11/6

07027831

82- SUBMISSIONS FACING SHEET

Follow-Up Materials

MICROFICHE CONTROL LABEL

REGISTRANT'S NAME Highpine Oil & Gas Ltd

*CURRENT ADDRESS

**FORMER NAME

BEST AVAILABLE COPY

PROCESSED
NOV 09 2007
THOMSON FINANCIAL

**NEW ADDRESS

FILE NO. 82- 34869 FISCAL YEAR 12-31-06

* *Complete for initial submissions only* ** *Please note name and address changes*

INDICATE FORM TYPE TO BE USED FOR WORKLOAD ENTRY:

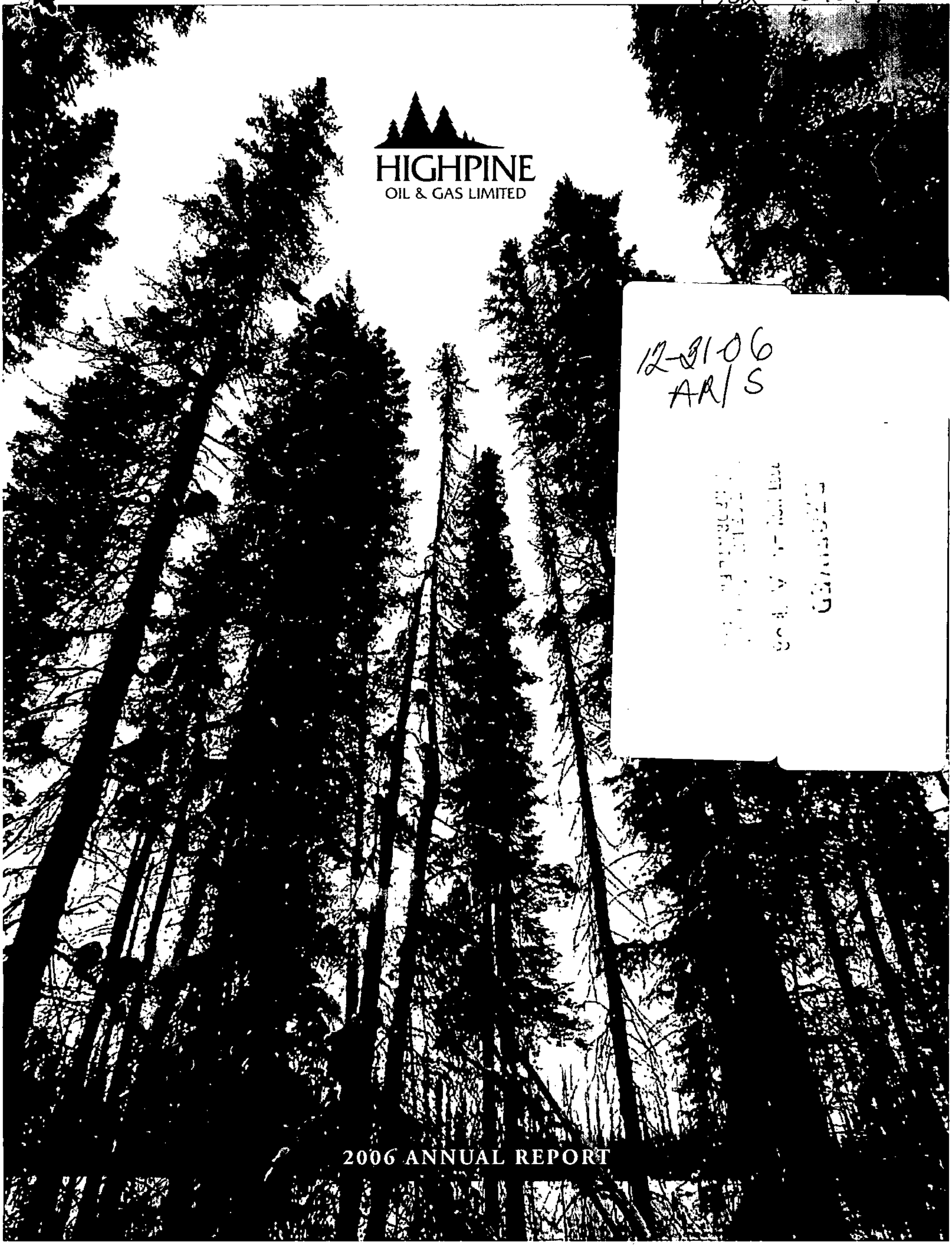
12G3-2B (INITIAL FILING)	☐	AR/S (ANNUAL REPORT)	☑
12G32BR (REINSTATEMENT)	☐	SUPPL (OTHER)	☐
DEF 14A (PROXY)	☐		

OICF/BY: dle

DAT : 11/7/07

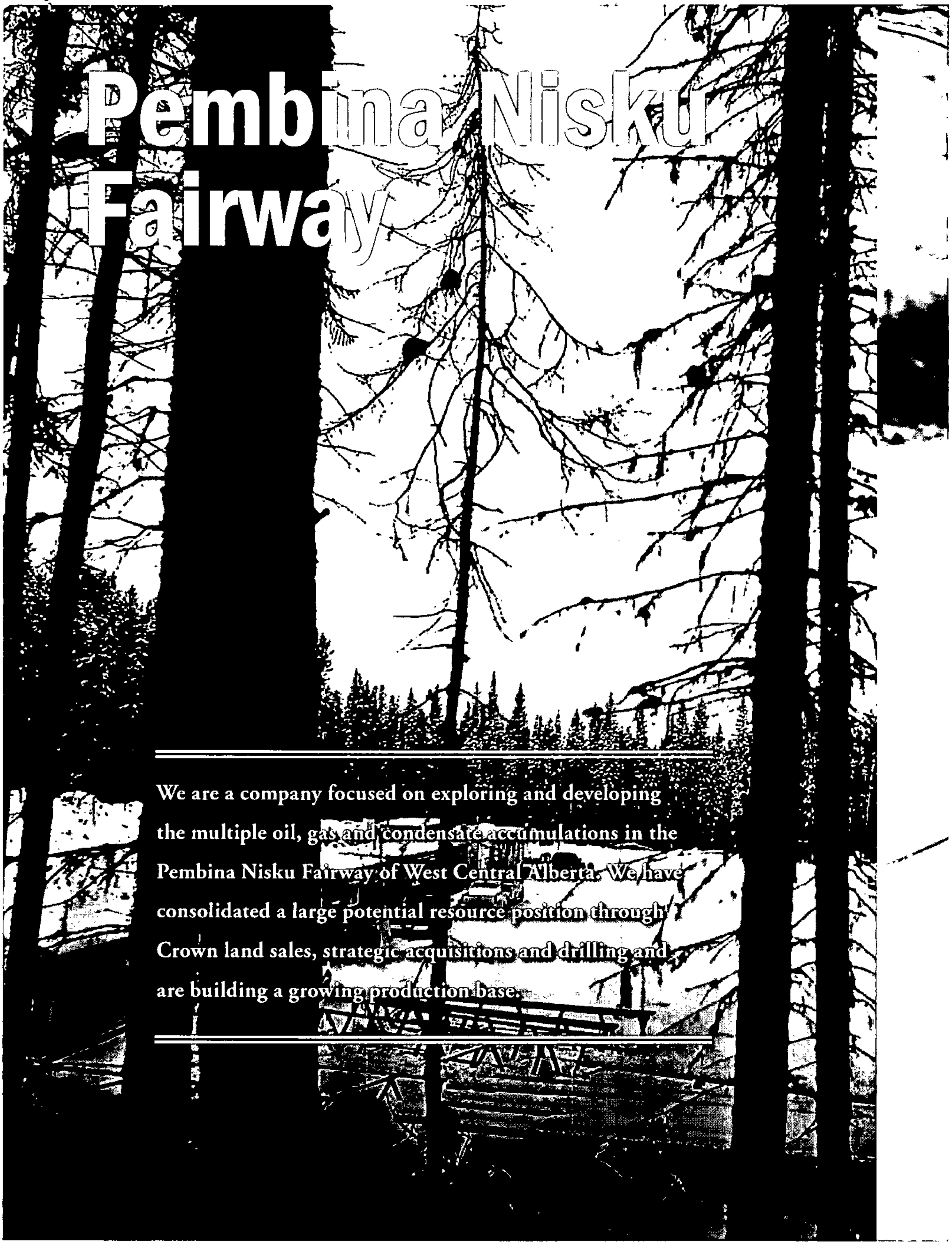
082-34864

HIGHPINE
OIL & GAS LIMITED



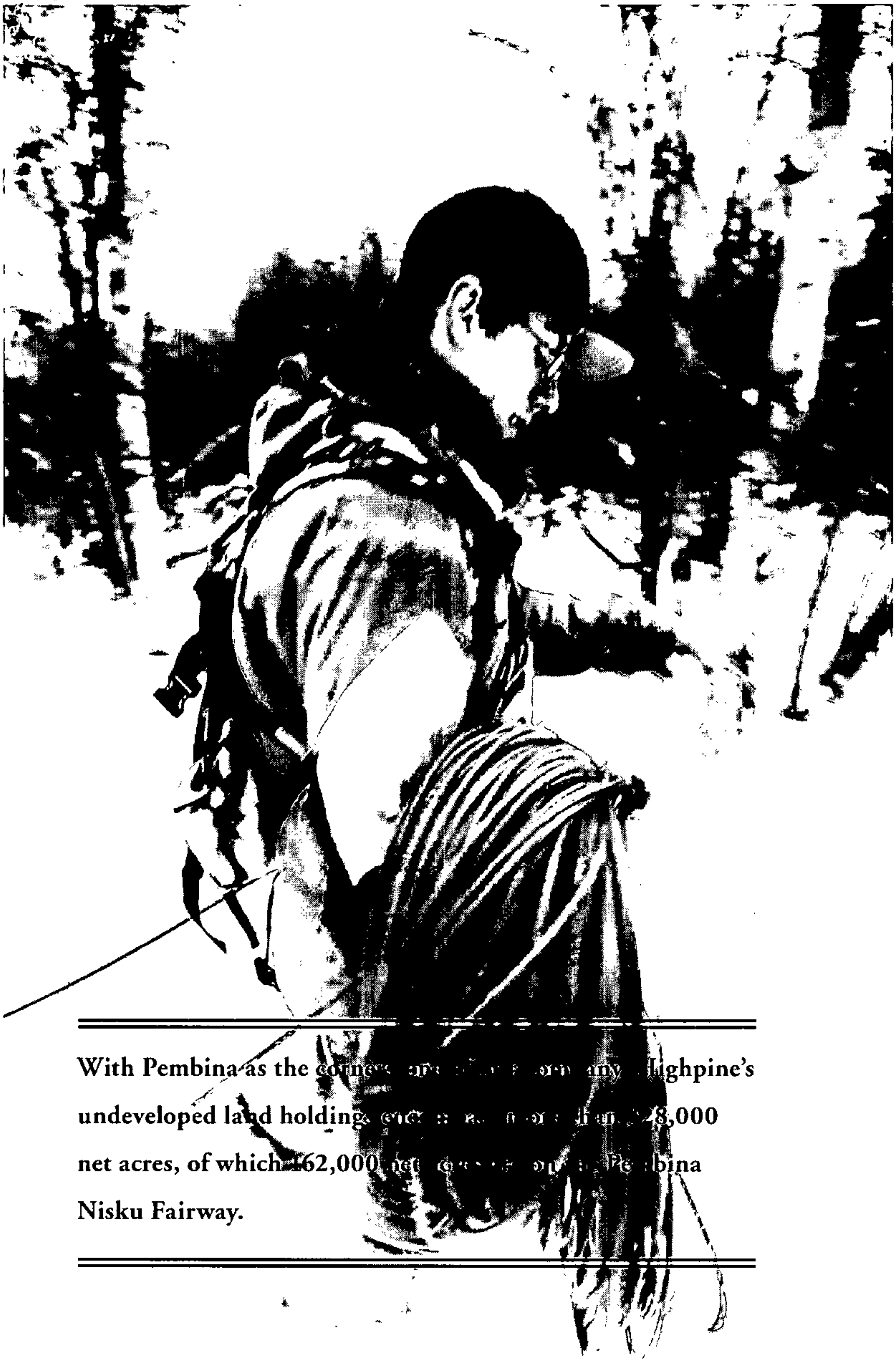
12-31-06
AR/S

2006 ANNUAL REPORT

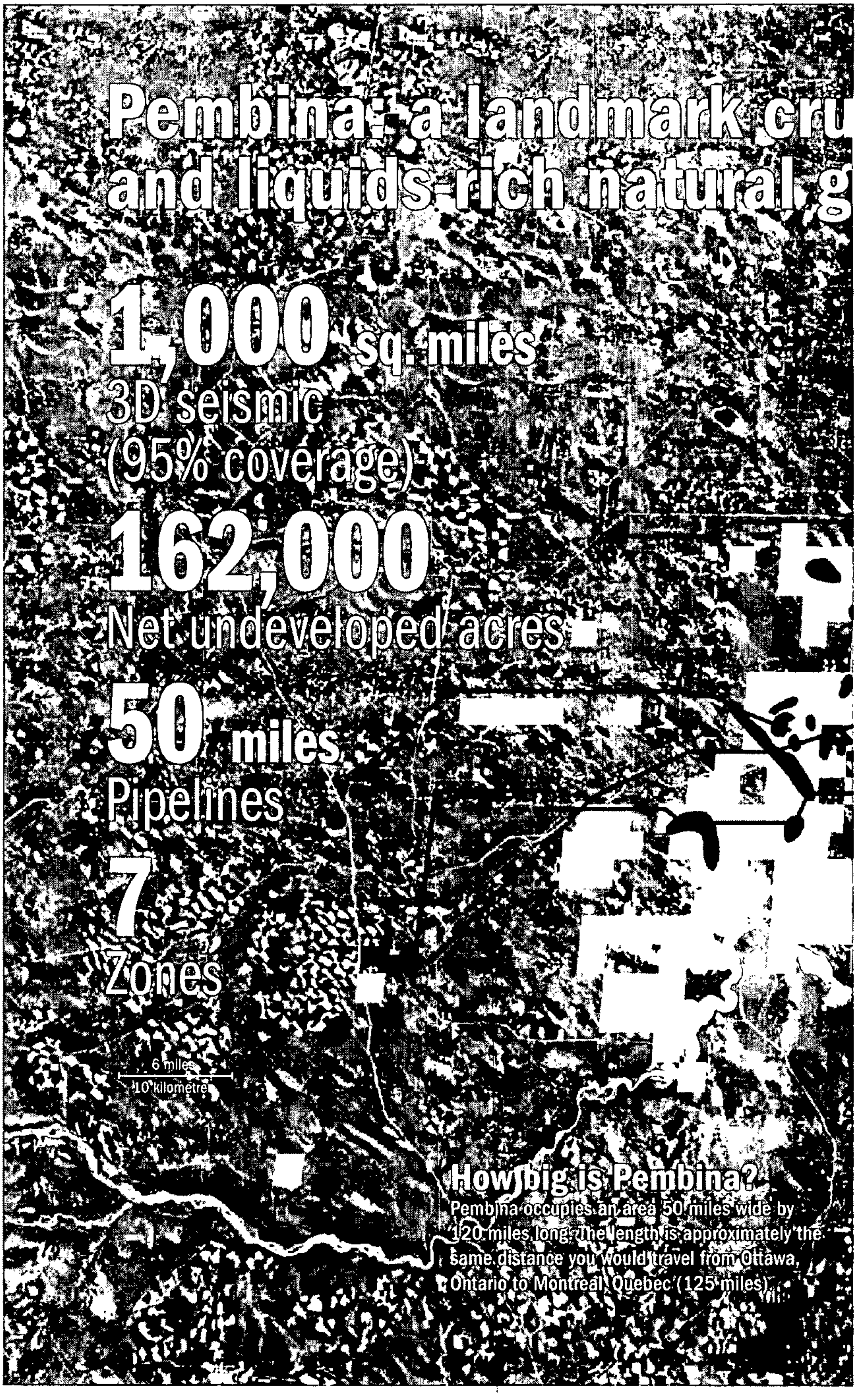


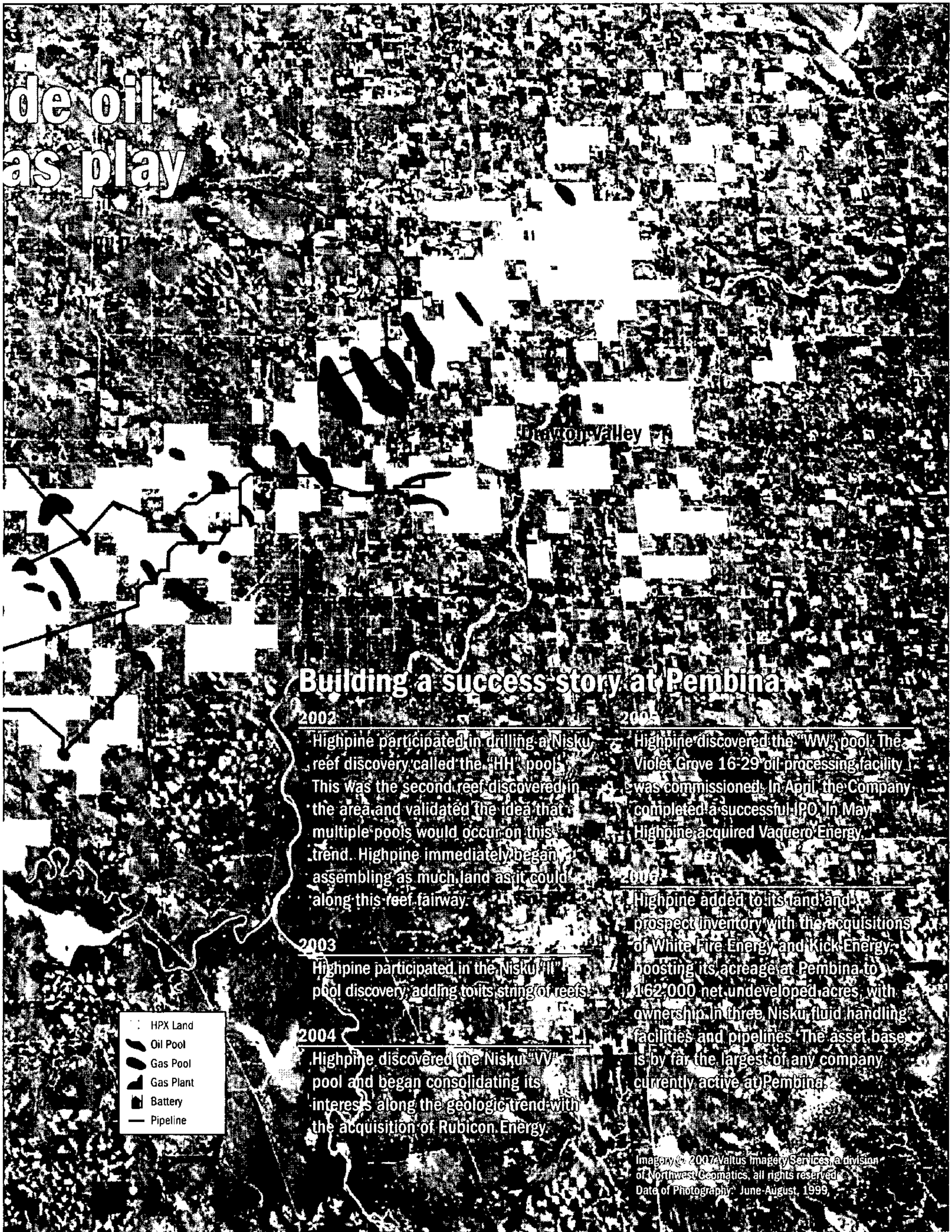
Pembina Nisku Fairway

We are a company focused on exploring and developing the multiple oil, gas and condensate accumulations in the Pembina Nisku Fairway of West Central Alberta. We have consolidated a large potential resource position through Crown land sales, strategic acquisitions and drilling and are building a growing production base.



With Pembina as the cornerstone of the company, Highpine's undeveloped land holdings encompass more than 228,000 net acres, of which 162,000 net acres are on the Pembina Nisku Fairway.


Pembina: a landmark cru
and liquids-rich natural g
1,000 sq. miles
3D seismic
(95% coverage)
162,000
Net undeveloped acres
50 miles
Pipelines
7
Zones
6 miles
10 kilometre
How big is Pembina?
Pembina occupies an area 50 miles wide by 120 miles long. The length is approximately the same distance you would travel from Ottawa, Ontario to Montreal, Quebec (125 miles).



Building a success story at Pembina

2002

Highpine participated in drilling a Nisku reef discovery called the "HH" pool. This was the second reef discovered in the area and validated the idea that multiple pools would occur on this trend. Highpine immediately began assembling as much land as it could along this reef fairway.

2003

Highpine participated in the Nisku "II" pool discovery, adding to its string of reefs.

2004

Highpine discovered the Nisku "VV" pool and began consolidating its interests along the geologic trend with the acquisition of Rubicon Energy.

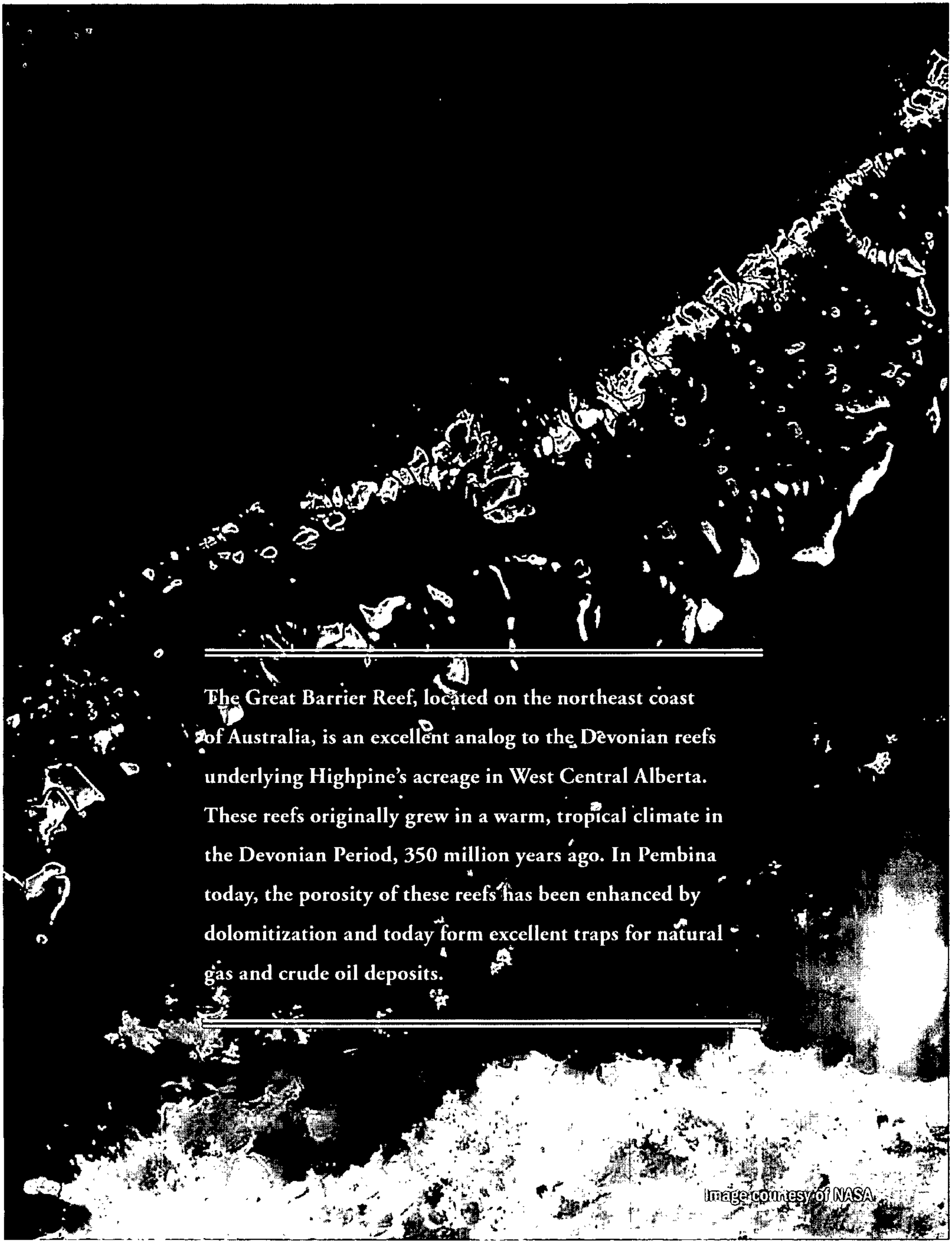
2005

Highpine discovered the "WW" pool. The Violet Grove 16-29 oil processing facility was commissioned. In April, the Company completed a successful IPO. In May, Highpine acquired Vaquero Energy.

2006

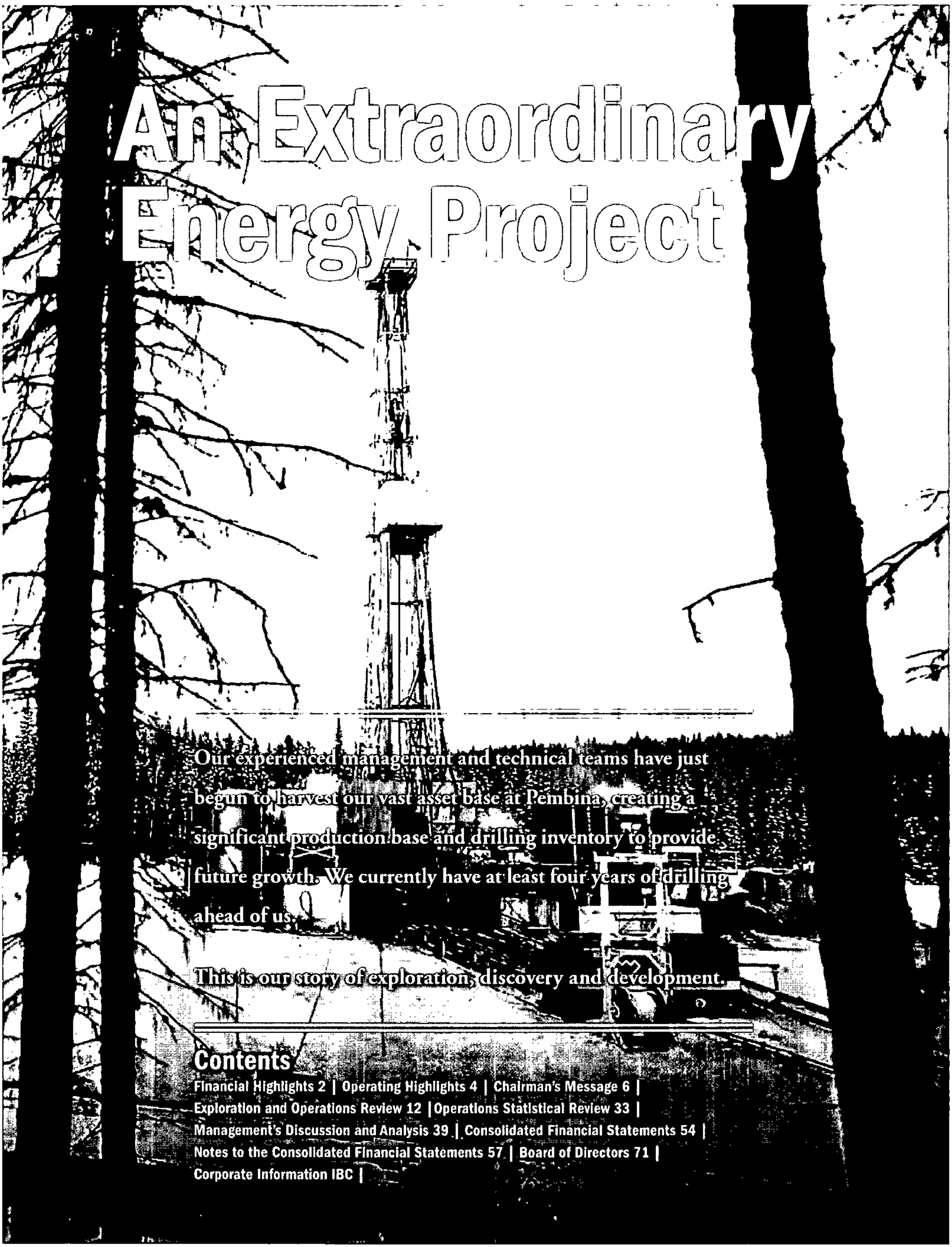
Highpine added to its land and prospect inventory with the acquisitions of White Fire Energy and Kick Energy, boosting its acreage at Pembina to 162,000 net undeveloped acres, with ownership in three Nisku fluid handling facilities and pipelines. The asset base is by far the largest of any company currently active at Pembina.

Date of Photography: June-August, 1999.



The Great Barrier Reef, located on the northeast coast of Australia, is an excellent analog to the Devonian reefs underlying Highpine's acreage in West Central Alberta. These reefs originally grew in a warm, tropical climate in the Devonian Period, 350 million years ago. In Pembina today, the porosity of these reefs has been enhanced by dolomitization and today form excellent traps for natural gas and crude oil deposits.

Image courtesy of NASA



An Extraordinary Energy Project

Our experienced management and technical teams have just begun to harvest our vast asset base at Pembina, creating a significant production base and drilling inventory to provide future growth. We currently have at least four years of drilling ahead of us.

This is our story of exploration, discovery and development.

Contents

Financial Highlights 2 | Operating Highlights 4 | Chairman's Message 6 |
Exploration and Operations Review 12 | Operations Statistical Review 33 |
Management's Discussion and Analysis 39 | Consolidated Financial Statements 54 |
Notes to the Consolidated Financial Statements 57 | Board of Directors 71 |
Corporate Information IBC |

Financial Highlights

($ thousands, except share numbers and per share amounts)

	2006	2005	% Change
Total revenue	254,938	141,634	80
Cash flow from operations	127,072	74,550	70
Per share (basic)	2.20	2.13	3
Per share (diluted)	2.17	2.09	4
Net earnings	6,953	12,274	(43)
Per share (basic)	0.12	0.35	(65)
Per share (diluted)	0.12	0.34	(64)
Net debt (2)	169,570	109,599	55
Total assets	1,392,911	753,690	85
Shareholders' equity (3)	1,002,001	511,023	96
Capital expenditures (4)	222,214	153,606	45
Total shares outstanding	67,648	44,250	53
Weighted average common shares			
Basic	57,744	35,051	65
Diluted	58,674	35,718	64

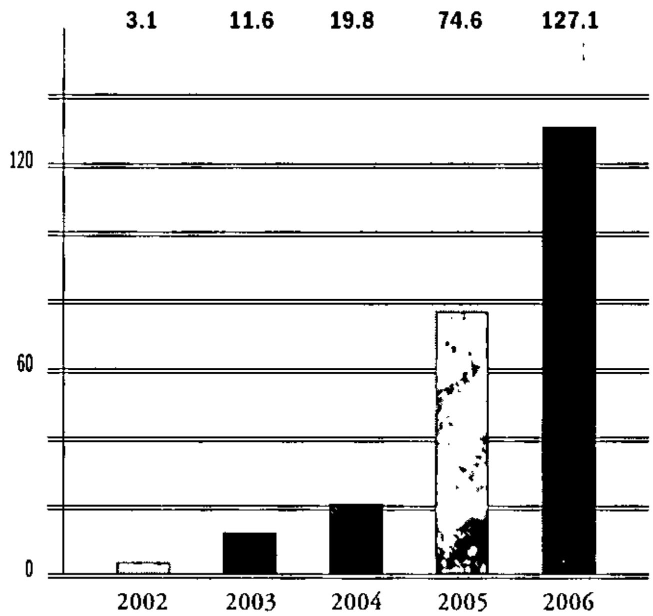
(1) Total revenue includes realized and unrealized hedging losses and gains.

(2) Net debt includes working capital excluding unrealized financial instruments.

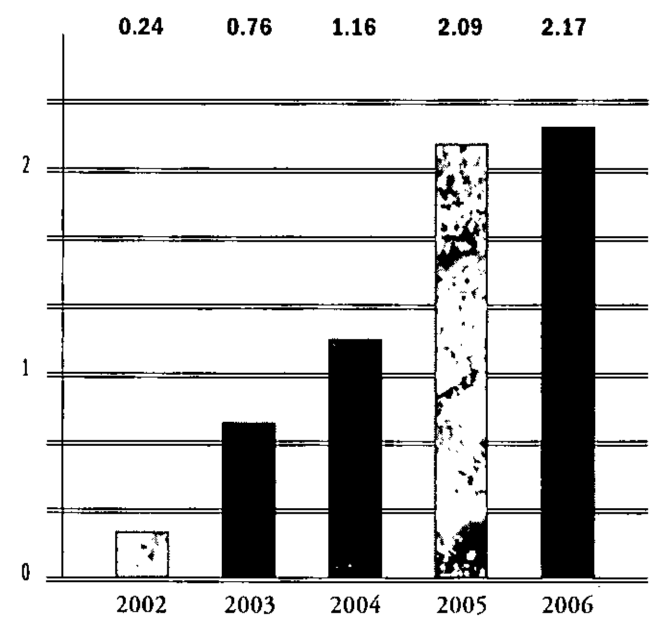
(3) Shareholders' equity includes share capital, retained earnings and contributed surplus.

(4) Capital expenditures include property acquisitions and are presented net of property disposals.

Cash Flow



Annual *($millions)*



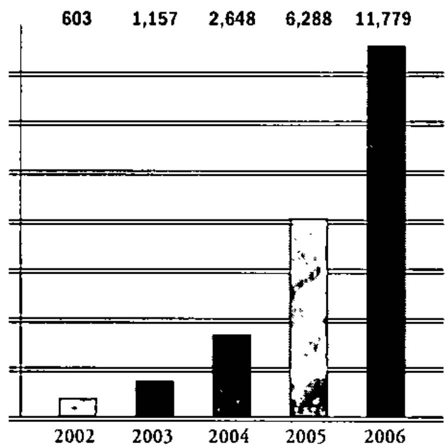
Per Diluted Share *($)*

At left: Typical flowing Nisku oil wellhead and surface facilities.

