in the market price and demand for oil and natural gas; and regulation of the oil and natural gas industry by various levels of government. The reserve and recovery information contained in this prospectus are estimates only and the actual production and ultimate reserves recovered from the Corporation's properties may be greater or less than the estimates contained in this prospectus. The success of further exploration or development projects cannot be assured. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation. There is currently no market through which the Common Shares or the Special Warrants may be sold and purchasers may not be able to resell the Common Shares purchased under this prospectus. See "Risk Factors".

GLOSSARY

In this prospectus, unless the context otherwise requires, the following words and terms shall have the meanings set forth below:

"**ABCA**" means the *Business Corporations Act* (Alberta), together with any amendments thereto and all regulations promulgated thereunder;

"**AEUB**" means the Alberta Energy and Utilities Board;

"**Agency Agreement**" means the agency agreement, dated effective as of September 21, 2004, between the Corporation and the Special Warrant Agents;

"**ARTC**" means Alberta Royalty Tax Credit;

"**Charter**" means Charter Land Services Ltd., independent consulting petroleum landmen, Calgary, Alberta;

"**Charter Reports**" means the independent evaluations, dated February 1, 2005, prepared by Charter in respect of undeveloped lands of each of HAC, Pino Alto and Highpine Partnership, effective January 14, 2005;

"**CICA**" means the Canadian Institute of Chartered Accountants;

"**Class B Shares**" means Class B common non-voting shares in the capital of Highpine;

"**Clearance Date**" means the date upon which a receipt for the final version of this prospectus is issued by or on behalf of the securities commissions in the Filing Provinces;

"**Clearance Deadline**" means 4:30 p.m. (Calgary time) on October 20, 2005;

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

"**Common Shares**" means Class A common voting shares in the capital of Highpine;

"**Corporation**" or "**Highpine**" means Highpine Oil & Gas Limited, a corporation incorporated pursuant to the ABCA and, unless the context otherwise requires, include HAC, Pino Alto, Rubicon and Highpine Partnership;

"**Easyford Battery**" means the sour oil processing battery located at 11-14-50-8 W5M, which is approximately 15 kilometres north of Drayton Valley, Alberta;

"**Economic Life**" means, with respect to an oil and natural gas property, the time remaining before production of Petroleum Substances from the property is forecast to be uneconomic under forecast cost and price assumptions;

"**Equity Shares**" means Common Shares and Series 1 Class B Shares;

"**Expiry Date**" means that date which is five business days following the date upon which a receipt for the final version of this prospectus is issued by or on behalf of the securities commission in each of the Filing Provinces;

"**Expiry Time**" means 4:30 p.m. (Calgary time) on the Expiry Date;

"**Filing Provinces**" means the provinces of Alberta, British Columbia and Ontario;

"**GAAP**" means Canadian generally accepted accounting principles;

"**HAC**" means Highpine Asset Corporation, a corporation incorporated pursuant to the ABCA;

"**Highpine Partnership**" means Highpine Oil & Gas Partnership, a general partnership organized under the laws of the Province of Alberta;

"**Joffre Gas Plant**" means the natural gas processing plant located at 6-17-40-27 W4M, which is approximately 30 kilometres north of Red Deer, Alberta;

"**NI 51-101**" means National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities adopted by the Canadian Securities Administrators;

"**Paddock**" means Paddock Lindstrom & Associates Ltd., independent petroleum consultants, Calgary, Alberta;

"**Paddock Report**" means the February 3, 2005 report prepared by Paddock, evaluating the crude oil, natural gas and NGL reserves of Highpine, as at December 31, 2004, in accordance with the standards contained in the COGE Handbook and the reserves definitions set out by the Canadian Securities Administrators in NI 51-101 and the COGE Handbook;

"**Petroleum Substances**" means petroleum, natural gas and related hydrocarbons, (including condensate and NGLs) and all other substances (including sulphur and its compounds), whether liquid, solid or gaseous and whether hydrocarbons or not, produced in association therewith;

"**Pino Alto**" means Pino Alto Energy II Ltd., a corporation incorporated pursuant to the ABCA;

"**Reserve Value**" means, for any petroleum and natural gas property at any time, the present worth of all of the estimated pre-tax net cash flow from the total proved plus probable reserves shown in the most recent engineering report relating to such property, discounted at 10% and using forecast price and cost assumptions (a common benchmark in the oil and natural gas industry).

"**Rubicon**" means Rubicon Energy Corporation, a corporation formed by amalgamation pursuant to the ABCA;

"**Rubicon Acquisition**" means the indirect acquisition by Highpine of an undivided 50% interest in all of the assets of Rubicon (and assumption of related liabilities) in March 2004, as more particularly described under "Highpine's Business – Rubicon Acquisition";

"**Rubicon Assets**" means Highpine's indirect undivided 50% interest in all of the assets and liabilities of Rubicon, which was acquired pursuant to the Rubicon Acquisition;

"**Seaton-Jordan**" means Seaton-Jordan & Associates Ltd., independent land evaluators, Calgary, Alberta;

"**Seaton-Jordan Report**" means the independent evaluation, dated February 4, 2005, prepared by Seaton-Jordon in respect of Highpine's undeveloped lands, effective January 14, 2005;

"**Series 1 Class B Shares**" means Class B common non-voting shares, Series 1, in the capital of Highpine;

"**Special Warrants**" means the 3,300,000 special warrants issued by the Corporation on October 20, 2004, at a price of $9.00 per special warrant, pursuant to the Special Warrant Indenture;

"**Special Warrant Agents**" means FirstEnergy Capital Corp. and Tristone Capital Inc.;

"**Special Warrant Indenture**" means the special warrant indenture, dated as of October 20, 2004, between the Corporation and the Trustee authorizing and governing the Special Warrants;

"**Special Warrant Offering**" means the private placement of 3,300,000 Special Warrants completed on October 20, 2004 (see "Plan of Distribution – Special Warrant Offering");

"**Stock Dividend**" means the stock dividend declared by the Corporation effective February 15, 2005 of 0.047 of a Common Share in respect of each issued and outstanding Common Share as at February 15, 2005. No fractional Common Shares were issued and in the case that the stock dividend resulted in a shareholder becoming entitled to receive 0.5 or more of a Common

Share, an adjustment was made to round up to the next number of whole Common Shares, and in the case that the stock dividend resulted in a shareholder becoming entitled to receive less than 0.5 of a Common Share, an adjustment was made to round down to the next number of whole Common Shares;

"**Tax Act**" means the *Income Tax Act* (Canada) R.S.C. 1985, c.1 (5th Supp.), as amended;

"**Trustee**" means Valiant Trust Company in its capacity as trustee under the Special Warrant Indenture;

"**TSX**" means the Toronto Stock Exchange;

"**Underwriting Agreement**" means the underwriting agreement, dated March 24, 2005 between the Corporation and the Underwriters, with respect to the Offering, as more particularly described under the heading "Plan of Distribution – Public Offering";

"**Underwriters**" means, collectively, Tristone Capital Inc., FirstEnergy Capital Corp., BMO Nesbitt Burns Inc., RBC Dominion Securities Inc. and GMP Securities Ltd.;

"**United States**" or "**U.S.**" means the United States of America; and

"**Violet Grove Battery**" means the sour processing battery located at 16-29-48-9 W5M, which is approximately 20 kilometres west of Drayton Valley, Alberta.

CONVENTIONS

Certain terms used herein are defined in the "Glossary". Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars. All financial information with respect to the Corporation has been presented in Canadian dollars in accordance with GAAP.

ABBREVIATIONS

Crude Oil and Natural Gas Liquids

bbl	one barrel
bbls	barrels
bbls/d	barrels per day
mbbls	thousand barrels
boe	barrels of oil equivalent of natural gas on the basis of 1 boe for 6 mcf of natural gas (unless otherwise indicated)
mboe	one thousand barrels of oil equivalent
mmboe	one million barrels of oil equivalent
boe/d	barrels of oil equivalent per day
NGL	natural gas liquids
stb	standard stock tank barrel

Natural Gas

mcf	one thousand cubic feet
mmcf	one million cubic feet
bcf	one billion cubic feet
mcf/d	one thousand cubic feet per day
mmcf/d	one million cubic feet per day
GJ	gigajoule
GJs/d	gigajoules per day
btu	British thermal unit
mmbtu	million British thermal units

Boes may be misleading, particularly if used in isolation. A boe conversion ratio of six mcf to one 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. This conversion factor is an industry accepted norm and is not based on either energy content or current prices.

Other

WTI	means West Texas Intermediate.
°API	means the measure of the density or gravity of liquid petroleum products derived from a specific gravity.
psi	means pounds per square inch.

Conversion

The following table sets forth certain standard conversions from Standard Imperial units to the International System of Units (or metric units).

To Convert From	To	Multiply By
mcf	thousand cubic metres ("10^3m^3")	0.0282
thousand cubic metres	mcf	35.494
bbls	cubic metres ("m^3")	0.159
cubic metres	bbls	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

NON-GAAP MEASURES

The terms "cash flow", "cash flow from operations", "funds flow from operations" and "operating netback" are not recognized measures under GAAP and do not have standardized meanings prescribed by GAAP. Management believes that in addition to net earnings, cash flow, cash flow from operations, funds flow from operations and operating netback are useful supplemental measures as they demonstrate the Corporation's ability to generate the cash necessary to repay debt or fund future growth through capital investment. Investors are cautioned, however, that these measures should not be construed as an alternative to net earnings determined in accordance with GAAP as an indication of Highpine's performance. Highpine's method of calculating these measures may differ from other companies and accordingly, they may not be comparable to measures used by other companies. For these purposes, Highpine defines "cash flow", "cash flow from operations" and "funds flow from operations" as cash provided by operations before changes in non-cash operating working capital and defines "operating netback" as revenue less royalties and operating expenses.

HIGHPINE OIL & GAS LIMITED

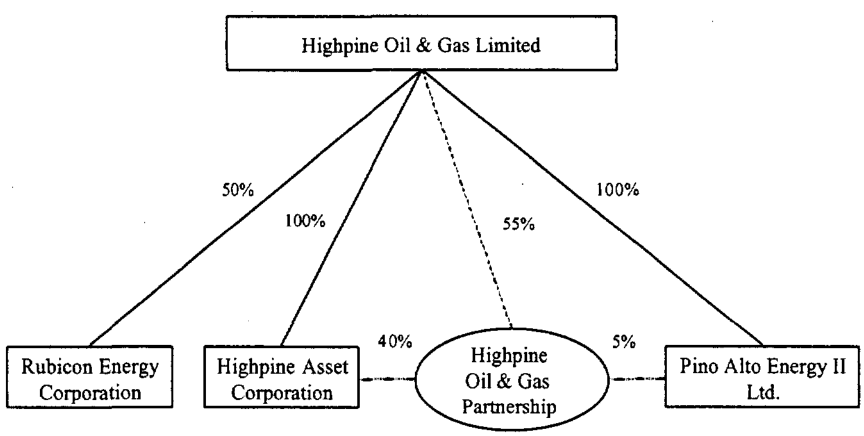
Highpine was incorporated under the name 779573 Alberta Inc. pursuant to the ABCA on April 2, 1998. On April 9, 1998, Highpine filed Articles of Amendment to change its name to Highpine Oil & Gas Limited. On December 14, 1999, Highpine filed Articles of Amendment to remove the "private company" provisions from its Articles. On December 23, 1999, Highpine filed Articles of Amendment to reorganize its share capital to provide for the issuance of an unlimited number of first preferred shares issuable in series and an unlimited number of second preferred shares issuable in series. On February 2, 2000, Highpine filed Articles of Amendment to reorganize its share capital to consist of an unlimited number of Common Shares and an unlimited number of Class B Shares, issuable in series. On February 17, 2000, Highpine filed Articles of Amendment to reorganize its share capital to fix the rights, privileges, restrictions and conditions of an initial series of 3,000,000 Class B Shares, designated as Series 1 Class B Shares. On February 18, 2000, Highpine filed Articles of Amendment to effect a split its then outstanding Common Shares on a 1.256440-for-one basis. On February 3, 2005, Highpine filed Articles of Amendment to amend the provisions of the Series 1 Class B Shares to provide for the automatic conversion of such shares into Common Shares on February 4, 2005. On February 7, 2005, Highpine filed Articles of Amendment to cancel the Series 1 Class B Shares. Unless otherwise stated, disclosure in this prospectus of the share capital of Highpine is presented after giving effect to the foregoing amendments to the Articles of Highpine.

Highpine's head office is located at Suite 2200, 500 – 4th Avenue S.W., Calgary, Alberta, T2P 2V6 and its registered office is located at Suite 1400, 350 – 7th Avenue S.W., Calgary, Alberta, T2P 3N9.

Highpine has two wholly-owned subsidiaries, Pino Alto and HAC, which were incorporated under the ABCA on April 12, 2000 and February 24, 2004, respectively. Highpine also owns 50% of the issued and outstanding common shares of Rubicon Energy Corporation ("**Rubicon**"), which was formed by Articles of Amalgamation filed pursuant to the ABCA on March 5, 2004. In addition, Highpine is the managing partner of Highpine Partnership, which was formed under the laws of Alberta pursuant to a partnership agreement, dated as of February 18, 2003, as amended, between the Corporation and Pino Alto (the "**Partnership Agreement**"). All of Highpine's assets have been contributed to Highpine Partnership with the exception of Highpine's Joffre area properties, which are held by Highpine, and its Pembina area properties, which are held by Highpine and HAC.

Unless the context otherwise requires, references herein to "Highpine" or the "Corporation" include Highpine, HAC, Pino Alto, Rubicon and Highpine Partnership.

The following diagram illustrates the corporate structure of the Corporation.



HIGHPINE'S BUSINESS

Highpine is an Alberta-based oil and gas corporation with an aggressive activity plan for future growth. The Corporation is engaged in the exploration for, and the acquisition, development and production of, natural gas and crude oil in western Canada. Highpine's business plan contemplates that the Corporation will pursue exploration, development and exploitation drilling, complemented with property or corporate acquisitions exhibiting synergy in lands, facilities, production and operating efficiencies. The vast majority of Highpine's current operations are in the Province of Alberta.

Business Plan and Growth Strategies

The business plan of Highpine will be to focus on sustainable and profitable growth in production, cash flow from operations and net asset value. To accomplish this, Highpine's management intends to pursue an integrated growth strategy, including exploration, development and exploitation drilling, complemented with acquisitions of properties in specific areas where further exploration, development or exploitation opportunities exist. Management believes that "full cycle" exploration and exploitation of oil and natural gas is the most efficient way to create "true" shareholder value (that is, generate significant rates-of-return on invested capital), in the current oil and natural gas environment. Management intends to internally generate exploration, development and exploitation opportunities, starting with thorough detailed regional mapping. Once trends and areas of interests have been established, Highpine will attempt to accumulate land in the applicable area by way of crown/freehold land acquisitions, industry farm-ins and joint ventures. To date, Highpine has chosen to concentrate its activities and focus to Alberta. Highpine's production is derived from the following three core operating and exploration areas:

Pembina/Nisku – Central Alberta:	These assets target oil and natural gas in the Nisku, Glauconitic, Rock Creek, Ellerslie and Pekisko zones.
Joffre/Gilby – Central Alberta:	These assets target natural gas and associated NGLs sands in the Edmonton, Belly River, Viking, Glauconitic and Ellerslie zones. In addition, Highpine is evaluating coal bed methane opportunities in this area.
Bantry/Retlaw – Southern Alberta:	These assets target lower risk oil and natural gas exploitation in the Mannville zone.

The Corporation also has interests in the following high risk prospect areas:

Sturgeon Lake – Central Alberta:	These assets target oil in the Leduc and Nisku zones.
Chambers – Central Alberta:	These assets target long-life natural gas reserves at drill depths of up to 3,600 metres in the Jurassic and Mississippian zones.

Highpine has production, shut-in volumes (including several oil and natural gas new pool discoveries) and an inventory of prospects in each of its core areas. Highpine's activities range from lower risk development to high risk exploration. Highpine maintains ownership and/or operatorship of the key facilities and infrastructure serving its core operating and exploration areas.

Highpine's prospect and drilling inventory contains some 70 locations on lands in which Highpine has a significant working interest and which have been geophysically and geologically evaluated. There are 50 "firm" and 9 "contingent" locations within the Pembina/Nisku trend. This inventory represents three years worth of drilling for Highpine at the current pace. Highpine's business plan includes the addition to and expansion of such prospect and drilling inventory with a focus on longer term sustainable and profitable growth.

In 2004, Highpine's net capital expenditures exceeded $116 million. The Corporation participated in the drilling of 54 gross wells (22.7 net) and realized an overall drilling success rate of 80%. In addition, the Rubicon Acquisition provided Highpine with significant production and landholdings and strategic facilities including a 25% ownership interest in the Easyford Battery. On December 14, 2004, Highpine received AEUB approval to expand the existing Violet Grove sour facility to a 15,000 bbls/d battery. On December 15, 2004, an oil and gas company filed a Notice of Objection with the AEUB requesting that the AEUB rescind the battery license that it had granted Highpine on December 14, 2004 to expand the Violet Grove sour facility. To date, the AEUB has not ruled on the merits of the objection. See "Risk Factors – Rescindment of Violet Grove Facility License" and "Legal Proceedings". Highpine participated in the construction of an 80 kilometre pipeline that connects the Easyford Battery with the Violet Grove Battery and will provide Highpine with take-away capacity for the sour solution gas which is a by-product of oil produced in the Nisku area. At Joffre/Gilby, Highpine completed construction of and commissioned the 100% owned and operated Joffre Gas Plant.

Highpine's capital budget for 2005 is approximately $60 million and includes the drilling of approximately of 40 gross wells (20 net). Of the total budget, approximately $15 million is allocated to development drilling, approximately $27 million is allocated to exploration drilling (including undeveloped land acquisition and seismic programs) and approximately $18 million is allocated to facilities and tie-ins. By area, approximately $46 million is allocated to Pembina/Nisku (including the drilling of 20 wells and the construction of associated treating and gas gathering and conditioning systems), approximately $6 million is allocated to Joffre/Gilby (including the drilling of 10 wells and the associated wellsite and gathering facilities), approximately $2 million is allocated to Bantry/Retlaw (including the drilling of three wells and the construction of associated well facilities and pipelines) and approximately $3 million is allocated to the higher risk prospect areas (including the drilling and completion of another well) with the remaining $3 million allocated to minor properties. This capital program will be funded through a combination of cash flow, bank debt and the net proceeds of the Offering. See "Use of Proceeds".

Historical Development of the Business

The following is a summary of significant events in the development of Highpine's business.

February 2000 – Highpine completed a private placement of 7,658,000 Common Shares for gross proceeds of approximately $7.7 million. Highpine invested $1.0 million of the equity proceeds into shares of Monolith Oil Corp. ("**Monolith**"), a private oil and gas company.

May 2000 – Highpine acquired a 40% interest in an oil property in the Bantry area in southern Alberta for approximately $3.2 million, after adjustments.

January 2002 – Highpine discovered the Ellerslie Gas channel at Joffre 4-16-40-27 W4M, which is located approximately 30 kilometres north of Red Deer, Alberta.

November 2002 – Highpine participated in the Pembina Nisku HH Pool discovery at 9-30-49-8 W5M, which is located approximately 10 kilometres west of Drayton Valley, Alberta. Highpine commenced an aggressive land acquisition strategy along the Nisku trend. Highpine's Joffre 4-16-40-27 W4M well commenced production at a rate of approximately seven mmcf/d.

March 2003 – Highpine participated in the Pembina Nisku II Pool discovery at 10-1-49-9 W5M, which is located approximately 15 kilometres west of Drayton Valley, Alberta.

September 2003 – Highpine sold its shares of Monolith for net proceeds of approximately $18 million.

March 2004 – Highpine indirectly acquired an undivided 50% interest in all of the assets and liabilities of Rubicon Energy Corporation ("**Rubicon**") for approximately $52 million including the assumption of liabilities. See "Highpine's Business – Rubicon Acquisition".

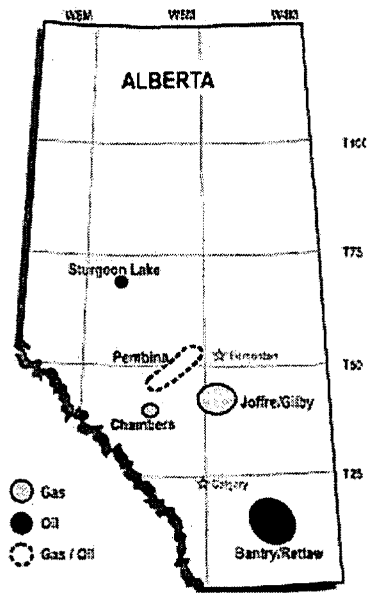
July 2004 – Highpine completed a private placement of 1,200,000 Common Shares, at a price of $5.00 per share, and 800,000 "flow-through" Common Shares, at a price of $6.00 per share, for aggregate gross proceeds of $10.8 million.

October 2004 – Highpine completed a private placement of 3,300,000 Special Warrants at a price of $9.00 per Special Warrant for aggregate gross proceeds of $29.7 million.

December 2004 – Highpine commissioned the Joffre Gas Plant, which is 100% owned and operated by Highpine and capable of processing in excess of 10 mmcf/d of raw natural gas. Highpine received AEUB approval to expand the existing Violet Grove sour facility to a 15,000 bbls/d battery in the Pembina area in which Highpine owns an approximate 55% interest. Construction of the Violet Grove Battery commenced in January 2005 and is expected to cost approximately $14 million. As at the date hereof, the Violet Grove Battery is approximately 50% built and is expected to be completed and commissioned in May 2005.

Principal Properties

The following is a description of Highpine's principal oil and natural gas properties and minor exploration properties as at December 31, 2004. The term "net", when used to describe Highpine's share of production, means Highpine's working interest share of production before deducting royalties owned by others. Unless otherwise specified, gross, net acres, well count and production information are as at December 31, 2004. Reserve amounts are stated (before deduction of royalties) as at December 31, 2004, based on escalating costs and price assumptions and are derived from reserve information contained in the Paddock Report. See "Highpine's Business – Oil and Natural Gas Reserves".



The following table summarizes certain production information for each of Highpine's principal properties for the periods indicated.

	Production (boe/d)		
	Average 2004	Exit 2004	First Week of February 2005
Pembina	1,380	1,500	1,700
Joffre/Gilby	700	1,000	1,100
Bantry/Retlaw	420	600	480
Other	160	300	320
	2,660	3,400	3,600

Pembina/Nisku – Central Alberta

The Pembina/Nisku property is located in the Drayton Valley area of Alberta approximately 100 kilometres southwest of Edmonton. The Pembina/Nisku property is Highpine's major property, producing approximately 1,700 boe/d, 83% of which is oil and NGL, and representing approximately 47% of Highpine's total production volumes. Highpine's property interests in Pembina/Nisku consist of working interests ranging from 10% to 100% and averaging 26% (reserves volume weighted). Highpine has an interest in 13 producing wells (2.6 net), one water disposal well (0.25 net) and 17 shut-in wells (6.6 net). The average Highpine working interest production from the property was 1,700 boe/d for the first week of February 2005. Highpine operates six wells associated with this property. In addition, Highpine has an average 40% working interest in two oil batteries. All of Highpine's on stream production is gathered in flowlines connecting wells to central batteries. At the central batteries, produced oil, natural gas and water is separated. All of the production is pipeline connected. Water is disposed of in water disposal wells.

The Pembina/Nisku property consists of 7,600 gross (2,200 net) acres of developed land and 76,400 gross (31,500 net) acres of undeveloped land.

The Paddock Report attributes proved plus probable reserves of 7,931 mboe to Highpine's working interest in the Pembina/Nisku area.

Highpine commenced activities in this area in November 2002 when the Corporation participated in the 9-30-49-8 W5M Nisku oil discovery. Highpine management viewed the 9-30-49-8 W5M Nisku prospect well as a "concept" well, whereby if successful, it would validate the potential for a geologically repeatable trend of Nisku reefs along a 70 mile long by 10 mile wide fairway. Subsequent to the successful 9-30-49-8 W5M Nisku oil discovery, which validated the "concept", Highpine captured a significant land position in this fairway, and has participated in several additional Nisku oil discoveries throughout 2003 and 2004. To date, Highpine has ownership in 14 discoveries in this area.

In March 2004, Highpine indirectly acquired an undivided 50% interest in all of the assets and liabilities of Rubicon. Rubicon's primary focus was in the Pembina/Nisku trend. Rubicon's assets included working interests in two Nisku oil pool discoveries, associated infrastructure and several Nisku oil prospects. The Rubicon Acquisition was considered by Highpine management to be complementary to Highpine's position in the trend. See "Highpine's Business – Rubicon Acquisition".

Infrastructure is very important in the Pembina/Nisku trend due to the "sour" nature of the production. The Rubicon Acquisition gave Highpine a 25% working interest in the Easyford Battery located on the northeast part of the trend. After an expansion, completed in the spring of 2004, this battery is capable of handling 12,000 bbls/d of sour oil (net capacity 3,000 bbls/d). To provide critical sour gas take-away capacity, Highpine has joined a consortium of mid-streamers (companies whose business is the transportation and processing of hydrocarbons without ownership in same) and area oil and gas producers which include Keyera Energy Canada Partnership, Duke Energy Midstream Services Canada Ltd. and Vaquero Energy Ltd. to construct an 80 kilometre pipeline, capable of carrying sour solution gas, or non-associated gas volumes to the Keyera Brazeau Gas Plant at 6-12-46-14 W5M, which is located approximately 170 kilometres southwest of Edmonton. Highpine has a 20% interest in this pipeline. To complete the required infrastructure, for servicing Highpine's future needs, Highpine submitted an application to the AEUB to approve the construction of the Violet Grove Battery, located on the southwest part of the trend. On December 14, 2004, the AEUB approved this sour oil battery application. Highpine's net working interest in this battery is 55% and Highpine is the operator. This battery is expected to be capable of handling 15,000 bbls/d (net capacity = 8,300 bbls/d).

Highpine's undeveloped land base at Pembina/Nisku holds an inventory of approximately 50 gross (26 net) firm drilling locations. The average working interest is 53% in the firm locations. The Corporation also has approximately 9 gross (5 net) contingent drilling locations. These locations are to be drilled if certain of the firm wells are successful. The Corporation expects to drill approximately 20 wells per year thereby giving Highpine a two to three year inventory of drilling opportunities. The average cost, assuming no significant drilling problems, to drill and complete wells in the Pembina/Nisku area is approximately $1.5 to $2.5 million. Costs to tie-in wells is an additional $500,000 to $1.0 million. Highpine also has ongoing 3D seismic and land acquisition programs which are designed to identify additional drilling opportunities to add to this inventory in the Pembina/Nisku area.

The Pembina/Nisku play is very competitive as many companies are actively acquiring land, drilling wells and attempting to obtain facility access. Nisku oil is "sour" oil which requires longer lead times in licensing wells and obtaining approval for associated facilities to bring these wells on stream. Lack of sour fluid handling capacity in this area has resulted in a significant amount of production that has been drilled but not put on stream. As a result, in the Pembina area, Highpine has significant shut-in Nisku oil production. It is anticipated that the Violet Grove Battery, currently under construction, will allow for the Corporation's shut-in production and future production drilled on the Pembina/Nisku trend to come on stream in a more timely manner.

When Nisku pools are developed, the operator's preferred method of producing these wells are at the highest withdrawal rates possible. This maximizes the economic value of wells and allows the facilities to operate at the most efficient levels. Maximum production rates require AEUB approval or the granting by the AEUB of Good Production Practice ("**GPP**"). GPP is granted when, in the opinion of the AEUB, all stakeholders holding interests in the pool are treated equitably, and the unrestricted flow rates do not reduce ultimate reservoir recovery of oil. The Nisku zone is thought to have an active water drive providing varying degrees of reservoir pressure support. The extent of this support is unknown at this time. The AEUB and industry producers, including Highpine, are monitoring this situation on an ongoing basis. Two of Highpine's Nisku pools have GPP and a third has been applied for. The AEUB will ultimately dictate reservoir operating conditions including the granting of GPP in potential new Nisku pools discoveries, possible recession of GPP, requirement for pressure maintenance (i.e., water injection), and/or specific production rates for individual Nisku wells or pools. It is Highpine's objective to maximize Nisku production; however, the above factors will influence the Corporation's ability to do so. Further, future production forecasts may be positively and/or negatively impacted as a result of such factors.

