



WINSTAR RESOURCES LTD.

**ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2006**

March 30, 2007

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INTERPRETATION

Glossary

In this Annual Information Form (as defined below), the highlighted terms set forth below have the following meanings:

“AIF” or **“Annual Information Form”** means this Annual Information Form of the Corporation dated March 30, 2007

“APA” means “APA Petroleum Engineering, a subsidiary of RPS Energy, operating as RPS-APA, independent reserve evaluators, Calgary, Alberta;

“Common Shares” means the common shares in the capital of the Corporation;

“Corporation” means Winstar Resources Ltd.;

“Crown” means Her Majesty the Queen in Right of Canada or a Province thereof;

“Crude oil” or **“oil”** means a mixture, consisting mainly of pentanes and heavier hydrocarbons that may contain sulphur compounds, that is liquid at the conditions under which its volume is measured or estimated, but excluding such liquids obtained from the processing of natural gas;

“Gross” means:

in relation to the Corporation’s interest in production and reserves, which are the Corporation’s interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Corporation;

in relation to wells, the total number of wells in which the Corporation has an interest; and

in relation to properties, the total area of properties in which the Corporation has an interest;

“McDaniel” means McDaniel & Associates Consultants Ltd., independent reserve evaluators, Calgary, Alberta;

“Natural gas” means the light hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions is essentially a gas, but which may contain liquids. Natural gas reserve estimates are reported on a marketable basis, that is gas which is available to a transmission line after removal of certain hydrocarbons and non-hydrocarbon compounds present in the raw natural gas and which meets specifications for use as a domestic, commercial or industrial fuel;

“**Natural gas liquids**” or “**NGL**” means those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants or recovered from field separators, scrubbers or other gathering facilities. These liquids include the hydrocarbon components ethane, propane, butanes and pentanes plus, or a combination thereof;

“**Net**” means:

in relation to the Corporation’s interest in production and reserves, the Corporation’s interest (operating and non-operating) share after deduction of royalties obligations, plus the Corporation’s royalty interest in production or reserves.

in relation to wells, the number of wells obtained by aggregating the Corporation’s working interest in each of its gross wells; and

in relation to the Corporation’s interest in the property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.

“**NI 51-101**” means National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*.

“**Undeveloped land**” refers to oil and gas properties to which no reserves are assigned.

Abbreviations

In this Annual Information Form, the abbreviations set forth below have the following meanings:

Crude Oil		Natural Gas	
bbl	barrel of oil	Mcf	thousand cubic feet of gas
bopd	barrels of oil per day	Mcfd	thousand cubic feet per day of gas
bpd	barrels per day	MMcf	million cubic feet of gas
Mbbl	thousand barrels of oil	m ³	cubic metres of gas
m ³	cubic metres of oil	boepd	barrels of oil equivalent per day
boepd	barrels of oil equivalent per day	NGL	natural gas liquids
		bcf	Billion cubic feet of gas

Conversion

To Convert From	To	Multiply By
Mcf	Boe	0.16
Mcf	m ³	28.174
m ³	cubic feet	35.494

To Convert From	To	Multiply By
Bbl	cubic metres	0.159
cubic metres	bbl	6.290
Acres	Hectares	0.405
Hectares	Acres	2.471

Forward-Looking Statements

This Annual Information Form contains forward-looking statements. These statements relate to future events or future performance of the Corporation. When used in this Annual Information Form, the words “may”, “would”, “could”, “will”, “intend”, “plan”, “anticipate”, “believe”, “estimate”, “predict”, “seek”, “propose”, “expect”, “potential”, “continue”, 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. Such statements reflect the Corporation’s current views with respect to certain events, and are subject to certain risks, uncertainties and assumptions. Many factors could cause the Corporation’s actual results, performance, or achievements to vary from those described in this Annual Information Form. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this Annual Information Form as intended, planned, anticipated, believed, estimated, or expected. Specific forward-looking statements in this Annual Information Form include, among others, statements pertaining to the following:

- factors upon which the Corporation will decide whether or not to undertake a specific course of action;
- world-wide supply and demand for petroleum products;
- expectations regarding the Corporation’s ability to raise capital;
- treatment under governmental regulatory regimes; and
- commodity prices.

With respect to forward-looking statements in this Annual Information Form, the Corporation has made assumptions, regarding, among other things:

- the impact of increasing competition;
- the Corporation’s ability to obtain additional financing on satisfactory terms; and
- the Corporation’s ability to attract and retain qualified personnel.

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

- general economic conditions;
- volatility in global market prices for oil and natural gas;

- competition;
- liabilities and risks, including environmental liability and risks, inherent in oil and gas operations;
- the availability of capital;
- alternatives to and changing demand for petroleum products;
- changes in legislation and the regulatory environment; and
- the other factors considered under “Risk Factors” herein.

Furthermore, statements relating to “reserves or “resources” are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitable in the future.

The forward-looking statements contained in this Annual Information Form are expressly qualified in their entirety by this cautionary statement. These statements speak only as of the date of this Annual Information Form. The Corporation does not intend and does not assume any obligation, to update these forward-looking statements to reflect new information, subsequent events or otherwise, except as required by law.

THE CORPORATION

The Corporation was incorporated by certificate of incorporation dated January 2, 1996 under the *Business Corporations Act* (Alberta) as 679601 Alberta Inc. The Corporation amended its articles on February 15, 1996 to, among other things, change its name to Virginia Energy Corporation. On August 1, 2000, the articles of the Corporation were amended to consolidate its Common Shares on the basis of one new Common Share for each five existing Common Shares and to change the Corporation’s name from Virginia Energy Corporation to Winstar Resources Ltd. On July 31, 2003, the Corporation was amalgamated with Warwick Energy Ltd. On October 25, 2005, the Corporation once again amended its articles to consolidate its Common Shares on the basis of one new Common Share for each five existing Common Shares. Effective December 29, 2006 the Common Shares began trading on the Toronto Stock Exchange under the symbol “WIX”. Simultaneously, the Common Shares were de-listed from the TSX Venture Exchange.

The Corporation has its registered office at Suite 4300, 888 – 3rd Street, S.W., Calgary, Alberta, T2P 5C5 and its principal business office at Suite 845, 401 – 9th Avenue S.W., Calgary, Alberta T2P 3C5.

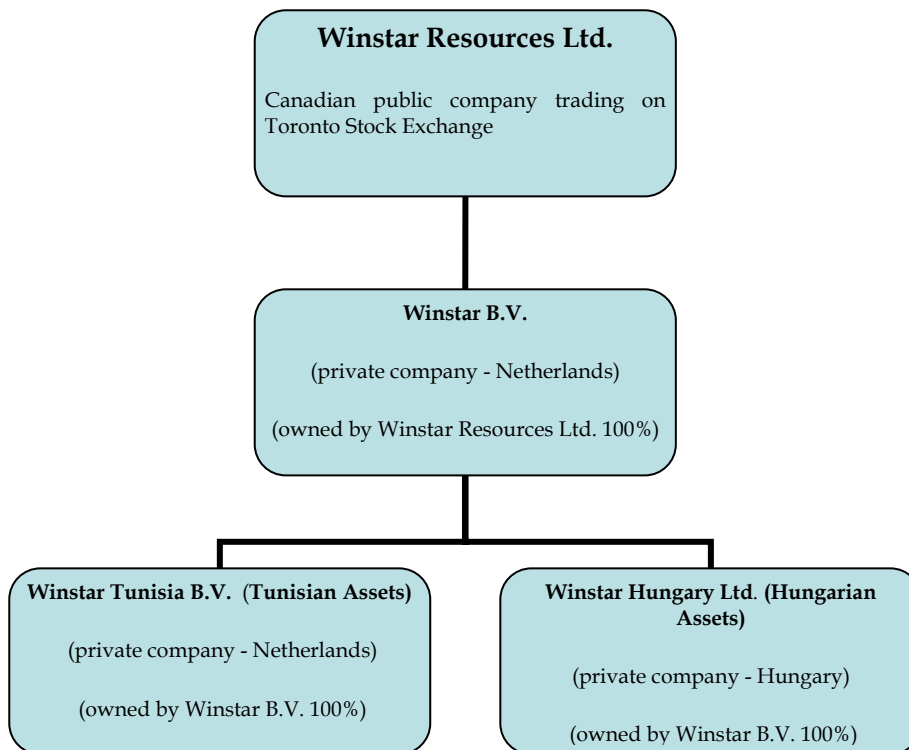
As at year-end 2006, the Corporation had 68 full time employees and contract employees.

The Corporation has one wholly owned subsidiary, Winstar B.V., a private company incorporated in Amsterdam, the Netherlands with limited liability under Dutch laws. Winstar B.V. was incorporated on May 1, 2001 under the name Athanor Tunisia Holding B.V. The name was changed effective June 19, 2001 to Athanor B.V. and again effective December 8, 2005 to Winstar B.V.

The official seat of Winstar B.V. is in Amsterdam, the Netherlands, which is the Dutch equivalent of a registered office. Winstar B.V. currently maintains its head office at Max Euwelaan 61, 3062 MA Rotterdam, the Netherlands.

Winstar B.V. currently has two wholly owned subsidiaries, Winstar Tunisia B.V. and Winstar Hungary Ltd. Winstar Tunisia B.V. is also a private company incorporated in Amsterdam, the Netherlands with limited liability under Dutch laws. Winstar Tunisia B.V. maintains an office at Immeuble Léman Center, 3eme étage Bloc D, Rue du Lac Léman, Tunis 1053, Tunisia. The other wholly owned subsidiary, Winstar Hungary Ltd., is a private corporation incorporated under the laws of Hungary with an office at Arany Janos u8, Szolnok 5000, Hungary.

The corporate structure of the Corporation is set out below:



GENERAL DEVELOPMENT OF THE BUSINESS

Since its inception in 1996, the Corporation has focused on the identification and acquisition of opportunities in oil and gas properties in Western Canada, specifically in the Province of Alberta. The Corporation was listed as a Junior Capital Pool company through the facilities of the Alberta Stock Exchange in April, 1996, with trading of its Common Shares commencing in May, 1996. On July 31, 1996, the Corporation completed its “qualifying transaction” whereby it acquired a 100% working interest in 640 acres in the Virginia Hills area of Alberta, a 75% working interest in 160 acres in the Zama Lake area of

Alberta and a 10% working interest at Sturgeon Lake, Alberta for aggregate consideration of \$1,412,500, consisting of 2,825,000 Common Shares valued at \$0.50 per share. During the same month, the Corporation farmed in on four additional prospects in the Zama Lake area, three at 100% and a fourth at 50%, whereby the Corporation granted the farmor a 10% non-convertible overriding royalty in such properties. The Corporation later acquired the remaining 50% interest in the fourth Zama Lake property in exchange for 166,800 Common Shares valued at \$0.60 per share for an aggregate consideration of \$100,080.

In December, 1996, the Corporation completed a public offering of 797,000 Common Shares at \$0.30 per share and 4,691,985 Common Shares issued on a "flow-through" basis at \$0.35 per share via a prospectus dated November 28, 1996 for gross proceeds of \$1,881,295.

In 1996 and 1997, the Corporation purchased oil and gas leases in the Virginia Hills area for a total cost to the Corporation of \$132,000. The Virginia Hills leases were not drilled by the Corporation and were subsequently sold in January 2000 for gross proceeds of \$64,000.

In August, 1997, the Corporation purchased an oil and gas lease in the Zama Lake area for \$15,500. In March, 1998, the Corporation acquired a suspended wellbore located on the Zama Lake lease, plus a capped gas well and 640 acres of associated lands in the Rainbow Lake area of Alberta for a nominal consideration and the assumption of all future abandonment and reclamation costs associated with such wells.

Effective March, 1998, the Corporation acquired an additional 23.3334% working interest in the Sturgeon Lake property at a total cost to the Corporation of \$410,000, thereby increasing its interest in the property to 33.3334%. The Corporation financed this acquisition through its operating capital, bank financing of \$170,000, and a private placement to several of the Corporation's directors of 1,000,000 Common Shares at \$0.10 per share.

In March, 1999, the Corporation sold a 10% working interest in the Sturgeon Lake property for total proceeds of \$220,000, and farmed out a 23.3334% working interest in a test well drilled on its Sturgeon Lake lands. That farmout also included an option to drill additional wells at Sturgeon Lake, whereby the farmee would participate for a 20.0% working interest and the Corporation would participate for a 3.3334% working interest. In total, three wells were drilled on the Sturgeon Lake property pursuant to the farmout and option. The farmout well was a Leduc oil well in which the Corporation retained an overriding royalty before payout, convertible to an 11.3334% working interest after payout of the well, and the two option wells were dry holes.

In July, 2000, the Corporation amended its articles to consolidate its 16,116,499 issued and outstanding Common Shares on a one for five basis, following which 3,233,300 Common Shares were issued and outstanding. The Corporation also changed its name to Winstar Resources Ltd. as part of such amendment.

Effective October 30, 2000, three directors of the Corporation acquired from Backer Petroleum Corp. ("**Backer**"), debt in the amount of \$177,734 owing from the Corporation to Backer. Upon completion of such acquisition, the Corporation converted the debt into

1,481,117 Common Shares at a price of \$0.12 per share. As of November 23, 2000, there were 4,704,417 Common Shares of the Corporation issued and outstanding.

In November, 2000, the Corporation farmed out a significant portion of the costs required to tie-in and equip a previously suspended 100% working interest gas well in the Rainbow Lake area of northwest Alberta. Construction of approximately 10 kilometres of flow line was initiated in December, 2000, and the well was placed on production in February, 2001. The Corporation retained a 48% working interest in the well until payout of the flow line and equipping costs, at which time the Corporation's after payout interest increased to 77.5%.

In December, 2000, the Corporation completed a private placement of 1,500,000 Common Shares on a "flow-through" basis at a price of \$0.25 per share, for gross proceeds of \$375,000. These funds were raised to finance the Corporation's ongoing activities on its Sturgeon Lake property.

In February, 2001, the Corporation entered into a joint venture agreement with Pivotal Energy Ltd. ("**Pivotal**"), a junior energy corporation whose shares traded on the Canadian Venture Exchange, whereby until February 2002, the Corporation had the opportunity to participate for 15% of Pivotal's interest in specific new oil and gas exploration, development, or acquisition opportunities developed by Pivotal.

During the second and third quarters of 2001, various remedial workovers were implemented on three of the Corporation's previously suspended Nisku or Devonian oil wells at Sturgeon Lake. These efforts were successful in establishing additional natural gas production from two of the worked over wells. Also during the third quarter of 2001, a suspended Leduc oil well in which the Corporation holds a gross overriding royalty was reworked by the operator, at no cost to the Corporation, and successfully established oil production from the Nisku formation. The Nisku has proven productive in two other Sturgeon Lake wells in which the Corporation holds a working interest, one of which continues to produce. See discussion of Sturgeon Lake under heading "Business and Properties of the Corporation - Principal Properties".

On December 28, 2001, the Corporation announced that a non-brokered private placement of 887,500 Common Shares on a flow-through basis was closed. Those Common Shares were issued at a price of \$0.20 per share, with total proceeds to the Corporation of \$175,500. Those funds were used for ongoing development at Sturgeon Lake and to participate in a joint venture with Cigar Oil and Gas Ltd.

During the fourth quarter of 2001, the Corporation recompleted two existing well bores, drilled two new wells, and re-entered and recompleted a previously abandoned well at Sturgeon Lake South increasing sales production to 715 Mcfd net to the Corporation by year end. At that time, the Corporation had a varied working interest from 15.6% to 23.3% at Sturgeon Lake. At Rainbow South, the Corporation shut-in its 48% before payout working interest gas well during the fourth quarter. The gas well which averaged 429 Mcfd and 8.5 bbl of condensate per day net during September, 2001, was shut-in due to low natural gas prices and high gas processing fees charged by a third party gas processor. By year-end the Corporation, pursuant to the Cigar Joint Venture, acquired 15% working

interest in 1440 gross acres (216 net acres), and participated at a 15% working interest in the drilling of three exploratory dry holes plus a successful recompletion of a suspended gas well at Gordondale in the Peace River Arch area of northwest Alberta.

On January 29, 2002 the Corporation issued 350,000 Common Shares for \$0.16 per share through a private placement for gross proceeds of \$56,000. On February 18, 2002 the Corporation entered into a purchase agreement to acquire an additional 40% working interest before payout at Rainbow South for \$500,000. This purchase, plus the reversion of 4.5% working interest to the Corporation from a partner at payout, increased the Corporation's position to 92.5% working interest during the first quarter of 2002.

On March 13, 2002 the Corporation completed an asset swap which was entered into in January 2002. The Corporation swapped its 92.5% working interest at Rainbow South, for a net 92.5% working interest in a net +60 boepd producing oil field at Taber (Midland) plus net \$940,000 cash. The transaction resulted in a loss of \$216,542 based upon the relative values of proved reserves of the disposed property to total reserve value. During the first quarter the Corporation began producing gas from two new wells and one recompleted well at Sturgeon Lake (0.6 net well), plus a recompleted well at Gordondale (0.15 net well).