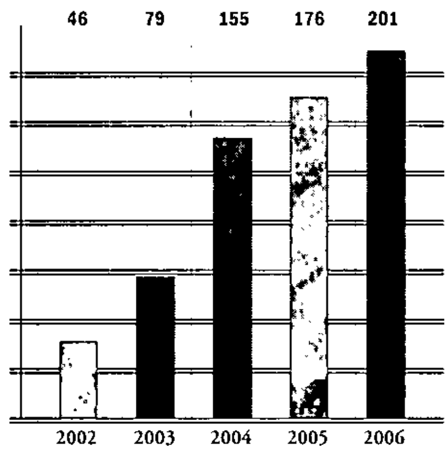
Operating Highlights

	2006	2005	% Change
Average daily production			
Oil and NGL (bbls/d)	**7,554**	3,984	90
Natural gas (mcf/d)	**25,350**	13,823	83
Total (boe/d)	**11,779**	6,288	87
Daily production per million shares	**201**	176	14
Average prices			
Oil and NGL ($/bbl)	**66.19**	67.16	(1)
Natural gas ($/mcf)	**7.06**	9.84	(28)
Combined average ($/boe)	**57.64**	64.18	(10)
Wells drilled			
Gross	**74**	56	32
Net	**46.7**	36.4	28
Operating netback ($/boe)			
Oil and gas sales	**57.64**	64.18	(10)
Royalties	**(16.40)**	(16.99)	(3)
Operating costs	**(8.57)**	(6.35)	35
Transportation costs	**(0.71)**	(1.06)	(33)
Realized hedging gain (loss)	**1.09**	(2.88)	-
Operating netback	**33.05**	36.90	(10)

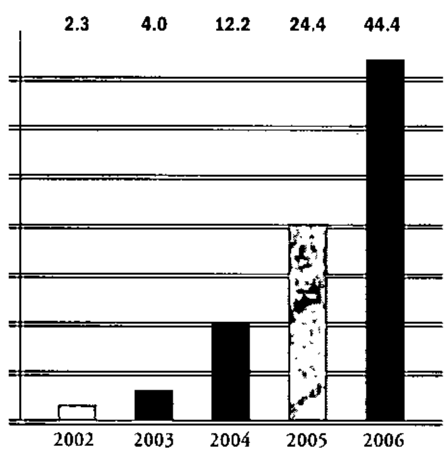
Production and Reserves



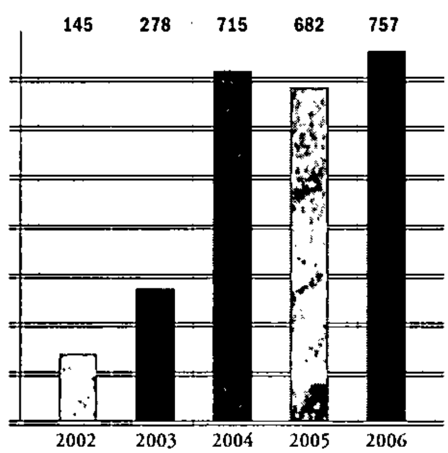
Average Daily Production *(boe/d)*



Average Daily Production per Share
(boe/d per million shares – diluted)



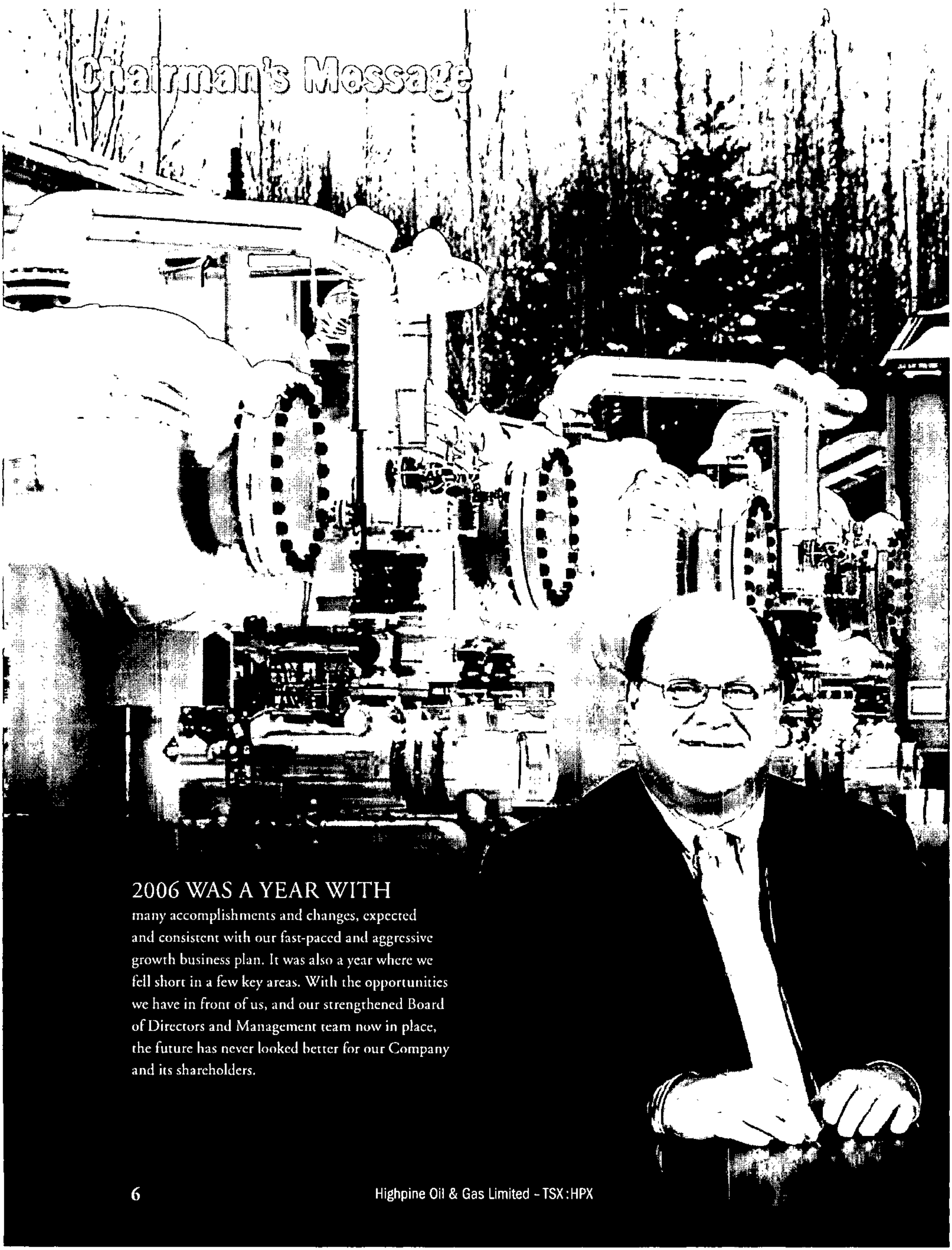
Reserves *(P+P) (mmboe)*



Reserves per Share
(P+P) (boe per thousand shares – diluted)

At left: Pembina Nisku Fairway drilling operations underway in February 2007.

Chairman's Message



2006 WAS A YEAR WITH

many accomplishments and changes, expected and consistent with our fast-paced and aggressive growth business plan. It was also a year where we fell short in a few key areas. With the opportunities we have in front of us, and our strengthened Board of Directors and Management team now in place, the future has never looked better for our Company and its shareholders.

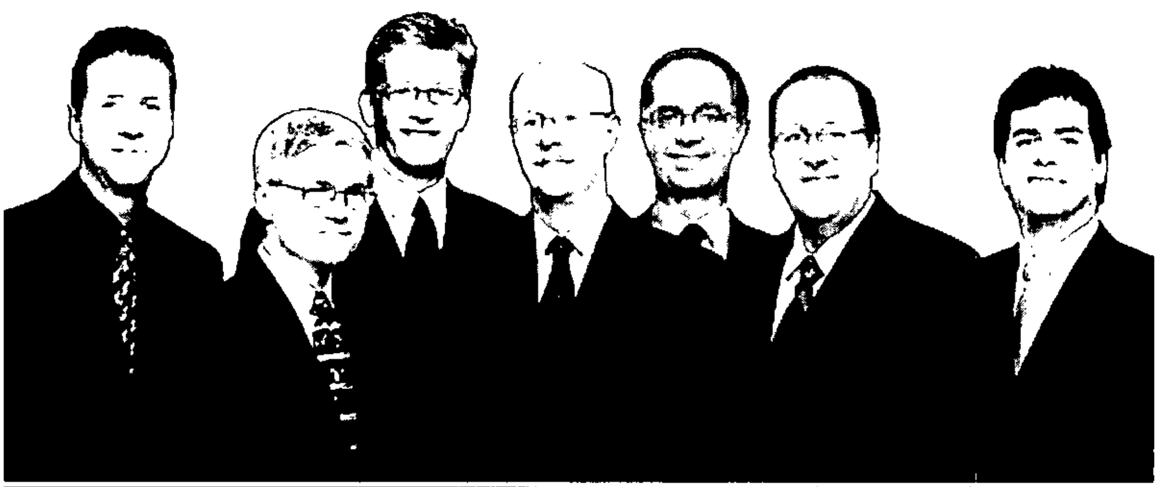
Harvesting the potential of the Pembina Nisku Fairway play accelerated in the second half of 2006, with an 80 percent drilling success rate in targeting locations that will produce oil and natural gas. That success continued through the first quarter of 2007. During most of this period, we had three rigs actively drilling in Pembina. The results of this drilling success will become evident in 2007 as our production ramps up.

This level of activity cannot be sustained without significantly advancing our well licensing program. We made excellent progress in working with all stakeholders in 2006, generating our highest-ever number of approved drilling licences. Highpine is positioned for its busiest drilling year ever at Pembina in 2007 as we continue to exploit the growth potential of our prospective Pembina Nisku lands. Growth through drilling is what we envisioned when we accumulated our large undeveloped land position, (which is believed to contain at least 100 future Nisku drilling locations), acquired a 1,000 square mile 3D seismic data base, built the necessary oil and natural gas infrastructure, and strategically consolidated the play.

We have made great strides in developing the knowledge and hands-on expertise to operate the facilities, drill and produce the wells and manage the reservoirs – all activities that are necessary for maximum economic development of the Pembina Nisku play. On-stream times for our operated wells and facilities exceeded 95 percent. This on-stream rate is outstanding, especially when considering the safety and environmental issues associated with producing sour fluids.

We continued to consolidate the Pembina Nisku play which, in the longer term, will benefit Highpine and its shareholders. During 2006, we completed the acquisition of White Fire Energy Ltd. and Kick Energy Corporation, as well as selected Pembina assets owned by industry partners. These acquisitions contributed high-quality production, infrastructure and drilling

Left to right: Bob Fryk - *Senior Vice President, Engineering*
Chuck Buckley - *Senior Vice President, Exploration*
Bob Rosine - *Executive Vice President, Corporate Development*
Greg Baum - *President and COO*
Harry Cupric - *Vice President, Finance and CFO*
Wayne Gray - *Vice President, Land*
and Dave Humphreys - *Vice President, Operations.*



Left page: A. Gordon Stollery – Chairman and CEO
Background photo: Satellite facility that tests, separates and measures oil and gas.

prospects which will result in additional growth potential and more capital-efficient development of our Nisku assets. These acquisitions also strengthened our Company by providing Highpine with additional experienced directors, and high-quality and motivated senior management and technical staff. We have completed the building of a team that can successfully carry out our business plan.

Highpine finished 2006 with very strong exploration results. Early in the year, many of our West Central Alberta Gas Fairway prospects were drilled while making progress on the licensing of wells at Pembina. As Pembina drilling licences were approved, we shifted our drilling priorities to the Pembina Nisku.

In 2006, Highpine and its acquired companies discovered nine new Nisku hydrocarbon pools, including three oil pools and six natural gas condensate pools. The Company also had multiple oil and natural gas discoveries in the West Central Alberta Gas Fairway.

Highpine participated in 74 (47 net) wells in 2006, with better than an 80 percent success rate in our total program, including the previously-mentioned Pembina Nisku success. Notable drilling successes in the West Central Alberta Gas Fairway included oil discoveries at Chip Lake and Joffre and natural gas discoveries at Ante Creek, Joffre and Edson. Edson is a newly emerging, natural gas exploration area.

Two of the most important accomplishments of 2006 were the technical confirmation of the potential of our assets and the creation of a solid, high-quality production base that will support the development of our assets in the future. We exited 2006 with a very strong production base of 14,000 barrels of oil equivalent per day that will provide the cash flow to drill our inventory of exploration and development opportunities, estimated at this time to take a minimum of three years. In our Pembina Nisku Fairway alone, we have over 100 drilling locations. The success of our Pembina Nisku drilling program in 2006 and so far in 2007 has strengthened our belief in the resource potential of the Pembina Nisku Fairway.

Despite the above accomplishments, not everything was perfect. We fell short in getting our production on-stream within the timelines that we anticipated. This was due to a variety of delays, including regulatory, services, weather and facility construction. Our own expectations for getting things done were too optimistic. The result was the negative impact on delivering our forecast production volumes and, therefore, our projected cash flows. Accurate production forecasting has become our number one priority for 2007, and our last major challenge to resolve in order to provide the cash flow for future re-investment and realize our long-term vision of being a successful Devonian reef exploration and production company.

We expect that 2007 will be Highpine's best year yet. Virtually all of our behind-pipe volumes are expected to be on-production. We have the best management, technical and field operating teams in our history – all of them committed to executing our operating plan.

We also anticipate 2007 being our most active drilling year in the Pembina Nisku Fairway. We expect to drill in excess of 30 wells, targeting Nisku production and reserve additions. We have allocated approximately 75 percent of our $200 million capital expenditure budget to the Pembina Nisku Fairway.

In our West Central Alberta Gas Fairway, we will selectively drill high-quality prospects while continuing to expand an already sizeable drilling inventory for future development when natural gas prices rebound and the Company's cash flow can be re-allocated. We have developed new concepts targeting Devonian reefs and other high-impact plays for the future, beyond the Pembina Nisku.

We have learned that there are many challenges when a company becomes dominant in the development of a high-quality, and high-profile light oil, condensate and natural gas play in the Western Canada Sedimentary Basin. Our Board and staff have helped us meet many of our challenges. I am confident we will resolve the remaining ones.

We expect to drill more than 30 wells at Pembina in 2007, and have allocated 75 percent of a planned $200 million capital budget to the area.

I wish to personally thank our Board of Directors and our committed and dedicated staff for their efforts in 2006.

To our shareholders, be assured that you have the best human resources team focused on unlocking value from a world-class resource. We thank you for your patience in 2006 and look forward to updating you on what should be an outstanding year in 2007.

[Signed] "A. Gordon Stollery"

A. Gordon Stollery
Chairman and CEO
March 12, 2007

An Extraordinary Team

The search for and development of hydrocarbons requires a highly skilled team. Highpine employs specialists in each aspect of its business. Dedication and the extraordinary commitment of Highpine employees are at the heart of the Company's success.

"Oil is found in the minds of men."* Our highly trained exploration personnel employ state-of-the-art analysis techniques and a wealth of experience to interpret complex data sets and define the likely location and size of hydrocarbon pools. The geotechnical effort involves the integration of geology, petrophysics, hydrodynamics, engineering and geophysics. Our team has proven that it combines the geotechnical excellence and creativity to find hydrocarbon pools.

Once a prospect is defined, the mineral rights must be acquired by purchase of mineral leases at Crown land sales, acquisition of freehold mineral leases, or business deals to secure the right to drill wells on the prospect.

Our dominant land position at Pembina is a testament to the hard work and innovative deal-making of the members of the Highpine land department.

Stakeholder Consultation

When the mineral rights are acquired, we begin the process to get approval to drill a well from the provincial regulatory authority (Energy and Utilities Board). Due to the sour nature of many of our prospects, we have a dedicated team of consultation specialists to communicate with all of the stakeholders affected by a proposed well. By listening to the concerns of stakeholders and consulting with our technical drilling, completions, and production groups, the consultation experts communicate the numerous measures that Highpine undertakes to ensure a safe field operation and to mitigate the impact on local residents wherever possible.

Our drilling and completions personnel do an exemplary job of coordinating a very busy and complex program with the additional responsibility of complying with extensive regulations and our Emergency Response Plan for each critical sour well.

Bringing Production On-stream

After a well has been drilled and completed, facilities are designed and constructed in co-ordination with our production plans. Our facilities engineers are specialists in dealing with sour gas associated with volatile oils and condensate-rich natural gas. Best-practices designed facilities result in a higher percentage of on-stream time once wells are producing.

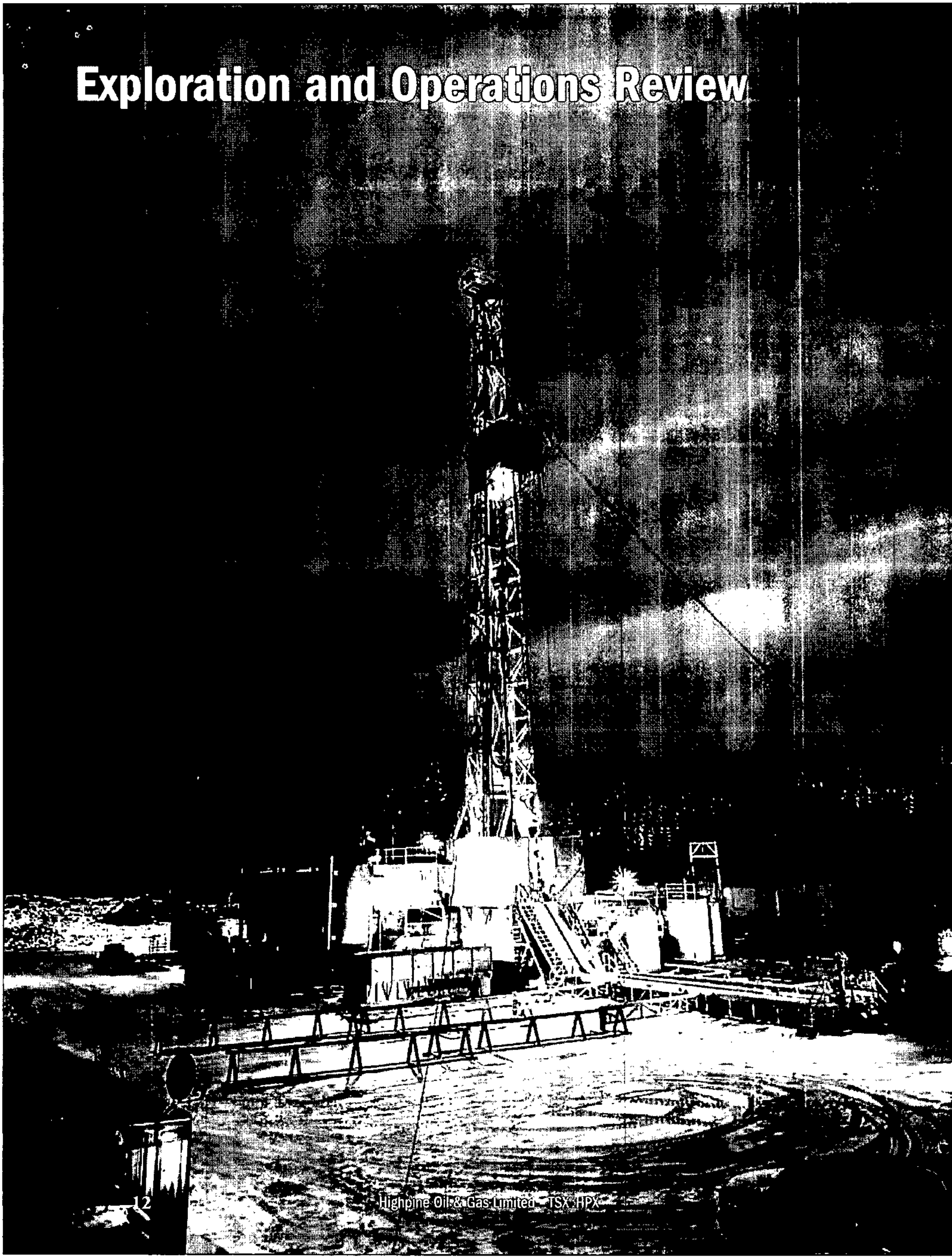
Highpine operates production from 40 wells at Pembina, and over 95 wells in the West Central Alberta Gas Fairway. Our 30 field personnel are specially trained in operating and dealing with the risks involved in hydrocarbon production and have an ongoing health and safety training program.

With a capital budget of more than $200 million, the finance, accounting and administrative teams play an important role in Highpine's success.

* *Wallace E. Pratt was one of the world's most eminent petroleum geologists.*

Left Page - Left to right: Sandra Forsythe - *Land;* Blair Lambe - *Exploration;* Joan Paterson - *Engineering;* Doug Reid - *Surface Land;* Donna Maas - *Engineering;* Bryan Chan - *Accounting;* and Noemi Dani - *Accounting*
Right Page - Left to right: Christine Paterson - *Operations;* Sandy Rautenberg - *Exploration;* Joe Arcuri - *Engineering;* Al Lyon - *Land;* and Steve Blizzard - *Accounting.*

Exploration and Operations Review



PEMBINA NISKU FAIRWAY

Exploration Approach

The Pembina Nisku play is a classic example of Highpine's approach to exploration and its ability to achieve exploration success. The Company's philosophy centres on identifying mappable geological trends, and targeting multiple and predictable high-quality reservoirs. Exploring trends allows for repeatable oil and natural gas discoveries, which increases knowledge and reduces risk as the trend is drilled. High-quality reservoirs generate the highest economic returns, are able to withstand commodity price cycles and offer ongoing exploration and exploitation opportunities.

Overview

Pembina, which is Highpine's most significant core asset, is located in the Drayton Valley area of Alberta, approximately 60 miles southwest of Edmonton. At Pembina, Highpine holds an average 83 percent working interest in more than 193,000 (162,000 net) acres of undeveloped land and is targeting light oil (±40° API) and liquids-rich natural gas from the Devonian Nisku formation.

The wells at Pembina are prolific in production and reserves. Successful wells are exhibiting initial production rates in excess of 1,000 barrels of oil equivalent per day and can recover more than 1 million barrels of oil equivalent. With an inventory of approximately 100 Nisku drilling locations, the Company expects to drill exploration and development wells for at least the next three to four years. All locations have been identified on 3D seismic, which covers approximately 95 percent of Highpine's lands at Pembina.

2006 Activity – Continued Consolidation

Highpine maintained its aggressive Nisku play "capture" strategy in 2006, with successful drilling and continued consolidation of strategic Pembina Nisku Fairway-focused companies and assets. The Company closed its acquisition of White Fire Energy Ltd. on February 21, 2006, followed by the acquisition of Kick Energy Corporation on August 1, 2006. During the year, Highpine also acquired Nisku properties from industry partners. This activity further elevated Highpine's already dominant position along the Pembina Nisku Fairway. Highpine plans to focus on drilling in 2007 and will continue to evaluate strategic consolidation opportunities if they are supported by economics.

Apart from acquisitions, Highpine also increased its acreage at Pembina through public Crown land sales. The Company acquired 9,440 acres of petroleum and natural gas rights in 2006 at an average price of $1,300 per acre. The combination of corporate acquisitions and Crown land sales boosted Highpine's acreage in the Pembina Nisku Fairway to almost 162,000 net undeveloped acres at year-end 2006.

At left: A triple drilling rig in Highpine's Pembina Nisku Fairway in February 2007.

2006 Activity – Drilling

The Company has established a team to work specifically on obtaining Pembina Nisku drilling licences, which can take up to 12 months from initiation of surveying to receipt of approval. In 2006, the team's success led to the highest number of Nisku wells licenced by Highpine to date.

In 2006, Highpine participated in 26 (18.7 net) wells at Pembina. Of 15 wells targeting Nisku production, the Company was successful on 12 for an overall success rate of 80 percent. In addition, the Company drilled 5 (3.2 net) wells for use as water source or water injection to support the development and pressure maintenance of the reservoirs.

Highpine's 2006 drilling program discovered six new Nisku hydrocarbon pools – three oil pools and nine natural gas condensate pools – in which Highpine has an 85 percent average working interest.

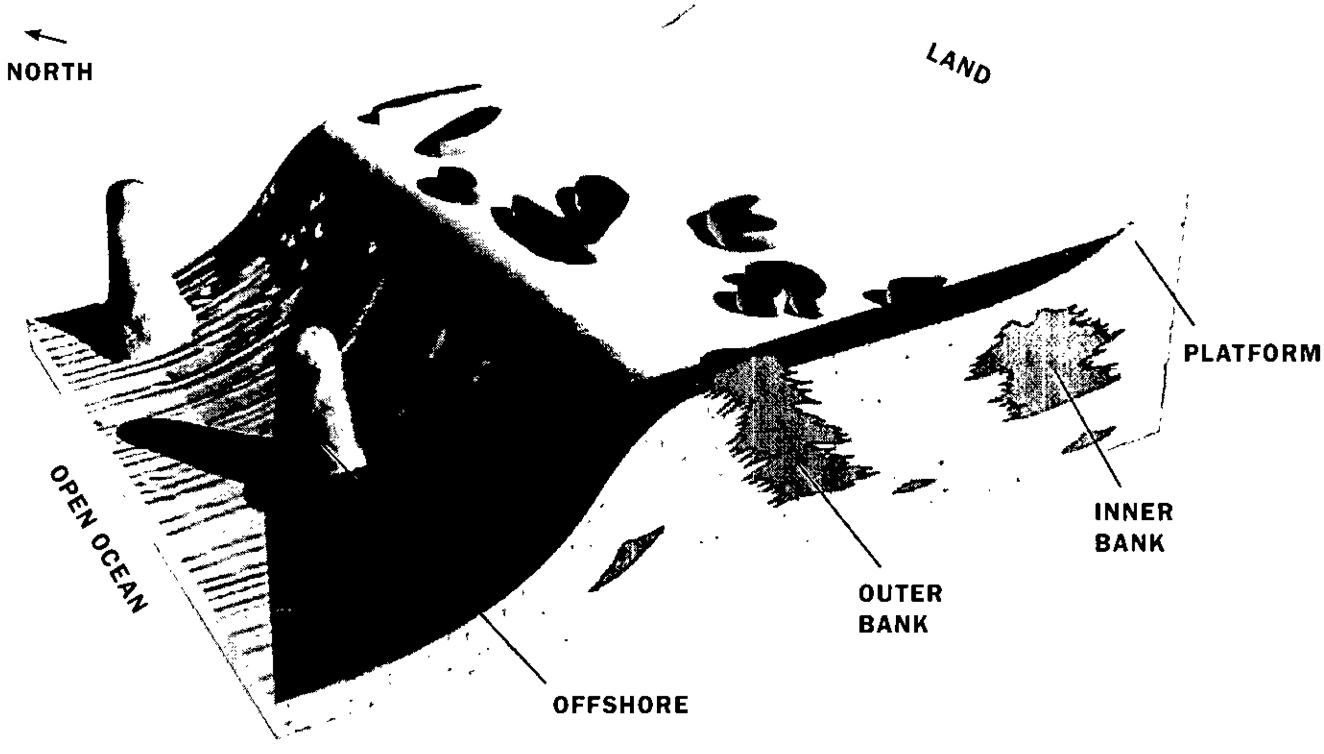
Geology

The hydrocarbons in the Pembina Nisku Fairway are trapped in dolomitized reefs encased in dirty off-reef limestone and siltstone. The reefs grew in a warm tropical climate in the Devonian Period, about 350 million years ago. The environment of deposition has been directly compared with the Great Barrier Reef off northeastern Australia.

Highpine's current exploration is focused on reefs along a southwest-to-northeast-trending carbonate bank margin, which is parallel to and southeast of extensive pinnacle reef exploration that took place in the late 1970s. The discoveries in the late 1970s were sparked by recording and processing techniques applied to 2D seismic data. The reefs had a median size of less than 320 acres, and were defined by lateral variations in the strength of signal from the Nisku on seismic. Once defined, the reefs had virtually 100 percent chance of success due to excellent trapping by the surrounding siltstone, known as the Cynthia shale.

Today, our exploration is driven by better recording and processing techniques utilizing 3D seismic data. The reefs are similar in size to those found three decades ago, but the inter-reef sediments are variable, ranging from siltstone to limestone. Finding the hydrocarbon trap is the key to the current round of exploration, but, as trapping is often poorly defined, it requires careful processing and interpretation of the 3D seismic data.

In addition to the Nisku, Highpine's lands contain abundant natural gas accumulations in the Rock Creek formation, which is found up-hole of the Nisku.



The Nisku reefs in the Pembina Nisku Fairway grew in a shallow Devonian seaway with the shoreline to the southeast, as shown on the illustration above. Highpine is exploring for reefs in the inner and outer bank region with off-reef carbonate sediments between them.

The reason for the prolific nature of our reef target is shown below in the photograph of a piece of core recovered from the Pembina Nisku II pool reef. This quartz sandstone sample shows brecciated (broken rock) fossil fragments with large pores indicating high porosities and permeabilities that contain oil in reservoirs at depths of 7,500 to 11,000 feet.

Highpine's Pembina Nisku Pools

Pembina Nisku GG, HH, MM, and NN Pools

The Pembina Nisku GG pool, discovered in April 2002, was the catalyst that started the current round of Nisku exploration in the oil-prone portion of the Pembina Nisku Fairway. The pool has approximately 10 million barrels of oil-in-place (as per independent evaluation by Paddock, Lindstrom & Associates Ltd.) and has been on-production since November 2002. Water injection to provide pressure support was implemented in January 2006.

Numerous similar pools have been discovered adjacent and parallel (see map) to the Nisku GG pool on the outer shelf margin. The Nisku HH pool was discovered in December 2002 with 12.4 million barrels of oil-in-place, followed by the Nisku MM pool in August 2003 with 3.2 million barrels of oil-in-place and the Nisku NN pool in February 2004 with 1 million barrels of oil-in-place (as per independent evaluation by Paddock, Lindstrom & Associates Ltd.). To maintain reservoir pressure and maximize oil recovery, each of these pools has an assigned minimum operating pressure and requires water injection to maintain this pressure. Some of these pools are in pressure communication through a lower Nisku platform, and separate injectors may not be necessary to support each pool. Although Highpine's reserve report currently recognizes up to a maximum recovery factor of 50 percent in the pools with the longest production histories on a proved plus probable basis, substantially higher recovery factors have been observed in other dolomitized carbonate reefs with underlying water in other parts of Alberta. Over time, we would anticipate this to be the case on the Pembina Nisku Fairway pools as well. High-quality oil and gas pools will normally outperform the early life oil and gas reserve assessment.

Additional development wells are planned in 2007 in the Pembina Nisku GG, HH, MM, and NN pools to maximize oil recovery.

Pembina Nisku II, QQ and VV Pools

The Pembina Nisku II pool is the largest oil pool discovered to date in the Pembina Nisku Fairway with more than 30 million barrels of oil-in-place. Highpine has a 25 percent interest in the pool. Discovered in March 2003, the pool has been developed with 5 (1.5 net) producing wells. Water injection to provide pressure support has been in place since April 2006. Current production is 6,000 barrels of oil equivalent per day with a capability of 10,000 barrels of oil equivalent per day. In November 2006, Highpine drilled a 50 percent interest development well at 15-36-48-9W5 that was successful and encountered 40 feet of pay.

The Pembina Nisku QQ natural gas and condensate pool sits adjacent to the Nisku II oil pool. Highpine owns a 25 percent interest in the discovery well at 12-11-49-9W5. In November 2006, Highpine drilled a 100 percent interest well at 15-2-49-9W5 in an attempt to drill into the QQ pool; however, the well has a different waterline than the 12-11 well, and is believed to be a separate new pool discovery. In February 2007, Highpine drilled a 100 percent interest well at 9-10-49-9W5 to increase its share of production from the QQ pool. Both wells are expected to be on-stream by the end of the second quarter. Current pool production is approximately 2,400 barrels of oil equivalent per day.

The Pembina Nisku VV oil pool sits adjacent to the Nisku II pool, and is likely in pressure communication with the II pool through the common underlying aquifer. The discovery well at 14-31-48-8W5 (75 percent interest) was drilled in 2004. Highpine drilled a successful 75 percent working-interest delineation well at 6-31-48-8W5 in December 2006. Current pool production from the 14-31 well is approximately 2,000 barrels of oil equivalent per day with additional production anticipated in 2007 when the 6-31 well commences production.

Pembina WW Pool

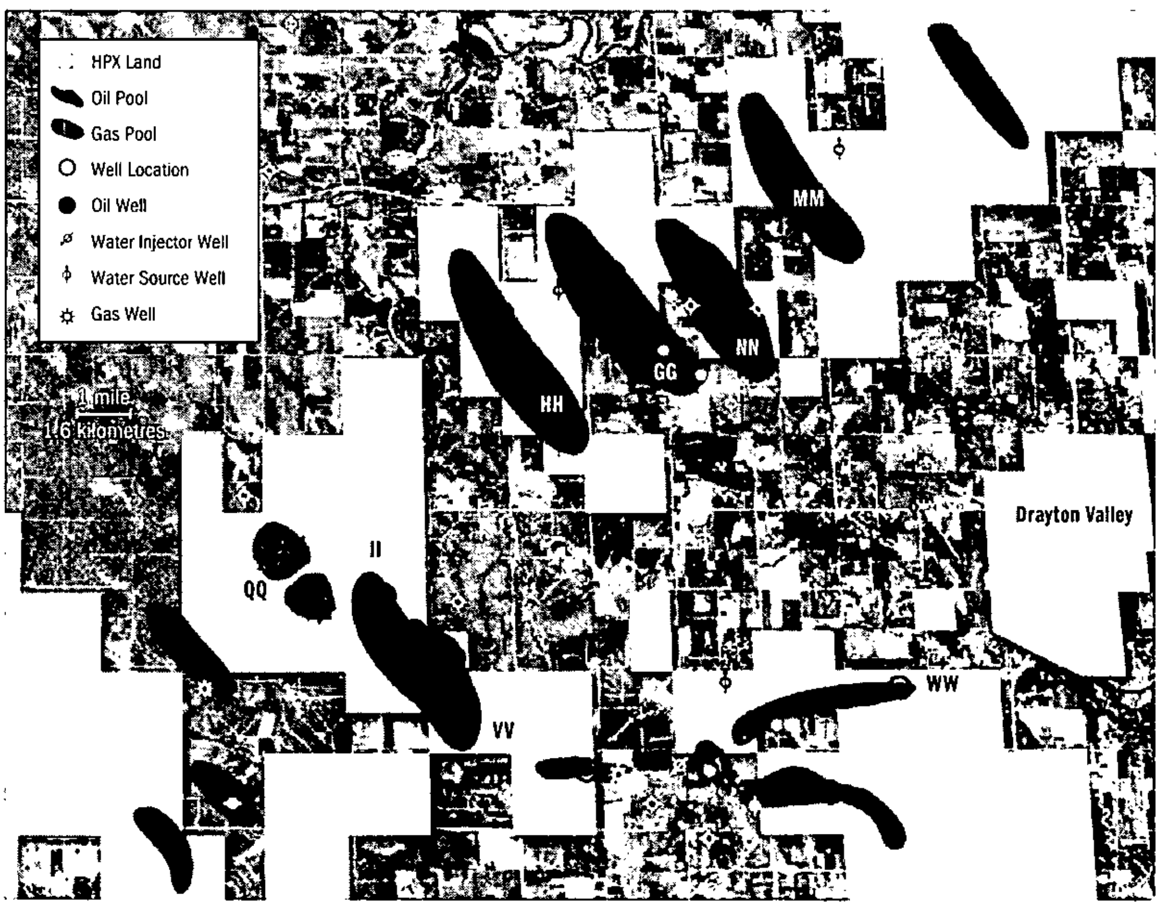
The Pembina Nisku WW pool was discovered in March 2005 with the 9-35-48-8W5 well, in which Highpine owns 100 percent working interest. The 9-35 well produced 363,000 barrels of oil before being shut-in to await pressure support. In September 2006, Highpine drilled a Nisku water injector at 8-34-48-8W5, and a Wabamun water source well at 7-34-48-8W5. Water injection commenced in January 2007 and production from the 9-35-48-8W5 well recommenced in February 2007.