Joffre/Gilby – Central Alberta

The Joffre/Gilby property is located in the Lacombe area of Alberta approximately 100 kilometres south of Edmonton. The Joffre/Gilby property is Highpine's second major property, producing approximately 1,100 boe/d and representing approximately 31% of Highpine's total production volumes. Highpine's property interests in Joffre/Gilby consist of working interests ranging from 20% to 100% and averaging 62% (reserves volume weighted). Highpine has an interest in 18 producing wells (13.9 net) and 4 suspended wells (1.44 net). The average Highpine working interest production from the property was 1,100 boe/d for the first week of February 2005, 83% of which was natural gas. Highpine operates 16 wells associated with this property. In addition, Highpine has an average 100% working interest in one gas plant which processes natural gas for Highpine and its partners.

The Joffre/Gilby property consists of 11,500 gross (8,000 net) acres of developed land and 37,000 gross (33,000 net) acres of undeveloped land.

The Paddock Report attributes proved plus probable reserves of 1,525 mboe to Highpine's working interest in the Joffre/Gilby area.

Highpine commenced activities in this area in January 2002 when Highpine made its first significant exploration discovery with the 4-16-40-27 W4M gas well. This well produced initial rates in excess of seven mmcf/d and has recovered approximately four bcf of natural gas and significant quantities of NGLs. To date, Highpine has drilled three significant Ellerslie natural gas discoveries and several oil and natural gas producing wells from secondary targeted zones.

In December 2004, Highpine commissioned a 10 mmcf/d, 100% owned and operated natural gas processing facility, located near the middle of Highpine's Joffre acreage. The facility is designed to process natural gas from all of the potential producing horizons in the Joffre area, including low pressure gas and coal bed methane. In addition to processing Highpine's working interest natural gas volumes, Highpine's management believes that this facility will provide third party custom processing and transportation service to a large area in which Highpine and others are currently active.

Highpine's ongoing activity at Joffre consists of selective exploration and exploitation drilling. Typically, Highpine drills two wells at a time, after which results are incorporated into the Corporation's regional interpretation of all of the various producing zones. Based upon accumulated data, subsequent drilling locations are identified. In 2005, Highpine's capital budget contemplates that the Corporation will participate in the drilling of approximately 10 wells in this area. The average cost, assuming no significant drilling problems, to drill and complete wells in the Joffre/Gilby area is approximately $300,000 to $500,000. Costs to tie-in wells is an additional $300,000 to $500,000.

Bantry/Retlaw – Southern Alberta

The Bantry/Retlaw property is located in the Brooks area of Alberta approximately 200 kilometres southeast of Calgary, Alberta. The Bantry/Retlaw property is Highpine's major southern Alberta property producing approximately 480 boe/d and representing approximately 13% of Highpine's total production volumes. Highpine's interests in Bantry/Retlaw consist of working interests ranging from 40% to 65% and averaging 45% (reserves volume weighted). Highpine has an interest in 38 (14.68 net)producing wells, 8 water disposal wells (4 net) and 21 suspended wells (6.7 net). The average Highpine working interest production from the property was 480 boe/d for the first week of February 2005. Highpine operates nine wells associated with this property. In addition, Highpine has an average 53% working interest in two oil batteries. All of Highpine's production is gathered in flowlines connecting wells to central batteries. At the central batteries, produced oil, natural gas and water are separated. Water is disposed of in water disposal wells, which are operated and/or partially owned by Highpine. Highpine's management believes that the Corporation will have sufficient working interests in water disposal wells in the area to dispose of its share of produced water.

The Bantry/Retlaw property consists of 6,234 gross (1,617 net) acres of developed land and 3,700 gross (1,100 net) acres of undeveloped land.

The Paddock Report attributes proved plus probable reserves of 1,315 mboe to Highpine's working interest in the Bantry/Retlaw area.

In May 2000, Highpine acquired a 40% working interest in an oil property at Bantry. This property consists of 18 wells, producing approximately 200 net bbl/d of 25? API oil and miscellaneous associated and non-associated gas volumes. The Bantry property is characterized by long-life oil with ongoing exploitation opportunities, including uphole natural gas re-completions.

Highpine commenced activities in the Retlaw region in March 2002 when it acquired working interests in various oil properties in the area. The properties consisted of several minor working interest producing wells and a 65% working interest in a suspended 29? API Mannville oil pool. The producing properties were subsequently sold at a price equivalent to what was paid for the entire interest acquired in March 2002. In late 2003, after a technical study was completed on the suspended pool, Highpine decided to re-activate the old wells, drill additional wells and install facilities capable of bringing all of the wells on production under high volume lift. These facilities were commissioned in June 2004. Production from the Retlaw area (which is derived from the foregoing oil wells and some uphole natural gas exploitation) is currently averaging approximately 300 boe/d net. Highpine anticipates further oil optimization and development natural gas drilling on this property in 2005.

Highpine continues to optimize production and reduce the operating costs of certain wells on both properties. Optimization efforts will consist of well stimulations, chemical treatments and the installation of high volume lift and additional water disposal facilities. Highpine is budgeting for the drilling of up to three wells at Bantry/Retlaw in 2005. The average cost, assuming no significant drilling problems, to drill and complete wells in Retlaw/Bantry area is approximately $300,000 to $500,000. Costs to tie-in wells is an additional $100,000 to $200,000.

Sturgeon Lake – Central Alberta

The Sturgeon Lake property is located in the North Central area of Alberta approximately 80 kilometres east of Grande Prairie.

The Sturgeon Lake property consists of 2,480 gross (992 net) acres of undeveloped land.

Highpine has committed to participation (40% before payout, reverting to a 32% after payout), in an exploration oil prospect, targeting the Leduc and Nisku zones. This prospect has been fully evaluated with 3D seismic coverage and geological interpretation. The test well is currently in the licensing phase, and because of the expectation for "sour" fluids, it is likely that this prospect will not be drilled until the fall of 2005. There is sufficient infrastructure in the area to produce this field if the drilling is successful. The estimated costs to drill and complete the test well is approximately $3.0 million.

Chambers – Central Alberta

The Chambers property is located in the West Central area of Alberta approximately 120 kilo metres west of Red Deer.

The Chambers property consists of 640 gross (480 net) acres of developed land and 1,280 gross (960 net) acres of undeveloped land.

Highpine currently has one well being completed and tested in the area.

Rubicon Acquisition

On March 3, 2004, Highpine and West Energy Ltd. ("**West Energy**") jointly acquired all of the issued and outstanding common shares of Rubicon by way of takeover bid. As a result of a number of transactions which occurred following the acquisition of all of the common shares of Rubicon each of Highpine and West Energy indirectly acquired an undivided 50% interest in all of the assets of Rubicon (and became responsible for the associated liabilities). At the date of acquisition, the Rubicon Assets included production of approximately 1,600 boe/d (consisting of 1,000 bbls/d of oil and NGLs and 3.5 mmcf/d of natural gas), proven plus probable reserves of 2.67 million boes of oil and natural gas reserves, 199,000 (net 55,500) acres of undeveloped land and 252 square miles of 3D seismic. The consideration paid by Highpine for the Rubicon Assets (including the amount of the associated liabilities) was approximately $52 million. The acquisition was initially financed primarily through the Corporation's credit facility. See "Financial Statements for the Rubicon Energy Properties" for the financial statements in respect of the Rubicon Assets.

Selected Combined Financial Information

The following tables set out certain consolidated financial information for Highpine and Rubicon as well as certain unaudited pro forma financial information after giving effect to Highpine's indirect 50% interest in the Rubicon Acquisition and certain other adjustments. The following information should be read in conjunction with the unaudited pro forma consolidated financial statements of Highpine included in this prospectus.

	Highpine for the Nine Month Period Ended September 30, 2004 (unaudited)	Rubicon for the Two Month Period Ended February 29, 2004 (unaudited)	Pro Forma for the Nine Month Period Ended September 30, 2004 (unaudited)
Revenues, net of royalties	$ 21,617,000	$ 2,719,000	$ 24,336,000
Net earnings (loss)	$ 2,129,000	$ (2,207,000)	$ 2,370,000
Per Equity Share (basic)	$ 0.14	N/A	$ 0.16
Per Equity Share (diluted)	$ 0.14	N/A	$ 0.16

	Highpine for the Year Ended December 31, 2003 (audited)	Rubicon for the Year Ended December 31, 2003 (audited)	Pro Forma for the Year Ended December 31, 2003 (unaudited)
Revenues, net of royalties	$ 13,817,000	$ 12,395,000	$ 26,212,000
Net earnings (loss)	$ 19,108,000	$ 3,280,000	$ 18,293,000
Per Equity Share (basic)	$ 1.32	N/A	$ 1.26
Per Equity Share (diluted)	$ 1.31	N/A	$ 1.26

Oil and Natural Gas Reserves

The tables below summarize Highpine's crude oil, NGL and natural gas reserves and the estimated present worth of future net cash flows associated with such reserves, as at December 31, 2004. The information set forth below is derived from the Paddock Report, which was prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101 and the COGE Handbook. The tables summarize and aggregate the data contained in the Paddock Report and, as a result, may contain slightly different numbers than the Paddock Report due to rounding. **All evaluations of future net cash flows are stated before and after the provision for income taxes and prior to indirect costs and after deduction of royalties, estimated future capital expenditures and well abandonment costs and after giving effect to ARTC. It should not be assumed that the present values of estimated future net cash flows shown below is representative of the fair market value of Highpine's crude oil, NGL and natural gas reserves. There is no assurance that the price and cost assumptions**

used in estimating such future net cash flows will be consistent with actual prices and costs and variances could be material. The recovery and reserve estimates of Highpine's crude oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGL and natural gas reserves may be greater than or less than the estimates provided herein.

The Report of Highpine Management and Directors on Reserves Data and Other Information (on Form 51-101F3) and the Report on Reserves Data by Paddock (on Form 51-101F2) are included in this prospectus. See "Report of Highpine Management and Directors on Oil and Gas Disclosure in Accordance with Form 51-101F3" and "Report on Reserves Data by Paddock Lindstrom & Associates Ltd. in Accordance with Form 51-101F2", respectively.

Summary of Crude Oil, NGL and Natural Gas Reserves and Net Present Values of Estimated Future Net Revenue as of December 31, 2004 Based on Constant Price Assumptions

	Reserves							
	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids	
Reserves Category	Gross (mbbl)	Net (mbbl)	Gross (mbbl)	Net (mbbl)	Gross (mmcf)	Net (mmcf)	Gross (mbbl)	Net (mbbl)
Proved								
Developed Producing	1,463	1,129	680	581	12,420	9,944	518	390
Developed Non-Producing	1,171	870	95	80	4,397	3,514	312	235
Total Developed	2,634	1,999	775	662	16,817	13,458	830	625
Undeveloped	367	621	-	-	1,136	887	79	62
Total Proved	3,501	2,620	775	662	17,953	14,345	909	687
Probable	2,246	1,682	152	131	7,942	6,284	294	222
Total Proved Plus Probable	5,747	4,302	927	793	25,895	20,629	1,203	909

	Net Present Values of Future Net Revenue									
	Before Income Taxes Discounted at (%/year)					After Income Taxes Discounted at (%/year)				
Reserves Category	0	5	10	15	20	0	5	10	15	20
	(Thousands of Dollars)									
Proved										
Developed Producing	113,314	94,330	81,512	72,252	65,231	89,448	73,792	63,378	55,930	50,320
Developed Non-Producing	58,443	46,498	38,655	33,102	28,959	42,651	33,507	27,623	23,511	20,473
Total Developed	171,757	140,829	120,167	105,354	94,190	132,099	107,299	91,001	79,441	70,793
Undeveloped	23,590	18,016	14,282	11,601	9,588	11,793	8,591	6,404	4,815	3,612
Total Proved	195,347	158,845	134,449	116,956	103,778	143,892	115,890	97,405	84,255	74,404
Probable	104,270	73,208	55,733	44,674	37,106	69,485	48,337	36,525	29,076	23,990
Total Proved Plus Probable	299,617	232,053	190,182	161,630	140,884	213,377	164,227	133,930	113,331	98,395

Total Future Net Revenue (Undiscounted) as of December 31, 2004 Based on Constant Prices and Costs

Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Well Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Taxes
				(Thousands of Dollars)				
Proved Reserves	360,989	81,792	73,295	9,506	1,100	195,346	51,454	143,892
Proved Plus Probable	540,549	123,325	103,273	13,112	1,223	299,616	86,240	213,376

Future Net Revenue by Production Group as of December 31, 2004 Based on Constant Prices and Costs

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year) (Thousands of Dollars)
Proved	Light and Medium Crude Oil (including solution gas and other by–products)	73,152
	Heavy Oil (including solution gas and other by–products)	10,171
	Natural Gas (including by–products but excluding solution gas from oil wells)	47,789
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and other by–products)	113,832
	Heavy Oil (including solution gas and other by–products)	11,839
	Natural Gas (including by–products but excluding solution gas from oil wells)	60,560

Summary of Crude Oil, NGL and Natural Gas Reserves and Net Present Values of Estimated Future Net Revenue as of December 31, 2004 Based on Forecast Price Assumptions

	Reserves							
	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids	
Reserves Category	Gross (mbbl)	Net (mbbl)	Gross (mbbl)	Net (mbbl)	Gross (mmcf)	Net (mmcf)	Gross (mbbl)	Net (mbbl)
Proved								
Developed Producing	1,462	1,143	680	582	12,423	9,948	518	393
Developed Non-Producing	1,171	900	95	80	4,390	3,520	312	239
Total Developed	2,633	2,043	775	662	16,813	13,468	830	632
Undeveloped	867	642	-	-	1,136	890	80	63
Total Proved	3,500	2,685	775	662	17,949	14,358	910	695
Probable	2,239	1,751	144	125	7,954	6,300	292	224
Total Proved Plus Probable	5,739	4,436	919	787	25,903	20,658	1,202	919

	Net Present Values of Future Net Revenue									
	Before Income Taxes Discounted at (%/year)					After Income Taxes Discounted at (%/year)				
Reserves Category	0	5	10	15	20	0	5	10	15	20
	(Thousands of Dollars)									
Proved										
Developed Producing	97,087	82,927	73,085	65,800	60,157	78,217	66,007	57,664	51,568	46,893
Developed Non-Producing	51,245	41,264	34,678	29,985	26,460	34,438	27,246	22,632	19,400	17,000
Total Developed	148,332	124,191	107,763	95,785	86,617	112,655	93,252	80,296	70,968	63,893
Undeveloped	20,603	15,760	12,507	10,171	8,413	13,502	9,970	7,604	5,911	4,642
Total Proved	168,935	139,951	120,270	105,956	95,031	126,157	103,222	87,900	76,879	68,534
Probable	90,611	64,092	49,198	39,761	33,281	60,395	42,269	32,173	25,802	21,440
Total Proved Plus Probable	259,545	204,042	169,468	145,717	128,312	186,552	145,491	120,073	102,681	89,974

Total Future Net Revenue (Undiscounted) as of December 31, 2004 Based on Forecast Prices and Costs

Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Well Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Taxes
				(Thousands of Dollars)				
Proved Reserves	334,944	72,972	82,130	9,520	1,387	168,935	42,778	126,157
Proved Plus Probable	501,648	107,741	119,534	13,160	1,667	259,546	72,994	186,552

Future Net Revenue by Production Group as of December 31, 2004 Based on Forecast Prices and Costs

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year) (Thousands of Dollars)
Proved	Light and Medium Crude Oil (including solution gas and other by–products)	67,299
	Heavy Oil (including solution gas and other by–products)	8,467
	Natural Gas (including by–products but excluding solution gas from oil wells)	41,352
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and other by–products)	104,051
	Heavy Oil (including solution gas and other by–products)	9,760
	Natural Gas (including by–products but excluding solution gas from oil wells)	51,833

Notes:

(1) Columns may not add due to rounding.

(2) "**Gross**" means Highpine's total working interest and/or royalty interest share before royalties owned by others.

"**Net**" means Highpine's total working interest and/or royalty interest share after deducting the amounts attributable to royalties owned by others.

"**Royalties**" refers to royalties paid to others. The royalties deducted from the reserves are based on the percentage royalty calculated by applying the applicable royalty rate or formula. In the case of Crown sliding scale royalties, which are dependent on selling prices, the price forecasts for the individual properties in question have been employed.

"**Reserves**" are the estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates.

"**Proved Reserves**" are those Reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated Proved Reserves. At least a 90% probability that the quantities actually recovered will equal or exceed the estimated Proved Reserves is the targeted level of certainty.

"**Probable Reserves**" are those additional Reserves that are less certain to be recovered than Proved Reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved plus Probable Reserves. At least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved plus Probable Reserves is the targeted level of certainty.

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

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

"**Developed Non-Producing Reserves**" are those Reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

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

(3) The forecast cost and price assumptions assume the continuance of current laws and regulations and increases in wellhead selling prices, and take into account inflation with respect to future operating capital costs. In the Paddock Report, operating costs are assumed to escalate at 2% per annum. Crude oil and natural gas base case prices as forecast by Paddock effective December 31, 2004 are as follows:

Summary of Pricing and Inflation Rate Assumptions as at December 31, 2004
Forecast Prices and Costs

	Oil				Natural Gas	Edmonton Liquids Prices				
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Hardisty Heavy 25° API ($Cdn/bbl)	Cromer Medium 29.3° API ($Cdn/bbl)	AECO Gas Price ($Cdn/mmbtu)	Propane ($Cdn/bbl)	Butane ($Cdn/bbl)	Pentanes Plus ($Cdn/bbl)	Inflation Rates [(a)] %/Year	Exchange Rate[(b)] ($US/$Cdn)
Forecast										
2005	42.00	50.22	36.72	46.70	6.78	30.13	37.16	50.22	2%	0.820
2006	40.00	47.76	35.76	44.42	6.52	28.66	34.87	47.76	2%	0.820
2007	37.50	44.69	34.69	41.56	6.26	26.81	32.18	44.69	2%	0.820
2008	35.00	41.62	33.62	38.71	6.00	24.97	29.14	41.62	2%	0.820
2009	33.00	39.16	31.00	36.42	5.73	23.50	27.41	39.16	2%	0.820
2010	33.50	39.75	31.43	36.97	5.85	23.85	27.82	39.75	2%	0.820
2011	34.00	40.34	31.85	37.51	5.96	24.20	28.24	40.34	2%	0.820
2012	34.50	40.92	32.27	38.06	6.08	24.55	28.65	40.92	2%	0.820
2013	35.00	41.51	32.68	38.61	6.21	24.91	29.06	41.51	2%	0.820
2014	35.50	42.10	33.09	39.15	6.33	25.26	29.47	42.10	2%	0.820
Thereafter					+ 2%/year					

Notes:

(a) Inflation rates for forecasting prices and costs.

(b) Exchange rates used to generate the benchmark reference prices in this table.

(4) Weighted average historical prices realized by Highpine for the nine months ended September 30, 2004 were $6.71/mcf for natural gas, $43.31/bbl for oil and $38.66/bbl for NGLs. Transportation expense has been included in the realized price to align with pricing assumptions contained in the Paddock Report.

(5) The constant price assumptions assume the continuance of current laws, regulations and operating costs in effect on the date of the Paddock Report. Product prices were not escalated beyond December 31, 2004. In addition, operating and capital costs have not been increased on an inflationary basis. The prices used for the mix of crude oil gravities and various gas contracts were as follows (adjusted for quality and transportation).

Summary of Pricing Assumptions as of December 31, 2004
Constant Prices and Costs

	Oil				Natural Gas	Edmonton Liquid Prices			
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Hardisty Heavy 25° API ($Cdn/bbl)	Cromer Medium 29.3° API ($Cdn/bbl)	AECO Gas Price ($Cdn/Mmbtu)	Propane ($Cdn/bbl)	Butane ($Cdn/bbl)	Pentanes Plus ($Cdn/bbl)	Exchange Rate ($US/$Cdn)
2004	43.45	48.07	36.74	39.70	6.88	30.18	34.10	48.07	0.8308

(6) The extent and character of all factual data supplied to Paddock was accepted by Paddock as represented. The crude oil and natural gas reserve calculations and any projections upon which the Paddock Report are based were determined in accordance with generally accepted evaluation practices. No field inspections were conducted. Salvage values for facilities and base reclamation costs for any of the Corporation's wells which were assigned no reserves have not been included in the Paddock Report. No costs were included in the Paddock Report for the abandonment of surface facilities or gathering systems or for the reclamation of surface leases.

(7) ARTC is included in the cumulative cash flow amounts. ARTC is based on the program announced November 1989 by the Alberta government with modifications effective January 1, 1995. The Corporation will qualify for the maximum ARTC.

(8) Estimated future abandonment and reclamation costs related to a property have been taken into account by Paddock in determining reserves that should be attributed to a property, and, in determining the aggregate future net revenue therefrom, Paddock deducted the reasonable estimated future well abandonment costs.

Reconciliations of Changes in Reserves and Future Net Revenue

Reconciliation of
Company Net Reserves
by Principal Product Type
Based on Constant Prices and Costs

	Light and Medium Oil			Heavy Oil			Associated and Non-Associated Gas		
Factors	Net Proved (mbbl)	Net Probable (mbbl)	Net Proved Plus Probable (mbbl)	Net Proved (mbbl)	Net Probable (mbbl)	Net Proved Plus Probable (mbbl)	Net Proved (mmcf)	Net Probable (mmcf)	Net Proved Plus Probable (mmcf)
December 31, 2003	590.4	219.6	810.0	627.3	205.4	832.7	5,052.0	2,044.0	7,096.0
Extensions	0.0	0.0	0.0	0.0	0.0	0.0	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
Technical Revisions	358.1	(52.8)	305.3	56.7	(81.1)	(24.4)	(2,484.0)	(2,359.0)	(4,843.0)
Discoveries	1,430.3	1,326.4	2,756.7	0.0	0.0	0.0	6,862.0	4,319.0	11,181.0
Acquisitions	559.1	188.6	747.7	34.8	7.2	42.0	3,236.0	625.0	3,861.0
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0	144.0	17.0	161.0
Economic Factors	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Production	317.9	0.0	317.9	57.0	0.0	57.0	1,277.0	0.0	1,277.0
December 31, 2004	2,620.0	1,681.8	4,301.8	661.8	131.5	793.3	11,245.0	4,612.0	15,857.0

Reconciliation of Changes in
Net Present Values of Future Net Revenue
Discounted at 10% Per Year
Proved Reserves
Constant Prices and Costs

Period and Factor	After Tax 2004
	(Thousands of Dollars)
Estimated Future Net Revenue at December 31, 2003	34,021
Sales and Transfers of Oil and Gas Produced, Net of Production Costs and Royalties [1]	(24,100)
Net Change in Prices, Production Costs and Royalties Related to Future Production	6,317
Changes in Previously Estimated Development Costs Incurred During the Period	(732)
Changes in Estimated Future Development Costs	8,941
Extensions and Improved Recovery	0
Discoveries	66,326
Acquisitions of Reserves	28,749
Dispositions of Reserves	(548)
Net Change Resulting from Revisions in Quantity Estimates	6,056
Accretion of Discount [2]	3,402
Net Change in Income Taxes [3]	(29,482)
All Other Changes	(1,545)
Estimated Future Net Revenue at December 31, 2004	97,405

Notes:

(1) Cash flow from operations.
(2) Estimated as 10% of the beginning of period net present value.
(3) The difference between income taxes at beginning of period and income taxes at end of period.

Future Development Costs

The following table sets forth development costs deducted by Paddock in the estimation of the future net revenue for Highpine's properties and assets attributable to the reserve categories noted below.

Year	Forecast Prices and Costs: Proved Reserves	Forecast Prices and Costs: Proved Plus Probable Reserves	Constant Prices and Costs: Proved Reserves	Constant Prices and Costs: Proved Plus Probable Reserves
		(Thousands of Dollars)		
2005	8,834	10,726	8,834	10,726
2006	671	2,421	659	2,373
2007	0	0	0	0
2008	14	14	14	14
2009	0	0	0	0
Total: Undiscounted	9,520	13,160	9,506	13,112
Total: Discounted at 10%/year	9,015	12,335	9,003	12,293

In all years for which economic forecasts were made by Paddock in the Paddock Report, the net revenues from the reserves attributable to Highpine's properties and assets are well in excess of the estimated future development costs. Therefore, the Paddock Report assumes that the Corporation will be able to fund the anticipated expenditures for future development entirely out of its cash flow and will not require other sources in order to develop the proved or probable reserves. As a result, interest or other costs of external funding are not included in the reserves and future net revenue estimates.

Undeveloped Reserves

The following tables set forth the proved undeveloped reserves and the probable undeveloped reserves, each by product type, attributed to the Corporation as at the end of each of the financial years noted.

Proved Undeveloped Reserves

Year	Light and Medium Oil	Heavy Oil	Natural Gas	Natural Gas Liquids	BOE
	(mbbls)	(mbbls)	(mmcf)	(mbbls)	(mboe)
2002	6	–	1	0	6
2003	217	–	156	9	252

In 2003, proved undeveloped reserves were attributed to the Pembina/Nisku HH and II properties on account of two drilling locations and increased recovery factors. As of the date of this prospectus, one of the two wells has been successfully drilled and the other is expected to be drilled in the next two years.

Probable Undeveloped Reserves

Year	Light and Medium Oil	Heavy Oil	Natural Gas	Natural Gas Liquids	BOE
	(mbbls)	(mbbls)	(mmcf)	(mbbls)	(mboe)
2002	64	208	1,567	35	568
2003	294	215	2,962	57	1,060

In 2002 and 2003, probable undeveloped reserves related to an increased recovery factor in certain existing pools and drilling locations that were, or were expected to be drilled on Highpine's oil and natural gas properties.

Undeveloped Reserves

In general, once proved and/or probable undeveloped reserves are identified they are integrated into Highpine's development plans. The Corporation's business plan generally envisions the development of proved and probable undeveloped reserves within two years of the date of such integration. The various factors that could result in delayed or cancelled development include:

- changing economic conditions;
- changing technical conditions (production anomalies (i.e., water breakthrough, accelerated depletion));
- multi-zone developments (i.e. a prospective formation completion may be delayed until the initial completion is no longer economic);
- a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and
- surface access issues (landowners, weather conditions and regulatory approvals, for example).

Significant Factors or Uncertainties

Other than the various risks and uncertainties that participants in the oil and gas industry are exposed to generally, Highpine is unable to identify any important economic factors or significant uncertainties that will affect any particular components of the reserves data disclosed herein. See "Risk Factors".

Landholdings

Highpine's developed and undeveloped landholdings (in acres) as at January 14, 2005, are set forth in the following table.

	Undeveloped		Developed		Total	
	Gross [(1)]	Net [(2)]	Gross [(1)]	Net [(2)]	Gross [(1)]	Net [(2)]
Alberta	196,304	90,605	68,887	16,263	265,191	106,868
Saskatchewan	–	–	960	–	960	–
Total	196,304	90,605	69,847	16,263	266,151	106,868

Notes:

(1) "**Gross**" means, collectively, the total number of acres in which Highpine, Pino Alto, HAC and Highpine Partnership have an interest.

(2) "**Net**" means, collectively, the aggregate of the percentage working interests of Highpine, Pino Alto, HAC and Highpine Partnership in the Gross acres.