On July 11, 2002 pursuant to an option agreement dated May 29, 2002, the Corporation issued 8,000,000 Common Shares at \$0.275 per share to assignees of O'Regan Resources Ltd., generating gross proceeds of \$2,200,000. On December 18, 2002, the Corporation completed a private placement of 4,420,000 Common Shares on a flow-through basis for \$0.40 per share for gross proceeds of \$1,768,000. As of December 31, 2002 the Corporation had 20,099,917 issued and outstanding Common Shares (21,702,247 on a fully diluted basis).

On July 18, 2003 the Corporation committed to spend \$10.5 million on drilling, completion and equipping costs on the Ferrier-Whitecourt lands prior to July 2005, to earn approximately 82 net (approximately 182 gross) sections within the Ferrier Whitecourt corridor of Central Alberta.

On July 31, 2003, the Corporation completed the acquisition of all of the outstanding shares of Warwick Energy Ltd. ("**Warwick**"), a private Canadian company having an enterprise value of \$8.1 million, for total consideration of 302,858 Common Shares valued at \$0.70 per share and \$7,382,500 in cash plus the assumption of Warwick's net liabilities. Warwick was amalgamated with the Corporation on July 31, 2003.

On August 8, 2003, the Corporation closed a private placement of 10,000,000 Common Shares at a price of \$0.70 per share for gross proceeds of \$7,000,000. Proceeds of that offering were designated to finance continuing exploration and development activities and for general corporate purposes.

On December 5, 2003, the Corporation completed an issue of 1,907,000 Common Shares at a price of \$1.05 per share and 3,570,000 Common Shares on a "flow-through" basis at a price of \$1.40 per share with an underwriting syndicate led by First Associates Investments Inc. and including Haywood Securities Inc. The net proceeds of that offering

were utilized primarily to fund an exploration program on the Corporation's farm-in acreage, and for continued exploration and development on its inventory of properties.

During 2004, the Corporation participated in the drilling of ten wells (2.73 net wells), resulting in three gas wells (1.7 net wells), three oil wells (0.27 net wells), one dry hole (0.5 net wells) and three standing wells (0.26 net wells). In addition to drilling the Corporation re-completed eleven wells (8.61 net wells) resulting in three gas wells (2.16 net wells), two oil wells (1.5 net wells), one producing oil and gas well (0.6 net wells) and five suspended wells (4.35 net wells).

On December 17, 2004, the Corporation completed a non-brokered private placement of 381,818 Common Shares on a "flow-through" basis at \$0.55 per share for aggregate proceeds of \$210,000. The Corporation has since satisfied its obligations to renounce resource expenditures in respect of such Common Shares.

Beginning in late 2004 and culminating in February 2005, the Corporation embarked upon a number of transactions in an attempt to refocus the Corporation towards assets in Alberta that have a high working interest, are well operated, with low finding and development costs and high operating income netbacks.

In January 2005, the Corporation commenced a \$7 million capital program, consisting of the drilling of six new wells (of which the Corporation will have a working interest in the range of 25% - 100%) and the re-completion of nine suspended wells (of which the Corporation will have a working interest in the range of 10% - 100%).

On January 25, 2005, the Corporation fulfilled the earning obligations under the July 2003 farm-in agreement in the Ferrier-Whitecourt Area. The Corporation, on basic terms of pay (100% to earn, 60% without payout), spent \$6.5 million gross (\$2.5 million net) on drilling five gross oil and gas wells (0.98 net wells) and the re-completion of six existing oil and gas wells (6.0 net wells) resulting in 270 boepd (130 boepd net) of productive capacity. The Corporation earned 137 gross (58 net) sections of Cretaceous petroleum and natural gas rights.

On February 2, 2005, the Corporation closed the purchase of the residual working and royalty interests within 137 gross sections of Ferrier-Whitecourt land earned in January 2005, effective as of December 1, 2004. Pursuant to the purchase, the Corporation acquired an additional 29 net sections of undeveloped land, with six gross (1.78 net) wells that are producing or capable of producing approximately 212 gross (85 net) boepd; 50 net sections of land with five gross (3.9 net) producing wells (having a 2.5% - 10% GORR interest); and 7.45 net suspended wells with re-completion potential. In addition, the Corporation was relieved of \$0.9 million of additional obligations under its original farm-in agreement. The Corporation paid \$2.45 million and transferred the Corporation's 60% working interest in two gross (1.20 net) sections, including the 10-35-59-2W6 Boltan Creek well bore which the Corporation drilled and cased in November 2004.

On February 18, 2005, the Corporation sold all of its Saskatchewan assets to an oil and gas royalty trust, effective January 1, 2005. The Corporation received \$11.75 million, subject to purchase price adjustments, for the sale of approximately 350 (net) boepd of

current production and 30 gross (19 net) sections of developed and undeveloped land concentrated in southeast Saskatchewan. The Corporation's Saskatchewan reserves were independently evaluated by McDaniel in their report dated February 10, 2005 at \$7.5 million for proved and probable reserves (proved reserves of 602.1 Mbbl and probable reserves of 248.0 Mbbl), discounted at 10% based on forecast prices and costs effective December 31, 2004. The Corporation's Saskatchewan undeveloped lands were evaluated by Seaton-Jordan at \$0.25 million effective December 31, 2004.

On August 22, 2005, the Corporation completed its acquisition of Athanor B.V. ("**Athanor**"), a private Dutch oil and gas company active in Tunisia and Hungary and incorporated in the Netherlands, for 56.98 million Common Shares. Athanor owned and operated five onshore concessions in Tunisia covering an area of 236 net square miles (four concessions at 100% working interest, one at 45% working interest) with approximately 570 boepd of high net back production. The Sabria Concession (45% working interest) located in west-central Tunisia is Athanor's core asset with production 775 (350 net) boepd from a fractured Ordovician quartzite at 4,000 meters depth. At the time of the acquisition, the Sabria field had an estimated 1.1 million barrels of net proven reserves and an additional 5.3 million barrels of probable reserves (at December 31, 2004: APA Petroleum Engineers-Constant Price Evaluation). See sections "Principal Properties" and "Reserves Data and Other Oil and Gas Information" below for current status of properties and reserve values.

At the time of the acquisition, Athanor also had a Hungarian subsidiary, El Paso Hungary Oil and Gas Limited Liability Company (now Winstar Hungary Ltd.) with 470 boepd of high net back gas production in Hungary. Production was derived from a single gas well, in south-western Hungary, completed in a Tertiary Limestone at less than 800 meters depth, with 2.6 bcf remaining recoverable reserves (December 31, 2004: APA Petroleum Engineers Constant Price Evaluation). See sections "Principal Properties" and "Reserves Data and Other Oil and Gas Information" below for current status of properties and reserve values. Included is 420 miles of in-house seismic and offset mineral rights (888 square miles). Athanor consultant Gabor Tihanyi, a Hungarian petroleum engineer with more than 20 years of oil and gas industry experience, assumed all operational responsibilities as General Manager of the Hungarian operations for the Corporation.

On August 22, 2005, the Corporation also completed a private placement of 17,111,111 Common Shares at a price of \$0.45 per share for gross proceeds of approximately \$7,199,999 and the deemed issuance of Common Shares pursuant to the 30,333,334 subscription receipts of the Corporation issued pursuant to a private placement on July 7, 2005 at a price of \$0.45 per subscription receipt for gross proceeds of approximately \$13,650,000.

On October 25, 2005, the Common Shares were consolidated on a one for five basis and the Corporation's stock symbol was changed from "WRL" to "WIX". Pre-consolidation shareholders of the Corporation were issued one Common Share for each five Common Shares of the Corporation held prior to consolidation.

On December 16, 2005, the Corporation completed a private placement of "flow-through" Common Shares of the Corporation. The private placement was completed on a

non-brokered basis for 212,766 Common Shares, at a price of \$2.35 per share for gross proceeds of \$500,000.

On December 13, 2006, the Corporation completed a private placement of 100,000 Common Shares on a "flow-through" basis to directors, officers and employees of the Corporation at \$3.00 per share for gross proceeds of \$300,000.

In 2007, the Corporation is looking to follow up on the results of the high impact drilling in Tunisia and Canada, and to continue with exploration in Hungary. The Corporation is also actively looking for other opportunities internationally and in Canada.

The Corporation's principal focus now is the identification and acquisition of opportunities in oil and gas properties in Western Canada, Tunisia and Hungary. At year end of 2006, the Corporation owned working interests in four principal producing oil and gas properties in Alberta, five production concessions in Tunisia, one exploration permit in Hungary and a production concession in Hungary.

BUSINESS AND PROPERTIES OF THE CORPORATION

Principal Properties

Alberta properties and assets

The following is a description of the principal properties of the Corporation located with the Province of Alberta.

Taber: Taber is located about 240 kilometres south of Calgary. The Corporation has a 100% working interest in 2,760 gross acres in Taber. There are 13 producing oil wells which at year end 2006 produced a total of 105 boepd of medium gravity crude from the Mannville. There is one water disposal well into which about 900 boepd of produced water is re-injected to the Mannville zone.

Sturgeon Lake: Sturgeon Lake is just west of Valleyview, approximately 360 kilometres northwest of Edmonton. The Corporation has an average 69.2% working interest in 6,611 gross acres, approximately 4,573 net acres of land. The Corporation has a 51.7% working interest in a producing Notikewin/Fahler gas well and 90% in a Montney gas well. In addition, the Corporation has working interests ranging from 33.5% to 51.7% in seven suspended oil wells and five suspended gas wells. Plans are underway to drill a horizontal Leduc test from an existing surface lease. Due to the sour nature of this target, planning and approvals are a lengthy process. The Corporation anticipates drilling this Leduc test and a Montney well in the second and third quarter of 2007. At the year ended December 31, 2006, Sturgeon Lake was producing 25 boepd net (monthly average). Current production is approximately 20 boepd net.

Herronton: Herronton is located about 100 kilometres southeast of Calgary. The Corporation participated in the drilling of two wells in 2005, resulting in a 50% working interest in an oil well and a 25% working interest in a gas well. The Corporation now operates three wells in this area which are tied-in to a central processing facility and at the

year ended December 31, 2006, were producing a 20 boepd net. Current production is approximately net 15 boepd (monthly average).

Ferrier (Brazeau & Sunchild) - Whitecourt (Edson, Windfall, West Pembina): In July 2003, the Corporation entered into an agreement with a major company for a two year, \$10.5 million work commitment to earn an interest in about 182 gross (82 net) sections of land. The Corporation during 2004 fulfilled this commitment, as well as evaluated other adjacent assets through the 5 gross (4.5 net) recompletions or re entries on pre-existing wells and drilling of 6 gross (1.73 net) new wells, resulting in 4 gross (2.76 net) successful recompletions and 5 gross (1.65 net) new discoveries of oil or gas. The Corporation continues to develop the extensive land base in this area.

The Corporation continued to develop the extensive land base in this area. During 2005 nine wells were drilled resulting in three gross (1.1 net) gas wells and two gross (0.75 net) oil wells, three gross (0.9 net) standing cased and one gross (0.29 net) dry hole. Five gross (3.1 net) wells were recompleted in 2005 and two gross (1.5 net) wells were equipped and tied in. At the years ended December 31, 2006, this region was generating approximately 340 boepd net. Current production is approximately 350 boepd net (monthly average).

Strachan: Strachan is located approximately 30 kilometres southwest of Rocky Mountain House. The Corporation has an average 64% working interest in 1,280 acres of land. The re-entry and sidetracking of the Strachan 13-10-38-10W5M well (50% working interest, 70% of reserves and production) was spud at the end of October 2006. This well was successfully drilled to a depth of 5,045 metres (true vertical depth of 4,200 metres), encountering the reef at the target depth with better than expected porosity and pay. The well was completed and stimulated with a hydraulic acid fracture treatment, was tied in during March of 2007 and testing has begun.

Canadian properties and assets in general

The cost of services in the Canadian industry was historically high in 2006. The Corporation expects that as the Canadian industry's activity level declines, there will be significant improvement in the cost of services.

In 2006, the Corporation drilled seven (2.3 net) new wells, resulting in one gas well, four standing wells, one well that was still drilling at year end and one well that was abandoned as uncommercial. The Corporation also participated in three (2.2 net) recompletions and one (0.9 net) well re-activation, resulting in three (2.4 net) gas wells and one standing well.

Canadian average monthly production was 508 boepd for the fourth quarter of 2006 and was 501 boepd average for the full year.

Tunisia properties and assets

The following is a description of the principal properties of the Corporation located in Tunisia.

Tunisia in general: Following the acquisition of Athanor, the Corporation now operates five production concessions in Tunisia. As of December 31, 2006 the following table describes the Corporation's net interests in such concessions:

Concession	Gross Surface (acres)	Working Interest	Operator	Number of Producing Wells	Type of Production
Sabria	11,520	45%	Corporation	3	Oil and Gas
Zinnia	17,920	100%	Corporation	1	Oil and Gas
Sanrhar	35,840	100%	Corporation	1	Oil
Chouech Es Saida	52,480	100%	Corporation	3	Oil
Ech-Chouech	33,920	100%	Corporation	0	N/A

The Corporation has improved its daily production, through enhanced artificial lift, at its southern Tunisian concessions of Sanrhar and Chouech Es Saida (both described in greater detail below). As a result, Tunisian production has improved from approximately 500 boepd during the first quarter of 2006 to over 1000 boepd in the first quarter of 2007.

Sabria: The Sabria Concession is located near the southern margin of Chott el Jerid in the Sahara Desert of Tunisia. The Sabria Concession, named after the nearby village of Sabriyah, was carved out of the Kebili Exploration Permit. The first seismic survey was carried out by Mobil who held the exploration permit for the area from 1970-1977. From 1978-1985 the area was operated by Amoco, who drilled four wells; SAB-N1, SAB-N2, SAB-N3 and W-SAB-1. The first exploratory well SAB-N1, was drilled in 1979. SAB-N2 was drilled in 1980-81, W-SAB-1 in 1981-82 and SAB-N3 was drilled in 1984. These exploration wells indicated oil in the Ordovician formations but were considered non-commercial at the time.

In 1991 MOL Hungarian Oil & Gas PLC ("**MOL**") became the operator of the Sabria concession. From 1991-1995 MOL performed three 2D seismic surveys and based on these surveys and re-evaluation of the previous wells, MOL recompleted W-SAB-1 as a horizontal well (W-SAB-1H) near the top of the Hamra Formation. This well tested hydrocarbon potential in August 1996. In 1998 MOL acquired 2D & 3D seismic of the Sabria concession, which led to drilling well SAB-NW1. This well was completed as a horizontal producer. In late 1998-early 1999 MOL re-entered SAB-N1 and drilled a new horizontal leg. Based on disappointing results the well was suspended in 1999.

Sabria was put on stream in October 1998 with well W-SAB-1H, followed by SAB-NW1 in May 1999 and SAB-N3H in January 2002. In early 2000 Athanor acquired the MOL interest in the Sabria concession and became the field operator. In 2002, the SAB-N3 well was re entered, drilled and completed as a horizontal producer (SAB-N3H). The current operation is comprised of three production wells, W-SAB-1H, SAB-NW1H and SAB-N3H, all producing under natural flow. The wells have open hole completions with dual

concentric tubing strings and production packers. Salt deposits are flushed from the producing wells by intermittent circulation of fresh water across the bottom of the wellbore to dissolve the native salt and produce it with the oil. Associated gas is recovered at the field, compressed to 100 bar pressure and delivered into a third party gas pipeline from where it is transported and sold to STEG, the Tunisian State Electricity and Gas Company. Condensate is recovered from the associated gas via a chilling unit and slip-streamed back into the crude oil stream for sales.

During 2006 the transportation arrangements were upgraded such that oil is now trucked from the field to a transfer terminal on the local pipeline network at Oumchia from which it is transported via pipeline to the Mediterranean Coast at Skhira.

The drilling program for the two (0.9 net) new multi-lateral wells in Sabria has begun. To date, one of the horizontal legs in the first well has been completed with the second horizontal leg currently being planned. These wells are being drilled “underbalanced”, meaning the well can flow while drilling, allowing formation productivity, downhole pressures and various logging parameters to be measured as the well progresses.

Zinnia: The Zinnia oil field is located onshore on the Cap Bon peninsula of Tunisia, 60 kilometres Southeast of Tunis, 10 kilometres from the town of Nabeul, approximately 3 kilometres from the Mediterranean shore.

The field was discovered in 1989 by Shell, with the drilling of the ZNN-1 well on the west flank of a faulted anticlinal structure. The productive formation is the Abiod formation, a late Cretaceous fractured carbonate formation. AGIP took over as operator in March 1990 and completed the ZNN-1 well as an oil producer. In April 1991, AGIP drilled a second producer, ZNN-2D, from the same surface location, in an up-dip bottom hole location position to improve the structural control of the northeast area of the trap. This well tested both oil and gas.

Well ZNN-1 was shut-in in July 1993 and then converted to a water disposal well. The ZNN-2D producer is completed with 2 7/8 inch tubing and an ESP pump which requires close monitoring due to CO₂ corrosion.

Zinnia oil is trucked to the refinery at Bizerte and the gas is sold at the plant gate into a STEG pipeline. At year-end 2006, production from the Zinnia concession was approximately 100 boepd net.