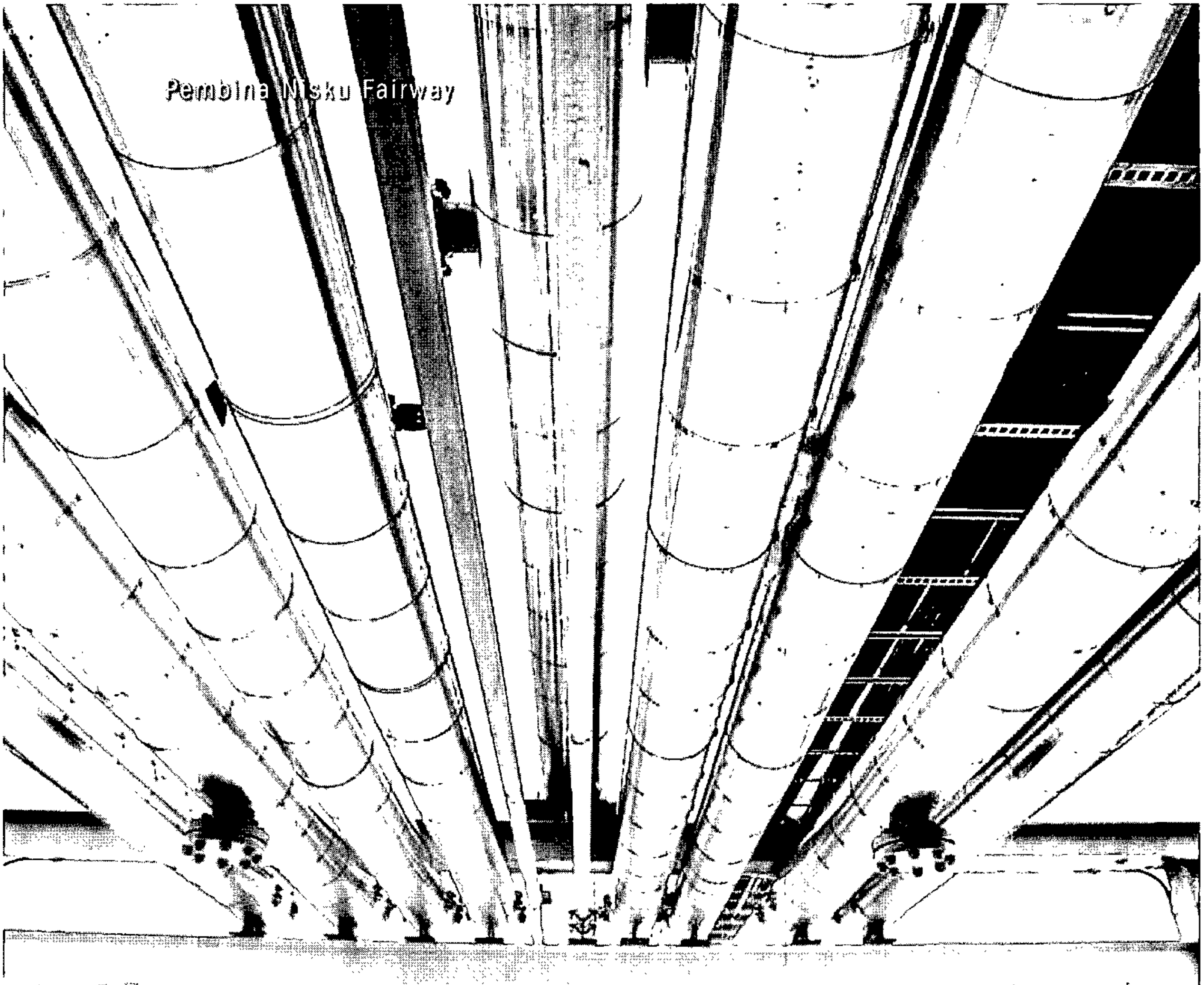
Highpine plans to drill up to two 100-percent owned development wells that will reach more than two miles laterally from the surface location to the bottom-hole locations in the WW pool. These "long reach" wells are necessary to efficiently drain the reserves from the pool, while minimizing the impact on the town of Drayton Valley from an emergency planning zone.

The 3D seismic image of this reservoir is excellent, such that the drilling of these wells is considered to be low-risk with respect to encountering the thick Nisku reef.

Highpine has 100 percent working interest in seismic features similar to the WW pool that have been mapped about one mile to the south.

Select Nisku Pools





Pembina Infrastructure

Early in its involvement at Pembina, Highpine decided to build and own as much of the oil and natural gas handling and transportation infrastructure as possible. Today, the Company owns interests in three oil and natural gas production facilities, which provide more than 20,000 barrels per day (net) of oil handling capability and more than 30 million cubic feet per day (net) of sour gas handling capability. In early 2007, Highpine began inter-connecting some of the oil batteries. This will help ensure continuous processing availability when some facilities experience downtime or are shut down for maintenance.

Facilities ownership will be very important in 2007 with the volume of our behind-pipe production anticipated to come on-stream early in the year. At the same time, Highpine will have high-priority access to excess capacity in these facilities to handle future drilled volumes.

Highpine has similar ownership and access to a number of strategic pipeline systems throughout the Pembina Nisku Fairway.

2007 Program

Seventy-five percent of Highpine's 2007 capital budget is allocated to Pembina. The Company anticipates the drilling of 37 Nisku wells, comprised of 20 (16 net) exploratory wells into new Nisku reefs defined on 3D seismic and 17 (14 net) development wells into proven Nisku oil and natural gas pools. In addition, Highpine will drill 4 (3 net) Wabamun wells as water source wells, and 5 (4 net) Rock Creek natural gas wells for acreage retention and/or management of offset drainage considerations.

Highpine shot a 100-square-mile 3D seismic program in the first quarter of 2007 which yielded numerous new Nisku exploration drilling prospects. The Company continues to evaluate additional 3D seismic programs depending on success in the ongoing drilling of exploration wells.

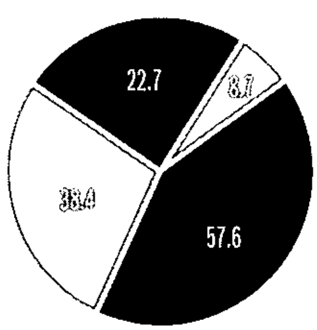
Exploration targeting new Nisku oil pools will be conducted within the existing productive portion of the Pembina Nisku Fairway as well as testing an extension of the Nisku play to the northeast.

Highpine plans to drill several high-quality anomalies in proximity to a successful well drilled recently by a competitor in the Crossfire area. This includes a significant 3D seismic-identified anomaly planned for drilling in the third quarter of 2007.

Development drilling is planned throughout the Pembina Nisku Fairway, including the HH, GG, MM, NN and WW pools.

In February 2007, Highpine re-started production from the Pembina Nisku WW pool after implementing water injection for pressure maintenance in January 2007. Also, the Nisku KK pool water injection scheme has commenced through the 7-29-48-9W5 injection well, allowing for continuous production from the 01-32-48-9W5 well. Behind-pipe production from the 11-32-48-9W5 KK pool well is anticipated to commence during the first half of 2007. With pressure maintenance now in place in the Nisku KK pool, Highpine expects a significant increase in oil recovery through the life of this pool.

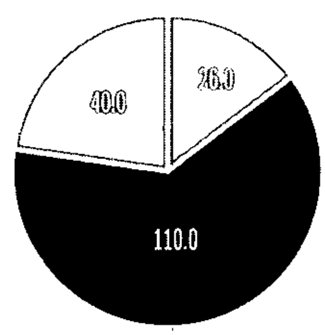
2006 Pembina Capital*: $127.4 Million
Spending by Activity ($ millions)



☐ Land/Seismic ☐ Facilities
■ Property Acquisitions ■ Drilling & Completions

* Actual

2007 Pembina Capital*: $176 Million
Spending by Activity ($ millions)



☐ Land/Seismic ■ Drilling & Completions
☐ Facilities

* Budgeted as of March 2007

At left: Highpine infrastructure in the Pembina Nisku Fairway.

PEMBINA: RESPONDING TO QUESTIONS

LAND

Q: Does the Pembina Nisku play continue and is there any more undeveloped land to be acquired?

(Wayne Gray, VP Land)

A: We strongly believe there is a continuation to the Nisku play along a relatively defined fairway. Within this fairway we see opportunities for further acquisitions of undeveloped land by purchase, farm-ins, or other creative land deals.

Q
DRILLING PROSPECTS

You have had great drilling success to date in the development of the Pembina Nisku Fairway play. Do you still have high-quality prospects left in inventory and can you continue to maintain similar success in the future?

A
(Chuck Buckley, Senior VP, Exploration)

Highpine has more than 100 high-quality drilling prospects in the Pembina Nisku Fairway defined on existing Highpine lands. The development of new prospects is ongoing. With each new well, we learn more about the interpretation of the 3D seismic through the integration of new geologic data. Successful wells often result in additional locations being added to our inventory, while unsuccessful wells cause us to revisit our previous interpretation to fit in the newly acquired information. We continue to expand and reprocess our 3D seismic coverage in prospective areas, usually resulting in better prospect definition and more prospects.

Q
WELL LICENCES

Can you briefly describe the regulatory process for attaining Pembina Nisku drilling licences and do you envision being able to get these licences for the locations carried in your drilling inventory?

A
(Dave Humphreys, VP Operations)

Once public consultation has been conducted in the field with every resident within the EPZ (Emergency Planning Zone) of the subject wells, Highpine prepares a well licence application and submits it to the EUB for approval. The well licence application includes a full audit package complete with well application, consultation documentation, drilling program, survey plan, surface land package, mineral land documentation, proof of drilling insurance, and ERP (Emergency Response Plan). Once the well licence application and ERP are deemed technically complete, the EUB will grant a well licence, provided all outstanding concerns by residents within the EPZ have been addressed and there are no outstanding objections remaining on the application.

Highpine is very confident that we have both the resources and the processes in place, and over time will continue to obtain the well licences in Pembina that are identified in our drilling inventory.

Q
CONSOLIDATION

Highpine has acquired several companies and assets in Pembina in the past few years. Are you planning to continue this strategy?

A
(Bob Rosine, Executive VP, Corporate Development)

During calendar 2006 we acquired both White Fire Energy Ltd. (February 2006) and Kick Energy Corporation (August 2006). These acquisitions strengthened the management and technical teams significantly and expanded our land, production and exploration and development drilling prospect inventory throughout the Pembina Nisku Fairway. These two acquisitions are consistent with our overall exploration and development strategy for the Nisku Fairway, which is to acquire and consolidate properties and/or companies on a selective and strategic basis that are value-accretive and material to the Company as well as synergistic with our current and ongoing exploration, development and exploitation program. Other prior and significant acquisitions that demonstrate this strategy are Rubicon (2004) and Vaquero (2005).

In short, yes, we will continue to consolidate the Nisku Fairway where significant value to Highpine's shareholders can be demonstrated.

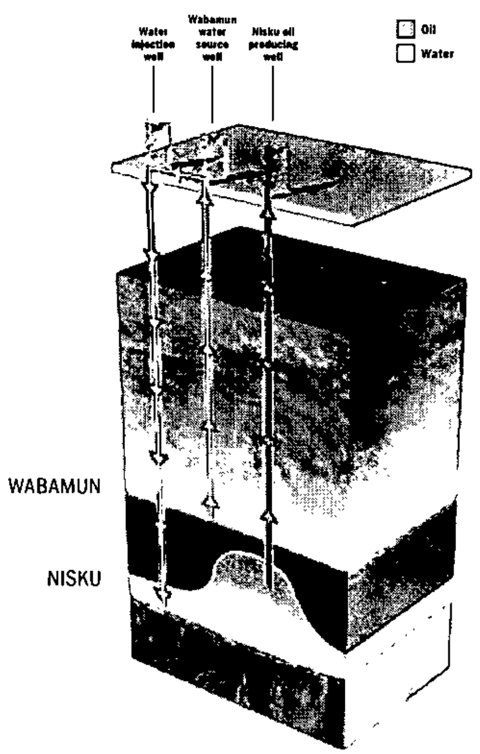
At left: Inspecting raw seismic records during a 3D seismic shoot.

PRESSURE MAINTENANCE

Q How is the pressure maintenance (i.e. water injection) working in the Nisku reservoir?

A *(Bob Fryk, Senior VP, Engineering)*
Simply put, pressure maintenance is working very well. Currently we operate six pressure maintenance schemes and are owners in two outside-operated schemes in the Nisku Fairway. We source the water from the Wabamun formation above the Nisku, bring it to surface in the source well and then transfer it across to a Nisku water injection well that is proximal to Nisku oil producers. The water requires minimal surface treatment as both the Wabamun and Nisku waters are Devonian in age and highly compatible. The Wabamun formation and water source appear to be extensive in area across the Nisku Fairway. In other words, the source is plentiful and highly productive. Productivities for source wells range from 4,000 barrels of water per day to 8,000 barrels of water with minimal pressure drawdown experienced to date. With pressure maintenance, Highpine is expecting total oil recoveries in the range of 45 to 55 percent of oil-in-place.

Pembina Nisku Water Injection Scheme



DECLINE RATE

Q What is the decline rate for the Nisku wells? Once these wells produce water, how does that affect production rates?

A *(Greg Baum, President and COO)*
The majority of Highpine's Nisku wells are still in a relatively early stage of their producing lives and definitive decline trends have not been established. The reasons for this include the quality of our pools being that of the thickest net pay zones in the Pembina Nisku trend meaning that the wellbores have not seen the boundary of the reservoir that they will ultimately drain, the limited production history under GPP flowing conditions, and the influence from pressure maintenance schemes. Having said that, Highpine budgets on a well-by-well basis with an assigned decline rate built in. As there is an underlying aquifer throughout the Pembina Nisku Fairway, we expect that all wells will likely produce water at some point. This is planned for in our facility design and construction. In the case of Nisku oil wells, significant amounts of oil can continue to be produced even with increasing water cuts as indicated in the 6-33-49-8W5M (GG pool) well production profile shown on page 23. In the case of Nisku gas wells, operating techniques such as minimizing the flowing pressure drawdowns can help to reduce water influx, which will allow production of maximum volumes of gas and associated condensates.

PRODUCTION

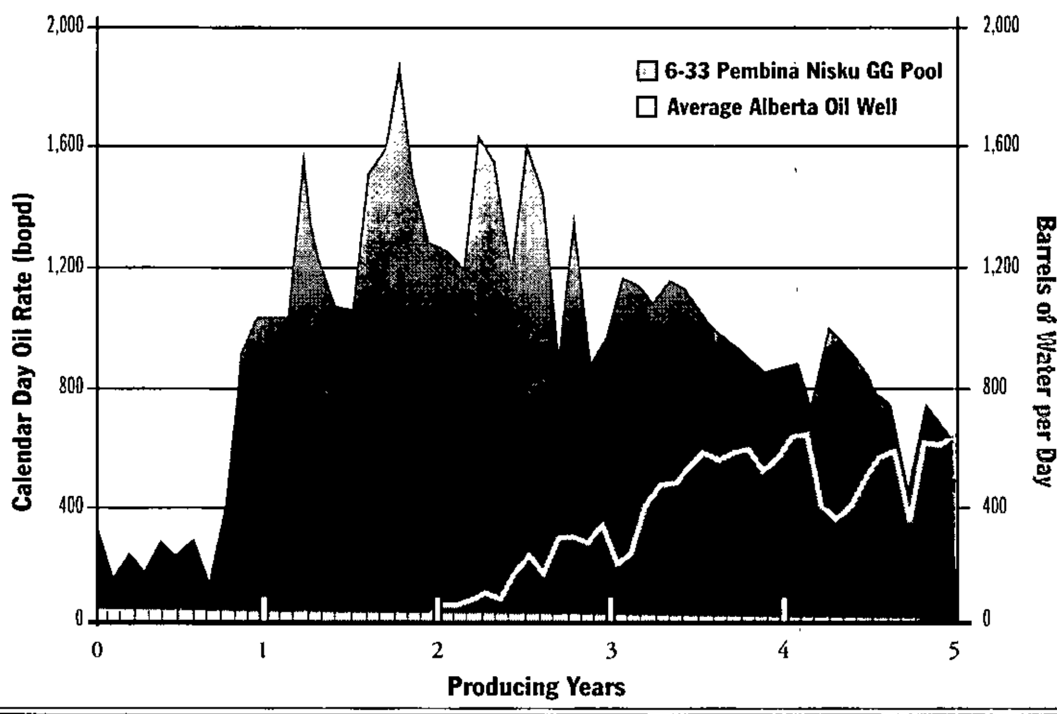
Q A challenge for Highpine in 2006 was being unable to get its production volumes on-stream in a timely and predictable manner. What is the Company doing to rectify this problem and where are you currently in 2007?

A *(Greg Baum, President and COO)*
Delays in getting our production on-stream last year were caused by many issues, mostly notably obtaining the necessary regulatory approvals and the heavy workload experienced by the required services and our staff. During the last half of 2006 we had many critical sour tie-in projects on the go. We have made adjustments along the way to accommodate this surge, and any future surges in activity. We have hired additional staff and services to manage our workloads. Further, the top priority for Highpine has been to successfully manage these projects over the past six months and the majority of them will be completed and on production in the near future.

Regulatory delays included getting pipeline approval permits and water injectors approved in the timelines envisioned. A specific example of change to the consultation process included dealings with the provincial government's SRD (Sustainable Resource Development) department. Recently the government imposed changes with respect to required industry consultations with First Nations. This resulted in additional, unexpected consultation that caused delays to some of our tie-in projects. We are currently in discussions with SRD on ways to improve the efficiency and to provide further clarification for Highpine with respect to these matters.

By the end of the first quarter of 2007 we will be caught up with the backlog of projects. On a go-forward basis, we will have sufficient resources in place to keep up with our planned drilling programs.

Nisku Oil Well Production vs. Average Alberta Oil Well

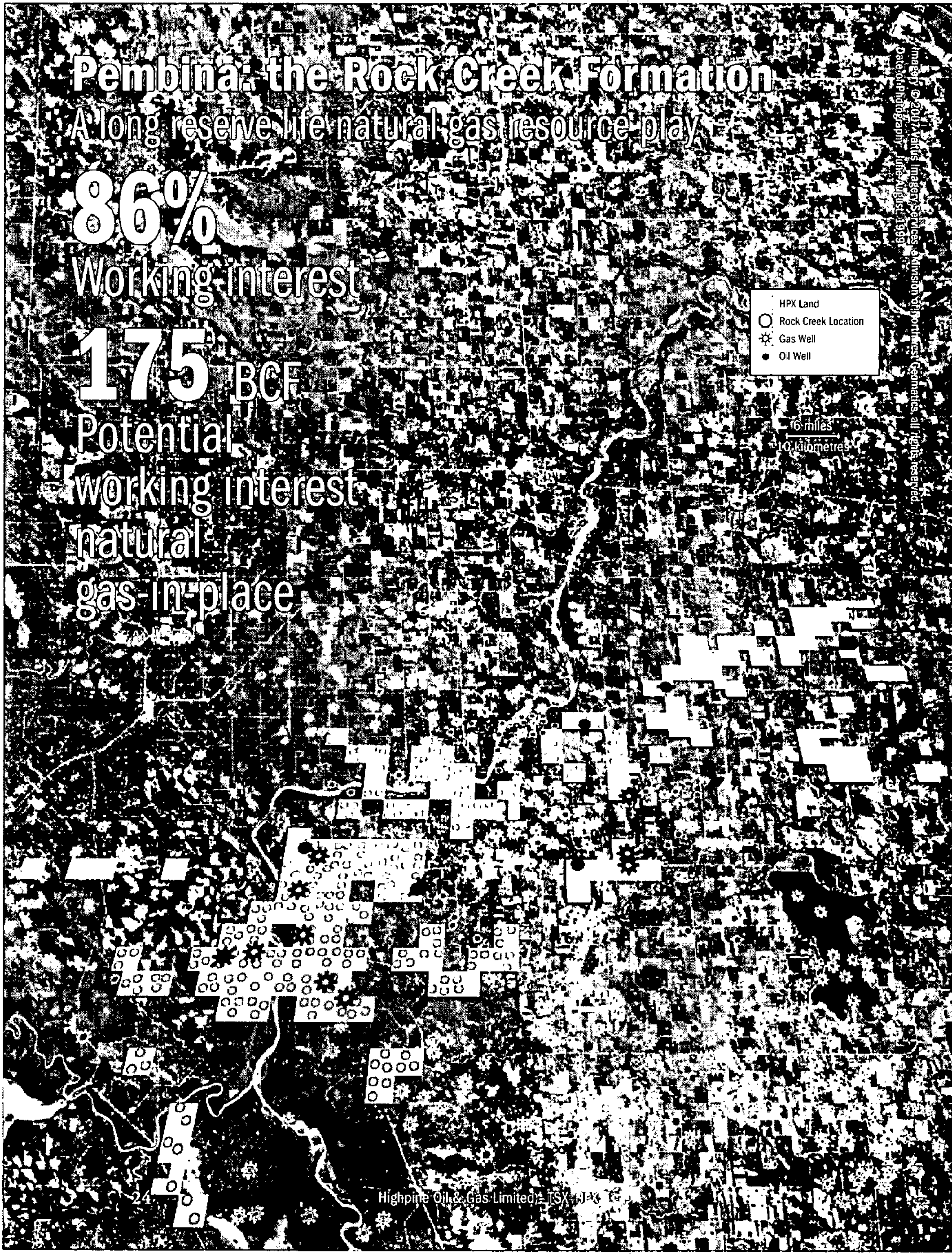


Pembina: the Rock Creek Formation

A long reserve life natural gas resource play

86%
Working interest

175 BCF
Potential working interest natural gas-in-place



A LONG RESERVE LIFE NATURAL GAS RESOURCE PLAY
Uphole at Pembina
The Rock Creek and Ellerslie Formations

In addition to the prolific Nisku potential at Pembina, there are several attractive secondary producing horizons which are found uphole of the Nisku. These horizons include the Belly River, Cardium, Viking, Glauconite, Ostracod, Ellerslie, Rock Creek, and Pekisko formations.

Highpine has identified more than 150 drilling locations for the Rock Creek and Ellerslie horizons at Pembina. This represents an estimated resource of more than 175 billion cubic feet of working-interest raw natural gas-in-place on Highpine lands. Others have built entire companies around a single-minded focus on exploiting this resource on their lands.

Rock Creek Geology

The Rock Creek is very fine to fine-grained clear, quartz sandstone as illustrated in the background picture. Observed under a microscope, the numerous facets of the quartz grains reflect like diamonds in the rough. The sample shown has approximately 10 percent porosity. The sample is representative of a typical Rock Creek reservoir capable of an initial flow rate in excess of 1 million cubic feet per day of natural gas with greater than 20 barrels of natural gas liquids per million cubic feet of natural gas.

The Rock Creek is underpressured and natural gas-saturated, as a result of being part of the Deep Basin in the Triassic, Jurassic and Cretaceous formations of the Western Canada Sedimentary Basin. The Rock Creek was deposited as shallow marine sandstones near the eastern shore of a vast Jurassic seaway. Sands are up to 50 feet thick and have porosity ranging from 3 to 12 percent.

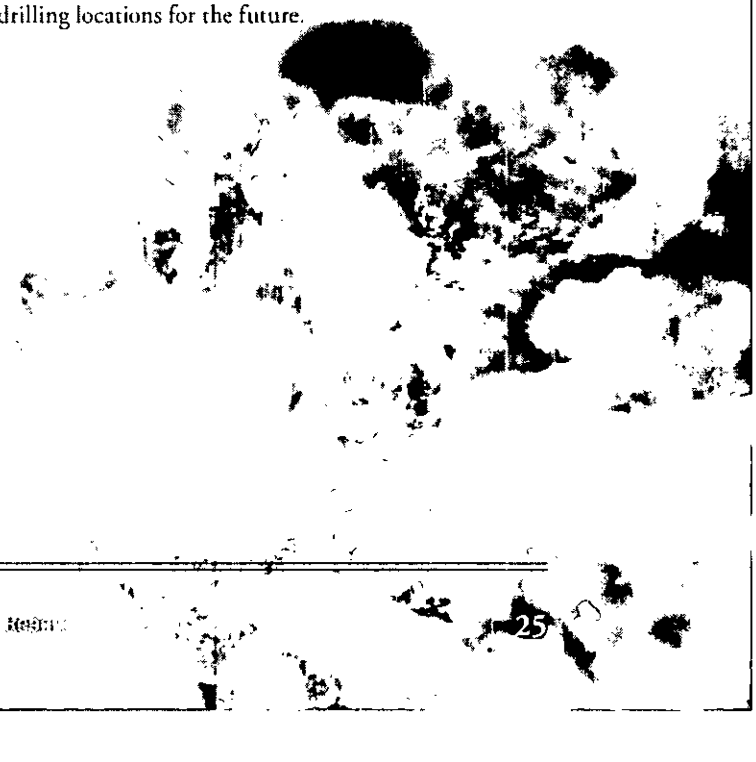
Permeability is the main challenge in the Rock Creek. All wells require fracture stimulation to release the natural gas. Production profiles show a 50 percent decline in the first six to 12 months, followed by a 6 to 8 percent decline per year. This means that after completing flush production rates, the wells can settle into a long-life, predictable production stream. It also means that reservoirs can be drilled on quarter-section spacing to optimize the economic value of the resource.

Ellerslie Formation

The Ellerslie Formation was deposited as channel sands in the earliest part of the Cretaceous period and is located above the Rock Creek. The Ellerslie sands are less continuous than the Rock Creek; however, Highpine is able to evaluate the Ellerslie and the Rock Creek horizons, while drilling for the Nisku. Successful Ellerslie wells can deliver production rates up to 1 million cubic feet per day of natural gas and provide natural gas reserves of up to 1 billion cubic feet per well.

In 2006, Highpine drilled 6 (4.4 net) wells targeting uphole horizons, resulting in 4 (2.7 net) gas wells, all of which have been tied-in and are currently on production.

Highpine will drill a selected number of Rock Creek wells in 2007 because current economics favour Nisku wells. However, as the Nisku wells penetrate the uphole horizons, this will help the Company's geologists define the better permeability trends and generate uphole drilling locations for the future.



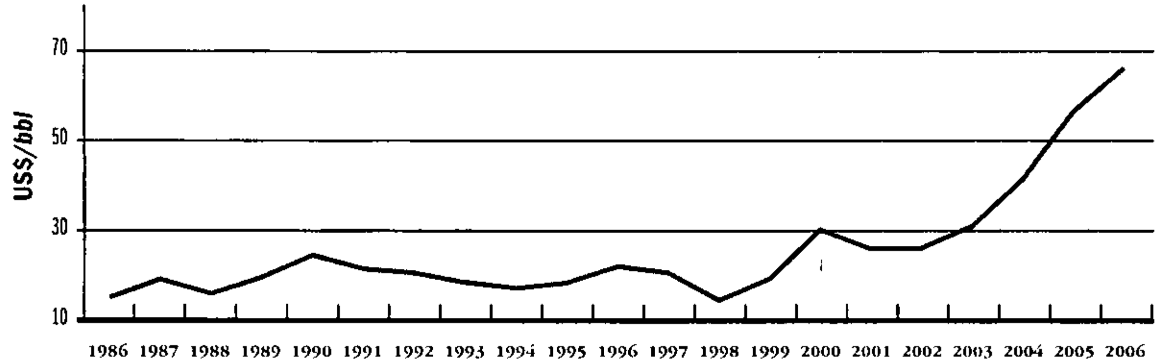
This quartz sample, shown at 120 times magnification, is representative of the Rock Creek zone and has approximately 10 percent porosity.

Commodities and Marketing

Strong energy prices in 2006 were driven by several factors, including increased demand for commodities from rapidly expanding economies such as India and China and continued political unrest in parts of the world. The price of West Texas Intermediate (W.T.I.) averaged US$66.25 per barrel in 2006, which was 17 percent higher than the previous record in 2005 of US$56.61 per barrel.

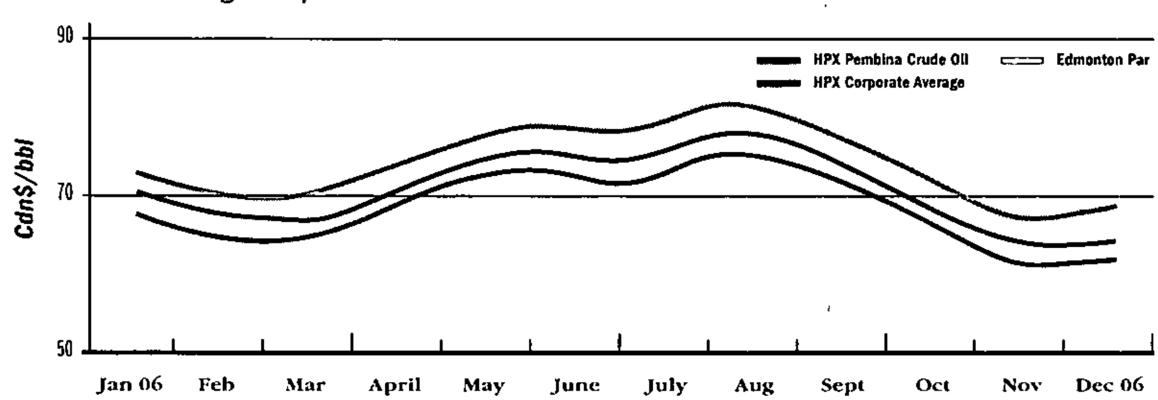
In contrast, AECO (Alberta gas benchmark trading price) natural gas prices weakened significantly from their winter 2005 highs. Concerns about large natural gas inventories, combined with lower demand, continued to depress natural gas prices through most of 2006. AECO natural gas prices also lost ground due to the continued relative strength of the Canadian dollar versus the U.S. dollar.

W.T.I. Oil Price@ Cushing, Oklahoma



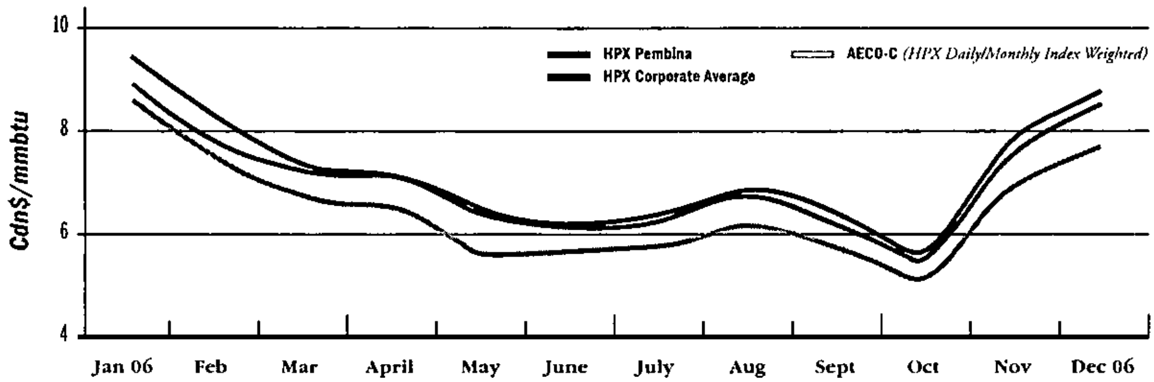
The sizable increase in the W.T.I. benchmark price for crude oil during 2006 was partially offset by the impact of the continued strength of the Canadian dollar. The Company realized an average crude oil price of $68.94 per barrel 2006. The average quality differential and transportation charge to Edmonton was $2.27 per barrel and $3.83 per barrel for Pembina crude oil and total corporate crude oil respectively. These quality and transportation charges are some of the lowest in the Western Canada Sedimentary Basin and are a testament to the high-quality crude oil that Highpine produces in Pembina and elsewhere. Highpine's overall quality of crude oil remained very high in 2006, averaging ± 38 degrees API, while Pembina Nisku crude oil quality averaged ± 40 degrees API. The majority of the Company's production is sold at the pipeline inlet to selected marketing companies.

Crude Oil Pricing Comparative



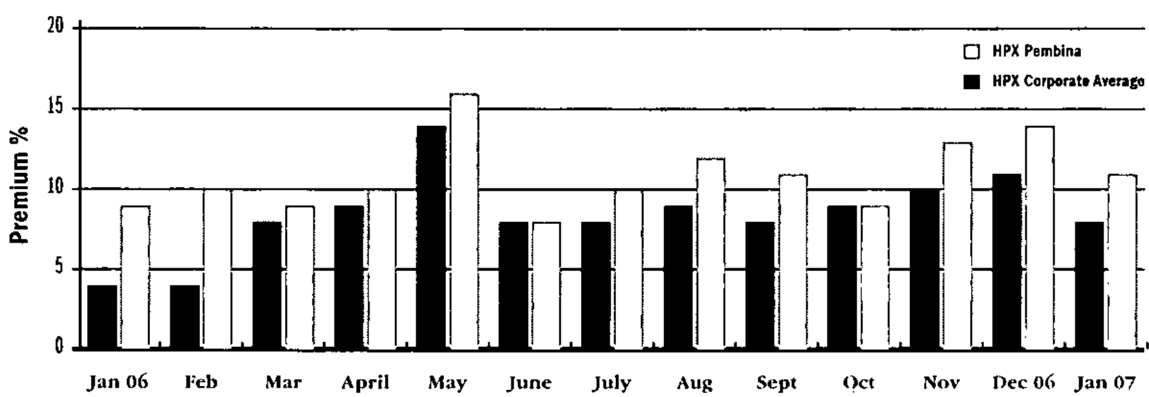
A 25 percent decline in average daily AECO prices was the primary contributing factor in the decrease in average realized price to $7.06 per mcf in 2006 compared to $9.84 per mcf in 2005. Pembina Nisku natural gas commanded an 11 percent premium to indexed AECO gas prices, while total corporate natural gas commanded an 8 percent premium on the same basis.

Natural Gas Pricing Comparative



The Company maintained significant weighting to the Alberta natural gas market in 2006, as this market continued to offer a premium netback relative to other indices. During 2006, the Company marketed approximately 99 percent of its natural gas sales directly, with the remaining 1 percent marketed by aggregators.

Energy Premium to AECO (HPX Daily/Monthly Index)



Highpine will continue to employ sound marketing practices in an attempt to partially offset the cyclical nature of commodity pricing which is subject to external influences beyond Highpine's control.

West Central Alberta Gas Fairway

The West Central Alberta Gas Fairway is located west of Edmonton, Alberta and trends from Red Deer, Alberta approximately 200 miles northwest. It includes natural gas and crude oil properties at Ante Creek, Edson, Windfall, McLeod, Goodwin, Chip Lake, Wilson Creek, Ferrier and Joffre.