The Seaton-Jordan Report has estimated the fair value of Highpine's undeveloped landholdings, as at January 14, 2005, at approximately $23.6 million. The Charter Reports have estimated the replacement cost of HAC's, Pino Alto's and Highpine Partnership's undeveloped landholdings, as at January 14, 2005, at approximately $3.0 million. For purposes of the Seaton-Jordan Report, "fair value" is defined as the price which Seaton-Jordan feels could reasonably be expected to be received for the undeveloped lands. In order to determine fair market value, Seaton-Jordan considered the following factors: the acquisition cost of the undeveloped properties; recent sales by others of interests in the same undeveloped properties; terms and conditions (expressed in monetary terms) of recent farm-in agreements and work commitments related to the undeveloped properties; and recent sales of similar properties in the same general area. Charter's valuation (as set out in the Charter Reports) represents Charter's estimate of the replacement costs for the undeveloped lands, based on current industry activity. In determining such replacement costs, Charter analyzed all prior and current Crown land sale prices paid at land sales for properties in the vicinity of the lands evaluated and reviewed all offsetting industry drilling results adjacent to such lands. Highpine's undeveloped landholdings, having an aggregate value of approximately $26.6 million, constitute properties with no attributed reserves.

The Corporation expects that rights to explore develop and exploit 37,752 gross (23,794 net) acres of undeveloped landholdings attributable to Highpine's properties and assets may expire by December 31, 2005.

Oil and Natural Gas Wells

The following table summarizes Highpine's interest, as at December 31, 2004, in producing wells and wells that Highpine considers to be capable of production.

	Producing Wells				Shut-in Wells [3]			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross [1]	Net [2]	Gross [1]	Net [2]	Gross [1]	Net [2]	Gross [1]	Net [2]
Alberta	115	18.5	816	111.7	52	14.9	36	13.7
Saskatchewan	7	–	–	–	–	–	–	–

Notes:

(1) "**Gross**" refers to all wells in which Highpine has either a working interest or a royalty interest.
(2) "**Net**" refers to the aggregate of the percentage working interests of Highpine in the gross wells, before the deduction of royalties.
(3) "**Shut-in Wells**" refers to wells that are capable of producing crude oil or natural gas, but which are not producing due to lack of available transportation facilities, available markets or other reasons. Shut-in wells in which Highpine has an interest are located no further than 10 kilometres from existing pipelines.

Capital Expenditures

The following table sets out Highpine's capital expenditures for various categories of expenditure, for the periods indicated.

	Nine Months Ended September 30, 2004	Years Ended December 31,		
		2003	2002	2001
	($) (unaudited)	($)	($)	($)
Land and seismic	7,136,000	11,644,000	4,118,000	1,102,000
Drilling and completions	23,739,000	8,793,000	4,286,000	1,377,000
Facilities and equipment	11,127,000	2,843,000	2,053,000	124,000
Property acquisitions and dispositions (net)	(4,565,000)	194,000	776,000	–
Corporate acquisition	51,151,000	–	–	–
Other	77,000	32,000	35,000	35,000
Total	88,665,000	23,506,000	11,268,000	2,638,000

Drilling Activity

The following table summarizes Highpine's drilling results for the periods indicated.

	Nine Months Ended September 30, 2004		Year Ended December 31, 2003		Year Ended December 31, 2002		Year Ended December 31, 2001	
	Gross [1]	Net [2]	Gross [1]	Net [2]	Gross [1]	Net [2]	Gross [1]	Net [2]
Crude oil	10.0	4.4	5.0	1.6	5.0	3.3	2.0	0.8
Natural gas	21.0	6.1	10.0	6.1	4.0	1.4	3.0	0.1
Suspended	6.0	2.8	–	–	1.0	0.4	–	–
Dry and abandoned	10.0	3.3	9.0	6.6	6.0	5.5	4.0	2.7
Total	47.0	16.6	24.0	14.3	16.0	10.6	9.0	3.6

Notes:

(1) "**Gross**" wells refers to all wells in which Highpine has either a working interest or a royalty interest.
(2) "**Net**" wells refers to the aggregate of the percentage working interests of Highpine in the gross wells, before the deduction of royalties.

History – Daily Sales Volumes and Netbacks

The following tables set forth Highpine's daily sales volumes and netbacks on a quarterly basis for the periods indicated.

	2004			
	Nine Months Ended September 30, 2004	Third Quarter	Second Quarter	First Quarter
	(unaudited)	(unaudited)	(unaudited)	(unaudited)
Production				
Crude oil and NGL (bbls/d)	1,471	1,812	1,628	969
Natural gas (mcf/d)	6,301	7,091	6,759	5,046
Oil equivalent (boe/d)	2,521	2,994	2,754	1,810
Netbacks per boe				
Revenue [(1)]	$ 42.10	$ 41.78	$ 45.10	$ 38.10
Royalties	10.81	12.24	10.99	8.14
Production expenses [(2)]	6.66	5.59	8.14	6.21
Netback	24.63	23.95	25.97	23.75
Netbacks per bbl – Oil and NGL				
Revenue [(1)]	$ 43.10	$ 43.92	$ 45.48	$ 37.52
Royalties	11.62	12.43	12.02	8.26
Production expenses [(2)]	7.94	6.41	9.74	7.00
Netback	23.54	25.08	23.72	22.26
Netbacks per mcf – Natural Gas				
Revenue[(1)]	$ 6.79	$ 6.41	$ 7.42	$ 6.46
Royalties	1.67	1.99	1.58	1.33
Production expenses [(2)]	0.82	0.72	0.97	0.88
Netback	4.30	3.70	4.87	4.24
Capital Expenditures				
Land and seismic	$ 7,136,000	$ 2,530,000	$ 3,513,000	$ 1,093,000
Drilling and completion	23,739,000	9,027,000	10,047,000	4,665,000
Facilities and equipment	11,127,000	4,271,000	4,328,000	2,528,000
Property acquisitions and dispositions (net)	(4,565,000)	(3,395,000)	(1,170,000)	–
Corporate acquisition	51,151,000	–	–	51,151,000
Other	77,000	69,000	7,000	1,000
Total	$ 88,665,000	$ 12,502,000	$ 16,725,000	$ 59,438,000

	2003					2002
	Year Ended December 31	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter
	(audited)	(unaudited)	(unaudited)	(unaudited)	(unaudited)	(unaudited)
Production						
Crude oil and NGL (bbls/d)	443	514	474	378	405	407
Natural gas (mcf/d)	4,281	4,281	4,508	4,117	4,215	4,617
Oil equivalent (boe/d)	1,157	1,227	1,225	1,064	1,107	1,177

	2003					2002
	Year Ended December 31	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter
	(audited)	(unaudited)	(unaudited)	(unaudited)	(unaudited)	(unaudited)
Netbacks per boe						
Revenue[(1)]	$ 40.10	$ 38.35	$ 36.86	$ 40.36	$ 45.46	$ 34.12
Royalties	7.36	6.88	6.78	7.35	8.60	8.07
Production expenses [(2)]	5.44	8.79	3.35	4.52	4.87	4.59
Netback	27.30	22.68	26.73	28.49	31.99	21.46
Netbacks per bbl – Oil and NGL						
Revenue [(1)]	$ 34.29	$ 32.55	$ 31.77	$ 32.72	$ 41.07	$ 34.05
Royalties	7.28	7.18	6.92	6.85	8.26	7.84
Production expenses [(2)]	8.25	12.92	5.63	5.48	7.32	6.43
Netback	18.76	12.45	19.22	20.39	25.49	19.78
Netbacks per mcf – Natural Gas						
Revenue [(1)]	$ 7.28	$ 7.09	$ 6.68	$ 7.43	$ 8.00	$ 5.69
Royalties	1.24	1.12	1.11	1.27	1.46	1.30
Production expenses [(2)]	0.64	0.98	0.32	0.66	0.58	0.60
Netback	5.40	4.99	5.25	5.50	5.96	3.79
Capital Expenditures						
Land and seismic	$ 11,644,000	$ 5,308,000	$ 2,988,000	$ 2,684,000	$ 664,000	$ 2,223,000
Drilling and completion	8,793,000	978,000	1,370,000	3,031,000	3,414,000	1,797,000
Facilities and equipment	2,843,000	317,000	146,000	1,852,000	528,000	1,743,000
Acquisitions	194,000	16,000	1,016,000	3,000	(841,000)	(325,000)
Other	32,000	12,000	9,000	3,000	8,000	31,000
Total	$ 23,506,000	$ 6,631,000	$ 5,529,000	$ 7,573,000	$ 3,773,000	$ 5,469,000

Notes:

(1) After giving effect to commodity hedges.

(2) Production expenses include expenses related to well workovers, fuel and power costs related to operation of wells, operator wages and salaries and other miscellaneous production costs.

Forward Contracts

At February 1, 2005, Highpine had a financial crude oil hedge in place to sell 700 bbls/d for the remainder of 2005 at Cdn $47.20 per barrel.

Additional Information Concerning Abandonment and Reclamation Costs

The following table sets forth information respecting future abandonment and reclamation costs (net of estimated salvage values) for surface leases, wells, facilities and pipelines, which are expected to be incurred for the periods indicated in respect of Highpine's properties and assets.

	Abandonment and Reclamation Costs Escalated at 2% Undiscounted	Abandonment and Reclamation Costs Escalated at 2% Discounted at 10%
	(Thousands of Dollars)	
Total as at December 31, 2004	13	13
Anticipated to be paid in 2005	25	24
Anticipated to be paid in 2006	36	31
Anticipated to be paid in 2007	1	1

The amounts disclosed in the foregoing table that have not been deducted as abandonment and reclamation costs in estimating the future net revenue disclosed elsewhere in this prospectus are $4.317 million on an undiscounted basis and $1.45 million on a discounted basis.

Highpine estimates the costs to abandon and reclaim all its shut in and producing wells, facilities, gas plants, pipelines, batteries and satellites. Highpine's model for estimating the amount and timing of future abandonment and reclamation expenditures was done on an operating area level. Estimated expenditures for each operating area are based on the AEUB methodology, which details the cost of abandonment and reclamation in each specific geographic region. Each region was assigned an average cost per well to abandon and reclaim the wells in that area. Facility reclamation costs are scheduled to be incurred in the year following the end of the reserve life of its associated reserves. The Corporation will be liable for its share of ongoing environmental obligations and for the ultimate reclamation of the properties held by it upon abandonment. Ongoing environmental obligations are expected to be funded out of cash flow. The Corporation currently estimates that the future environmental and reclamation obligations net of salvage value in respect of Highpine's properties and assets will aggregate approximately $4.4 million escalated at 2% per year.

As at December 31, 2004, Highpine expected to incur reclamation and abandonment costs in respect of 1,026 gross (159 net) wells located on its properties and assets.

Tax Horizon

Highpine's management does not expect that Highpine will be taxable in the next two to three years. Highpine has estimated approximately $72 million oftax pools will be available as at December 31, 2004, which can be used to off-set taxable income.

Costs Incurred

The following table summarizes certain costs (irrespective of whether such costs were capitalized or recorded as an expense) incurred by Highpine for the periods indicated.

Expenditures	Nine Months Ended September 30, 2004	Year Ended December 31, 2003
	(unaudited)	
	(Thousands of Dollars)	
Property acquisition costs – Unproved properties	7,136 (1)	11,644
Property acquisition costs – Proved properties	46,586	194
Exploration costs	11,870	4,396
Development costs (2)	22,996	7,240
Other	77	32
Total	88,665	23,506

Notes:

(1) Cost of land acquired, geological and geophysical capital expenditures and drilling costs for 2004 exploration wells drilled.

(2) Development and facilities capital expenditures.

Exploration and Development Activities

The following table sets out the number of exploratory and development wells (both on a gross and net basis) in which Highpine participated during the periods indicated.

	Nine Months Ended September 30, 2004			
	Exploratory Wells		Development Wells	
	Gross [1]	Net [2]	Gross [1]	Net [2]
Oil	5.00	1.08	7.00	3.26
Natural Gas	2.00	1.11	19.00	5.02
Service	2.00	0.50	8.00	2.81
Dry	1.00	0.33	5.00	2.50
Total:	10.00	3.02	37.00	13.59

	Year Ended December 31, 2003			
	Exploratory Wells		Development Wells	
	Gross [1]	Net [2]	Gross [1]	Net [2]
Oil	2	0.35	3	1.25
Natural Gas	2	1.60	7	4.49
Service	–	–	–	–
Dry	3	1.07	6	5.50
Total:	7	3.02	16	11.24

Notes:

(1) "**Gross**" means the total number of wells in which the Corporation has an interest.

(2) "**Net**" means the number of wells obtained by aggregating the working interest to be acquired by the Corporation in each of its gross wells.

For details concerning anticipated 2005 exploration and development activities in respect of Highpine's properties and assets, see "Highpine's Business – Principal Properties".

Production Estimates

The following table sets out the volumes of the proved plus probable gross production estimated forthe year ending December 31, 2005 as estimated by Paddock in assessing the future net revenue disclosed in the tables contained under "Highpine's Business – Oil and Natural Gas Reserves".

	Light and Medium Oil (bbls/d)	Heavy Oil (bbls/d)	Natural Gas (mcf/d)	Natural Gas Liquids (bbls/d)	BOE (boe/d)
2005 Pembina [1]	1,693	–	1,378	80	2,003
2005 Joffre/Gilby [1]	67	–	4,476	110	923
Total 2005	1,929	349	10,318	436	4,434

Note:

(1) Pembina and Joffre/Gilby each account for more than 20% of the estimated production attributable to Highpine's properties and assets.

Production History

The following tables summarize certain information respecting the production, product prices received, royalties paid, operating expenses and resulting netback for Highpine for the periods indicated.

Product Type/2004 Quarter	Average Daily Production Volume (1)	Average per Unit of Volume Production ($/bbl, $/mcf) Price Received	Royalties Paid	Production Costs	Resulting Netback
Light and Medium Oil and NGLs					
First Quarter	794	38.89	8.97	6.80	23.12
Second Quarter	1,425	46.87	12.61	9.01	25.25
Third Quarter	1,605	44.34	13.07	5.73	25.54
Heavy Oil					
First Quarter	175	31.32	5.76	7.91	17.65
Second Quarter	203	35.70	7.92	14.85	12.93
Third Quarter	207	40.70	7.83	11.70	21.17
Natural Gas					
First Quarter	5,046	6.46	1.33	0.88	4.24
Second Quarter	6,759	7.42	1.58	0.97	4.87
Third Quarter	7,091	6.41	1.99	0.72	3.70

Notes:

(1) Before deduction of royalties.

(2) Netbacks are calculated by subtracting royalties, operating expenses and transportation expenses from revenues.

The following table summarizes certain production information for each of Highpine's important fields for the nine months ended September 30, 2004.

	Light and Medium Oil (mbbls)	Heavy Oil (mbls)	Natural Gas (mmcf)	Natural Gas Liquids (mbbls)
Bantry	4.1	37.3	44.5	–
Joffre	20.7	–	925.7	24.0
Pembina/Nisku	246.8	–	540.8	26.5
Retlaw	19.7	19.6	46.4	1.4
Other	1.1	–	168.8	1.9
Total	292.4	56.9	1,726.2	53.8

Summary of Selected Reserve Information

The following table sets forth the interest to be acquired, gross reserves, Economic Life and Reserve Value information in respect of Highpine's properties and assets as at December 31, 2004.

	% Interest Acquired (1)(2)	Gross Reserves (mboe) (2)(3)(7)	Economic Life (years) (2)(3)(7)	Reserve Value (2)(3)(4)(5) ($000's)	%
Bantry	38.4	758	14.1	5,220	3.2
Joffre	62.0	1,525	23.0	26,646	16.1
Pembina/Nisku	26.0	7,931	40.0	109,250	66.0
Retlaw	56.8	557	15.0	7,983	4.8
Other	2.2	1,406	40.0	16,542	9.9
TOTAL (6)	12.1	12,177	32.0	165,641	100.0

Notes:

(1) The weighted average percentage interest share of total proved plus probable reserves to be acquired by the Corporation in respect of its properties and assets before the deduction of royalties payable to others.

(2) Based on total proved plus probable reserves as set out in the Paddock Report.

(3) Utilizing forecast cost and price assumptions.

(4) Discounted at 10%, before general and administrative expenses, interest costs, taxes, site restoration and abandonment costs.

(5) Net of capital expenditures. Does not include the value of the undeveloped lands.

(6) Columns may not add due to rounding.
(7) Average of the Economic Life column.

Incremental Exploitation and Development Potential

Management of the Corporation has identified several opportunities to increase existing production in Highpine's properties and assets, which are in addition to the future development projects taken into consideration by Paddock in estimating the reserve values contained in the Paddock Report. Opportunities being considered include:

- approximately 70 exploration and development drilling locations at Pembina, Joffre and Sturgeon Lake;
- well re-completions to convert wells that have been producing in various zones evaluated in the Paddock Report to produce from zones to which Paddock did not assign reserves;
- additional drilling locations that have been identified through a review of 2-D and 3-D seismic data;
- drilling of additional water injection wells and the addition of free-water knockouts to increase water disposal capacity at Bantry and Retlaw, which may allow for further increases in oil production beyond those evaluated in the Paddock Report; and
- increased production rates from the granting of GPP (unrestricted well flow notes) and incremental increases of oil reserves from higher reservoir recovery factors.

Neither the capital costs nor the potential incremental production associated with these opportunities are reflected in the Paddock Report.

The Corporation may also identify further development projects and other opportunities to optimize production from its properties and implement operational efficiencies to lower operating expenses from those forecasted in the Paddock Report, as it enhances its understanding of its properties and assets with the benefit of new information generated from ongoing operations.

Production History

The following table summarizes the sales volumes of crude oil and natural gas attributable to Highpine's properties and assets, before deduction of royalties, for the periods indicated. Average production for the month of September 2004 was approximately 3,190 boe/d.

	Nine Months Ended September 30,	Years Ended December 31,	
	2004	2003	2002
	(unaudited)	(audited)	(audited)
Crude oil and natural gas liquids (mbbls)	403	162	110
Average daily production (bbls/d)	1,471	443	301
Natural gas sales (mmcf)	1,726	1,563	660
Average daily sales (mcf/d)	6,301	4,281	1,809
Total oil equivalent (mboe)	691	422	220
Average daily production (boe/d)	2,521	1,157	603

Direct Revenue and Operating Expenses

The following table summarizes the revenue and operating expenses directly attributable to Highpine's properties and assets for the periods indicated.

	Nine Months Ended September 30,	Years Ended December 31,	
	2004	2003	2002
	(unaudited)	(audited)	(audited)
	$	$	$
Revenue:			
Petroleum and natural gas sales (1)	29,083,000	16,926,000	6,647,000
Royalties	7,466,000	3,109,000	1,426,000
Operating expenses	4,603,000	2,294,000	1,367,000
Operating Income	17,014,000	11,523,000	3,854,000

Note:

(1) Average product prices received: nine months ended September 30, 2004 - $42.10/boe; 2003 - $40.10/boe; and 2002 - $30.22/boe.

Marketing Arrangements

Highpine Crude Oil Summary

Crude oil produced by Highpine is currently marketed via Plains Marketing L.P. on 30 day Evergreen contracts, which are renegotiated on an annual basis.

Highpine did not enter into any physical hedging arrangements in 2004.

Highpine Natural Gas and Natural Gas Liquids Summary

Highpine markets the majority of its natural gas production on both the ATCO and TransCanada Corporation pipeline systems, to various creditworthy counterparties at the Canadian Gas Price Reporter 4A Daily Index under 30 day rolling arrangements.

Highpine holds two minor system gas contracts with Pan-Alberta Gas Ltd. and Cargill Ltd. which are for the economic life of reserves.

Highpine did not enter into any physical hedging arrangements in 2004.

Highpine's natural gas liquids are sold for the April 1 – March 31 contract year to various counterparties which are all now under price renegotiation for the 2005-2006 period.

SELECTED FINANCIAL INFORMATION

The following table summarizes selected financial information of Highpine as at and for the periods indicated and should be read in conjunction with the consolidated financial statements of Highpine and the notes to such consolidated financial statements included elsewhere in this prospectus.

	Nine Months Ended September 30, 2004	Years Ended December 31,		
		2003	2002	2001
	(unaudited) $	(audited) $	(audited) $	(audited) $
Revenues, net of royalties	21,617,000	13,817,000	5,221,000	2,429,000
Operating expenses	4,603,000	2,294,000	1,367,000	935,000
Cash flow from operations (1)	13,518,000	11,616,000	3,130,000	889,000
Per Equity Share (basis)	0.90	0.80	0.24	0.07
Per Equity Share (diluted)	0.89	0.80	0.24	0.07
Net earnings	2,129,000	19,108,000	1,056,000	59,000
Per Equity Share (basis)	0.14	1.32	0.08	0.00
Per Equity Share (diluted)	0.14	1.31	0.08	0.00
Total assets	138,941,000	44,041,000	23,697,000	12,645,000
Working capital (deficiency), excluding current bank debt	(13,581,000)	5,258,000	(633,000)	3,015,000
Bank debt	46,729,000	–	–	–
Shareholders' equity	47,538,000	34,385,000	15,086,000	10,847,000

Note:

(1) "Cash flow from operations" is not a recognized measure under GAAP. See "Non-GAAP Measures".

MANAGEMENT'S DISCUSSION AND ANALYSIS

Overview

This management's discussion and analysis ("**MD&A**") is intended to assist in the understanding of the trends and significant changes in the financial condition and results of operations of Highpine for the periods presented. The MD&A has been prepared by management in accordance with GAAP and should be read in conjunction with the audited consolidated financial statements as at December 31, 2003 and 2002 and for the years ended December 31, 2003, 2002 and 2001 and the unaudited interim consolidated financial statements as at and for the nine months ended September 30, 2004 and 2003 included in this prospectus.

Nine Months Ended September 30, 2004 Compared to Nine Months Ended September 30, 2003

On March 3, 2004, Highpine indirectly acquired the Rubicon Assets, for approximately $52 million (including associated liabilities). At the time of the Rubicon Acquisition, Rubicon owned significant producing properties relative in location to Highpine's Pembina producing properties. The results of operations from the Rubicon Acquisition are included in Highpine's operations from March 3, 2004. See "Highpine's Business – Rubicon Acquisition" and "Financial Statements for the Rubicon Energy Properties".

Revenues and Production

Gross revenue for the nine months ended September 30, 2004 amounted to $29.1 million, an increase of 131% from the same period in 2003 of $12.6 million. The increase in revenue was primarily as a result of increased production volumes resulting from the Rubicon Acquisition combined with production increases in the Pembina and Joffre areas; and increased commodity prices. Oil and NGL revenue was impacted by hedging losses of $1.5 million for the nine months ended September 30, 2004. Hedging gains were $150,000 for the nine months ended September 30, 2003.

Production increased by 1,388 boe/d or 123% for the nine months ended September 30, 2004 as compared to 2003.

The following table sets out production volumes for the periods indicated.

	Nine Months Ended September 30, 2004	2003	% Change
Production			
Oil and NGLs (bbls/d)	1,471	419	251%
Natural gas (mcf/d)	6,301	4,281	47%
Oil equivalent/day (boe/d)	2,521	1,133	123%

Oil and NGL contribution to revenue increased to 60% of total revenue for the nine months ended September 30, 2004 from 32% in the same period in 2003, reflecting the impact of the Rubicon Acquisition on the production mix, combined with increased oil production in the Pembina area.

The following tables set out the components of revenue and commodity pricing for the periods indicated:

	Nine Months Ended September 30, 2004	2003	% Change
	(unaudited)		
Revenue			
Oil and NGLs	$ 17,366,000	$ 4,007,000	333%
Natural gas	11,717,000	8,589,000	36%
	$ 29,083,000	$ 12,596,000	131%
Revenue Contribution			
Oil and NGLs	60%	32%	
Natural gas	40%	68%	

Royalties

Royalties, after giving effect to hedges, averaged 26% of revenue for the first nine months of 2004 compared to 19% for the first nine months of 2003. Royalty rates (excluding the hedging loss) averaged 24% of revenue for the first nine months of 2004. Royalty rates as a percentage of revenue were higher in the first nine months of 2004 due to higher royalty rates on properties acquired pursuant to the Rubicon Acquisition and higher royalty rates on wells at Pembina.

Operating Costs

Operating costs totalled $4.6 million for the nine months ended September 30, 2004 compared to $1.3 million for the nine months ended September 30, 2003. Operating costs increased 58% to $6.66/boe for the nine months ended September 30, 2004 from $4.21/boe for the nine months ended September 30, 2003. These increases were as a result of higher operating costs relating to the properties acquired pursuant to the Rubicon Acquisition and increased industry related costs.

Operating Netbacks

Operating netbacks decreased 15% from $28.98/boe for the nine months ended September 30, 2003 to $24.63 for the nine months ended September 30, 2004, primarily as a result of increased royalties and operating costs per boe.

The following table summarizes operating net backs for the periods indicated.

	Nine Months Ended September 30,	
	2004	2003
Oil and NGL price/ bbl	$ 43.10	$ 35.01
Natural gas price/mcf	6.79	7.35
Sales price/boe	$ 42.10	$ 40.73
Net royalties/boe	$ 10.81	$ 7.54
Production expenses/boe	6.66	4.21
Operating netbacks/boe	$ 24.63	$ 28.98

General and Administrative Expenses

General and administrative expenses decreased 37% from $3.77/boe for the nine months ended September30, 2003 to $2.38/boe for the nine months ended September 30, 2004 as overheads were spread over largerproduction volumes.

The following table sets out general and administrative costs for the periods indicated.

	Nine Months Ended September 30,		% Change
	2004	2003	
	(unaudited)		
Gross expenses	$ 1,878,000	$ 1,298,000	45%
Capitalization	(232,000)	(133,000)	74%
Net expenses	$ 1,646,000	$ 1,165,000	41%
$/boe	2.38	3.77	
% capitalized	12%	10%	

Financing Costs

Interest costs increased to $1.8 million from $0.2 million for the first nine months of 2004 compared to the same period in 2003, primarily as a result of costs of arranging for and financing the Rubicon Acquisition.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion expense ("**DD&A**") increased 191% to $10.4 million in the first nine months of 2004 from $3.6 million in the same period of 2003. On a per boe basis, DD&A increased 30% to $15.06/boe in the first nine months of 2004 from $11.75/boe in the first nine months of 2003. The increase in DD&A was due to costs included in the depletion base in respect of the Rubicon Assets as well as significant land and facility expenditures made in the first nine months of 2004.

Stock Based Compensation

Effective September 30, 2004, Highpine retroactively adopted the amended standard with respect to stock-based compensation which requires the use of the fair value method of valuing stock options granted, which resulted in $0.2 million of costs for the first nine months of 2004, as compared to $0.1 million for the first nine months of 2003. The increase for the nine months of 2004 is due to additional options granted in the period.

Gain on Sale of Investment

During the nine month period ended September 30, 2003, Highpine sold its shares in Monolith, a private oil and gas company, for a gain totalling approximately $18 million. Consideration received on the disposition of the investment consisted of $14.2 million of cash or cash equivalents and a secured debenture in the principal amount of $3.7 million bearing interest at 9% per annum, payable monthly. The debenture, which was secured, but subordinate to the purchaser's secured credit facility, was repaid in its entirety in January 2004. As a result of the resolution of certain contingent items on the disposition of the shares in Monolith, the net proceeds and gain on sale were adjusted during the three months ended December 31, 2003 resulting in a decrease in the gain on sale of approximately $0.6 million and were further adjusted in the nine months ended September 30, 2004 resulting in an increase in the gain on sale of $0.3 million. As a result, the final net gain on sale as at September 30, 2004, of Highpine's investment in Monolith totalled approximately $17.7 million.

Income Taxes

Highpine has not incurred any cash taxes, other than Large Corporation Tax, which amounted to $0.1 million for the first nine months of 2004 compared to $53,000 for the first nine months of 2003. Highpine does not expect to pay any cash taxes in 2004 based on existing tax pools and planned expenditures. Although current tax horizons depend on product prices, production levels and the nature, magnitude and timing of capital expenditures, Highpine management currently believes no cash income tax will be payable for two to three years. The effective income tax rate for the nine months ended September 30, 2003 was lowered significantly from the rate for the comparable period in 2004 by the exclusion of half of the capital gain on the sale of the Monolith shares and the receipt of a non-taxable dividend from Monolith of approximately $2.1 million.