Sanrhar: The Sanrhar field is located 60 kilometres Northeast of the El Borma oil field in the Sahara desert of Southern Tunisia. Three wells have been drilled on the Sanrhar domal structure of the Triassic Tagi Sandstone formation. The first well in 1957, Sanrhar-1 (SN-1), was drilled on the flank of the structure near the original oil/water contact. Sanrhar North 1 (SNN-1) the “discovery well” drilled by AGIP in 1989 located near the top of the structure. In 2002, Anadarko drilled a third well, Sanrhar West-1 (SNW-1), 6km to the west down dip on the west flank of the structure. This well was wet and was plugged and abandoned. SNN-1 is the sole oil producer in the field and has been on-stream since 1991. At year-end 2006, production for the Sanrhar concession was approximately 40 boepd.

Chouech Es Saida: The Chouech Es Saida oil field is located in the southwest of the southern part of Tunisia. Seven wells were drilled on the Chouech Essaida structure between 1971 and 1992. The field was put on production in 1977, with well CS-1, which remained on production until 1992. In 1993, wells CS-3BIS and CS7-BIS were put on production, and were produced for seven and two years respectively. In 1996, well CS-5 was tested briefly, and then suspended. Athanor Tunisia BV (Athanor Tunisia) acquired the concession together with the neighbouring Ech Chouech concessions, from AGIP in 2002. The field was shut in from 1999 until late 2003, at which time Athanor Tunisia brought well CS7-BIS back on production. Production is from one or more of seven identified zones of the Trias Argilo-Gereseux "Shaly Arenaceus Unit". The production completion records are sketchy and inconsistent; therefore, it is unclear which of the units have contributed to production.

Oil is transported to a sales point at El Borma by a six inch, 80 kilometre pipeline that is owned by the Corporation. Gas is currently used for fuel or flared, but the Corporation has arranged for the natural gas from the concession to be tied in to new separation facilities at El Borma and sold to STEG beginning in the second quarter of 2007.

During the last half of November 2006, the Corporation re-activated the CS-5 well. Upon perforating a new zone in the Triassic, the well flowed at rates in excess of 1,000 boepd and gas rates of 1 MMcf/day. Extended testing of this well is being carried out in early 2007. The results of this test and production to date indicate no water production and very limited pressure drawdown of the reservoir. At year end, the CS-5 well was contributing significantly to total production from the Chouech Es Saida concession of approximately 100 boepd net. Currently, production from the concession is approximately 550-600 boepd net as the CS-5 well has been temporarily curtailed to allow for tie-in of the natural gas.

Ech Chouech: Five wells have been drilled by AGIP in the Ech Chouech concession since 1970.

The field was discovered by the well EC-1, which encountered oil in the Devonian - Ouan Kasa sandstone formation at a depth of 3220 metres. The well was completed in 1991 tested for 6 months in order to help determine the commerciality of the field.

The well tested at rates around 200-220 boepd and produced a total of 34,000 bbl of oil. The test was terminated by a well-bore blockage. A workover would be required to reactivate the well. Well EC-2 tested a small quantity of gas in the Ouan Kasa sand to a depth of 3,182 metres. Well EC-3 only encountered traces of gas but well EC-4 tested oil in the Ouan Kasa sandstone (DST#2).

AGIP assessed the field reserves to be some 478,000 bbl and no further development has since been undertaken. The Corporation plans to workover and re-activate well EC-4 in the second quarter of 2007.

Hungary properties and assets

The following is a description of the principal properties located in Hungary.

Törökkoppány: The Törökkoppány gas field is located in Sornogy County, south-western Hungary, 2.5 kilometres south-east of the village of Törökkoppány, about 230 km south-west of Budapest. The field was discovered in 2001 by El Paso Magyarorszag Kft., a subsidiary of Houston based El Paso Production Oil and Gas Company, with the drilling of Törökkoppány #1 (“**Toro 1**”), the third exploratory well drilled on the IGAL exploration concession. The field is located in the Sornogy-Drave sub-basin, located in the central part of the Pannonian Basin, south of Lake Balaton.

The Toro 1 well encountered gas in the Miocene Badenian limestone of the Rakos limestone formation, at a depth of 652 metres. The well was drilled to a total depth of 771 metres.

Field production began in July 2003 from well Toro-1. Gas is piped to a regional gas distribution network and is sold locally to DDGaz, a subsidiary of E.On. The Törökkoppány field production has substantial seasonal variations, which are driven by regional gas demand.

In November of 2005, the Corporation drilled to 860 metres, tested and abandoned its Szakcs (100% working interest) \$1.2 million exploratory well. The well encountered Miocene Badenian Limestone at anticipated depths and thickness but with poor reservoir qualities and produced only water after stimulation. A second producer, Toro-2 was drilled by the Corporation and put on production in December of 2005.

In October 2006, the Corporation drilled to 870 metres, tested and abandoned its Koppanyszanto (100% working interest) \$1.2 million exploratory well. The well encountered porous and permeable Miocene Badenian Limestone at anticipated depths and thickness. Further to the results of 2 drill-stem tests, which recovered drilling mud or water with immaterial gas in solution, the well was abandoned.

Oil and Natural Gas Markets

Crude Oil

The Corporation markets its Alberta oil to Plains Marketing Canada, L.P. under a 30 day evergreen agreement. The Corporation’s strategy is to commit all of its oil under short term arrangements. Pricing under these contracts is generally related to prices for West Texas Intermediate (“**WTI**”) crude oil, which results in prices received by the Corporation being affected by the U.S. and Canada dollar exchange rate.

In respect of the Corporation’s Tunisian oil production, oil from the Zinnia concession is sold into a local refinery while oil production from Sabria, Chouech Essaida and Sanrhar concessions is trucked and then pipelined to a storage terminal. From the terminal the oil is loaded onto oil tankers arranged by third parties and sold on the world market every one to three months, depending on production levels. The price paid for oil is directly tied to the price quoted for Ashtart crude (Zinnia) and Zarzaitine crude (all other crude production). The oil tanker price is the lower of either the average price for the five days following loading or the five days preceding loading or the average price of the first

five days of the month of loading or the five day average price 10 days following loading. Revenue from tanker sales is recognized only when the oil has been loaded onto tankers.

Natural Gas

The Corporation's Alberta natural gas production is sold to Gibson Energy Marketing Ltd under a one year contract at AECO reference daily index spot pricing.

In Tunisia, associated gas production from the Sabria and Zinnia is sold into the domestic market. The price is indexed at 75% of the high sulphur fuel oil price for Zinnia gas and at 77% of the low sulphur fuel oil price for Sabria gas.

Winstar's Hungarian production is from two 100% working interest wells (Törökkoppany #1 and #2) located in western Hungary. Gas is processed at a 100% owned and operated gas plant with a design capacity of 15 MMcf/day. Gas currently is sold into the local retail market on a demand contract, renewable annually.

The local retail market in Hungary is subject to seasonal demand resulting in limited summer sales and full capacity winter sales. The price of natural gas in Hungary is determined by negotiation under the above mentioned demand contract. The gas prices obtained to date by the Corporation appears to be comparable to other European gas prices.

RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The following tables set forth certain information relating to the oil, natural gas and natural gas liquids reserves of the Corporation and its subsidiaries and the net present values of future net revenue of such reserves as at December 31, 2006. Such reserves were evaluated by McDaniel in a report (the "**McDaniel Report**") dated January 30, 2007, in the case of the Corporation's Canadian reserves data, and by APA in a report (the "**APA Report**") dated March 12, 2007, in the case of the Corporation's Tunisian and Hungarian reserves. Both McDaniel and APA are independent qualified reserves evaluators appointed by the Corporation pursuant to NI 51-101. Substantially all of the Corporation's oil and gas properties with reserves in Canada, Tunisia and Hungary were independently evaluated by McDaniel and APA, respectively. Readers should note that totals in the following tables may not add due to rounding.

The following tables summarize the activities in 2006 which is the first full reporting year after the merger of Athanor with the Corporation.

In order to provide a single unit of production for analytical purposes, natural gas production and reserves volumes are mathematically converted to equivalent barrels of oil (boe). The Corporation uses a conversion rate of six thousand cubic feet of natural gas to one barrel of oil (6 Mcf = 1 bbl). The 6:1 boe ratio approximates an equivalent energy value at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

The estimated future net revenue figures contained in the following tables do not necessarily represent the fair market value of the Corporation's reserves. There is no assurance that the forecast price and cost assumptions contained in the McDaniel Report and the APA Report will be attained and variances could be material. Other assumptions relating to costs and other matters are included in the McDaniel Report and the APA Report. The recovery and reserves estimates attributed to the Corporation's properties described herein are estimates only. The actual reserves attributed to the Corporation's properties may be greater or less than those calculated.

The Report on Reserves Data by Independent Qualified Reserves Evaluator and the Report of Management and Directors on Oil and Gas Disclosure can be found in Appendix A and Appendix B, respectively.

Reserves Data (Constant Prices and Costs)

SUMMARY OF PETROLEUM AND NATURAL GAS RESERVES AS AT DECEMBER 31, 2006
(based on constant prices and cost assumptions)

FORM 51-101F1										
TABLE 2.1.1										
SUMMARY OF OIL AND GAS RESERVES as of December 31, 2006 CONSTANT PRICES AND COSTS										
RESERVE CATEGORY	RESERVES									
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS		SULFUR	
	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mbbbl)	Net (Mbbbl)	Gross (MMscf)	Net (MMscf)	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mlti)	Gross (Mlti)
CANADA										
PROVED										
Developed Producing	251	195	-	-	1,475	1,211	37	29	-	-
Developed Non Producing	7	6	-	-	54	44	2	1	-	-
Undeveloped	-	-	-	-	-	-	-	-	-	-
TOTAL PROVED	259	201	-	-	1,529	1,255	38	30	-	-
PROBABLE	92	73	-	-	699	564	18	14	-	-
TOTAL PROVED PLUS PROBABLE	351	274	-	-	2,227	1,820	56	44	-	-
TUNISIA										
PROVED										
Developed Producing	1,068	943	-	-	1,535	1,380	14	13	-	-
Developed Non Producing	-	-	-	-	-	-	-	-	-	-
Undeveloped	1,301	1,152	-	-	2,872	2,544	29	26	-	-
TOTAL PROVED	2,369	2,095	-	-	4,407	3,924	44	39	-	-
PROBABLE	4,273	3,690	-	-	8,528	7,378	73	63	-	-
TOTAL PROVED PLUS PROBABLE	6,642	5,785	-	-	12,935	11,302	117	102	-	-
HUNGARY										
PROVED										
Developed Producing	-	-	-	-	1,056	908	-	-	-	-
Developed Non Producing	-	-	-	-	-	-	-	-	-	-
Undeveloped	-	-	-	-	-	-	-	-	-	-
TOTAL PROVED	-	-	-	-	1,056	908	-	-	-	-
PROBABLE	-	-	-	-	472	406	-	-	-	-
TOTAL PROVED PLUS PROBABLE	-	-	-	-	1,528	1,314	-	-	-	-
TOTAL COMPANY										
PROVED										
Developed Producing	1,319	1,138	-	-	4,066	3,499	51	42	-	-
Developed Non Producing	7	6	-	-	54	44	2	1	-	-
Undeveloped	1,301	1,152	-	-	2,872	2,544	29	26	-	-
TOTAL PROVED	2,628	2,296	-	-	6,992	6,087	82	69	-	-
PROBABLE	4,365	3,763	-	-	9,699	8,349	91	77	-	-
TOTAL PROVED PLUS PROBABLE	6,993	6,059	-	-	16,690	14,436	173	147	-	-

Tunisian and Hungarian taxes throughout this evaluation are based on project cash flows, assuming no financing charges, and no tax considerations outside of Tunisia and Hungary have been included.

NET PRESENT VALUES OF FUTURE NET REVENUE AS AT DECEMBER 31, 2006
(based on constant prices and cost assumptions)

FORM 51-101F1										
TABLE 2.1.2										
NET PRESENT VALUE OF FUTURE NET REVENUE as of December 31, 2006 CONSTANT PRICES AND COSTS										
RESERVE CATEGORY	NET PRESENT VALUE OF FUTURE NET REVENUE (Cdn\$ millions)									
	BEFORE INCOME TAXES					AFTER INCOME TAXES				
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
CANADA										
PROVED										
Developed Producing	10.75	9.50	8.53	7.76	7.14	10.75	9.50	8.53	7.76	7.14
Developed Non Producing	(.24)	(.16)	(.11)	(.07)	(.04)	(.24)	(.16)	(.11)	(.07)	(.04)
Undeveloped	-	-	-	-	-	-	-	-	-	-
TOTAL PROVED	10.51	9.34	8.42	7.69	7.10	10.51	9.34	8.42	7.69	7.10
PROBABLE	4.71	3.53	2.80	2.32	2.00	4.71	3.53	2.80	2.32	2.00
TOTAL PROVED PLUS PROBABLE	15.22	12.87	11.22	10.01	9.10	15.22	12.87	11.22	10.01	9.10
TUNISIA										
PROVED										
Developed Producing	54.18	42.61	35.50	30.79	27.45	38.67	31.36	26.76	23.65	21.40
Developed Non Producing	-	-	-	-	-	-	-	-	-	-
Undeveloped	72.35	53.74	42.15	34.37	28.83	34.43	26.89	21.76	18.06	15.28
TOTAL PROVED	126.53	96.34	77.65	65.16	56.28	73.10	58.25	48.52	41.71	36.68
PROBABLE	235.95	140.59	100.77	79.45	65.98	112.79	72.49	54.40	44.13	37.37
TOTAL PROVED PLUS PROBABLE	362.48	236.93	178.43	144.61	122.26	185.89	130.74	102.92	85.85	74.05
HUNGARY										
PROVED										
Developed Producing	4.36	4.23	4.10	3.98	3.86	4.00	3.88	3.77	3.66	3.56
Developed Non Producing	-	-	-	-	-	-	-	-	-	-
Undeveloped	-	-	-	-	-	-	-	-	-	-
TOTAL PROVED	4.36	4.23	4.10	3.98	3.86	4.00	3.88	3.77	3.66	3.56
PROBABLE	2.83	2.62	2.44	2.27	2.13	2.45	2.27	2.10	1.96	1.84
TOTAL PROVED PLUS PROBABLE	7.19	6.85	6.53	6.25	5.99	6.45	6.15	5.88	5.62	5.40
TOTAL COMPANY										
PROVED										
Developed Producing	69.29	56.33	48.13	42.53	38.46	53.42	44.74	39.06	35.07	32.10
Developed Non Producing	(.24)	(.16)	(.11)	(.07)	(.04)	(.24)	(.16)	(.11)	(.07)	(.04)
Undeveloped	72.35	53.74	42.15	34.37	28.83	34.43	26.89	21.76	18.06	15.28
TOTAL PROVED	141.40	109.91	90.17	76.83	67.25	87.61	71.47	60.71	53.06	47.34
PROBABLE	243.50	146.74	106.01	84.04	70.11	119.96	78.29	59.31	48.42	41.20
TOTAL PROVED PLUS PROBABLE	384.89	256.64	196.18	160.87	137.36	207.57	149.76	120.02	101.48	88.54

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS AT DECEMBER 31, 2006
(based on constant prices and cost assumptions)

FORM 51-101F1 TABLE 2.1.3a										
TOTAL FUTURE NET REVENUE (UNDISCOUNTED) as of December 31, 2006 CONSTANT PRICES AND COSTS										
RESERVE CATEGORY	REVENUE	ROYALTIES	OTHER REVENUE	OPERATING COSTS	ABANDONMENT COSTS	DEVELOPMENT COSTS	CREDIT / SURCHARGE	FUTURE NET REVENUE BEFORE INCOME TAXES	INCOME TAXES	FUTURE NET REVENUE AFTER INCOME TAXES
	(MM\$Cdn)	(MM\$Cdn)	(MM\$Cdn)	(MM\$Cdn)	(MM\$Cdn)	(MM\$Cdn)	(MM\$Cdn)	(MM\$Cdn)	(MM\$Cdn)	(MM\$Cdn)
CANADA										
TOTAL PROVED	25.72	4.89	-	8.66	1.36	0.29	-	10.52	-	10.52
TOTAL PROVED PLUS PROBABLE	36.17	6.82	-	12.48	1.36	0.29	-	15.22	-	15.22
TUNISIA										
TOTAL PROVED	197.92	22.71	13.37	37.18	7.97	16.90	-	126.53	53.43	73.10
TOTAL PROVED PLUS PROBABLE	558.51	71.76	13.37	96.55	10.97	30.11	-	362.48	176.59	185.89
HUNGARY										
TOTAL PROVED	9.89	1.38	-	3.73	0.41	-	-	4.36	0.36	4.00
TOTAL PROVED PLUS PROBABLE	14.31	2.00	-	4.70	0.41	-	-	7.19	0.74	6.45
TOTAL COMPANY										
TOTAL PROVED	233.53	28.99	13.37	49.58	9.74	17.19	-	141.41	53.78	87.62
TOTAL PROVED PLUS PROBABLE	608.99	80.59	13.37	113.73	12.75	30.40	-	384.89	177.33	207.57

FUTURE NET REVENUE BY PRODUCTION GROUP AS AT DECEMBER 31, 2006
(based on constant prices and cost assumptions)