The West Central Alberta Gas Fairway is more than 16,000 square miles in size and targets multiple Deep Basin sands, such as the Dunvegan, Cardium, Viking, Notikewin, Falher, Bluesky, Gething, Cadomin and Rock Creek, and Triassic sands such as the Halfway, Doig and Montney. Large pools of hydrocarbons can also occur in the even deeper Devonian Wabamun, Nisku and Leduc formations.

Geologic Considerations

Deep Basin natural gas sands are generally found at depths of 8,000 to 12,000 feet and produce from quartzose sandstones and conglomerates that require fracture stimulation to improve permeability. Geologic mapping is used to define prospective areas using existing wellbores. Seismic is used to attempt to define areas of thicker sands and higher porosity. The multi-zone potential of these areas continues to attract land sale bids of more than $500,000 per section ($5,000 per acre). Reserves per well range from 1 to 5 billion cubic feet with median reserves of 1.5 billion cubic feet. In addition, most of the targeted zones contain natural gas liquids, which enhances the economics.

Highpine Prospect Targets

Along the Fairway, Highpine is targeting medium risk, medium-depth, multi-zone drilling potential for sweet natural gas and crude oil production and reserves. Sweet means the majority of the producing horizons do not contain hydrogen sulphide (H_2S) and can be licenced, drilled and brought on-stream quickly.

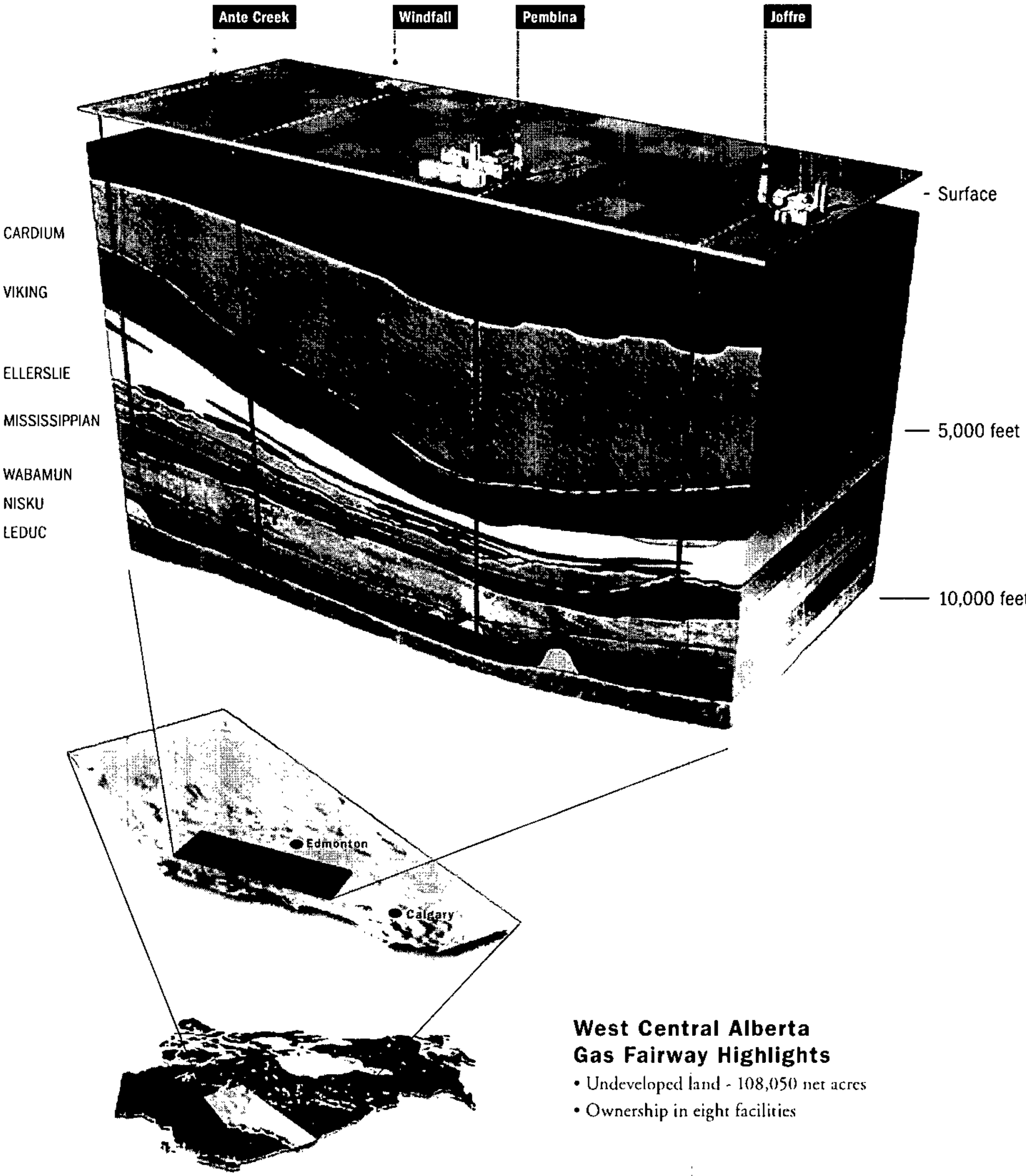
Typically, the quality of the natural gas (including associated natural gas liquids) and the crude oil earns premium prices, allowing for high netbacks and good economics in most oil and natural gas price environments.

The West Central Alberta Gas Fairway is Highpine's second most significant property. In 2006, the Company participated in the drilling of 48 (27.9 net) wells in the Fairway. The program resulted in 40 (23.1 net) oil and natural gas wells and 8 (4.8 net) dry holes, for an overall success rate of approximately 83 percent. Notable areas of activity included Joffre, where several successful oil and natural gas wells were drilled; Chip Lake, where Highpine made two new crude oil pool discoveries; Ante Creek, where multiple natural gas (with condensate) pools were found; and Edson, which is an emerging natural gas area for Highpine.

Although Highpine has numerous prospects in West Central Alberta, they will be drilled selectively in 2007 due to the superior economics for drilling in the Pembina area.

Large Undeveloped Land Base

Highpine's undeveloped land base of 148,441 (108,050 net) acres in the Fairway will provide several years of drilling opportunities. The Company currently has a drilling inventory of 75 locations on its Fairway lands and expects to drill approximately 10 to 12 (7-9 net) wells in 2007, including selected natural gas prospects at Ante Creek, Edson and Joffre. Crude oil exploration drilling is anticipated at Chip Lake. The remaining drilling locations in inventory, and additional locations that are expected to be generated from geological work, can be drilled in future years when Highpine elects to do so.



West Central Alberta Gas Fairway Highlights

- Undeveloped land - 108,050 net acres
- Ownership in eight facilities

Production and Reserves

In 2006, Highpine produced approximately 2,640 barrels of oil equivalent per day from the West Central Alberta Gas Fairway, representing 22 percent of the Company's total production. In February, 2007 this Fairway contributed approximately 3,600 barrels of oil equivalent per day with a few working-interest wells remaining to be tied-in.

At December 31, 2006 the Paddock, Lindstrom & Associates reserves engineering report attributed 8.6 million barrels of oil equivalent of proved plus probable reserves to the Company's West Central Alberta Gas Fairway. This represents approximately 19 percent of Highpine's total working interest reserves.

Edson

Gas-saturated reservoirs in the Cadomin and Bluesky formations are our main targets for drilling at Edson. Uphole secondary targets include the Dunvegan, Cardium, Viking, and Notikewin. Triassic sands, below the Cadomin, may also be exploratory targets. Geologic mapping defines localized areas for detailed seismic definition of drilling locations.

Highpine drilled one successful natural gas well in this area in 2006 and plans to drill up to 4 wells in 2007. Highpine holds 8,960 (3,680 net) acres of prospective land at Edson.

Ante Creek

The Wabamun natural gas at Ante Creek is trapped in porosity created by hydrothermal dolomites associated with basement faulting. Detailed interpretation of 3D seismic assists in the definition of drilling locations.

Highpine discovered 4 new Wabamun natural gas pools in drilling 7 (3 net) exploratory wells. This adds to 2 pools discovered in 2005. Highpine plans to drill a minimum of 3 Wabamun wells in 2007.

Joffre

Ellerslie channels at a depth of 5,000 feet are the main reservoir targeted at Joffre. These hydrocarbon-saturated channels can be up to 80 feet thick, with porosity up to 15 percent, and generally contain no water. Secondary targets include coal-bed methane, Edmonton, Belly River, and Viking sands.

In 2006, Highpine drilled 2 (2 net) Ellerslie oil wells and 2 (2 net) Ellerslie natural gas wells. Highpine also owns a 100 percent interest in a natural gas processing plant that processes gas from our wells.

The Alberta government recently approved the increased density of drilling in the Joffre area. Highpine has an extensive exploitation drilling program that can be initiated when appropriate.

Health, Safety and Environment

Highpine is committed to conducting activities in a manner that will safeguard the health and safety of employees and the public and that will preserve the quality of the environment. Each of our employees and contractors share the responsibility for providing the leadership and direction needed to effectively manage the required plans and programs. We encourage innovative solutions that will assist us in improving our health, safety and environment. In order to fulfill our business goals as well as meet the needs of our shareholders, exemplary performance in the area of health, safety and the environment is essential.

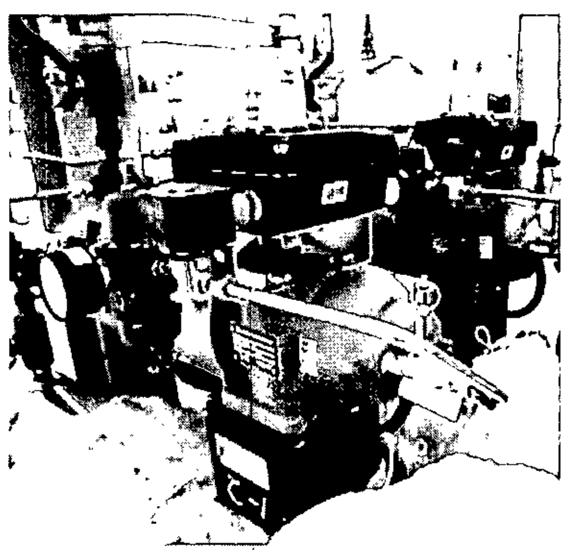
Highpine is committed to integrating many important objectives into the decisions affecting our day to day operations, such as:

- Providing all employees and contractors with the education and training required to ensure these goals are achieved.
- Striving to meet or exceed all regulatory requirements, industry standards, and best practices.
- Promoting meaningful consultation with the public, government agencies and other stakeholders who could be adversely affected by our operations and also ensuring that we respond to their concerns.
- Ensuring emergency response capabilities are in place and that proper training and periodic deployment exercises are conducted.
- Conducting internal audits and assessments of our operations to identify risks and take proactive steps to mitigate exposure.
- Reporting all accidents and incidents and conducting investigations that will identify improvements needed to prevent recurrence.

Highpine has entered into commitment agreements with some of the major stakeholders in certain core areas that it operates in. These stakeholders have acknowledged that all of these commitments with respect to drilling, completions, facilities and emergency response plans exceed minimum regulations or guidelines which ensure a higher standard of safety and environmental protection in their communities. In an effort to reduce greenhouse gas emissions, Highpine is making every effort to minimize flared volumes during well testing operations. Highpine has committed to flare for a maximum of eight hours, and in many cases will in-line test the well after a short four hour clean-up period if the well was stimulated.

Highpine has experienced tremendous growth over a relatively short period of time and, as a result, has significantly increased its field personnel. Consequently, we are currently in the process of developing and implementing a performance-based evaluation system by which we can monitor our progress in implementing our goals and targets.

We expect excellence in health, safety and environmental performance to be achieved through the support and active participation of all management, employees and contractors working for Highpine.



Typical emergency shut-down valve stops the flow of sour gas at pre-set levels of pressure.

Community Partnership

Highpine takes great pride in being a good corporate citizen and a responsible neighbour in the communities in which it works.

In Drayton Valley and surrounding areas, Highpine is a committed sponsor for many valuable activities and programs. These include sponsorship of several high school rodeo clubs, Drayton Valley Horse Club, Drayton Valley 4H Club, Shangri-la Lodge Expansion, Eldorado School, Drayton Valley Christian School, Drayton Valley Health Services Foundation, Drayton Valley Scholarship Trust Society, Whitby Community League, Sasquatch Community Arts Society, as well as a Platinum-level sponsorship of the Drayton Valley Field House Recreation Centre.

Donations have also been made to many other charitable organizations, including the Alzheimer Society of Calgary, Kids Cancer Care Foundation, Heart and Stroke Foundation, Breast Cancer, Leukemia & Lymphoma Society, and the United Way Campaign.

Highpine also sponsors the World Professional Chuckwagon Association at the Calgary Stampede and the Ponoka Stampede. These sponsorships provide Highpine's staff – and the residents of the communities in which we work – a great opportunity to get involved with this exhilarating sport. The Company has established this tradition as a way to support the community for years to come.

Left to right: Ed Dusterhoft presenting a donation to Sharon Hjartarson of the Drayton Valley Health Services Foundation.

Left to right: Karl Pischke, Jerry Bremner, Melissa Lang and Ed Dusterhoft

Operations Statistical Review

Acreage Summary

	Total		Undeveloped	
(acres)	Gross	Net	Gross	Net
Pembina Nisku Fairway	226,742	187,284	193,302	161,585
West Central Alberta Gas Fairway	216,590	143,162	148,441	108,050
Other	200,752	71,237	152,495	58,978
Total	644,084	401,683	494,238	328,613

* *Antelope Land Services Ltd., an independent land broker, conducted an evaluation of Highpine's land base. At December 31, 2006 Highpine's undeveloped land value was estimated at Cdn$131.5 million.*

Drilling Activity

	2006		2005		2004	
(wells)	Gross	Net	Gross	Net	Gross	Net
Exploratory						
Oil	5	3.3	8	6.4	6	1.4
Gas	21	13.6	12	9.0	2	1.1
Service	-	-	10	4.0	1	0.3
Dry	10	6.6	13	11.7	4	1.6
Subtotal	36	24	43	31	13	4
Success Rate (%)	72	72	70	62	69	64
Average working interest (%)	65		72		34	
Development						
Oil	10	8.2	1	0.1	7	5.2
Gas	22	11.4	7	2.0	23	8.9
Service	5	3.2	1	0.4	6	2.4
Dry	1	0.5	4	2.8	5	1.8
Subtotal	38	23	13	5	41	18
Success Rate (%)	97	98	62	47	88	90
Average working interest (%)	61		41		45	
Total						
Oil	15	11.5	9	6.5	13	6.6
Gas	43	25.0	19	11.0	25	10.0
Service	5	3.2	11	4.4	7	2.7
Dry	11	7.1	17	14.5	9	3.4
Total	74	47	56	36	54	23
Success Rate (%)	85	85	70	60	83	85
Average working interest (%)	63		65		42	

Operations Statistical Review

Daily Production Volumes

	2006	2005	% Change
Crude oil and NGL (bbls/d)			
Pembina Nisku Fairway	6,549	3,239	102
West Central Alberta Gas Fairway	562	224	151
Bantry/Retlaw	371	420	(12)
Minor Properties	72	101	(29)
Total crude oil and NGL	7,554	3,984	90
Natural gas (mcf/d)			
Pembina Nisku Fairway	10,653	4,126	158
West Central Alberta Gas Fairway	12,474	7,614	64
Bantry/Retlaw	621	941	(34)
Minor Properties	1,602	1,142	40
Total natural gas	25,350	13,823	83
Total (boe/d)			
Pembina Nisku Fairway	8,324	3,927	112
West Central Alberta Gas Fairway	2,640	1,492	77
Bantry/Retlaw	475	576	(18)
Minor Properties	340	293	16
Grand total	11,779	6,288	87

Reserves

Year-end Reserves Summary

As at December 31, 2006, the Company's total proved plus probable gross working interest reserves were 44.4 million barrels of oil equivalent, an increase of 82 percent compared to 24.4 million barrels of oil equivalent as at December 31, 2005.

The growth in reserve volumes resulted principally from Highpine's successful 2006 Pembina drilling program and the acquisition of White Fire and Kick.

Paddock, Lindstrom & Associates Ltd. has evaluated all of Highpine's reserves as at December 31, 2006. The December 31, 2006 reserves presented below include Company working interests before royalty interests and before royalty costs. Where volumes are expressed on a barrel of oil equivalent (boe) basis, natural gas volumes have been converted to barrels of oil in the ratio of one barrel of oil to six thousand cubic feet of natural gas.

Summary of Crude Oil, NGL and Natural Gas Reserves and Net Present Values of Estimated Future Net Revenue as of December 31, 2006

Based on Forecast Price Assumptions*

December 31, 2006	Natural Gas	Crude Oil & NGL	Total (6:1)
	(bcf)	(mbbls)	(mboe)
Proved developed producing	45.49	11,249	18,831
Proved developed non-producing	16.86	3,478	6,289
Proved undeveloped	12.59	2,037	4,135
Total proved	74.94	16,764	29,254
Probable additional	37.73	8,852	15,141
Total proved plus probable	112.67	25,616	44,395

* *Highpine working interest only – does not include Highpine royalty interests and royalty costs.*

	Net Present Values of Future Net Revenue Before Income Taxes Discounted at (%/year)				
Reserves Category	0	5	10	15	20
			(Thousands of Dollars)		
Proved					
Developed producing	543,822	461,926	405,730	364,344	332,367
Developed non-producing	150,028	127,734	111,676	99,547	90,055
Total developed	693,850	589,660	517,406	463,891	422,422
Undeveloped	90,164	64,901	50,105	40,159	32,923
Total proved	784,014	654,561	567,511	504,050	455,345
Probable	435,116	278,815	206,469	163,100	133,629
Total proved plus probable	1,219,130	933,376	773,980	667,150	588,974

Oil and Gas Price Forecast	WTI @ Cushing US$/bbl	US$/CDN$ Exchange Rate	AECO C CDN$/mmbtu
Year			
2007	61.00	0.87	7.33
2008	60.00	0.87	7.91
2009	60.00	0.87	7.89
2010	58.00	0.87	7.87
2011	56.00	0.87	8.02

Operations Statistical Review

Reserves Reconciliation*

	Natural Gas		Crude Oil & NGL		Total	
	Total Proved	Proved + Probable	Total Proved	Proved + Probable	Total Proved	Proved + Probable
	(bcf)		(mbbls)		(mboe)	
December 31, 2005	31.76	47.14	10,431	16,500	15,725	24,356
Drilling additions	24.05	39.84	3,928	4,691	7,936	11,331
Acquisitions	25.96	36.58	4,591	6,969	8,917	13,065
Dispositions	-	-	-	-	-	-
Technical revisions	2.42	(1.64)	572	214	975	(58)
Production	(9.25)	(9.25)	(2,758)	(2,758)	(4,299)	(4,299)
December 31, 2006	74.94	112.67	16,764	25,616	29,254	44,395

** Highpine working interests only – does not include Highpine royalty interests and royalty costs.*

Finding, Development and Acquisition Costs

Highpine has calculated FD&A costs for 2006 and for the three-year period from 2004 to 2006.

The 2006 F&D costs for the exploration and development program only, averaged $17.24 per barrel of oil equivalent for proved plus probable reserves and $21.81 per barrel of oil equivalent for proved reserves, before changes in future capital and after revisions ($24.24 and $26.65 per barrel of oil equivalent respectively, including future capital).

This 2006 F&D costs include top decile F&D costs of $10.62 per barrel of oil equivalent for proved plus probable reserves and $14.78 per barrel of oil equivalent for proved reserves ($18.92 and $21.06 barrel of oil equivalent respectively, including future capital) in the Pembina Nisku Fairway which yields superior reinvestment efficiency ratios of 3.2 and 2.3, displaying the economic power of the Nisku play type. The 2006 Pembina results support the realization of Highpine's vision of the high economic growth potential of the Pembina Nisku Fairway which led the Company to aggressively commit up-front capital expenditures for land, seismic and facilities during the past four years. Highpine also realized upward reserve revisions in several of its Nisku pools, reaffirming Highpine's confidence in the quality of its Pembina assets. Highpine expects to allocate the majority of its capital expenditure budgets in the foreseeable future to its Pembina Nisku Fairway to capitalize on its significant inventory of drilling locations and its progress in procuring drilling licences.

Despite a successful drilling year in Pembina, corporate F&D costs of $24.24 per barrel of oil equivalent (including future capital) for proved plus probable reserves are higher than desired due primarily to negative performance-based reserve revisions in certain properties in the West Central Alberta Gas Fairway. Highpine intends to allocate capital to select properties and drilling prospects contained in this Fairway.

The acquisition costs of $35.85 per barrel of oil equivalent for proved plus probable reserves are in line with expectations from evaluations conducted when assessing the acquisitions. Highpine expects that these costs will decrease with future exploitation of the drilling prospects that accompanied these acquisitions. For example, Highpine acquired 30 drillable Nisku prospects with the acquisition of Kick.

For the three-year period ended December 31, 2006, F&D costs for the Company's exploration and development program only, averaged $17.37 per barrel of oil equivalent for proved plus probable reserves and $24.12 per barrel of oil equivalent for proved reserves, excluding an adjustment for future capital and after revisions ($22.00 and $27.46 per barrel of oil equivalent respectively, including future capital).

On a standalone basis, Pembina's three year exploration and development program F&D costs averaged $12.49 per barrel of oil equivalent for proved plus probable reserves and $18.91 per barrel of oil equivalent for proved reserves before future capital ($17.85 and $23.04 per barrel of oil equivalent respectively, including future capital). Re-investment efficiency ratios for the same three-year period are 3.0 and 2.0 for proved plus probable and total proved reserves respectively. These strong F&D costs create a strong re-investment efficiency ratio which clearly demonstrates Highpine's success in developing the robust economic potential of the Pembina Nisku Fairway.

Total 2006 FD&A costs, including changes in future capital, were $30.47 per barrel of oil equivalent for proved plus probable reserves and $39.59 per barrel of oil equivalent for proved reserves. Average FD&A costs for the three-year period ended December 31, 2006 were $30.01 per barrel of oil equivalent for proved plus probable reserves and $40.95 per barrel of oil equivalent for proved reserves. Highpine expects that its FD&A costs will improve in the future as it allocates the majority of its capital expenditures to the Pembina Nisku Fairway.

Total Proved Finding, Development and Acquisition Costs

Years Ended December 31,	**2006**	2005	2004
(000s, except per unit)	**$**	$	$
Excluding effect of acquisitions and dispositions			
Total exploration & development capital costs	**194,394**	147,306	66,000
Net change from previous year's estimated future development costs	**43,104**	3,773	9,520
Total estimated capital for finding & development costs	**237,499**	151,079	75,520
Additions to total proved reserves (mboe)	**8,911**	3,673	4,318
Finding & development costs ($/boe) – Before Change in Future Development Costs	**21.81**	40.10	15.29
Finding & development costs ($/boe)	**26.65**	41.13	17.49
Three-year average finding & development cost ($/boe)	**27.46**	-	-
Including effect of acquisitions and dispositions			
Total exploration & development capital costs	**662,751**	552,606	113,747
Net change from previous year's estimated future development costs	**43,104**	3,773	9,520
Total estimated capital for finding & development costs	**705,855**	556,379	123,267
Additions to total proved reserves (mboe)	**17,829**	9,844	6,165
Finding & development costs ($/boe) – Before Change in Future Development Costs	**37.17**	56.14	18.45
Finding & development costs ($/boe)	**39.59**	56.52	19.99
Three-year average finding & development cost ($/boe)	**40.95**	-	-

Total Proved Plus Probable Finding, Development and Acquisition Costs

Years Ended December 31,	**2006**	2005	2004
(000s, except per unit)	**$**	$	$
Excluding effect of acquisitions and dispositions			
Total exploration & development capital costs	**194,394**	147,306	66,000
Net change from previous year's estimated future development costs	**78,896**	16,637	13,160
Total estimated capital for finding & development costs	**273,291**	163,943	79,160
Additions to total proved plus probable reserves (mboe)	**11,273**	5,399	6,804
Finding & development costs ($/boe) – Before Change in Future Development Costs	**17.24**	27.28	9.70
Finding & development costs ($/boe)	**24.24**	30.36	11.63
Three-year average finding & development cost ($/boe)	**22.00**	-	-
Including effect of acquisitions & dispositions			
Total estimated exploration & development capital costs	**662,751**	552,606	113,747
Net change from previous year's estimated future development costs	**78,896**	16,637	13,160
Total estimated capital for finding & development costs	**741,647**	569,243	126,907
Additions to total proved plus probable reserves (mboe)	**24,338**	14,474	9,106
Finding & development costs ($/boe) – Before Change in Future Development Costs	**27.23**	38.18	12.49
Finding & development costs ($/boe)	**30.47**	39.33	13.94
Three-year average finding & development cost ($/boe)	**30.01**	-	-

Note: The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

Management's Discussion and Analysis

This Management's Discussion and Analysis (MD&A) is dated and based on information at March 12, 2007. This MD&A has been prepared by management and should be read in conjunction with the audited consolidated financial statements for the years ended December 31, 2006 and 2005 for a complete understanding of the financial position and results of operations of Highpine Oil & Gas Limited ("Highpine" or the "Company").

Certain information set forth in this MD&A contains forward-looking statements including expectations of future production, procurement of drilling permits, plans for and results of exploration and development activities and other operational developments and components of cash flow and earnings. Readers are cautioned that assumptions used in the preparation of such statements may prove to be incorrect. Events or circumstances may cause actual results to differ materially from those predicted, as a result of numerous known and unknown risks, uncertainties, and other factors, many of which are beyond the control of the Company. These risks include, but are not limited to: the risks associated with the oil and natural gas industry, commodity prices, and exchange rate changes. Industry related risks include, but are not limited to: operational risks in exploration, development and production of oil and natural gas and production risks associated with sour hydrocarbons, dependence on third-party owned and operated production facilities, availability of skilled personnel and services, failure to obtain industry partner, regulatory and other third-party consents and approvals, delays or changes in plans, risks associated with the uncertainty of reserve estimates, health and safety risks and the uncertainty of estimates and projections of reserves, production, costs and expenses. The risks outlined above should not be construed as exhaustive. Readers are cautioned not to place undue reliance on these statements. The Company undertakes no obligation to update or revise any forward-looking statements except as required by applicable securities laws.

This MD&A uses the terms "cash flow from operations," "cash flow," "cash flow per share," and "operating netback" which are not recognized measures under Canadian generally accepted accounting principles (GAAP). Management believes that in addition to net earnings, cash flow is a useful supplemental measure as it provides an indication of the results generated by Highpine's principal business activities before the consideration of how these activities are financed or how the results are taxed. Investors are cautioned, however, that this measure 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 cash flow may differ from other companies, especially those in other industries and, accordingly, may not be comparable to measures used by other companies. Highpine calculates cash from operations as cash from operating activities before the change in non-cash working capital related to operating activities. Highpine also uses operating netback as an indicator of operating performance. Operating netback is calculated on a per boe basis taking the sales price and deducting royalties, operating costs, transportation costs and realized hedging gains and losses.

Where amounts are expressed on a barrel of oil equivalent (boe) basis, natural gas volumes have been converted to equivalent barrels of oil using a conversion factor of six thousand cubic feet equal to one barrel of oil equivalent unless otherwise indicated. This conversion ratio of 6:1 is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Boe figures may be misleading, particularly if used in isolation.

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

Additional information relating to Highpine Oil & Gas Limited, including the Company's annual information form, is available on SEDAR at www.sedar.com and on the Company's website at www.highpineog.com.

Financial Results

Oil and Natural Gas Revenue

($000s)	Year Ended December 31, 2006	2005	% Change
Crude oil and natural gas liquids (NGL) revenue	182,509	97,674	87
Natural gas revenue	65,295	49,629	32
	247,804	147,303	68
Realized hedging gain (loss)	4,703	(6,613)	–
Unrealized hedging gain (loss)	2,431	944	158
Total oil and natural gas revenue	254,938	141,634	80

For the year ended December 31, 2006, total oil and natural gas revenue rose to $254.9 million from $141.6 million in 2005. The increase was due primarily to production increases which resulted in a $116.0 million increase in revenues. Decreases in commodity prices, primarily natural gas were partially offset by the Company's commodity price risk management program.

Production

	Year Ended December 31, 2006	2005	% Change
Daily Production			
Crude oil and NGL (bbls/d)	7,554	3,984	90
Natural gas (mcf/d)	25,350	13,823	83
Boe/d	11,779	6,288	87
Production Mix			
Crude oil and NGL	64%	63%	–
Natural gas	36%	37%	–
	100%	100%	–

(boe/d)	Year Ended December 31, 2006	2005	% Change
Daily Production by Area			
Pembina Nisku Fairway	8,324	3,927	112
West Central Alberta Gas Fairway	2,640	1,492	77
Bantry/Retlaw	475	576	(18)
Other	340	293	16
Total	11,779	6,288	87

Production for the year ended December 31, 2006 increased by 87 percent to 11,779 boe/d from 6,288 boe/d in 2005. The acquisition of White Fire Energy Ltd. ("White Fire") contributed 600 boe/d from February 22, 2006 onward. The acquisition of Kick Energy Corporation ("Kick") added 3,600 boe/d from August 1, 2006 onwards. Additional production gains are attributable to a full year of production from the acquisition of Vaquero Energy Ltd. ("Vaquero") which was completed on May 31, 2005, bringing on new production from the Company's drilling program and property acquisitions.

The Company is estimating that bringing currently shut-in volumes on-stream and continued drilling success should result in its 2007 production rate exceeding 20,000 boe/d.

Pricing

	Year Ended December 31,		
	2006	2005	% Change
Selling Prices Before Hedges			
Crude oil and NGL ($/bbl)	66.19	67.16	(1)
Natural gas ($/mcf)	7.06	9.84	(28)
Total combined ($/boe)	57.64	64.18	(10)

	Year Ended December 31,		
	2006	2005	% Change
Benchmark Prices			
WTI oil (US$/bbl)	62.25	56.61	17
US$/Cdn$ exchange rate	0.88	0.83	6
AECO natural gas ($/mcf)	6.51	8.73	(25)

An increase in the WTI benchmark price for crude oil of 17 percent was offset by a stronger Canadian dollar. A 25 percent decrease in average AECO prices was the primary driver of the decrease in realized natural gas prices.

Commodity Price Risk Management

The Company enters into derivative instruments to manage its commodity price exposure. The Company does not enter into derivative instruments contracts for trading or speculative purposes.

	Year Ended December 31,		
	2006	2005	% Change
Average volumes hedged (boe/d)	4,736	1,086	336
Percent of production hedged	40%	17%	135
Realized hedging gain (loss) ($000s)	4,703	(6,613)	–
Realized hedging gain (loss) ($/boe)	1.09	(2.88)	–

For the year ended December 31, 2006, Highpine realized a $5.3 million natural gas hedging gain and a $0.6 million crude oil hedging loss.

The following contracts are outstanding at December 31, 2006:

Term	Contract	Volume	Fixed Price
Jan 07 to Dec 07	Oil Collar	1,750 bbls/d	US$55.00 to $86.15/bbl
Jan 07 to Dec 07	Oil Collar	1,750 bbls/d	US$60.00 to $80.70/bbl
Jan 07 to Dec 07	Oil Swap	500 bbls/d	Cdn$73.00/bbl
Jan 07 to Dec 07	Oil Swap	500 bbls/d	Cdn$73.70/bbl
Jan 07 to Dec 07	Oil Swap	500 bbls/d	Cdn$74.70/bbl
Jan 07 to Dec 07	Oil Swap	500 bbls/d	Cdn$75.82/bbl
Jan 07 to Dec 07	Natural Gas Swap	2,500 GJs/d	Cdn$7.55/GJ
Jan 07 to Dec 07	Natural Gas Swap	2,500 GJs/d	Cdn$7.62/GJ
Jun 06 to Mar 07	Natural Gas Collar	5,000 GJs/d	Cdn$5.40 to $12.00/GJ
Jul 06 to Mar 08	Natural Gas Collar	5,000 GJs/d	Cdn$6.00 to $11.10/GJ

As at December 31, 2006, the unrealized mark-to-market gain on outstanding crude oil contracts was $1.1 million and the unrealized mark-to-market gain on outstanding natural gas contracts was $2.1 million.

Royalty Expense

	Year Ended December 31,		
	2006	2005	% Change
Total royalties, net of ARTC ($000s)	70,529	38,995	81
As a percent of oil and natural gas sales (before hedging)	28%	26%	8
$/boe	16.40	16.99	(3)

Royalty rates as a percentage of oil and natural gas sales were higher in 2006 than in 2005 due to gross overriding royalties on certain Pembina wells along with a higher proportion of the Company's production coming from Pembina which attracts higher Crown royalties.

Operating Costs

	Year Ended December 31,		
	2006	2005	% Change
Operating costs ($000s)	36,839	14,575	153
$/boe	8.57	6.35	35

For the year ended December 31, 2006, operating costs on a per boe basis increased by 35 percent over 2005. The increases were a result of the Company incurring fixed costs at the Violet Grove oil battery while certain Pembina volumes were shut-in, increased costs at Pembina associated with sour oil production and higher overall processing costs on some of the Company's properties.

Transportation Costs

	Year Ended December 31, 2006	2005	% Change
Transportation costs ($000s)	3,069	2,439	26
$/boe	0.71	1.06	(33)

For the year ended December 31, 2006, transportation costs decreased by 33 percent to $0.71/boe from $1.06/boe in 2005. Transportation costs for 2005 were higher as a $0.4 million sulphur trucking charge related to 2004 production was included in 2005.

Operating Netback

($/boe)	Year Ended December 31, 2006	2005	% Change
Sales price before hedging	57.64	64.18	(10)
Royalties	(16.40)	(16.99)	(3)
Operating costs	(8.57)	(6.35)	35
Transportation costs	(0.71)	(1.06)	(33)
Netback before hedges	31.96	39.78	(20)
Realized hedging gain (loss)	1.09	(2.88)	–
Operating netback	33.05	36.90	(10)

Operating netback before realized hedging gains or losses was $31.96/boe for the year ended December 31, 2006 compared to $39.78/boe in 2005. The 20 percent decrease was due to lower realized natural gas prices as well as higher operating costs.

Operating netback for the year ended December 31, 2006 was positively impacted by realized natural gas hedging gains.

General and Administrative Expenses

	Year Ended December 31, 2006	2005	% Change
Gross expenses ($000s)	12,931	7,154	81
Capitalized ($000s)	(3,249)	(1,377)	136
Net expenses ($000s)	9,682	5,777	68
$/boe	2.25	2.52	(11)
Percent capitalized	25%	19%	32

Net expenses rose by 68 percent to $9.7 million in 2006 from $5.8 million in 2005 as a result of salaries related to personnel obtained from the corporate acquisitions made during the year as well as staff increases necessary to manage the growth of the Company. At December 31, 2006, Highpine had 55 Calgary-based office employees compared to 39 at December 31, 2005. On a per boe basis, general and administrative expenses decreased by 11 percent to $2.25/boe in 2006 from $2.52/boe in 2005.

