



Delphi Energy Corp.

ANNUAL INFORMATION FORM
For the year ended December 31, 2006

March 29, 2007

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INTRODUCTORY INFORMATION

Delphi Energy Corp. ("Delphi" or "Corporation") was formed on June 19, 2003 through the business combination ("Merger") of DT Energy Ltd. ("DTE") and Rise Energy Ltd. ("Rise"). The Merger was completed by way of a plan of arrangement, pursuant to which Rise acquired all of the common shares of DTE in consideration for common shares issued by Rise. Rise's name was changed to Delphi Energy Corp. and its board of directors and senior management positions were reconstituted. The two companies then amalgamated, resulting in Delphi being the only corporate entity at the time.

In this Annual Information Form, unless otherwise specified or the content otherwise requires, reference to "Delphi" or the "Corporation" includes reference to subsidiaries of and partnership interests held by Delphi Energy Corp. and its subsidiaries.

Defined terms, abbreviations and conversions used throughout this Annual Information Form which are not defined or explained in the text can be found in Appendix "C".

Unless otherwise specified, all dollar amounts are expressed in Canadian dollars, all references to "dollars" or "\$" are to Canadian dollars and all references to "US\$" are to United States dollars.

FORWARD-LOOKING INFORMATION

This Annual Information Form contains certain forward-looking statements relating to, but not limited to, the operations, anticipated financial performance, business prospects and strategies of Delphi. Forward-looking information typically contains statements with words such as "anticipate", "believe", "plan" or similar words suggesting future outcomes.

Readers are cautioned not to place undue reliance on forward-looking information because it is possible that predictions, forecasts, projections and other forms of forward-looking information will not be achieved by Delphi. By its nature, Delphi's forward-looking information involves numerous assumptions, inherent risks and uncertainties including, but not limited to, the following factors: general global economic and business conditions including the effect, if any, of a potential economic slowdown in the U.S. and/or Canada; changes in business strategies; the availability and price of energy commodities from the perspective of both a producer and a user of such commodities; the effects of competition and pricing pressures; industry overcapacity; shifts in market demands; changes in laws and regulations, including environmental and regulatory laws such as the imposition of restrictions in response to environmental concerns with respect to the production of oil and gas; potential increases in maintenance and operating costs; uncertainties of litigation; labour disputes; timing of completion of capital or maintenance projects; currency and interest rate fluctuations; various events which could disrupt operations, including severe weather conditions; and technological changes.

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 profitably produced in the future. Readers are cautioned that the forgoing list of factors is not exhaustive. The forward-looking statements in this annual information form and the documents incorporated herein by reference are expressly qualified by this cautionary statement.

Delphi does not undertake any obligation to publicly update or revise any forward-looking statement unless required by applicable law. Further, readers should also carefully consider the matters discussed under the heading "Risk Factors" in this annual information form.

CORPORATE STRUCTURE

Name, Address and Incorporation

As described under "Introductory Information", Delphi was formed on June 19, 2003 through the Merger of DTE and Rise. Delphi is subject to the *Business Corporations Act (Alberta)* ("ABCA"). On January 1, 2004, the Corporation filed Articles of Amalgamation to complete a short-form amalgamation with two wholly-owned subsidiaries Murias Energy Corporation ("Murias") and Fish Creek Resources Inc. ("Fish Creek") which it had acquired in 2003. On February 1, 2005, the Corporation filed Articles of Amalgamation to complete a short-form amalgamation with its wholly-owned subsidiary, Tercero Energy Inc. ("Tercero") which it acquired in 2004.

DTE was incorporated on September 20, 2000 under the ABCA. On October 19, 2000, DTE filed Articles of Amendment to remove the restrictions of share transfers. On December 12, 2001, DTE filed Articles of Amendment to allow, subject to certain conditions, its Board to appoint directors between annual meetings, with such directors serving until the next annual meeting of shareholders.

Rise was incorporated under the ABCA on June 8, 1995 as "657334 Alberta Ltd." On November 14, 1995, the company amended its Articles of Incorporation by changing its name from 657334 Alberta Ltd. to "Rise Resources Ltd.". On December 23, 1996, Rise amended its articles by changing its share capital structure to authorize the issuance of an unlimited number of Class A, Class B, Class C, Class D, Class E and Class F shares of Rise with the rights, privileges and restrictions set out in the Articles of Amendment. On August 17, 2001, Rise amalgamated the Red Raven Resources Inc., a company incorporated under the ABCA on September 13, 1996. The common shares of Red Raven Resources Inc. traded on the Canadian Venture Exchange, as the company had previously completed its major transaction under the junior capital pool rules.

The Corporation has its registered office at 2500, 450 – 1st Street S.W., Calgary, Alberta T2P 5H1 and its head and principal office at Suite 1500, 444 - 5th Avenue S.W., Calgary, Alberta, T2P 2T8.

Intercorporate Relationships

As of the date of this Information Circular the Corporation has a wholly-owned subsidiary, Delphi Energy Ltd., a corporation incorporated in the province of Alberta. Delphi Energy Corp. and Delphi Energy Ltd. are the partners of Delphi Energy Partnership established on December 30, 2005.

GENERAL DEVELOPMENT OF THE BUSINESS

Four Year History

The four year history of the Corporation is as follows:

2003

During 2003, the Corporation carried out a \$27.6 million capital program, which included \$16.6 million directed towards acquisitions. The Corporation closed two corporate acquisitions during 2003, as well as several property acquisitions and Crown land purchases. In March 2003, DTE completed its winter development program in Fontas and commenced exploration drilling as part of a joint venture with a senior oil and gas producer. The Corporation drilled 16 gross wells (6.9 net) during 2003. The remaining significant events for the Corporation in 2003 are as follows:

Acquisition of the Fontas Property

On February 26, 2003 the Corporation completed the acquisition of additional working interests in the Fontas wells that were acquired from a senior oil and gas producer together with three additional wells. The purchase price of approximately \$1.88 million was paid in cash.

Merger of DTE and Rise

On June 19, 2003 DTE completed the Merger with Rise, whose common shares were listed for trading on the TSX Venture Exchange ("TSX-V"). Delphi assumed Rise's listing on the TSX-V and its Common Shares commenced trading on June 26, 2003. The purchase price consisted of the issuance of 20,067,920 common shares of Rise to DTE shareholders and the assumption of Rise's net debt of \$3.40 million. Following completion of the arrangement, previous shareholders and special warrant holders of DTE held approximately 87.5% of the common shares of the Corporation. Additional disclosure of the Merger is available in the Joint Information Circular of DTE and Rise dated May 21, 2003, which is available on SEDAR at www.sedar.com.

The operations of Rise were concentrated in the Airdrie-Crossfield area in south central Alberta and the John Lake and Thompson Lake areas in east central Alberta. Production from Rise was approximately 400 boe/d.

Acquisition of Murias Energy Corporation

On September 17, 2003, the Corporation acquired all of the issued and outstanding shares of Murias, a private oil and gas company, in exchange for an aggregate purchase price of \$2.03 million, comprised of \$1.30 million cash, 358,000 Common Shares of Delphi issued from treasury at a price of \$1.75 per share and the assumption of Murias's working capital deficiency. The acquisition added net production of approximately 125 boe/d in the Corporation's core area of east central Alberta and approximately 180,000 boe of proved plus probable reserves to the operations and assets of the Corporation.

Acquisition of Fish Creek Resources Inc.

On October 31, 2003, the Corporation acquired all of the issued and outstanding shares of Fish Creek, a private oil and gas company, in exchange for an aggregate purchase price of \$2.75 million, comprised of \$1.75 million cash, 540,540 Common Shares of Delphi from treasury at a price of \$1.85 per share and the assumption of Fish Creek's working capital deficiency. The acquisition added net production of approximately 160 boe/d in the Corporation's core area of east central Alberta and approximately 254,000 boe of proved plus probable reserves to the operations and assets of the Corporation.

Equity Financings

On January 30, 2003 DTE raised gross proceeds of \$1.80 million through the private placement of 1,836,000 special warrants.

On December 18, 2003, the Corporation issued 1,136,364 flow-through common shares from treasury at \$2.20 per share for gross proceeds of \$2.50 million. The proceeds of the financing were used to fund the Corporation's exploration program.

Appointment of Senior Officer

On October 17, 2003 the Corporation appointed Brenda F. Mawhinney as Vice President, Finance and Chief Financial Officer.

2004

In 2004, the Corporation incurred capital expenditures of \$85.7 million, including the acquisition of all the outstanding shares of Tercero for \$52.4 million, providing Delphi with natural gas production and development opportunities in North East British Columbia. The remaining capital was directed to the Corporation's North West Alberta and East Central Alberta areas. The Corporation drilled 15 gross (4.3 net) wells during 2004. The remaining significant events for the Corporation in 2004 are as follows:

Trading on the Toronto Stock Exchange

On Tuesday, August 3, 2004, Delphi Energy Corp. began trading on the Toronto Stock Exchange and was delisted from the TSX Venture Exchange. Delphi's trading symbol remained "DEE".

Acquisition of Tercero Energy Inc.

On December 9, 2004, the Corporation acquired all of the issued and outstanding shares of Tercero, a private oil and gas company, for cash consideration of \$42.5 million and the assumption of debt plus working capital. The acquisition added net production of approximately 1,200 boe/d, predominantly in northeast British Columbia, and approximately 4.7 million boe of proved plus probable reserves to the operations and assets of the Corporation.

Equity Financings

On November 10, 2004, the Corporation issued 1,333,334 flow-through common shares at a price of \$3.00 per share for gross proceeds of \$4.0 million.

On November 23, 2004, the Corporation issued 9,090,910 subscription receipts at a price of \$2.20 per share for gross proceeds of \$20.0 million. The proceeds of the offering and additional debt financing were used to acquire all the issued and outstanding common shares of Tercero Energy Inc. on December 9, 2004. Upon closing of the acquisition, the subscription receipts were exchanged for common shares of Delphi.