FORM 51-101F1 TABLE 2.1.3b			
NPV FUTURE NET REVENUE BEFORE TAXES BY PRODUCTION GROUP as of December 31, 2006 CONSTANT PRICES AND COSTS			
RESERVE CATEGORY	FUTURE NET REVENUE BY PRODUCTION GROUP BEFORE INCOME TAXES		
	Net present value discounted at 10% per year		
	LIGHT AND MEDIUM OIL (including solution gas and other by-products)	HEAVY OIL (including solution gas and other by-products)	NATURAL GAS (including by-products and ARTC but excluding solution gas from oil wells)
	(\$Cdn Millions)	(\$Cdn Millions)	(\$Cdn Millions)
CANADA			
TOTAL PROVED	3.99	-	4.43
TOTAL PROVED PLUS PROBABLE	4.95	-	6.27
TUNISIA			
TOTAL PROVED	77.65	-	-
TOTAL PROVED PLUS PROBABLE	178.43	-	-
HUNGARY			
TOTAL PROVED	-	-	4.10
TOTAL PROVED PLUS PROBABLE	-	-	6.53
TOTAL COMPANY			
TOTAL PROVED	81.64	-	8.53
TOTAL PROVED PLUS PROBABLE	183.38	-	12.80

Reserves Data (Forecast Prices and Costs)

SUMMARY OF PETROLEUM AND NATURAL GAS RESERVES AS AT DECEMBER 31, 2006 (based on forecast prices and cost assumptions)

FORM 51-101F1										
TABLE 2.2.1										
SUMMARY OF OIL AND GAS RESERVES as of December 31, 2006 FORECAST PRICES AND COSTS										
RESERVE CATEGORY	RESERVES									
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS		SULFUR	
	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mbbbl)	Net (Mbbbl)	Gross (MMscf)	Net (MMscf)	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mlt)	Gross (Mlt)
CANADA										
PROVED										
Developed Producing	245.10	190.20	-	-	1,478.70	1,215.00	36.70	29.10	-	-
Developed Non Producing	7.30	6.10	-	-	53.90	44.00	1.70	1.20	-	-
Undeveloped	-	-	-	-	-	-	-	-	-	-
TOTAL PROVED	252.40	196.30	-	-	1,532.60	1,259.00	38.40	30.30	-	-
PROBABLE	80.30	63.50	-	-	695.80	561.80	17.60	13.80	-	-
TOTAL PROVED PLUS PROBABLE	332.70	259.80	-	-	2,228.40	1,820.80	56.00	44.10	-	-
TUNISIA										
PROVED										
Developed Producing	1,050.81	928.62	-	-	1,535.06	1,380.87	14.33	12.87	-	-
Developed Non Producing	-	-	-	-	-	-	-	-	-	-
Undeveloped	1,301.38	1,152.24	-	-	2,871.87	2,544.56	29.41	26.06	-	-
TOTAL PROVED	2,352.18	2,080.87	-	-	4,406.93	3,925.43	43.74	38.93	-	-
PROBABLE	4,186.71	3,615.42	-	-	8,453.62	7,312.46	73.13	63.38	-	-
TOTAL PROVED PLUS PROBABLE	6,538.89	5,696.28	-	-	12,860.56	11,237.89	116.88	102.31	-	-
HUNGARY										
PROVED										
Developed Producing	-	-	-	-	1,056.11	908.25	-	-	-	-
Developed Non Producing	-	-	-	-	-	-	-	-	-	-
Undeveloped	-	-	-	-	-	-	-	-	-	-
TOTAL PROVED	-	-	-	-	1,056.11	908.25	-	-	-	-
PROBABLE	-	-	-	-	472.09	406.00	-	-	-	-
TOTAL PROVED PLUS PROBABLE	-	-	-	-	1,528.20	1,314.25	-	-	-	-
TOTAL COMPANY										
PROVED										
Developed Producing	1,295.91	1,118.82	-	-	4,069.87	3,504.12	51.03	41.97	-	-
Developed Non Producing	7.30	6.10	-	-	53.90	44.00	1.70	1.20	-	-
Undeveloped	1,301.38	1,152.24	-	-	2,871.87	2,544.56	29.41	26.06	-	-
TOTAL PROVED	2,604.58	2,277.17	-	-	6,995.64	6,092.68	82.14	69.23	-	-
PROBABLE	4,267.01	3,678.92	-	-	9,621.51	8,280.25	90.73	77.18	-	-
TOTAL PROVED PLUS PROBABLE	6,871.59	5,956.08	-	-	16,617.15	14,372.93	172.88	146.41	-	-

NET PRESENT VALUES OF FUTURE NET REVENUE AS AT DECEMBER 31, 2006
(based on forecast prices and cost assumptions)

TABLE 2.2.2										
NET PRESENT VALUE OF FUTURE NET REVENUE as of December 31, 2006 FORECAST PRICES AND COSTS										
RESERVE CATEGORY	NET PRESENT VALUE OF FUTURE NET REVENUE (Cdn\$ millions)									
	BEFORE INCOME TAXES					AFTER INCOME TAXES				
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
CANADA										
PROVED										
Developed Producing	11.99	10.70	9.66	8.82	8.14	11.99	10.70	9.66	8.82	8.14
Developed Non Producing	0.22	0.14	0.08	0.04	0.01	0.22	0.14	0.08	0.04	0.01
Undeveloped	-	-	-	-	-	-	-	-	-	-
TOTAL PROVED	11.77	10.56	9.58	8.78	8.13	11.77	10.56	9.58	8.78	8.13
PROBABLE	5.65	4.26	3.38	2.81	2.40	5.65	4.26	3.38	2.81	2.40
TOTAL PROVED PLUS PROBABLE	17.42	14.82	12.96	11.59	10.53	17.42	14.82	12.96	11.59	10.53
TUNISIA										
PROVED										
Developed Producing	50.64	40.02	33.47	29.13	26.06	36.30	29.60	25.33	22.43	20.34
Developed Non Producing	-	-	-	-	-	-	-	-	-	-
Undeveloped	70.14	51.64	40.27	32.72	27.39	33.05	25.78	20.80	17.23	14.55
TOTAL PROVED	120.77	91.66	73.74	61.84	53.44	69.35	55.38	46.14	39.66	34.89
PROBABLE	256.27	140.95	97.11	75.39	62.33	119.83	71.97	52.30	41.98	35.48
TOTAL PROVED PLUS PROBABLE	377.04	232.60	170.85	137.23	115.77	189.18	127.35	98.44	81.64	70.37
HUNGARY										
PROVED										
Developed Producing	4.16	4.05	3.95	3.85	3.75	3.80	3.71	3.62	3.53	3.44
Developed Non Producing	-	-	-	-	-	-	-	-	-	-
Undeveloped	-	-	-	-	-	-	-	-	-	-
TOTAL PROVED	4.16	4.05	3.95	3.85	3.75	3.80	3.71	3.62	3.53	3.44
PROBABLE	2.63	2.46	2.30	2.16	2.03	2.28	2.13	2.00	1.87	1.76
TOTAL PROVED PLUS PROBABLE	6.79	6.51	6.25	6.01	5.79	6.08	5.84	5.61	5.40	5.21
TOTAL COMPANY										
PROVED										
Developed Producing	66.78	54.77	47.08	41.80	37.95	52.08	44.01	38.61	34.78	31.93
Developed Non Producing	0.22	0.14	0.08	0.04	0.01	0.22	0.14	0.08	0.04	0.01
Undeveloped	70.14	51.64	40.27	32.72	27.39	33.05	25.78	20.80	17.23	14.55
TOTAL PROVED	136.70	106.27	87.27	74.47	65.33	84.91	69.65	59.33	51.97	46.47
PROBABLE	264.55	147.66	102.79	80.36	66.76	127.77	78.36	57.68	46.66	39.65
TOTAL PROVED PLUS PROBABLE	401.25	253.93	190.06	154.83	132.09	212.68	148.01	117.01	98.63	86.11

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS AT DECEMBER 31, 2006
(based on forecast prices and cost assumptions)

TABLE 2.2.3a									
TOTAL FUTURE NET REVENUE (UNDISCOUNTED) as of December 31, 2006 FORECAST PRICES AND COSTS									
RESERVE CATEGORY	REVENUE	ROYALTIES	OTHER REVENUE	OPERATING COSTS	DEVELOPMENT COSTS	ABANDONMENT COSTS	FUTURE NET REVENUE BEFORE INCOME TAXES	INCOME TAXES	FUTURE NET REVENUE AFTER INCOME TAXES
	(M\$Cdn)	(M\$Cdn)	(MM\$Cdn)	(M\$Cdn)	(M\$Cdn)	(M\$Cdn)	(M\$Cdn)	(M\$Cdn)	(M\$Cdn)
CANADA									
TOTAL PROVED	28.43	5.35		9.39	0.29	1.63	11.77	-	11.77
TOTAL PROVED PLUS PROBABLE	40.65	7.59		13.68	0.29	1.67	17.42	-	17.42
TUNISIA									
TOTAL PROVED	198.88	22.72	13.19	41.46	17.08	10.04	120.77	51.43	69.35
TOTAL PROVED PLUS PROBABLE	606.27	77.57	13.19	115.87	30.73	18.24	377.04	187.86	189.18
HUNGARY									
TOTAL PROVED	9.83	1.38	-	3.86	-	0.44	4.16	0.36	3.80
TOTAL PROVED PLUS PROBABLE	14.12	1.98	-	4.90	-	0.45	6.79	0.71	6.08
TOTAL COMPANY									
TOTAL PROVED	237.15	29.44	13.19	54.70	17.37	12.11	136.70	51.79	84.91
TOTAL PROVED PLUS PROBABLE	661.04	87.14	13.19	134.46	31.02	20.36	401.25	188.57	212.68

FUTURE NET REVENUE BY PRODUCTION GROUP AS AT DECEMBER 31, 2006
(based on forecast prices and cost assumptions)

FORM 51-101F1		TABLE 2.2.3b		
FUTURE NET REVENUE BY PRODUCTION GROUP as of December 31, 2006 FORECAST PRICES AND COSTS				
FUTURE NET REVENUE BY PRODUCTION GROUP BEFORE INCOME TAXES				
Net present value discounted at 10% per year				
RESERVE CATEGORY	LIGHT AND MEDIUM OIL <small>(including solution gas and other by-products)</small> (\$Cdn Millions)	HEAVY OIL <small>(including solution gas and other by-products)</small> (\$Cdn Millions)	NATURAL GAS <small>(including by-products and ARTC but excluding solution gas from oil wells)</small> (\$Cdn Millions)	
CANADA				
TOTAL PROVED	3.87	-	5.71	
TOTAL PROVED PLUS PROBABLE	4.85	-	8.11	
TUNISIA				
TOTAL PROVED	73.74	-	-	
TOTAL PROVED PLUS PROBABLE	170.85	-	-	
HUNGARY				
TOTAL PROVED	-	-	3.95	
TOTAL PROVED PLUS PROBABLE	-	-	6.25	
TOTAL COMPANY				
TOTAL PROVED	77.61	-	9.66	
TOTAL PROVED PLUS PROBABLE	175.70	-	14.36	

Pricing Assumptions

Constant Prices used in Estimates

The constant benchmark reference product price and exchange rate assumptions reflected in the reserves data are summarized in the following table.

FORM 51-101F1		TABLE 3.1								
SUMMARY OF PRICING ASSUMPTIONS										
Constant Prices & Exchange rates										
Using Year End 2006 Values										
	Oil Benchmarks		AECO Spot Gas Price	US Henry Hub Gas	Hungary Domestic Gas	Tunisia Domestic Gas	Inflation Rate	Currency Exchange Rates		
	WTI at Cushing Oklahom a	Brent @ Sollem Voe								
	US\$/bbl	US\$/bbl	C\$/GJ	US\$/Mmbtu	US\$/Mcf	US\$/Mcf	%/annum	US\$/Cdn\$	TND/US\$	HUF/US\$
All Years	61.05	58.96	5.51	N/A	8.04	6.26	0%	0.86	1.31	190.74

Forecast Prices used in Estimates

Forecast benchmark reference product price, inflation rate and exchange rate assumptions are summarized in the following table. These forecast assumptions were provided in the Reports. It should be noted that, for evaluation consistency, the forecast of Brent oil prices used in the APA Report was prepared using the Brent (\$US/bbl) price forecast from the McDaniel Report at the Corporation's request.

FORM 51-101F1		Table 3.2 SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS FORECAST PRICES AND COSTS as at December 31, 2006							
Year	Oil Benchmarks		AB Avg. Plantgate Price	Hungary Domestic Gas *	Tunisia Domestic Gas *	Inflation Rate	Currency Exchange Rates		
	WTI at Cushing Oklahoma	Brent @ Sollem Voe							
	US\$/bbl	US\$/bbl					Cdn\$/Mmbtu	US\$/Mcf	US\$/Mcf
2007	62.50	60.50	7.00	6.84	6.66	2.00	0.87	1.35	200.0
2008	61.20	59.20	7.25	6.75	6.51	2.00	0.87	1.35	200.0
2009	59.80	57.70	7.60	6.64	6.35	2.00	0.87	1.35	200.0
2010	58.40	56.30	7.70	6.53	6.19	2.00	0.87	1.35	200.0
2011	56.80	54.60	7.90	6.40	6.01	2.00	0.87	1.35	200.0
2012	58.00	55.80	8.15	6.49	6.14	2.00	0.87	1.35	200.0
2013	59.10	56.80	8.30	6.57	6.25	2.00	0.87	1.35	200.0
2014	60.30	58.00	8.45	6.66	6.38	2.00	0.87	1.35	200.0
2015	61.50	59.20	8.65	6.75	6.51	2.00	0.87	1.35	200.0
2016	62.70	60.30	8.80	6.83	6.63	2.00	0.87	1.35	200.0
2017	64.00	61.60	9.00	6.92	6.78	2.00	0.87	1.35	200.0
2018	65.30	62.80	9.20	7.00	6.91	2.00	0.87	1.35	200.0
2019	66.60	64.10	9.35	7.09	7.05	2.00	0.87	1.35	200.0
2020	67.90	65.30	9.55	7.17	7.18	2.00	0.87	1.35	200.0
2021	69.30	66.70	9.75	7.26	7.34	2.00	0.87	1.35	200.0
2022	70.69	68.03	9.95	7.35	7.48	2.00	0.87	1.35	200.0
2023	72.10	69.39	10.14	7.43	7.63	2.00	0.87	1.35	200.0
2024	73.54	70.78	10.35	7.52	7.79	2.00	0.87	1.35	200.0
2025	75.01	72.20	10.55	7.60	7.94	2.00	0.87	1.35	200.0

Note: Columns marked with * were not explicitly available from the McDaniel forecast
These forecast data have been generated using APA's correlations

Currency Abbreviations
Cdn\$ Canadian Dollar
HUF Hungarian Florint
TND Tunisian Dinar
US\$ United States Dollar

Reconciliation of Changes in Reserves

A reconciliation of changes to the Corporation's net proved, net probable and net proved plus probable reserves is provided in the following table. This reconciliation reflects changes to the Corporation's reserves estimated using constant prices and costs. (Note: there is no synthetic oil reserve data to report).