Stock-Based Compensation

Stock-based compensation expense totalled $5.7 million in 2006 compared to $3.2 million in 2005. The increase was primarily the result of stock options that were granted to new employees as well as to former Vaquero and White Fire employees who remained with the Company.

Interest and Finance Costs

Interest and finance costs for 2006 were $5.1 million versus $3.6 million in 2005. The 42 percent increase was due to higher average debt levels and an increase in the prime interest rate.

Depletion, Depreciation and Accretion

	Year Ended December 31,		
	2006	2005	% Change
Depletion and depreciation ($000s)	124,627	53,566	133
Accretion of asset retirement obligation ($000s)	679	327	108
Total DD&A ($000s)	125,306	53,893	133
DD&A rate ($/boe)	29.15	23.48	24

The depletion, depreciation, and accretion (DD&A) rate increased to $29.15/boe in 2006 from $23.48/boe in 2005. The higher DD&A rate is primarily attributable to the White Fire and Kick acquisitions for which Highpine recorded a higher proportionate cost per barrel of proved reserves compared to the Company's existing properties.

Income Taxes

For the year ended December 31, 2006, a future tax reduction of $8.0 million was realized due to a decrease in the Canadian federal and Alberta tax rates, which resulted in a non-recurring $9.1 million tax reduction.

Although current tax horizons depend on product prices, production levels and the nature, magnitude and timing of capital expenditures, Highpine's management currently believes no cash income tax will be payable in 2007 or 2008.

Cash Flow and Net Earnings

	Year Ended December 31,		
	2006	2005	% Change
Cash from operations ($000s)	127,072	74,550	70
Per diluted share ($)	2.17	2.09	4
Net earnings ($000s)	6,953	12,274	(43)
Per diluted share ($)	0.12	0.34	(65)

For the year ended December 31, 2006, cash flow increased by 70 percent to $127.1 million from $74.6 million in 2005. Cash flow per diluted share increased by 4 percent to $2.17 in 2006 from $2.09 in 2005.

During 2006, net earnings totalled $7.0 million, a 43 percent decrease from 2005. Net earnings for 2006 include a $9.1 million non-recurring future tax reduction realized as a result of enacted Canadian federal and Alberta tax rate reductions. Earnings were negatively impacted by higher DD&A and lower natural gas prices.

Liquidity and Capital Resources

In the third quarter of 2006 the Company increased its syndicated credit facilities to $205 million. The repayment terms of the revolving term credit facility were amended such that in the event that the term date is not extended, the balance under the facility would be repayable 365 days after the term date. As a result of the amendment, the balance outstanding under the facility has been reclassified as long-term in the consolidated balance sheet. The next term date is May 29, 2007.

At December 31, 2006, the Company had a revolving term credit facility of $205 million and a demand operating credit facility of $20 million with $138.9 million drawn against these facilities, thereby providing remaining credit capacity of $86.1 million. At December 31, 2006, the Company had a working capital deficiency of $30.7 million and net debt of $169.6 million. The ratio of December 31, 2006 net debt to 2006 cash flow was 1.33 times.

As at ($000s except market price and debt ratios)	December 31, 2006	December 31,2005
Capitalization ($000s)		
Bank debt	138,890	104,707
Working capital deficiency[1]	30,680	4,892
Net debt	169,570	109,599
Shares outstanding ($000s)	67,648	44,250
Market price at end of year ($)	15.70	20.70
Market capitalization ($000s)	1,062,074	915,975
Total capitalization ($000s)	1,231,644	1,025,574
Net debt as a percent of total capitalization	14%	11%
Cash flow ($000s)	127,072	74,550
Net debt to cash flow ratio	1.33	1.47

[1] *Working capital excludes unrealized financial instruments.*

Highpine's 2007 capital budget of $200 million is expected to be funded from the Company's existing credit facilities and cash flow from operations.

At March 12, 2007, the Company's bank debt was approximately $142 million.

Capital Expenditures

Capital expenditures, excluding corporate acquisitions and property dispositions, totaled $194.8 million for the year ended December 31, 2006 compared to $149.9 million for 2005.

Highpine acquired White Fire in February 2006 for total consideration of $114.3 million. The Company acquired Kick in August 2006 for total consideration of $326.6 million. Both White Fire and Kick had operations focused in Highpine's Pembina Nisku fairway.

Highpine also completed property acquisitions totalling $27.5 million in 2006. The property acquisitions were in Pembina, Brazeau River and Ante Creek.

Highpine drilled 74 gross (46.7 net) wells in 2006.

($000s)	Year Ended December 31, 2006	2005	% Change
Land	17,392	42,346	(59)
Geologic and geophysical	10,431	14,064	(26)
Drilling and completions	110,665	53,233	108
Facilities and equipment	52,649	36,441	44
Capitalized general and administrative	3,258	1,202	171
Office and other	358	2,610	(86)
Total capital expenditures	194,753	149,896	30
Property acquisitions	27,461	4,119	567
Property dispositions	–	(409)	–
Corporate acquisitions[1]	440,895	399,415	10
Total capital expenditures and acquisitions	663,109	553,021	20

[1] *Represents total consideration for the transactions, including fees, but is prior to the related future income tax liability and asset retirement obligation.*

Shareholders' Equity

On August 1, 2006, the Company issued 14.8 million Common Shares to acquire all of the issued and outstanding shares of Kick for $283.3 million.

On February 21, 2006, the Company issued 4.1 million Common Shares to acquire all of the issued and outstanding shares of White Fire for $95.5 million.

On February 22, 2006, Highpine issued 4.3 million Common Shares at a price of $23.40 per share for gross proceeds totalling $100.6 million. Costs associated with the issuance of the Common Shares totalled $4.3 million resulting in net proceeds of $96.3 million.

Outstanding Common Shares

As at March 12, 2007, the Company had 67.7 million Common Shares outstanding and had granted options to optionees to acquire a further 4.5 million Common Shares with an average exercise price of $15.31 per share.

Fourth Quarter Review

Highpine increased its average production to 13,690 boe/d in the fourth quarter of 2006 from 8,549 boe/d in the fourth quarter of 2005. The increase in production is attributable to the White Fire and Kick acquisitions as well as the Company's drilling programs.

Highpine incurred $72.8 million of capital expenditures in the fourth quarter of 2006 compared to $50.8 million in the fourth quarter of 2005. Capital expenditures were focused on the Company's drilling programs and tie-ins of wells.

Highpine's cash flow per diluted share decreased by 29 percent in the quarter as a result of realizing significantly lower commodity prices as well as incurring higher operating costs. Highpine incurred a net loss of $5.4 million in the fourth quarter of 2006 primarily as a result of higher DD&A expense.

Future Accounting Change

Financial Instruments

The Canadian Institute of Chartered Accountants (CICA) has issued new accounting standards, CICA Handbook section 3855, "Financial Instruments Recognition and Measurement," CICA Handbook section 1530, "Comprehensive Income," and CICA Handbook section 3865, "Hedges." The standards deal with the recognition and measurement of financial instruments and comprehensive income. The new standards are effective for fiscal years beginning on or after October 1, 2006. The Company is currently assessing the impact of these standards on its financial statements.

Critical Accounting Estimates

The preparation of the Company's financial statements requires management to adopt accounting policies that involve the use of significant estimates and assumptions. These estimates and assumptions are developed based on the best available information and are believed by management to be reasonable under the circumstances. New events or additional information may result in the revision of these estimates over time.

Depletion, Depreciation and Accretion

Highpine follows CICA accounting guideline AcG-16 on full cost accounting in the oil and natural gas industry to account for oil and natural gas properties. Under this method, all costs associated with the acquisition of, exploration for, and the development of crude oil and natural gas reserves are capitalized and costs associated with production are expensed. The capitalized costs are depleted using the unit-of-production method based on estimated proved reserves using management's best estimate of future prices. Reserves estimates can have a significant impact on earnings, as they are a key component in the calculation of depletion.

Asset Impairment

Producing properties and unproved properties are assessed for impairment annually or as economic events dictate. The cash flows used in the impairment assessment require management to make estimates and assumptions as to recoverable reserves, future commodity prices and operating costs. Changes in any of the estimates or assumptions could result in an impairment of the carrying value of producing properties and unproved properties.

Asset Retirement Obligations

Asset retirement obligations require that management make estimates and assumptions regarding future liabilities and cash flows involving environmental reclamation and remediation. Estimates of future liabilities and cash flows are subject to uncertainty associated with the method of reclamation and remediation, environmental legislation, the timing of reclamation and remediation activities and the cost of reclamation and remediation activities.

Purchase Price Allocation

Business acquisitions are accounted for by the purchase method of accounting. Under this method, the purchase price is allocated to the assets acquired and the liabilities assumed based on the fair value at the time of acquisition. The excess purchase price over the fair value of identifiable assets and liabilities acquired is goodwill. The determination of fair value often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of property, plant and equipment acquired generally require the most judgment and include estimates of reserves acquired, future commodity prices and discount rates. Future net earnings can be affected as a result of changes in future depletion and depreciation, asset impairment or goodwill impairment.

Goodwill Impairment

Goodwill is subject to impairment tests annually, or as economic events dictate, by comparing the fair value of the reporting entity to its carrying value, including goodwill. If the fair value of the reporting entity is less than its carrying value, a goodwill impairment loss is recognized as the excess of the carrying value of the goodwill over the implied value of the goodwill. The determination of fair value requires management to make assumptions and estimates about recoverable reserves, future commodity prices, operating costs, production profiles and discount rates. Changes in any of these assumptions, such as a downward revision in reserves, a decrease in future commodity prices, an increase in operating costs or an increase in discount rates could result in an impairment of all or a portion of the goodwill carrying values in future periods.

Accounting for Stock Options

The Company recognizes compensation expense on options granted pursuant to its stock option plan. Compensation expense is based on the theoretical fair value of each option at its grant date, the estimation of which requires management to make assumptions about the future volatility of the Company's stock price, future interest rates and the timing of optionee's decisions to exercise the options. The effects of a change in one or more of these variables could result in a materially different fair value.

Disclosure Controls

Disclosure controls and procedures have been designed to ensure that information required to be disclosed by the Company is accumulated and communicated to the Company's management as appropriate to allow timely decisions regarding required disclosure. The Company's Chief Executive Officer and Chief Financial Officer have concluded based on their evaluation that the Company's disclosure controls and procedures were operating effectively during 2006 to provide reasonable assurance that material information related to the Company, including its consolidated subsidiaries, is made known to them by others within those entities.

Internal Controls Over Financial Reporting

Internal controls have been designed to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements together with the other financial information for external purposes in accordance with Canadian GAAP. The Company's Chief Executive Officer and Chief Financial Officer have designed or caused to be designed under their supervision internal controls over financial reporting related to the Company, including its consolidated subsidiaries.

The Company's Chief Executive Officer and Chief Financial Officer are required to cause the Company to disclose herein any change in the Company's internal control over financial reporting that occurred during the Company's most recent interim period that materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting. During 2006, the Company engaged external consultants to assist in documenting and assessing the Company's design of internal control over financial reporting. No material changes were identified in the Company's internal control of financial reporting during the three months ended December 31, 2006, that had materially affected, or are reasonably likely to materially affect, the Company's internal control of financial reporting.

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

Business Risks and Uncertainties

Highpine is exposed to numerous risks and uncertainties associated with the exploration for and development, production and acquisition of crude oil, natural gas and NGL. Primary risks include:

- Uncertainty associated with obtaining drilling licences and other consents and approvals;
- Finding and producing reserves economically;
- Production risks associated with sour hydrocarbons;
- Marketing reserves at acceptable prices; and
- Operating with minimal environmental impact.

Highpine strives to minimize and manage these risks in a number of ways, including:

- Employing qualified professional and technical staff;
- Communicating openly with members of the public regarding its activities;
- Concentrating in a limited number of areas;
- Utilizing the latest technology for finding and developing reserves;
- Constructing high-quality, environmentally sensitive, safe production facilities;
- Maximizing operational control of drilling and producing operations; and
- Minimizing commodity price risk through strategic hedging.

Environmental Risks

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. In 2002, the Government of Canada ratified the Kyoto Protocol (the "Protocol"), which calls for Canada to reduce its greenhouse gas emissions to specified levels. There has been much public debate with respect to Canada's ability to meet these targets and the government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Protocol or as otherwise determined could have a material impact on the nature of oil and natural gas operations, including those of the Company. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict either the nature of those requirements or the impact on the Company and its operations and financial condition.

Selected Annual Information

	2006	2005	2004
Financial			
($000s, except per share amounts)			
Total revenue[1]	254,938	141,634	41,025
Net earnings	6,953	12,274	3,177
Per share – basic	0.12	0.35	0.19
Per share – diluted	0.12	0.34	0.19
Cash flow from operations	127,072	74,550	19,773
Per share – basic	2.20	2.13	1.18
Per share – diluted	2.17	2.09	1.16
Corporate acquisitions	379,345	257,314	51,151
Capital expenditures[2]	222,214	153,606	61,133
Long-term debt	138,890	–	–
Total assets	1,392,911	753,690	163,388
Operating			
Average daily production			
Oil and NGL (bbls/d)	7,554	3,984	1,578
Natural gas (mcf/d)	25,350	13,823	6,423
Total (boe/d)	11,779	6,288	2,648

[1] *Total revenue is after realized and unrealized hedging losses and gains.*

[2] *Capital expenditures are net of property dispositions.*

Summary of Quarterly Results

	2006				2005			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Financial								
($000s, except per share amounts)								
Total revenue[1]	67,552	60,205	62,765	64,416	54,229	51,495	21,817	14,093
Net earnings (loss)	(5,446)	514	10,594	1,291	4,855	6,683	(32)	768
Per share – basic	(0.08)	0.01	0.20	0.03	0.11	0.15	(0.00)	0.04
Per share – diluted	(0.08)	0.01	0.20	0.03	0.11	0.15	(0.00)	0.04
Cash flow from operations	29,657	31,165	34,704	31,546	27,957	29,796	9,856	6,941
Per share – basic	0.44	0.50	0.66	0.66	0.63	0.67	0.31	0.32
Per share – diluted	0.44	0.49	0.65	0.65	0.62	0.65	0.31	0.32
Corporate acquisitions	–	289,694	–	89,651	–	–	257,314	–
Capital expenditures[2]	72,711	56,144	46,590	46,769	50,861	48,149	19,839	34,757
Long-term debt	138,890	113,287	–	–	–	–	–	–
Total assets	1,392,911	1,361,249	920,941	910,157	753,690	715,360	677,834	198,599
Operating								
Average daily production								
Oil and NGL (bbls/d)	8,653	6,675	6,940	7,950	5,881	5,562	2,617	1,816
Natural gas (mcf/d)	30,221	24,837	25,562	20,681	16,006	18,277	11,593	9,293
Total (boe/d)	13,690	10,814	11,201	11,397	8,549	8,608	4,549	3,365

(1) *Total revenue is after realized and unrealized hedging losses and gains.*

(2) *Capital expenditures are net of property dispositions.*

Management's Report

Management has prepared the consolidated financial statements in accordance with accounting principles generally accepted in Canada and in accordance with accounting policies detailed in the notes to the financial statements. If alternative policies exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise since they include certain amounts based on informed estimates and judgments. Management has ensured that the consolidated financial statements are presented fairly in all material respects. Management has also prepared the financial information presented in this annual report and ensured that it is consistent with that presented in the financial statements.

Management has designed internal controls over the financial reporting process to provide reasonable assurance that relevant and reliable information is produced.

The Board of Directors is responsible for reviewing and approving the consolidated financial statements and financial information in the annual report. Their financial statement related responsibilities are fulfilled mainly through the Audit Committee. The Audit Committee is appointed by the Board of Directors and is composed entirely of independent directors. The Audit Committee meets regularly with management and with the external auditors to discuss internal controls over the financial reporting process and financial reporting issues and to ensure that management's responsibilities are properly discharged. The Audit Committee also considers, for review by the Board and approval by shareholders, the engagement or reappointment of external auditors.

KPMG LLP, the external auditor, has audited the consolidated financial statements in accordance with the auditing standards generally accepted in Canada on behalf of the shareholders. KPMG LLP has full and free access to the Audit Committee.

[Signed] "A. Gordon Stollery"

A. Gordon Stollery
Chief Executive Officer

[Signed] "Harry D. Cupric"

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

Calgary, Canada
March 12, 2007

Auditors' Report

Auditors' Report to the Shareholders

We have audited the consolidated balance sheets of Highpine Oil & Gas Limited as at December 31, 2006 and 2005 and the consolidated statements of earnings and retained earnings and cash flows for the years then ended. 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, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Chartered Accountants

[Signed] "KPMG LPP"

Calgary, Canada
March 12, 2007

Consolidated Balance Sheets

As at December 31 ($000s)	2006	2005
Assets		
Current assets		
Accounts receivable	54,944	40,716
Prepaid expenses and deposits	2,928	1,795
Financial instruments (note 10)	3,194	763
	61,066	43,274
Property, plant and equipment (note 4)	972,599	493,330
Long-term investment, at cost (note 5)	1,150	1,000
Deferred charges	–	251
Goodwill (note 3)	358,096	215,835
	1,392,911	753,690
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	88,552	47,403
Bank indebtedness	–	104,707
	88,552	152,110
Long-term debt (note 6)	138,890	–
Future income taxes (note 11)	151,802	84,167
Asset retirement obligations (note 7)	11,258	5,898
Deferred lease inducements	408	492
Shareholders' equity		
Share capital (note 8)	957,186	479,496
Contributed surplus (note 8)	9,962	3,627
Retained earnings	34,853	27,900
	1,002,001	511,023
Commitments (note 9)		
	1,392,911	753,690

See accompanying notes to the consolidated financial statements.

On behalf of the Board:

[Signed] "Hank Swartout"

Hank Swartout
Director

[Signed] "John Brussa"

John Brussa
Director

Consolidated Statements of Earnings and Retained Earnings

($000s, except per share amounts)	Year Ended December 31, 2006	2005
Revenues		
Oil and natural gas revenues	247,804	147,303
Royalties, net of ARTC	(70,529)	(38,995)
Financial instruments		
Realized gains (losses)	4,703	(6,613)
Unrealized gains	2,431	944
	184,409	102,639
Interest and other income	85	7
	184,494	102,646
Expenses		
Operating costs	36,839	14,575
Transportation costs	3,069	2,439
General and administrative	9,682	5,777
Depletion, depreciation and accretion	125,306	53,893
Interest and finance costs	5,076	3,631
Stock-based compensation (note 8)	5,677	3,151
	185,649	83,466
Earnings (loss) before taxes	(1,155)	19,180
Taxes (reduction)		
Current	(127)	723
Future (note 11)	(7,981)	6,183
	(8,108)	6,906
Net earnings	6,953	12,274
Retained earnings, beginning of year	27,900	23,992
Stock dividend and adjustment (note 8)	–	(8,366)
Retained earnings, end of year	34,853	27,900
Net earnings per share (note 8)		
Basic	$0.12	$0.35
Diluted	$0.12	$0.34

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Cash Flows

($000s)	Year Ended December 31, 2006	2005
Cash provided by (used in):		
Operating Activities		
Net earnings	6,953	12,274
Items not involving cash:		
Depletion, depreciation and accretion	125,306	53,893
Future income taxes (reduction)	(7,981)	6,183
Stock-based compensation	5,677	3,151
Unrealized (gains) on financial instruments	(2,431)	(944)
Abandonment expenditures	(368)	–
Amortization of deferred lease inducements	(84)	(7)
	127,072	74,550
Change in non-cash operating working capital	(18,018)	(18,017)
	109,054	56,533
Financing Activities		
Common shares issued for cash	100,620	72,000
Share issue costs	(4,606)	(4,811)
Proceeds on exercise of stock options	1,202	176
Increase in bank debt	4,618	32,857
	101,834	100,222
Investing Activities		
Property, plant and equipment additions	(194,753)	(149,896)
Property acquisitions	(27,461)	(4,119)
Purchase of investments	(150)	–
Net cash paid on business combination (note 3)	(1,091)	(429)
Proceeds on the disposition of property, plant and equipment	–	409
Deferred lease inducements	–	581
Deferred charges	251	(251)
Change in non-cash investing working capital	12,316	(3,050)
	(210,888)	(156,755)
Change in cash	–	–
Cash, beginning of year	–	–
Cash, end of year	–	–
Cash interest paid	4,865	3,070
Cash taxes paid	263	494

See accompanying notes to the consolidated financial statements.

Notes to the Consolidated Financial Statements

Year ended December 31, 2006 and 2005
(tabular amounts in thousands of dollars, unless otherwise noted)

1. Description of Business

Highpine Oil & Gas Limited (the "Company") was incorporated under the laws of the Province of Alberta on April 2, 1998. The Company is engaged in the exploration for, and the development and production of crude oil, natural gas and natural gas liquids in Western Canada.

2. Significant Accounting Policies

a) Principles of consolidation

These consolidated financial statements include the accounts of the Company and its subsidiaries.

b) Property, plant and equipment

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 natural gas reserves are capitalized and accumulated in one cost centre. These costs include lease acquisition costs, geologic and geophysical expenses, carrying charges of unproved properties, costs of drilling and completing wells and oil and natural 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 more than 20 percent, in which case a gain or loss is computed and reflected in the consolidated statement of earnings.

Depletion, depreciation and amortization

Depletion of exploration and development costs and depreciation of production equipment are provided on the unit-of-production method based upon estimated proved oil and natural gas reserves before royalties in each cost centre 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 unproved properties is 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.

Office furniture, equipment and computers are depreciated on a declining balance basis at 20 percent per year. Leasehold improvements are amortized on a straight line basis over the lease term. Buildings are amortized on a straight line basis over 20 years. Land is not depreciated.

Ceiling test

The Company 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 ceiling test is an impairment test whereby the carrying amount of property, plant and equipment is compared to the sum of the undiscounted cash flows expected from the production of proved reserves and the lower of cost and market of unproved properties. If the carrying amount exceeds the undiscounted cash flows, an impairment loss would be determined by comparing the carrying amount to the sum of the net present value of future pre-tax cash flows from proved plus probable reserves and the lower of cost or market value of the Company's unproved properties. The impairment loss would be recorded in earnings.

c) Asset retirement obligations

The Company recognizes the fair value of an Asset Retirement Obligation (ARO) in the period in which it is incurred. The fair value of the estimated ARO is recorded as a liability on a discounted basis, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted using 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 earnings in the period. Actual costs incurred upon the settlement of the ARO are charged against the ARO.

d) Goodwill

The Company records goodwill 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 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.

e) Revenue recognition

Revenues from the sale of crude oil, natural gas and natural gas liquids are recorded when title passes to the customer.

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) Financial instruments

The Company may enter into derivative instrument contracts to manage its commodity price exposure. The Company does not enter into derivative instrument contracts for trading or speculative purposes. When the Company enters into a hedge, it formally assesses both at the hedge's inception and on an ongoing basis whether the hedge is highly effective in offsetting charges in cash flows of the hedged item. Financial instruments that are considered highly effective are not recognized on the balance sheet and realized gains and losses are recognized in revenues in the same period in which the revenues associated with the hedged transactions are recorded. Financial instruments that do not qualify as effective hedges for accounting purposes or were not designated as effective hedges at inception are recorded on a mark-to-market basis with the resulting gains or losses taken into earnings.

h) Future income taxes

The Company follows 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 a change in rates on future income tax liabilities and assets is recognized in the period in which the change occurs.

i) Stock-based compensation plans

The Company has a stock option plan. The Company records compensation expense using the fair value method. Under the fair value method, a compensation cost is measured at fair value 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 received together with the amount previously recorded in contributed surplus is recorded as an increase to share capital.

The Company has a deferred share unit plan. The Company accrues a liability equal to the closing price of the Company's class A common shares (Common Shares) for each unit issued under the plan.

j) 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. A future tax liability is recognized upon the renunciation of tax pools and share capital is reduced by a corresponding amount.

k) 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.

l) Earnings per share

Basic earnings per Common Share are computed by dividing earnings by the weighted average number of Common Shares outstanding for the period. Diluted per share amounts reflect the potential dilution that could occur if securities or other contracts to issue Common Shares were exercised or converted to Common Shares. The treasury stock method is used to determine the dilutive effect of stock options and other dilutive instruments. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options are used to repurchase Common Shares at the average market price for the reporting period.

m) Joint interests

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.

n) Measurement uncertainty

The amounts recorded for the depletion and depreciation of oil 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 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.

o) Deferred lease Inducements

Deferred lease inducements are accounted for as a reduction of rent expense over the term of the lease.

3. Acquisitions

On August 1, 2006, Highpine acquired Kick Energy Corporation ("Kick") for consideration of 14.8 million Common Shares at $283.3 million. Kick was a publicly traded oil and natural gas exploration and production company active in the Western Canada Sedimentary Basin. The transaction has been accounted for using the purchase method with the allocation of the purchase price as follows:

Net assets acquired and liabilities assumed		
Property, plant and equipment (including unproved properties totalling $27,092 and seismic totalling $5,477)	$	289,694
Goodwill		106,215
Working capital (deficiency)		(17,680)
Bank indebtedness		(25,095)
Asset retirement obligations		(2,835)
Future income taxes		(66,466)
	$	283,833
Consideration		
Acquisition costs	$	564
Class A common shares issued		283,269
	$	283,833

On February 21, 2006, Highpine acquired White Fire Energy Ltd. ("White Fire") for consideration of 4.1 million Common Shares at $95.5 million. White Fire was a publicly traded oil and natural gas exploration and production company active in the Western Canada Sedimentary Basin. The transaction has been accounted for using the purchase method with the allocation of the purchase price as follows:

Net assets acquired and liabilities assumed		
Property, plant and equipment (including unproved properties totalling $25,800)	$	89,651
Goodwill		36,046
Working capital (deficiency)		(13,810)
Bank indebtedness		(4,470)
Asset retirement obligations		(1,145)
Future income taxes		(10,265)
	$	96,007
Consideration		
Acquisition costs	$	527
Class A common shares issued		95,480
	$	96,007

On May 31, 2005, the Company acquired Vaquero Energy Ltd. ("Vaquero") for consideration of 19.5 million Common Shares at $350.9 million. Vaquero was a publicly traded oil and natural gas exploration and production company active in the Western Canada Sedimentary Basin. The transaction has been accounted for using the purchase method with the allocation of the purchase price as follows:

Net assets acquired and liabilities assumed		
Property, plant and equipment (including unproved properties totalling $78,657)	$	257,314
Goodwill		201,754
Working capital (deficiency)		(11,062)
Bank indebtedness		(37,028)
Asset retirement obligations		(1,903)
Financial instruments		(181)
Future income taxes		(57,569)
	$	351,325
Consideration		
Acquisition costs	$	429
Class A common shares issued		350,896
	$	351,325

4. Property, Plant and Equipment

2006	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties	$ 1,169,995	$ 200,211	$ 969,784
Land, buildings and leaseholds	2,389	219	2,170
Office equipment and computers	1,002	357	645
	$ 1,173,386	$ 200,787	$ 972,599

2005			
Petroleum and natural gas properties	$ 566,538	$ 75,869	$ 490,669
Land, buildings and leaseholds	2,358	41	2,317
Office equipment and computers	594	250	344
	$ 569,490	$ 76,160	$ 493,330

At December 31, 2006, approximately $152.2 million (December 31, 2005 – $112.4 million) of unproved property costs and unevaluated seismic costs were excluded from the depletion calculation. Future development costs of $56.4 million (December 31, 2005 – $13.3 million) were included in the depletion calculation. Salvage value of $23.9 million (December 31, 2005 – $nil) was excluded from the depletion calculation. During the year ended December 31, 2006, general and administrative expenses of $4.1 million (year ended December 31, 2005 – $1.4 million) were capitalized, including stock-based compensation of $0.9 million.

The Company performed a ceiling test at December 31, 2006 to assess the recoverable value of property, plant and equipment and other assets. The future oil and natural gas prices are based on the commodity price forecast of the Company's 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.

	Oil ($/bbl)	Natural Gas ($/mcf)	Condensate ($/bbl)	NGLs ($/bbl)
2007	63.88	7.77	61.76	47.85
2008	62.84	8.41	60.69	46.97
2009	62.76	8.37	60.65	46.94
2010	60.50	8.34	58.55	45.30
2011	58.12	8.49	56.48	43.68
2012 and thereafter	61.70	9.23	61.13	47.68
Prices after 2011 escalate at approximately 1% to 2% per annum				

5. Long-Term Investment

At December 31, 2006 the Company's long-term investment of $1.2 million was comprised of 1,080,000 common shares of In Depth Resources Ltd., a privately held oil and natural gas company in which the Chairman of the Company is a director. The investment represents approximately 10 percent of the outstanding common shares of In Depth Resources Ltd. The Company has a right of first refusal to participate in certain prospects generated by In Depth Resources Ltd.

6. Long-Term Debt

At December 31, 2006, the Company had available a $205 million revolving term credit facility with a syndicate of Canadian financial institutions and a $20 million demand operating credit facility with its primary financial institution.

The revolving term credit facility has a 364-day extendable revolving period plus a one-year maturity. The term date of the revolving term credit facility is May 29, 2007. In the event that the term date of May 29, 2007 is not extended, the balance under the facility will be repayable on May 28, 2008. The revolving term credit facility bears interest within a range of the lenders' prime rate to prime plus 0.25 percent depending on financial ratios of the Company. The demand operating facility bears interest at the lenders' prime rate.

The lenders review the credit facilities semi-annually. The facilities are secured by a general security agreement and a first floating charge over all of the Company's assets.

Interest expense for 2006 includes $5.0 million (2005 – $3.6 million) in respect of debt initially incurred for a period exceeding one year.

7. Asset Retirement Obligations

At December 31, 2006, the estimated total undiscounted cash flows required to settle asset retirement obligations were $17.9 million (December 31, 2005 – $10.0 million). Expenditures to settle asset retirement obligations will be incurred between 2007 and 2027. Estimated cash flows have been discounted using an annual credit-adjusted risk-free interest rate of 8.0 percent per annum and have been inflated using an inflation rate of 2.0 percent per annum.

Changes to asset retirement obligations were as follows:

	Year ended December 31,	
	2006	2005
Asset retirement obligations, beginning of year	5,898	1,974
Liabilities acquired	3,980	1,903
Liabilities incurred	1,069	1,694
Liabilities settled	(368)	–
Accretion expense	679	327
Asset retirement obligations, end of year	11,258	5,898

8. Share Capital

(a) Authorized:

(i) an unlimited number of Class A common shares without par value; and

(ii) an unlimited number of Class B common shares without par value issuable in series. The Class B common shares are non-voting and are not entitled to the receipt of dividends.

	Year Ended December 31, 2006		Year Ended December 31, 2005	
	Shares (thousands)	Amount ($thousands)	Shares (thousands)	Amount ($thousands)
Class A common shares:				
Balance, beginning of year	44,250	479,496	15,208	24,247
Issued to acquire Vaquero (note 3)	–	–	19,494	350,896
Issued to acquire White Fire (note 3)	4,089	95,480	–	–
Issued to acquire Kick (note 3)	14,831	283,269	–	–
Issued for cash	4,300	100,620	4,000	72,000
Conversion of Class B shares	–	–	1,271	1
Special warrants exercised	–	–	3,300	28,582
Stock dividend and adjustment	–	–	930	8,366
Flow-through shares renounced	–	–	–	(1,613)
Stock options exercised	178	1,202	47	176
Contributed surplus transferred on exercise of stock options	–	225	–	35
Share issue costs less tax effect of (2006 – $1,500; 2005 – $1,617)	–	(3,106)	–	(3,194)
Balance, end of year	67,648	957,186	44,250	479,496
Class B common shares:				
Balance, beginning of year	–	–	1,271	1
Conversion of class B shares	–	–	(1,271)	(1)
Balance, end of year	–	–	–	–
Special warrants:				
Balance, beginning of year	–	–	3,300	28,582
Exercised	–	–	(3,300)	(28,582)
Balance, end of year	–	–	–	–
Total		957,186		479,496

On August 1, 2006, the Company issued 14.8 million Common Shares to acquire all of the issued and outstanding shares of Kick for $283.3 million.

On February 21, 2006, the Company issued 4.1 million Common Shares to acquire all of the issued and outstanding shares of White Fire for $95.5 million.

On February 22, 2006, the Company issued 4.3 million Common Shares at a price of $23.40 per share for gross proceeds totalling $100.6 million. Costs associated with the issuance of the Common Shares totalled $4.3 million resulting in net proceeds of $96.3 million.

On May 31, 2005, the Company issued 19.5 million Common Shares to acquire all of the issued and outstanding shares of Vaquero.

On April 5, 2005, 4.0 million Common Shares of the Company were issued pursuant to the Company's initial public offering. Costs associated with the initial public offering totalled approximately $4.8 million.

On March 31, 2005, 3.5 million Common Shares of the Company were issued upon the exercise of the special warrants.

On February 15, 2005, the Company declared a stock dividend in the amount of $7.0 million which resulted in 0.047 of a Common Share being issued for each issued and outstanding Common Share. In accordance with the terms of the issued and outstanding special warrants of the Company the stock dividend resulted in an additional 0.2 million Common Shares being issuable upon exercise of the outstanding special warrants.

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 Common Shares on February 4, 2005.

Per Share Amounts

	Year Ended December 31,	
	2006 (thousands)	2005 (thousands)
Weighted average number of Common Shares outstanding		
Basic	57,744	35,051
Dilutive effect of stock options	930	667
Diluted	58,674	35,718

Anti-dilutive options excluded from the calculation of diluted earnings per share in 2006 were 3.2 million (2005 – 232,000).

Stock Options

The Company has a stock option plan pursuant to which options to purchase Common Shares of the Company may be granted to directors, officers, employees and consultants. The outstanding stock options of the Company are exercisable for a period of six years and vest over a period of four years.

A summary of changes is as follows:

	Year Ended December 31, 2006		Year Ended December 31, 2005	
	Common Shares Issuable Upon Exercise of Options (thousands)	Weighted Average Exercise Price ($/share)	Common Shares Issuable Upon Exercise of Options (thousands)	Weighted Average Exercise Price ($/share)
Balance, beginning of year	3,652	13.06	1,542	5.26
Granted	2,016	20.42	2,308	18.96
Exercised	(178)	(6.75)	(47)	(3.89)
Cancelled	(413)	(18.06)	(224)	(17.00)
Stock dividend adjustment	–	–	73	–
Balance, end of year	5,077	15.80	3,652	13.06
Exercisable, end of year	1,271	9.44	556	4.33

Details of the exercise prices and expiry dates of options outstanding at December 31, 2006 are as follows:

	Options Outstanding			Options Exercisable	
Range of exercise price	Common Shares Issuable (thousands)	Weighted Average Years to Expiry (years)	Weighted Average Exercise Price ($/share)	Common Shares Issuable (thousands)	Weighted Average Exercise Price ($/share)
$2.60 – $5.00	1,023	2.74	$ 3.68	676	$ 3.43
$8.10 – $14.00	463	4.00	$ 10.32	191	$ 9.55
$16.35 – $23.25	3,591	4.97	$ 19.96	404	$ 19.43
	5,077	4.43	$ 15.80	1,271	$ 9.44

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

	2006	2005
Weighted average expected volatility (%)	34	45
Risk-free rate of return (%)	4.9	4.5
Expected option life (years)	4	4
Weighted average fair value ($/share)	7.39	7.43

The Company does not anticipate paying any dividends during the expected life of the options.