Funds Flow and Net Earnings

Funds flow from operations increased 40% to $13.5 million in the first nine months of 2004 compared to $9.7 million in the first nine months of 2003 reflecting increased production volumes and commodity prices received. Net earnings declined in the first nine months of 2004 versus the comparative period in 2003 primarily as a result of the one time gain on the sale of shares of Monolith included in the 2003 net earnings. Highpine defines "funds flow from operations" as cash provided by operations before changes in non-cash operating working capital. See "Non-GAAP Measures".

Capital Expenditures

Gross capital expenditures were $42.1 million in the first nine months of 2004, excluding the Rubicon Acquisition, up 135% from gross capital expenditures of $17.9 million in the first nine months of 2003. The increase relates primarily to Highpine's drilling programs at Pembina and Joffre.

The following table sets out Highpine's net capital expenditures for various categories of expenditure for the periods indicated.

	Nine Months Ended September 30,		
	2004	2003	% Change
	(unaudited)		
Land and seismic	$ 7,136,000	$ 6,336,000	13%
Drilling and completions	23,739,000	7,815,000	204%
Facilities and equipment	11,127,000	2,526,000	340%
Property acquisitions and dispositions (net)	(4,565,000)	178,000	–
Corporate acquisition	51,151,000	–	–
Other	77,000	20,000	305%
Total	$ 88,665,000	$ 16,875,000	425%

Rubicon Acquisition

In March 2004, Highpine indirectly acquired the Rubicon Assets. See "Highpine's Business – Rubicon Acquisition". The acquisition was accounted for by the purchase method of accounting with the results of operations included from the date of acquisition. The allocation to the fair value of assets and liabilities acquired was as follows:

Net assets acquired and liabilities assumed:		(unaudited)
Property, plant and equipment	$	51,151,000
Goodwill		14,081,000
Working capital deficiency		(6,314,000)
Asset retirement obligation		(950,000)
Future income taxes		(12,485,000)
Bank indebtedness		(3,394,000)
	$	42,089,000

Consideration was comprised of		
Cash	$	41,810,000
Transaction costs		279,000
	$	42,089,000

Changes in Accounting Policies

Asset Retirement Obligations

A new Canadian accounting standard for asset retirement obligations is effective for fiscal years beginning on or after January 1, 2004. As a result of the implementation of this new standard, the present value of the liability for future abandonment costs has been recorded at $1.4 million at September 30, 2004. The transitional provisions associated with this new standard require that it be applied retroactively which gives rise to a restatement of certain prior periods. As a result, comparative numbers for the year ended December 31, 2003 have been restated. Property plant and equipment increased by $0.3 million, future income taxes increased by $70,000 and retained earnings increased by $0.1 million

Stock-Based Compensation

Highpine retroactively adopted the amended standard with respect to stock based compensation, effective September 30, 2004. As a result of its adoption of the amended standard, Highpine recognized a compensation expense of $0.1 million for the year ended December 31, 2003 and $12,000 for the year ended December 31, 2002, with a decrease in net earnings and a corresponding increase in contributed surplus.

Hedging

Effective for 2004, the new CICA Accounting Guideline 13, "Hedging Relationships" requires that hedging relationships be identified, designated, documented and measured in order for Highpine to apply hedge accounting. Highpine was in compliance with this new standard, and all hedges will continue to be accounted for using hedge accounting.

Transportation

Effective January 1, 2004, Highpine commenced classifying field level transportation costs separately as an operating cost rather than as a deduction from oil and gas revenues. The comparative figures have been disclosed in a similar manner. Adopting this presentation has no impact on funds from operations or net earnings.

Financial Instruments

Highpine makes use of specific commodity hedging instruments to reduce the variability in cash flows from fluctuations in product prices to help ensure a source of funding for the capital programs.

At September 30, 2004, Highpine had commodity swap agreements under which it agreed to sell 300 bbl/d at $40.85/bbl and 500/bbl/d at $44.00/bbl to December 31, 2004, and another agreement to sell 700/bbl/d at $47.20/bbl for the 2005 calendar year. The contracts settle monthly and qualify for hedge accounting whereby any gains or losses are included in oil revenue in the month realized.

Year Ended December 31, 2003 Compared to Year Ended December 31, 2002

Revenue and Production

Gross revenue for 2003 totalled $16.9 million representing a 155% increase over 2002 gross revenue of $6.6 million as a result of higher production volumes and higher product prices.

Production volumes for 2003 averaged 1,157 boe/d compared to an average rate of 603 boe/d in 2002, an increase of 554/boe/d or 92%. The production increase for the year was due primarily to increased production in the Joffre area, which accounted for 67% of production in 2003 as compared to 29% in 2002 on a boe basis.

The following table sets out production volumes for the periods indicated.

	Years Ended December 31, 2003	2002	% Change	Years Ended December 31, 2002	2001	% Change
Production						
Oil and NGLs (bbls/d)	443	301	47%	301	237	27%
Natural gas (mcf/d)	4,281	1,809	137%	1,809	545	232%
Boe/d	1,157	603	92%	603	328	84%

Natural gas prices in 2003 averaged $7.28/mcf as compared to $4.71/mcf in 2002, an increase of 55%. Oil and NGL prices in 2003 were $34.29/bbl as compared to $32.20/bbl in 2002, an increase of 6%.

The contribution of natural gas to revenue increased to 67% in 2003 from 47% in 2002, reflecting a weighting of new production to natural gas, particularly in the Joffre area.

The following table sets out the change in components of revenue for the periods indicated.

	Years Ended December 31, 2003	2002	% Change	Years Ended December 31, 2002	2001	% Change
Revenue						
Oil and NGLs	$ 5,546,000	$ 3,540,000	57%	$ 3,540,000	$ 2,192,000	61%
Natural gas	11,380,000	3,107,000	266%	3,107,000	813,000	282%
	$ 16,926,000	$ 6,647,000	155%	$ 6,647,000	$ 3,005,000	121%
Revenue Contribution						
Oil and NGLs	33%	53%		53%	73%	
Natural gas	67%	47%		47%	27%	

Royalties

Royalties totalled $3.1 million and averaged 18% of production revenue for 2003 as compared to a total of $1.4 million and an average rate of 21% for 2002, all net of ARTC.

Operating Costs

Operating costs were $2.3 million in 2003 and on a boe basis decreased 13% to $5.44/boe from 2002 operating costs of $6.22/boe and $1.4 million. The decrease is attributable to lower operating costs on Joffre gas production.

Operating Netbacks

The increase in commodity prices combined with lower operating costs resulted in a 56% increase in operating netbacks in 2003 compared to 2002.

The following table summarizes operating netbacks for the periods indicated.

	Years Ended December 31,	
	2003	2002
Oil and NGLs price/bbl	$ 34.29	$ 32.20
Natural gas price/mcf	7.28	4.71
Sales price/boe	40.10	30.22
Net royalties/boe	(7.36)	(6.48)
Production expenses/boe	(5.44)	(6.22)
Operating netbacks/boe	$ 27.30	$ 17.52

General and Administrative Expenses

General and administrative expenses decreased 20% from $5.47/boe in 2002 to $4.40/boe in 2003 as the volumes increase in 2003 resulted in lower per unit costs.

The following table summarizes general and administrative expenses for the periods indicated.

	Years Ended December 31,			Years Ended December 31,		
	2003	2002	% Change	2002	2001	% Change
Gross expenses	$ 2,032,000	$ 1,413,000	44%	$ 1,413,000	$ 915,000	54%
Capitalization	(176,000)	(209,000)	(16%)	(209,000)	(203,000)	3%
Net expenses	$ 1,856,000	$ 1,204,000	54%	$ 1,204,000	$ 712,000	69%
$/boe	4.40	5.47		5.47	5.95	
% capitalized	9%	15%		15%	22%	

Financing Costs

Interest and finance costs increased to $0.2 million, up from $0.1 million in 2002 due to higher average debt levels in 2003 that arose from capital spending during the year. Bank debt was eliminated in September 2003 with the proceeds received from the sale of the Monolith shares.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion amounted to $4.9 million or $11.55/boe for 2003, compared with $1.7 million or $7.88/boe in 2002, representing a 47% increase on a per boe basis. The increase is due to the higher costs of adding new reserves.

Other Income

During 2003, Highpine sold its shares in Monolith for a net gain of $17.7 million and also received a dividend of $2.1 million on account of its Monolith Shares. During the year ended December 31, 2002, Highpine received a dividend of $0.6 million on account of its Monolith Shares.

Income Taxes

Taxes are comprised of future income taxes and capital taxes. Capital taxes relate to the Large Corporation Tax of $70,000 in 2003, up from $14,000 in 2002 due primarily to the net earnings of $19.1 million realized in 2003 that is included in the capital base for capital taxes purposes. The effective tax rate decreased in 2003 as compared to 2002 due to the non-taxable portion of the Monolith capital gain and non-taxable dividend.

Funds Flow and Net Earnings

Funds flow from operations increased 271% to $11.6 million in 2003, up from $3.1 million in 2002. Net earnings increased to $19.1 million from $1.1 million in 2002. The increases in cash flow and net earnings in 2003 were primarily due to higher production volumes and commodity prices realized in 2003. In addition, earnings were substantially higher in 2003 due to the

$17.7 million gain and $2.1 million dividend realized on the Monolith investment. Highpine defines "funds flow from operations" as cash provided by operations before changes in non-cash operating working capital. See "Non-GAAP Measures".

Capital Expenditures

Gross capital expenditures of $24.6 million were incurred in 2003, up from $11.7 million in 2002. Divestitures of non-strategic properties resulted in proceeds of $1.1 million in 2003.

The following table sets out Highpine's net capital expenditures for the periods indicated.

	Years Ended December 31, 2003	Years Ended December 31, 2002	% Change
Land and seismic	$ 11,644,000	$ 4,118,000	183%
Drilling and completions	8,793,000	4,286,000	105%
Facilities and equipment	2,843,000	2,053,000	39%
Property acquisitions and disposition (net)	194,000	776,000	(75%)
Other	32,000	35,000	(11%)
Total	$ $23,506,000	$ $11,268,000	109%

Exploration and development expenses more than doubled from $4.3 million in 2002 to $8.8 million in 2003 with expenditures for land increasing 470% to $8.9 million in 2003.

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

Revenue and Production

Gross revenue for 2002 totalled $6.6 million, an increase of 121% over 2001 gross revenue of $3.0 million. Production volumes for 2002 averaged 603 boe/d, an increase of 84% compared to the 2001 average of 328 boe/d.

The following table sets out production contribution by product for the periods indicated.

	Years Ended December 31, 2002	Years Ended December 31, 2001	% Change
Production			
Oil and NGLs (bbls/d)	301	237	27%
Natural gas (mcf/d)	1,809	545	232%
Boe/d	603	328	84%

Oil and NGL prices averaged $32.20/bbl in 2002 compared to $25.37 in 2001, an increase of 27%, and natural gas prices averaged $4.71/mcf in 2002 compared to $4.09 in 2001, an increase of 15%.

The contribution of natural gas to total revenue increased to 47% in 2002 from 27% in 2001, as a result of gas production increases in the Joffre area.

The following table sets out the components of revenue for the periods indicated.

	Years Ended December 31, 2002	Years Ended December 31, 2001	% Change
Revenue			
Oil and NGLs	$ 3,540,000	$2,192,000	62%
Natural gas	3,107,000	813,000	282%
	$ 6,647,000	$3,005,000	121%
Revenue Contribution			
Oil and NGLs	53%	73%	
Natural gas	47%	27%	

Royalties

Royalties totalled $1.4 million in 2002 or $6.48/boe, as compared to $0.6 million and $4.82/boe in 2001. Royalties constituted 21% of revenues in 2002 and 19% of revenues in 2001.

Operating Costs

Operating costs totalled $1.4 million in 2002 and $935,000 in 2001. Operating costs on a per boe basis decreased to $6.22/boe in 2002 compared to $7.82/boe in 2001, a decline of 20%. This was a result of gas production in the Joffre area that had lower operating costs.

Operating Netbacks

Increases in commodity prices combined with lower operating costs resulted in a 40% increase in operating netbacks in 2002 as compared to 2001.

The following table summarizes operating netbacks for the periods indicated.

	Years Ended December 31,	
	2002	**2001**
Oil & NGLs price/bbl	$ 32.20	$ 25.37
Natural gas price/mcf	4.71	4.09
Sales price/boe	30.22	25.14
Net royalties/boe	(6.48)	(4.82)
Operating costs/boe	(6.22)	(7.82)
Operating netbacks/boe	$ 17.52	$ 12.50

General and Administrative Expenses

General and administrative expenses decreased 8% from $5.95/boe in 2001 to $5.47/boe in 2002 as volume increases in 2002 resulted in lower per unit costs.

The following table summarizes general and administrative expenses for the periods indicated.

	Years Ended December 31,		
	2002	**2001**	**% Change**
Gross expenses	$ 1,413,000	$ 915,000	54%
Capitalization	(209,000)	(203,000)	3%
Net expenses	$ 1,204,000	$ 712,000	69%
$/boe	5.47	5.95	
% capitalized	15%	22%	

Financing Costs

Interest and finance costs were $0.1 million in 2002 due to bank borrowings in the third and fourth quarters. Highpine repaid this debt by year end of 2002. No debt was incurred in 2001.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion amounted to $1.7 million or $7.88/boe for the year ended December 31, 2002, compared to $796,000 or $6.66/boe in 2001. The increase is due to the production volume increases in the year combined with higher costs of adding new reserves.

Other Income

During 2002, Highpine received dividend and interest income aggregating $0.6 million with interest and other income of $0.1 million received in 2001.

Income Taxes

Taxes are comprised of future income taxes and capital taxes. Capital taxes relate to the Large Corporation Tax of $14,000 in 2002, up from $3,000 in 2001 due to the larger capital base resulting from the equity issue in 2002. Future taxes increased as a result of the higher earnings realized in 2002.

Funds Flow and Net Earnings

Funds flow from operations increased 252% to $3.1 million in 2002, up from $0.9 million in 2001. Net earnings increased to $1.1 million from $59,000 in 2001. The increases in cash flow and net earnings in 2002 were primarily due to higher production volumes and commodity prices realized in 2002. Highpine defines "funds flow from operations" as cash provided by operations before changes in non-cash operating working capital. See "Non-GAAP Measures".

Capital Expenditures

Gross capital expenditures of $11.7 million were incurred in 2002, up from $2.6 million in 2001. Divestitures of non-strategic properties resulted in proceeds of $0.5 million in 2002.

The following table summarizes capital expenditures for the periods indicated.

	Years Ended December 31, 2002	2001	% Change
Land and seismic	$ 4,118,000	$ 1,102,000	274%
Drilling and completions	4,286,000	1,377,000	211%
Facilities and equipment	2,053,000	124,000	1,556%
Property acquisition and disposition (net)	776,000	–	–
Other	35,000	35,000	–
Total	$ 11,268,000	$ 2,638,000	327%

Liquidity and Capital Resources

At September 30, 2004, the Corporation had a working capital deficiency of $13.6 million with capital expenditures being funded by funds from operations, the $10.8 million of gross proceeds realized from the private placement of 2,000,000 Common Shares in July 2004 and the Corporation's bank line which was drawn to $46.7 million. At September 30, 2004, the Corporation had approximately $28.3 million available on its bank line, which was being used to fund the working capital deficiency and ongoing operations. Subsequent to September 30, 2004, the Corporation completed the Special Warrant Offering for gross proceeds of $29.7 million, of which $13 million was used to pay down a portion of the bank debt, with the remainder of the proceeds used to fund ongoing operations. In February 2005, the Corporation's credit facilities were increased to $80 million with $25 million being non-revolving and due for repayment no later than May 31, 2005. For a description of the credit facilities, see note 1 to the table under "Capitalization". At February 28, 2005, approximately $54 million was outstanding under the credit facilities.

Highpine's capital budget for 2005 is approximately $60 million and includes the drilling of approximately of 40 gross wells (20 net). Of the total budget, approximately $15 million is allocated to development drilling, approximately $27 million is allocated to exploration drilling (including undeveloped land acquisition and seismic programs) and approximately $18 million is allocated to facilities and tie-ins. See also "Highpine's Business – Business Plan and Growth Strategies". This capital program will be funded through a combination of cash flow, bank debt and the net proceeds of the Offering. See "Use of Proceeds".

Critical Accounting Estimates

Highpine follows the full cost method of accounting for exploration and development expenditures wherein all costs related to the exploration for and the development of oil and gas reserves are capitalized whether successful or not. Depletion of exploration and development costs and depreciation of production equipment are provided on the unit-of-production method based upon estimated proven oil and gas reserves before royalties in each area of interest. For purposes of this calculation, reserves and production of natural gas are converted to common units based on their approximate relative energy content. The cost of acquiring and evaluating unproven properties are initially excluded from the depletion calculation. These properties are assessed periodically for impairment. 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 the costs subject to depletion. Changes in estimated proven reserves or further development costs have a direct impact on depletion and depreciation expense.

The alternate method of accounting for oil and natural gas properties and equipment is the successful efforts method. A major difference in applying the successful efforts method is that exploratory dry holes and geological and geophysical exploration costs would be charged against net earnings in the year incurred rather than being capitalized to property, plant and equipment.

Oil and natural gas reserves

All of Highpine's proved oil and gas reserves are evaluated and reported on by an independent petroleum engineering consultant. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to a number of uncertainties and various interpretations. Highpine expects that over time its reserve estimates will be revised upward or downward based on updated information such as results of future drilling, testing and production levels. Reserve estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion and depreciation. A revision to the reserve estimates could result in a higher or lower DD&A charge to net earnings. Downward revisions to reserve estimates could also result in a write-down of oil and natural gas properties, plant and equipment under the ceiling test.

Full Cost Accounting Ceiling Test

Highpine places a limit on the carrying value of property, plant and equipment, which may be depleted against revenues of future periods (the "**ceiling test**"). The carrying value is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying value. When the carrying value is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value of assets exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market expected from the production of proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate. No write-down was required at September 30, 2004.

Asset Retirement Obligations

Highpine recognizes the fair value of an Asset Retirement Obligation ("**ARO**") in the period in which it is incurred when a reasonable estimate of the fair value can be made. The fair value of the estimated ARO is recorded as a liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on the unit-of-production method based on proved reserves. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is expensed to income in the period. Actual costs incurred upon the settlement of the ARO are charged against the ARO.

Determination of the original undiscounted costs are based on estimates using current costs and technology in accordance with existing legislation and industry practice. The estimation of these costs can be affected by factors such as the number of wells, drilled, well depth and area specific environmental legislation.

Goodwill

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the sum of the amounts allocated to the assets acquired, less liabilities assumed, based on their fair values. Goodwill is not amortized and is tested for impairment annually or more frequently if events or changes in circumstances indicate that the asset might be impaired. The impairment test is carried out in two steps. In the first step, the carrying amount of the reporting segment is compared to its fair value. When the fair value of a reporting segment exceeds its carrying amount, goodwill of the reporting segment is considered not be impaired and the second step of the impairment test is unnecessary. The second step is carried out when the carrying amount of the reporting segment's goodwill exceeds its fair value, in which case the implied fair value of the reporting segment's goodwill is compared with its carrying amount to measure the amount of the impairment loss, if any. The implied fair value of goodwill is determined in the same manner as the value of the goodwill is determined in a business combination using the fair value of the reporting segment as if it were the purchase price. When the carrying amount of the reporting segment's goodwill exceeds the implied fair value of the goodwill, an imp airment loss is recognized in an amount equal to the excess.

Future Income Taxes

Highpine's income taxes are calculated using the liability method of accounting for income taxes. Under this method, future income tax liabilities and future income tax assets are recorded based on the differences between the carrying amount of assets and liabilities in the consolidated balance sheet and their tax basis using income tax rates substantively enacted at the balance sheet date. The effect of changes in rates on future income tax liabilities and assets is recognized in the period in which the change occurs. A valuation allowance is recorded against any future income tax assets if it is more likely than not that the asset will not be realized.

The liability method of accounting requires Highpine to schedule out all existing temporary differences and to recalculate the future income tax balance using tax rates in effect when temporary differences are expected to reverse. Forecasts of estimated net revenue streams are utilized to calculate the future tax provision and, as such, are subject to revisions, both upwards and downwards, that are not known at this time. In addition to these revisions, future capital activities can impact the timing of the reversal of any temporary differences. These differences can have an impact on the amount of future taxes determined at a point in time, and to the extent that these differences are created, they can impact the charge against earnings for future taxes.

Stock-based Compensation

Highpine's share option plan provides for granting of options to officers, directors, employees, consultants and other service providers. Highpine uses the fair value method for valuing stock option grants. Compensation costs attributable to share options granted are measured at estimated fair value at the grant date and expensed over the term of the option with a corresponding increase to contributed surplus. Upon exercise of the stock options, consideration paid by the option holder, together with the amount previously recognized in contributed surplus is recorded as an increase to share capital.

Business Risks and Uncertainties

Highpine is exposed to numerous risks and uncertainties associated with the exploration for and development and acquisition of crude oil, natural gas and NGLs. Primary risks include the uncertainty associated with exploration drilling, changes in production practices, product pricing, industry competition and government regulation.

Drilling activities are subject to numerous technical risks and uncertainties. Highpine attempts to minimize exploration risk by utilizing trained professional staff and conducting extensive geological and geophysical analysis prior to drilling wells.

Highpine utilizes sound marketing practices in an attempt to partially offset the cyclical nature of commodity prices which is subject to external influences beyond Highpine's control. Fluctuations in commodity prices and foreign exchange rates may significantly impact Highpine's revenue. The oil and natural gas industry is extremely competitive and Highpine must compete with numerous larger, well-established organizations in all phases of the exploration business.

Highpine monitors and complies with current government regulations that affect its activities, although operations may be adversely affected by changes in government policy, regulations or taxation. In addition, Highpine maintains a level of liability, property and business interruption insurance which is believed to be adequate for Highpine's size and activities, but is unable to obtain insurance to cover all risks within the business or in amounts to cover all possible claims.

See "Risk Factors" for additional information on the risks and uncertainties to which Highpine is subject.

CAPITALIZATION

The following table outlines Highpine's capitalization as at the dates noted.

	Authorized	Outstanding as at December 31, 2003	Outstanding as at February 28, 2005	Outstanding as at February 28, 2005 after giving effect to the Offering (4)
		(audited)	(unaudited)	(unaudited)
Debt:				
Bank Loan (1)		$nil	$54,000,000	$nil
Special Warrants:	3,300,000	$nil	$28,584,000 (3,300,000 wts)	$nil (nil wts)
Share Capital:(2)				
Common Shares (3)	Unlimited	$13,454,933 (13,195,083 shares)	$31,213,000 (17,252,906 shares)	$127,454,800 (24,708,011 shares)
Series 1 Class B Shares	3,000,000	$157 (1,270,833 shares)	$nil (nil shares)	$nil (nil shares)

Notes:

(1) Highpine has an extendible revolving term credit facility (the "Revolving Facility") in the amount of $45 million, a non-revolving non-extendible term credit facility (the "Non-Revolving Facility") in the amount of $25 million and a demand operating credit facility (the "Operating Facility") in the amount of $10 million with Canadian financial institutions (collectively, the "Credit Facilities"). The Revolving Facility and Non-Revolving Facility must be repaid by May 31, 2005 and the Operating Facility must be repaid on demand. The Revolving Facility may be extended by the Corporation for a further 364 day revolving period. The Revolving Facility may be drawn down or repaid at any time and bears interest at the bank's prime rate plus 0.25% per annum. The Non-Revolving Facility bears interest at the bank's prime rate plus 1.75% per annum. The Operating Facility bears interest at the bank's prime rate plus 1.75% per annum. The Corporation is required to meet certain financial based covenants to maintain the Credit Facilities. The Credit Facilities are secured by a general security agreement and a first floating charge over all of the Corporation's assets. Various borrowing options are available under the Credit Facilities, including prime rate loans and bankers' acceptances loans. The Credit Facilities contain standard commercial covenants for facilities of this nature. The current borrowing base under the Revolving Facility and Operating Facility is approximately $54 million.

(2) Highpine is authorized to issue an unlimited number of Common Shares and an unlimited number of Class B Shares, issuable in series. At the dates referred to in this table, other than the 1,270,833 Series 1 Class B Shares outstanding as at December 31, 2003, there were no Class B Shares outstanding. See "Share Capital"

(3) As at February 28, 2005, 1,774,637 Common Shares were reserved for issuance under Highpine's share option plan at exercise prices ranging from $2.60 to $14.00. See "Share Option Plan".

(4) Based on the issuance of 4,000,000 Common Shares for aggregate gross proceeds of $72,000,000 less the Underwriters' fee of $3,742,200 and expenses of the Offering estimated to be $600,000, the net proceeds to the Corporation from the Offering are estimated to be $67,657,800. These values also give effect to the issuance of 3,455,105 Common Shares issuable upon the exercise or deemed exercise of the 3,300,000 Special Warrants. See "Plan of Distribution".

(5) As at September 30, 2004, Highpine's retained earnings were $22,945,000, its asset retirement obligations totalled $1,401,000 and its provision for future income tax was $20,407,000. See "Pro Forma Consolidated Financial Statements of Highpine Oil & Gas Limited".

USE OF PROCEEDS

The net proceeds to the Corporation from the sale of Common Shares hereunder are estimated to be $67,657,800, after deducting the Underwriters' fee of $3,742,200 and the estimated expenses of the Offering of $600,000. See "Plan of Distribution – Public Offering". The net proceeds of the Offering will be used by the Corporation to temporarily reduce bank indebtedness, which is expected to be redrawn, as needed, to fund the Corporation's ongoing exploration and development activities, and for general working capital purposes. In particular, the net proceeds will be used, together with cash flow and bank debt, to fund the Corporation's 2005 capital expenditure program, which contemplates expenditures of approximately $60 million. See "Highpine's Business – Business Plans and Growth Strategies" for additional information on Highpine's planned capital expenditures. There may be circumstances, however, where, for sound business reasons, a reallocation of funds may be necessary. See also "Relationship Between Highpine's Banker and an Underwriter".

The net proceeds to the Corporation from the sale of Special Warrants were used by the Corporation to reduce bank indebtedness incurred as a result of the Rubicon Acquisition and for funding the Corporation's exploration and development activities.

PLAN OF DISTRIBUTION

Public Offering

Pursuant to an underwriting agreement (the "**Underwriting Agreement**") dated as of March 24, 2005, between the Corporation and the Underwriters, the Corporation has agreed to issue and sell an aggregate of 4,000,000 Common Shares to the Underwriters, and the Underwriters have severally agreed to purchase such Common Shares on April 5, 2005, or such other date, not later than April 19, 2005, as may be agreed by the Corporation and the Underwriters. Delivery of the Common Shares is conditional upon payment of $18.00 per Common Share by the Underwriters to the Corporation at closing. The Underwriting Agreement provides that the Corporation will pay the Underwriters' fee of $0.99 per Common Share in respect of 3,780,000 Common Shares issued and sold by the Corporation, for an aggregate fee payable by the Corporation of $3,742,200, in consideration for their services in connection with the Offering. The offering price of the Common Shares was determined by negotiation between the Corporation and the Underwriters.

The obligations of the Underwriters under the Underwriting Agreement are several and not joint, and may be terminated at their discretion on the basis of their assessment of the state of the financial markets and may also be terminated by the Underwriters upon the occurrence of certain stated events. If an Underwriter fails to purchase the Common Shares that it has agreed to purchase, the other Underwriters may, but are not obligated to, purchase such Common Shares. The Underwriters are, however, obligated to take up and pay for all Common Shares if any are purchased under the Underwriting Agreement. The Underwriting Agreement also provides that the Corporation will indemnify the Underwriters and their directors, officers, agents, shareholders and employees against certain liabilities and expenses.

It is expected that closing will occur on or about April 5, 2005, or such other date, not later than April 19, 2005, as the Corporation and the Underwriters may agree. Definitive certificates representing the Common Shares will be available for delivery at closing.