On December 23, 2004, the Corporation issued 1,622,352 flow-through common shares at a price of \$3.70 per share for gross proceeds of \$6.0 million.

On December 23, 2004, the Corporation issued 10,169,494 subscription receipts at a price of \$2.95 per share for gross proceeds of \$30.0 million. The proceeds of the offering were held in trust until the closing of the Bigstone property acquisition, announced on December 6, 2004, which closed on February 1, 2005. Upon closing of the acquisition, the subscription receipts were exchanged for common shares of Delphi.

Appointment/Resignation of Senior Officers

On May 18, 2004, the Corporation appointed Frank M. Lowe as Vice President, Production. On September 17, 2004, Brenda F. Mawhinney resigned as Vice President, Finance and Chief Financial Officer. On December 1, 2004, Brian P. Kohlhammer joined Delphi as Vice President, Finance and Chief Financial Officer.

2005

In 2005, the Corporation acquired its liquids rich natural gas properties at Bigstone, Alberta for \$51.3 million. Capital expenditures for the year were \$61.2 million in the drilling of 45 gross (22.6 net) wells. The majority of the capital expenditures were directed at exploitation efforts in Bigstone.

Property Acquisition at Bigstone, Alberta

On February 1, 2005, the Corporation purchased the liquids rich natural gas properties at Bigstone, Alberta. At the time the properties were producing approximately 1,200 boe/d. The acquisition provided a significant inventory of development and infill opportunities and a working interest in critical infrastructure to expand the field.

Equity Financings

On March 31, 2005, the Corporation issued 2,727,500 flow-through common shares at a price of \$4.40 per share for gross proceeds of \$12.0 million.

On December 13, 2005, the Corporation issued 1,958,500 flow-through common shares at a price of \$7.15 per share for gross proceeds of \$14.0 million.

On December 29, 2005, the Corporation issued 2,500,000 common shares at a price of \$5.60 per share for gross proceeds of \$14.0 million.

Appointment/Resignation of Senior Officers

On January 10, 2005, the Corporation appointed Michael S. Kaluza as Vice President, Engineering. On June 29, 2005 Frank M. Lowe resigned as Vice President, Production.

2006

In 2006, the Corporation completed its earning operations at Bigfoot in North East British Columbia resulting in the Corporation having a 50 percent working interest in 116 sections of land and infrastructure in the area. The Corporation also has a 50 percent interest in 19 wells and 100 percent interest in two wells.

Appointment/Resignation of Senior Officers

On February 16, 2006, the Corporation appointed Michael S. Kaluza as Chief Operating Officer and Rod A. Hume as Vice President Engineering.

Equity Financings

On June 29, 2006, the Corporation issued 5,209,000 flow-through common shares at a price of \$4.80 per share for gross proceeds of \$25.0 million.

Significant Acquisitions

On December 9, 2004, the Corporation acquired all of the issued and outstanding common shares of Tercero Energy Inc., a private oil and gas company, for a cash consideration of \$42.5 million and the assumption of debt plus working capital. Reference is made to Form 51-102F4 filed on SEDAR on March 2, 2005 under the heading "Business Acquisition Report", which information is incorporated herein by reference.

On February 1, 2005, the Corporation closed the acquisition of liquids-rich, natural gas properties at Bigstone, Alberta for cash consideration of \$51.3 million. Reference is made to Form 51-102F4 filed on SEDAR on April 8, 2005 under the heading "Business Acquisition Report", which information is incorporated herein by reference.

NARRATIVE DESCRIPTION OF THE BUSINESS

General

Delphi is an independent public corporation which is engaged in the acquisition, exploration, development and production of crude oil and natural gas in western Canada. Delphi's operations are principally concentrated in three core regions: (i) North West Alberta; (ii) North East British Columbia; and (iii) East Central Alberta. Delphi's stated objective is to grow shareholder value by delivering consistent growth in production and reserve additions, through a strategy of:

- production and reserve growth by drilling lower risk development opportunities;
- moderate exposure to higher risk / higher reward exploration drilling;
- capitalize on relationships with industry partners to enhance prospect opportunity flow;
- strategic property or corporate acquisitions that enhance both development and exploration drilling inventory; and
- focus efforts within technical areas of expertise.

The Corporation will evaluate both crude oil and natural gas opportunities. Delphi funds its capital program with cash flow from operations, debt financing and strategic use of new equity when appropriate.

Areas of Operations

During 2006, Delphi's production averaged 5,228 barrels of oil equivalent per day, an increase of 24 percent from the 2005 average of 4,221 boe/d. In 2006, Delphi participated in drilling 52 wells (21.7 net), achieving a net success rate of 90 percent. Total capital expenditures were \$165.4 million while proceeds on the disposition of assets were \$34.9 million. Approximately 55 percent of all capital was incurred on the Company's joint venture at Bigfoot in North East British Columbia and 17 percent was spent at Bigstone in North West Alberta.

North West Alberta

Bigstone

The Bigstone area in North West Alberta is located 150 kilometres southeast of Grande Prairie. Delphi produced 2,524 boe/d in 2006, consisting of 12,300 mcf/d of natural gas and 470 bbl/d of natural gas liquids. Bigstone production is primarily from the Cretaceous Dunvegan sands, however deeper drilling into multiple intervals of the Bullhead group as well as shallower completions in the Cardium has also proven successful. Delphi operates in excess of 95 percent of its production in the area and has an undeveloped land base of approximately 4,000 net acres. The Corporation also has a 29 percent working interest in an 80 mmcf/d natural gas plant and associated gathering system. The ownership of infrastructure is a key contributor to low operating costs for the area which translates into premium netbacks per boe.

Well control and sub-surface mapping indicates the undeveloped lands are highly prospective for multiple zones similar to the producing intervals in Bigstone proper. In 2006, the Corporation drilled 10 wells (5.3 net), primarily on these western lands, resulting in a light oil discovery and continued success in the Gething and Dunvegan formations. This success continues to generate additional drilling opportunities and the Company anticipates drilling 8 to 10 wells in 2007 at an average working interest of approximately 50 percent. The gas wells are characterized by initial average production rates of 1,500 mcf/d (approximately 250 boe/d) with individual well rates as high as 6,000 mcf/d (approximately 1,000 boe/d). First year decline rates are on the order of 40 to 50 percent moderating to 12 to 15 percent over the life of the reserves. The high initial production rates and netbacks are instrumental in recouping invested capital in less than two years and the future low decline rates provide for a stable and predictable cash flow stream. The current inventory of drilling prospects will provide for sustained drilling over the next three to five years.

North East British Columbia

Bigfoot

The Bigfoot area in North East British Columbia is located 80 kilometres southeast of Fort Nelson. First production was initiated in April 2006, and averaged 551 boe/d net (97 percent natural gas) to Delphi over the eight months from April to December. Currently all Bigfoot production is from the Jean Marie, however there is significant secondary potential in the Cretaceous, Triassic, Mississippian, and Devonian formations. The Jean Marie wells are characterized by very strong initial flush production rates as high as 2-3 mmcf/d declining over 50 percent in the first year with a typical decline rate of less than 10 percent over the life of the reserves.

In November 2005, Delphi announced a farm-in agreement with a senior industry producer to jointly develop a natural gas resource play in the Bigfoot area of North East British Columbia. The agreement provided Delphi an opportunity to earn a 50 percent working interest in excess of 200 sections of land, with an Area of Mutual Interest (“AMI”) being established which covers more than 200 additional sections of land. The farm-in involved the Jean Marie trend which is considered one of the largest regional plays discovered in the Western Canada Sedimentary Basin in the past decade. To date, in excess of 1,100 wells have been drilled and completed in the Jean Marie formation. Current production and cumulative recoveries for the trend are in excess of 465 mmcf/d and 1.1 trillion cubic feet of gas, respectively.

The agreement divided the lands into a northern block (“Area 1”) consisting of 118 sections of land and a southern block (“Area 2”) consisting of 92 sections of land. The earning commitment on the northern half of the joint venture lands involved the drilling of 19 wells and the tie-in of five existing productive wells, installation of a 30 kilometre, 12-inch natural gas transmission pipeline to transport the natural gas from the Bigfoot area to an existing processing facility in the Greater Sierra area owned and operated by the joint venture partner and construction of a 54 kilometre all-season road providing access to the undeveloped lands. The earning provision also included the acquisition of approximately 200 square kilometres of 3D seismic in Area 2. The Company was required to pay 90 percent of the capital expenditures to earn a 50 percent working interest in the lands and infrastructure.

Operations began shortly after signing the agreement with the mobilization of construction equipment, as weather conditions allowed, to build winter roads for drilling and the construction of key infrastructure. By the end of the 2005/2006 winter season, the all-season road from the north end to the south end of Area 1 had been completed and the transmission pipeline had been installed and connected to the operator’s natural gas processing facilities in the Greater Sierra area. The Company incurred expenditures of \$81.4 million on Area 1, consisting of \$30 million of non-recurring infrastructure costs which will provide year-round future development on the lands in Area 1.

With the earning phase for Area 1 complete and the overall project metrics for the Jean Marie formation

on track, the Company has the opportunity to develop a long life asset with a significant drilling inventory characterized by low risk and low finding and development costs. Based on the initial development phase, independently evaluated estimates of proved plus probable reserves are 3.6 million barrels of oil equivalent net to Delphi. The indicated reserves, as evaluated by GLJ Petroleum Consultants Ltd., are based on the 21 wells drilled to date and seven additional locations which develops less than 10 percent of the 118 gross sections (50 percent net to Delphi). Joint venture earning terms and cost overruns primarily associated with the infrastructure contributed to an all in finding and development cost of approximately \$25.40 per boe. Future finding and development costs are estimated to be approximately \$14.00 per boe now that the necessary infrastructure is in place to accommodate the significant development potential of this asset. Based on 2006 production rates, the Bigfoot asset has a reserve life index in excess of 15 years for the proven plus probable reserves.