Contributed Surplus

	Year Ended December 31, 2006	2005
Balance, beginning of year	3,627	511
Stock-based compensation expense, net of recovery	5,677	3,151
Capitalized stock-based compensation expense	883	–
Transferred to share capital on exercise of stock options	(225)	(35)
Balance, end of year	9,962	3,627

Deferred Share Units Plan

In 2006, the Company implemented a deferred share unit (DSU) plan for outside directors. Under the terms of the plan, DSUs awarded will vest immediately and will be settled with cash in the amount equal to the closing price of the Company's Common Shares on the date the director specifies upon tendering his or her resignation from the Board.

The Company has recorded $137,000 of expense in the year relating to DSUs and there are 8,800 DSUs outstanding at year-end.

9. Commitments

The Company is committed to operating leases for office space and equipment annually as follows:

2007	1,309
2008	1,247
2009	1,243
2010	1,212
2011	1,212
Thereafter	1,112

10. Financial Instruments

a) Commodity Price Risk Management

The Company uses a variety of derivative instruments to reduce its exposure to fluctuations in commodity prices. The derivative instruments have been accounted for as an asset on the consolidated balance sheets based on their fair value. The following commodity price risk management agreements were in place as at December 31, 2006.

Financial WTI Crude Oil Contracts

Term	Contract	Volume (bbls/d)	Fixed Price ($/bbl)	Unrealized Gain (Loss) As at December 31, 2006 (Cdn $000s)
Jan 07 to Dec 07	Collar	1,750	US$55.00 to $86.15	643
Jan 07 to Dec 07	Collar	1,750	US$60.00 to $80.70	1,206
Jan 07 to Dec 07	Swap	500	Cdn$73.00	(419)
Jan 07 to Dec 07	Swap	500	Cdn$73.70	(295)
Jan 07 to Dec 07	Swap	500	Cdn$74.70	(116)
Jan 07 to Dec 07	Swap	500	Cdn$75.82	83

Financial AECO Natural Gas Contracts

Term	Contract	Volume (GJs/d)	Fixed Price ($/GJ)	Unrealized Gain (Loss) As at December 31, 2006 (Cdn $000s)
Jun 06 to Mar 07	Collar	5,000	Cdn$5.40 to $12.00	36
Jul 06 to Mar 08	Collar	5,000	Cdn$6.00 to $11.10	481
Jan 07 to Dec 07	Swap	2,500	Cdn $7.55	756
Jan 07 to Dec 07	Swap	2,500	Cdn $7.62	819

Subsequent to December 31, 2006, the Company entered into the following financial AECO natural gas contracts:

Term	Contract	Volume (GJs/d)	Fixed Price ($/GJ)
Feb 07 to Mar 08	Swap	1,250	Cdn$7.68
Feb 07 to Mar 08	Swap	1,250	Cdn$7.70

b) Credit Risk

A substantial portion of the Company's accounts receivable are with customers and joint venture partners in the oil and natural gas industry and are subject to normal industry credit risks.

c) Fair Value

The carrying values of the Company's financial assets and liabilities, with the exception of the Company's long-term investment (note 5), approximated their fair values as at December 31, 2006 and 2005. The fair value of the Company's long-term investment was considered undeterminable due to the inability to apply a valuation method or obtain market prices.

d) Interest Rate Risk

The Company is exposed to interest rate risk on debt instruments to the extent of changes in the prime rate.

e) Foreign Currency Exchange Risk

The Company is exposed to foreign currency fluctuations as crude oil and natural gas prices received are referenced to U.S. dollar-denominated prices.

11. Income 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 34.50 percent (2005 – 37.62 percent) to earnings (loss) before taxes. The difference results from the following:

	2006	2005
Statutory income tax rate	34.50%	37.62%
Computed expected income taxes (reduction)	$ (397)	$ 7,216
Add (deduct)		
Non-deductible Crown payments, net of Alberta Royalty Tax Credits	4	5,326
Resource allowance	(222)	(4,466)
Large corporation tax	(127)	723
Stock-based compensation	1,958	1,185
Effect of change in tax rate and other	(9,324)	(3,078)
	$ (8,108)	$ 6,906

The components of the future income tax liability at December 31, 2006 and 2005 are as follows:

	2006	2005
Property, plant and equipment	$ 133,018	$ 68,203
Partnership deferral	39,770	28,182
Asset retirement obligations	(3,419)	(1,983)
Attributed royalty income deductible for provincial taxes	(3,678)	(2,074)
Share issue costs	(2,710)	(2,758)
Loss carryforward	(12,186)	(5,700)
Financial instruments	970	257
Long-term investments	37	40
Future income tax liability	$ 151,802	$ 84,167

The provision for future income taxes for the year ended December 31, 2006 was reduced by $9.1 million due to the substantively enacted reduction in Canadian federal and Alberta provincial corporate income tax rates. The reduction was recorded in the second quarter of 2006.

12. Comparative Balances

Certain of the comparative balances have been reclassified to conform to the current year's presentation.

	Years ended December 31				
	2006	2005	2004	2003	2002
Financial Information					
($ thousands, except per share amount)					
Total revenue	254,938	141,634	41,025	16,926	6,647
Net earnings	6,953	12,274	3,177	19,108	1,017
Per share – basic	$0.12	$0.35	$0.19	$1.26	$0.08
Per share – diluted	$0.12	$0.34	$0.19	$1.25	$0.08
Cash flow from operations	127,072	74,550	19,773	11,616	3,130
Per share – basic	$2.20	$2.13	$1.18	$0.77	$0.24
Per share – diluted	$2.17	$2.09	$1.16	$0.76	$0.24
Capital expenditures, net of dispositions	222,214	153,606	61,133	24,651	11,268
Corporate acquisitions	379,345	257,314	51,151	–	–
Property, plant and equipment, net	972,599	493,330	134,282	36,240	17,362
Total assets	1,392,911	753,690	163,388	44,041	23,697
Net debt	169,570	109,599	49,637	(5,257)	634
Shareholders' equity	1,002,001	511,023	77,333	34,385	15,086
Share Information					
(share numbers in thousands)					
Common shares outstanding	67,648	44,250	19,779	14,466	14,549
Weighted diluted average shares outstanding	58,674	35,718	17,036	14,563	13,082
Trading Information					
Trading volume	44,067	26,445	N/A	N/A	N/A
Share price ($/share)					
High	$24.75	$24.75	N/A	N/A	N/A
Low	$15.00	$16.60	N/A	N/A	N/A
Close	$15.70	$20.70	N/A	N/A	N/A
Operating Information					
Production					
Crude oil and NGL (bbls/d)	7,554	3,984	1,578	443	301
Natural gas (mcf/d)	25,350	13,823	6,423	4,281	1,809
Total oil equivalent (boe/d)	11,779	6,288	2,648	1,157	603
Operating netback ($/boe)	33.05	36.90	25.75	27.30	17.52

John A. Brussa[2]
Partner
Burnet, Duckworth & Palmer, LLP
Mr. Brussa is senior tax partner of Burnet, Duckworth & Palmer and is on the boards of numerous publicly traded energy companies.

Richard G. Carl[3]
President and Chief Operating Officer
AGS Capital Corp.
Mr. Carl has been President and Chief Operating Officer of AGS Capital Corp. since May 15, 2006. He previously served as Special Advisor to TerraNova Partners L.P. from January 1, 2006 to May 15, 2006.

Timothy T. Hunt[3]
Independent Businessman
Mr. Hunt has been an independent businessman since August 1, 2006. He was previously President and Chief Executive Officer of Kick Energy Corporation.

W. Andrew Krusen, Jr.[1][3]
Chairman and Chief Executive Officer
DFG Management Inc.
Mr. Krusen is Chairman, President and Chief Executive Officer of Dominion Financial Group Inc.

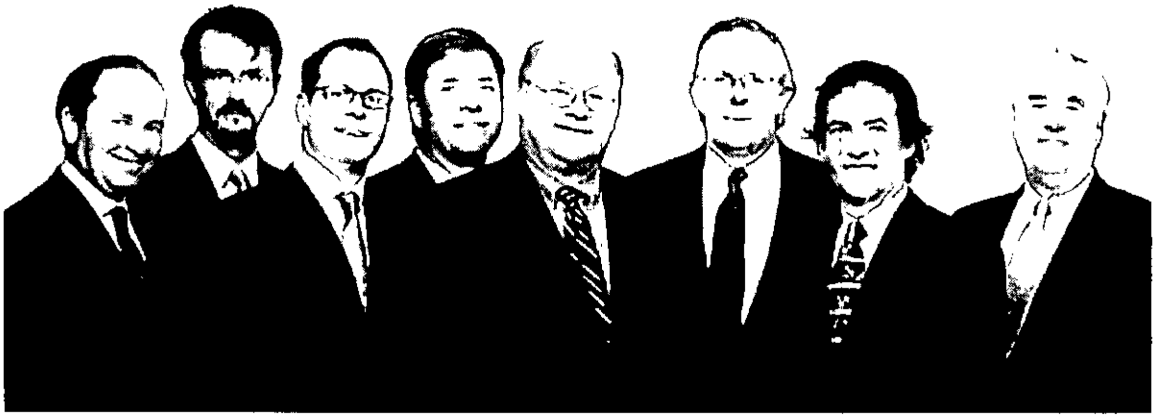
A. Gordon Stollery, P. Eng.
Chairman and Chief Executive Officer
Highpine Oil & Gas Limited
Mr. Stollery is Chairman and Chief Executive Officer of Highpine Oil & Gas Limited. He was formerly Chairman, Chief Executive Officer and President of Morrison Petroleum Ltd.

Hank B. Swartout[1][2]
Executive Chairman
Precision Drilling Corporation
Mr. Swartout was appointed Executive Chairman of Precision Drilling Trust on January 1, 2007. He previously served as Chairman, President and Chief Executive Officer of Precision Drilling Corporation.

Ken S. Woolner[1][2][3]
Chairman
Oban Energy Ltd.
Mr. Woolner has been an independent businessman since February 21, 2006. He served as Executive Chairman of White Fire Energy Ltd. since April 2005.

(1) Member of the Audit Committee
(2) Member of the Compensation, Nominating and Corporate Governance Committee
(3) Member of the Reserves Committee

Left to right: Richard G. Carl, Ken S. Woolner, Fred D. Davidson (Corporate Secretary), Hank B. Swartout, A. Gordon Stollery, John A. Brussa, Timothy T. Hunt and W. Andrew Krusen, Jr.



Executive Officers

A. Gordon Stollery, P. Eng.
Chairman & CEO

Greg N. Baum, P. Eng.
President & COO

Charles L. Buckley, P. Geol.
Senior Vice President, Exploration

Harry D. Cupric, CA
Vice President, Finance & CFO

Robert B. Fryk, P. Eng.
Senior Vice President, Engineering

Wayne Gray, P. Land
Vice President, Land

Dave Humphreys, R.E.T.
Vice President, Operations

Robert W. Rosine, P. Eng.
Executive Vice President, Corporate Development

Fred D. Davidson, LL.B
Corporate Secretary

Evaluation Engineers

Paddock, Lindstrom & Associates Ltd.
Calgary, AB

Registrar and Transfer Agent

Valiant Trust Company
Calgary, AB

Stock Listing

Toronto Stock Exchange: HPX

Bankers

Royal Bank of Canada
Calgary, AB
Bank of Montreal
Calgary, AB
ATB Financial
Calgary, AB

Auditors

KPMG, LLP
Calgary, AB

Legal Counsel

Burnet, Duckworth & Palmer, LLP
Calgary, AB

Corporate Head Office

Suite 4000, 150-6th Avenue S.W.
Calgary, Alberta T2P 3Y7
Tel: (403) 265-3333
Fax: (403) 265-3362
Email: info@highpineog.com
Website: www.highpineog.com

Drayton Valley Office

5459A-55 Street
Drayton Valley, Alberta T7A 1S4
Tel: (780) 621-3383
Fax: (780) 621-3936
Email: info@highpineog.com
Website: www.highpineog.com

Abbreviations

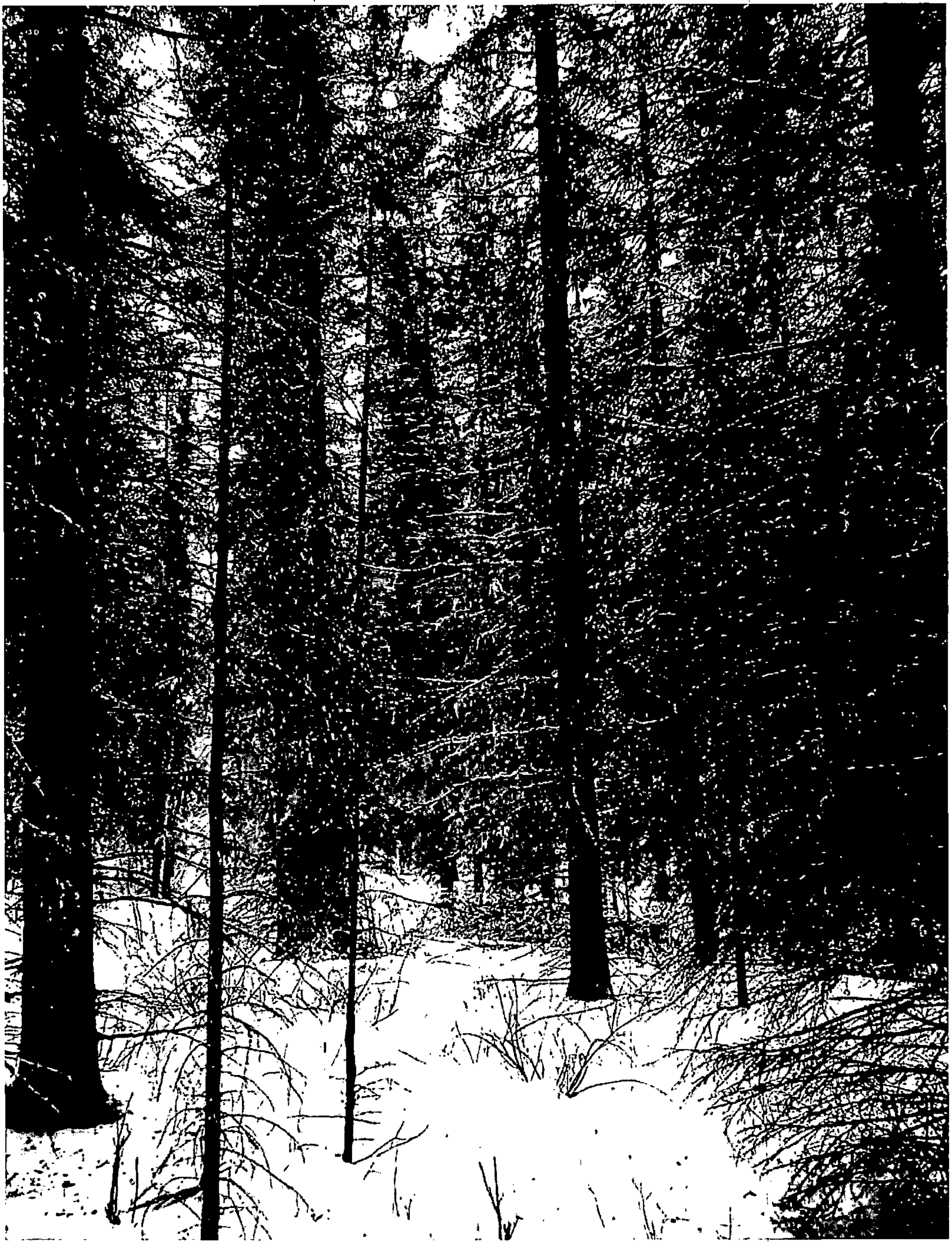
WTI	West Texas Intermediate
API	American Petroleum Institute
bbl	one stock tank barrel
mbbl	thousand barrels
bbls/d	barrels per day
boe*	barrels of oil equivalent
mboe	thousand barrels of oil equivalent
boe/d	barrels of oil equivalent per day
NGL	natural gas liquids
mcf	thousand standard cubic feet
mmcf	million standard cubic feet
bcf	billion standard cubic feet
mcf/d	thousand standard cubic feet per day
mmcf/d	million standard cubic feet per day
GJ	gigajoule
GJs/d	gigajoules per day
ARTC	Alberta Royalty Tax Credit

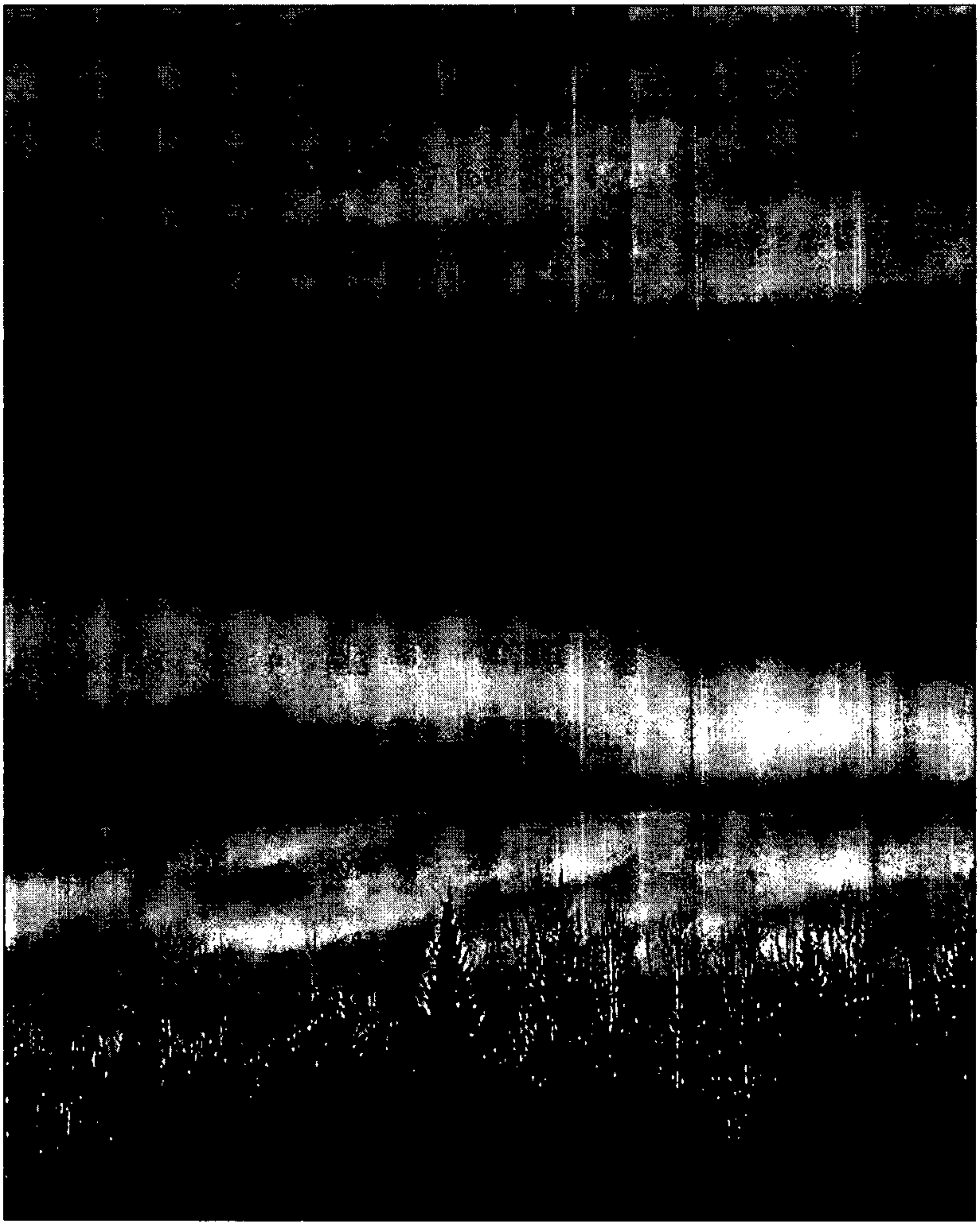
** Barrels of Oil Equivalent*
A barrel of oil equivalent (boe), is derived by converting natural gas to oil in the ratio of six thousand cubic feet of gas to one barrel of oil. This may be misleading, particularly if used in isolation.
A boe conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Annual General Meeting

The annual general meeting of the securityholders of Highpine Oil & Gas Limited will be held on May 9, 2007 at 10:00 am M.D.T. in the Grand Lecture Hall at The Metropolitan Centre, 333 Fourth Ave. S.W., Calgary, Alberta. All securityholders are encouraged to attend. Those unable to attend should sign and return the proxy form as soon as possible.

DESIGNED AND PRODUCED BY MERLIN EDGE INC. WWW.MERLINEDGE.COM PRINTED IN CANADA





HIGHPINE
OIL & GAS LIMITED

Suite 4000, 150-6th Avenue S.W.
Calgary, Alberta T2P 3Y7
Tel: 403-265-3333
Fax: 403-265-3362
info@highpineog.com
www.highpineog.com

082-34869

HIGHPINE
OIL & GAS LIMITED

ANNUAL INFORMATION FORM

for the year ended December 31, 2006

March 30, 2007

TABLE OF CONTENTS

	Page
CONVENTIONS	2
SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS	2
CORPORATE STRUCTURE	4
GENERAL DEVELOPMENT OF THE BUSINESS	5
DESCRIPTION OF THE BUSINESS	6
DESCRIPTION OF PRINCIPAL PROPERTIES	9
STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION	12
INDUSTRY CONDITIONS	25
RISK FACTORS	31
DIVIDENDS	38
DESCRIPTION OF CAPITAL STRUCTURE	38
MARKET FOR SECURITIES	38
PRIOR SALES	39
ESCROWED SECURITIES	39
DIRECTORS AND EXECUTIVE OFFICERS	39
LEGAL PROCEEDINGS	42
INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS	42
TRANSFER AGENT AND REGISTRAR	42
MATERIAL CONTRACTS	42
INTEREST OF EXPERTS	42
AUDIT COMMITTEE INFORMATION	42
ADDITIONAL INFORMATION	47
GLOSSARY OF TERMS	48
ABBREVIATIONS	50
CONVERSION	50

SCHEDULE A – REPORT ON RESERVES DATA BY PADDOCK LINDSTROM & ASSOCIATES LTD. IN ACCORDANCE WITH FORM 51-101F2

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

CONVENTIONS

Certain terms used herein are defined under the heading "Glossary of Terms".

Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars.

Unless the context otherwise requires, references herein to "Highpine" or the "Corporation" include Highpine, Rubicon, Highpine Partnership, Highpine Energy and 665162.

Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

Unless otherwise specified, information in this Annual Information Form is as at the end of the Corporation's most recently completed financial year, being December 31, 2006

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements contained in this Annual Information Form and the documents incorporated by reference herein 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 Annual Information Form and the documents incorporated by reference herein should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form or as of the date specified in the documents incorporated by reference herein.

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

- the performance characteristics of the Corporation's oil and natural gas properties;
- 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;
- availability of rigs, equipment and other goods and services;
- procurement of drilling licenses;
- 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;
- treatment under governmental regulatory regimes and tax laws; and
- realization of the anticipated benefits of acquisitions and dispositions.

The Corporation's actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Annual Information Form and the documents incorporated by reference herein:

- general economic, market and business conditions in Canada, the United States and globally;
- volatility in market prices for oil and natural gas;
- risks inherent in oil and natural gas operations, including production risks associated with sour hydrocarbons;
- operational dependence on other companies;

- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands, skilled personnel and services;
- unanticipated operating events which can reduce production or cause production to be shut in or delayed;
- 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;
- failure to obtain industry partner and other third party consents and approvals, when required; and
- the other factors discussed under "Risk Factors" in this Annual Information Form.

Statements relating to "reserves" or "resources" are by their nature forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described can be profitably produced in the future. 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.

CORPORATE STRUCTURE

Name, Address and Incorporation

Highpine Oil & Gas Limited

Head Office:
Suite 4000, 150 – 6th Avenue S.W.
Calgary, Alberta T2P 3Y7

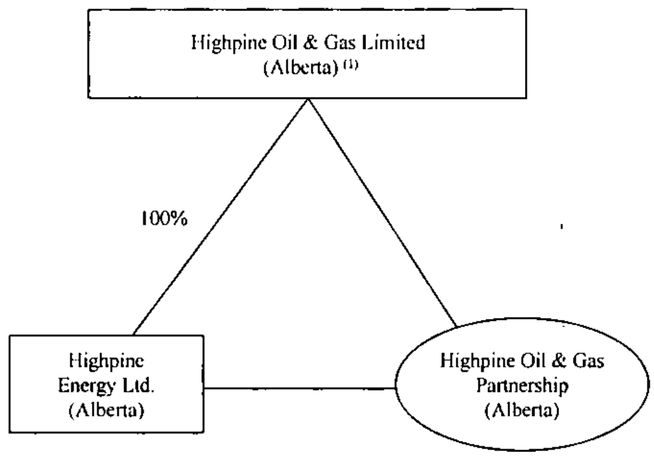
Registered Office:
Suite 1400, 350 – 7th Avenue S.W.
Calgary, Alberta T2P 3N9

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 Annual Information Form of the share capital of Highpine is presented after giving effect to the foregoing amendments to the Articles of Highpine.

Intercorporate Relationships

Highpine has two wholly-owned subsidiaries, Highpine Energy and 665162. Highpine Energy was incorporated under the ABCA on May 5, 1995 and on January 1, 2007 was amalgamated pursuant to the ABCA with Highpine's wholly-owned subsidiaries, Highpine Asset Corporation, Pino Alto Energy II Ltd., White Fire and Kick. 665162 was incorporated under the *Business Corporations Act* (British Columbia) on March 4, 2003. Highpine also owns 50% of the issued and outstanding common shares of 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 Highpine Energy. Substantially all of Highpine's producing assets have been contributed to Highpine Partnership with the exception of Highpine's Joffre area properties, which are held by Highpine, and certain Pembina area properties, which are held by Highpine and Highpine Energy. 665162 and Rubicon are inactive subsidiaries in which the total assets of each of 665162 and Rubicon on an individual basis do not exceed 10% of the consolidated assets of the Corporation.

The following diagram illustrates the corporate structure of the Corporation, the percentage of voting securities owned and the jurisdiction of incorporation or formation of Highpine and its subsidiaries as at the date of the Annual Information Form.



Notes:

(1) Highpine directly and indirectly owns 100% of Highpine Partnership.

(2) Highpine has two inactive subsidiaries, 100% owned 665162 and 50% owned Rubicon.

GENERAL DEVELOPMENT OF THE BUSINESS

Historical Development of the Business

The following is a summary of the development of Highpine's business over the last three completed financial years.

March 2004 – Highpine indirectly acquired an undivided 50% interest in all of the assets and liabilities of Rubicon for approximately $51 million.

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 80% interest. Construction of the Violet Grove Battery was completed and commissioned in May 2005.

April 2005 – Highpine completed the Initial Public Offering on April 5, 2005. Upon completion of the Initial Public Offering, Highpine's Common Shares were listed and posted for trading on the TSX under the symbol "HPX". The net proceeds of the Initial Public Offering were used to temporarily reduce bank indebtedness and to fund the Corporation's exploration and development activities, and for general working capital purposes.

May 2005 – Highpine acquired all of the issued and outstanding common shares of Vaquero pursuant to the Vaquero Arrangement. See "General Development of the Business – Significant Acquisitions and Recent Developments".

February 2006 – Highpine acquired all of the issued and outstanding common shares of White Fire pursuant to the White Fire Arrangement. See "General Development of the Business – Significant Acquisitions and Recent Developments".

February 2006 – Highpine completed a public offering of 4,300,000 Common Shares at a price of $23.40 per share for gross proceeds of $100.62 million.

August 2006 – Highpine acquired all of the issued and outstanding common shares of Kick pursuant to the Kick Arrangement. See "General Development of the Business – Significant Acquisitions and Recent Developments".

Significant Acquisitions and Recent Developments

Vaquero Arrangement

On May 31, 2005 Highpine acquired all of the issued and outstanding common shares of Vaquero pursuant to the Vaquero Arrangement for consideration of $399.4 million comprised of 19.5 million Common Shares with an ascribed value of $350.9 million, the assumption of bank debt and working capital deficiency of $48.1 million and acquisition costs of $0.4 million. Further information respecting the Vaquero Arrangement is contained in the business acquisition report of Highpine in the form of the information circular – proxy statement of Vaquero dated April 29, 2005 relating to the annual and special meeting of the securityholders of Vaquero held on May 31, 2005 to approve the Vaquero Arrangement filed with various securities commissions or similar authorities in the provinces of Canada on August 11, 2005.

White Fire Arrangement

On February 21, 2006, Highpine acquired all of the issued and outstanding common shares of White Fire pursuant to the White Fire Arrangement. Highpine issued 4,089,087 Common Shares to former shareholders of White Fire.

Upon completion of the White Fire Arrangement, Mr. Ken Woolner joined the board of directors of Highpine and Mr. Robert Rosine, Mr. Robert Fryk and Mr. Dave Humphreys, senior officers of White Fire, joined the management of Highpine in the following capacities: Robert Rosine – Executive Vice President, Corporate Development, Robert Fryk – Senior Vice President, Engineering and Operations and Dave Humphreys – Vice President, Operations.

Bought Deal Equity Financing

On February 23, 2006, Highpine completed a bought deal equity financing pursuant to which Highpine issued 4,300,000 Common Shares at a price of $23.40 per share for gross proceeds of $100.62 million.

Kick Arrangement

On August 1, 2006, Highpine acquired all of the issued and outstanding common shares of Kick pursuant to the Kick Arrangement. Highpine issued 14,830,840 Common Shares to former shareholders of Kick.

Upon completion of the Kick Arrangement, Mr. Tim Hunt joined the board of directors of Highpine and Mr. Charles Buckley, a senior officer of Kick, joined the management of Highpine as Senior Vice President, Exploration.

Further information respecting the Kick Arrangement is contained in the business acquisition report of Highpine dated August 4, 2006 filed with various securities commissions or similar authorities in the provinces of Canada.

DESCRIPTION OF THE BUSINESS

General

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 is to focus on sustainable and profitable growth in production, cash flow from operations and net asset value. To accomplish this, Highpine's management pursues 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 internally generates exploration, development and exploitation opportunities, starting with thorough detailed regional mapping. Once trends and areas of interests have been established, Highpine accumulates land in core areas 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.
West Central Alberta Gas Fairway:	These assets target liquids-rich natural gas in the Notikewin, Rock Creek, Nordegg, 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.

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 in excess of 300 total locations on lands in which Highpine has a significant working interest and which have been geophysically and geologically evaluated. There are in excess of 100 locations within the Pembina Nisku trend. This inventory represents three to four 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 2006, Highpine's net capital expenditures were $222.2 million, excluding the acquisitions of White Fire and Kick. The Corporation participated in the drilling of 74 gross wells (46.7 net) and realized an overall drilling success rate of 85% on fully evaluated wells. In addition, the acquisitions of White Fire and Kick provided Highpine with significant production, drilling prospects, landholdings and strategic facilities.

Highpine's capital budget for 2007 is approximately $200 million and includes the drilling of approximately 50 to 60 gross wells (42 to 50 net). Of the total budget, approximately $150 million (75%) is allocated for drilling, facilities and well tie-ins in Highpine's Pembina Fairway, including the drilling of approximately 30 to 35 gross (25 to 30 net) wells that target production from the Nisku formation. Approximately $20 million of the capital budget has been allocated for exploration and development activity in the West Central Alberta Gas Fairway and $30 million for unallocated land and seismic purchases. This capital program will be funded through a combination of cash flow and bank debt.

Specialized Skill and Knowledge

Strong Management

Drawing on a collective experience of more than 200 years in the oil and gas business, Highpine's management team has a demonstrated track record of bringing together all of the key components to a successful exploration and production company: strong technical skills; expertise in planning and financial controls; ability to execute on business development opportunities; capital markets expertise; and an entrepreneurial spirit that allows Highpine to effectively identify, evaluate and execute on value-added initiatives. See "Directors and Executive Officers".

Competitive Conditions

Companies operating in the petroleum industry must manage risks which are beyond the direct control of company personnel. Among these risks are those associated with exploration, environmental damage, commodity prices, foreign exchange rates and interest rates.

The oil and natural gas industry is intensely competitive and Highpine will be required to compete with a substantial number of other corporations which may have greater technical or financial resources. With the maturing nature of the Western Canadian Sedimentary Basin, the access to new prospects is becoming more and more competitive and complex. Management believes that Highpine will be able to explore and develop new production and reserves with the objective of increasing its cash flow and reserve base.

Highpine will attempt to enhance its competitive position by operating in areas where its technical personnel are able to reduce some of the risks associated with exploration, production and marketing because they are familiar with the areas of operation.

Cycles

The Corporation's business is generally not cyclical. The exploration and development of oil and natural gas reserves is dependent on access to areas where production is to be conducted. Seasonal weather variation, including freeze-up and break-up affect access in certain circumstances.

Environmental Protection

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Compliance with such legislation can require significant expenditures or result in operational restrictions. 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, all of which might have a significant negative impact on earnings and overall competitiveness. See "Industry Conditions – Environmental Regulation".

Employees

As at December 31, 2006, Highpine had 72 full-time employees and 18 consultants, all of whom were located at its office in Calgary except for 17 full-time employees and 7 consultants that were located at its Drayton Valley field office.

Environmental, Health and Safety Policies

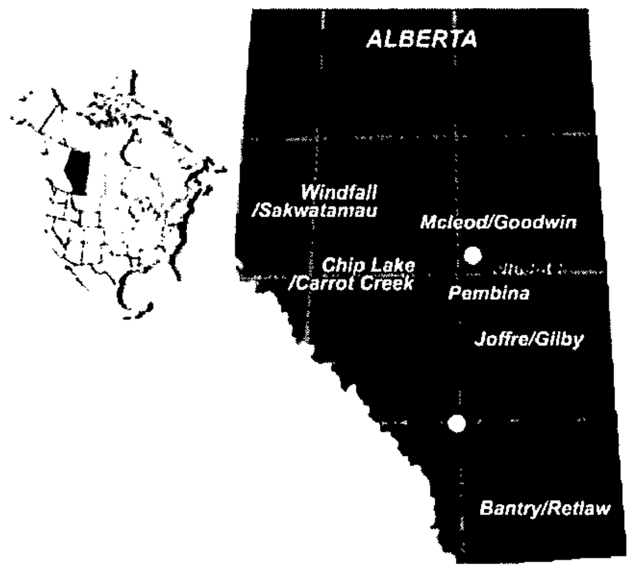
Environmental protection and employee health and safety are core values recognized and supported by the Corporation. The Corporation actively supports these areas by integrating the essential principles and practices through its environmental management systems and employee occupational health and safety programs. The Corporation ensures policies and procedures are fully integrated with and within all operating units by advising and educating employees, suppliers and contractors in the safe use, transportation, storage and disposal of products and materials. The Corporation promotes and enhances safety and environmental awareness and protection through the implementation and communication of the Corporation's environmental management and employee occupational health and safety programs policies and procedures. Effective committee structures are established in the Corporation's operations to allow for employee participation and development of Corporation policies and programs which provide employees with job orientation, training, instruction and supervision necessary to assist them in conducting their activities in an environmentally responsible and safe manner.