Pursuant to policy statements of certain securities commissions, the Underwriters may not, throughout the period of distribution, bid for or purchase Common Shares. The foregoing restriction is subject to exceptions, on the condition that the bid or purchase not be engaged in for the purpose of creating actual or apparent active trading in, or raising the price of, the Common Shares. Such exceptions include a bid or purchase permitted under the by-laws and rules of the TSX relating to market stabilization and passive market making activities and a bid or purchase made for and on behalf of a customer where the order was not solicited during the period of distribution, provided that the bid or purchase was not engaged in for the purpose of creating actual or apparent active trading in, or raising the price of the Common Shares. The Corporation has been advised by the Underwriters that, in connection with the Offering, the Underwriters may effect transactions which stabilize or maintain the market price of the Common Shares at levels other than those which might otherwise prevail in the open market. Such transactions, if commenced, may be discontinued at any time.

The Corporation has agreed that, subject to certain exceptions, it will not offer or issue, or enter into an agreement to offer or issue, Common Shares or any securities convertible or exchangeable into Common Shares for a period of 90 days subsequent to the closing date of the Offering without the consent of Tristone Capital Inc. and FirstEnergy Capital Corp., on behalf of the Underwriters, which consent may not be unreasonably withheld.

The Corporation has applied to list the Common Shares distributed pursuant to the Offering and the Common Shares issuable upon exercise of the outstanding Special Warrants on the TSX. Listing will be subject to the Corporation fulfilling all of the listing requirements of the TSX.

The Common Shares offered hereby have not been and will not be registered under the *United States Securities Act of 1933*, as amended (the "**1933 Act**"), or any state securities laws, and accordingly may not be offered or sold within the United States or to U.S. persons (as such term is defined in Regulation S under the 1933 Act), except in transactions exempt from the registration requirements of the 1933 Act and applicable state securities laws. The Underwriting Agreement permits the Underwriters to offer and resell the Common Shares that they have acquired pursuant to the Underwriting Agreement to certain qualified institutional buyers and accredited investors in the United States, provided such offers and sales are made in accordance with Rule 144A under the 1933 Act or another exemption from the registration requirements of the 1933 Act.

In addition, until 40 days after the commencement of the Offering, an offer or sale of Common Shares offered under this prospectus within the United States by any dealer (whether or not participating in the Offering) may violate the registration requirements of the 1933 Act.

Special Warrant Offering

On October 20, 2004, the Corporation completed a private placement of an aggregate 3,300,000 Special Warrants at a price of $9.00 per Special Warrant pursuant to prospectus exemptions under applicable securities legislation and in accordance with the Agency Agreement between Highpine and the Special Warrant Agents. Pursuant to the Agency Agreement, the Special Warrant Agents agreed to offer the Special Warrants for sale on a private placement basis, at a price of $9.00 per Special Warrant. The gross proceeds received by the Corporation from the sale of the Special Warrants totalled $29,700,000. Pursuant to the Agency Agreement, the Special Warrant Agents received a fee equal to 5.5% of the gross proceeds from the sale of the Special Warrants, for an aggregate fee of $1,633,500. No commission or fee will be payable to the Special Warrant Agents or otherwise by the Corporation in connection with the distribution of the Common Shares upon exercise of the Special Warrants. The Common Shares issuable upon exercise of the Special Warrants are not being underwritten by the Underwriters and the Underwriters will not receive any fees in connection with the distribution of those Common Shares, except for any fee that FirstEnergy Capital Corp. and Tristone Capital Inc. received in their capacity as the Special Warrant Agents.

The Special Warrants were issued pursuant to the Special Warrant Indenture between the Corporation and the Trustee. Since the date of issuance, no Special Warrants have been exercised. Subject to certain adjustments, each Special Warrant entitles the holder thereof to acquire, at no additional cost to the holder, 1.047 Common Share and at any time until the Expiry Time.

In the event that a receipt for this prospectus has not been obtained on or prior to the Clearance Deadline from the securities commissions in each of the Filing Provinces, each holder of Special Warrants resident in a Filing Province in which such receipt has not been obtained (or, in the case of holders of Special Warrants resident outside of the Filing Provinces, if a receipt has not been obtained in the Province of Alberta) shall thereafter be entitled to receive, upon the exercise or deemed exercise of the Special Warrants, 1.152 Common Shares (in lieu of 1.047 Common Share otherwise receivable) at no additional cost.

This prospectus is being filed in the Filing Provinces to qualify the distribution of the Common Shares to be issued upon the exercise of the Special Warrants in addition to the Common Shares to be distributed in connection with the Offering.

Any Special Warrants not exercised prior to the Expiry Time shall, by their terms, be deemed to have been exercised immediately prior to the Expiry Time without any further action on the part of the holder.

Holders of Special Warrants who wish to exercise the Special Warrants held by them and acquire Common Shares thereunder should complete the exercise forms on the Special Warrant certificates and deliver the certificates and the executed exercise forms to the Trustee at its principal office in Calgary, Alberta.

RELATIONSHIP BETWEEN HIGHPINE'S BANKER AND AN UNDERWRITER

RBC Dominion Securities Inc. is a wholly owned subsidiary of a Canadian chartered bank that is a lender to Highpine. See note 1 to the table under "Capitalization" for a description of Highpine's Credit Facilities. As a result, Highpine may be considered to be a connected issuer of RBC Dominion Securities Inc. under applicable Canadian securities laws. At February 28, 2005, the Corporation's indebtedness under the Credit Facilities was approximately $54 million. Highpine is in compliance with all material terms of the agreements governing such Credit Facilities. Neither Highpine's financial position nor the value of the security under the Credit Facilities has changed adversely since the indebtedness under the Credit Facilities was incurred.

The decision to distribute the Common Shares offered under this prospectus and the determination of the terms of the distribution were made through negotiations between Highpine and the Underwriters. The bank affiliated with RBC Dominion Securities Inc. did not have any involvement in such decision or determination, but has been advised of this issuance and its terms. As a consequence of the Offering, RBC Dominion Securities Inc. will receive its share of the Underwriters' fee and Highpine intends to use certain proceeds of the Offering to temporarily repay outstanding indebtedness under the Credit Facilities. See "Use of Proceeds".

SHARE CAPITAL

The following is a summary of the rights, privileges, restrictions and conditions attaching to the Common Shares and Class B Shares. As at February 28, 2005, there were 17,252,906 Common Shares issued and outstanding. No Class B Shares are currently issued and outstanding.

Common Shares

Highpine is authorized to issue an unlimited number of Common Shares without nominal or par value. Holders of Common Shares are entitled to one vote per share at meetings of shareholders of Highpine, except meetings of another class or series of shares of Highpine, which are required by law to be held separately. Subject to the rights of the holders of any other shares having priority over the Common Shares, holders of Common Shares are entitled to dividends if, as and when declared by the Board of Directors and, upon liquidation, dissolution or winding-up, to receive the remaining property of Highpine.

Class B Shares

Highpine is authorized to issue an unlimited number of Class B Shares issuable in series, each series consisting of such number of shares and having such rights, privileges, restrictions and conditions as may be determined by the Board of Directors of Highpine prior to the issuance thereof. Subject to applicable law, the holders of Class B Shares are not entitled to receive notice of, attend or vote at any meetings of the shareholders of the Corporation. The holders of Class B Shares are not entitled to receive any dividends on the Class B Shares and are not be entitled, in the event of any liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, or any other distribution of the assets of the Corporation among its shareholders for the purpose of winding-up its affairs, to receive the remaining property of Highpine.

DIVIDEND RECORD AND POLICY

Highpine has not declared or paid any dividends on the Common Shares or Series 1 Class B Shares since incorporation except for the Stock Dividend. Any decision to pay dividends on the Common Shares will be made by the Board of Directors on the basis of Highpine's earnings, financial requirements and other conditions existing at such future time.

PRIOR SALES

In the preceding 12 months, Highpine has issued the following Common Shares and Special Warrants.

On July 27, 2004, Highpine completed a private placement of 1,200,000 Common Shares, at a price of $5.00 per share and 800,000 "flow-through" Common Shares, at a price of $6.00 per share for aggregate gross proceeds of $10.8 million.

On October 20, 2004, Highpine completed the Special Warrant Offering for aggregate gross proceeds of $29.7 million.

On February 4, 2005, Highpine issued 1,270,833 Common Shares pursuant to the conversion of 1,270,833 Series 1 Class B Shares.

On February 15, 2005, Highpine completed the Stock Dividend.

DIRECTORS AND OFFICERS

The name, municipality of residence and principal occupation of each of the directors and senior officers of Highpine are as follows:

Name and Municipality of Residence	Positions with Highpine [(1)]	Principal Occupation
A. Gordon Stollery Calgary, Alberta	Chairman, President, Chief Executive Officer and Director	Chairman, President and Chief Executive Officer of Highpine
John A. Brussa [(3)] Calgary, Alberta	Director	Partner, Burnet, Duckworth & Palmer LLP (law firm)
Richard G. Carl [(2)(3)(4)] Calgary, Alberta	Director	Managing Partner, Lawrence & Company Inc. (investment firm)
Andrew Krusen [(2)(4)] Tampa, Florida	Director	Chairman, President and Chief Executive Officer, Dominion Financial Group Inc. (investment and financial services firm)
Hank B. Swartout [(2)(3)(4)] Calgary, Alberta	Director	Chairman, President and Chief Executive Officer, Precision Drilling Corporation (oil and gas services company)
Greg N. Baum Calgary, Alberta	Executive Vice President and Chief Operating Officer	Executive Vice President and Chief Operating Officer of Highpine
Harry D. Cupric Calgary, Alberta	Vice President, Finance and Chief Financial Officer	Vice President, Finance and Chief Financial Officer of Highpine
Vince L. Farkas Calgary, Alberta	Vice President, Operations and Engineering	Vice President, Operations and Engineering of Highpine
Wayne Gray Calgary, Alberta	Vice President, Land	Vice President, Land of Highpine
Doug McArthur Calgary, Alberta	Vice President and Chief Geologist	Vice President and Chief Geologist of Highpine
Fred D. Davidson Calgary, Alberta	Corporate Secretary	Partner, Burnet, Duckworth & Palmer LLP (law firm)

Notes:

(1) All of the directors of Highpine have been appointed to hold office until the next annual general meeting of shareholders or until their successor is duly elected or appointed, unless their office is earlier vacated. Mr. Stollery has been a director of Highpine since April 1998, Messrs. Brussa, Krusen and Swartout have been directors of Highpine since February 2000 and Mr. Carl has been a director since August 2003.

(2) Member of the Audit Committee.

(3) Member of the Compensation, Nominating and Corporation Governance Committee.

(4) Member of the Reserves Committee.

(5) Highpine does not have an Executive Committee.

The number of Common Shares beneficially owned, directly or indirectly, by all of the directors and officers of Highpine is 10,632,000 Common Shares, being approximately 62% of the issued and outstanding Common Shares. After completion of the Offering and the issuance of 3,455,105 Common Shares issuable upon exercise of the 3,300,000 Special Warrants, the directors and officers of Highpine will beneficially own, directly or indirectly, 10,946,000 Common Shares, or approximately 44.3% of the outstanding Common Shares (assuming the directors and officers of Highpine do not purchase any Common Shares pursuant to the Offering).

Each of the directors and officers has held the same principal occupation or other offices with the same entity over the past five years except for Mr. Cupric who, prior to January 2003, was Vice President, Finance and Chief Financial Officer of Ascot Energy Resources Ltd. (oil and gas company); Mr. Farkas who, prior to May 2001, was Manager of Business Development with Vermilion Resources Ltd. (oil and gas company); and Mr. Gray who prior to September 2002 was Vice President, Land with Trident Exploration Ltd. (oil and gas company).

PERSONNEL

As at the date of this prospectus, Highpine has 19 full-time employees, all of whom are located at its office in Calgary.

PRINCIPAL SHAREHOLDERS

The following table sets out, to the best of the knowledge of the directors and officers of Highpine, information respecting the ownership of voting securities of Highpine of Highpine's President and Chief Executive Officer. To the best of the knowledge of management of Highpine, there are no other persons who own, directly or indirectly, or exercise control or direction over shares carrying more than 10% of the voting rights attached to any class of voting securities of Highpine.

Name and Municipality of Residence	Type of Ownership	Common Shares	Percentage of all Voting Securities	Percentage of all Voting Securities After Giving Effect to the Offering (3)
Pino Grande Holdings Corp. (1) Vancouver, British Columbia	Of record	6,748,318 (2)	39.1%	27.5%

Notes:

(1) Highpine understands that Pino Grande Holdings Corp. ("**Pino Grande**") is owned by trusts of which A. Gordon Stollery and members of his family are discretionary beneficiaries.

(2) In addition, Pino Grande is the registered owner of 50,000 Special Warrants.

(3) Gives effect to the issuance of 3,455,105 Common Shares issuable upon exercise of 3,300,000 Special Warrants and assumes Pino Grande does not purchase any Common Shares pursuant to the Offering. Assuming Pino Grande does not purchase any Common Shares pursuant to the Offering, Pino Grande will own 25.7% of the voting securities of Highpine after giving effect to the Offering and assuming all of the outstanding share options of Highpine are fully exercised.

COMPENSATION OF EXECUTIVE OFFICERS AND DIRECTORS

Compensation of Named Executive Officers

The following table sets out information respecting the compensation paid to the Chief Executive Officer, the Chief Financial Officer and the three other most highly compensated executive officers of Highpine, whose salary and bonus for the financial year ended December 31, 2004 exceeded $150,000 (collectively the "**Named Executive Officers**"), for each of Highpine's last three financial years.

		Annual Compensation			Long-term Compensation	
Name and Principal Position	Fiscal Year	Salary	Bonus	Other Annual Compensation	Shares under Options Granted (3)	All Other Compensation
		($)	($)	($)	(#)	($)
A. Gordon Stollery	2004	60,000	35,000	(2)	125,640	nil
Chairman, President and Chief	2003	60,000	nil	(2)	nil	nil
Executive Officer	2002	60,000	nil	(2)	nil	nil

Name and Principal Position	Fiscal Year	Annual Compensation			Long-term Compensation	
		Salary	Bonus	Other Annual Compensation	Shares under Options Granted (3)	All Other Compensation
		($)	($)	($)	(#)	($)
Greg N. Baum	2004	145,000	70,000	(2)	125,640	nil
Executive Vice President and	2003	131,800	35,000	(2)	nil	nil
Chief Operating Officer	2002	125,000	15,000	(2)	nil	nil
Harry D. Cupric (1)	2004	125,000	50,000	(2)	104,700	nil
Vice President, Finance and	2003	120,000	20,000	(2)	209,000	nil
Chief Financial Officer						
Vince L. Farkas	2004	120,000	50,000	(2)	177,990	nil
Vice President, Operations and	2003	110,000	20,000	(2)	nil	nil
Engineering	2002	100,000	nil	(2)	nil	nil
Doug McArthur	2004	125,000	60,000	(2)	125,640	nil
Vice President and Chief	2003	110,000	30,000	(2)	nil	nil
Geologist	2002	100,000	5,000	(2)	nil	nil

Notes:

(1) Mr. Cupric has acted as Vice President, Finance and Chief Financial Officer of Highpine since January 2003.

(2) The value of perquisites and benefits for each Named Executive Officer did not amount to the lesser of $50,000 and 10% of such officer's salary and bonus.

(3) Gives effect to the adjustment in the number of Common Shares issuable upon exercise of the options as a result of the Stock Dividend.

Option Grants

The following table sets out information respecting grants of options to purchase Common Shares to the Named Executive Officers during the most recently completed financial year.

Name	Options Granted (1)(2)	% of Total Options Granted to Employees in Financial Year	Exercise Price	Market Value of Common Shares on the Date of Grant (3)	Expiration Date
	(#)	(%)	($/share)	($/share)	
A. Gordon Stollery	100,000	12.0	5.00	N/A	May 28, 2010
	20,000	2.4	9.00	N/A	December 13, 2010
Greg N. Baum	100,000	12.0	5.00	N/A	May 28, 2010
	20,000	2.4	9.00	N/A	December 13, 2010
Harry D. Cupric	50,000	6.0	5.00	N/A	May 28, 2010
	50,000	6.0	9.00	N/A	December 13, 2010
Vince L. Farkas	50,000	6.0	5.00	N/A	May 28, 2010
	120,000	14.4	9.00	N/A	December 13, 2010
Doug McArthur	100,000	12.0	5.00	N/A	May 28, 2010
	20,000	2.4	9.00	N/A	December 13, 2010

Notes:

(1) The options vest as to one-quarter on each of the first, second, third and fourth anniversaries of the date of grant.

(2) Each option is exercisable to acquire 1.047 Common Shares in accordance with the terms of the respective option agreement.

(3) There was no public market for the Common Shares on the date of grant of the options.

Option Exercises

No options to purchase Common Shares were exercised by the Named Executive Officers during the most recently completed financial year.

Employment Contracts and Termination of Employment Arrangements

There are no employment contracts or "change in control agreements" between Highpine and any of the executive officers of Highpine.

Other

Highpine has no retirement plans, pension plans or other forms of retirement compensation for its employees.

Compensation of Directors

For the fiscal year ended December 31, 2004, each of the non-employee directors of Highpine was entitled to receive an annual retainer in the amount of $12,500, which was satisfied, in each case, by the issuance of 2,500 Common Shares at a deemed price of $5.00 per share. During the fiscal year ended December 31, 2004, directors were not paid fees for attendance at board or committee meetings but were entitled to be reimbursed for all reasonable expenses incurred in order to attend such meetings. Directors are entitled to participate in Highpine's share option plan and options to purchase an aggregate of 52,000 Common Shares, at an exercise price of $3.25 per share, options to purchase an aggregate of 93,600 Common Shares, at an exercise price of $5.00 per share and options to purchase an aggregate of 15,600 Common Shares, at an exercise price of $9.00 per share have previously been granted to non-employee directors. See "Share Option Plan".

INDEBTEDNESS OF DIRECTORS AND OFFICERS

At no time since January 1, 2004 has any director or officer, or any associate of any such director or officer, been indebted to Highpine (other than in respect of routine indebtedness) or to any other entity which is, or at any time since January 1, 2004 has been, the subject of a guarantee, support agreement, letter of credit or other similar arrangement or understanding provided by Highpine, other than as set out in the following table.

Name and Principal Position	Involvement of Highpine	Largest Amount Outstanding During the Fiscal Year Ended December 31, 2004	Amount Outstanding as at February 28, 2005	Security for Indebtedness
Vince L. Farkas Vice President, Operations and Engineering	Lender	$116,800[(1)]	$117,700	59,829 Common Shares

Note:

(1) On April 10, 2003, the Corporation loaned $100,000 to Mr. Farkas to enable him to acquire 57,143 Common Shares from treasury. The loan is evidenced by a loan agreement and promissory note and is secured by the pledge of 57,143 Common Shares plus the 2,686 Common Shares issued in respect of such shares pursuant to the Stock Dividend. Subject to certain exceptions, the loan is due 60 days following a written demand being made by Highpine to Mr. Farkas, or, if such demand has not been made on or before July 3, 2006, then on September 1, 2006. The loan accrues interest at a rate of 4.75% per annum, which interest is payable annually in arrears.

SHARE OPTION PLAN

Highpine has established a share option plan (the "**Share Option Plan**"), which is administered by the Board of Directors (or any committee of the Board of Directors to whom the operation of the Share Option Plan may be delegated). The Share Option Plan includes the following terms:

1. officers, directors, employees and consultants of Highpine (or any of its subsidiaries) and others who provide services to the Corporation (or any of its subsidiaries), are eligible to receive options under the Share Option Plan;

2. the maximum number of Common Shares issuable pursuant to the plan is equal to 10% of the outstanding Common Shares. Any increase in the issued and outstanding Common Shares will result in an increase in the number of Common Shares available under the Share Option Plan, and any exercises of options will make new grants available under the Share Option Plan;

3. the vesting arrangements are within the discretion of the Board of Directors;

4. the term of share option grants are within the discretion of the Board of Directors, but cannot exceed six years;

5. the aggregate number of Common Shares reserved for issuance to any one person under the Share Option Plan may not exceed 5% of the then outstanding Common Shares and the number of Common Shares, together with all of the Corporation's other previously established or proposed security based compensation arrangements reserved for issuance to insiders of the Corporation, may not exceed 10% of the outstanding Common Shares;

6. options terminate within a set period of time following an optionholder ceasing to be at least one of an officer, director, employee, consultant or other service provider of the Corporation (or a subsidiary). However, in the event of death, the Board of Directors has the discretion to extend the expiry date in any event, provided that the option cannot have a term greater than six years;

7. the lowest exercise price of a share option is the "market price" at the time of grant, which is determined by the Board of Directors, or if the applicable shares are listed on a stock exchange determined in accordance with the rules of that stock exchange;

8. the Board of Directors may, by resolution, amend the Share Option Plan without shareholder approval, however, the directors will not be entitled to amend an option held by an insider to lower the exercise price or to extend the expiry date;

9. every three years after institution, all unallocated options must be approved by shareholders; and

10. optionees will have the right (the "Put Right") to request that the Corporation purchase each of their vested Options for a price (the "Purchase Price") equal to the excess of the market price, determined on the date (the "Notice Date") of receipt of written notice of exercise (the "Put Notice") by the Corporation, over the exercise price for each option being purchased under the Put Right. Upon the exercise of the Put Right, the Corporation is required to deliver to the optionee a cheque representing the Purchase Price within three business days of the Notice Date. Notwithstanding the foregoing, (a) the Board of Directors or the optionee may select all or a portion of the Purchase Price to be satisfied wholly or in part by the issuance of Common Shares from treasury; and (b) the Board of Directors, or any committee of the Board of Directors to whom the operation of the Share Option Plan has been delegated, may at its sole discretion decline to accept the exercise of a Put Right at any time.

All options currently outstanding under the Share Option Plan shall expire six years from the date of the grant. The options vest over four years commencing one year after the date of grant subject to accelerated vesting in the case of a change of control of the Corporation.

The following table sets out information with respect to the options outstanding under the Share Option Plan as of the date hereof.

Group (Number)	Date Options Granted	Shares Under Option (3)	Exercise Price	Closing Price One Day Prior to Grant (1)	Expiration Date	Market Value of Options (1)
			($/share)			($/share)
Executive Officers (7)	September 4, 2002	157,050	2.60	N/A	September 4, 2008	N/A
	January 6, 2003	183,225	2.60	N/A	January 6, 2009	N/A
	November 27, 2003	26,175	3.50	N/A	November 27, 2009	N/A
	May 28, 2004	418,800	5.00	N/A	May 28, 2010	N/A
	December 13, 2004	293,160	9.00	N/A	December 13, 2010	N/A
Directors (2) (4)	August 14, 2003	52,350	3.25	N/A	August 14, 2009	N/A

Group (Number)	Date Options Granted	Shares Under Option (3)	Exercise Price	Closing Price One Day Prior to Grant (1)	Expiration Date	Market Value of Options (1)
	May 28, 2004	94,230	5.00	N/A	May 28, 2010	N/A
	December 13, 2004	15,705	9.00	N/A	December 13, 2010	N/A
Employees (14)	September 4, 2002	20,940	2.60	N/A	September 4, 2008	N/A
	February 24, 2003	52,350	3.25	N/A	February 24, 2009	N/A
	April 1, 2003	36,645	3.25	N/A	April 1, 2009	N/A
	June 16, 2003	10,470	3.25	N/A	June 16, 2009	N/A
	September 22, 2003	10,470	3.25	N/A	September 22, 2009	N/A
	November 27, 2003	5,235	3.50	N/A	November 27, 2009	N/A
	March 1, 2004	52,350	3.50	N/A	March 1, 2010	N/A
	May 10, 2004	26,175	4.50	N/A	May 10, 2010	N/A
	July 3, 2004	20,940	5.00	N/A	July 3, 2010	N/A
	October 1, 2004	12,564	8.10	N/A	October 1, 2010	N/A
	October 25, 2004	50,000	8.10	N/A	October 25, 2010	N/A
	November 25, 2004	26,175	8.10	N/A	November 25, 2010	N/A
	December 13, 2004	49,628	9.00	N/A	December 13, 2010	N/A
	February 25, 2005	160,000	14.00	N/A	February 24, 2011	N/A
		1,774,637				

Notes:

(1) There was no public market for the Common Shares as at the applicable times.

(2) Directors who are not also executive officers.

(3) Gives effect to the adjustment in the number of Common Shares issuable upon exercise of the options as a result of the Stock Dividend.

RISK FACTORS

An investment in and ownership of the Common Shares should be considered speculative due to the nature of the Corporation's involvement in the exploration for, and the acquisition, development and production of, oil and natural gas reserves. Investors should consider carefully the risk factors set out below. In addition, investors should carefully review and consider all other information contained in this prospectus before making an investment decision. There can be no assurance that Highpine's future exploration and development efforts will result in the discovery and development of additional commercial accumulations of oil, natural gas and NGLs.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of Highpine depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, Highpine's existing reserves and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Highpine's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that Highpine will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, Highpine may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by Highpine.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient petroleum substances 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 rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, Highpine explores for and produces sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to Highpine. In accordance with industry practice, Highpine is not fully insured against all of these risks, nor are all such risks insurable. Although Highpine maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event Highpine could incur significant costs that could have a material adverse effect upon its financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks could have a material adverse effect on Highpine.

Operational Dependence

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

Project Risks

Highpine manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic.

Highpine's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Corporation's control, including:

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

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

Competition

The petroleum industry is competitive in all its phases. Highpine competes with numerous other organizations in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Highpine's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than Highpine. Highpine's ability to increase reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery.

Regulatory

Oil and natural gas operations (exploration, production, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "Industry Conditions". Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for natural gas and crude oil and increase Highpine's costs, any of which may have a material adverse effect on Highpine's business, financial condition and results of operations. In order to conduct oil and gas operations, Highpine requires licenses from various governmental authorities. There can be no assurance that Highpine will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

Rescindment of Violet Grove Facility License

On December 15, 2004, an oil and gas company filed a Notice of Objection with the AEUB requesting that the AEUB rescind the battery license that it granted Highpine on December 14, 2004 to expand the Violet Grove sour facility. Although management of Highpine is of the view that the objection submitted is without merit, it is possible that the AEUB may rescind the license or render another decision in this matter which could have an adverse effect on Highpine's processing capacities in the Pembina/Nisku area. A prolonged restriction on Highpine's processing capabilities in the Pembina/Nisku area would have an adverse effect on Highpine's cash flow. See "Legal Proceedings".

Kyoto Protocol

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". Highpine's exploration and production facilities and other operations and activities emit greenhouse gases which will likely subject Highpine to possible future legislation regulating emissions of greenhouse gases. The Government of Canada has put forward a Climate Change Plan for Canada, which suggests further legislation will set greenhouse gases emission reduction requirements for various industrial activities, including oil and gas exploration and production. Future federal legislation, together with provincial emission reduction requirements, such as those proposed in Alberta's Climate Change and Emissions Management Act (partially in force), may require the reduction of emissions (or emissions intensity) produced by the Corporation's operations and facilities. The direct or indirect costs of these regulations may adversely affect the business of the Corporation.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require Highpine to incur costs to remedy such discharge. Although Highpine believes that it is in material compliance with current applicable environmental regulations no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect Highpine's financial condition, results of operations or prospects. See "Industry Conditions – Environmental Regulation".

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by Highpine is and will continue to be affected by numerous factors beyond its control. Highpine's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. Highpine may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

Both oil and natural gas prices are unstable and are subject to fluctuation. Any material decline in prices could result in a reduction of Highpine's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or gas and a reduction in the volumes of Highpine's reserves. Highpine might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in Highpine's net production revenue and a reduction in its oil and gas acquisition, development and exploration activities. In addition, bank borrowings available to Highpine are in part determined by Highpine's borrowing base. A sustained material decline in prices from historical average prices could reduce Highpine's borrowing base, therefore reducing the bank credit available to Highpine which could require that a portion, or all, of Highpine's bank debt be repaid and a liquidation of assets.