Delphi also completed the acquisition of 3D seismic over 65,000 gross acres in Area 2. The data, costing approximately \$10 million, has been processed and is of very high quality with mapping suggesting Area 2 is equally as prospective as Area 1. As part of the agreement, Delphi had an option to enter into a similar type of earning commitment on Area 2, during the winter of 2007/2008, to earn a 50 percent working interest on these lands. Due to the high costs of services experienced on Area 1 and the volatility of natural gas prices experienced over the past six months, the Company chose not to exercise its option on these lands under the original terms contemplated. The operator has significantly curtailed the Area 2 capital program, indicating there may be an opportunity to farm-in on these lands in the future.

Other Properties

The Company's remaining assets in North East British Columbia produce from various fields and formations; including the shallow Cretaceous Bluesky at Kotcho, the deeper Permian Mattson at Windflower and Mississippian Debolt at Helmet, and the deep Devonian Jean Marie and Slave Point carbonates at Helmet North and Missile.

Early in 2006, the Corporation participated in drilling 7 wells (3.4 net) on these properties and net production averaged approximately 1,075 boe/d in 2006. At Clarke Lake and Bullmoose, Delphi divested its small, non-operated working interest for total proceeds of \$16.3 million. At Peggo, Delphi acquired 2,900 acres of undeveloped land, a 100 percent working interest in 13 kilometres of a sour gas transmission pipeline and a 50 percent working interest in a 30 mmcf/d processing facility.

Currently, Delphi has access to 19,000 net undeveloped acres at operated and non-operated working interests that vary from one to 100 percent. While the 2006/2007 winter program has been focused on remedial well work and optimization projects associated with the drilling program from earlier in the year, the 2007/2008 winter program will see a return to the low risk, predictable drilling of infill and step-out locations.

North West Alberta

Fontas

At Fontas, Alberta, located 300 kilometres north of Grande Prairie, Delphi produced approximately 470 boe/d in 2006, consisting of 2,800 mcf/d gas through a company owned facility. Production is primarily from the Mississippian Debolt/Elkton and the Cretaceous Detrital formations which are typically less than 800 metres in depth. A combination of sub-surface data, 2D and 3D seismic data is utilized to identify low-risk development wells in the existing pools and medium-risk step-out wells that create development opportunities for the following winter drilling season. The majority of the drilling and rework activity occurs in the winter months, usually the end of December through the middle of March, due to local surface conditions. At Fontas, Delphi has a 20 percent working interest in a contiguous land base in excess of 160,000 acres, the gathering system and a 40 mmcf/d processing facility that is tied into the Nova pipeline

system.

During the winter of 2005/2006, Delphi participated in drilling 13 wells (2.6 net) at Fontas. Nine of the wells were successfully completed as gas wells and tied-in, 3 wells were suspended pending further evaluation and 1 well was abandoned. The capital program also included numerous well workovers, reactivations, pipeline projects, facility modifications and general maintenance which at the end of the drilling season had increased the Company's net production to approximately 600 boe/d. This level of activity is typical of a winter program and results in a capital commitment to Delphi of approximately \$5.0 million annually. Although Fontas is not considered a "growth" property, the consistency and predictability of the development program coupled with the high operating netbacks associated with a company owned facility, make this a very desirable property from a cash flow perspective. Fontas is currently producing approximately 370 boe/d net to Delphi.

During the year, the majority working interest partner and operator of the property sold its working interest to an oil and gas royalty trust. For the winter of 2006/2007, the new operator has significantly scaled back the capital program to focus on remedial well work and maintenance projects, taking the time to further evaluate the property and develop a go forward plan. Due to the high cost of services for building winter access roads and transporting and establishing field camp facilities, the operator is considering a more extensive capital program every other year to improve the economics of the capital program.

East Central Alberta

East Central Alberta assets produced approximately 500 boe/d net to Delphi in 2006, consisting of 80 percent medium and heavy oil and 20 percent natural gas. The Company has an average working interest of 75 percent in the producing properties and an undeveloped land position of approximately 5,700 net acres. On these lands the Company has identified numerous infill and step-out drilling locations primarily on four properties: Horseshoe, Hayter, Thompson Lake and Sounding Lake.

During 2006, the Company incurred capital expenditures of approximately \$1.4 million performing well reactivations and facility optimizations. While it is difficult to generate production growth with such a modest level of capital expenditures, the Company has been able to minimize production declines. In 2007, the Company will be pursuing multiple infill and step-out drilling opportunities and continued well reactivation work due to the lower capital costs and improved overall economics associated with the strength in crude pricing. The assets are currently producing approximately 400 boe/d net to Delphi.

Exploration

Delphi's exploration team has continued its efforts to define future growth opportunities for the Company. The Company focuses its efforts on those areas and plays where it has existing in-house expertise. Emphasis is placed on multizone sweet gas targets with substantial future development upside. The Company makes use of its industry relationships to capture opportunities on both new and existing acreage.

Tower Creek, Alberta

At Tower Creek, operations to equip and tie-in the Company's exploration discovery are proceeding on schedule and are anticipated to be completed in the second quarter of 2007. As previously announced, Delphi and its working interest partners have signed an agreement with a midstream company that will construct an 18 kilometre, 8-inch diameter, high-pressure, sour gas pipeline to tie-in the well to the Kaybob South # 3 gas plant for processing, where significant excess capacity is available. Initial gross raw gas production rates are estimated to be between 20 and 25 mmcf/d (500 to 600 boe/d net to Delphi).

The second exploration test is scheduled to start drilling after spring break-up. This seismically defined deep exploration test is targeting high pressure sweet gas from the highly fractured Wabamun formation. Wabamun analogs in the area have commenced production at gross raw rates of up to 30 mmcf/d of sweet gas. Delphi will pay 23.9 percent of the costs of the well to earn a 20.8 percent working interest in the wellbore and surrounding acreage.

Brazeau, Alberta

At Brazeau, the Company intends to drill a twin well to an earlier discovery targeting several sandstone reservoirs within the Belly River Formation. Analogue production on offsetting lands ranges from 100 to 500 boe/d per well. Delphi has a 27 percent working interest in 2,560 acres where up to 8 development wells could be drilled upon success.

Cutbank, British Columbia

At Cutbank, the Company is currently in discussions with senior oil and gas producers regarding potential joint operations to develop existing acreage in this area. Delphi has a 50 percent working interest in a previously drilled exploration well which has successfully tested natural gas from two Cretaceous zones at rates in excess of 1,000 mcf/d. Several step-out locations to this discovery have been identified as part of a development program which would incorporate the tie-in of the existing discovery well.

Employees

The Corporation employs or retains the services of 24 individuals (including personnel hired on a contract basis) at its head office in Calgary, Alberta. In addition, Delphi also retains the services of 12 individuals in field operations in various locations in Alberta and British Columbia.

Risk Factors

Exploration, Development and Production Risks

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

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or

transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

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

Competition

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

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government that may be amended from time to time. Delphi's operations may require licenses from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all necessary licenses and permits that may be required to carry out exploration and development at its projects.

Kyoto Protocol

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". Delphi's exploration and production facilities and other operations and activities emit a small amount of greenhouse gases, which may subject Delphi to legislation regulating emissions of greenhouse gases. The Government of Canada has put forward a Climate Change Plan for Canada which suggests further legislation will set greenhouse gases emission reduction requirements for various industrial activities, including oil and gas exploration and production. Future federal legislation, together with provincial emission reduction requirements such as those in 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.

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 Delphi 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 Delphi's financial condition, results of operations or prospects.

Prices, Markets and Marketing

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

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

Substantial Capital Requirements

Delphi anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If Delphi's revenues or reserves decline, it 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 Delphi. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on its financial condition, results of operations or prospects.

Additional Funding Requirements

Delphi'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 Delphi to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If Delphi's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect Delphi's ability to expend the necessary capital to replace its reserves or to maintain its production. If Delphi'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 Delphi.

Issuance of Debt

From time to time Delphi 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 Delphi's debt levels above industry standards. Depending on future exploration and development plans, Delphi may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. Neither Delphi's articles nor its by-laws limit the amount of indebtedness that Delphi may incur. The level of Delphi's indebtedness from time to time, could impair Delphi'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 Delphi 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, Delphi will not benefit from such increases. Similarly, from time to time Delphi 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, Delphi will not benefit from the fluctuating exchange rate.

Availability of Drilling Equipment and Access

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

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat Delphi's claim which could result in a reduction of the revenue received by Delphi.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves and cash flows to be derived therefrom, including many factors beyond Delphi's control. 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. 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. Delphi'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.

In accordance with applicable securities laws, GLJ Petroleum Consultants Ltd., the Corporation's independent qualified reserves evaluator, has used both constant and escalated price and cost estimates in calculating reserve quantities in their report ("GLJ Report") summarized under "Oil and Gas Activities" below. Actual future net cash flows will be affected by other factors such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

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

Insurance

Delphi's involvement in the exploration for and development of oil and natural gas properties may result in Delphi becoming subject to liability for pollution, blow-outs, property damage, personal injury or other hazards. Although prior to drilling, Delphi 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, Delphi 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 Delphi. The occurrence of a significant event that Delphi is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on Delphi'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 expand, train and manage its employee base. The inability of the Corporation to deal with this growth could have a material adverse impact on its business, operations and prospects.

Expiration of Licences and Leases

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

Aboriginal Claims

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

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. There can be no assurance that these seasonal factors will not adversely affect the timing and scope of the Corporation's exploration and development activities, which could in turn have a material adverse impact on the Corporation's business, operations and prospects.

Third Party Credit Risk

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

Reliance on Key Personnel

Delphi'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 Delphi. Delphi does not have key person insurance in effect for management. The contributions of these individuals to the immediate operations of Delphi 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 Delphi 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 Delphi.

Oil and Gas Activities

National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" establishes a standard of disclosure for all Canadian reporting issuers in upstream oil and natural gas activities and reserves definitions for proved and probable reserves categories. The reserves disclosure presented below conforms with the requirements of NI 51-101. All of the Corporation's reserves are in western Canada and specifically in the provinces of Alberta and British Columbia.