RECONCILIATION OF COMPANY NET RESERVES BY PRINCIPAL PRODUCT TYPE
(based on constant prices and cost assumptions)

RECONCILIATION OF COMPANY NET RESERVES BY PRINCIPAL PRODUCT TYPE CONSTANT PRICES AND COSTS									
FACTORS	LIGHT AND MEDIUM OIL (Includes NGL's)			HEAVY OIL			ASSOCIATED AND NON-ASSOCIATED GAS		
	Net Proved (Mbb)	Net Probable (Mbb)	Net Proved + Probable (Mbb)	Net Proved (Mbb)	Net Probable (Mbb)	Net Proved + Probable (Mbb)	Net Proved (MMscf)	Net Probable (MMscf)	Net Proved + Probable (MMscf)
CANADA									
December 31, 2005	93.70	46.20	139.90	163.00	23.20	186.20	1,318.60	581.60	1,900.20
Extensions	11.30	5.30	16.60	-	-	-	420.80	197.60	618.40
Improved Recovery	-	-	-	-	-	-	-	-	-
Technical Revisions	165.40	36.80	202.20	(163.00)	(23.20)	(186.20)	78.40	(192.70)	(114.30)
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	12.20	(1.20)	11.00	-	-	-	(24.00)	(17.00)	(41.00)
Production + Inventory changes	(51.30)	(.40)	(51.70)	-	-	-	(538.70)	(5.10)	(543.80)
December 31, 2006	231.30	86.70	318.00	-	-	-	1,255.10	564.40	1,819.50
TUNISIA									
December 31, 2005	1,736.19	4,092.89	5,829.08	-	-	-	3,185.52	6,943.17	10,128.69
Extensions	-	-	-	-	-	-	-	-	-
Improved Recovery	114.01	201.65	315.65	-	-	-	-	850.39	850.39
Technical Revisions	498.27	(405.64)	92.63	-	-	-	1,257.10	(342.93)	914.17
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	(81.77)	(137.23)	(219.00)	-	-	-	(305.08)	(74.33)	(379.41)
Production + Inventory changes	(133.17)	2.15	(131.01)	-	-	-	(213.71)	2.19	(211.52)
December 31, 2006	2,133.54	3,753.82	5,887.35	-	-	-	3,923.84	7,378.49	11,302.33
HUNGARY									
December 31, 2005	-	-	-	-	-	-	1,776.94	509.27	2,286.21
Extensions	-	-	-	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-	-	-	-
Technical Revisions	-	-	-	-	-	-	78.40	(178.01)	(99.61)
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	15.67	64.89	80.56
Production + Inventory changes	-	-	-	-	-	-	(962.75)	9.85	(952.91)
December 31, 2006	-	-	-	-	-	-	908.25	406.00	1,314.25
TOTAL COMPANY									
December 31, 2005	1,829.89	4,139.09	5,968.98	163.00	23.20	186.20	6,281.06	8,034.05	14,315.10
Extensions	11.30	5.30	16.60	-	-	-	420.80	197.60	618.40
Improved Recovery	114.01	201.65	315.65	-	-	-	-	850.39	850.39
Technical Revisions	663.67	(368.84)	294.83	(163.00)	(23.20)	(186.20)	1,413.90	(713.64)	700.26
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	(69.57)	(138.43)	(208.00)	-	-	-	(313.41)	(26.44)	(339.85)
Production + Inventory changes	(184.47)	1.75	(182.71)	-	-	-	(1,715.16)	6.93	(1,708.23)
December 31, 2006	2,364.84	3,840.52	6,205.35	-	-	-	6,087.19	8,348.89	14,436.08

A reconciliation of changes to the net present value of the Corporation's future net revenue discounted at 10% attributable to the Corporation's net proved reserves estimated using constant prices and costs is provided in the following table:

RECONCILIATION OF CHANGES IN NET PRESENT VALUES OF FUTURE NET REVENUE OF
PROVED RESERVES DISCOUNTED AT 10% PER YEAR
(based on constant prices and cost assumptions)

FORM 51-101F1	
TABLE 4.2	
RECONCILIATION OF COMPANY FUTURE NET REVENUE NET PRESENT VALUES OF FUTURE NET REVENUE Discounted at 10% per Year	
TOTAL PROVED RESERVES CONSTANT PRICES AND COSTS	
PERIOD AND FACTOR	2006 - m\$Cdn
CANADA	
Estimated Future Net Revenue at December 31, 2005 (NPV After Tax)	\$ 12,048
Sales and Transfers of Oil and Gas, Net of Production Costs and Royalties	\$ (4,483)
Net Changes in Prices, Production Costs and Royalties related to Future (Forecast) Production	\$ (2,561)
Changes in Previously Estimated Development Costs incurred during the period	\$ 7,967
Changes in Estimated Future (Forecast) Development Costs	\$ (6,992)
Extensions and Improved Recovery	\$ 1,905
Discoveries	\$ (9)
Acquisitions of Reserves	\$ -
Dispositions of Reserves	\$ -
Net Change Resulting from (Technical Reserves) revisions plus all other changes	\$ 187
Accretion of Discount	\$ -
Net Change in Income Taxes	\$ 359
Other significant factors	\$ -
Estimated Future Net Revenue at December 31, 2006 (NPV After Tax)	\$ 8,421
TUNISIA	
Estimated Future Net Revenue at December 31, 2005 (NPV After Tax)	\$ 42,337
Sales and Transfers of Oil and Gas, Net of Production Costs and Royalties	\$ (9,109)
Net Changes in Prices, Production Costs and Royalties related to Future (Forecast) Production	\$ (156)
Changes in Previously Estimated Development Costs incurred during the period	\$ 2,407
Changes in Estimated Future (Forecast) Development Costs	\$ (9,337)
Extensions and Improved Recovery	\$ 1,780
Discoveries	\$ -
Acquisitions of Reserves	\$ -
Dispositions of Reserves	\$ -
Net Change Resulting from (Technical Reserves) revisions plus all other changes	\$ 21,199
Accretion of Discount	\$ 7,053
Net Change in Income Taxes	\$ (7,654)
Other significant factors	\$ -
Estimated Future Net Revenue at December 31, 2006 (NPV After Tax)	\$ 48,520
HUNGARY	
Estimated Future Net Revenue at December 31, 2005 (NPV After Tax)	\$ 5,535
Sales and Transfers of Oil and Gas, Net of Production Costs and Royalties	\$ (6,646)
Net Changes in Prices, Production Costs and Royalties related to Future (Forecast) Production	\$ (260)
Changes in Previously Estimated Development Costs incurred during the period	\$ (167)
Changes in Estimated Future (Forecast) Development Costs	\$ 500
Extensions and Improved Recovery	\$ -
Discoveries	\$ -
Acquisitions of Reserves	\$ -
Dispositions of Reserves	\$ -
Net Change Resulting from (Technical Reserves) revisions plus all other changes	\$ 4,761
Accretion of Discount	\$ 372
Net Change in Income Taxes	\$ (328)
Other significant factors	\$ -
Estimated Future Net Revenue at December 31, 2006 (NPV After Tax)	\$ 3,769
TOTAL COMPANY	
Estimated Future Net Revenue at December 31, 2005 (NPV After Tax)	\$ 59,921
Sales and Transfers of Oil and Gas, Net of Production Costs and Royalties	\$ (20,238)
Net Changes in Prices, Production Costs and Royalties related to Future (Forecast) Production	\$ (2,977)
Changes in Previously Estimated Development Costs incurred during the period	\$ 10,207
Changes in Estimated Future (Forecast) Development Costs	\$ (15,829)
Extensions and Improved Recovery	\$ 3,685
Discoveries	\$ (9)
Acquisitions of Reserves	\$ -
Dispositions of Reserves	\$ -
Net Change Resulting from (Technical Reserves) revisions plus all other changes	\$ 26,147
Accretion of Discount	\$ 7,425
Net Change in Income Taxes	\$ (7,623)
Other significant factors	\$ -
Estimated Future Net Revenue at December 31, 2006 (NPV After Tax)	\$ 60,709

Additional Information Relating to Reserves Data

Undeveloped Reserves

The Corporation's undeveloped reserves are all associated with its Canadian and Tunisian properties. Most of these reserves are designated within the undeveloped category because relatively significant capital expenditures will be required in order to render these reserves capable of production.

Plans for future development of these undeveloped reserves (based on forecast prices) are summarized as follows:

Canadian Properties

The Canadian assets have been determined by McDaniel to contain undeveloped reserves (gross, working interest proven probable) of 92 Mbbls of oil, 750 MMcf of gas and 19 Mbbls of associated liquids. The large majority of these reserves were assigned to various wells in the Brazeau, Ferrier, Taber and Sunchild assets and are associated with the production performance of the existing wells.

Tunisian Properties

Sabria: Sabria is an established oilfield producing from the Ordovician Hamra sandstone. With the aid of 3D seismic acquired and interpreted over the whole concession, distinct areas with a high degree of natural fracturing have been identified. Oil is being currently produced from 3 horizontal wells and it is the Corporation's position that horizontal wells appear to be the optimal development approach for intersecting the fractures thought necessary for commercial production. The Corporation has a 45% working interest in the Sabria concession.

APA assigns 1,787 Mboe gross proved undeveloped and 4,443 probable additional undeveloped reserves to the Sabria field (the Corporation's 45% working interest). These volumes are forecast to be recovered from the infill drilling of two undeveloped proved reserve locations in 2007 and drilling a lateral sidetrack from one existing producer and lengthening the horizontal leg in one existing producer in 2008. The probable undeveloped reserves are associated with two more horizontal wells and an additional sidetrack to be drilled in 2008 and 2009.

Chouech Es Saida: The producing and prospective reservoirs are Triassic channel sands. During 2006, the Corporation was successful in conducting recompletions work and installation of higher volume artificial lift in two wells.

APA assigns 780 Mboe (Corporation 100% working interest share) gross probable additional undeveloped reserves to the Chouech Es Saida field. These volumes are forecast to be recoverable from the re-completion of production well, CS-1 initiated in 2006 and to be completed in 2007. In addition, field facilities to tie-in and transport sales gas are included in 2007.

Zinnia: At Zinnia, there is one producing well from the upper Cretaceous Abiod limestone reservoir. Future plans include production of the second well in the field, which is currently shut in as an oil producer and used as a water disposal well. APA assigns no undeveloped proved reserves to Zinnia and forecasts 130 Mboe of additional Probable developed reserves due to more favorable decline performance, and re-activation of the ZNN-1 well.

Sanrhar: At Sanrhar, there is one producing well from the Triassic sandstone reservoir. The Corporation may consider new wells on the same structure depending on economic conditions, for deeper horizons.

APA assigns no undeveloped proved reserves to Sanrhar and forecasts 84 Mboe of additional, probable developed reserves associated with installing a higher volume artificial lift pump in the existing producer.

Ech Chouech: AGIP, as previous operator, drilled five wells in this concession to the Devonian (approximately 3,800 metres depth). Two wells proved to be productive. One well (EC-1) has produced 164,000 bbls and is suspended due to a wellbore mechanical problem. A second well (EC-4), which is currently suspended, had a successful initial production test but was never put on permanent production. It is the Corporation's intent to attempt to reactivate and place on production the EC-4 well during 2007.

APA assigns 231 Mboe gross probable undeveloped reserves to the Ech Chouech field in anticipation of the Corporation re-activating the former EC-4 well.

Hungarian Properties

Törökkoppany: The Törökkoppany field, is fully developed, with compression successfully installed in 2006. The field is on decline, and no undeveloped reserves are assigned.

Significant Factors or Uncertainties

Aside from the potential impact of material fluctuations in commodity prices, material changes to existing taxation or royalty rates and/or regulations in any of the countries in which the Corporation operates, other significant factors or uncertainties that may affect either the Corporation's reserves or the future net revenue associated with such reserves include:

Canada: Technical risk associated with producing natural gas and associated liquids from relatively low permeability reservoirs.

Tunisia: Technical risk associated with finding the areas of reservoir fracturing in Sabria.

Hungary: The technical risks associated with the final stages of field decline performance for Törökkoppany.

Future Development Costs

A summary of the estimated development costs deducted in the estimation of future net revenue attributable to various reserves categories and prepared under various price and cost assumptions are summarized in the following table.

FORM 51-101F1		TABLE 5.3		
SUMMARY OF ESTIMATED DEVELOPMENT COSTS ATTRIBUTABLE TO RESERVES				
ESTIMATED DEVELOPMENT COSTS (\$Cdn millions)				
		TOTAL PROVED		TOTAL PROVED + PROBABLE
		CONSTANT PRICES & COSTS	FORECAST PRICES AND COSTS	FORECAST PRICES AND COSTS
CANADA				
	2007	0.29	0.29	0.29
	2008	-	-	-
	2009	-	-	-
	2010	-	-	-
	2011	-	-	-
Total all years				
	Undiscounted	0.29	0.29	0.29
	Discounted @ 10%	0.26	0.26	0.26
TUNISIA				
	2007	13.02	13.10	13.78
	2008	3.88	3.98	11.25
	2009	-	-	5.71
	2010	-	-	-
	2011	-	-	-
Total all years				
	Undiscounted	16.90	17.08	30.73
	Discounted @ 10%	15.78	15.94	27.38
HUNGARY				
	2007	-	-	-
	2008	-	-	-
	2009	-	-	-
	2010	-	-	-
	2011	-	-	-
Total all years				
	Undiscounted	-	-	-
	Discounted @ 10%	-	-	-
TOTAL COMPANY				
	2007	13.31	13.39	14.07
	2008	3.88	3.98	11.25
	2009	-	-	5.71
	2010	-	-	-
	2011	-	-	-
Total all years				
	Undiscounted	17.19	17.38	31.03
	Discounted @ 10%	16.04	16.21	27.65

The Corporation expects to fund its estimated future development costs through some combination of internally generated cash flow and debt financing, or the possible sale of existing assets. There can be no guarantee that funds will be available or that the Board of Directors of the Corporation will allocate funding to develop all of the reserves requiring development in the McDaniel Report and the APA Report. Failure to develop such reserves could negatively impact future net revenue.

The Corporation's weighted average cost of capital is between six and ten percent, depending upon the assumptions used. The effect of these costs of capital on funding the Corporation's reserves and future net revenue is not expected to be material.

Other Oil and Gas Information

Oil and Gas Properties and Wells

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

The producing lands of Ferrier (twp 40-44, Rge 8-10W5M), Taber (twp 8, Rge 15W4M) and Brazeau River sections 15 and 3-45-11W5) represent 83% of the net present value (10% discount) of the Corporation's Canadian assets. All are located onshore and all are producing assets. All producing lands are held until the lands are no longer productive at which time, the individual spacing units revert back to the Crown.

The principal property of the Corporation in Tunisia is the onshore oil producing Sabria concession which represents 85% of the Corporation's net asset value in Tunisia. The state oil company, ETAP, has already exercised its right to back in to the concession and no other relinquishments, surrenders or back-ins are anticipated until the concession expiry term in the year 2028. The Corporation is currently preparing an application to Tunisian authorities to obtain an extension of the Sabria concession, reflecting the unusually long economic life projected for the wells.

The Ech Chouech concession in Tunisia is thought to be capable of producing but is not currently on production. The EC-4 well was successfully tested in 2006 and will be tie-in to production in 2007. The well is located 1 kilometre away from a four inch gathering line that connects to the Chouech Essaida separation and shipping facility.

Also in Tunisia, one of the two suspended wells in the Chouech Es Saida concession is scheduled for a workover in 2007 to resume production.

The principal property of the Corporation in Hungary is the onshore gas producing Igal Mining Permit which represents 100% of the Corporation's value in Hungary. There is a small dehydration and separation facility to process the gas from the Corporation's two wells. There are no non-producing wells or properties that the Corporation has that are thought to be capable of production. There are no surrenders, back-ins or changes in ownership anticipated.

The following table sets forth the number and status of the Corporation's crude oil and natural gas wells in as at December 31, 2006.

	<u>Crude Oil</u>		<u>Natural Gas</u>		<u>Suspended⁽¹⁾</u>		<u>Service⁽²⁾</u>		<u>Total</u>	
	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>
Canada	19.0	14.0	20.0	9.3	38.0	24.4	1.0	1.0	78.0	49.0
Tunisia	8.0	6.4	-	-	3.0	3.0	1.0	1.0	12.0	10.4
Hungary	-	-	2.0	2.0	-	-	-	-	2.0	2.0
TOTAL	27.0	20.0	22.0	11.3	41.0	7.4	2.0	2.0	92.0	61.4

Notes:

- (1) "Suspended" wells means wells which are capable of production but which, for a variety of reasons, including, but not limited to lack of markets or development are not placed on production at the present time.
- (2) "Service" wells are used for the disposal or injection of water.

Properties with No Attributed Reserves

The Corporation's unproved, undeveloped properties, including those for which the Corporation expects its rights to explore, develop and exploit to expire within one year, are outlined in the following table.

	<u>Canada</u>	<u>Tunisia</u>	<u>Hungary</u>
Unproved Properties			
Gross Area (acres)	84,256.24	155,934	567,880
Net Area (acres)	43,670.96	143,081	567,880
Work Commitments	0	0	0
Unproved Properties expected to expire in 2007:			
Gross Area (acres)	7,954	0	0
Net Area (acres)	4,861	0	0
Work Commitments	0	0	0

Forward Contracts

The Corporation is not bound by any agreements which may impact the realization of future full market prices for its oil and gas production as described in the McDaniel Report and the APA Report.

The Corporation has no transportation obligations or commitments for future deliveries which exceed its expected related future production from proved reserves, as estimated using forecast prices and costs.

Additional Information Concerning Abandonment and Reclamation Costs

The Corporation uses historical costs to estimate its abandonment and reclamation costs when available. The costs are estimated on an area by area basis. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment requirements.

Canada: the Corporation has 49 net wells that it anticipates abandoning over the next 14 plus years for an undiscounted cost net of salvage value of \$1,630,700 or \$786,900 (10% discounted forecast price)

Tunisia: the Corporation has 10.4 net wells for which it expects to incur abandonment and reclamation costs. The total of such costs, forecast net of estimated salvage value, is \$6.75 million (undiscounted) and \$2.77 million (10% discounted forecast price) 100% of such amounts were deducted as abandonment and reclamation costs in estimating future net revenue of the Corporation disclosed above.

Hungary: the Corporation estimates that the abandonment cost for the Törrökoppany wells and facility will amount to approximately (undiscounted) \$0.45 million or \$0.29 million (10% discounted forecast price) based on in-house engineering and operational estimates and anticipated abandonments in 2010.

Estimate abandonment costs for the next three years are as follows for the Corporation on a consolidated basis:

Total Consolidated Forecast Prices and Costs (Total Proved) (\$000)

<u>Year</u>	<u>Abandonment</u>	<u>Abandonment</u>
2007	19.3	17.6
2008	946.8	788.8
2009	924.0	688.3
TOTAL	1,890.1	1,494.7

Tax Horizon

Canada: Canadian operations are not forecast to become taxable under the forecast price scenario.

Tunisia: The Sabria concession is forecast to become marginally taxable in 2007 and beyond under the forecast price scenario for proved reserves.

Hungary: The Törrökoppany mining plot is not forecast to become taxable.

Costs Incurred

For the year ended December 31, 2006, the Corporation incurred costs related to its acquisition, exploration and development activities as outlined in the following table.