Substantial Capital Requirements

Highpine anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If Highpine's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to Highpine. The inability of Highpine to access sufficient capital for its operations could have a material adverse effect on Highpine's financial condition, results of operations and prospects.

Additional Funding Requirements

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

Issuance of Debt

From time to time Highpine may enter into transactions to acquire assets or the shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase Highpine's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, Highpine may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. Neither Highpine's articles nor its by-laws limit the amount of indebtedness that Highpine may incur. The level of Highpine's indebtedness from time to time, could impair Highpine's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

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

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to Highpine and may delay exploration and development activities. To the extent Highpine is not the operator of its oil and gas properties, Highpine will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

Title to Assets

Although title reviews may be conducted prior to the purchase of 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 Highpine's claim which could result in a reduction of the revenue received by Highpine.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this prospectus are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. All such estimates are to some degree speculative, and classifications of reserves are only attempts to define the degree of speculation involved. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. Highpine's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. In Highpine's case, 60% of proved reserves are estimated using volumetric analysis. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, Paddock has used both constant and escalated prices and costs in estimating the reserves and future net cash flows contained in the Paddock Report. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from Highpine's oil and gas reserves will vary from the estimates contained in the Paddock Report, and such variations could be material. The Paddock Report is based in part on the assumed success of activities Highpine intends to undertake in future years. The reserves and estimated cash flows set out in the Paddock Report will be reduced to the extent that such activities do not achieve the level of success assumed in the Paddock Report.

Insurance

Highpine's involvement in the exploration for and development of oil and natural gas properties may result in Highpine becoming subject to liability for pollution, blow outs, property damage, personal injury or other hazards. Although Highpine maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, such risks are not, in all circumstances, insurable or, in certain circumstances, Highpine may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to

Highpine. The occurrence of a significant event that Highpine is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on Highpine.

Dividends

To date, other than the Stock Dividend, Highpine has not declared or paid any dividends on the outstanding Common Shares or Series 1 Class B Shares. Any decision to pay dividends on the Common Shares will be made by the Board of Directors on the basis of Highpine's earnings, financial requirements and other conditions existing at such future time. At present, Highpine does not anticipate declaring and paying any dividends in the near future.

Conflicts of Interest

Certain directors of Highpine are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA. See "Conflicts of Interest".

Principal Shareholder

After giving effect to the Offering and assuming Pino Grande does not purchase any Common Shares pursuant to the Offering, Pino Grande will own 6,800,668 Common Shares, representing approximately 27.5% of the Common Shares and will be a "control person" of the Corporation under applicable securities laws. The securityholdings of Pino Grande are set forth under the heading "Principal Shareholders".

Reliance on Key Personnel

Highpine's success depends in large measure on certain key personnel. The loss of the services of such key personnel could have a material adverse affect on Highpine. Highpine does not have any key person insurance in effect for management. The contributions of the existing management team to the immediate and near term operations of Highpine 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 Highpine will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of Highpine.

Absence of Prior Public Market

Prior to the Offering there has been no public market for the Common Shares or the Special Warrants. The initial public offering price has been determined by negotiation between the Corporation and the Underwriters and may bear no relationship to the price at which the Common Shares will trade in the public market subsequent to the Offering.

INDUSTRY CONDITIONS

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

Pricing and Marketing – Oil and Natural Gas

The price of oil is determined by negotiation between buyers and sellers. Such price depends in part on oil quality, prices of competing oils, distance to market, the value of refined products and the supply/demand balance. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export license from the NEB and the issuance of such license requires the approval of the Governor in Council.

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than 2 years or for a term of 2 to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export license from the NEB and the issuance of such license requires the approval of the Governor in Council.

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

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, United States of America and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada – United States Free Trade Agreement. Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price; or (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. The agreement also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements, which is important for Canadian natural gas exports.

Provincial Royalties and Incentives

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

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

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provide various incentives for exploring and developing oil reserves in Alberta. Oil produced from horizontal extensions commenced at least 5 years after the well was originally spudded may also qualify for a royalty reduction. An 8,000 m^3 royalty exemption is available to production from a reactivated well that has not produced for the preceding 24-month period, if reactivation occurred after February 1, 1993. As well, oil production from eligible new field and new pool wildcat wells and deeper pool test wells spudded or deepened after September 30, 1992 is entitled to a 12-month royalty exemption (to a maximum of $1 million). Oil produced from low productivity wells, enhanced recovery schemes (such as injection wells) and experimental projects is also subject to royalty reductions.

The Alberta government has also introduced a Third Tier oil royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 30, 1992. The new oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 30% for oil pools discovered between April 1, 1974 and September 1, 1992. The old oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 35% for oil pools discovered prior to April 1, 1974.

In Alberta, the royalty reserved to the Crown in respect of natural gas production, subject to various incentives, is between 15% and 30%, in the case of new gas, and between 15% and 35%, in the case of old gas, depending upon a prescribed reference or corporate average price. Natural gas produced from qualifying exploratory gas wells spudded or deepened after July 31, 1985 and before June 1, 1988 is eligible for a royalty exemption for a period of 12 months, up to a prescribed maximum amount. Natural gas produced from qualifying intervals in eligible gas wells spudded or deepened to a depth below 2,500 meters is also subject to a royalty exemption, the amount of which depends on the depth of the well.

In Alberta, a producer of oil or natural gas is entitled to a credit against the royalties payable to the Crown by virtue of the ARTC program. The ARTC rate is based on a price sensitive formula and the ARTC rate varies between 75% at prices at and below \$100 per m^3 and 25% at prices at and above \$210 per m^3. The ARTC rate is applied to a maximum of \$2,000,000 of Alberta Crown royalties payable for each producer or associated group of producers. Crown royalties on production from producing properties acquired from a corporation claiming maximum entitlement to ARTC will generally not be eligible for ARTC. The rate will be established quarterly based on the average "par price", as determined by the Alberta Department of Energy for the previous quarterly period.

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

In November 2003, the Tax Act was amended to provide the following initiatives applicable to the oil and gas industry to be phased in over a five year period: (i) a reduction of the federal statutory corporate income tax rate on income earned from resource activities from 28 to 21%, beginning with a one percentage point reduction effective January 1, 2003, and (ii) a deduction for federal income tax purposes of actual provincial and other Crown royalties and mining taxes paid and the elimination of the 25% resource allowance. In addition, the percentage of ARTC that Highpine will be required to include in federal taxable income will be 5% in 2003; 12.5% in 2004; 17.5% in 2005; 32.5% in 2006; 50% in 2007; 60% in 2008; 70% in 2009; 80% in 2010; 90% in 2011, and 100% in 2012 and beyond.

Producers of oil and natural gas in the Province of British Columbia are also required to pay annual rental payments in respect of Crown leases and royalties and freehold production taxes in respect of oil and gas produced from Crown and freehold lands, respectively. The amount payable as a royalty in respect of oil depends on the vintage of the oil, the quantity of oil produced in a month and the value of the oil. Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production. The royalty payable on natural gas is determined by a sliding scale based on a reference price which is the greater of the amount obtained by the producer and a prescribed minimum price. Gas produced in association with oil has a minimum royalty of 8% while the royalty in respect of other gas may not be less than 15%.

On May 30, 2003, the Ministry of Energy and Mines for British Columbia announced an Oil and Gas Development Strategy for the Heartlands (the "**Strategy**"). The Strategy is a comprehensive program to address road infrastructure, targeted royalties, and regulatory reduction and British Columbia service-sector opportunities.

Some of the financial incentives in the Strategy include:

Royalty credits of up to \$10 million annually towards the construction, upgrading and maintenance of road infrastructure in support of resource exploration and development. Funding will be contingent upon an equal contribution from industry.

Changes to provincial royalties: new royalty rates for low-productivity natural gas to enhance marginally economic resources plays, royalty credits for deep gas exploration to locate new sources of natural gas, and royalty credits for summer drilling to expand the drilling season.

Land Tenure

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

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties.

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

British Columbia's *Environmental Assessment Act* became effective June 30, 1995. This legislation rolls the previous processes for the review of major energy projects into a single environmental assessment process which contemplates public participation in the environmental review.

CONFLICTS OF INTEREST

Certain directors of Highpine are associated with other companies or entities, which may give rise to conflicts of interest. In accordance with the ABCA, directors who have a material interest in any person who is a party to a material contract or proposed material contract with Highpine are required, subject to certain exceptions, to disclose that interest and abstain from voting on any resolution to approve the applicable contract. In addition, the directors are required to act honestly and in good faith with a view to the best interests of Highpine.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contracts entered into by Highpine within the two years prior to the date of this prospectus which can reasonably be regarded as presently material are the following:

1. the Agency Agreement referred to under "Plan of Distribution – Special Warrant Offering";
2. the Special Warrant Indenture referred to under "Plan of Distribution– Special Warrant Offering"; and
3. the Underwriting Agreement referred to under "Plan of Distribution – Public Offering".

LEGAL PROCEEDINGS

To the knowledge of management, Highpine is not a party to, nor are any of Highpine's properties subject to, any material legal proceedings other than on December 15, 2004, an oil and gas company filed a Notice of Objection with the AEUB requesting that the AEUB rescind the battery license that it granted Highpine on December 14, 2004 to expand the Violet Grove sour facility. The company alleges that their concerns, as an industry stakeholder in the area, and joint lease owner where the facility is being constructed, were not addressed by Highpine in the licensing process. On January 14, 2005, Highpine filed a submission with the AEUB responding to the issues raised in the objection. Subsequent to January 14, 2005, each of the parties have filed correspondence with the AEUB relating to the Notice of Objection. To date, the AEUB has not ruled on the merits of the Notice of Objection. Management of Highpine is of the view that the objection submitted is without merit and will continue to defend Highpine's interests in the Violet Grove Battery.

INTEREST OF MANAGEMENT IN MATERIAL TRANSACTIONS

No director, executive officer, or principal holder of securities (as described under "Principal Shareholders") or any associate or affiliate or the foregoing has, or has had, any material interest in any transaction prior to the date hereof or any proposed transaction that has materially affected or will materially affect Highpine or any of its affiliates, except as disclosed in this prospectus and the following:

1. A. Gordon Stollery, the Chairman, President and Chief Executive Officer of Highpine, is also a director and shareholder of In Depth Resources Ltd., a private oil and gas company in which the Corporation subscribed for 200,000 "flow-through" common shares on December 31, 2003 at a price of $1.20 per share for an aggregate subscription price of $240,000. On January 8, 2004, the Corporation subscribed for an additional 760,000 common shares of In Depth Resources Ltd. at a price of $1.00 per share for an aggregate subscription price of $760,000. The Corporation has a right of first refusal to participate in prospects generated by In Depth Resources Ltd.

2. A. Gordon Stollery, the Chairman, President and Chief Executive Officer of Highpine, was also a director and shareholder of West, which company, together with Highpine, jointly acquired all of the outstanding common shares of Rubicon on March 3, 2004. Highpine's share of the acquisition was approximately $52 million (including the amount of the associated liabilities). See "Highpine's Business – Acquisition of Rubicon".

3. John A. Brussa, a director of Highpine, and Fred D. Davidson, the Corporate Secretary of Highpine, are partners of Burnet, Duckworth & Palmer LLP, which firm receives fees for legal services provided to Highpine.

AUDITORS, REGISTRAR AND TRANSFER AGENT

The auditors of Highpine are KPMG LLP, Chartered Accountants, Suite 1200, 205 - 5th Avenue S.W., Calgary, Alberta, T2P 4B9.

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

INTEREST OF EXPERTS

Certain legal matters relating to the Offering will be passed upon by Burnet, Duckworth & Palmer LLP on behalf of the Corporation, and by Bennett Jones LLP on behalf of the Underwriters. As at the date hereof, the partners and associates of Burnet, Duckworth & Palmer LLP, as a group, own, directly or indirectly, less than 1% of the Common Shares and the partners and associates of Bennett Jones LLP, as a group, own, directly or indirectly, less than 1% of the Common Shares. Further, as of the date hereof, none of the partners of KPMG LLP own any of the Common Shares, nor do any of the partners of Charter, Paddock or Seaton-Jordan own, directly or indirectly, any of the Common Shares. Mr. Brussa, a director of Highpine, and Mr. Davidson, the Corporate Secretary of Highpine, are partners of Burnet, Duckworth & Palmer LLP.

STATUTORY RIGHTS OF WITHDRAWAL AND RESCISSION

Securities legislation in certain of the provinces of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus and any amendment. In several of the provinces, securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, damages if the prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, provided that the remedies for rescission or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province of residence. The purchaser should refer to any applicable provisions of the securities legislation of the province in which the purchaser resides for the particulars of these rights or consult with a legal advisor.

CONTRACTUAL RIGHT OF ACTION FOR RESCISSION

In the event that a holder of a Special Warrant, who acquires Common Shares upon the exercise of a Special Warrant as provided for in this prospectus, is or becomes entitled under applicable legislation to the remedy of rescission by reason of this prospectus or any amendment hereto containing a misrepresentation, the holder shall be entitled to rescission not only of the holder's exercise of its Special Warrant but also of the private placement transaction pursuant to which the Special Warrant was initially acquired, and shall be entitled, in connection with such rescission, to a full refund of all consideration paid to Highpine on the acquisition of the Special Warrant. In the event the holder is a permitted assignee of the interest of the original Special Warrant subscriber, that permitted assignee shall be entitled to exercise the rights of rescission and refund granted hereunder as if the permitted assignee was the original subscriber.

The contractual rights of action described above are in addition to and without derogation from any other right or remedy that the purchaser may have at law.

AUDITORS' CONSENT

The Board of Directors of Highpine Oil & Gas Limited

We have read the prospectus of Highpine Oil & Gas Limited (the "Corporation") dated March 24, 2005 relating to the issue and sale of common shares of the Corporation and the qualification for distribution of 3,455,105 common shares issuable upon exercise of 3,300,000 special warrants of the Corporation. We have complied with Canadian generally accepted standards for an auditor's involvement with offering documents.

We consent to the use in the above-mentioned prospectus of our report to the directors of the Corporation on the consolidated balance sheets of the Corporation as at December 31, 2003 and 2002 and the consolidated statements of earnings and retained earnings and cash flows for each of the years in the three-year period ended December 31, 2003. Our report was dated February 18, 2005, except for note 14 which is as of March 24, 2005.

We also consent to the use in the above-mentioned prospectus of our report to the directors of the Corporation on the balance sheets of the Rubicon Energy Properties as at December 31, 2003 and 2002 and the statements of operations and net assets and cash flows for each of the years in the three-year period ended December 31, 2003. Our report is dated February 18, 2005.

(Signed) KPMG LLP
Chartered Accountants
Calgary, Canada
March 24, 2005

kpmg

Consolidated Financial Statements of

HIGHPINE OIL & GAS LIMITED

AUDITORS' REPORT TO THE DIRECTORS

We have audited the consolidated balance sheets of Highpine Oil & Gas Limited as at December 31, 2003 and 2002 and the consolidated statements of earnings and retained earnings and cash flows for each of the years in the three year period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits 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 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 consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2003 and 2002 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2003 in accordance with Canadian generally accepted accounting principles.

(Signed) KPMG LLP
Chartered Accountants

Calgary, Canada
February 18, 2005, except as to note 14
which is as of March 24, 2005

HIGHPINE OIL & GAS LIMITED

Consolidated Balance Sheets

	September 30, 2004	December 31, 2003	December 31, 2002
	(Unaudited)	(Restated – note 2)	
Assets			
Current assets:			
Cash and cash equivalents	$ –	$ 538,000	$ 1,590,000
Accounts receivable	8,657,000	3,128,000	4,082,000
Debenture receivable (note 5)	–	3,737,000	–
Prepaid expenses and deposits	628,000	158,000	163,000
	9,285,000	7,561,000	5,835,000
Goodwill (note 13)	14,081,000	–	–
Property, plant and equipment (note 4)	114,575,000	36,240,000	17,362,000
Long-term investments, at cost (note 5)	1,000,000	240,000	500,000
	$ 138,941,000	$ 44,041,000	$ 23,697,000
Liabilities and Shareholders' Equity			
Current liabilities:			
Accounts payable and accrued liabilities	$ 22,866,000	$ 2,303,000	$ 6,468,000
Bank indebtedness (note 6)	46,729,000	–	–
	69,595,000	2,303,000	6,468,000
Future income taxes (note 9)	20,407,000	6,975,000	2,013,000
Asset retirement obligations (note 7)	1,401,000	378,000	130,000
Shareholders' equity:			
Share capital (note 8)	24,248,000	13,455,000	13,366,000
Contributed surplus (note 8)	345,000	114,000	12,000
Retained earnings	22,945,000	20,816,000	1,708,000
	47,538,000	34,385,000	15,086,000
Commitments (notes 8, 11 and 12)			
Subsequent events (notes 6, 8 and 14)			
	$ 138,941,000	$ 44,041,000	$ 23,697,000

See accompanying notes to consolidated financial statements.

On behalf of the Board:

(Signed) Richard G. Carl — Director

(Signed) Hank B. Swartout — Director

HIGHPINE OIL & GAS LIMITED

Consolidated Statements of Earnings and Retained Earnings

	Nine months ended September 30, 2004	Nine months ended September 30, 2003	Years ended December 31, 2003	Years ended December 31, 2002	Years ended December 31, 2001
	(Unaudited)		(Restated – note 2)		
Revenues:					
Oil and gas revenues	$ 29,083,000	$ 12,596,000	$ 16,926,000	$ 6,647,000	$ 3,005,000
Royalties	(7,466,000)	(2,332,000)	(3,109,000)	(1,426,000)	(576,000)
	21,617,000	10,264,000	13,817,000	5,221,000	2,429,000
Expenses:					
Operating costs	4,603,000	1,301,000	2,294,000	1,367,000	935,000
General and administrative	1,646,000	1,165,000	1,856,000	1,204,000	712,000
Depletion, depreciation and accretion	10,403,000	3,571,000	4,876,000	1,733,000	796,000
Interest and finance costs	1,848,000	189,000	195,000	92,000	–
Stock-based compensation (note 8)	231,000	71,000	102,000	12,000	–
	18,731,000	6,297,000	9,323,000	4,408,000	2,443,000
Earnings (loss) before the undernoted	2,886,000	3,967,000	4,494,000	813,000	(14,000)
Other items:					
Interest and dividend income (note 5)	48,000	2,098,000	2,214,000	586,000	110,000
Gain on sale of investment (note 5)	294,000	18,035,000	17,439,000	–	–
	342,000	20,133,000	19,653,000	586,000	110,000
Earnings before taxes	3,228,000	24,100,000	24,147,000	1,399,000	96,000
Taxes (note 9):					
Current	112,000	53,000	70,000	14,000	3,000
Future	987,000	4,738,000	4,969,000	329,000	34,000
	1,099,000	4,791,000	5,039,000	343,000	37,000
Net earnings	2,129,000	19,309,000	19,108,000	1,056,000	59,000
Retained earnings, beginning of period (note 2)	20,816,000	1,708,000	1,708,000	652,000	593,000
Retained earnings, end of period	$ 22,945,000	$ 21,017,000	$ 20,816,000	$ 1,708,000	$ 652,000
Net earnings per share (note 8):					
Basic	$ 0.14	$ 1.33	$ 1.32	$ 0.08	$ –
Diluted	$ 0.14	$ 1.33	$ 1.31	$ 0.08	$ –

See accompanying notes to consolidated financial statements.

HIGHPINE OIL & GAS LIMITED

Consolidated Statements of Cash Flows

	Nine months ended September 30,		Years ended December 31,		
	2004	2003	2003	2002	2001
	(Unaudited)		(Restated – note 2)		
Cash provided by (used in):					
Operations:					
Net earnings	$ 2,129,000	$ 19,309,000	$ 19,108,000	$ 1,056,000	$ 59,000
Items not involving cash:					
Depletion, depreciation and accretion	10,403,000	3,571,000	4,876,000	1,733,000	796,000
Gain on sale of investment	(294,000)	(18,035,000)	(17,439,000)	–	–
Future income taxes	987,000	4,738,000	4,969,000	329,000	34,000
Shares issued for services performed	62,000	–	–	–	–
Stock-based compensation	231,000	71,000	102,000	12,000	–
	13,518,000	9,654,000	11,616,000	3,130,000	889,000
Change in non-cash working capital relating to operations (note 10)	(2,909,000)	(2,988,000)	(2,200,000)	1,604,000	87,000
	10,609,000	6,666,000	9,416,000	4,734,000	976,000
Financing:					
Common shares issued for cash, net of share issue costs	10,691,000	82,000	82,000	3,989,000	3,140,000
Increase (decrease) in bank indebtedness	43,335,000	–	–	–	–
	54,026,000	82,000	82,000	3,989,000	3,140,000
Investments:					
Property, plant and equipment additions	(42,079,000)	(17,890,000)	(24,653,000)	(11,729,000)	(2,638,000)
Debentures receivable repayment	3,737,000	–	–	–	–
Proceeds on sale/ return of capital on investment	294,000	9,748,000	14,202,000	500,000	–
Long-term investment, at cost	(760,000)	–	(240,000)	–	–
Proceeds on the disposition of property, plant and equipment	4,565,000	1,015,000	1,147,000	461,000	–
Change in non-cash working capital relating to investing activities (note 10)	11,159,000	(861,000)	(1,006,000)	224,000	570,000
Net cash paid on business combination (note 13)	(42,089,000)	–	–	–	–
	(65,173,000)	(7,988,000)	(10,550,000)	(10,544,000)	(2,068,000)
Increase (decrease) in cash and cash equivalents	(538,000)	(1,240,000)	(1,052,000)	(1,821,000)	2,048,000
Cash and cash equivalents, beginning of period	538,000	1,590,000	1,590,000	3,411,000	1,363,000
Cash and cash equivalents, end of period	$ –	350,000	$ 538,000	$ 1,590,000	$ 3,411,000

See accompanying notes to consolidated financial statements.

Incorporation:

Highpine Oil & Gas Limited (the "Company") was incorporated under the laws of the Province of Alberta on April 2, 1998. The Company is involved in the exploration, development and production of petroleum and natural gas.

1. Significant accounting policies:

The consolidated financial statements of the Company have been prepared by management in accordance with Canadian generally accepted accounting principles. In the preparation of these financial statements, management has made estimates and assumptions that affect the recorded amounts of certain of the Company's assets, liabilities, revenues and expenses. The most significant estimates relate to the amounts recorded for the depletion and depreciation of property, plant and equipment and the determination of the asset retirement obligations as well as the cost recovery assessment for property, plant and equipment, goodwill and long-term investments. While it is the opinion of management that these consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the significant accounting policies summarized below, actual results could differ from the estimates made.

(a) Basis of presentation:

These consolidated financial statements include the accounts of the Company and its subsidiaries. The Company's investment in Rubicon Energy Corporation representing a 50% ownership interest is accounted for as a joint venture and accordingly, the financial statements reflect only the Company's proportionate interest in the assets, liabilities, revenues and expenses of Rubicon Energy Corporation.

Substantially all of the Company's exploration and development activities are conducted jointly with others. Accordingly, the financial statements reflect only the Company's proportionate interest in such activities.

Certain of the comparative figures have been reclassified to conform to the current period's presentation.

(b) Petroleum and natural gas properties:

The Company follows the full cost method of accounting for exploration and development expenditures wherein all costs related to the exploration for and the development of oil and gas reserves are capitalized. These costs include lease acquisition costs, geological and geophysical expenses, carrying charges of unproven properties, costs of drilling and completing wells and oil and gas production equipment. Proceeds received from the disposal of properties are normally credited against accumulated costs unless this would result in a significant change in the depletion rate of in excess of 20%, in which case a gain or loss is computed and reflected in the consolidated statement of earnings.

1. **Significant accounting policies (continued):**

(b) Petroleum and natural gas properties (continued):

Depletion of exploration and development costs and depreciation of production equipment are provided on the unit-of-production method based upon estimated proven oil and gas reserves before royalties in each area of interest as determined by independent engineers. For purposes of this calculation, reserves and production of natural gas are converted to common units based on their approximate relative energy content. The cost of acquiring and evaluating unproven properties are initially excluded from the depletion calculation. These properties are assessed periodically for impairment. 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 the costs subject to depletion.

The Company places a limit on the carrying value of property, plant and equipment and other assets, which may be depleted against revenues of future periods (the "ceiling test"). The carrying value is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying value. When the carrying value is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value of assets exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate.

(c) Asset retirement obligations:

The Company recognizes the fair value of an Asset Retirement Obligation ("ARO") in the period in which it is incurred when a reasonable estimate of the fair value can be made. The fair value of the estimated ARO is recorded as a liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on the unit-of-production method based on proved reserves. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is expensed to income in the period. Actual costs incurred upon the settlement of the ARO are charged against the ARO.

1. Significant accounting policies (continued):

(d) Office equipment and computers:

Office equipment and computers are stated at cost. Depreciation is provided for using the declining balance method at 20% per year.

(e) Goodwill:

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the sum of the amounts allocated to the assets acquired, less liabilities assumed, based on their fair values. Goodwill is not amortized and is tested for impairment annually or more frequently if events or changes in circumstances indicated that the asset might be impaired. The impairment test is carried out in two steps. In the first step, the carrying amount of the segment is compared to its fair value. When the fair value of the segment exceeds its carrying amount, goodwill is considered not to be impaired and the second step of the impairment test is unnecessary. The second step is carried out when the carrying amount of the Company's goodwill exceeds its fair value, in which case the implied fair value of the Company's goodwill is compared with its carrying amount to measure the amount of the impairment loss, if any. The implied fair value of goodwill is determined in the same manner as the value of the goodwill is determined in a business combination using the fair value of the Company as if it were the purchase price. When the carrying amount of the Company's goodwill exceeds the implied fair value of the goodwill, an impairment loss is recognized in an amount equal to the excess.

(f) Long-term investment:

The Company's long-term investment is accounted for by the cost method (see note 5). The net income of this company is reflected in the determination of the net earnings of the Company only to the extent of dividends received.

The carrying value of the Company's long-term investment is periodically reviewed by management to determine if the facts and circumstances suggest that the investment may be impaired. Any impairment identified through this assessment would result in a write-down of the investment and a corresponding charge to earnings.

(g) Revenue recognition:

Revenues associated with sales of crude oil, natural gas and natural gas liquids are recorded when title passes to the customer. Revenues from properties in which the Company has an interest with other producers are recognized on the basis of the Company's net working interest.

1. Significant accounting policies (continued):

(h) Financial instruments:

The Company may enter into derivative instrument contracts to manage its exposure related to oil and gas prices. The Company does not enter into derivative instrument contracts for trading or speculative purposes. The Company believes that all derivative instruments entered into are effective hedges, both at inception and over the term of the instrument, as the term and notional amount have not and are not expected to exceed the Company's firm commitment or forecasted production. These derivative instrument contracts are recognized in oil and gas revenues and cash flows in the period in which the revenues associated with the hedged transaction are recognized.

(i) Future income taxes:

Income taxes are calculated using the liability method of accounting for income taxes. Under this method, future income tax liabilities and future income tax assets are recorded based on the differences between the carrying amount of assets and liabilities in the consolidated balance sheet and their tax basis using income tax rates substantively enacted at the balance sheet date. The effect of change in rates on future income tax liabilities and assets is recognized in the period in which the change occurs. A valuation allowance is recorded against any future income tax assets if it is more likely than not that the asset will not be realized.

(j) Stock-based compensation:

Effective September 30, 2004 the Company retroactively adopted the amended standard with respect to stock-based compensation (see note 3(c)), which requires the use of the fair value method of valuing all stock options granted and other stock-based payments whether they be to employees, directors or non-employees. Under the fair value method, a compensation cost is measured at fair value for stock options granted at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. Upon the exercise of the stock options, consideration paid together with the amount previously recognized to contributed surplus is recorded as an increase to share capital.

(k) Flow-through shares:

The tax attributes of expenditures financed by the issuance of flow-through shares are renounced to investors in accordance with income tax legislation. Share capital issued is recorded on the date of issue net of estimated benefits renounced to investors with a corresponding future tax liability for the tax benefits renounced to investments.