The Corporation develops emergency response teams and preparedness plans in conjunction with local authorities, emergency services and the communities it operates in to ensure prompt response to an environmental incident should it arise. Environmental assessments are undertaken for new projects or when acquiring new properties or facilities to identify, assess and minimize environmental risks and operational exposures. The Corporation conducts audits of operations to confirm compliance with internal standards and to stimulate improvement in practices where needed. Accurate documentation is maintained to support internal accountability and measure operational performance against recognized industry indicators to ensure the objectives of the policies and programs are achieved.

The Corporation also faces environmental, health and safety risks in the normal course of its operations due to the handling and storage of hazardous substances. The Corporation's environmental and occupational health and safety management systems are designed to identify, prevent and control such risks in the Corporation's business and ensure immediate action is taken to mitigate the extent of any environmental, health or safety impacts from such operations. A key aspect of these systems is the performance of annual environmental and occupational health and safety audits.

DESCRIPTION OF PRINCIPAL PROPERTIES

The following is a description of Highpine's principal oil and natural gas properties and minor exploration properties as at December 31, 2006. 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, 2006. Reserve amounts are stated (before deduction of royalties) as at December 31, 2006, based on escalating costs and price assumptions and are derived from reserve information contained in the Paddock Report. See "Statement of Reserves Data and Other Oil and Gas Information".



Pembina – Central Alberta

The Pembina property is located in the Drayton Valley area of Alberta approximately 100 kilometres southwest of Edmonton. The Pembina property is Highpine's major property, producing approximately 8,324 BOE/d in 2006, 79% of which is oil and NGLs, and representing approximately 71% of Highpine's total 2006 production volumes. Highpine's property interests in Pembina consist of working interests ranging from 10% to 100% and averaging 60%. The average Highpine working interest production from the property was approximately 14,850 BOE/d for the first ten days of March 2007. Highpine operates 167 wells associated with this property. In addition, Highpine has an average 53% working interest on a combined basis in three 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 with the raw gas sent to gas plants for further processing and the oil is shipped through Pembina Pipelines to market.

The Pembina property consists of 33,440 gross (25,699 net) acres of developed land and 193,302 gross (161,585 net) acres of undeveloped land.

The Paddock Report attributes proved plus probable reserves of 35.8 MMboe to Highpine's working interest in the Pembina area. The Paddock Report attributes proved reserves of 22.6 MMboe to Highpine's working interest in the Pembina 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 120 mile long by 50 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 to 2006.

In May 2005, Highpine acquired Vaquero. Vaquero's assets included working interests in 11 joint Nisku oil pool discoveries, associated infrastructure and several Nisku oil prospects. The acquisition of Vaquero was considered by Highpine management to be complementary to Highpine's position in the trend. See "General Development of the Business – Significant Acquisitions and Recent Developments".

In February 2006, Highpine acquired White Fire. White Fire's assets included production, reserves and lands in Pembina, Ferrier and Karr. In August 2006, Highpine acquired Kick. Kick's assets included production, reserves and lands in the Pembina and Brazeau areas. The acquisition of White Fire and Kick was considered by Highpine management to be complementary to Highpine's position in the trend. See "General Development of the Business – Significant Acquisitions and Recent Developments".

Infrastructure is very important in the Pembina/Nisku trend due to the "sour" nature of the production. The Rubicon Acquisition and the Vaquero Acquisition gave Highpine a 65% 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 9,000 bbls/d of sour oil (net capacity 5,850 bbls/d). To provide critical sour gas take-away capacity, Highpine 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 and Duke Energy Midstream Services Canada Ltd. and constructed 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 36% interest in this pipeline. Highpine's working interest in the Violet Grove Battery is 80% and Highpine is the operator. This battery is capable of handling 15,000 bbls/d (net capacity of 12,000 bbls/d). In October 2005, Highpine acquired a 15% interest in the Dominion Violet Grove Battery. The battery is capable of handling 19,000 bbls/d (net capacity of 2,850 bbls/d).

Highpine's undeveloped land base at Pembina/Nisku holds an inventory of approximately 100 gross (82 net) firm drilling locations. The Corporation expects to drill approximately 25 to 35 wells per year thereby giving Highpine a three to four year inventory of drilling opportunities. The average cost, assuming no significant drilling problems, to drill and complete wells in the Nisku area is approximately $3.5 million. Costs to tie-in wells is an additional $1.0 to 1.5 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. It is anticipated that Highpine's current facility ownership position will allow for the Corporation's future production drilled on the Pembina/Nisku trend to come on stream in a 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. Highpine is involved in nine water injection (i.e., pressure maintenance) schemes and operates seven of the projects. Many of Highpine's Nisku pools have GPP with others in the application process. 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 foregoing 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.

West Central Alberta Gas Fairway

The West Central Alberta Gas Fairway property is located northwest of Edmonton, Alberta and trends approximately 200 miles southeast towards Red Deer. It includes natural gas properties in Joffre, Chip Lake, Windfall/Sakwatamau, McLeod/Goodwin, Ante Creek and Wilson Creek and Ferrier. The West Central Alberta Gas Fairway property is Highpine's second major property, producing approximately 2,640 BOE/d in 2006 and representing approximately 22% of Highpine's total production volumes in

2006. Highpine's property interests in West Central Alberta Gas Fairway consist of working interests ranging from 7.5% to 100% and averaging 45%. The average Highpine working interest production from the property was approximately 3,107 BOE/d for the first ten days of March 2007, 74% of which was natural gas. In addition, Highpine has interests in three gas plants which process natural gas for Highpine and its partners.

As at December 31, 2006, the West Central Alberta Gas Fairway property consisted of 68,149 gross (35,112 net) acres of developed land and 148,441 gross (108,050 net) acres of undeveloped land.

The Paddock Report attributes proved plus probable reserves of 7.6 MMboe to Highpine's working interest in the West Central Alberta Gas Fairway area. The Paddock Report attributes proved reserves of 5.8 MMboe to Highpine's working interest in the West Central Alberta Gas Fairway 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 7.0 MMcf/d and to date has recovered approximately 5.4 Bcf of natural gas and significant quantities of NGLs.

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 in West Central Alberta Gas Fairway consists of selective exploration and exploitation drilling. In 2007, Highpine's capital budget contemplates that the Corporation will participate in the drilling of in excess of 10 gross wells in this area. The average cost, assuming no significant drilling problems, to drill and complete wells in the West Central Alberta Gas Fairway area is approximately $700,000. Estimated costs to tie-in wells is an additional $700,000.

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 475 BOE/d and representing approximately 4% of Highpine's total production volumes in 2006. Highpine's interests in Bantry/Retlaw consist of working interests ranging from 1% to 65% and averaging 50%. The average Highpine working interest production from the property was 670 BOE/d for the first ten days of March 2007. 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 (1,618 net) acres of developed land and 3,040 gross (1,025 net) acres of undeveloped land.

The Paddock Report attributes proved plus probable reserves of 1.0 MMboe to Highpine's working interest in the Bantry/Retlaw area. The Paddock Report attributes proved reserves of 0.8 MMboe 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 130 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 400 BOE/d net.

The operator of the property continues to optimize production and reduce the operating costs of certain wells on both properties. Optimization efforts are likely to consist of well stimulations, chemical treatments and the installation of high volume lift and additional water disposal facilities.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated March 30, 2007. The effective date of the Statement is December 31, 2006 and the preparation date of the Statement is February 15, 2007.

Disclosure of Reserves Data

The reserves data set forth below (the "**Reserves Data**") is based upon an evaluation by Paddock with an effective date of December 31, 2006 contained in the Paddock Report. The Reserves Data summarizes the crude oil, NGL and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using constant prices and costs and forecast prices and costs. The Reserves Data for Highpine conforms to the requirements of NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which Highpine believes is important to the readers of this information. Highpine engaged Paddock to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible 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, 2006. 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. **All evaluations of future net revenue are stated before and after the provision for income taxes and prior to indirect costs and after deduction of royalties, estimated future capital expenditures, production costs, development costs and well abandonment costs for only those wells assigned reserves by Paddock. Other assumptions and qualifications relating to cash, process for future production and other matters are summarized therein. It should not be assumed that the estimates of future net revenues 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 revenue 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 Oil and Gas Disclosure (on Form 51-101F3) and the Report on Reserves Data by Paddock (on Form 51-101F2) are included in this Annual Information Form. See Schedule B - "Report of Highpine Management and Directors on Oil and Gas Disclosure in Accordance with Form 51-101F3" and Schedule A - "Report on Reserves Data by Paddock Lindstrom & Associates Ltd. in Accordance with Form 51-101F2", respectively.

All of Highpine's reserves are in Canada and, substantially all of such reserves, are in the Province of Alberta.

Reserves Data (Constant Prices and Costs)

Summary of Crude Oil, NGL and Natural Gas Reserves and Net Present Values of Future Net Revenue as of December 31, 2006 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	7,128	5,257	526	445	45,619	35,842	3,600	2,444
Developed Non-Producing	1,958	1,359	0	0	16,870	12,846	1,521	1,051
Undeveloped	1,469	1,005	0	0	12,678	10,566	571	409
Total Proved	10,555	7,621	526	445	75,167	59,254	5,692	3,904
Total Probable	6,389	4,561	82	70	37,843	30,643	2,383	1,670
Total Proved Plus Probable	16,944	12,182	608	515	113,010	89,897	8,075	5,574

	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	492,605	421,992	372,052	334,678	305,538	492,605	421,992	372,052	334,678	305,538
Developed Non-Producing	133,425	113,855	99,593	88,755	80,244	103,327	88,278	77,565	69,563	63,357
Undeveloped	69,507	51,738	40,325	32,261	26,229	50,896	36,062	26,830	20,446	15,741
Total Proved	695,537	587,585	511,970	455,694	412,011	646,827	546,332	476,448	424,687	384,636
Total Probable	358,938	245,717	185,734	147,608	121,037	259,310	173,817	129,239	101,237	81,881
Total Proved Plus Probable	1,054,475	833,302	697,704	603,302	533,048	906,137	720,149	605,686	525,924	466,517

Total Future Net Revenue (Undiscounted) as of December 31, 2006 Based on Constant Prices and Costs

Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Well Abandonment and Reclamation Costs	Future Net Revenue Before Deducting Future Income Tax Expenses	Income Tax Expenses	Future Net Revenue After Deducting Future Income Tax Expenses
				(Thousands of Dollars)				
Proved	1,504,761	393,082	354,079	56,310	5,753	695,537	48,710	646,827
Proved Plus Probable	2,295,401	596,117	530,264	108,204	6,341	1,054,475	148,338	906,137

Future Net Revenue by Production Group as of December 31, 2006 Based on Constant Prices and Costs

Reserves Category	Production Group	Future Net Revenue Before Deducting Future Income Tax Expenses (discounted at 10%/year) (Thousands of Dollars)
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	294,690
	Heavy Oil (including solution gas and other by-products)	7,678
	Natural Gas (including by-products but excluding solution gas from oil wells)	208,574
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	429,633
	Heavy Oil (including solution gas and other by-products)	8,402
	Natural Gas (including by-products but excluding solution gas from oil wells)	258,642

Reserves Data (Forecast Prices and Costs)

Summary of Crude Oil, NGL and Natural Gas Reserves and Net Present Values of Future Net Revenue as of December 31, 2006 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	7,128	5,257	526	445	45,490	35,633	3,594	2,438
Developed Non-Producing	1,958	1,359	0	0	16,864	12,707	1,521	1,040
Undeveloped	1,469	1,005	0	0	12,587	10,432	568	401
Total Proved	10,555	7,621	526	445	74,941	58,772	5,683	3,879
Total Probable	6,389	4,561	82	70	37,732	30,032	2,381	1,632
Total Proved Plus Probable	16,944	12,182	608	515	112,673	88,804	8,064	5,511

	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	543,822	461,926	405,730	364,344	332,367	539,799	458,692	403,099	362,182	330,572
Developed Non-Producing	150,028	127,734	111,676	99,547	90,055	106,448	90,585	79,428	71,148	64,757
Undeveloped	90,164	64,901	50,105	40,159	32,923	66,661	45,621	33,786	26,023	20,465
Total Proved	784,014	654,561	567,511	504,050	455,345	712,909	594,898	516,312	459,352	415,793
Total Probable	435,116	278,815	206,469	163,100	133,629	309,350	195,772	143,222	111,793	90,495
Total Proved Plus Probable	1,219,130	933,376	773,980	667,150	588,974	1,022,259	790,670	659,534	571,145	506,289

**Total Future Net Revenue (Undiscounted)
as of December 31, 2006 Based on
Forecast Prices and Costs**

Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Well Abandonment and Reclamation Costs	Future Net Revenue Before Deducting Future Income Tax Expenses	Income Tax Expenses	Future Net Revenue After Deducting Future Income Tax Expenses
				(Thousands of Dollars)				
Proved	1,667,753	428,020	392,169	56,397	7,153	784,014	71,105	712,909
Proved Plus Probable	2,611,491	660,120	615,158	108,693	8,393	1,219,130	196,871	1,022,259

**Future Net Revenue by Production Group
as of December 31, 2006 Based on
Forecast Prices and Costs**

Reserves Category	Production Group	Future Net Revenue Before Deducting Future Income Tax Expenses (discounted at 10%/year) (Thousands of Dollars)
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	298,130
	Heavy Oil (including solution gas and other by-products)	7,144
	Natural Gas (including by-products but excluding solution gas from oil wells)	261,209
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	433,556
	Heavy Oil (including solution gas and other by-products)	7,845
	Natural Gas (including by-products but excluding solution gas from oil wells)	331,551

Definitions and Other Notes

In the tables set forth above in "Statement of Reserves Data and Other Oil and Gas Information" and elsewhere in this Annual Information Form the following definitions and other notes are applicable:

(1) "**Gross**" means:

(a) in relation to Highpine's interest in production or reserves, Highpine's working interest (operating or non operating) share before deduction of royalties and without including any of Highpine's royalty interests;

(b) in relation to wells, the total number of wells in which Highpine has an interest; and

(c) in relation to properties, the total area of properties in which Highpine has an interest.

(2) "**Net**" means:

(a) in relation to Highpine's interest in production or reserves, Highpine's working interest (operating or non operating) share after deduction of royalty obligations, plus Highpine's royalty interests in production or reserves;

(b) in relation to Highpine's interest in wells, the number of wells obtained by aggregating Highpine's working interest in each of Highpine's gross wells; and

(c) in relation to Highpine's interest in a property, the total area in which Highpine will have an interest multiplied by the working interest owned by Highpine.

(3) The crude oil, NGL and natural gas reserve estimates presented in the Paddock Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below:

Reserve Categories

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

the analysis of drilling, geological, geophysical and engineering data;

the use of established technology; and

specified economic conditions.

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

(a) **"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.

(b) **"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.

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

Development and Production Status

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

(c) **"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 (for example, 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.

  (i) **"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.

  (ii) **"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.

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

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

Levels of Certainty for Reported Reserves

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

at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

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

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

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

Forecast prices and costs

Future prices and costs that are:

(e) generally acceptable as being a reasonable outlook of the future; and

(f) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which Highpine will be legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

The forecast summary table under "Pricing Assumptions" below identifies benchmark reference prices that apply to Highpine.

Constant prices and costs

Prices and costs used in an estimate that are:

(g) Highpine's prices and costs as at the effective date of the estimation, held constant throughout the estimated lives of the properties to which the estimate applies; and

(h) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which Highpine will be legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

For the purposes of paragraph (a), Highpine's prices will be the posted price for oil and the spot price for natural gas, after historical adjustments for transportation, gravity and other factors.

(4) **"Future income tax expenses"** estimated:

(a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;

(b) without deducting estimated future costs that are not deductible in computing taxable income;

(c) taking into account estimated tax credits and allowances; and

(d) applying to the future pre-tax net cash flows relating to Highpine's oil and gas activities the appropriate year end statutory tax rates, taking into account future tax rates already legislated.

(5) **"Development well"** means a well drilled inside the established limits of an oil or gas reservoir or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

(6) **"Development costs"** means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

(7) **"Exploration well"** means a well that is not a development well, a service well or a stratigraphic test well.

(8) **"Exploration costs"** means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

(9) "Service well" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

(10) Numbers may not add due to rounding.

Pricing Assumptions

Constant Prices Used in Estimates

The constant benchmark reference prices utilized by Paddock in the Paddock Report were as follows:

Summary of Pricing Assumptions as of December 31, 2006
Constant Prices and Costs

	Oil		Natural Gas	Edmonton Liquid Prices		
Year	Edmonton Par Price 40° API ($Cdn/bbl)	Hardisty Heavy 25° API ($Cdn/bbl)	AECO Gas Price ($Cdn/MMbtu)	Propane ($Cdn/bbl)	Butane ($Cdn/bbl)	Pentanes Plus ($Cdn/bbl)
2006	67.06	48.77	6.07	42.13	54.06	71.78

The weighted average historical prices realized by Highpine for the year ended December 31, 2006, were $7.06/Mcf for natural gas, $67.86/bbl for light oil and condensate and $51.54 /bbl for NGLs.

Forecast Prices Used in Estimates

The forecast benchmark reference prices, inflation rates and exchange rates utilized by Paddock in the Paddock Report were as follows:

Summary of Pricing and Inflation Rate Assumptions as at December 31, 2006
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										
2007	61.00	68.58	47.58	63.78	7.33	41.15	48.01	68.58	2.0	0.87
2008	60.00	67.40	47.40	62.69	7.91	40.44	47.18	67.40	2.0	0.87
2009	60.00	67.37	49.37	62.66	7.89	40.42	47.16	67.37	2.0	0.87
2010	58.00	65.04	48.54	60.49	7.87	39.03	45.53	65.04	2.0	0.87
2011	56.00	62.71	45.88	58.32	8.02	37.63	43.90	62.71	2.0	0.87
2012	57.12	63.97	46.80	59.49	8.19	38.38	44.78	63.97	2.0	0.87
Thereafter					+ 2%/year					

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			Natural Gas Liquids		
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)	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)
December 31, 2005	6,075	3,932	10,007	530	85	615	25,229	12,147	37,376	1,095	336	1,431
Extensions	1,091	(74)	1,017	-	-	-	1,048	(362)	686	52	(5)	47
Improved Recovery	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	115	(238)	(123)	(39)	(15)	(54)	1,415	(3,077)	(1,662)	207	(7)	200
Discoveries	394	143	537	-	-	-	17,985	13,848	31,833	1,163	537	1,700
Acquisitions	1,306	798	2,104	-	-	-	20,088	8,087	28,175	1,888	809	2,697
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production	(1,360)	-	(1,360)	(46)	-	(46)	(6,511)	-	(6,511)	(501)	-	(501)
December 31, 2006	7,621	4,561	12,182	445	70	515	59,254	30,643	89,897	3,904	1,670	5,574

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

Period and Factor	Before Tax 2006 (Thousands of Dollars)
Estimated Future Net Revenue at December 31, 2005	349,597
Sales and Transfers of Oil and Gas Produced, Net of Production Costs and Royalties [(1)]	(144,642)
Net Change in Prices, Production Costs and Royalties Related to Future Production	(64,175)
Changes in Previously Estimated Development Costs Incurred During the Period	3,583
Changes in Estimated Future Development Costs	49,997
Extensions and Improved Recovery	-
Discoveries	106,712
Acquisitions of Reserves	132,418
Dispositions of Reserves	-
Net Change Resulting from Revisions in Quantity Estimates	21,179
Accretion of Discount [(2)]	34,960
Net Change in Income Taxes [(3)]	32,568
All Other Changes	(45,749)
Estimated Future Net Revenue at December 31. 2006	476,448

Notes:

(1) Cash flow from operations.

(2) 10% of discounted future net revenue at the beginning of the financial year.

(3) The difference between income taxes at beginning of period and income taxes at end of period.

Additional Information Relating to Reserves Data

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)
2003	216	-	156	9	251
2004	830	-	649	38	976
2005	532	-	333	14	602
2006	1,469	-	12,587	568	4,135

In 2006, proved undeveloped reserves were attributed to six Nisku drilling locations in the Pembina Nisku GG, HH, NN, WW and other Nisku locations. In addition, proved undeveloped reserves were assigned to 17 Pembina Rock Creek gas locations. As of the date of this Annual Information Form, three of the six Nisku wells have been drilled and the Rock Creek locations are 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)
2003	97	-	1,423	15	349
2004	1,073	-	3,968	62	1,796
2005	3,104	-	7,399	161	4,498
2006	2,357	-	19,764	1,052	6,703

In 2006, the majority of the probable undeveloped reserves were attributed to 10 Nisku drilling locations in the Pembina Nisku AA, HH, NN, II, WW, T and other Nisku locations. In addition, probable undeveloped reserves were assigned to 16 Pembina Rock Creek gas locations. As of the date of this Annual Information Form, all of the wells are expected to be drilled in the next two years.

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

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserves estimates contained herein are based on current production forecasts, prices and economic conditions.

As circumstances change and additional data become available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices, and reservoir performance. Such revisions can be either positive or negative.

Other than as discussed above and 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".

Future Development Costs

The table below sets out the development costs deducted in the estimation of future net revenue attributable to the proved reserves (using both constant prices and costs and forecast prices and costs) and the proved plus probable reserves (using both constant prices and costs and forecast prices and costs) contained in the Paddock Report.

	Forecast Prices and Costs		**Constant Prices and Costs**	
Year	**Proved Reserves**	**Proved Plus Probable Reserves**	**Proved Reserves**	**Proved Plus Probable Reserves**
	(Thousands of Dollars)			
2007	52,757	85,163	52,757	85,163
2008	3,216	22,826	3,153	22,378
2009	-	-	-	-
2010	425	703	400	663
2011	-	-	-	-
Total: Undiscounted	56,397	108,693	56,310	108,204
Total: Discounted at 10%/year	53,393	101,487	53,321	101,069

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.

Other Oil and Gas Information

Oil and Natural Gas Wells

The following table summarizes Highpine's interest, as at December 31, 2006, in producing wells and wells that Highpine considers to be capable of production.

	Producing Wells				Shut-in Wells [(1)]			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	149	42.6	1,138	78.9	14	8.3	25	14.5
British Columbia	-	-	-	-	-	-	1	0.3

Note:
(1) **"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.

Properties with No Attributed Reserves

The following table summarizes the gross and net acres of unproved properties, effective December 31, 2006, in which Highpine has an interest in.

	Undeveloped Acres [(1)(2)]	
	Gross	Net
Alberta	438,415	315,893
British Columbia	55,823	12,720
Total	494,238	328,613

Notes:
(1) There are no material work commitments in respect of Highpine's unproved properties.
(2) Highpine expects its rights to explore, develop and exploit approximately 32,705 net acres of its unproved property to expire within one year.

Forward Contracts

Highpine will not be bound by any agreement (including any transportation agreement), directly or through an aggregator, under which it may be precluded from fully realizing, or may be protected from the full effect of, future market prices for oil or natural gas other than as set forth in the table below. In addition, Highpine's transportation obligations or commitments for future physical deliveries of oil or natural gas will not exceed Highpine's expected related future production from its proved reserves, estimated using forecast prices and costs, as disclosed herein.

At March 30, 2007, Highpine had the following financial commodity contracts for the remainder of 2007:

Commodity Contract	Period	Volume	Price
Oil collar	January 2007 to December 2007	1,750 bbls/d	U.S.$55.00 to U.S.$86.15/bbl
Oil collar	January 2007 to December 2007	1,750 bbls/d	U.S.$60.00 to U.S.$80.70/bbl
Oil swap	January 2007 to December 2007	500 bbls/d	$73.00/bbl
Oil swap	January 2007 to December 2007	500 bbls/d	$73.70/bbl
Oil swap	January 2007 to December 2007	500 bbls/d	$74.70/bbl
Oil swap	January 2007 to December 2007	500 bbls/d	$75.82/bbl
Gas collar	June 2006 to March 2007	5,000 GJs/d	$5.40 to $12.00/GJ
Gas collar	July 2006 to March 2008	5,000 GJs/d	$6.00 to $11.10/GJ
Gas swap	January 2007 to December 2007	2,500 GJs/d	$7.55/GJ
Gas swap	January 2007 to December 2007	2,500 GJs/d	$7.62/GJ
Gas swap	February 2007 to March 2008	1,250/GJs/d	$7.68/GJ
Gas swap	February 2007 to March 2008	1,250/GJs/d	$7.70/GJ

Additional Information Concerning Abandonment and Reclamation Costs

The following table discloses the expected abandonment and reclamation costs of the proven and probable Highpine Assets as at December 31, 2006, calculated both undiscounted and at a 10 percent discount rate with a portion thereof anticipated to be paid in each of the next three years.

	Abandonment and Reclamation Costs (\$000)	**Abandonment and Reclamation Costs in Disclosed Reserves Data – Forecast Prices (\$000)**
Total as at December 31, 2006	17,900	8,393
Total as at December 31, 2006 – Discounted 10%	7,900	2,670
Anticipated to be paid in 2007	829	80
Anticipated to be paid in 2008	274	124
Anticipated to be paid in 2009	427	151

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 following sets forth certain information regarding Highpine's anticipated abandonment and reclamation costs for surface leases, wells, facilities and pipelines.

(a) It is expected that Highpine will incur reclamation and abandonment costs in respect of approximately 234 net wells.

(b) The total amount of Highpine's abandonment and reclamation costs expected to be incurred is \$17.9 million (undiscounted) and \$7.9 million (discounted at 10%). Highpine estimates salvage value to be \$23.9 million.

(c) \$1.5 million of the \$17.9 million of abandonment and reclamation costs disclosed in paragraph (b) above are expected to be paid in the next three years by Highpine.

Tax Horizon

Highpine's management does not expect that Highpine will be taxable in the next one to two years. Highpine has estimated approximately \$570 million of tax pools will be available as at December 31, 2006, which can be used to off-set taxable income in future years.

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 fiscal year ended December 31, 2006.

Expenditures	Year Ended December 31, 2006
	(Thousands of Dollars)
Property acquisition costs – Unproved properties (1)	89,450 (3)
Property acquisition costs – Proved properties	409,987
Exploration drilling and completions	70,900
Development costs (2)	42,414
Other	358
Total	663,109

Notes:
(1) Cost of land acquired and geological and geophysical capital expenditures.
(2) Development drilling and facility and equipping.
(3) Property acquisition costs – Unproved properties includes $32,569 allocated to unproved properties as part of the Kick Arrangement and $25,800 as part of the White Fire Arrangement.

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 fiscal year ended December 31, 2006.

	Year Ended December 31, 2006			
	Exploratory Wells		Development Wells	
	Gross (1)	Net (2)	Gross (1)	Net (2)
Oil	5	3.3	10	8.2
Natural Gas	21	13.6	22	11.4
Service	-	-	5	3.2
Dry	10	6.6	1	0.5
Total:	36	23.5	38	23.3

For details concerning anticipated 2007 exploration and development activities in respect of Highpine's properties and assets, see "Description of Principal Properties".

Production Estimates

The following table sets out the volumes of the proved plus probable gross production estimated for the year ending December 31, 2007 as estimated by Paddock in assessing the future net revenue disclosed in the tables above.

	Light and Medium Oil (bbls/d)	Heavy Oil (bbls/d)	Natural Gas (mcf/d)	Natural Gas Liquids (bbls/d)	BOE (boe/d)
2007 Pembina	9,321	-	28,114	3,175	17,182
2007 West Central Alberta Gas Fairway	199	-	12,408	608	2,874
Total 2007	9,851	141	45,206	3,864	21,390

Other than Highpine's Pembina property and West Central Alberta Gas Fairway Property, it is not anticipated that any one field will account for 20% or more of Highpine's estimated total production for the year ended December 31, 2007 as disclosed above.

Production History

The following table discloses, on a quarterly basis for the year ended December 31, 2006, certain information in respect of production, product prices received, royalties paid, Highpine's production costs and resulting netback.

	Quarter Ended 2006			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production (1)				
Light and Medium Crude Oil (bbl/d)	5,474	4,182	5,223	6,630
Heavy Oil (bbl/d)	149	147	152	157
Gas (Mcf/d)	30,221	24,837	25,562	20,681
NGLs (bbl/d)	3,030	2,346	1,565	1,163
Combined (Boe/d)	13,690	10,814	11,201	11,397
Average Prices Received				
Light and Medium Crude Oil ($/bbl)	59.66	74.04	76.44	66.22
Heavy Oil (bbl/d)	46.71	58.29	61.03	41.35
Gas ($/Mcf)	7.24	6.27	6.62	8.29
NGLs ($/bbl)	56.61	65.54	63.70	59.92
Combined ($/Boe)	52.88	58.05	60.48	60.26
Royalties Paid (2)				
Light and Medium Crude Oil ($/bbl)	20.08	19.44	24.35	21.39
Heavy Oil (bbl/d)	8.97	10.18	10.67	7.25
Gas ($/Mcf)	1.25	0.76	1.50	2.75
NGLs ($/bbl)	17.64	21.28	19.34	19.27
Combined ($/Boe)	14.80	14.02	17.61	19.49

Notes:

(1) Before deduction of royalties.

(2) Royalties after ARTC.

(3) Operating expenses are composed of direct costs incurred to operate both oil and gas wells. A number of assumptions have been made in allocating these costs between oil, natural gas and natural gas liquids production. Operating recoveries associated with operated properties were excluded from operating costs and accounted for as a reduction to general and administrative costs.

(4) Netbacks are calculated by subtracting royalties, operating costs and transportation costs.

(5) The following table sets forth the average daily production volumes for the year ended December 31, 2006 for each of Highpine's important fields.

	Light and Medium Oil (bbls/d)	Heavy Oil (bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (bbls/d)	BOE (Boe/d)
Pembina	4,906	-	10,653	1,642	8,324
West Central Gas Fairway	206	-	12,474	356	2,640
Other	259	151	2,223	34	815
Total	5,371	151	25,350	2,032	11,779

For the year ended December 31, 2006, approximately 74% of the gross revenue with respect to Highpine's properties was derived from crude oil and NGL production and 26% was derived from natural gas production.

Highpine expects to market 100% of its crude oil and natural gas to a third party based on indexed prices.

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 the Corporation'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 the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing – Oil and Natural Gas

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance, and other contractual terms. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issuance of such licence 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 and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 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 licence from the NEB and the issuance of such licence 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 availability, transportation arrangements, and market considerations.

Pipeline Capacity

Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market natural gas production. In addition, the pro-rationing of capacity on the inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas.

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. In the context of energy resources, 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 subject to an exception with respect to certain voluntary measures which only restrict the volume of exports; and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum or maximum export or import price requirements, provided, in the case of export price requirements, prohibition in any circumstances in which any other form of quantitative restriction is prohibited, and in the case of import-price requirements, such requirements do not apply with respect to enforcement of countervailing and anti-dumping orders and undertakings.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector by 2010 and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, which is important for Canadian natural gas exports.

Provincial Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection, and other matters. The royalty regime is a significant factor in the profitability of crude oil, 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, method of recovery, and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally 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. Royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments and would increase the net income and funds from operations of such producers. However, the trend in recent years has been for provincial governments to eliminate, amend or allow such incentive programs to expire without renewal, and consequently few such incentive programs are currently operative.

The Canadian federal corporate income tax rate levied on taxable income is 22.1% effective January 1, 2007 for active business income including resource income. With the elimination of the corporate surtax effective January 1, 2008 and other rate reductions introduced in the 2006 Federal Budget, the federal corporate income tax rate will decrease to 19% in three steps: 20.5% on January 1, 2008, 20% on January 1, 2009 and 19% on January 1, 2010.

Alberta

In Alberta, companies are granted the right to explore, produce and develop petroleum and natural gas resources in exchange for royalties, bonus bid payments and rents. Currently, the amount of royalties that are payable is influenced by the oil production, density of the oil, and the vintage of the oil. Originally, the vintage classified oil in "new oil" and "old oil" depending on when the oil pools were discovered. If discovered prior to March 31, 1974 it is considered "old oil", if discovered after March 31, 1974 and before September 1, 1992, it is considered "new oil". The Alberta government introduced in 1992 a Third Tier Royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 1, 1992. The new oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 30%. The old oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 35%.

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 natural gas, and between 15% and 35%, in the case of old natural gas, depending upon a prescribed or corporate average reference price. Natural gas produced from qualifying intervals in eligible gas wells spudded or deepened to a depth below 2,500 metres is also subject to a royalty exemption, the amount of which depends on the depth of the well.

Oil sands projects are subject to a specific regulation made effective July 1, 1997, and expiring June 30, 2007, which, among other things, determines the Crown's share of crude and processed oil sands products.

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provided various incentives for exploring and developing oil reserves in Alberta. However, the Alberta Government announced in August of 2006 that four royalty programs were to be amended, a new program was to be introduced and the Alberta Royalty Tax Credit Program ("**ARTC**") was eliminated, effective January 1, 2007. The programs affected by this announcement are: (i) Deep Gas Royalty Holiday; (ii) Low Productivity Well Royalty Reduction; (iii) Reactivated Well Royalty Exemption; and (iv) Horizontal Re-Entry Royalty Reduction. The program being introduced is the Innovative Energy Technologies Program (the "**IETP**") which is intended to promote the producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP provides royalty reductions which are presumed to reduce financial risk. Alberta Energy will be the one to decide which projects qualify and the level of support that will be provided. The deadline for the IETP's third round of applications is May 31, 2007.

On February 16, 2007, the Alberta Government announced that a review of the province's royalty and tax regime (including income tax and freehold mineral rights tax) pertaining to oil, gas and oil sands will be conducted by a panel of experts, with the assistance of individual Albertans and key stakeholders. The purpose of this process is to ensure that Albertans are receiving a fair share from energy development through royalties, taxes and fees. The issues to be reviewed during this examination process are: (i) undertaking a comparison of Alberta's royalty system to other oil and gas producing jurisdictions, taking into account investment economics and industry returns and risks in Alberta; (ii) whether Alberta's royalty system is sufficiently sensitive to market conditions; (iii) whether the current revenue minus cost system for oil sands royalties is optimal; (iv) which programs built into the existing royalty system should be retained or strengthened, and which should be adapted or eliminated; (v) how the tax treatment of the oil and gas sector compares to other sectors and jurisdictions; (vi) the economic and fiscal impacts of any possible changes to the royalty and corporate tax structures; and (vii) how existing resource development should be treated if changes are to be made to the fiscal regime. The review panel is to produce a final report that will be presented to the Minister of Finance by August 31, 2007.