The Corporation engaged GLJ Petroleum Consultants Ltd. ("GLJ"), independent qualified reserves evaluators, to evaluate and report on 100 percent of the Corporation's proved and proved plus probable reserves. The crude oil, natural gas and natural gas liquids reserves of the Corporation were evaluated by GLJ, with an effective date of December 31, 2006 in a report dated February 28, 2007 ("GLJ Report").

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

Definitions, abbreviations and conversions used throughout the following tables can be found in Appendix C.

Reserves Data (Constant Prices and Costs)

Reserves

	Light & Medium Oil (mbbls)		Heavy Oil (mbbls)		Natural Gas (mmcf)		Natural Gas Liquids (mbbls)		BOE (6:1) (mboe)	
	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾
	Proved ⁽³⁾⁽⁶⁾									
Developed producing ⁽⁴⁾	405	321	92	91	38,843	31,950	794	545	7,765	6,282
Developed non-producing ⁽⁴⁾	111	94	30	26	12,067	9,069	78	56	2,231	1,687
Undeveloped ⁽⁵⁾	-	-	-	-	6,939	5,982	105	78	1,261	1,074
Total proved	516	415	122	117	57,849	47,001	977	679	11,257	9,043
Probable ⁽³⁾⁽⁶⁾	308	245	766	741	26,477	21,897	441	308	5,928	4,944
Total proved plus probable	824	660	888	858	84,326	68,898	1,418	987	17,185	13,987

Net Present Value of Future Net Revenue

(\$ thousands)	Before Income Taxes Discounted at					After Income Taxes Discounted at				
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
	Proved ⁽³⁾⁽⁶⁾									
Developed producing ⁽⁴⁾	149,445	123,246	105,482	92,651	82,943	149,445	123,246	105,482	92,651	82,943
Developed non-producing ⁽⁴⁾	45,156	34,531	27,774	23,112	19,705	45,156	34,531	27,774	23,112	19,705
Undeveloped ⁽⁵⁾	15,276	7,251	3,237	944	(485)	14,318	6,901	3,098	885	(511)
Total proved	209,877	165,028	136,493	116,707	102,163	208,919	164,678	136,354	116,648	102,137
Probable ⁽³⁾⁽⁶⁾	99,762	63,500	44,315	32,781	25,225	70,623	45,878	32,656	24,578	19,190
Total proved plus probable	309,639	228,528	180,808	149,488	127,388	279,542	210,556	169,010	141,226	121,327

Breakdown of Future Net Revenue

(\$ thousands, undiscounted)	Revenue		Operating Costs	Development Costs	Well Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
	Revenue	Royalties						
Proved reserves	421,323	83,024	102,254	21,477	4,691	209,877	957	208,920
Proved plus probable	644,508	121,224	164,016	43,790	5,839	309,639	30,097	279,542

Future Net Revenue by Production Group

Reserve Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year)
		(\$ thousands)
Proved reserves ⁽³⁾⁽⁶⁾	Light & medium oil	3,200
	Heavy oil	1,044
	Natural gas	132,249
TOTAL		136,493

Summary of Pricing Assumptions

This summary table identifies benchmark reference pricing that applies to the Corporation for constant prices and costs.

Pricing assumptions	Light and Medium Oil			Heavy Oil	Natural Gas Liquids			Natural Gas	Inflation Rate	Exchange Rate
	West Texas Intermediate Cushing Oklahoma (US\$/bbl)	Edmonton Par Price 40 API (Cdn\$/bbl)	Cromer Medium 29 API (Cdn\$/bbl)	Hardisty Heavy 12 API (Cdn\$/bbl)	Edmonton Propane (Cdn\$/bbl)	Edmonton Butane (Cdn\$/bbl)	Edmonton Pentanes Plus (Cdn\$/bbl)	AECO-C spot (Cdn\$/mmbtu)	%/year	\$/US/\$Cdn
	Historical									
2002	26.08	40.33	35.48	26.57	21.39	27.08	40.73	4.04	2.2	0.637
2003	31.07	43.66	37.55	26.26	32.14	34.36	44.23	6.66	2.8	0.721
2004	41.38	52.96	45.75	29.11	34.70	39.97	54.07	6.88	1.8	0.768
2005	56.58	69.11	56.62	34.07	43.04	51.80	69.47	8.58	2.2	0.825
2006	66.22	73.16	62.24	41.87	43.97	66.64	75.69	7.02	2.1	0.882
Dec 31, 2006	60.85	67.58	59.47	38.63	43.25	54.06	71.55	6.07	-	0.858

Reserves Data (Forecast Prices and Costs)

Reserves

	Light & Medium Oil (mbbls)		Heavy Oil (mbbls)		Natural Gas (mmcf)		Natural Gas Liquids (mbbls)		BOE (6:1) (mboe)	
	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾
	Proved ⁽³⁾⁽⁶⁾									
Developed producing ⁽⁴⁾	402	318	95	93	39,392	32,351	795	547	7,857	6,350
Developed non-producing ⁽⁴⁾	111	94	42	36	12,089	9,047	78	56	2,246	1,693
Undeveloped ⁽⁵⁾	-	-	-	-	6,941	5,980	105	78	1,262	1,074
Total proved	513	412	137	129	58,422	47,378	978	681	11,364	9,117
Probable ⁽³⁾⁽⁶⁾	297	236	757	734	26,508	21,917	441	309	5,913	4,931
Total proved plus probable	810	648	894	863	84,930	69,295	1,419	990	17,278	14,049

Net Present Value of Future Net Revenue

(\$ thousands)	Before Income Taxes Discounted at					After Income Taxes ⁽¹⁰⁾ Discounted at				
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
	Proved ⁽³⁾⁽⁶⁾									
Developed producing	216,254	174,490	147,199	128,012	113,782	213,132	172,800	146,230	127,429	113,416
Developed non-producing	63,895	47,596	37,717	31,117	26,400	45,362	34,668	28,155	23,736	20,517
Undeveloped	30,577	16,093	9,263	5,488	3,162	21,582	10,908	5,826	2,993	1,241
Total proved	310,726	238,179	194,179	164,617	143,344	280,076	218,376	180,211	154,158	135,174
Probable	162,714	98,534	67,109	49,184	37,845	114,360	68,590	46,177	33,398	25,328
Total proved plus probable	473,440	336,713	261,288	213,801	181,189	394,436	286,966	226,388	187,556	160,502

Breakdown of Future Net Revenue

(\$ thousands, undiscounted)	Revenue	Royalties, including ARTC ⁽⁴⁾	Operating Costs	Development Costs	Well Abandonment Costs	Future Net Revenue Before Income Taxes	Future Net Revenue After Income Taxes
						Income Taxes ⁽¹⁰⁾	Income Taxes
Proved reserves	563,818	105,141	120,707	21,677	5,567	310,726	280,076
Proved plus probable	876,497	155,177	196,099	44,470	7,311	473,440	394,435

Future Net Revenue by Production Group

Reserve Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year)
		(\$ thousands)
Proved reserves	Light & medium oil	2,987
	Heavy oil	1,484
	Natural gas	189,708
	TOTAL	194,179
Proved plus probable reserves	Light & medium oil	3,991
	Heavy oil	4,307
	Natural gas	252,990
	TOTAL	261,288

Summary of Pricing Assumptions

This summary table identifies benchmark reference pricing that applies to the Corporation for forecast prices and costs.

Pricing assumptions	Light and Medium Oil			Heavy Oil	Natural Gas Liquids			Natural Gas	Inflation Rate	Exchange Rate
	West Texas Intermediate Cushing Oklahoma (US\$/bbl)	Edmonton Par Price 40 API (Cdn\$/bbl)	Cromer Medium 29 API (Cdn\$/bbl)	Hardisty Heavy 12 API (Cdn\$/bbl)	Edmonton Propane (Cdn\$/bbl)	Edmonton Butane (Cdn\$/bbl)	Edmonton Pentanes Plus (Cdn\$/bbl)	AECO-C spot price (Cdn\$/mmbtu)	%/year	\$US/\$Cdn
Historical										
2002	26.08	40.33	35.48	26.57	21.39	27.08	40.73	4.04	2.2	0.6376
2003	31.07	43.66	37.55	26.26	32.14	34.36	44.23	6.66	2.8	0.7213
2004	41.38	52.96	45.75	29.11	34.70	39.97	54.07	6.88	1.8	0.7680
2005	56.58	69.11	56.62	34.07	43.04	51.80	69.47	8.58	2.2	0.825
2006	66.22	73.16	62.24	41.87	43.97	66.64	75.69	7.02	2.1	0.882
Forecast										
2007	62.00	70.25	61.25	39.25	45.00	56.25	71.75	7.20	2.0	0.8700
2008	60.00	68.00	59.25	40.00	43.50	50.25	69.25	7.45	2.0	0.8700
2009	58.00	65.75	57.25	39.75	42.00	48.75	67.00	7.75	2.0	0.8700
2010	57.00	64.50	56.00	39.75	41.25	47.75	65.75	7.80	2.0	0.8700
2011	57.00	64.50	56.00	40.25	41.25	47.75	65.75	7.85	2.0	0.8700
2012	57.50	65.00	56.50	41.50	41.50	48.00	66.25	8.15	2.0	0.8700
2013	58.50	66.25	57.75	42.50	42.50	49.00	67.50	8.30	2.0	0.8700
2014	59.75	67.75	59.00	43.50	43.25	50.25	69.00	8.50	2.0	0.8700
2015	61.00	69.00	60.00	44.25	44.25	51.00	70.50	8.70	2.0	0.8700
2016	62.25	70.50	61.25	45.25	45.00	52.25	72.00	8.90	2.0	0.8700
2017	63.50	71.75	62.50	46.00	46.00	53.00	73.25	9.10	2.0	0.8700
Escalate thereafter at	2.0%/yr.	2.0%/yr.	2.0%/yr.	2.0%/yr.	2.0%/yr.	2.0%/yr.	2.0%/yr.	2.0%/yr.	2.0	0.8700