	Costs Incurred (\$000)		
	<u>Canada</u>	<u>Tunisia</u>	<u>Hungary</u>
Property Acquisition Costs:			
Proved Properties	0	0	0
Unproved Properties	161	0	0
Exploration Costs	190	0	1,006
Development Costs	7,616 ⁽¹⁾	8,540	572

Note:

- (1) These costs do not include charges of \$2,986,353 associated with the drilling of the Strachan 8-10-38-10W5M well which was still in progress at year end. It also does not include \$547,450 associated with drilling lease construction for wells that will be drilled in 2007.

Exploration and Development Activities

The Corporation's drilling activity and results for the year ended December 31, 2006 are summarized in the following table. It should be noted that the data outlined in this table reflects those wells that the Corporation participated in and where the rig was released during the period. The difference between the gross wells and net wells represents the Corporation's contribution to the capital expense of the wells.

	<u>Exploratory Wells</u>		<u>Development Wells</u>	
	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>
Canada				
Oil Wells	0	0	0	0
Gas Wells	0	0	1	0.39
Service Wells	0	0	0	0
Suspended Wells	0	0	4	0.9
Abandoned Wells	1	0.25	0	0
Total Wells	1	0.25	5	1.29
Tunisia				
Oil Wells	0	0	0	0
Gas Wells	0	0	0	0
Service Wells	0	0	0	0
Suspended Wells	0	0	0	0
Abandoned Wells	0	0	0	0
Total Wells	0	0	0	0
Hungary				
Oil Wells	0	0	0	0
Gas Wells	0	0	0	0
Service Wells	0	0	0	0
Suspended Wells	0	0	0	0
Abandoned Wells	1	1	0	0

	<u>Exploratory Wells</u>		<u>Development Wells</u>	
	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>
Total Wells	1	1	1	1

The Corporation's important exploration and development activities are summarized as follows:

Canada: During 2006, the Corporation drilled 5 development wells in the Ferrier and West Pembina areas. One exploration well was drilled in Duncan that was dry and abandoned.

Tunisia: During 2006, the Corporation undertook no exploration activity. Development activity was comprised of initiation of drilling activities in Sabria, installation of high volume artificial lift in Chouech Essaida and Sanghar, and workovers of wells in Chouech Essaida and Ech Chouech.

Hungary: During 2006, the Corporation drilled an unsuccessful exploration well at Koppanyzanto-1, adjacent to the Törökkoppany field. For development activities, the Corporation installed compression in the Törökkoppany gas field.

Production Estimates

Estimated production volumes derived from the first year (2007) of the cash flow forecasts prepared in conjunction with the Corporation's reserves data (and included in the McDaniel Report and the APA Report) are provided in the following table.

FORM 51-101F1			
TABLE 6.8			
SUMMARY OF PRODUCTION ESTIMATES PROVED + PROBABLE RESERVES CASE FOR YEAR 2007			
RESERVE CATEGORY	Estimated Production - 2007		
	LIGHT AND MEDIUM OIL (Mbbbl)	NATURAL GAS (MMscf)	NATURAL GAS LIQUIDS (Mbbbl)
CANADA			
Total Company	44.40	620.90	13.80
Significant Fields ⁽¹⁾			
Brazeau River	0.10	207.90	3.10
Ferrier	3.20	186.10	6.90
Strachan	-	4.70	0.10
Sunchild	0.30	122.00	2.40
Taber	32.20	-	-
TUNISIA			
Total Company	502.41	907.43	5.70
Significant Fields ⁽¹⁾			
Sabria	247.75	556.40	5.70
Chouech Es Saida	170.35	225.57	-
HUNGARY			
Total Company	-	629.65	-
Significant Fields ⁽¹⁾			
Törökkoppany	-	629.65	-

(1): Significant fields represent greater than 20% of Company total (by country) of production in first year of forecast

Production History

The Corporation's historical production and netback data for period ended December 31, 2006 is presented in the following table.

FORM 51-101F1	TABLE 6.9														
SUMMARY OF 2006 COMPANY SHARE OF PRODUCTION AND NETBACKS															
RESERVE CATEGORY	LIGHT AND MEDIUM OIL					NATURAL GAS					NATURAL GAS LIQUIDS				
	Q1	Q2	Q3	Q4	Total Year	Q1	Q2	Q3	Q4	Total Year	Q1	Q2	Q3	Q4	Total Year
CANADA															
Company share of daily production (Bbl/d or Mscf/d before deduction of royalties)	129	133	144	129	134	1,376	1,721	2,535	2,001	1,912	42	55	50	46	48
Average (\$/bbl, or \$/Mcf)															
Price received	47.02	66.98	62.46	48.13	56.41	8.37	6.37	6.11	7.36	6.90	60.41	67.31	68.62	54.87	63.17
Royalties paid	9.17	11.79	10.22	10.46	10.42	1.77	0.93	1.09	0.58	1.04	13.86	13.40	21.29	7.27	14.07
Production costs	13.64	14.59	14.87	17.82	15.22	2.22	2.39	2.44	2.94	2.52	13.26	13.71	14.26	17.76	14.76
Netback	24.22	40.60	37.37	19.85	30.78	4.39	3.04	2.58	3.84	3.34	33.29	40.20	33.07	29.84	34.34
Total Annual Production (Mbl or MMScf before deduction of royalties)	11,625	12,071	13,220	11,893	48,809	123,884	156,570	233,231	184,090	697,775	3,773	4,989	4,562	4,226	17,550
Important fields (greater than 20% of Total)															
Taber	97	88	117	105	102	-	-	-	-	-	-	-	-	-	-
Ferrier	-	-	-	-	-	605	649	538	559	587	26	26	17	21	22
Sunchild	-	-	-	-	-	117	578	598	468	441	2	11	16	7	9
Brazeau	-	-	-	-	-	213	196	1,047	754	555	5	4	14	16	10
TUNISIA															
Company share of daily production (Bbl/d or Mscf/d before deduction of royalties)	324	487	484	711	503	483	861	668	657	668	-	-	-	-	-
Average (\$/bbl, or \$/Mcf)															
Price received	72.29	72.75	72.36	69.79	71.81	7.70	7.60	7.77	7.43	7.62	-	-	-	-	-
Royalties paid	4.52	7.18	7.10	12.74	7.99	0.31	0.24	0.27	0.26	0.26	-	-	-	-	-
Production costs	17.04	12.96	14.15	10.02	12.85	1.82	1.89	2.21	2.66	2.15	-	-	-	-	-
Netback	50.73	52.61	51.11	47.03	50.97	5.57	5.47	5.29	4.51	5.21	-	-	-	-	-
Total Annual Production (Mbl or MMScf before deduction of royalties)	29,185	44,302	44,497	65,436	183,420	43,444	78,369	61,500	60,474	243,787	-	-	-	-	-
Important fields (greater than 20% of Total)															
Sabria	208	204	199	196	202	472	454	447	440	453	-	-	-	-	-
Chouech Essaida	69	185	184	394	209	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HUNGARY															
Company share of daily production (Bbl/d or Mscf/d before deduction of royalties)	-	-	-	-	-	6,740	1,249	621	3,390	2,984	-	-	-	-	-
Average (\$/bbl, or \$/Mcf)															
Price received	-	-	-	-	-	6.94	6.82	7.61	8.65	7.45	-	-	-	-	-
Royalties paid	-	-	-	-	-	0.74	1.52	1.01	1.22	0.98	-	-	-	-	-
Production costs	-	-	-	-	-	0.53	0.31	3.36	1.00	0.79	-	-	-	-	-
Netback	-	-	-	-	-	5.67	4.99	3.24	6.43	5.68	-	-	-	-	-
Total Annual Production (Mbl or MMScf before deduction of royalties)	-	-	-	-	-	606,600	113,658	57,094	311,880	1,089,232	-	-	-	-	-
Important fields (greater than 20% of Total)															
TorokkopynyField represents 100% of above	-	-	-	-	-	6,740	1,249	621	3,390	2,984	-	-	-	-	-

Competition in the Oil and Gas Industry

The oil and gas industry is highly competitive. Competition includes bidding for oil and natural gas rights and sale of oil and natural gas wherein price is the main determinant.

In searching for oil and gas prospects, the Corporation competes with other companies and individuals, some of which have greater resources than the Corporation. In addition, the oil and gas industry also competes with other industries in supplying the energy needs of consumers.

The marketability of oil and natural gas discovered by the Corporation will be affected by numerous factors beyond its control. These factors include crude oil and natural gas prices, proximity and capacity of oil and natural gas processing and transportation facilities, governmental production regulations, OPEC and non-OPEC production quotas, royalty rates, currency fluctuations and potential civil disturbances.

The management of, and consultants utilized by, the Corporation possess a high level of technical expertise. The Corporation's expertise is enhanced through the use of sophisticated analytical tools such as computer work stations for effective interpretation, computer mapping systems and extensive technical data banks. However, the Corporation recognizes that other companies and individuals with greater resources may have access to greater expertise.

RISK FACTORS

The Corporation is subject to risk factors due to its involvement in the exploration for, and the acquisition, development, production and marketing of, oil and natural gas and its current stage of development.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation 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 the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired businesses 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 the Corporation 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 the Corporation, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Corporation.

Operations

To the extent that the Corporation is not the operator of its oil and natural gas properties, the Corporation 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. As a result, there is no assurance that the development work required to bring the proven non-producing properties of the Corporation to proven producing status will be completed.

Exploration and Development

The Corporation is engaged in oil and natural gas exploration and development drilling, which is a high-risk venture with uncertain prospects for success. No assurance can be given that commercial accumulations of oil or natural gas will be discovered as a result of the efforts of the Corporation and shareholders must rely upon the ability, expertise, judgment, discretion, integrity, and good faith of the management of the Corporation.

Replacement Reserves

In general, the volume of production from oil and natural gas properties declines as reserves are depleted. The decline rates depend on reservoir characteristics and vary from reservoir to reservoir. Except to the extent the Corporation acquires properties containing proved reserves or conducts successful development and exploration activities, or both, the reserves of the Corporation will decline as reserves are produced. The Corporation's future natural gas and oil production is, therefore, highly dependent upon its level of success in finding or acquiring additional reserves. The business of exploring for, developing or acquiring reserves is capital intensive. To the extent cash flow from operations is reduced and external sources of capital become limited or unavailable, the Corporation's ability to make the necessary capital investment to maintain or expand its asset base of oil and gas reserves would be impaired. In addition, there can be no assurance that the Corporation's future development, acquisition and exploration activities will result in additional reserves or that the Corporation will be able to drill productive wells at acceptable costs.

Operating Hazards and Drilling Risks

Oil and natural gas exploration operations are subject to all the risks and hazards typically associated with such operations, hazards such as fire, explosion, blowouts, and oil spills, each of which could result in substantial damage to oil and natural gas wells, producing facilities, other property and the environment or in personal injury. Although the Corporation or the operators of the wells, maintain liability insurance in an amount which they consider adequate the nature of these risks is such that liabilities could exceed policy limits, in which event the Corporation could incur significant costs that could have a materially 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 premature decline of reservoirs and the invasion of water into producing formations.

Drilling involves numerous risks, including the risk that no commercially productive oil and gas reservoirs will be encountered. The cost of drilling and completing wells is often unpredictable, and drilling operations may be curtailed, delayed or cancelled as a result of a variety of factors, including unexpected drilling conditions, pressure or irregularities in formations, equipment failures or accidents, weather conditions and shortages or delays in delivery of equipment. There can be no assurance as to the success of the Corporation's future drilling activities.

Industry Conditions

The oil and natural gas industry is highly competitive and the Corporation must compete with many companies with greater financial strength and technical resources. Generally, there is intense competition for the acquisition of resource properties considered to have commercial potential. Prices paid for both oil and gas produced are subject to market fluctuations and will directly affect the profitability of producing any oil or gas reserves which may be acquired or developed by the Corporation.

Oil and natural gas operations, including lease acquisitions, are subject to extensive government regulation. Operations may be affected from time to time in varying degrees by political and environmental developments, such as restrictions on production, price controls, tax increases, expropriation of property, pollution controls and changes in conditions under which oil and gas may be exported. Sales are subject to the authorization of state, provincial and federal government agencies. Competition may also be presented by alternative fuels.

Government Regulation

The Corporation's oil and natural gas operations in Canada are subject to various Canadian federal, provincial and local governmental regulation. Matters subject to regulation include permits for drilling operations, reports concerning operations, the spacing of wells, and unitization and pooling of properties and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and natural gas wells below actual production capacity in order to conserve supplies of oil and natural gas. The production, handling, storage, transportation and disposal of oil and natural gas, by-products thereof and other substances and materials produced or used in connection with oil and natural gas operations are also subject to regulation under federal, state, provincial and local laws and regulations primarily relating to the protection of human health and the environment. To date, expenditures related to complying with these laws and for remediation of existing environmental contamination have not been significant in relation to the results of operations of the Corporation. Although the Corporation believes it is in substantial compliance with all applicable laws and regulations, the requirements imposed by such laws and regulations are frequently changed and subject to interpretation, and the Corporation is unable to predict the ultimate cost of compliance with these requirements or their effect on its operations.

In the areas where the Corporation conducts activities there are statutory laws and regulations governing the activities of oil and gas companies. These laws and regulations allow administrative agencies to govern the activities of oil companies in the development, production and sale of both oil and gas. Changes in these laws and regulations may substantially increase or decrease the costs of conducting any exploration or development project. The Corporation believes that its operations comply with all applicable legislation and regulations and that the existence of such regulations has no more restrictive effect on the Corporation's method of operations than on similar companies in the industry.

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 may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation 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 the Corporation's financial condition, results of operations or prospects.

In 1994, the United Nations' Framework Convention on Climate Change came into force and three years later led to the Kyoto Protocol (the "**Protocol**"). The Protocol came into force on February 16, 2005 and requires certain nations to reduce their emissions of carbon dioxide and other greenhouse gases. Under the terms of the Protocol, Canada will be required to reduce its greenhouse gas emissions to 6% below 1990 levels over the period beginning in 2008 and ending in 2012. Currently, Canadian oil and gas producers are in discussions with the provincial and federal levels of government regarding implementation mechanisms for the industry. It is premature to predict what impact the Protocol could have on Canadian oil and gas producers (and specifically, if and in what manner it will be implemented) but it is likely that any mandated reduction in greenhouse gas emissions will result in increased costs.

Future federal legislation, together with provincial emission reduction requirements, such as those required under the *Climate Change and Emissions Management Act* (Alberta), 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.

Price Volatility

The Corporation's revenue, profitability and future rate of growth are also substantially dependent upon the prevailing prices of, and demand for, oil and natural gas. Prices for oil and natural gas are subject to wide fluctuation in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond the control of the Corporation. These factors include the level of consumer product demand, weather conditions, domestic and foreign governmental regulations, the price and availability of alternative fuels, political conditions

in the Middle East, the foreign supply of oil and natural gas, the price of oil and gas imports and overall economic conditions. From time to time, excess domestic and imported supplies have depressed oil and gas prices. There can be no assurance that current price levels will be sustained. It is impossible to predict future oil and natural gas price movements with any certainty. Declines in oil and natural gas prices will adversely affect the Corporation's financial condition, liquidity and results of operations and may reduce the amount of the Corporation's oil and natural gas that can be produced economically.

The exchange rate differential between the Canadian and U.S. dollar also affects the profitability of the Corporation. World oil prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. exchange rate that may fluctuate over time. The Corporation may reduce the impact of fluctuation to foreign exchange fluctuations by using risk management tools related to foreign exchange rates and commodity prices. The Corporation has not entered into any foreign exchange contracts at this time.

Marketability

The marketability of oil and natural gas acquired or discovered will be affected by numerous factors beyond the control of the Corporation. These factors include reservoir characteristics, market fluctuations, the proximity and capacity of oil and natural gas pipelines and processing equipment and government regulation. 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.

Substantial Capital Requirements

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. In the event the Corporation's revenues or reserves decline, the Corporation may have limited ability to expend the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's financial condition, results of operations or prospects.

Additional Funding Requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation 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 the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to

expend the necessary capital to replace its reserves or to maintain its production. If the Corporation's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available on terms acceptable to the Corporation.

Issuance of Debt

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

Hedging

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

Title

No assurances can be given that title defects to the assets owned by the Corporation do not exist. If title defects do exist, it is possible that the Corporation may lose all or a portion of its right, title, estate and interest in and to the properties to which the title defect relates.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and cash flows to be derived therefrom, including many factors beyond the Corporation's control. The reserve and associated cash flow information set forth in this Annual Information Form represents estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may

vary from actual results. 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 expected therefrom prepared by different engineers, or by the same engineers at different times, may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

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

In accordance with applicable securities laws, McDaniel and APA, the independent evaluators, have used both constant and forecast price and cost estimates in calculating reserve quantities included in this Annual Information Form. Actual future net revenue will be affected by other factors such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and revenues derived therefrom will vary from the estimates contained in the McDaniel Report and APA Report, and such variations could be material. The McDaniel Report and APA Report are based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the McDaniel Report and APA Report will be reduced to the extent that such activities do not achieve the level of success assumed in such reports.

Insurance

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

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 expend, 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.

