Delphi Energy Corp.

ANNUAL INFORMATION FORM
For the year ended December 31, 2004

March 30, 2005

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INTRODUCTORY INFORMATION

Delphi Energy Corp. ("Delphi" or the "Corporation") was formed on June 19, 2003 through the business combination (the "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 all of the special warrants of DTE were converted to common shares of DTE. Rise then 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, leaving only Delphi.

In this annual information form, unless otherwise specified or the context otherwise requires, reference to "Delphi" or the "Corporation" for periods prior to the Merger are to Delphi's founding companies, DTE and Rise.

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.

CORPORATE STRUCTURE

Name 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) (the "ABCA"). On January 1, 2004, the Corporation filed Articles of Amalgamation to complete a short-form amalgamation with its wholly-owned subsidiaries Murias Energy Corporation ("Murias") and Fish Creek Resources Inc. ("Fish Creek"). 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").

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 of Directors 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 4500, 855 - 2nd Street S.W., Calgary, Alberta T2P 4K7 and its head and principal office at Suite 1500, 444 - 5th Avenue S.W., Calgary, Alberta, T2P 2T8.

As of the date of this Information Circular the Corporation does not have any subsidiaries.

GENERAL DEVELOPMENT AND DESCRIPTION OF THE BUSINESS

Business of the Corporation

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) northwest Alberta; (ii) northeast 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 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, including heavy oil reservoirs. Delphi funds its capital program with cash flow, debt financing and strategic use of new equity when appropriate.

Three Year History

The three year history of the Corporation is as follows:

2002

During 2002, DTE carried out a $15.9 million capital program with the expenditures primarily directed toward northwest Alberta. DTE completed a nine well horizontal drilling program, three deeper vertical tests, and two re-entries of existing abandoned wellbores at Copton. The results from this program had led DTE and the operator of the property to evaluate the longer term production performance prior to proceeding with additional drilling. DTE raised additional gross proceeds of $3,038,162 through the private placement of 5,063,603 common shares of DTE in July 2002. On December 17, 2002, the Corporation acquired certain assets from EnCana Oil & Gas Partnership, EnCana Resources and EnCana Corporation (collectively "Encana") for a purchase price of $8,964,082 cash, and entered into the 2002 Exploration Drilling Joint Venture with Encana. DTE raised gross proceeds of $6,772,203 through the private placement of 12,458,672 special warrants in December 2002 to fund the Fontas acquisition.

2003

During 2003, the Corporation carried out a $27.6 million capital program, which included $16.6 million directed towards acquisitions. The Corporation closed three 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 within the 2002 Exploration Drilling Joint Venture. The Corporation drilled 16 gross wells (6.9 net) during 2003. The remaining significant events for the Corporation in 2003 follow:

New Issue Equity Financings

On January 30, 2003 DTE raised gross proceeds of $1,800,000 through the private placement of 3,600,000 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 $2,500,000. These proceeds were used to fund the Corporation's exploration programs.

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 EnCana together with three additional wells. The purchase price was $1,883,057. This consideration 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 million common shares to DTE shareholders and the assumption of Rise's net debt of $3.4 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. The circular are available on SEDAR (http://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, private oil and gas company, in exchange for an aggregate purchase price of $2,031,500 comprised of $1,300,000 cash, 358,000 Common Shares of Delphi issued from treasury at a price of $1.75 per share and the assumption of Murias' working capital deficiency. The assets added net production of approximately 125 boe/d in the Corporation's core area of east central Alberta and approximately 180,000 boe of established 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, for an aggregate purchase price of $2,750,000, comprised of $1,750,000 cash, the issuance of 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 Fish Creek assets added net production of approximately 160 boe/d in the Corporation's core area of east central Alberta and approximately 254,000 boe of established reserves to the operations and assets of the Corporation.

Appointment of Senior Officers

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

2004

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 Energy Inc., a private oil and gas company, for cash consideration of $42.5 million and the assumption of debt plus working capital of $13.9 million. The Tercero assets added net production of approximately 1,200 boe/d, predominantly in northeast British Columbia, and approximately 4.7 million proved plus probable boe's to the operations and assets of the Corporation.

New Issue 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.

Delphi has current production of approximately 18.0 mmcf/d of natural gas and 1,000 bbl/d of crude oil and natural gas liquids, or 4,000 boe/d. Delphi has built a large inventory of development and high impact exploration opportunities on an undeveloped land base of approximately 363,000 gross acres (67,000 net acres).

Trends

There are a number of trends that have been developing in the oil and gas industry during the past few years that appear to be shaping the near future of the business. The first trend appears to be the establishment of an increasing number of royalty trusts and start-up companies with experienced management teams and access to capital. This situation appears to be a result of the previous consolidation phase of the industry in recent years. This has resulted in increased competition for many of the corporate and property acquisitions that will be available. The second trend is that oil prices have remained high for an extended period of time and, while subject to large fluctuation due to political events, appear to be supported by continuing increased worldwide demand and actual or potential supply disruptions in the Middle East. Crude oil and natural gas prices are volatile and subject to a number of external factors. World prices for oil and natural gas have fluctuated widely in recent years as a result of shifts in the balance between supply and demand, inventory and storage levels, the Organization of the Petroleum Exporting Countries ("OPEC") policy, weather patterns and other factors.