Reconciliation of Corporation's Net ⁽²⁾ Reserves

Forecast Prices and Costs ⁽⁷⁾

	Light & Medium Oil			Heavy Oil			Natural Gas			Natural Gas Liquids			BOE		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	(mmbbls)			(mmbbls)			(mmcf)			(mmbbls)			(mboe)		
December 31, 2005	412	95	508	537	533	1,069	39,773	14,482	54,255	613	168	781	8,191	3,210	11,401
Extensions	97	124	221	-	-	-	9,055	7,279	16,335	204	144	348	1,811	1,480	3,291
Improved recovery	-	-	-	-	-	-	12	(12)	-	-	-	-	2	(2)	-
Technical revisions	61	84	145	(362)	183	(179)	(4,189)	(2,259)	(6,448)	(79)	(22)	(102)	(1,078)	(133)	(1,211)
Discoveries	-	-	-	-	-	-	12,099	3,617	15,716	103	27	130	2,120	629	2,749
Acquisitions	-	-	-	-	-	-	338	31	369	2	-	2	58	6	64
Dispositions	(78)	(69)	(147)	-	-	-	(2,768)	(1,287)	(4,055)	(25)	(7)	(32)	(564)	(290)	(854)
Economic factors	3	2	5	9	18	27	92	66	158	-	(1)	(1)	27	31	58
Production	(85)	-	(85)	(55)	-	(55)	(7,034)	-	(7,034)	(137)	-	(137)	(1,449)	-	(1,449)
December 31, 2006	412	236	648	129	734	863	47,378	21,917	69,295	681	309	990	9,118	4,931	14,049

Reconciliation of Changes in Net Present Values of Future Net Revenue

Constant Prices and Costs ⁽⁸⁾, discounted at 10% per year and after taxes

Proved Reserves

Period and Factor	2006 (\$ thousands)
Estimated net present value at December 31, 2005	186,583
Oil and gas sales during the period net of production costs and royalties	(58,273)
Net change in prices, production costs and royalties related to future production	(96,026)
Changes in previously estimated development costs incurred during the period	148,033
Changes in estimated future development costs	(159,050)
Extensions and improved recovery	30,349
Discoveries	24,306
Acquisition of reserves	769
Disposition of reserves	(14,369)
Accretion of discount	23,013
Net change in income taxes	43,412
Changes resulting from technical revisions	(15,370)
Other changes	23,004
Estimated future net revenue at December 31, 2006 (after income tax)	136,354

Additional Information Relating to Reserves Data

Undeveloped Reserves ⁽⁵⁾

Proved Undeveloped Reserves

The following table sets forth the volumes of proved undeveloped reserves that were attributed to each product type for the year ended December 31, 2006:

	Light and medium oil(mbbls)	Heavy Oil (mbbls)	Natural gas (mmcf)	Natural gas liquids (mbbls)
Proved undeveloped	-	-	6,941	105

Of the Corporation's total proved reserves in 2006, only 11.1% were undeveloped. Most of the Corporation's undeveloped reserves are forecasted to be drilled in 2007 and 2008.

Probable Undeveloped Reserves

The following table sets forth the volumes of probable undeveloped that were attributed to each product type for the year ended December 31, 2006:

	Light and medium oil(mbbls)	Heavy Oil (mbbls)	Natural gas (mmcf)	Natural gas liquids (mbbls)
Probable undeveloped	139	109	9,177	146

32.5% of the Corporation's probable reserves are classified as undeveloped and are attributed to drilling locations, recompletions and tie-ins that are anticipated to proceed in the near term but do not meet the required confidence factor to be booked as proved.

Significant Factors or Uncertainties

The process of evaluating reserves is complex and requires significant judgments and decisions based upon a number of variable factors and assumptions, such as commodity prices, projected production from the properties, the assumed effects of regulation by government agencies and future operating costs. All of these estimates may vary from actual results. The reserve estimates contained in this report are based on current production forecasts, prices and economic conditions. Estimates of the recoverable oil and natural gas reserves attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of future net revenues expected there from, may vary. The Corporation's actual production, revenues, taxes, development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material.

Future Development Costs

Period	(\$ thousands)	Forecast Prices and Costs ⁽⁷⁾		Constant Prices and Costs ⁽⁸⁾
		Proved Reserves	Proved Plus Probable Reserves	Proved Reserves
2007		11,788	19,035	11,788
2008		9,639	16,279	9,450
2009		219	8,861	211
2010		31	295	28
2011		-	-	-
Remainder		-	-	-
Total for all years undiscounted		21,677	44,470	21,477
Total for all years discounted at 10% per year		19,789	39,453	19,617

The future development costs are capital costs required in the future for Delphi to convert proved undeveloped reserves and probable reserves into proved developed producing reserves. On an on-going basis Delphi will typically use its internally generated cash flow, which is well in excess of estimated future development costs, to fund requirements for future development required to develop the proved or the proved plus probable reserves.

Other Oil and Gas Information

Oil and Gas Properties and Wells

The following table sets forth the number and status of wells in which Delphi had a working interest as at December 31, 2006.

	Producing Wells						Non-Producing Wells					
	Oil		Gas		Service		Oil		Gas		Service	
	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾
Alberta	118	113	136	61	11	11	72	63	101	33	-	-
British Columbia	5	2	48	18	1	1	2	1	60	20	-	-

Properties with No Attributed Reserves

The following table sets forth the Corporation's undeveloped land holdings as at December 31, 2006.

(Acres)	Undeveloped	
	Gross	Net
North West Alberta	121,440	22,457
North East British Columbia	145,141	57,932
East Central Alberta	8,000	5,673
Total	274,581	86,062

During 2007, approximately 30,251 net acres of the Corporation's undeveloped land is set to expire, however, a substantial portion of these lands can be continued by proving production capability.

Additional Information Concerning Abandonment and Reclamation Costs

The Corporation estimates the costs associated with abandonment and reclamation costs for surface leases, wells and facilities based on previous experience or by estimating such costs. The following table discloses the abandonment costs for wells with reserves of Delphi estimated at December 31, 2006 calculated both undiscounted and at a 10% discount rate with a portion thereof anticipated to be paid in each of the next three years. The reclamation costs of the Corporation are estimated to be approximately \$8.0 million at December 31, 2006. The Corporation currently anticipates incurring abandonment and reclamation costs on 372 net wells.

Abandonment Costs For Wells with Reserves									
(\$ thousands)	2007	2008	2009	2010	2011	2012	Remainder	Total	Discounted at 10%
Proved producing	647	138	328	199	255	269	2,859	4,695	2,413
Total proved	563	177	328	317	315	331	3,536	5,567	2,660
Total proved plus probable	418	244	216	266	335	411	5,421	7,311	2,933

Tax Horizon

The income taxes deducted in the calculation of future net revenue above assume a blow down scenario whereby the Corporation produces out its existing reserves. Under this scenario Delphi is taxable in 2006.

The Corporation forecasts its tax horizon assuming reinvestment of cash flow to achieve production and reserve growth. The Corporation does not expect to be required to pay income taxes for the 2007 financial year. The Corporation estimates that income taxes may become payable in 2009, depending on commodity prices, production levels and capital spending.

Costs Incurred

During 2006 the Corporation incurred the following costs in Canada:

	2006 (\$ thousands)
Property and capital costs – Unproved properties	3,578
Property and capital costs – Proved properties	34,087
Exploration costs ⁽¹⁴⁾	30,352
Development costs ⁽¹²⁾	97,335

Exploration and Development Activities

The following table sets forth the number of exploratory and development wells Delphi participated during the year ended December 31, 2006.

	Exploratory Wells ⁽¹³⁾		Development Wells ⁽¹¹⁾	
	Gross	Net	Gross	Net
Natural gas wells	5.0	1.5	38.0	17.5
Oil wells	1.0	0.6	-	-
Dry holes	8.0	2.1	-	-
Total wells	14.0	4.2	38.0	17.5

Production Forecasts

The following table sets forth the volume of daily production estimated for the year 2007 in the reserves forecast for proved and proved plus probable reserves. The production volumes are the same in both the constant dollar and the forecast price case.

Proved

Forecast and Constant Price Cases	Light & medium oil (bbls/d)	Heavy oil (bbls/d)	Natural gas (mcf/d)	Natural gas liquids (bbls/d)	BOE/d
Bigstone	55	-	11,272	405	2,339
Bigfoot	-	-	3,305	44	595
Fontas	-	-	2,471	1	413
Northeast British Columbia	12	-	4,628	7	790
Other	191	103	3,211	32	861
Total Proved	258	103	24,887	489	4,998

Proved Plus Probable

Forecast and Constant Price Cases	Light & medium oil (bbls/d)	Heavy oil (bbls/d)	Natural gas (mcf/d)	Natural gas liquids (bbls/d)	BOE/d
Bigstone	92	-	12,342	444	2,593
Bigfoot	-	-	3,637	48	655
Fontas	-	-	2,537	1	424
Northeast British Columbia	12	-	4,894	7	836
Other	216	239	3,677	41	1,107
Total Proved plus Probable	320	239	27,087	541	5,615

Production History

Delphi's 2006 average net daily production before deduction of royalties, for the periods indicated is summarized below:

Average Daily Production	Q1	Q2	Q3	Q4
Crude oil (bbls/d)	544	531	444	388
Natural gas (mcf/d)	23,695	28,797	25,403	24,919
Natural gas liquids (bbls/d)	518	503	412	441
Total (boe/d)	5,011	5,834	5,090	4,982

Netback By Product

The following table sets forth information in respect of quarterly average net product prices received, royalties paid, operating expenses and operating netbacks by product for the year ended December 31, 2006.