(l) Cash equivalents:

The Company considers all highly liquid investments with a maturity of three months or less at the time of purchase to be cash equivalents and therefore classifies them with cash.

1. Significant accounting policies (continued):

(m) Earnings per share:

Basic net earnings per common share is computed by dividing net earnings from operations 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. Under the treasury stock method, only options for which the exercise price is less than the market value impact the dilution calculations.

(n) Use of estimates:

The amounts recorded for the depletion and depreciation of petroleum and natural gas properties and for the determination of asset retirement obligations are based on estimates. The ceiling test calculation and the goodwill impairment test are based, in part, on estimates of proved reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effects of changes in such estimates in future years on financial statements could be significant.

2. Change in accounting policies:

(a) Full cost accounting guideline:

Effective January 1, 2004 the Company adopted the new Canadian accounting guideline for the full cost method of accounting for oil and gas entities. The recoverability of a cost centre is tested by comparing the carrying value of the cost centre to the sum of the undiscounted cash flows expected from the cost centre's use and eventual disposition. If the carrying value is unrecoverable the cost centre is written down to its fair value using the expected present value approach. This approach incorporates risks and uncertainties in the expected future cash flows which are discounted using a risk free rate. The cash flows are estimated using expected future product prices and costs. The adoption of this guideline had no effect on the Company's financial results.

Prior to January 1, 2004, the Company applied a ceiling test to ensure capitalized costs did not exceed the aggregate of the cost of the unproved properties and undiscounted future net revenues of proved reserves at year end commodity prices less future administrative, financing and income tax expenses.

2. Change in accounting policies (continued):

(b) Asset retirement obligation:

Effective January 1, 2004, the Company retroactively adopted the new standard "Asset Retirement Obligations". This standard requires the recognition of the fair value of obligations associated with the retirement of tangible long-lived assets be recorded in the period the asset is put into use, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are statutory, contractual or legal obligations. The liability is accreted over time and the accretion is included in depletion, depreciation and accretion expense. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depreciation, depletion and amortization of the underlying asset. Actual costs incurred upon the settlement of asset retirement obligations are charged against the asset retirement obligation. The impact of the adoption on prior periods was as follows:

Consolidated Balance Sheet as at December 31, 2003:

	As Reported	Change	As Restated
Asset:			
Property, plant and equipment	$35,955,000	$ 285,000	$36,240,000
Liabilities and shareholders' equity:			
Future income taxes	6,905,000	70,000	6,975,000
Asset retirement obligations	–	378,000	378,000
Provision for site restoration	274,000	(274,000)	–
Retained earnings	20,705,000	111,000	20,816,000

Consolidated Balance Sheet as at December 31, 2002:

	As Reported	Change	As Restated
Asset:			
Property, plant and equipment	$17,259,000	$ 103,000	$17,362,000
Liabilities and shareholders' equity:			
Future income taxes	1,952,000	61,000	2,013,000
Asset retirement obligations	–	130,000	130,000
Provision for site restoration	187,000	(187,000)	–
Retained earnings	1,609,000	99,000	1,708,000

2. Change in accounting policies (continued):

(b) Asset retirement obligation (continued):

Consolidated Statement of Earnings and Retained Earnings

	Year ended December 31, 2003			Nine months ended September 30, 2003		
	As Reported	Change	As Restated	As Reported	Change	As Restated
Depletion and depreciation	$ 4,897,000	$ (49,000)	$ 4,848,000	$ 3,632,000	$ (75,000)	$ 3,557,000
Accretion	–	28,000	28,000	–	14,000	14,000
Depletion, depreciation and accretion	4,897,000	(21,000)	4,876,000	3,632,000	(61,000)	3,571,000
Future income taxes	4,961,000	8,000	4,969,000	4,716,000	22,000	4,738,000
Net earnings	19,095,000	13,000	19,108,000	19,270,000	39,000	19,309,000

	Year ended December 31, 2001			Year ended December 31, 2002		
	As Reported	Change	As Restated	As Reported	Change	As Restated
Depletion and depreciation	$ 843,000	$ (50,000)	$ 793,000	$ 1,814,000	$ (90,000)	$ 1,724,000
Accretion	–	3,000	3,000	–	9,000	9,000
Depletion, depreciation and accretion	843,000	(47,000)	796,000	1,814,000	(81,000)	1,733,000
Future income taxes	17,000	17,000	34,000	299,000	30,000	329,000
Net earnings	29,000	30,000	59,000	1,005,000	51,000	1,056,000

Prior to January 1, 2004, the Company provided for future site restoration and abandonment costs over the life of the proved reserves on a unit-of-production basis. The charge was recorded in deletion and depreciation expense and the liability was recorded net of actual costs incurred. Had the Company continued to provide for future site restoration and abandonment costs over the life of the proved reserves on a unit-of-production basis, the provision for site restoration for the nine months ended September 30, 2004 would have been $218,000, the provision for depletion and depreciation would have been $10,251,000, future income taxes would have been $963,000 and net earnings would have been $2,087,000.

(c) Stock-based compensation:

Effective September 30, 2004 the Company retroactively adopted the amended standard with respect to stock-based compensation, which requires the use of the fair value method for valuing all stock options granted whether they be to employees, directors or non-employees. As a result of adopting this amended standard, the Company recognized an expense for all options granted effective January 1, 2002 (see note 8). As such, stock-based compensation expense recorded totalled $12,000 during the year ended December 31, 2002 and $102,000 during the year ended December 31, 2003 with a decrease in net earnings and a corresponding increase in contributed surplus. During the nine months ended September 30, 2004 stock-based compensation totalled $231,000 (nine months ended September 30, 2003 - $71,000).

As at December 31, 2003 and 2002 and for the years ended December 31, 2003, 2002 and 2001
(Information as at September 30, 2004 and for the nine months ended September 30, 2004 and 2003 is unaudited)

3. Accounts receivable:

As at September 30, 2004 accounts receivable included a loan due from an officer of the Company totalling $100,000 (December 31, 2003 - $100,000; December 31, 2002 - $100,000). The loan bears interest at 4.75% compounded annually per annum, is payable on demand and is secured by the pledge of 57,143 Class A common shares of the Company.

4. Property, plant and equipment:

2004 (unaudited)	Cost	Accumulated depletion and depreciation	Net book value
Petroleum and natural gas properties	$ 132,398,000	$17,994,000	$ 114,404,000
Office equipment and computers	321,000	150,000	171,000
	$ 132,719,000	$18,144,000	$ 114,575,000
2003			
Petroleum and natural gas properties	$ 43,816,000	$ 7,699,000	$ 36,117,000
Office equipment and computers	243,000	120,000	123,000
	$ 44,059,000	$ 7,819,000	$ 36,240,000
2002			
Petroleum and natural gas properties	$ 20,123,000	$ 2,882,000	$ 17,241,000
Office equipment and computers	211,000	90,000	121,000
	$ 20,334,000	$ 2,972,000	$ 17,362,000

At September 30, 2004, approximately $11,057,000 (September 30, 2003 - $1,400,000) of unproved properties were excluded from the depletion calculation and future development costs totalling $4,700,000 (September 30, 2003 - $6,900,000) were included in the depletion calculation. During the nine months ended September 30, 2004, overhead applicable to acquisition, development and exploration activities in the amount of approximately $232,000 (nine months ended September 30, 2003 - $133,000) was capitalized to petroleum and natural gas properties.

4. Property, plant and equipment (continued):

At December 31, 2003, approximately $6,400,000 (December 31, 2002 - $1,461,000; December 31, 2001 - $757,000) of unproved properties were excluded from the depletion calculation. Future development costs included in the depletion and depreciation calculation totalled $3,900,000 (December 31, 2002 - $1,000,000; December 31, 2001 - $112,000) at December 31, 2003. During the year ended December 31, 2003, overhead applicable to acquisition, development and exploration activities in the amount of approximately $176,000 (year ended December 31, 2002 - $209,000; year ended December 31, 2001 – $203,000) was capitalized to petroleum and natural gas properties.

As at September 30, 2004 property, plant and equipment includes $798,000 (December 31, 2003 - $285,000; December 31, 2002 - $102,000), net of accumulated depletion related to asset retirement obligations.

The Company performed a ceiling test at September 30, 2004 to assess the recoverable value of property, plant and equipment and other assets. The oil and gas future prices are based on the commodity price forecast of our independent reserve evaluators.

The following table summarizes the benchmark prices used in the ceiling test calculation. The Canadian dollar prices have been adjusted for commodity quality differentials specific to the Company. Based on these assumptions, the undiscounted value of future net revenues from proved reserves exceeds the carrying value of property, plant and equipment at September 30, 2004.

	WTI Oil ($U.S./bbl)	Foreign exchange rate	Edmonton Light Crude Oil ($Cdn/bbl)	AECO Gas ($Cdn/mmbtu)
2004	41.00	0.75	48.82	7.67
2005	37.00	0.75	44.74	6.98
2006	31.00	0.75	37.33	5.87
2007	27.00	0.75	32.18	5.12
2008	27.54	0.75	32.67	5.13
Escalate thereafter 2%				

5. Long-term investments:

(a) Investment in In Depth Resources Ltd.:

At September 30, 2004 the Company's long-term investment totalling $1,000,000 was comprised of 960,000 common shares of In Depth Resources Ltd., a private oil and gas company in which the president of the Company is a director. The investment represents approximately 10% of the outstanding common shares of In Depth Resources Ltd. The Company has a right of first refusal to participate in prospects generated by In Depth Resources Ltd. At December 31, 2003 the Company's long-term investment was comprised of 200,000 flow-through common shares of In Depth Resources Ltd., which were acquired during the year ended December 31, 2003 at a cost of $240,000.

(b) Investment in Monolith Oil Corp.:

During the year ended December 31, 2003, the Company sold its investment in Monolith Oil Corp., a private oil and gas company in which the president of the Company was a director, for a gain totalling $17,439,000. Consideration received on the disposition of the investment in Monolith Oil Corp. consisted of $14,202,000 of cash or cash equivalents and a secured debenture totalling $3,737,000 bearing interest at 9% per annum, payable monthly. The debenture was repaid in its entirety in January 2004. The debenture was secured but subordinate to the purchaser's secured credit facility. During the nine months ended September 30, 2004, the Company received proceeds totalling $294,000 relating to the sale of its investment in Monolith Oil Corp. resulting from the resolution of various contingent matters.

During the year ended December 31, 2003, the Company received a dividend of approximately $2,100,000 from its investment in Monolith Oil Corp.

At December 31, 2002 the Company's long-term investment was comprised of 1,000,000 class "A" common shares of Monolith Oil Corp. with a net book value of $500,000. During the year ended December 31, 2002, the Company received $500,000 as a return of capital from its investment in Monolith Oil Corp. and received a dividend totalling $581,000 which was included in interest and other income.

6. Bank indebtedness:

At September 30, 2004 the Company had available a revolving demand facility to a maximum of $35,000,000 (December 31, 2003 - $12,000,000; December 31, 2002 - $6,000,000) and non-revolving demand facility to a maximum of $40,000,000 (December 31, 2003 and 2002 - $nil) with a Chartered Canadian bank. The revolving facility bears interest at the bank's prime rate plus 0.25% per annum and the non-revolving demand facility bears interest at the bank's prime rate plus 1.75% per annum. Any balance outstanding on the non-revolving demand facility is to be repaid by March 31, 2005. As at September 30, 2004, $33,229,000 (December 31, 2003 and 2002 - $nil) was outstanding under revolving demand facility and $13,500,000 (December 31, 2003 and 2002 - $nil) was outstanding under the non-revolving demand facility.

The facility is secured by a general security agreement with a floating charge covering land registered in Alberta, British Columbia and Saskatchewan.

In October 2004 $13.0 million of borrowings under the non-revolving demand facility was repaid from a portion of the proceeds received on the sale of the special warrants (see note 14). The amount available under the non-revolving demand facility after the repayment was reduced to $11,400,000.

7. Asset retirement obligations:

At September 30, 2004, the estimated total undiscounted amount required to settle asset retirement obligations was $2,400,000 which will be incurred between 2005 and 2025. This amount has been discounted using an annual credit adjusted risk-free interest rate of 8.0 percent per annum and an inflation rate of 2.0 per cent per annum.

Charges to asset retirement obligations were as follows:

	Nine months ended September 30, 2004	Year ended December 31, 2003	Year ended December 31, 2002
	(unaudited)		
Asset retirement obligations, beginning of period	$ 378,000	$ 130,000	$ 43,000
Liabilities acquired in the period	950,000	–	–
Liabilities incurred during period	593,000	220,000	78,000
Liabilities disposed of in the period	(600,000)	–	–
Accretion	80,000	28,000	9,000
Asset retirement obligations, end of period	$ 1,401,000	$ 378,000	$ 130,000

As at December 31, 2003 and 2002 and for the years ended December 31, 2003, 2002 and 2001 (Information as at September 30, 2004 and for the nine months ended September 30, 2004 and 2003 is unaudited)

8. Share capital:

(a) Authorized:

(i) an unlimited number of class A common voting shares without par value;

(ii) an unlimited number of class B common shares without par value issuable in series of which the Company has authorized the issuance of 3,000,000 series 1 class B shares. The class B common shares are non-voting and are not entitled to the receipt of dividends. The series 1 class B common shares are convertible into class A common shares only upon the Company achieving certain performance conditions. The conditions to be met relate to meeting or exceeding a defined fair market value per class A common voting share.

(b) Shares issued:

	Nine months ended September 30, 2004		Years ended December 31, 2003		2002	
	Number	Amount	Number	Amount	Number	Amount
	(unaudited)					
Class A common shares:						
Balance, beginning of period	13,195,000	$ 13,455,000	11,827,000	$ 13,366,000	10,344,000	$10,196,000
Issued for cash	1,200,000	6,000,000	57,000	100,000	769,000	2,000,000
Shares issued for services performed	13,000	62,000	–	–	–	–
Conversion of class B shares	–	–	1,311,000	–	–	–
Flow-through shares issued	800,000	4,800,000	–	–	714,000	2,000,000
Tax effect of flow-through shares		–		–		(824,000)
Share issue costs less tax effect of $40,000 (2003 - $7,000; 2002 - $5,000)		(69,000)		(11,000)		(6,000)
Balance, end of period	15,208,000	24,248,000	13,195,000	13,455,000	11,827,000	13,366,000
Series 1 class B shares:						
Balance, beginning of period	1,271,000	–	2,722,000	–	2,788,000	–
Issued for cash	–	–	–	–	67,000	–
Conversion of class B shares	–	–	(1,311,000)	–	–	–
Cancelled	–	–	(140,000)	–	(133,000)	–
Balance, end of period	1,271,000	$ –	1,271,000	$ –	2,722,000	$ –
Total		24,248,000		$ 13,455,000		$ 13,366,000

8. Share capital (continued):

(b) Shares issued (continued):

On February 3, 2005 the Company filed Articles of Amendment to amend the provisions of the series 1 class B shares and as such, the series 1 class B shares were automatically converted into class A common shares on February 4, 2005. On February 15, 2005 the Company declared a stock dividend in the amount of approximately $6,970,000 which resulted in 0.047 of a class A common share being issued for each issued and outstanding class A common share and each class A common share issuable upon the exercise of each issued and outstanding special warrant (see note 14(a)). This resulted in the issuance of 774,490 class A common shares at a price of $9.00 per share.

As at September 30, 2004 the Company had incurred $1,800,000 of expenditures relating to the flow through shares issued in July 2004. Expenditures of $3,000,000 are remaining to be incurred by December 31, 2005 pursuant to the terms of the flow through shares issued.

(c) Stock options:

The Company has a stock option plan to provide options for directors, officers and employees to purchase class A common shares of the Company. The stock options are exercisable over six (6) years, with a vesting period over four (4) years.

The following summarizes the options outstanding:

	Nine months ended September 30, 2004		Years ended December 31, 2003		2002	
	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
Balance, beginning of period	530,000	$ 2.84	170,000	$ 2.60	–	$ –
Granted	585,000	4.85	360,000	2.94	170,000	2.60
Balance, end of period	1,115,000	3.90	530,000	$ 2.84	170,000	$ 2.60
Exercisable, end of period	168,000	2.75	42,500	$ 2.60	–	$ –

8. Share capital (continued):

(c) Stock options (continued):

	Options outstanding			Options Exercisable	
Range of exercise price	Number outstanding September 30, 2004	Weighted average remaining contractual life	Weighted average exercise price	Number exercisable September 30, 2004	Weighted average exercise price
		(years)			
$ 2.60	345,000	4.3	$ 2.60	129,000	$ 2.60
$ 3.25 - $3.50	235,000	5.1	3.34	39,000	3.25
$ 4.50 - $5.00	535,000	5.8	4.98	–	–
	1,115,000	5.2	$ 3.90	168,000	$ 2.75

As a result of the stock dividend noted in note 8(b), each option holder will receive an additional 0.047 options.

The Company determines the fair value of stock options when they are granted to employees, officers, directors and non-employees. The fair value of the stock options is then recorded as compensation expense over the vesting period of the option.

The fair value of stock options granted was estimated using the Black-Scholes option pricing model with the following assumptions:

	Nine months ended September 30, 2004	Year ended December 31, 2003	Year ended December 31, 2002
	(unaudited)		
Dividend yield	0%	0%	0%
Expected volatility	50%	25%	25%
Risk free rate of return	4.5%	4.5%	4.5%
Expected option life	4 years	4 years	4 years
Weighted-average fair market value per option	$2.60	$1.00	$0.89

8. Share capital (continued):

(d) Per share amounts:

The weighted average number of shares outstanding during the nine months ended September 30, 2004 was approximately 14,954,000 (nine-months ended September 30, 2003 - 14,466,000; year ended December 31, 2003 - 14,466,000; year ended December 31, 2002 - 13,080,000). The weighted average number of dilutive shares outstanding during the nine months ended September 30, 2004 was approximately 15,198,000 (nine month ended September 30, 2003 - 14,535,000; year ended December 31, 2003 - 14,564,000; year ended December 31, 2002 - 13,082,000).

(e) Contributed surplus:

The following summaries the continuity of contributed surplus:

	Nine months ended September 30, 2004	Year ended December 31, 2003	Year ended December 31, 2002
	(unaudited)		
Balance, beginning of period	$ 114,000	$ 12,000	$ –
Stock-based compensation	231,000	102,000	12,000
Balance, end of period	$ 345,000	$ 114,000	$ 12,000

9. Taxes:

The provision for income taxes differs from the result that would be obtained by applying the combined Canadian Federal and Provincial income tax rate of approximately 40.62% (2002 – 42.1%) to earnings before taxes. The difference results from the following:

	Nine months ended September 30, 2004	Nine months ended September 30, 2003	Years ended December 31, 2003	Years ended December 31, 2002	Years ended December 31, 2001
	(unaudited)				
Effective tax rate	38.62%	40.62%	40.62%	42.1%	42.6%
Computed expected income taxes	$ 1,247,000	$ 9,789,000	$ 9,809,000	$ 589,000	$ 41,000
Add (deduct):					
Non-deductible crown payments	1,930,000	769,000	988,000	374,000	94,000
Resource allowance	(1,423,000)	(780,000)	(980,000)	(310,000)	(82,000)
Non-taxable portion of capital gain	(57,000)	(3,663,000)	(3,539,000)	–	11,000
ARTC	(88,000)	(191,000)	(184,000)	(81,000)	(5,000)
Stock-based compensation	89,000	29,000	41,000	5,000	–
Attributed royalty income deductible for provincial taxes	(134,000)	(55,000)	(73,000)	–	–
Capital taxes	112,000	53,000	70,000	14,000	3,000
Other	3,000	2,000	2,000	7,000	(16,000)
Changes in enacted tax rate	(580,000)	(318,000)	(251,000)	(10,000)	(9,000)
Non-taxable dividend	–	(844,000)	(844,000)	(245,000)	–
	$ 1,099,000	$ 4,791,000	$ 5,039,000	$ 343,000	$ 37,000

The components of the net future income tax are as follows:

	September 30, 2004	December 31, 2003	December 31, 2002
	(unaudited)		
Future income tax assets:			
Asset retirement obligations	$ 451,000	$ 125,000	$ 41,000
Attributed royalty income deductible for provincial taxes	202,000	73,000	–
Share issue and financing costs	135,000	35,000	21,000
	788,000	233,000	62,000
Future income tax liabilities:			
Property, plant and equipment	(21,149,000)	(7,159,000)	(2,075,000)
Long-term investments	(46,000)	(49,000)	–
	21,195,000	(7,208,000)	(2,075,000)
Net future income tax liability	$20,407,000	$ 6,975,000	$ 2,013,000

9. Taxes (continued):

Corporate tax returns are subject to assessment by Canada Revenue Agency in the normal course of business. The result of any assessments will be accounted for as a charge to net earnings in the period in which they are realized.

10. Supplemental cash flow disclosures:

(a) Changes in non-cash working capital balances:

	September 30,		December 31,		
	2004	2003	2003	2002	2001
Changes in non-cash working capital:					
Accounts receivable	$ (3,143,000)	$ 659,000	$ 954,000	$ (3,653,000)	$ 102,000
Prepaid expenses and deposits	(299,000)	66,000	5,000	(96,000)	–
Accounts payable and accrued liabilities	11,692,000	(4,574,000)	(4,165,000)	5,577,000	555,000
	8,250,000	(3,849,000)	(3,206,000)	1,828,000	657,000
Changes in non-cash working capital relating to investing	(11,159,000)	861,000	1,006,000	(224,000)	(570,000)
Changes in non-cash working capital relating to operations	$ (2,909,000)	$ (2,988,000)	$ (2,200,000)	$ 1,604,000	$ 87,000

(b) Cash payments:

The following cash payments were received (paid):

	September 30,		December 31,		
	2004	2003	2003	2002	2001
Dividends received	$ –	$ 2,077,000	$ 2,077,000	$ 581,000	$ –
Interest received (paid)	(1,289,000)	(114,000)	137,000	(67,000)	110,000
Taxes paid	(60,000)	(28,000)	(28,000)	(4,000)	–

11. Financial Instruments:

(a) Commodity price risk management:

The Company entered into commodity swap agreements as at September 30, 2004. The details of these agreements are as follows:

Commodity	Notional Volumes	Contract Term	Fixed Price
Crude Oil	300 barrels per day	January 1, 2004 to December 31, 2004	CDN $40.85 per barrel
Crude Oil	500 barrels per day	July 1, 2004 to December 31, 2004	CDN $44.00 per barrel
Crude Oil	700 barrels per day	January 1, 2005 to December 31, 2005	CDN $47.20 per barrel

As at September 30, 2004 the outstanding commodity swap agreements had an unrealized loss of $4.1 million.

The 300 barrels per day crude oil swap agreement had been entered into prior to December 31, 2003, and had an unrealized gain as at December 31, 2003 of approximately $150,000.

At December 31, 2002 the Company had entered into a crude oil swap agreement. Terms of the agreement include notional volumes of 200 barrels per day for the contract term extending from April 1,2003 to December 31, 2003 with a fixed price of CDN $40.15 per barrel. As this agreement had been entered into prior to December 31, 2002, the contract had an unrealized loss as at December 31, 2002 of approximately $70,000.

(b) Credit risk:

The Company's accounts receivable are with customers and joint venture partners in the petroleum and natural gas industry and are subject to normal industry credit risks. Purchasers of the Company's natural gas, crude oil and natural gas liquids are subject to an internal credit review to minimize the risk of non-payment. The Company does not believe that there are any significant concentrations of credit risk.

(c) Fair values:

The carrying values of the Company's financial assets and liabilities, with the exception of the Company's long-term investments (see note 5), approximated their fair values as at September 30, 2004, December 31, 2003 and 2002. The fair value of the Company's long-term investments was considered undeterminable due to the inability to apply a valuation method or obtain market prices. As noted in note 5, during the year ended December 31, 2003 the Company sold its investment in Monolith for a gain of approximately $17,733,000.

12. Commitment:

The Company is committed to a lease for office space annually as follows:

October 1, 2004 to December 31, 2004	$ 67,000
Year ended December 31, 2005	275,000
Year ended December 31, 2006	330,000
Year ended December 31, 2007	340,000
Year ended December 31, 2008	345,000

13. Acquisition of Rubicon Energy Assets:

In March 2004, the Company acquired 50% of the issued and outstanding shares of Rubicon Energy Corporation ("Rubicon"), an oil and gas company. The acquisition was accounted for by the purchase method of accounting with the results of operations included from the date of acquisition. The allocation to the fair value of the assets and liabilities was as follows:

Net assets acquired and liabilities assumed:

Property, plant and equipment	$ 51,151,000
Goodwill	14,081,000
Working capital deficiency	(6,314,000)
Bank indebtedness	(3,394,000)
Asset retirement obligation	(950,000)
Future income taxes	(12,485,000)
	$ 42,089,000

Consideration was comprised of:

Purchase of Rubicon common shares for cash	$ 41,810,000
Transaction costs	279,000
	$ 42,089,000

14. Subsequent events:

(a) Issuance of special warrants:

On October 20, 2004 the Company issued 3,300,000 special warrants at a price of $9.00 per special warrant for gross proceeds totalling $29,700,000. Costs associated with the issuance of the special warrants totalled approximately $1,704,000 including a commission received by the agent equal to 5.5% of the gross proceeds from the sale of the special warrants for an aggregate fee of approximately $1,634,000. Each special warrant entitles the holder thereof to acquire 1.047 common shares at no additional cost on that date which is five business days following the date upon which a receipt for the final version of a prospectus is issued by the appropriate securities commissions.

If a receipt for the final version of a prospectus has not been obtained on or prior to October 20, 2005, then each holder of special warrants in which such receipt has not been obtained shall be entitled to receive 1.152 common shares for each special warrant.

(b) Credit facilities:

In February 2005 a new banking arrangement was entered into by the Company with Canadian financial institutions. The facilities consisted of a $45 million revolving term credit facility, a $10 million demand operating credit facility and a $25 million non-revolving, non-extendible term credit facility. The $45 million revolving term facility revolves until May 31, 2005 unless it is extended for a 364-day period. The $25 million non-revolving, non-extendible term credit facility shall be repaid no later than May 31, 2005. The revolving term credit facility bears interest at the lenders' prime rate plus 0.25% per annum. The non-revolving, non-extendible term credit facility and the demand operating credit facility bears interest the lenders' prime rate plus 1.75% per annum. The facilities are secured by a general security agreement and a first floating charge over all of the Company's assets.

(c) Initial public offering:

Pursuant to an underwriting agreement dated March 24, 2005 between the Company and certain underwriters, the Company has agreed to sell to the underwriters 4,000,000 common shares at a price of $18.00 per share for gross proceeds totalling $72,000,000. Costs associated with the issuance of the common shares are estimated to be approximately $4,342,200 including the underwriters' fee of $3,742,200 and other expenses.

The obligations of the underwriters under the underwriting agreement are several and not joint, and may be terminated at their discretion. It is expected that closing will occur on or about April 5, 2005 or such other date, not later than April 19, 2005, as the Company and the underwriters may agree.

14. Subsequent events (continued):

(c) Initial public offering (continued):

The Company has applied to list the common shares distributed pursuant to the offering and the common shares issuable upon the exercise of the outstanding special warrants (see note 14(a)) on the Toronto Stock Exchange. Listing will be subject to the Company fulfilling all of the listing requirements of the Toronto Stock Exchange.

15. Contingency:

On December 14, 2004 the Company was granted a license from the Alberta Energy and Utilities Board (the "AEUB") relating to the expansion of an existing facility. On December 15, 2004 a notice of objection was filed with the AEUB by a corporation which is a joint lease owner where the facility is being constructed. To date, the AEUB has not ruled on the merits of the notice of objection. Although management of the Company is of the view that the objection submitted by the corporation is without merit and will continue to defend the interests of the Company in the facility, it is possible that the AEUB may render a decision in this matter which would have an adverse effect on the Company and its processing capabilities in an area which is significant to the Company.

PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS OF HIGHPINE OIL & GAS LIMITED

COMPILATION REPORT

To the Board of Directors of Highpine Oil & Gas Limited

We have read the accompanying unaudited pro forma consolidated statements of operations of Highpine Oil & Gas Limited (the "Company") for the nine months ended September 30, 2004 and for the year ended December 31, 2003 and have performed the following procedures:

1. Compared the figures in the columns captioned "Highpine Oil & Gas Limited" to the unaudited consolidated financial statements of the Company for the nine months ended September 30, 2004 and the audited consolidated financial statements of the Company for the year ended December 31, 2003, respectively and found them to be in agreement.
2. Compared the figures in the column captioned "Rubicon Energy Net Assets Acquired" to the unaudited financial statements of the Rubicon Energy Properties for the two-month period ended February 29, 2004 and the audited financial statements of the Rubicon Energy Properties for the year ended December 31, 2003, respectively and found them to be in agreement.
3. Made enquiries of certain officials of the Company who have responsibility for financial and accounting matters about:
    a. the basis for determination of the pro forma adjustments; and
    b. whether the pro forma consolidated financial statements comply as to form in all material respects with the published requirements of the Canadian Securities legislation.

The officials:

a. described to us the basis for determination of the pro forma adjustments; and
b. stated that the pro forma consolidated financial statements comply as to form in all material respects with the published requirements of the Canadian securities legislation.

4. Read the notes to the pro forma consolidated financial statements, and found them to be consistent with the basis described to us for determination of the pro forma adjustments.

5. Recalculated the application of the pro forma adjustments to the aggregate of the amounts in the respective columns for the nine months ended September 30, 2004 and for the year ended December 31, 2003, and found the amounts in the columns captioned "Total" to be arithmetically correct.

A pro forma financial statement is based on management assumptions and adjustments which are inherently subjective. The forgoing procedures are substantially less than either an audit or a review, the objective of which is the expression of assurance with respect to management's assumptions, the pro forma adjustments, and the application of the adjustments to the historical financial information. Accordingly, we express no such assurance. The foregoing procedures would not necessarily reveal matters of significance to the pro forma consolidated financial statements, and we therefore, make no representation about the sufficiency of the procedures for the purposes of a reader of such statements.

(Signed) KPMG LLP
Chartered Accountants

Calgary, Canada
March 24, 2005

HIGHPINE OIL & GAS LIMITED

Pro Forma Consolidated Statement of Operations

Nine months ended September 30, 2004
(Unaudited)
(in thousands of dollars)

	Highpine Oil & Gas Limited	Rubicon Energy Net Assets Acquired	Adjustments (note 2)	Total
Revenues:				
Petroleum and natural gas	$ 29,083	$ 3,592	$ –	$ 32,675
Royalties	(7,466)	(873)	–	(8,339)
	21,617	2,719	–	24,336
Expenses:				
Operating	4,603	1,000	–	5,603
General and administrative	1,646	212	–	1,858
Transaction costs	–	3,833	(3,833)	–
Depletion, depreciation and accretion	10,403	841	(444)	10,800
Stock based compensation	231	–	–	231
Interest	1,848	24	323	2,195
	18,731	5,910	(3,954)	20,687
Other items:				
Interest and dividend income	48	–	–	48
Gain on sale of investment	294	–	–	294
	342	–	–	342
Income taxes:				
Large corporations tax	112	6	(6)	112
Future	987	(990)	1,512	1,509
	1,099	(984)	1,506	1,621
Net earnings (loss) for the period	$ 2,129	$ (2,207)	$ 2,448	$ 2,370
Net earnings per share:				
Basic				$ 0.16
Diluted				$ 0.16

See accompanying notes to pro forma consolidated financial statements.

HIGHPINE OIL & GAS LIMITED

Pro Forma Consolidated Statement of Operations

Year ended December 31, 2003
(Unaudited)
(in thousands of dollars)

	Highpine Oil & Gas Limited	Rubicon Energy Net Assets Acquired	Adjustments (note 3)	Total
Revenues:				
Petroleum and natural gas	$ 16,926	$ 15,922	$ –	$ 32,848
Royalties	(3,109)	(3,527)	–	(6,636)
	13,817	12,395	–	26,212
Expenses:				
Operating	2,294	2,801	–	5,095
General and administrative	1,856	1,042	–	2,898
Depletion, depreciation and accretion	4,876	3,273	3,941	12,090
Stock based compensation	102	–	–	102
Interest	195	229	2,568	2,992
	9,323	7,345	6,509	23,177
Other items:				
Interest and dividend income	2,214	–	–	2,214
Gain on sale of investment	17,439	–	–	17,439
	19,653	–	–	19,653
Income taxes:				
Large corporations tax	70	36	68	174
Future	4,969	1,734	(2,482)	4,221
	5,039	1,770	(2,414)	4,395
Net earnings (loss) for the period	$ 19,108	$ 3,280	$ (4,095)	$ 18,293
Net earnings per share:				
Basic				$ 1.26
Diluted				$ 1.26

See accompanying notes to pro forma consolidated financial statements.

HIGHPINE OIL & GAS LIMITED

Notes to Pro forma Consolidated Financial Statements

For the nine months ended September 30, 2004 and for the year ended December 31, 2003
(Unaudited)
(tabular amounts in thousands of dollars)

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1. **Basis of presentation:**

Pursuant to an initial public offering, Highpine Oil & Gas Limited ("Highpine") will become a public company listed on the TSX. Highpine is a private company and is engaged in the exploration for, and the development of, oil and natural gas.

The accompanying unaudited pro forma consolidated financial statements have been prepared by the management of Highpine in accordance with accounting principles generally accepted in Canada.

The unaudited pro forma consolidated statement of operations for the nine months ended September 30, 2004 is based on:

(a) the unaudited consolidated statement of earnings of Highpine for the nine months ended September 30, 2004; and

(b) the unaudited statement of operations of the Rubicon Energy Properties for the two month period ended February 29, 2004.

The unaudited pro forma consolidated statement of operations for the year ended December 31, 2003 is based on:

(a) the audited consolidated statement of earnings of Highpine for the year ended December 31, 2003; and

(b) the audited statement of operations of the Rubicon Energy Properties for the year ended December 31, 2003.

These pro forma financial statements may not be indicative of results that actually would have occurred if the events reflected herein had been in effect on the dates indicated or of the results that may be obtained in the future.

It is the recommendation of management that this financial information should be read in conjunction with the financial statements and notes thereto of the financial statements referred to above.

(tabular amounts in thousands of dollars)

2. Pro forma transactions and assumptions (nine months ended September 30, 2004):

The pro forma combined statement of operations for the nine month period ended September 30, 2004 gives effect to the following:

(i) the acquisition of net assets and liabilities acquired by Highpine from Rubicon Energy Corporation for consideration of approximately $42 million as if it had occurred on January 1, 2003 instead of the actual closing date of March 2004.

Net assets acquired and liabilities assumed are as follows:

Property, plant and equipment	$	51,151
Goodwill		14,081
Working capital deficiency		(6,314)
Bank indebtedness		(3,394)
Asset retirement obligation		(950)
Future income taxes		(12,485)
	$	42,089

Consideration was comprised of:

Purchase of Rubicon Energy Corporation common shares for cash	$	41,810
Transaction costs		279
	$	42,089

(ii) a provision for depletion, depreciation and accretion expense based on combining reserves, production and cost of capital assets under the full cost method of accounting for oil and gas properties.

(iii) increase in interest expense of $323,000 arising from increased bank debt used to fund the purchase, net of assumed debt repayments from increased cash flow.

(iv) capital taxes have been decreased to reflect the consolidated capital base at September 30, 2004.

(v) elimination of the transaction costs of $3.8 million as these costs were incurred by Rubicon Energy Corporation prior to the acquisition of the net assets and liabilities by Highpine.

(vi) the provision for income taxes has been adjusted to reflect the impact of the above adjustments.

3. Pro forma transactions and assumptions (year ended December 31, 2003):

The pro forma consolidated statement of operations for the year ended December 31, 2003 gives effect to the transaction referred to note 2(i) above and the following:

(i) a provision for depletion, depreciation and accretion expense based on combining reserves, production and cost of capital assets under the full cost method of accounting for oil and gas properties.

(ii) increase in interest expense of $2.6 million arising from increased bank debt used to fund the purchase, net of assumed debt repayments from increased cash flow.

(iii) capital taxes have been increased by $68,000 to reflect the impact of a larger capital tax base.

(iv) the provision for income taxes has been adjusted to reflect the impact of the above adjustments.

kpmg

Financial Statements of

RUBICON ENERGY PROPERTIES

Period ended February 29, 2004 and three years ended December 31, 2003

AUDITORS' REPORT TO THE DIRECTORS OF HIGHPINE OIL & GAS LIMITED

We have audited the balance sheets of the Rubicon Energy Properties as at December 31, 2003 and 2002 and the statements of operations and net assets and cash flows for each the years in the three-year period ended December 31, 2003. These financial statements are the responsibility of Highpine Oil & Gas Limited's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits 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 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 Rubicon Energy Properties as at December 31, 2003 and 2002 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2003 in accordance with Canadian generally accepted accounting principles.

(Signed) KPMG LLP
Chartered Accountants

Calgary, Canada
February 18, 2005

RUBICON ENERGY PROPERTIES

Balance Sheets

	February 29, 2004	December 31, 2003	December 31, 2002
	(unaudited)	(audited)	
Assets			
Current assets:			
Accounts receivable	$ 3,143,485	$ 2,805,335	$ 1,184,405
Capital assets (note 4)	22,840,647	22,017,114	14,791,002
Loans receivable	–	367,500	392,500
	$ 25,984,132	$ 25,189,949	$16,367,907
Liabilities and Net Assets			
Current liabilities:			
Bank indebtedness (note 5)	$ 3,758,714	$ 5,478,969	$ 4,156,349
Accounts payable and accrued liabilities	9,192,268	3,519,807	1,567,589
	12,950,982	8,998,776	5,723,938
Asset retirement obligation (note 6)	966,000	950,000	530,000
Future income taxes (note 7)	1,978,716	2,968,232	1,233,500
Net assets	10,088,434	12,272,941	8,880,469
	$ 25,984,132	$25,189,949	$16,367,907

See accompanying notes to financial statements.

RUBICON ENERGY PROPERTIES
Statements of Operations and Net Assets

	Period ended February 29, 2004	Years ended December 31, 2003	2002	2001
	(unaudited)		(audited)	
Revenue:				
Oil and gas production	$ 3,592,432	$15,922,423	$ 5,886,770	$ 4,334,481
Royalties	(914,862)	(3,776,650)	(1,402,007)	(1,102,301)
Alberta royalty tax credit	41,500	250,000	204,051	125,421
	2,719,070	12,395,773	4,688,814	3,357,601
Expenses:				
Operating	999,563	2,801,273	1,322,085	691,933
General and administrative	212,233	1,042,115	603,498	699,916
Transaction costs (note 3)	3,832,618	–	–	–
Interest on bank indebtedness	23,650	228,534	165,989	108,242
Depletion and depreciation and accretion	841,029	3,273,500	1,967,500	1,390,000
	5,909,093	7,345,422	4,059,072	2,890,091
Income (loss) before income taxes	(3,190,023)	5,050,351	629,742	467,510
Income taxes (note 7):				
Capital taxes	6,000	36,000	25,270	35,500
Future income taxes	(989,516)	1,734,732	228,500	167,962
	(983,516)	1,770,732	253,770	203,462
Net income (loss)	(2,206,507)	3,279,619	375,972	264,048
Net assets, beginning of period	12,272,941	8,880,469	8,444,497	4,579,981
Equity issued by Rubicon	22,000	112,853	60,000	3,600,468
Net assets, end of period	$10,088,434	$12,272,941	$8,880,469	$ 8,444,497

See accompanying notes to financial statements.

RUBICON ENERGY PROPERTIES

Statements of Cash Flows

	Period ended February 29, 2004	Years ended December 31, 2003	2002	2001
	(unaudited)		(audited)	
Cash provided by (used in):				
Operations:				
Net income (loss)	$ (2,206,507)	$ 3,279,619	$ 375,972	$ 264,048
Items not involving cash:				
Depletion and depreciation	841,029	3,273,500	1,967,500	1,390,000
Future income taxes	(989,516)	1,734,732	228,500	167,962
Funds from operations	(2,354,994)	8,287,851	2,571,972	1,822,010
Change in non-cash working capital	5,334,311	331,288	171,606	(598,695)
Asset retirement expenditures	–	(47,822)	(12,968)	(9,077)
	2,979,317	8,571,317	2,730,610	1,214,238
Financing activities:				
Equity issued by Rubicon	22,000	112,853	60,000	3,600,468
Bank indebtedness	(1,720,255)	1,322,620	1,505,729	2,650,621
Proceeds on loans receivable	367,500	25,000	–	–
Cash held in trust	–	–	–	211,633
	(1,330,755)	1,460,473	1,565,729	6,462,722
Investing activities:				
Additions to capital assets	(1,648,562)	(10,786,290)	(3,559,267)	(6,299,288)
Purchase of capital assets	–	(158,000)	(825,000)	(2,113,516)
Proceeds on sale of capital assets	–	912,500	87,928	207,500
	(1,648,562)	(10,031,790)	(4,296,339)	(8,205,304)
Decrease in cash	–	–	–	(528,344)
Cash, beginning of period	–	–	–	528,344
Cash, end of period	$ –	$ –	$ –	$ –
Cash payment for:				
Interest	$ 23,650	$ 228,534	$ 165,989	$ 108,242
Taxes	$ –	$ 28,421	$ 54,319	$ 1,229

See accompanying notes to financial statements.

1. Basis of presentation:

These financial statements have been prepared to reflect the financial position and results of operations of Highpine Oil & Gas Limited's interest in properties acquired when it jointly acquired Rubicon Energy Corporation. These financial statements reflect Highpine Oil & Gas Limited's 50% interest in the historical accounts of Rubicon Energy Corporation.

These financial statements have been prepared in accordance with Canadian generally accepted accounting principles.

(a) Capital assets:

Rubicon followed the full cost method of accounting for oil and natural gas activities, whereby all costs related to the acquisition of, the exploration for and development of oil and gas reserves were capitalized. Costs included lease acquisition, geological and geophysical expenditures, drilling expenditures, and related plant and production equipment costs. Administrative costs were not capitalized other than to the extent of the working interest in operated capital expenditure programs on which operator's fees were charged equivalent to standard industry operating agreements.

Petroleum and natural gas properties, including future development costs, were depleted on the unit-of-production method based on estimated proven reserves before royalties as determined by independent engineers. Gas volumes were converted to equivalent energy units of oil on the basis of six thousand cubic feet to one barrel of oil.

The net carrying cost of the capital assets was compared to the sum of the undiscounted cash flows expected from proved reserves and the lower of cost or market of unproved properties. Cash flow estimates were based on future prices, adjusted for contracted prices and quality differentials. If the carrying cost exceeded this ceiling test amount, Rubicon measured, and recorded, an impairment by comparing the carrying cost of capital assets to the estimated net present value of future cash flows from proved plus probable reserves and the lower of cost and market of unproved properties. A risk-free interest rate was used to determine the present value.

Proceeds on sales of petroleum and natural gas properties were generally applied against capitalized costs without recognition of a gain or loss except for those sales, which would significantly alter the depletion and depreciation rate by 20% or more.

1. **Basis of presentation (continued):**

(b) Asset retirement obligation:

Effective January 1, 2004 Rubicon adopted the new accounting standard for asset retirement obligations. The new standard required that Rubicon record the fair value of an asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of long-lived assets. The associated asset retirement costs are capitalized as part of the carrying amount of the capital assets and depleted and depreciated using a unit of production method over estimated gross proved reserves. Subsequent to the initial measurement of the asset retirement obligations, the obligations are adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The effect of adoption of the new standard is disclosed in note 2.

(c) Joint interest operations:

Certain of the exploration and production activities were conducted jointly with other entities and accordingly the accounts reflect only the proportionate interest in such activities.

(d) Office equipment:

Office equipment was recorded at cost upon acquisition. Depreciation was provided on the declining balance basis using rates of 20% and 30% per annum.

(e) Income taxes:

Rubicon followed the liability method of accounting for income taxes. Under this method, income tax liabilities and assets were recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets was recognized in income in the period that the change occurs.

(f) Revenue recognition:

Revenues associated with sales of crude oil, natural gas and natural gas liquids were recorded when title passed to the customer.

(g) Stock based compensation:

Rubicon had a stock option plan enabling certain officers, directors and employees to purchase common shares at exercise prices equal to the estimated market value on the date the option was granted. Rubicon followed the fair value method to account for options granted pursuant to the plan. Application of the fair value method resulted in the recognition of compensation expense for options granted.

2. Changes in accounting policies:

In January 2004 Rubicon adopted *AcG-16 "Oil and Gas Accounting"*, a new guideline replacing *AcG-5*. Under *AcG-5*, future net revenues for the ceiling test was an undiscounted amount based on proved reserves at constant prices; estimated future administrative and financing costs were deducted in determining the ceiling test amount. There were no changes to previously reported income, capital assets or other reported amounts as a result of the retroactive adoption of this new standard.

Effective January 1, 2004 Rubicon changed its accounting for asset retirement obligations. Prior to 2004 the estimated costs for future site restoration were provided for on a unit of production basis. The effect of the retroactive adoption of the new policy on the balance sheet was:

	2003	2002	2001
Increase to capital assets	$ 356,000	$ 288,000	$138,000
Increase to asset retirement obligation	356,000	288,000	138,000
Change to net assets	–	–	–

Site restoration and reclamation expense recorded under the previous accounting policy approximated the depletion and depreciation and accretion expense under the application of the new policy. As a result, prior period statements of operations were not restated.

Effective January 1, 2004 Rubicon changed its accounting policy for stock options from the intrinsic method to the fair value method. The new method was applied retroactively. Compensation expense recorded following the intrinsic method approximated the compensation expense recorded under the fair value method. As a result, there were no changes to previously reported income or other reported amounts as a result of the change.

3. Transaction costs:

In conjunction with the sale of the company, Rubicon incurred transaction costs, including severance, cash expended to cancel outstanding stock options and legal fees.

4. Capital assets:

	February 29,	December 31,	
	2004	2003	2002
Petroleum and natural gas properties, including equipment and facilities	$ 32,492,651	$ 30,837,497	$ 20,456,579
Office equipment	63,791	63,995	50,800
	32,556,442	30,901,492	20,507,379
Accumulated depletion and depreciation	9,715,795	8,884,378	5,716,377
	$ 22,840,647	$ 22,017,114	$ 14,791,002

Rubicon had not excluded the cost of unproven properties from depletion and depreciation calculations. During the period ended February 29, 2004 future development costs of $nil (years ended December 31, 2003 - $1,194,000; 2002 - $1,026,000; 2001 - $1,753,000) were included in the calculations.

5. Bank indebtedness:

Rubicon had an $8,500,000 revolving demand credit facility, which could be drawn down in the form of loans or bankers acceptances. As at December 31, 2003 Rubicon had drawn $5,478,969 on the credit facility consisting of a $1,287,500 demand loan and $3,500,000 in banker's acceptances. Interest on the demand loan was calculated at the bank's prime rate plus 1/4% per annum. Interest on the banker's acceptances was calculated at the bank's prime acceptance fee plus 1.25% per annum. This facility was secured by a general security agreement and a fixed and floating charge oil and gas debenture. Borrowings under the facility were limited to a borrowing base determined by the lender. The loan is repayable on demand.

	February 29,	December 31,	
	2004	2003	2002
Operating demand credit facility	$ 3,500,000	$ 4,787,500	$ 4,055,000
Bank overdraft	258,714	691,469	101,349
	$ 3,758,714	$ 5,478,969	$ 4,156,349

RUBICON ENERGY PROPERTIES

Notes to Financial Statements, Page 5

Years ended December 31, 2003, 2002 and 2001

6. Asset retirement obligation:

	February 28 2004	December 31, 2003	December 31, 2002
Balance, beginning of period	$ 950,000	$ 530,000	$ 380,000
Liabilities incurred	–	365,000	112,000
Accretion expense	16,000	102,822	50,968
Current period expenditures	–	(47,822)	(12,968)
Balance, end of period	$ 966,000	$ 950,000	$ 530,000

7. Income taxes:

The provision for income taxes differs from the amount, which would result from applying the combined expected Canadian federal and provincial income tax rate of 38.6% (2003 – 40.62%; 2002 - 42.1%, 2001 – 42.6%) to income before income taxes. The principal reasons for this difference were:

	Period ended February 29, 2004	Years ended December 31, 2003	2002	2001
Expected provision for income taxes	$ (1,231,349)	$ 2,051,453	$ 265,119	$ 199,160
Increase (decrease) resulting from:				
Non-deductible crown charges, net of ARTC257,852	1,121,042	373,236		335,069
Federal resource allowance	–	(1,001,182)	(358,318)	(271,832)
Provincial royalty rebates	(16,019)	(76,326)	(45,169)	(57,000)
Tax rate reduction	–	(360,255)	(6,368)	(37,435)
Capital taxes	6,000	36,000	25,270	35,500
	247,833	(280,721)	(11,349)	4,302
Reported provision for income taxes	$ (983,516)	$ 1,770,732	$ 253,770	$ 203,462

The provision for future income taxes arose from temporary differences in the recognition of revenues and expenses for income tax and accounting purposes. The components comprising the future income tax liability were as follows:

	February 29, 2004	December 31, 2003	December 31, 2002
Future income tax assets:			
Share issue costs	$ 2,000	$ 2,000	$ 3,950
Asset retirement obligation	80,600	77,200	51,000
Provincial royalty rebates	184,500	172,500	100,000
	267,100	251,700	154,950
Future income tax liabilities:			
Capital assets	2,245,816	3,219,932	1,388,450
Future income tax liability	$ 1,978,716	$ 2,968,232	$ 1,233,500

8. Financial instruments:

(a) Credit risk management:

The accounts receivable are with customers and joint venture partners in the petroleum and natural gas industry and are subject to normal industry credit risks. Purchasers of the natural gas, crude oil and natural gas liquids are subject to an internal credit review to minimize the risk of non-payment. Rubicon did not believe that there are any significant concentrations of credit risk.

(b) Fair values of financial instruments:

Accounts receivable, accounts payable and accrued liabilities have carrying values that approximate fair value due to the near-term maturity of these financial instruments. The fair value of the loans receivable approximated the carrying value.

(c) Interest rate risk:

Rubicon was exposed to changes in interest rates with respect to its outstanding bank debt.

9. Related party transactions:

In November 2003 a director, two officers and a shareholder formed a new company and purchased proven and unproven properties from Rubicon for $818,500, being the fair value of the properties as determined by management based on an independent reserve and land valuation reports.

At December 31, 2003, the accounts receivable balance included $241,000 and the accounts payable and accrued liabilities balance includes $24,000 due from/to this company.

10. Contingency:

In December 2003 a contractor invoiced Rubicon for $527,500 for drilling services. Rubicon was disputing the amount invoiced and included $300,000 in accounts payable and accrued liabilities at December 31, 2003.

REPORT OF HIGHPINE MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE IN ACCORDANCE WITH FORM 51-101F3

Management of Highpine Oil & Gas Limited (the "Corporation") are responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

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

(ii) the related estimated future net revenue; and

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

(ii) the related estimated future net revenue.

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

The Board of Directors of the Corporation has

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

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

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

The Board of Directors of the Corporation has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has approved

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

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

(h) 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) A. Gordon Stollery
Chairman, President and Chief Executive Officer

(Signed) Greg N. Baum
Executive Vice President and Chief Operating Officer

(Signed) Richard G. Carl
Director

(Signed) Hank B. Swartout
Director

February 18, 2005

REPORT ON RESERVES DATA BY PADDOCK LINDSTROM & ASSOCIATES LTD. IN FORM 51-101F2

To the Board of Directors of Highpine Oil & Gas Limited (the "Corporation"):

1. We have prepared an evaluation of the Corporation's Reserves Data as at December 31, 2004. The Reserves Data consist of the following:

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

(ii) the related estimated future net revenue; and

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

(ii) the related estimated future net revenue.

2. The Reserves Data are the responsibility of the Corporation's management. Our responsibility is to express an opinion on the Reserves Data based on our evaluation.

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

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the Reserves Data of the Corporation evaluated by us for the year ended December 31, 2004, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Corporation's Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) Audited ($)	Evaluated ($)	Reviewed ($)	Total ($)
Paddock	Evaluation of the P&NG Reserves of Highpine Oil & Gas Limited, as of December 31, 2004 prepared February 3, 2005	Canada	0	169,466	0	169,466

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

6. We have no responsibility to update this evaluation for events and circumstances occurring after its preparation date.

7. Because the Reserves Data are based on judgments 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
February 18, 2005

(Signed) Dennis L. Paddock, P. Eng.
Vice President

CERTIFICATE OF THE CORPORATION

Dated: March 24, 2005

This prospectus constitutes full, true and plain disclosure of all material facts relating to the securities offered by this prospectus as required by Part 9 of the *Securities Act* (British Columbia), Part 9 of the *Securities Act* (Alberta), Part XI of *The Securities Act, 1988* (Saskatchewan), Part VII of the *Securities Act* (Manitoba) and Part XV of the *Securities Act* (Ontario), and by the respective regulations thereunder. For the purpose of the Province of Québec, this prospectus contains no misrepresentation that is likely to affect the value or the market price of the securities to be distributed.

HIGHPINE OIL & GAS LIMITED

(Signed) A. Gordon Stollery
Chairman, President and Chief Executive Officer

(Signed) Harry D. Cupric
Vice President, Finance and Chief Financial Officer

ON BEHALF OF THE BOARD OF DIRECTORS

(Signed) John A. Brussa
Director

(Signed) Richard G. Carl
Director

CERTIFICATE OF THE UNDERWRITERS

Dated: March 24, 2005

To the best of our knowledge, information and belief, this prospectus constitutes full, true and plain disclosure of all material facts relating to the securities offered by this prospectus as required by Part 9 of the *Securities Act* (British Columbia), Part 9 of *Securities Act*, (Alberta), Part XI of *The Securities Act, 1988* (Saskatchewan), Part VII of the *Securities Act* (Manitoba) and Part XV of the *Securities Act* (Ontario), and by the respective regulations thereunder. For the purpose of the Province of Québec, to our knowledge, this prospectus does not contain any misrepresentation that is likely to affect the value or the market price of the securities to be distributed.

TRISTONE CAPITAL INC.

By: (Signed) Vincent L. Chahley

FIRSTENERGY CAPITAL CORP.

By: (Signed) John S. Chambers

BMO NESBITT BURNS INC.

By: (Signed) Shane C. Fildes

RBC DOMINION SECURITIES INC.

By: (Signed) Robi Contrada

GMP SECURITIES LTD.

By: (Signed) Christopher T. Graham

AUTORITÉ DES MARCHÉS FINANCIERS

DÉCISION N° : 2005-MC-1045

NUMÉRO DE PROJET SÉDAR: 740559

DOSSIER N° : 23950

Objet : Highpine Oil & Gas Limited
Demande de visa

Vu la demande présentée le 21 février 2005;

vu les articles 11, 13 et 14 de la *Loi sur les valeurs mobilières*, L.R.Q., c. V-1.1;

vu l'Instruction générale Q-28, *Exigences générales relatives aux prospectus*;

vu les pouvoirs délégués conformément à l'article 24 de la *Loi sur l'Autorité des marchés financiers*, L.R.Q., c. A-7.03.

En conséquence, l'Autorité des marchés financiers octroie le :

visa pour le prospectus du 24 mars 2005 de Highpine Oil & Gas Limited concernant le placement de 4 000 000 d'actions ordinaires au prix de 18,00 $ l'action et de 3 455 105 actions ordinaires en contrepartie de 3 300 000 bons de souscription spéciaux antérieurement placés au prix de 9,00 $ le bon.

Le visa prend effet le 24 mars 2005.

(s) Benoit Dionne
Benoit Dionne
Chef du Service du financement des sociétés

JB/pg

800, square Victoria, 22ième étage, tour de la Bourse, C.P. 246, Montréal (Québec) H4Z 1G3
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