British Columbia

Producers of oil and natural gas in the Province of British Columbia are required to pay annual rental payments with respect to the Crown leases and royalties and freehold production taxes in respect of oil and gas produced from Crown and freehold lands. The amount payable as a royalty in respect of oil depends on the type of oil, the value of the oil, the quantity of oil produced in a month, and the vintage of the oil. Generally, the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 (old oil), between October 31, 1975, and June 1, 1998 (new oil), or after June 1, 1998 (third-tier oil). The royalty rates are calculated in three stages, which take into account the vintage of the oil, if the oil produced has already been sold and any royalty exempt value applicable (exempt wells). Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production or 11,450m^3 produced, whichever comes first; and the royalties for third-tier oil are the lowest reflecting the higher costs of exploration and extraction that the producers would incur. The royalty payable on natural gas is determined by a sliding scale based on a reference price, which is the greater of the price obtained by the producer, and a prescribed minimum price. However, when the reference price is below the select price (a parameter used in the royalty rate formula), the royalty rate is fixed. As an incentive for the production and marketing of natural gas, which may have been flared, natural gas produced in association with oil has a lower royalty then the royalty payable on non-conservation gas.

On May 30, 2003, the Ministry of Energy and Mines for the Province of British Columbia announced an Oil and Gas Development Strategy for the Heartlands ("**Strategy**"). The Strategy is a comprehensive program to address road infrastructure, targeted royalties and regulatory reduction, and British Columbia service sector opportunities. In addition, the Strategy will result in economic and employment opportunities for communities in British Columbia's heartlands.

Some of the financial incentives in the Strategy include:

- Royalty credits of up to $30 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.

On February 27, 2007 the Government of British Columbia unveiled the Energy Plan outlining the Province's strategy towards the environment and which includes targeting for zero net greenhouse gas emissions, promoting new investments in innovation, and becoming the world's leader in sustainable environmental management. With regards to the oil and gas industry the objective is to achieve clean energy through conservation and energy efficient practices, whilst competitiveness is advocated in order to attract investment for the development of the oil and gas sector. Among the changes to be implemented are: (i) a new of Net Profit Royalty Program; (ii) the creation of a Petroleum Registry; (iii) the establishing of an infrastructure royalty program (combining roads and pipelines); (iv) the elimination of routine flaring at producing wells; (v) the creation of policies and measures for the reduction of emissions; (vi) the development of unconventional resources such as tight gas and coalbed gas; and (vii) new the Oil and Gas Technology Transfer Incentive Program that encourages the research, development and use of innovative technologies to increase recoveries from existing reserves and promotes responsible development of new oil and gas reserves.

Saskatchewan

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

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

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

- A new Crown royalty and freehold production tax regime applicable to associated natural gas (gas produced from oil wells) that is gathered for use or sale. The royalty/tax will be payable on associated natural gas produced from an oil well that exceeds approximately 65 thousand cubic metres in a month.

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

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

In 1975, the Government of Saskatchewan introduced a Royalty Tax Rebate ("**RTR**") as a response to the federal government disallowing crown royalties and similar taxes as a deductible business expense for income tax purposes. As of January 1, 2007, the remaining balance of any unused RTR will be limited in its carry forward to five years since the federal government had the initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income.

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, licences, and permits for varying terms from two years, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore 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 licences and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

Environmental legislation in the Province of Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (the "**EPEA**"), which came into force on September 1, 1993, and the *Oil and Gas Conservation Act* (Alberta) (the "**OGCA**"). The EPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations, and significantly increased penalties. In 2006, the Alberta Government enacted regulations pursuant to the EPEA to specifically target sulphur oxide and nitrous oxide emissions from industrial operations including the oil and gas industry. No additional expenses are foreseen that are associated with complying with the new regulations. The Corporation will be committed to meeting its responsibilities to protect the environment wherever it operates and 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 EPEA and similar legislation in other jurisdictions in which it operates. We believe that we are in material compliance with applicable environmental laws and regulations. We also believe 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 with public participation in the environmental review process.

In December, 2002, the Government of Canada ratified the Kyoto Protocol ("**Protocol**"). The Protocol calls for Canada to reduce its greenhouse gas emissions to 6% below 1990 "business-as-usual" levels between 2008 and 2012. Given revised estimates of Canada's normal emissions levels, this target translates into an approximately 40% gross reduction in Canada's current emissions. It remains uncertain whether the Kyoto target of 6% below 1990 emission levels will be enforced in Canada. The Federal Government has introduced legislation aimed at reducing greenhouse gas emissions using a "intensity based" approach, the specifics of which have yet to be determined. Bill C-288, which is intended to ensure that Canada meets its global climate change obligations under the Kyoto Protocol, was passed by the House of Commons on February 14, 2007. As details of the implementation of this legislation have not yet been announced, the effect of our operations cannot be determined at this time.

Trends

There are a number of trends that have been developing in the oil and gas industry during the past several years that appear to be shaping the near future of the business.

The first trend is the volatility of commodity prices. Natural gas is a commodity influenced by factors within North America. A tight supply-demand balance for natural gas causes significant elasticity in pricing, whereas higher than average storage levels tend to depress natural gas pricing. Drilling activity, weather, fuel switching and demand for electrical generation are all factors that affect the supply-demand balance. Changes to any of these or other factors create price volatility.

Crude oil is influenced by the world economy, Organization of the Petroleum Exporting Countries' ability to adjust supply to world demand and weather. Crude oil prices have been kept high by political events causing disruptions in the supply of oil and concern over potential supply disruptions triggered by unrest in the Middle East and more recently have been impacted by weather and increased storage levels. Political events trigger large fluctuations in price levels.

The impact on the oil and gas industry from commodity price volatility is significant. During periods of high prices, producers generate sufficient cash flows to conduct active exploration programs without external capital. Increased commodity prices frequently translate into very busy periods for service suppliers triggering premium costs for their services. Purchasing land and properties similarly increase in price during these periods. During low commodity price periods, acquisition costs drop, as do internally generated funds to spend on exploration and development activities. With decreased demand, the prices charged by the various service suppliers also decline.

A second trend within the Canadian oil and gas industry is the fairly consistent "renewal" of private and small junior oil and gas companies starting up business. These companies often have experienced management teams from previous industry organizations that have disappeared as a part of the ongoing industry consolidation. Many are able to raise capital and recruit well qualified personnel. The Corporation will have to compete with these companies and others to attract qualified personnel.

A third trend currently affecting the oil and gas industry is the impact on capital markets caused by investor uncertainty in the North American economy. The capital market volatility in Canada has also been affected by uncertainties surrounding the economic impact that the Protocol, and other environmental initiatives, will have on the sector and, in more recent times, by the October 31, 2006 proposals of the Federal government of Canada (the "October 31, 2006 Proposals") relating to income trusts and other "specified investment flow-through" entities ("SIFTs"). Pursuant to the existing provisions of the *Income Tax Act* (Canada), to the extent that a SIFT has any income for a taxation year after certain inclusions and deductions, the SIFT will be permitted to deduct all amounts of income which are paid or become payable by it to unitholders in the year. Under the October 31, 2006 Proposals, SIFTs will be liable for tax at a rate consistent with the taxes currently imposed on corporations commencing in January 2011, provided that the SIFT experiences only "normal growth" and no "undue expansion" before then, in which case the tax could be imposed prior to the January 2011 deadline. Although the October 31, 2006 Proposals will not affect the method in which the Corporation will be taxed, they may have an impact on the ability of a SIFT to purchase producing assets from junior oil and gas companies (as well as the price that a SIFT is willing to pay for such an acquisition) thereby affecting exploration and production companies' ability to be sold to a SIFT which has been a key "exit strategy" in recent years for small to mid-sized oil and gas companies. This may be a benefit for the Corporation as it will compete with SIFTs for the acquisition of oil and gas properties from junior producers. However, it may also limit the Corporation's ability to sell producing properties or pursue an exit strategy.

Generally during the past year, the economic recovery combined with increased commodity prices has caused an increase in new equity financings in the oil and gas industry, although the level of same was negatively impacted by the October 31, 2006 Proposals. The Corporation will compete with numerous new companies and their new management teams and development plans in its access to capital. The competitive nature of the oil and gas industry will cause opportunities for equity financings to be selective. The Corporation may have to rely on internally generated funds to conduct their exploration and developmental programs.

RISK FACTORS

Highpine's securities should be considered highly speculative due to the nature of Highpine's business. An investor should consider carefully the risk factors set out below. In addition, investors should carefully review and consider all other information contained or incorporated by reference in this Annual Information Form and in Highpine's other public filings before making an investment decision. An investment in securities of the Corporation should only be made by persons who can afford a significant or total loss of their investment.

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, any existing reserves Highpine may have at a particular time 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, management of 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 also 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.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

Highpine makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as Highpine's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of Highpine. The integration of acquired business may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of, so that Highpine can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of Highpine, if disposed of, could be expected to realize less than their carrying value on the financial statements of 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 availability of storage capacity;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;

- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

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 its 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 and storage. Competition may also be presented by alternate fuel sources.

Regulatory

Oil and natural gas operations (exploration, production, pricing, 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. At this time, the Alberta Government is in the process of examining the royalty and tax regime applicable to oil, gas and oil sands – see "Industry Conditions – Provincial Royalties and Incentives". 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.

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 proposed a Bill, 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 included 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. See "Industry Conditions – Environmental Regulation".

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, sour 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. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Kyoto Protocol or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of Highpine. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict either the nature of those requirements or the impact on Highpine and its operations and financial condition. 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 and storage 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.

Highpine's revenues, profitability and future growth and the carrying value of its oil and gas properties are substantially dependent on prevailing prices of oil and gas. Highpine's ability to borrow and to obtain additional capital on attractive terms is also substantially dependent upon oil and gas prices. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of Highpine. These factors include economic conditions in the United States and Canada, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on Highpine's carrying value of its proved reserves, borrowing capacity, revenues, profitability and cash flows from operations.

The exchange rate between the Canadian and U.S. dollar also affects the profitability of the Corporation and the Canadian dollar has strengthened recently against the U.S. dollar.

Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects. 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 acceptable to Highpine.

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 and Highpine may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. 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 Annual Information Form 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, 55% 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. The Paddock Report is effective as of December 31, 2006 and has not been updated and thus does not reflect changes in Highpine's reserves since that date.

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, leaks of sour natural gas, 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.

Geo-Political Risks

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 political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle-East, and other areas of the world, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of Highpine's net production revenue.

In addition, Highpine's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of Highpine's properties, wells or facilities are the subject of terrorist attack it could have a material adverse effect on Highpine. Highpine will not have insurance to protect against the risk from terrorism.

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 (as such term is defined herein). 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 "Directors and Executive Officers – Conflicts of Interest".

Dilution

Highpine may make further acquisitions or enter into financings or other transactions involving the issuance of securities of Highpine which may be dilutive.

Management of Growth

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

Expiration of Licences and Leases

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

Aboriginal Claims

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

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Corporation.

Third Party Credit Risk

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

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.

DIVIDENDS

Highpine has not declared or paid any dividends on the Common Shares or Series 1 Class B Shares during the three most recently completed financial years 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. There are no restrictions that could prevent the Corporation from paying dividends.

DESCRIPTION OF CAPITAL STRUCTURE

Highpine is authorized to issue an unlimited number of Common Shares and an unlimited number of Class B Shares, each having the rights, privileges, restrictions and conditions described below.

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.

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSX under the symbol "HPX". The following table sets forth the high and low sales prices (which are not necessarily the closing prices) and the trading volumes for the Common Shares on the TSX as reported by the TSX for the periods indicated:

	Price Range ($)		Trading
Period	**High**	**Low**	**Volume**
2006			
January	24.66	20.80	3,890,298
February	24.75	21.25	3,590,988
March	23.52	21.30	2,856,921
April	24.00	22.05	1,868,436
May	22.65	17.95	3,282,084
June	19.96	16.85	5,276,741
July	19.20	16.11	2,759,260
August	19.55	16.98	3,425,871
September	18.30	15.50	3,929,594
October	19.13	15.00	3,597,234
November	18.71	16.15	4,619,296
December	17.35	15.05	4,969,893
2007			
January	15.93	13.85	6,905,106
February	17.60	15.34	7,104,774
March (1 – 29)	15.84	11.58	11,653,821

PRIOR SALES

There is no class of securities of Highpine that is outstanding but not listed or quoted on a marketplace.

ESCROWED SECURITIES

The following table sets forth the number of securities of each class of the Corporation held in escrow and the percentage of the outstanding securities of the class.

Designation of Class	Number of Securities Held in Escrow	Percentage of Class
Common Shares	125,350	0.19

Note:

(1) Pursuant to the terms of the White Fire Arrangement, Robert Rosine, Robert Fryk and Dave Humphreys, who were appointed executive officers of Highpine upon completion of the White Fire Arrangement, deposited all of the Common Shares which they received pursuant to the White Fire Arrangement, being an aggregate of 112,558 Common Shares, in escrow with Burnet, Duckworth & Palmer LLP, Highpine's legal counsel, which Common Shares will be releasable to them as to one-third thereof on each of April 23, 2007, April 23, 2008 and April 23, 2009, provided that they are an employee of Highpine on the release dates. In addition, certain other employees of White Fire who continued as employees of Highpine on the effective date of the White Fire Arrangement deposited Common Shares which they received pursuant to the White Fire Arrangement in escrow with Burnet, Duckworth & Palmer LLP, of which the remaining 12,792 Common Shares will be releasable to them on August 31, 2007.

DIRECTORS AND EXECUTIVE OFFICERS

Name, Occupation and Security Holding

The following table sets forth certain information in respect of Highpine's directors and executive officers:

Name, Province/State and Country of Residence	Position(s) with Highpine [1]	Principal Occupation During the Five Preceding Years
A. Gordon Stollery Alberta, Canada	Chairman, Chief Executive Officer and Director	Chairman and Chief Executive Officer of Highpine since February 2006; and prior thereto, Chairman, President and Chief Executive Officer of Highpine.
John A. Brussa [3] Alberta, Canada	Director	Partner, Burnet, Duckworth & Palmer LLP (law firm).
Richard G. Carl [4] Ontario, Canada	Director	President and Chief Operating Officer of AGS Capital Corp. (investment company) since May 2006; Special Advisor to TerraNova Partners L.P. (oil and gas investment limited partnership) from January 2006 to May 2006; Interim President and Chief Executive Officer of Collective Bid Systems Inc. and CBID Markets Inc. (electronic fixed income trading platform offering trading services in the Canadian fixed income market to retail and institutional investors) from July 2005 to December 2005; and prior thereto, Managing Partner, Lawrence & Company Inc. (investment firm).
Timothy T. Hunt [4] Alberta, Canada	Director	Independent businessman since August 2006; and prior thereto President and Chief Executive Officer of Kick.

Name, Province/State and Country of Residence	Position(s) with Highpine [1]	Principal Occupation During the Five Preceding Years
Andrew Krusen [2][4] Florida, United States	Director	Chairman, President and Chief Executive Officer, Dominion Financial Group Inc. (investment and financial services firm).
Hank B. Swartout [2][3] Alberta, Canada	Director	Executive Chairman (since January 2007) and Chairman and Chief Executive Officer (from November 2005 until January 2007) of Precision Drilling Corporation (administrator to Precision Drilling Trust, an oil and gas services trust); and prior thereto Chairman, President and Chief Executive Officer of Precision Drilling Corporation (oil and gas services company).
Kenneth S. Woolner [2][3] Alberta, Canada	Director	Independent businessman since February 2006; prior thereto, Executive Chairman of White Fire since April 2005; President and Chief Executive Officer of Lightning Energy Ltd. (oil and gas company) from December 2001 to April 2005; and prior thereto, President of Velvet Exploration Ltd. (oil and gas company) from April 1997 to July 2001.
Greg N. Baum Alberta, Canada	President and Chief Operating Officer	President and Chief Operating Officer of Highpine since February 2006; and prior thereto, Executive Vice President and Chief Operating Officer of Highpine.
Robert W. Rosine Alberta, Canada	Executive Vice President, Corporate Development	Executive Vice President, Corporate Development of Highpine since February 2006; Chief Executive Officer of White Fire from April 2005 to February 2006; Chief Operating Officer of Lightning Energy Ltd. (oil and gas company) from June 2004 to April 2005; and prior thereto President of Brooklyn Energy Corporation (oil and gas company) from November 2001 to June 2004.
Harry D. Cupric Alberta, Canada	Vice President, Finance and Chief Financial Officer	Vice President, Finance and Chief Financial Officer of Highpine since January 2003; and prior thereto Vice President, Finance and Chief Financial Officer of Ascot Energy Resources Ltd. (oil and gas company).
Charles L. Buckley Alberta, Canada	Senior Vice President, Exploration	Senior Vice President, Exploration of Highpine since September 2006; and prior thereto, Vice President, Exploration of Kick.

Name, Province/State and Country of Residence	Position(s) with Highpine [1]	Principal Occupation During the Five Preceding Years
Robert B. Fryk Alberta, Canada	Senior Vice President, Engineering	Senior Vice President, Engineering of Highpine since September 2006; Senior Vice President, Engineering and Operations of Highpine from February 2006 to August 2006; Chief Operating Officer of White Fire from April 2005 to February 2006; Vice President, Engineering and Acquisitions of Lightning Energy Ltd. (oil and gas company) from June 2004 to April 2005; Vice President, Engineering and Operations of Brooklyn Energy Corporation (oil and gas company) from November 2001 to June 2004; and prior thereto Vice President and Chief Operating Officer and Vice President, Engineering and Operations of Maxx Petroleum Ltd. (oil and gas company) from November 1998 to May 2001.
Dave Humphreys Alberta, Canada	Vice President, Operations	Vice President, Operations of Highpine since February 2006; Vice President, Operations of White Fire from April 2005 to February 2006; Vice President, Operations of Virtus Energy Ltd. (oil and gas company) from April 2003 to April 2005; and prior thereto Production Manager of Husky Oil and Production Manager of Ionic Energy Ltd.
Wayne Gray Alberta, Canada	Vice President, Land	Vice President, Land of Highpine since September 2002; and prior thereto Vice President, Land of Trident Exploration Ltd. (oil and gas company).
Fred D. Davidson Alberta, Canada	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, Mr. Carl has been a director since August 2003, Mr. Woolner has been a director since February 2006 and Mr. Hunt has been a director since August 2006.

(2) Member of the Audit Committee.

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

(4) Member of the Reserves Committee.

(5) Highpine does not have an Executive Committee.

As at the date of this Annual Information Form, the number of Common Shares beneficially owned, directly or indirectly, by all of the directors and officers of Highpine is 12,184,000 Common Shares, being approximately 18% of the issued and outstanding Common Shares.

Conflicts of Interest

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

LEGAL PROCEEDINGS

There are no material legal proceedings to which the Corporation is a party or in respect of which any of its property is the subject, nor are any such proceedings known to the Corporation to be contemplated.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There are no material interests, direct or indirect, of any director or executive officer of the Company, any person or company that is the direct or indirect owner of, or who exercises control or direction of, more than 10% of any class or series of the Corporation's outstanding voting securities, or any associate or affiliate of any of the foregoing persons or companies, in any transaction during the year ended December 31, 2006 or during the current financial year that has materially affected or will materially affect the Corporation, other than as disclosed elsewhere in this Annual Information Form. 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.

TRANSFER AGENT AND REGISTRAR

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

MATERIAL CONTRACTS

Other than contracts entered into in the ordinary course of business, there are no material contracts entered into by Highpine during the year ended December 31, 2006 which can reasonably be regarded as presently material.

INTEREST OF EXPERTS

Names of Experts

The only persons or companies who are named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Corporation during, or relating to, the Corporation's most recently completed financial year, and whose profession or business gives authority to the statement, report or valuation made by the person or company, are KPMG LLP, the Corporation's independent auditors, and Paddock, the Corporation's independent engineering evaluators.

Interests of Experts

To the Corporation's knowledge, no registered or beneficial interests, direct or indirect, in any securities or other property of the Corporation or of one of the Corporation's associates or affiliates (i) were held by Paddock, when Paddock prepared the statement, report or valuation in question, (ii) were received by Paddock after Paddock prepared the statement, report or valuation in question, or (iii) is to be received by Paddock.

Neither KPMG LLP or Paddock, nor any director, officer or employee of KPMG LLP or Paddock is or is expected to be elected, appointed or employed as a director, officer or employee of the Corporation or of any associate or affiliate of the Corporation.

KPMG LLP is independent of the Corporation within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

AUDIT COMMITTEE INFORMATION

Composition of the Audit Committee

The Audit Committee of the Corporation is comprised of Hank B. Swartout (Chair), Andrew Krusen and Kenneth S. Woolner. The following table sets out the assessment of each Audit Committee member's independence, financial literacy and relevant educational background and experience supporting such financial literacy.

Name and Municipality of Residence	Independent	Financially Literate	Relevant Education and Experience
Hank B. Swartout Calgary, Alberta	Yes	Yes	Mr. Swartout's education and experience relevant to the performance of his responsibilities as an Audit Committee member are derived from his experience as the Executive Chairman (since January 2007) and as the Chairman and Chief Executive Officer (from November 2005 until January 2007) of Precision Drilling Corporation, the administrator to Precision Drilling Trust, an oil and gas services trust listed on the Toronto Stock Exchange and New York Stock Exchange, and his experience as the Chairman, President and Chief Executive Officer of Precision Drilling Corporation, an oil and gas services company listed on the Toronto Stock Exchange and New York Stock Exchange from July 1987 until November 2005. Through his interaction with Chief Financial Officers over the years, Mr. Swartout has also developed practical experience and understanding of procedures for financial reporting. He has also developed practical experience and understanding of internal controls and procedures for financial reporting from his service on boards and audit committees of numerous publicly traded companies. Mr. Swartout obtained a Petroleum Engineering Degree with honours from the University of Wyoming in 1977.
Andrew Krusen Tampa, Florida	Yes	Yes	Mr. Krusen's education and experience relevant to the performance of his responsibilities as an Audit Committee member are derived from his experience as the Chairman and Chief Executive Officer of Dominion Financial Group, Inc., a financial services company, since 1990. He has also developed practical experience and understanding of procedures for financial reporting from his service on boards of numerous publicly traded companies. Mr. Krusen obtained a Bachelor of Arts in Geology from Princeton University in 1970.
Kenneth S. Woolner Calgary, Alberta	Yes	Yes	Mr. Woolner's education and experience relevant to the performance of his responsibilities as an Audit Committee member are derived from his experience as a President and Chief Executive Officer of publicly traded oil and gas issuers during the past ten years and from his service on boards and audit committees of other publicly traded issuers. Through his interaction with Chief Financial Officers over the years, Mr. Woolner has also developed practical experience and understanding of procedures for financial reporting. Mr. Woolner is a Professional Engineer and obtained a B.Sc. (Geological Engineering) Degree from the University of Toronto in 1983.

Pre-Approval of Policies and Procedures

Under the Mandate and Terms of Reference of the Audit Committee, the Audit Committee is required to review and pre-approve any non-audit services to be provided to the Corporation or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Audit Committee may delegate to one or more independent members the authority to pre-approve non-audit services, provided that the member report to the Audit Committee at the next scheduled meeting such pre-approval and the member comply with such other procedures as may be established by the Audit Committee from time to time.

The Audit Committee has determined that in order to ensure the continued independence of the auditors, only limited non-audit related services will be provided to the Corporation by KPMG LLP and in such case, only with the prior approval of the Audit Committee.

Audit Committee Mandate and Terms of Reference

Role and Objective

The Audit Committee is a committee of the Board of Directors (the "**Board**") of the Corporation to which the Board has delegated its responsibility for the oversight of the nature and scope of the annual audit, the oversight of management's reporting on internal accounting standards and practices, the review of financial information, accounting systems and procedures, financial reporting and financial statements and has charged the Audit Committee with the responsibility of recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information.

The primary objectives of the Audit Committee are as follows:

1. to assist directors in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of the Corporation and related matters;

2. to provide better communication between directors and external auditors;

3. to enhance the external auditors' independence;

4. to increase the credibility and objectivity of financial reports; and

5. to strengthen the role of the independent directors by facilitating in depth discussions between directors on the Audit Committee, management and external auditors.

Membership of Audit Committee

1. The Audit Committee will be comprised of at least three (3) directors of the Corporation or such greater number as the Board of Directors may determine from time to time and all members of the Audit Committee shall be "independent" (as such term is used in Multilateral Instrument 52-110 – Audit Committees ("**MI 52-110**") unless the Board determines that the exemption contained in MI 52-110 is available and determines to rely thereon.

2. The Board of Directors may from time to time designate one of the members of the Audit Committee to be the Chair of the Audit Committee.

3. All of the members of the Audit Committee must be "financially literate" (as defined in MI 52-110) unless the Board determines that an exemption under MI 52-110 from such requirement in respect of any particular member is available and determines to rely thereon in accordance with the provisions of MI 52-110.

Mandate and Responsibilities of Audit Committee

It is the responsibility of the Audit Committee to:

1. Oversee the work of the external auditors, including the resolution of any disagreements between management and the external auditors regarding financial reporting.

2. Satisfy itself on behalf of the Board with respect to the Corporation's internal control systems:

   (a) identifying, monitoring and mitigating business risks; and

   (b) ensuring compliance with legal, ethical and regulatory requirements.

3. Review the annual and interim financial statements of the Corporation and related management's discussion and analysis ("**MD&A**") prior to their submission to the Board for approval. The process should include but not be limited to:

   (a) reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future years' financial statements;

   (b) reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;

   (c) reviewing accounting treatment of unusual or non-recurring transactions;

   (d) ascertaining compliance with covenants under loan agreements;

   (e) reviewing disclosure requirements for commitments and contingencies;

   (f) reviewing adjustments raised by the external auditors, whether or not included in the financial statements;

   (g) reviewing unresolved differences between management and the external auditors; and

   (h) obtain explanations of significant variances with comparative reporting periods.

4. Review the financial statements, prospectuses and other offering documents, MD&A, annual information forms ("**AIF**") and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval. The Audit Committee must be satisfied that adequate procedures are in place for the review of the Corporation's disclosure of all other financial information and will periodically assess the accuracy of those procedures.

5. Review and approve the disclosure of audit committee information required to be included in the AIF of the Corporation prior to its filing with regulatory authorities.

6. With respect to the appointment of external auditors by the Board:

   (a) recommend to the Board the external auditors to be nominated;

   (b) recommend to the Board the terms of engagement of the external auditors, including the compensation of the auditors and a confirmation that the external auditors will report directly to the Audit Committee;

   (c) on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Corporation to determine the auditors' independence;

   (d) when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and

   (e) review and pre-approve any non-audit services to be provided to the Corporation or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Audit Committee may delegate to one or more independent members the authority to pre-approve non-audit services, provided that the member(s) report to the Audit Committee at the next scheduled meeting such pre-approval and the member(s) comply with such other procedures as may be established by the Audit Committee from time to time.

7. Review with external auditors (and internal auditor if one is appointed by the Corporation) their assessment of the internal controls of the Corporation, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Audit Committee will also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of the Corporation and its subsidiaries.

8. Review risk management policies and procedures of the Corporation (i.e. hedging, litigation and insurance).

9. Establish a procedure for:

   (a) the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters; and

   (b) the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.

10. Review and approve the Corporation's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of the Corporation.

The Audit Committee has authority to communicate directly with the internal auditors (if any) and the external auditors of the Corporation. The external auditors shall be required to report directly to the Audit Committee. The Audit Committee will also have the authority to investigate any financial activity of the Corporation. All employees of the Corporation are to cooperate as requested by the Audit Committee.

The Audit Committee may also retain persons having special expertise and/or obtain independent professional advise to assist in filling their responsibilities at such compensation as established by the Audit Committee and at the expense of the Corporation without any further approval of the Board.

Meetings and Administrative Matters

1. At all meetings of the Audit Committee every question shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall be entitled to a second or casting vote.

2. The Chair will preside at all meetings of the Audit Committee, unless the Chair is not present, in which case the members of the Audit Committee that are present will designate from among such members the Chair for purposes of the meeting.

3. A quorum for meetings of the Audit Committee will be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Audit Committee will be the same as those governing the Board unless otherwise determined by the Audit Committee or the Board.

4. Meetings of the Audit Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Audit Committee will be taken. The Chief Financial Officer will attend meetings of the Audit Committee, unless otherwise excused from all or part of any such meeting by the Chairman.

5. The Audit Committee will meet with the external auditors at least once per year (in connection with the preparation of the year-end financial statements) and at such other times as the external auditors and the Audit Committee consider appropriate.

6. Agendas, approved by the Chair, will be circulated to Audit Committee members along with background information on a timely basis prior to the Audit Committee meetings.

7. The Audit Committee may invite such officers, directors and employees of the Corporation as it sees fit from time to time to attend at meetings of the Audit Committee and assist in the discussion and consideration of the matters being considered by the Audit Committee.

8. Minutes of the Audit Committee will be recorded and maintained and circulated to directors who are not members of the Audit Committee or otherwise made available at a subsequent meeting of the Board.

9. The Audit Committee may retain persons having special expertise and may obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation.

10. Any members of the Audit Committee may be removed or replaced at any time by the Board and will cease to be a member of the Audit Committee as soon as such member ceases to be a director. The Board may fill vacancies on the Audit Committee by appointment from among its members. If and whenever a vacancy exists on the Audit Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, following appointment as a member of the Audit Committee each member will hold such office until the Audit Committee is reconstituted.

11. Any issues arising from these meetings that bear on the relationship between the Board and management should be communicated to the Chairman of the Board by the Audit Committee Chair.

External Auditors Service Fees

The following table sets forth the audit service fees billed by Highpine's external auditors, KPMG LLP, for the periods indicated:

Type of Fees and Fiscal Year Ended	Aggregate Fees Billed	Description of Services
Audit Fees		
Fiscal Year Ended December 31, 2006	$210,000	Audit of consolidated financial statements and review of interim financial statements
Fiscal Year Ended December 31, 2005	$180,000	Audit of consolidated financial statements and review of interim financial statements
Audit – Related Fees		
Fiscal Year Ended December 31, 2006	$103,900	Professional services rendered with respect to the completion of the information circulars in connection with the White Fire Arrangement and the Kick Arrangement, completion of the February 22, 2006 equity offering and French translation of financial documents
Fiscal Year Ended December 31, 2005	$95,000	Professional services rendered with respect to the completion of the Initial Public Offering and the information circular in connection with the Vaquero Arrangement
Tax Fees		
Fiscal Year Ended December 31, 2006	$39,795	Various taxation matters
Fiscal Year Ended December 31, 2005	$33,620	Various taxation matters
All Other Fees		
Fiscal Year Ended December 31, 2006	$nil	Not applicable
Fiscal Year Ended December 31, 2005	$nil	Not applicable

ADDITIONAL INFORMATION

Additional information relating to Highpine may be found on SEDAR at www.sedar.com and also on Highpine's website at www.highpineog.com.

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Highpine's securities and securities authorized for issuance under equity compensation plans is contained in Highpine's information circular – proxy statement dated March 16, 2007 relating to the annual general meeting of shareholders to be held on May 9, 2007.

Additional information is also provided in Highpine's consolidated financial statements and management's discussion and analysis for the year ended December 31, 2006, which documents may be found on SEDAR at www.sedar.com.

GLOSSARY OF TERMS

"**665162**" means 665162 B.C. Ltd., a corporation incorporated pursuant to the *Business Corporations Act* (British Columbia);

"**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;

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

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

"**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, includes Rubicon, Highpine Partnership, Highpine Energy and 665162;

"**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;

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

"**Highpine Energy**" means Highpine Energy Ltd. (formerly Vaquero Energy Ltd.), a corporation amalgamated pursuant to the ABCA;

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

"**Initial Public Offering**" the initial public offering of 4,000,000 Common Shares of the Corporation at a price of $18.00 per Common Share completed on April 5, 2005;

"**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;

"**Kick**" means Kick Energy Corporation, a corporation incorporated pursuant to the ABCA;

"**Kick Arrangement**" means the plan of arrangement under the ABCA involving Highpine, Kick and the shareholders of Kick completed on August 1, 2006, as more particularly described under "General Development of the Business – Significant Acquisitions and Recent Developments";

"**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 15, 2007 report prepared by Paddock, evaluating the crude oil, natural gas and NGL reserves of Highpine, as at December 31, 2006, 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;

"**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 for approximately $51 million;

"**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 a special warrant indenture dated as of October 20, 2004 between the Corporation and Valiant Trust Company;

"**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;

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

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

"**Vaquero**" means Vaquero Energy Ltd., a corporation incorporated pursuant to the ABCA;

"**Vaquero Arrangement**" means the plan of arrangement under the ABCA involving Highpine, Vaquero and the securityholders of Vaquero completed on May 31, 2005, as more particularly described under "General Development of the Business – Significant Acquisitions and Recent Developments";

"**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;

"**White Fire**" means White Fire Energy Ltd., a corporation incorporated pursuant to the ABCA;

"**White Fire Arrangement**" means the plan of arrangement under the ABCA involving Highpine, White Fire and the shareholders of White Fire completed on February 21, 2006, as more particularly described under "General Development of the Business – Significant Acquisitions and Recent Developments".

ABBREVIATIONS

Crude Oil and Natural Gas Liquids		Natural Gas	
bbl	one barrel	Mcf	one thousand cubic feet
bbls	barrels	MMcf	one million cubic feet
bbls/d	barrels per day	Bcf	one billion cubic feet
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)	Mcf/d	one thousand cubic feet per day
Mboe	one thousand barrels of oil equivalent	MMcf/d	one million cubic feet per day
MMboe	one million barrels of oil equivalent	GJ	gigajoule
BOE/d	barrels of oil equivalent per day	GJs/d	gigajoules per day
NGL	natural gas liquids	Btu	British thermal unit
stb	standard stock tank barrel	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 between Standard Imperial Units and 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

SCHEDULE A
REPORT ON RESERVES DATA BY PADDOCK LINDSTROM & ASSOCIATES LTD.
IN ACCORDANCE WITH 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, 2006. The Reserves Data consist of the following:

   (a) proved and proved plus probable oil and gas reserves estimated as at December 31, 2006 using forecast prices and costs; and

   (b) the related estimated future net revenue; and

   (c) proved oil and gas reserves estimated as at December 31, 2006, using constant prices and costs; and

   (d) 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.

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

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

5. 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, 2006, 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 ($ thousands - before income taxes, 10% discount rate)			
			Audited ($)	Evaluated ($)	Reviewed ($)	Total ($)
Paddock Lindstrom & Associates Ltd.	Evaluation of the P&NG Reserves of Highpine Oil & Gas Limited, as of December 31, 2006 prepared February 15, 2007	Canada	0	773,980	0	773,980

6. 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.

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

8. 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
March 30, 2007

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

SCHEDULE B
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, 2006 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, 2006 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:

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

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

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

The Board of Directors 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:

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

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

(c) the content and filing of this report.

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

(Signed) A. Gordon Stollery Chairman and Chief Executive Officer	(Signed) Greg N. Baum President and Chief Operating Officer
(Signed) Richard G. Carl Director	(Signed) Andrew Krusen Director

March 30, 2007

END