	Light & Medium Oil (\$/bbl)			
	Q1	Q2	Q3	Q4
Average prices received	46.10	62.67	62.73	51.14
Royalties	5.44	10.23	8.85	4.00
Operating expenses	29.88	23.28	32.76	34.75
Transportation	2.05	2.12	2.06	1.59
Netback	8.73	27.05	19.06	10.81

	Heavy Oil (\$/bbl)			
	Q1	Q2	Q3	Q4
Average prices received	39.90	58.14	57.89	40.17
Royalties	1.15	1.35	1.92	1.14
Operating expenses	39.78	47.81	57.34	49.13
Transportation	2.78	2.81	3.83	2.78
Netback	(1.04)	8.99	(1.38)	(10.10)

	Natural Gas (\$/mcf)			
	Q1	Q2	Q3	Q4
Average prices received	8.54	7.59	7.20	8.41
Royalties	2.29	1.10	1.03	1.18
Operating expenses	0.93	1.01	1.00	1.06
Transportation	0.62	0.68	0.74	0.71
Netback	<u>4.70</u>	<u>4.81</u>	<u>4.43</u>	<u>5.46</u>

	Natural Gas Liquids (\$/bbl)			
	Q1	Q2	Q3	Q4
Average prices received	50.26	66.12	59.79	48.45
Royalties	15.85	19.58	16.07	15.76
Operating expenses	-	-	-	-
Transportation	-	-	-	-
Netback	<u>34.41</u>	<u>46.54</u>	<u>43.73</u>	<u>32.70</u>

Reports of the Independent Qualified Reserves Evaluator and Management

The reports of GLJ, the independent reserves evaluator, and management of Delphi can be found in Appendix A and Appendix B, respectively.

DIVIDENDS

The Corporation has not declared or paid any dividends on any of its shares since its formation on June 19, 2003, nor did DTE or Rise pay any dividends on their respective shares at any time prior thereto. The Corporation does not intend to pay dividends in the near future, as future earnings will be retained to finance further expansion of business and operations. Any decision to pay dividends on any class of shares will be made by the board of directors on the basis of earnings, financial requirements and other conditions existing at such future time. The credit facilities of the Corporation also restrict its ability to pay dividends.

DESCRIPTION OF CAPITAL STRUCTURE

Common Shares

The holders of the Common Shares are entitled to one vote per share at meetings of shareholders, to receive such dividends as declared by the Corporation and to receive the remaining property and assets of the Corporation upon dissolution or winding up of the Corporation. The Common Shares are not subject to any future call or assessment and there are no pre-emptive, conversion or redemption rights attached to such shares. An unlimited number of voting common shares, without par value, have been authorized, of which 60,662,491 Common Shares were outstanding at December 31, 2006.

Preferred Shares

An unlimited number of preferred shares issuable have also been authorized in series of which none are outstanding.

MARKET FOR SECURITIES

The Common Shares of the Corporation are listed and posted for trading on the Toronto Stock Exchange ("TSX") under the trading symbol "DEE". The following table sets forth the market price ranges and the aggregate volume of trading of the Common Shares on the TSX for the periods indicated:

<u>Period</u>	<u>High (\$)</u>	<u>Low (\$)</u>	<u>Close (\$)</u>	<u>Volume</u>
2006				
January	5.82	5.09	5.09	1,457,200
February	5.35	4.40	4.59	2,710,100
March	5.15	4.31	5.11	2,984,800
April	5.48	5.07	5.36	2,690,100
May	5.58	4.50	4.50	2,746,900
June	4.98	3.78	4.20	1,662,500
July	4.56	3.74	4.56	2,947,700
August	4.84	4.35	4.58	1,902,700
September	4.39	2.88	2.88	2,817,600
October	3.49	2.65	3.36	3,669,100
November	3.10	2.45	2.79	5,319,200
December	2.68	2.39	2.48	6,340,900

DIRECTORS AND OFFICERS

Name, Occupation and Security Holdings

The names, municipalities of residence, positions with the Corporation and the principal occupations of the directors and officers of the Corporation as at the date hereof are set out below.

<u>Name and Municipality of Residence</u>	<u>Office or Position with the Corporation</u>	<u>Present and Principal Occupation During the Last Five Years</u>
David J. Reid Calgary, Alberta, Canada	Director, President, Chief Executive Officer since June 2003; prior thereto a director of DTE since September 2000.	President and Chief Executive Officer of Delphi since June 19, 2003; President and Treasurer of DTE since September 20, 2000.
Tony Angelidis Calgary, Alberta, Canada	Director and Senior Vice President, Exploration since June 2003; prior thereto a director of DTE since September 2000.	Senior Vice President, Exploration Delphi since June 19, 2003; Vice President and Secretary of DTE since September 2000.
Robert A. Lehodey, Q.C. ⁽²⁾ Calgary, Alberta, Canada	Director since June 2003; prior thereto a director of DTE since September 2000.	Partner with the law firm Osler, Hoskin & Harcourt LLP since March 2006; prior thereto, independent businessman since November 2005; prior thereto partner with the law firm

Name and Municipality of Residence	Office or Position with the Corporation	Present and Principal Occupation During the Last Five Years
		Bennett Jones LLP since November 1997.
Harry S. Campbell, Q.C. ⁽²⁾	Director since June 2003; prior thereto a director of DTE since December 2000.	Partner with the law firm Burnet Duckworth & Palmer LLP since 1995.
Lamont C. Tolley ⁽¹⁾	Director since June 2003; prior thereto a director of DTE since December 2000.	Independent businessman since 1999.
Henry R. Lawrie, FCA ⁽¹⁾	Director since June 2003	Corporate director; advisor to Ross Smith Energy Group; Chief Accountant of the Alberta Securities Commission from 1997 through 2001; Chair of the Oil and Gas Securities Taskforce and Advisor to the Alberta Securities Commission; previously, Managing Partner, Calgary, member of Canadian Policy Board and Representative, World Firm Advisory Group, Price Waterhouse.
Andrew E. Osis ⁽¹⁾	Director since May 2005	President of Trissio Corporation, a corporate advisory and merchant capital corporation since 2004; Director Z28 Capital Corp. a TSX Venture company and illumiCell Corporation a private technology company; prior thereto Vice President , Global Banking of RBC Dominion Securities from 1999 through 2001.
Brian P. Kohlhammer	Vice President, Finance and Chief Financial Officer since December 2004	Vice President, Finance and Chief Financial Officer of Delphi since December 2004; prior thereto Vice President, Finance and Chief Financial Officer of Virtus Energy Ltd. from September 2001 to November 2004; prior thereto Vice President, Finance of Patchgear.com from September 2000 to April 2001.
Michael S. Kaluza.....	Chief Operating Officer since February 2006	Vice President, Engineering of Delphi Energy Corp. since January 2005; prior thereto Senior Exploitation Engineer of Dominion Exploration Canada Ltd. from February 2001 to January 2005.
Rod Hume.....	Vice President, Engineering since February 2006	Vice President, Engineering of Delphi Energy Corp. since February 2006; prior thereto Senior Exploitation Engineer of Delphi Energy Corp. from February 2005; prior thereto Exploitation Manager/Engineer of Dominion Exploration Canada Ltd. from September 2002 to January 2005; prior thereto Exploitation Engineer of Devon Canada Corporation from May 2000 to August 2002.

Notes:

- (1) Member of the Audit and Reserves Committee
- (2) Member of the Corporate Governance and Compensation Committee

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

As at March 8, 2007, the directors and executive officers of the Corporation, as a group, beneficially, owned, directly or indirectly, 2,725,331 shares or approximately 4.0% of the issued and outstanding Common Shares and held options to acquire a further 2,384,250 Common Shares. Assuming exercise of all options, the directors and executive officers of the Corporation, as a group, would beneficially own, directly and indirectly, 5,109,581 Common Shares or approximately 7.5% of the then issued and outstanding Common Shares. The information as to shares beneficially owned, not being within the knowledge of the Corporation, has been furnished by the respective individuals.

Conflicts of Interest

Certain directors of Delphi are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA. In accordance with the ABCA, directors who have a material interest in any person who is a party to a material contract or proposed material contract with Delphi are required, subject to certain exceptions, to disclose that interest and abstain from voting on any resolution to approve that contract. In addition, the directors are required to act honestly and in good faith with a view to the best interests of Delphi.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There are no material interests, direct or indirect, of directors, executive officers, senior officers, any direct or indirect shareholder of the Corporation who beneficially owns, or who exercises control over, more than 10% of the outstanding Common Shares or any known associate or affiliate of such persons, in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or will materially affect Delphi.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares is Olympia Trust Company at its office in Calgary, Alberta.

MATERIAL CONTRACTS

There are no material contracts to which Delphi is a party.

INTERESTS OF EXPERTS

KPMG LLP is independent in accordance with the auditor's rules of professional conduct of the Institute of Chartered Accountants of Alberta.

Information relating to reserves in this annual information form dated February 28, 2007 was evaluated by GLJ as independent reserves evaluators. The principals of GLJ as a group owns less than one percent of the Common Shares of Delphi.

AUDIT AND RESERVES COMMITTEE

Audit and Reserves Committee Mandate

Policy Statement

Delphi Energy Corp. ("Corporation") has established and maintains an Audit & Reserves Committee, ("Committee") composed entirely of independent directors, to assist the Board of Directors ("Board") in

carrying out its oversight responsibility with respect to public reporting related to: (i) the Corporation's internal controls, financial reporting and risk management processes; and (ii) the Corporation's petroleum and natural gas reserves reporting and risk management. The Committee will be provided with resources commensurate with the duties and responsibilities set out herein and assigned to it by the Board from time to time, including administrative support. If determined necessary by the 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

1. The Committee shall consist of at least three directors. The Board shall appoint the members of the Committee. The Board shall appoint one member of the Committee to be the chairman of the Committee ("Chairman");
2. Each director appointed to the committee by the Board shall be an outside director who is unrelated and "independent" as required under the applicable securities laws and the applicable rules of any stock exchange on which the securities of the Corporation are listed. 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 be 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, including without limitation *Multilateral Instrument 52-110 - Audit Committee's* ("MI 52-110")
3. Each member of the Committee shall be "financially literate" as required under the applicable securities laws, including without limitation MI 52-110. In order to be financially literate, a director must have 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 Corporation's financial statements. If available, 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 Committee shall be a member of the Committee until replaced by the Board or until his or her resignation.