Foreign Operations

The Corporation's oil and natural gas activities will be subject to extensive controls and regulations imposed by various governments, which may be amended from time to time and foreign oil and gas operations are subject to political, economic and other uncertainties. Those uncertainties include: (i) the risk of war, revolution, border disputes, expropriation, renegotiation or modification of existing contracts, import, export and transportation regulations and tariffs resulting in loss of revenue, property and equipment; (ii) nationalization of assets by foreign governments; (iii) taxation policies, including royalty and tax increases and retroactive tax claims; (iv) exchange controls, currency fluctuations and other uncertainties arising out of foreign government sovereignty over oil and gas properties; (v) laws and policies of Canada affecting foreign trade, taxation and investment; and (vi) the possibility of being subjected to the jurisdiction of foreign courts in connection with legal disputes and the possible inability to subject foreign persons to the jurisdiction of the courts of Canada, all of which could adversely affect the outcome of a legal dispute. Political instability in other countries could result in new governments or the adoption of new policies, laws or regulations that might exhibit a substantially more hostile attitude toward foreign investment in general or the Corporation in particular. In an extreme case, such change could result in termination of contract rights (including, without cause) and expropriation or nationalization of assets owned by foreign entities. Any such activity could result in significant loss to the Corporation. In addition, the Corporation may be at a disadvantage in that it may be required to compete against corporations or other entities from countries that are not subject to Canadian laws and regulations, including the *Corruption of Foreign Public Officials Act* (or similar legislation of other jurisdictions, including the United States *Foreign Corrupt Practices Act*). Residents or nationals of countries not subject to such legal régimes may offer inducements to foreign governments and foreign public officials to entice such governments and officials to deal with them to the disadvantage of the Corporation.

Foreign oil and gas operations involve substantial costs and are subject to certain risks owing to the underdeveloped nature of the oil and gas industry in such countries. The oil and gas industry in various countries is not as developed as the oil and gas industry in Canada and the United States. As a result, drilling and development operations may take longer to complete and may cost more than similar operations in Canada and the United States. The availability of technical expertise, specific equipment and supplies is more limited in various countries than in Canada and the United States. Such factors may subject oil and gas operations in other countries to economic and operating risks not experienced in Canada and the United States.

Oil and Gas Operations

The Corporation's operations are subject to all the risks normally incident to the exploration for and product of oil and gas including geological risks, operating risks, potential risks, development risks, marketing risks, and logistical risks of operation in Canada, Tunisia and Hungary.

Tax Considerations

The Canadian federal and provincial tax treatment of oil and natural gas activities has a material effect on the advisability of investing in the Common Shares. The return on a holder's investment is subject to changes in federal and provincial tax laws. There can be no assurance that the income tax legislation in Canada will not be amended so as to fundamentally alter the tax consequences of holding or disposing of the Common Shares.

Foreign Officers and Directors

Certain of the directors or officers of the Corporation, named herein reside outside of Canada. Certain of the assets of the Corporation are located outside of Canada. It may not be possible for investors to effect service of process within Canada upon the directors and officers referred to above. It may also not be possible to enforce against certain of the Corporation's directors and officers named herein judgments obtained in Canadian courts predicated upon the civil liability provisions of applicable securities laws in Canada.

Reliance on Key Personnel

The Corporation'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 the Corporation. The Corporation does not have key person insurance in effect for management. The contributions of these individuals to the immediate operations of the Corporation are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

DESCRIPTION OF CAPITAL STRUCTURE

The Corporation's authorized share capital consists of an unlimited number of Common Shares without nominal or par value and an unlimited number of First and Second Preferred Shares. All of the Common Shares are fully paid and non-assessable. As at December 31, 2006 there were 28,676,939 Common Shares issued and outstanding and no preferred shares were issued and outstanding.

Each Common Share entitles its holder to receive notice of and to attend all meetings of the shareholders of the Corporation (other than meetings at which only the holders of shares of other classes are entitled to vote pursuant to the *Business Corporations Act* (Alberta) and to one vote at such meetings. The holders of Common Shares are, subject to the rights

of the holders of the First Preferred Shares and the Second Preferred Shares and any other class of shares ranking senior to the Common Shares, entitled to receive and participate rateably in any dividends declared by the Board of Directors of the Corporation. The holders of the Common Shares are entitled to participate rateably in any distribution of the assets of the Corporation upon the liquidation, dissolution or winding up of the Corporation or other distribution of the assets of the Corporation among its shareholders for the purposes of winding up its affairs. Such participation is subject to the rights of the holders of the First Preferred Shares and the Second Preferred Shares and any other class of shares ranking senior to the Common Shares.

The First Preferred Shares are issuable in one or more series and subject to the articles, the Board of Directors is authorized to fix the number of shares in a series and the designation, rights, privileges, restrictions and conditions attaching to the shares of each series of First Preferred Shares. The First Preferred Shares of each series shall, with respect to the payment of dividends and the distribution of assets in the event of liquidation, dissolution or winding-up of the Corporation or any other distribution of the assets of the Corporation among its shareholders for the purpose of winding up its affairs, rank on a parity with the First Preferred Shares of every other series and be entitled to preference over the Second Preferred Shares and the Common Shares and any other class ranking junior to the First Preferred Shares. The First Preferred Shares of any series shall also be entitled to such other preferences over the Second Preferred Shares, Common Shares or the shares of any other class ranking junior to the First Preferred Shares as may be fixed by the Board of Directors in accordance with the above.

The Second Preferred Shares are issuable in one or more series and subject to the articles, the Board of Directors is authorized to fix the number of shares in a series and the designation, rights, privileges, restrictions and conditions attaching to the shares of each series of Second Preferred Shares. The Second Preferred Shares, in the above circumstances, shall rank on a parity with the Second Preferred Shares of every other series and be entitled to preference over the Common Shares and any other class ranking junior to the Second Preferred Shares. The Second Preferred Shares of any series shall also be entitled to such other preferences over the Common Shares or the shares of any other class ranking junior to the Second Preferred Shares as may be fixed by the Board of Directors in accordance with the above.

DIVIDENDS

The payment of dividends in the future is dependent on the earnings and financial condition of the Corporation and such other factors as the directors consider appropriate. The Corporation has not paid dividends in any of the three most recently completed financial years. The Corporation's articles do not contain any restrictions on the payments of dividends.

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the Toronto Stock Exchange under the symbol "WIX".

The Common Shares traded on the TSX Venture Exchange until December 28, 2006, whereafter they traded on the Toronto Stock Exchange. Simultaneously, the Common Shares were de-listed from the TSX Venture Exchange. The Common Shares only traded for one day on the Toronto Stock Exchange in 2006. The trading summary for the Corporation in 2006 on the TSX Venture Exchange is as follows:

Name of Market: Toronto Stock Exchange				
Month	High	Low	Close	Volume
December 2006 ⁽¹⁾	\$5.00	\$4.60	\$4.90	57,645

Note:

(1) The December 2006 data is for the period December 29-30, 2006.

Name of market: TSX Venture Exchange				
Month	High	Low	Close	Volume
December 2006 ⁽¹⁾	\$4.45	\$3.20	\$4.28	364,246
November 2006	\$3.74	\$2.40	\$3.57	350,690
October 2006	\$2.84	\$2.27	\$2.75	355,389
September 2006	\$3.10	\$2.31	\$2.45	181,321
August 2006	\$3.10	\$2.71	\$2.95	969,404
July 2006	\$3.00	\$2.62	\$2.75	308,320
June 2006	\$3.00	\$2.49	\$2.62	211,793
May 2006	\$3.40	\$2.70	\$2.82	384,228
April 2006	\$3.50	\$2.60	\$3.15	1,211,470
March 2006	\$3.24	\$1.84	\$2.90	782,730
February 2006	\$2.12	\$1.84	\$1.86	276,187
January 2006	\$2.40	\$1.75	\$2.12	737,881

Note:

(1) The December 2006 data is for the period December 1 - 28, 2006.

ESCROWED SECURITIES

As a result of the acquisition by the Corporation of all of the outstanding common shares of Athanor, an escrow agreement dated August 22, 2005 was entered into by the Corporation, Computershare Trust Company of Canada and certain shareholders of the Corporation, whereby a total of 940,743 Common Shares were escrowed in accordance with the rules of the TSX Venture Exchange. Those Common Shares that were escrowed are subject to release as to 25% thereof on October 21, 2005 (the date of the "Final Exchange Bulletin" confirming the acceptance by the TSX Venture Exchange of the acquisition previously described) and on the 6 month, 12 month and 18 month anniversaries of such date. There are currently 235,912 Common Shares that remain in escrow pursuant to that escrow agreement. Computershare Trust Company of Canada, Suite 600, 530 - 8th Avenue S.W., Calgary, Alberta, T2P 3S8 acts as escrow agent under that escrow agreement.

DIRECTORS AND OFFICERS

As at December 31, 2006 the following table sets out the names, municipalities of residence, and positions of the directors and officers of the Corporation as well as their principal occupations within the five preceding years, which are as follows:

Name and Principal Municipality of Residence	Occupation for the Past Five years	Date First Elected or Appointed
David A. Monachello President and Director Calgary, Alberta	President, and Chief Executive Officer of Winstar Resources Ltd.; President, Chief Executive Officer and director of Stylus Exploration Inc. from 1999 to 2002; President, Chief Executive Officer, and director of Coparex Canada Ltd. from 1996 to 1999.	July 11, 2002
Bruce R. Libin ⁽¹⁾⁽²⁾ Chairman and Director Calgary, Alberta	Chairman of the Board of Winstar Resources Ltd. since December 2002; Executive Chairman and Chief Executive Officer of Destiny Resources Services Corp.; President of B.R. Libin Capital Corp.; Director of Provident Energy Trust.	July 11, 2002
W. Russ Duncan ⁽³⁾ Director Calgary, Alberta	Vice President of Sky Hunter Exploration Ltd.; Officer and Director of Paramount Resources Ltd. and Newalta Corporation.	November 18, 2004
Roger G. McMechan Executive Vice President & Director Calgary, Alberta	Executive Vice President and Director of the Corporation, prior to 2005 General Manager -Exploration and Development Burlington Resources Canada, prior to 2000 General Manager of North Africa PetroCanada Resources	March 30, 2005
Charles A. de Mestral Chief Executive Officer and Director Geneva, Switzerland	General Manager and Director of Athanor until the Corporation acquired Athanor on August 22, 2005; prior to 1998 President of Coparex International (oil and gas exploration); and prior to 1992 President of American Cometra (oil and gas exploration).	August 19, 2005
Bernard P. de Combret ⁽²⁾⁽³⁾ Director Geneva, Switzerland	Businessman. Prior to 2002, Deputy Chairman of the Executive committee and President (gas and power trading) TotalFina Elf	August 19, 2005
Bryan H. Lawrence ⁽¹⁾ Director New York, USA	Co-Founder and general partner of Yorktown Partners LLC. Prior to 1997 manager of oil and gas investments at Dillon Read & Co.	August 19, 2005
Robert W. Mitchell ⁽³⁾ Director Calgary, Alberta Canada	Retired, prior to 2003, Executive Vice President of Talisman Energy Inc., Director of Provident Energy Trust	August 19, 2005
Douglas Baker ⁽¹⁾⁽²⁾ Director Calgary, Alberta Canada	Oil and Gas executive, formerly Vice President and Chief Financial Officer with Valiant Energy Inc.; President and Chief Financial Officer of Forte Resources Inc.	November 14, 2005
Christopher W. Nixon Corporate Secretary Calgary Alberta	Partner at Stikeman Elliott LLP	October 21, 2003
Don S. Milne Chief Financial Officer Calgary, Alberta	Chief Financial Officer of Winstar Resources Ltd. ; formerly controller of ARC Resources from 2005 to 2006; controller at Acclaim Energy Inc. from 1996 to 2002	November 17, 2006

Notes:

- (1) Members of the Audit Committee.
- (2) Members of the Compensation Committee.
- (3) Members of the Reserves Committee

The term of office of each of the directors of the Corporation expires at the next annual meeting of shareholders of the Corporation.

As at December 31, 2006, the directors and senior officers of the Corporation, as a group, beneficially owned, directly or indirectly, 1,408,084 Common Shares or approximately 4.9% of the issued and outstanding Common Shares.

Conflicts of Interest

Circumstances may arise where members of the board of directors of the Corporation are directors or officers of corporations which are in competition to the interests of the Corporation. No assurances can be given that opportunities identified by such board members will be provided to the Corporation. Pursuant to the *Business Corporations Act* (Alberta), directors who have an interest in a proposed transaction upon which the board of directors is voting are required to disclose their interests and refrain from voting on the transaction.

AUDIT COMMITTEE INFORMATION

Information concerning the Audit Committee of the Corporation, as required by Multilateral Instrument 52-110, is provided in Appendix "C" to this Annual Information Form.

LEGAL PROCEEDINGS

There are currently no outstanding legal proceedings material to the Corporation to which the Corporation or any subsidiary of the Corporation is a party or of which any property of the Corporation is the subject matter, or are any such proceedings known to the Corporation to be completed.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Management is not aware of any material interest, direct or indirect, of any director or executive officer of the Corporation, a person or company that is the direct or indirect beneficial owner of, or who exercises control or direction over, more than 10% of the Common Shares, or their respective associates or affiliates, in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or would materially affect the Corporation or any of its subsidiaries.

TRANSFERS AGENTS AND REGISTRARS

Computershare Trust Company of Canada at principal offices at Calgary Alberta and Toronto, Ontario is the transfer agent and registrar for the Common Shares of the Corporation.

MATERIAL CONTRACTS

The Corporation has not entered into any material contracts in the most recently completed financial year, except for contracts entered into by the Corporation in the ordinary course of business.

INTERESTS OF EXPERTS

The Corporation's auditor is Ernst & Young LLP, Chartered Accountants, Ernst & Young Tower, 100, 440 - 2nd Avenue S.W. Calgary Alberta T2P 5E9. The Corporation's audited financial statements for the year ended December 31, 2006 have been filed under National Instrument 51-102 in reliance on the report of Ernst & Young LLP, independent chartered accountants, given their authority as experts in auditing and accounting. Ernst & Young LLP is independent in accordance with the Rules of Professional Conduct as outlined by the Institute of Chartered Accountants of Alberta.

The reserves data set forth in this Annual Information Form is based upon an evaluation of the Corporation's Canadian assets by the independent qualified reserves evaluator, McDaniel in the McDaniel Report and of the Corporation's Tunisian and Hungarian assets by APA in the APA Report. APA and McDaniel are both independent qualified reserve evaluators in accordance with the standards of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

The partners and professional staff of Ernst & Young LLP, as a group, do not beneficially own, directly or indirectly, any of the Common Shares. As of the date hereof, the principals of APA and McDaniel, as a group, did not beneficially own, directly or indirectly, any of the outstanding Common Shares.

ADDITIONAL INFORMATION

Additional information relating to the Corporation may be found on SEDAR at www.sedar.com.

Additional information, including information as to directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities, options to purchase securities and interests of insiders in material transactions, where applicable, is contained in the Corporation's Information Circular for its most recent annual meeting of the security holders that involved the election of directors. Additional financial information is provided in the Corporation's audited consolidated financial statements for the year ended December 31, 2006 and related annual management's discussion and analysis.

Copies of the foregoing documents may be obtained from the Corporation upon request and in some cases upon payment of a reasonable charge or from the Corporation's website www.winstar.ca

For additional copies of this Annual Information Form and the materials listed in the preceding paragraph, please contact:

David A. Monachello
President
Winstar Resources Ltd.
845, 401 9th Ave S.W
Calgary, Alberta T2P 3C5
Tel: (403) 513-4200
Fax: (403) 205-2722
Email: dmonachello@winstar.ca
Website: www.winstar.ca

APPENDIX "A"
FORM 51-101F2 – REPORT ON RESERVES DATA BY CORPORATIONS
INDEPENDENT QUALIFIED RESERVES EVALUATOR

Report by McDaniel & Associates Consultant Ltd.

To the board of directors of Winstar Resources (the "Company"):

1. We have evaluated the Company'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 the related estimated future net revenue; and
 - (b) proved oil and gas reserves estimated as at December 31, 2006 using constant prices and costs and the related estimated future net revenue.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

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

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us, for the year ended December 31, 2006, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management:

Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue \$M (before income taxes, 10% discount rate)			
		Audited	Evaluated	Review	Total
January 30, 2007	Canada	-	12,964	-	12,964

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

6. We have no responsibility to update our report for events and circumstances occurring after the preparation date.
7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

(Signed) "P.A. Welch"

P.A. Welch, P.Eng.,
President & Managing Director

Calgary, Alberta

Report by APA Petroleum Engineering Inc.