Meetings and Operations

1. The Committee shall convene a minimum of four times each year at such times and places as may be designated by the Chairman and whenever a meeting is requested by the Board, a member of the Committee, the external auditors ("auditors"), the external independent engineers ("engineers") or an officer of the Corporation. Meetings of the Committee shall correspond with the review of the quarterly and annual financial statements and the associated management's discussion and analysis ("MD&A") and with the review of the Corporation's annual independent engineering report process and updates thereto.

2. Notice of each meeting of the Committee shall be given to each member of the Committee and to the auditors, who shall be entitled to attend each meeting of the Committee and who shall attend whenever requested to do so by a member of the Committee.
3. A quorum for the transaction of business at a meeting of the Committee shall consist of two members of the Committee.
4. A member or members of the Committee may participate in a meeting of the 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.
5. In the absence of the Chairman, the members of the Committee shall choose one of the members present to be chairman of the meeting. In addition, the members of the Committee shall choose one of the persons present to be the secretary of the meeting.
6. The President and Chief Executive Officer and the Vice President, Finance and Chief Financial Officer and other members of senior management shall be invited to attend meetings of the Committee upon the request of the Committee; subject, however, to the requirement that the Committee (i) hold in camera sessions of the members of the Committee, without management representatives present at every meeting of the Committee, and (ii) meet with the auditors and the engineers separately and independent of management at every meeting at which the auditors and/or engineers are in attendance.
7. Minutes shall be kept of all meetings of the Committee.

Authority and Reporting

1. In discharging its duties and responsibilities, the 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 staff of the Corporation, any affected party, contractors and consultants of the Corporation and the auditors, such accounts, records and other matters as any member of the Committee considers necessary and appropriate;
 - (c) engage independent counsel and other advisors (including a second firm of external auditors) as it determines necessary to carry out its duties; and
 - (d) set and pay the compensation for any advisors employed by the Committee.
2. The Committee shall 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.

Audit Function

Primary Duties and Responsibilities

1. The Committee's primary duties and responsibilities regarding its audit function are to:

- (a) review with management and the external auditors, and recommend to the Board for approval and release to shareholders, the quarterly and annual financial statements of the Corporation, together with related reports to shareholders, MD&A associated with such financial statements and, when applicable, other public filings (such as prospectus or annual information forms) containing financial disclosures;
 - (b) review with the auditors and management, and monitor the management of, the principal risks that could affect the financial reporting of the Corporation;
 - (c) review the framework of and periodically consider the integrity of the Corporation's financial reporting process and system of internal controls regarding financial reporting and accounting compliance;
 - (d) consider the independence and performance of the Corporation's auditors;
 - (e) deal directly with the auditors to approve external audit plans, other services (if any) and associated fees;
 - (f) approve the audit engagement and consider the external audit process and results;
 - (g) provide an avenue of communication among the auditors, management and the Board;
 - (h) review the implementation of a "complaints" procedure to permit stakeholders to express any concerns regarding accounting or financial matters to an appropriately independent individual, and
 - (i) review the minutes of any Committee meetings held in connection with any subsidiary companies of the Corporation.
2. The Committee shall, in connection with the financial aspects of the Corporation's business:
- (a) review the external audit plan with the Corporation's auditors and with management and approve the engagement letter relating thereto;
 - (b) discuss with management and the auditors any proposed changes in major accounting policies or principles, the presentation and effect 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 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 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 management the process of identifying, monitoring and reporting the principal risks affecting financial reporting;
 - (f) review and evaluate any recommendations of the auditors and decide the appropriate course of action;

- (g) consider consistency of the data reported in the financial statements, annual and quarterly reports and related public disclosure documents;
- (h) review audited annual financial statements and related documents in conjunction with the report of the auditors and significant variances between comparative reporting periods as set out in the MD&A;
- (i) consider and review with management:
 - (i) all unadjusted errors identified by the external auditors,
 - (ii) the internal control memorandum or management letter containing the recommendations of the auditors and management's response, if any, including any evaluation of the adequacy and effectiveness of the internal financial controls of the Corporation and subsequent follow-up to any identified weakness;
- (j) review with management and the auditors the quarterly unaudited financial statements and MD&A before release to the public;
- (k) before release, review and if appropriate, recommend for approval by the Board, all public disclosure documents containing audited or unaudited financial information, including any prospectus, annual reports, annual information forms, MD&A and press releases; and
- (l) review and approve the Corporation's hiring policies regarding employees and former employees of the present and former auditors.

Auditors

1. The Committee shall:
 - (a) consider the independence and performance of the auditors and annually recommend to the Board the appointment or discharge of the auditor when circumstances are warranted and recommend to the Board the compensation of the auditors;
 - (b) pre-approve all non-audit services to be provided to the Corporation or its subsidiary entities by the auditors, or the auditors of any of the Corporation's subsidiary entities;
 - (c) when there is to be a change of 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 related documentation required pursuant to *National Instrument 51-102 – Change of Auditors* (or any successor legislation) and the planned steps for an orderly transition period; and
 - (d) 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 auditors.

Reserves Functions

Primary Duties and Responsibilities

1. The Committee's primary duties and responsibilities regarding its reserves function are to:
 - (a) assist the Board in respect of annual independent and internal reviews of the Corporation's petroleum and natural gas reserves and future net revenue;
 - (b) report to the Board on the Corporation's petroleum and natural gas reserves and recommend to the Board the acceptance and inclusion of the contents of the report from the independent engineers or senior reserve personnel on the Corporation's petroleum and natural gas reserves, and in accordance with applicable regulatory requirements; and
 - (c) periodically consider the Corporation's operations, production and reserves.
2. The Committee shall in connection with the reserves aspect of the Corporation's business:
 - (a) in consultation with the Corporation's senior reserves personnel, meet with the engineers being considered for appointment by the Corporation to review their qualifications and independence to :
 - (i) gain reasonable assurance that the engineers being considered for appointment are technically qualified and competent, and obtain confirmation of the engineer's independence of management of the corporation; and
 - (ii) establish the terms of their engagement; and
 - (b) after consultation with the Corporation's senior reserves personnel, recommend to the Board the appointment of the engineers and approve their remuneration.
 - (c) in consultation with the Corporation's senior reserves personnel determine the scope of the reviews of the Corporation's petroleum and natural gas reserves by the engineers, having regard to applicable securities legislation and industry practice;
 - (d) consider the procedures for providing petroleum and natural gas reserves information to the engineers to enable them to provide a report that will comply with applicable securities legislation;
 - (e) in consultation with the Corporation's senior reserves personnel and the engineers, determine whether any restrictions affect the ability of the engineers to report on reserves data and review the reserves data;
 - (f) consider and recommend to the Board the acceptance and inclusion of the contents of the report from the engineers or senior reserves personnel on the Corporation's petroleum and natural gas reserves data for filing with the regulatory authorities;
 - (g) if required, co-ordinate meetings with the auditors, the Corporation's senior reserves personnel, the engineers and independent consultants, if any, to address matters of mutual

- interest or concern in respect of the Corporation's evaluation of petroleum and natural gas reserves and future net revenue;
- (h) review any required Statement of Reserves Data and Other Oil & Gas Information with reference to the requirements of applicable securities legislation;
 - (i) review and recommend to the Board for approval all of the Corporation's public disclosure of reserves data and information with reference to the requirements of applicable securities legislation;
 - (j) review press releases relating to the Corporation's reserves data and related information with reference to the requirements with applicable securities legislation;
 - (k) review any proposal to change the engineers or assist in resolving any material difference between the engineers and management of the Corporation; and
 - (l) meet on an annual basis with the Corporation's senior engineering management and the engineers to review and consider the evaluation of the Corporation's petroleum and natural gas reserves and future net revenue.

Financing Matters

1. The Committee shall:

- (a) review all securities offering documents (including documents incorporated therein by reference) of the Corporation;
- (b) review findings, if any, from examinations or reviews performed by regulatory agencies with respect to financial matters;
- (c) review management's consideration of the Corporation's compliance with laws and regulations;
- (d) review management's assessment of current and expected future compliance with covenants under any financing agreements;
- (e) if requested by the Board, review the proposed issuance of debt and equity instruments including public and private debt, equity and hybrid securities, credit facilities with banks and others, and other credit arrangements such as material capital and operating leases, as well as any related securities filings;
- (f) if requested by the Board, review the proposed repurchase of public and private debt, equity and hybrid securities; and
- (g) in consultation with management, understand the Corporation's capital structure and financial risks arising from exposure to such things as commodity prices, interest rates, foreign currency exchange rates and credit and review the management of these risks including any proposed hedging of the exposures, including receiving a summary report of the hedging activities and hedge-related instruments.

Other

1. The Committee shall consider 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.
2. The Committee shall consider the appointments of the Chief Financial Officer and any key financial managers who are involved in the financial reporting process.
3. The 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 Committee by any member of the Board, a shareholder of the Corporation, the auditors, or management.
4. The Committee shall review, on an annual basis this mandate and recommend any changes to the Board.
5. The Committee will perform any other activities consistent with this mandate, the Corporation's bylaws and applicable laws as the Committee or the Board deems necessary or appropriate.

Scope and Reliance

1. While the Committee has the responsibilities, duties and authorities herein, it is not required to plan or conduct audits or to determine that the Corporation's financial statements and disclosures are complete and accurate or are in accordance with generally accepted accounting principles and applicable rules and regulations. These are the responsibilities of management and the auditors. The Committee, its Chairman and any of its members who have accounting or related financial management experience or expertise, are members of the Board, appointed to the Committee to provide broad oversight to the financial disclosure, financial risk and control related activities of the Corporation, and are specifically not accountable nor responsible for the day-to-day operation of such activities. Although designation of a member or members as being "financially literate" or a "financial expert" is based on each such individual's education and experience, which that individual will bring to bear in carrying out his or her duties on the Committee, designation as being "financially literate" or a "financial expert" does not impose on such person any duties, obligations or liability that are greater than the duties, obligations and liability imposed on such person as a member of the Committee and Board in the absence of such designation. Rather, the role of any financially literate individual or financial expert, like the role of all Committee members, is to oversee the process and not to certify or guarantee the internal or external audit of the Corporation's; financial information or public disclosure.
2. Absent actual knowledge to the contrary (which shall be promptly reported to the Board), each member of the Committee shall be entitled to rely on (i) the integrity of those persons or organizations within and outside the Corporation from which it receives information, (ii) the accuracy of the information provided to the Committee by such persons or organizations, and (iii) representations made by management of the Corporation, the external auditors of the Corporation, independent counsel, and other advisors and experts to the Corporation and its subsidiaries.

Education and Experience

The Audit and Reserves Committee is comprised of three members of the Board of Directors: Henry R. Lawrie (Chairman), Lamont C. Tolley and Andrew E. Osis. Each of the members of the Audit and Reserves Committee is independent of management and each is financially literate. The relevant education and experience of each member is outlined below.

Henry R. Lawrie (Chairman)

Mr. Lawrie is an FCA and acts as a corporate director and consults to various entities, including the Ross Smith Energy Group. Prior to October 2002, he was an advisor to the Alberta Securities Commission, served as its Chief Accountant from July 1997 and acted as the Chair of the Oil and Gas Securities Taskforce. He was for many years in public accounting practice as a senior partner with Price Waterhouse in Calgary, Toronto, Dallas and Midland, Texas and twice was elected to the firm's Policy Board. His contributions to the Canadian Institute of Chartered Accountants included that of Chair of the Auditing Standards Board and the Canadian representative on the International Auditing Practices Committee. He was also Chair of the Full Cost Accounting Taskforce.

Lamont C. Tolley

Mr. Tolley has extensive experience in financial analysis and financial management. Mr. Tolley holds and has held directorships and executive positions in numerous public and private oil and gas corporations and royalty trusts. He has a Masters Degree of Business Administration from Dalhousie University.

Andrew E. Osis

Mr. Osis also has extensive experience in financial analysis, including employment as an investment banker and as an executive in several public and private corporations. Mr. Osis presently holds directorship in several corporations. He has a Bachelor of Commerce degree in Finance and has completed Level II of the Chartered Financial Analyst program.

Pre-Approval Policies and Procedures

The Audit and Reserves Committee has established a pre-approval policy and procedures for the engagement of non-audit services. The Audit and Reserves Committee must approve all engagements for non-audit services which are expected to exceed \$20,000 per engagement before the engagement may commence. For engagements for non-audit services which are expected to be less than \$20,000 the engagement may commence upon approval by the Chairman of the Audit and Reserves Committee with all members being informed of the service at the next meeting of the Committee. All recommendations for services will be submitted by the Vice-President, Finance and Chief Financial Officer.

External Auditor Service Fees

The following table provides the fees billed by KPMG LLP, the Corporation's external auditors during fiscal 2006 and 2005.

	2006	2005
Audit Fees	\$116,000	\$143,890
Audit-Related Fees	38,000	34,836
Tax Fees	24,000	-
All Other Fees	-	-
Total	<u>\$178,000</u>	<u>\$178,726</u>

ADDITIONAL INFORMATION

Additional information relating to Delphi is available through the Internet on the Canadian System for Electronic Document Analysis and Retrieval (SEDAR), which can be accessed at www.sedar.com. Additional information, including directors' and officers' remuneration, principal holders of the Corporation's securities, options to purchase securities and interest of insiders in material transactions, where applicable, is contained in the Information Circular of the Corporation for the Corporation's most recent annual meeting of shareholders that involved the election of directors.

Reference is made to the information filed on SEDAR on March 29, 2007 under the heading "Management's Discussion and Analysis" and included on pages 20 through 37 of the 2006 Annual Report of the Corporation, which information is incorporated herein by reference.

Reference is made to the information filed on SEDAR on March 29, 2007 under the headings "Consolidated Financial Statements" and included on pages 38 through 52 of the 2006 Annual Report of the Corporation, which information is incorporated herein by reference.

APPENDIX A

REPORT ON RESERVES DATA (NI 51-101 F2)

To the board of directors of Delphi Energy Corp. (the "Corporation"):

1. We have prepared an evaluation of the Corporation's reserves data as at December 31, 2006. The reserves data consist of the following:
 - (a)
 - (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2006, using forecast prices and costs; and
 - (ii) the related estimated future net revenue; and
 - (b)
 - (i) proved 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 Corporation's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

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

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

Independent Qualified Reserves Evaluator	Description and Preparation Date of Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate, 000's)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	February 5, 2007	Canada	0	\$261,288	0	\$261,288

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.
6. We have no responsibility to update this evaluation for events and circumstances occurring after the preparation dates.

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

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada

Dated February 28, 2007

ORIGINALLY SIGNED BY

Terry L. Aarsby, P. Eng.
Manager, Engineering

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

Management of Delphi Energy Corp. (the "Corporation") is responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consists of the following:

- (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2006 using forecasted prices and costs;
- (ii) the related estimated future net revenue;
- (b) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2006 using constant prices and costs; and
- (ii) the related estimated future net revenue.

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

The Audit Committee, with the mandate to review the engineering report, of the Board of Directors of the Corporation has:

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

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

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

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

(signed) David Reid

David Reid
President & Chief Executive Officer

(signed) Tony Angelidis

Tony Angelidis
Senior Vice President, Exploration

(signed) Harry Campbell

Harry Campbell, Q.C.
Director & Member of the Corporate
Governance and Compensation Committee

(signed) Henry Lawrie

Henry Lawrie, FCA
Director & Member of the Audit and Reserves
Committee

(signed) Robert Lehodey

Robert Lehodey, Q.C.
Director & Member of the Corporate
Governance and Compensation Committee

(signed) Andrew Osis

Andrew Osis
Director & Member of the Audit and
Reserves Committee

(signed) Lamont Tolley

Lamont Tolley
Director & Member of the Audit and
Reserves Committee

APPENDIX C

ABBREVIATIONS, EQUIVALENCIES AND DEFINITIONS

The following are abbreviations of terms used in this Annual Information Form. All calculations converting natural gas to crude oil equivalent have been made using a ratio of 6 mcf of natural gas to one barrel of crude equivalent.

Crude Oil and Natural Gas Liquids		Natural Gas	
bbl	One barrel equaling 34.972 Imperial gallons or 42 U.S. gallons	bcf	Billion cubic feet
bbl/d	Barrels per day	bcfe	Billion cubic feet equivalent
boe	Barrels of oil equivalent	bcf/d	Billion cubic feet per day
boe/d	Barrels of oil equivalent per day	mcf	Thousand cubic feet
Mboe	Thousand barrels of oil equivalent	mcf/e	Thousand cubic feet equivalent
Mmboe	Million barrels of oil equivalent	mcf/d	Thousand cubic feet per day
Mbbl	Thousand barrels	mmcfe	Million cubic feet equivalent
Mmbbls	Million barrels	mmcf	Million cubic feet
Mmlts	Million long tones	mmcf/d	Million cubic feet per day
NGL or NGLs	Natural gas liquids, consisting of any one or more of propane, butane and condensate	Mmbtu	Million British Thermal Units
WI	Working interest	GJ/d	Gigajoules per day

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

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471
GJ	Mcf	1.055

The following references are to the “Oil and Gas Activities” in the Annual Information Form.

- (1) Gross
 - (a) In relation to the Corporation's interest in production or reserves, its "company gross reserves", which are the Corporation's working interest (operating or non-operating) share before deduction of royalties and excluding any royalty interest of the Corporation;
 - (b) In relation to wells, the total number of wells in which the Corporation has an interest;
 - (c) In relation to properties, the total area of properties in which the Corporation has an interest.
- (2) Net

In relation to the Corporation's interest in production or reserves, the Corporation's working interest (operating and non-operating) share after deduction of royalty obligations, plus the Corporation's royalty interests in production or reserves;

In relation to the Corporation's interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.
- (3) Definitions used for reserve categories in the GLJ Report are as follows:

The following definitions apply to both estimates of individual reserves entities and the aggregate of reserves for multiple entities.

Reserve Categories

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

 - analysis of drilling, geological, geophysical and engineering data;
 - the use of established technology; and
 - specified economic conditions (see Economic Assumptions below)

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

 - Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
 - Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Development and Production Status.

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:
- (4) Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate;

These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty;

Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.
- (5) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned. In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.
- (6) Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the

highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

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

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

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

(7) Forecast prices and costs

Future prices and costs that are:

Generally accepted as being a reasonable outlook of the future;

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

The forecast summary table identifies benchmark reference pricing that apply to the Corporation.

(8) Constant prices and costs

Prices and costs used in an estimate that are:

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

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

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

(9) Royalty credits under the Alberta royalty tax credit ("ARTC") plan have not been included in this analysis, as the Alberta Government has eliminated this program effective January 1, 2007.

(10) Future income tax expenses

Future income tax expenses estimated:

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

Without deducting estimated future costs (for example, Crown royalties) that are not deductible in computing taxable income;

Taking into account estimated tax credits and allowances (for example, royalty tax credits); and

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

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

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

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

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

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

Provide improved recovery systems.

(13) Exploration well – A well that is not a development well, a service well or a stratigraphic test well.

- (14) Exploration costs – Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities are:
- Costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs");
 - Costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;
 - Dry hole contributions and bottom hole contributions;
 - Costs of drilling and equipping exploratory wells; and
 - Costs of drilling exploratory type stratigraphic test wells.
- (15) Service well – A well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.
- (16) Numbers may not add due to rounding.