To the board of directors of Winstar Resources Ltd.:

1. We have evaluated the Tunisian and Hungarian reserves data of Winstar Resources Ltd. (the “**Company**”) as at December 31, 2005. The reserves data consist of the following:
 - (a) (i) Proved and Proved plus Probable oil and gas and gas liquids reserves estimated as at December 31, 2006 using forecast prices and costs; and
 - (ii) the related estimated future net revenue; and
 - (b) (i) proved oil and gas reserves estimated as at December 31, 2006 using constant prices and costs; and
 - (ii) the related estimated future net revenue.
2. The reserves data are the responsibility of the Company’s management. Our responsibility is to express an opinion on the reserves data based on our evaluation. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the “**COGE Handbook**”) prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).
3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2006, and identifies the respective portions thereof that we have reported on to the Company’s management and board of directors:

Independent Qualified Reserves Evaluator	Description of Evaluation Report	Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue ⁽¹⁾ (Before Income Taxes Proved + Probable Reserves)		
				Million Canadian Dollars, 10% discount rate		
				Audited	Evaluated	Review
APA Petroleum Engineering Inc.	"Reserves Evaluation Tunisian and Hungarian Properties of Winstar Resources Ltd. as at December 31, 2006."	March 12, 2007	Tunisia and Hungary	\$n/a	\$179.2	\$n/a

Note:

(1) Future net revenue defined by "Companion Policy 51-101CP, Standards of Disclosure for Oil and Gas Activities, Appendix 1", using APA Petroleum Engineering Forecast of oil and gas prices. The value of NPV Future net Revenue before Tax for Proved and Probable reserves determined using the McDaniel Associates forecast of oil and gas prices is \$177.1 million.

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

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

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

Executed as to our report referred to above:

APA PETROLEUM ENGINEERING INC.

(Signed) "Brian D. Weatherill"

Brian D. Weatherill, P.Eng.

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

Management of Winstar Resources Ltd. (the "**Company**") is responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

- (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2006, the last day of the Company's most recently completed financial year, using forecast prices and costs; and
- (ii) the related estimated future net revenue; and
- (b) (i) proved oil and gas reserves estimated as at December 31, 2006, the last day of the Company's most recently completed financial year, using constant prices and costs; and
- (ii) the related estimated future net revenue.

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

The Reserves Committee of the board of directors of the Company has:

- (a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;
- (b) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation; and
- (c) reviewed the reserves data with management and the independent qualified reserves evaluator.

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

- (a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;
- (b) the filing of the report of the independent qualified reserves evaluators on the reserves data; and

(c) the content and filing of this report.

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

(Signed) "Charles de Mestral"

Charles de Mestral,
Chief Executive Officer

(Signed) "Roger McMechan"

Roger McMechan,
Executive V.P. Engineering & Operations

(Signed) "Robert Mitchell"

Robert Mitchell,
Director

(Signed) "Russ Duncan"

Russ Duncan,
Independent Director

APPENDIX "C" AUDIT COMMITTEE INFORMATION

Composition of Audit Committee

As at March 30, 2007 the Audit Committee of Winstar Resources Ltd. (the "Corporation") consists of Douglas Baker (Chairman), Bruce Libin and Bryan H. Lawrence. The Board of Directors has determined that all members of the Audit Committee are "independent" and "financially literate" as defined in Multilateral Instrument 52-110 - Audit Committees ("MI 52-110").

MI 52-110 states that a member of an audit committee is independent if the member has no direct or indirect material relationship with the issuer. A material relationship is a relationship which could, in the view of the issuer's Board of Directors, reasonably interfere with the exercise of a member's independent judgment.

In addition, an individual is considered financially literate if he or she has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the issuer's financial statements.

Education and Experience

Mr. Baker, who serves as the Vice-Chair of the Canadian Institute of Chartered Accountants, and served as the President of the Institute of Chartered Accountants of Alberta in 2003, brings considerable experience in finance, tax and accounting to the Corporation's Board of Directors. An independent businessman, Mr. Baker was Vice-President and Chief Financial Officer of Valiant Energy Inc. prior to its takeover by Peerless Energy Inc. in September 2006. He served as President and Chief Financial Officer of Forte Resources and its predecessors since August 2001. Before that, Mr. Baker held positions as President and Chief Financial Officer of Forte Energy Ltd. from July 1997 to May 2001, Vice-President and Chief Financial Officer of Territorial Resources Inc. from 1996 to 1997, Vice-President and Chief Financial Officer of Chancellor Energy Resources Inc. from 1993 to 1996, Vice-President and Chief Financial Officer of American Eagle Petroleum Ltd. from 1991 to 1993, Vice-President and Chief Financial Officer of Canadian Conquest Exploration Inc. from 1983 to 1991 and Manager and staff accountant with Deloitte, Haskins and Sells from 1975 to 1983. Mr. Baker is a graduate of the University of Saskatchewan and holds a Bachelor of Commerce degree with Honours and Distinction. He has been a chartered accountant since 1977. In 1996, Mr. Baker received the honour of being named a Fellow of Chartered Accountants.

Mr. Libin has been Executive Chairman and Chief Executive Officer of Destiny Resource Services Corp. since December 2000. From 1994 to 2000, his principal occupation was as President of B.R. Libin Capital Corp., an investment, merchant banking and investment banking advisory services company. Prior to that he was a senior partner, practicing mergers and acquisitions and securities law with law firm Bennett Jones, which he had joined in 1975. Mr. Libin has his Bachelor of Commerce degree (Honours) from the University of Toronto, his Juris Doctorate from the University of Pennsylvania Law School and his Master of Business Administration degree from the Wharton School. He was

appointed Queen's Counsel in 1990, received the Canada 125 Medal of Distinction in 1992 and was granted an Honorary Degree from the Southern Alberta Institute of Technology in May 2002. Mr. Libin is a member of the Board of Directors of Provident Energy Trust as well as several private corporations and foundations. Other corporate directorships have included Amoco Canada Petroleum Company Limited, Beau Canada Exploration Ltd., Mark's Work Warehouse Ltd., Maxx Petroleum Ltd., Tonko Development Corp. and United Inc.

Mr. Lawrence joined Dillon Read & Co. Inc. in 1966. During his career at Dillon Read he devoted a large portion of his time to energy-related projects, eventually overseeing all of Dillon Read & Co. Inc.'s investments in the energy industry. His clients included Amerada Hess, Arch Coal, Ashland Oil, Goodyear Tire, Hamilton Brothers, Homestake Mining, Noble Affiliates, Quantum Chemical, Vintage Petroleum and Texaco. Mr. Lawrence was critical in the establishment of Yorktown Energy Partners I and Yorktown Energy Partners II following the acquisition of Dillon Read by Swiss Bank Corp. in 1997. In 1997, Mr. Lawrence and six other Dillon Read executives became the general partners of Yorktown Partners LLC, the manager of Yorktown I and Yorktown II, and subsequent Yorktown III, IV, V and Yorktown VI partnerships.

External Auditor Service Fees

The following table present fees for the audits of the Company's annual consolidated financial statements for 2006 and 2005 and for other services provided by Ernst & Young LLP:

(Cdn \$ thousands)	2006	2005
Audit fees	333	280
Tax fees	11	16
All other fees	12	122

The Corporation incurred audit fees during the fiscal periods 2006 and 2005 relating to statutory requirements in all countries in which it operates.

The Corporation incurred fees for professional services by the Corporation's auditors in respect of tax compliance, tax planning and tax advice for the fiscal years ended 2006 and 2005.

The all other fees relate in fiscal 2005 relate to the review of pro forma financial statements, the issuance of required comfort letters, and the preparation of the management information circular respecting the Corporation's acquisition of Athanor B.V. All other fees in 2006 relate to assistance in the issuance of flow-through shares and the Corporation's Toronto Stock Exchange listing application.

The Audit Committee has implemented specific procedures regarding the pre-approval of services to be provided by the Company's external auditors. These procedures specify certain prohibited services that are not to be performed by the Company's external auditors. In addition, these procedures require that, at least annually, prior to the period in which the services are proposed to be provided, the Company's management, in conjunction with the

Company's external auditors, prepares and submits to the Audit Committee a complete list of all proposed services and related fees to be provided to the Company by the Company's external auditors. Under the Audit Committee pre-approval procedures, for those non-audit services proposed to be provided by the Company's external auditors that have not been previously approved by the Audit Committee, the Audit Committee has delegated to the Chairman of the Audit Committee the authority to grant pre-approvals of such services. The decision to pre-approve a service covered under this procedure is presented to the full Audit Committee at the next scheduled meeting. At each of the Audit Committee's regular meetings, the Audit Committee is provided an update as to the status of services previously approved.

Charter Of The Audit Committee

The following is the text of the Charter of the Audit Committee for the Corporation:

Policy Statement

It is the policy of WINSTAR RESOURCES LTD.. (the "**Corporation**") to establish and maintain an Audit Committee, composed entirely of independent directors, to assist the Board of Directors (the "**Board**") in carrying out their oversight responsibility for the Corporation's internal controls, financial reporting and risk management processes. The Audit Committee will be provided with resources commensurate with the duties and responsibilities assigned to it by the Board including administrative support. If determined necessary by the Audit Committee, it will have the discretion to institute investigations of improprieties, or suspected improprieties within the scope of its responsibilities, including the standing authority to retain special counsel or experts.

Composition of the Committee

1. The Audit Committee shall consist of at least three directors. The Board shall appoint the members of the Audit Committee. The Board shall appoint one member of the Audit Committee to be the Chair of the Audit Committee.
2. Each director appointed to the Audit Committee by the Board shall be an outside director who is unrelated. An outside, unrelated director is a director who is independent of management and is free from any interest, any business or other relationship which could, or could reasonably be perceived, to materially interfere with the director's ability to act with a view to the best interests of the Corporation, other than interests and relationships arising from shareholding. In determining whether a director is independent of management, the Board shall make reference to the then current legislation, rules, policies and instruments of applicable regulatory authorities.
3. Each member of the Audit Committee shall be "financially literate". In order to be financially literate, a director must be, at a minimum, able to read and understand basic financial statements, and at least one member shall have "accounting or related financial management expertise", meaning the ability to analyze and interpret a full

set of financial statements, including the notes attached thereto, in accordance with Canadian generally accepted accounting principles.

4. A director appointed by the Board to the Audit Committee shall be a member of the Audit Committee until replaced by the Board or until his or her resignation.
5. The Chairman of the Board shall be an ex officio member of the Audit Committee.

Meetings of the Committee

1. The Audit Committee shall convene a minimum of four times each year at such times and places as may be designated by the Chair of the Audit Committee and whenever a meeting is requested by the Board, a member of the Audit Committee, the auditors, or a senior officer of the Corporation. Meetings of the Audit Committee shall correspond with the review of the quarterly financial statements and management discussion and analysis.
2. Notice of each meeting of the Audit Committee shall be given to each member of the Audit Committee and to the auditors, who shall be entitled to attend each meeting of the Audit Committee and shall attend whenever requested to do so by a member of the Audit Committee.
3. Notice of a meeting of the Audit Committee shall:
 - (a) be in writing;
 - (b) state the nature of the business to be transacted at the meeting in reasonable detail;
 - (c) to the extent practicable, be accompanied by copies of documentation to be considered at the meeting; and
 - (d) be given at least two business days prior to the time stipulated for the meeting or such shorter period as the members of the Audit Committee may permit.
4. A quorum for the transaction of business at a meeting of the Audit Committee shall consist of a majority of the members of the Audit Committee (excluding the Chairman of the Board). However, it shall be the practice of the Audit Committee to require review, and, if necessary, approval of certain important matters by all members of the Audit Committee.
5. A member or members of the Audit Committee may participate in a meeting of the Audit Committee by means of such telephonic, electronic or other communication facilities, as permits all persons participating in the meeting to communicate adequately with each other. A member participating in such a meeting by any such means is deemed to be present at the meeting.

6. In the absence of the Chair of the Audit Committee, the members of the Audit Committee shall choose one of the members present to be Chair of the meeting. In addition, the members of the Audit Committee shall choose one of the persons present to be the Secretary of the meeting.
7. The Chairman of the Board, senior management of the Corporation and other parties may attend meetings of the Audit Committee; however the Audit Committee (i) shall meet with the external auditors independent of management; and (ii) may meet separately with management.
8. Minutes shall be kept of all meetings of the Audit Committee and shall be signed by the Chair and the Secretary of the meeting.

Duties and Responsibilities of the Committee

1. The Audit Committee's primary duties and responsibilities are to:
 - (a) identify and monitor the management of the principal risks that could impact the financial reporting of the Corporation;
 - (b) monitor the integrity of the Corporation's financial reporting process and system of internal controls regarding financial reporting and accounting compliance;
 - (c) monitor the independence and performance of the Corporation's external auditors;
 - (d) deal directly with the external auditors to approve external audit plans, other services (if any) and fees;
 - (e) directly oversee the external audit process and results (in addition to items described in Section 4 below);
 - (f) provide an avenue of communication among the external auditors, management and the Board; and
 - (g) ensure that an effective "whistle blowing" procedure exists to permit stakeholders to express any concerns regarding accounting or financial matters to an appropriately independent individual.
2. The Audit Committee shall have the authority to:
 - (a) inspect any and all of the books and records of the Corporation, its subsidiaries and affiliates;
 - (b) discuss with the management of the Corporation, its subsidiaries and affiliates and senior staff of the Corporation, any affected party and the external auditors, such accounts, records and other matters as any member of the Audit Committee considers necessary and appropriate;

- (c) engage independent counsel and other advisors as it determines necessary to carry out its duties; and
 - (d) to set and pay the compensation for any advisors employed by the Audit Committee.
3. The Audit Committee shall, at the earliest opportunity after each meeting, report to the Board the results of its activities and any reviews undertaken and make recommendations to the Board as deemed appropriate.
4. The Audit Committee shall:
- (a) review the audit plan with the Corporation's external auditors and with management;
 - (b) discuss with management and the external auditors any proposed changes in major accounting policies or principles, the presentation and impact of significant risks and uncertainties and key estimates and judgements of management that may be material to financial reporting;
 - (c) review with management and with the external auditors significant financial reporting issues arising during the most recent fiscal period and the resolution or proposed resolution of such issues;
 - (d) review any problems experienced or concerns expressed by the external auditors in performing an audit, including any restrictions imposed by management or significant accounting issues on which there was a disagreement with management;
 - (e) review with senior management the process of identifying, monitoring and reporting the principal risks affecting financial reporting;
 - (f) review audited annual financial statements and related documents in conjunction with the report of the external auditors and obtain an explanation from management of all significant variances between comparative reporting periods;
 - (g) consider and review with management, the internal control memorandum or management letter containing the recommendations of the external auditors and management's response, if any, including an evaluation of the adequacy and effectiveness of the internal financial controls of the Corporation and subsequent follow-up to any identified weaknesses;
 - (h) review with financial management and the external auditors the quarterly unaudited financial statements and management discussion and analysis before release to the public;

- (i) before release, review and if appropriate, recommend for approval by the Board, all public disclosure documents containing audited or unaudited financial information, including any prospectuses, annual reports, annual information forms, management discussion and analysis and press releases; and
 - (j) oversee any of the financial affairs of the Corporation, its subsidiaries or affiliates, and, if deemed appropriate, make recommendations to the Board, external auditors or management.
5. The Audit Committee shall:
- (a) evaluate the independence and performance of the external auditors and annually recommend to the Board the appointment of the external auditor or the discharge of the external auditor when circumstances are warranted;
 - (b) consider the recommendations of management in respect of the appointment of the external auditors;
 - (c) pre-approve all non-audit services to be provided to the Corporation or its subsidiary entities by its external auditors', or the external auditors of the Corporation's subsidiary entities;
 - (d) approve the engagement letter for non-audit services to be provided by the external auditors or affiliates, together with estimated fees, and considering the potential impact of such services on the independence of the external auditors;
 - (e) when there is to be a change of external auditors, review all issues and provide documentation related to the change, including the information to be included in the Notice of Change of Auditors and documentation required pursuant to National Policy 31 (or any successor legislation) of the Canadian Securities Administrators and the planned steps for an orderly transition period; and
 - (f) (f) review all reportable events, including disagreements, unresolved issues and consultations, as defined by applicable securities policies, on a routine basis, whether or not there is to be a change of external auditors.
6. The Audit Committee shall:
- (a) review with management at least annually, the financing strategy and plans of the Corporation; and
 - (b) review all securities offering documents (including documents incorporated therein by reference) of the Corporation.

7. The Audit Committee shall review the amount and terms of any insurance to be obtained or maintained by the Corporation with respect to risks inherent in its operations and potential liabilities incurred by the directors or officers in the discharge of their duties and responsibilities.
8. The Audit Committee shall review the appointments of the Chief Financial Officer and any key financial managers who are involved in the financial reporting process.
9. The Audit Committee shall enquire into and determine the appropriate resolution of any conflict of interest in respect of audit or financial matters, which are directed to the Audit Committee by any member of the Board, a shareholder of the Corporation, the external auditors, or senior management.
10. The Audit Committee shall periodically review with management the need for an internal audit function.
11. The Audit Committee shall review the Corporation's accounting and reporting of environmental costs, liabilities and contingencies.
12. The Audit Committee shall establish and maintain procedures for:
 - (a) the receipt, retention and treatment of complaints received by the Corporation regarding accounting controls, or auditing matters; and
 - (b) the confidential, anonymous submission by employees of the Corporation on concerns regarding questionable accounting or auditing matters.
13. The Audit Committee shall review and approve the Corporation's hiring policies regarding employees and former employees of the present and former external auditors or auditing matters.
14. The Audit Committee shall review with the Corporation's legal counsel as required but at least annually, any legal matter that could have a significant impact on the Corporation's financial statements, and any enquiries received from regulators, or government agencies.
15. The Audit Committee shall assess, on an annual basis, the adequacy of this Mandate and the performance of the Audit Committee.