The resolve of OPEC to steadily cut production throughout 2001, stabilized the West Texas Intermediate ("WTI") oil price in the low U.S. $20's per barrel level. Meanwhile unrest in Venezuela and the Middle East during 2002 caused the price to rise, reaching a peak of just under U.S. $40 per barrel prior to the war in Iraq. Since the war in Iraq prices initially decreased to approximately U.S. $25.00 per barrel and then strengthened due to higher world demand, especially in Asia, and lower inventory levels to over U.S. $55.00 per barrel in October 2004 and again in March 2005.

The overall supply and demand situation for natural gas in North America has been relatively firm over the past four years and as a result price volatility has been more extreme compared to the last 20 years. In early 2001 gas prices reached extremely high levels as a result of a supply shortage which resulted in high exploration activity throughout North America. The short-term result was increased natural gas deliverability, which coupled with an unusually mild winter resulted in a steady increase in natural gas supply. As a result, natural gas prices declined continuously throughout 2001. This trend reversed throughout 2002 and as a result of a colder than normal winter in the northeastern United States gas prices spiked again to as high as U.S. $9.00 per Mmbtu by February 2003. Prices remained high throughout 2003 and 2004 due to concerns about North American storage inventory levels and a lack of confidence in North American supply prospects.

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 of $13.9 million. 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 $50.7 million. The Corporation will be filing on SEDAR a Form 51-102F4 relating to this acquisition by mid-April 2005.

NARRATIVE DESCRIPTION OF THE BUSINESS

Attached as Schedule A is a report on Delphi's Reserves Data by Gilbert Laustsen Jung Associates Ltd. ("GLJ")(Form 51-101 F2), attached as Schedule B is the Report of Management and Directors of the Corporation on the oil and gas disclosure (Form 51-101 F3) and attached as Schedule C is the Corporation's Reserves Disclosure (51-101 F1).

General

Competition

The oil and gas industry in Canada is generally competitive. The Corporation competes with other companies in this sector for the exploration and development of oil and gas reserves. Competitive factors in the acquisition, development and marketing of oil and gas include pricing and the methods and reliability of delivery.

Seasonality of Markets

The market demand for oil and gas products varies on a seasonal basis, and that variation is affected by abnormalities in temperature and precipitation in key market areas.

Environmental Protection

All aspects of the oil and gas industry present potential environmental risks and are, accordingly, subject to a variety of Canadian federal, provincial and municipal environmental regulations. These regulatory regimes are laws of general application that apply to Delphi in the same manner as they apply to other participants in the energy industry.

Human Resources

The Corporation employs or retains the services of 20 individuals (including personnel hired on a contract basis) at its head office in Calgary, Alberta. The Corporation retains the services of 13 individuals in field operations in various locations in Alberta and British Columbia.

Industry Conditions and Risks

The oil and natural gas industry is subject to extensive controls and regulations imposed by various levels of government. Outlined below are some of the more significant aspects of the legislation, regulations and agreements governing the oil and natural gas industry. All current legislation is a matter of public record and we are unable to predict what additional legislation or amendments may be enacted.

Pricing and Marketing - Oil and Natural Gas

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Such price depends in part on oil quality, prices of competing oils, distance to market, the value of refined products and the supply/demand balance. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "NEB"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an export license from the NEB and the issuance of such licence requires the approval of the Governor in Council. The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices with purchasers, provided that the export contracts continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than 2 years or for a term of 2 to 20 years (in quantities of not more than 30,000 m3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export license from the NEB and the issue of such license requires the approval of the Governor in Council.

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

The lack of firm pipeline capacity continues to limit the ability to produce and market natural gas production although pipeline expansions are ongoing. In addition, the prorationing of capacity on the interprovincial pipeline systems continues to limit oil exports.

The North American Free Trade Agreement

On January 1, 1994, the North American Free Trade Agreement ("NAFTA") among the governments of Canada, the U.S. and Mexico became effective. The NAFTA carries forward most of the material energy terms contained in the Canada- U.S. Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports to the U.S. or Mexico will be allowed provided that the restrictions are justified under certain provisions of the General Agreement on Tariffs and Trade and then only if the export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of the energy resource (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price; and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

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

Provincial Royalties and Incentives

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

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

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provide various incentives for exploring and developing oil reserves in Alberta. Oil produced from horizontal extensions commenced at least 5 years after the well was originally spudded may also qualify for a royalty reduction. A 24-month, 8,000 m3 exemption is available to production from a well that has not produced for a 12-month period, if resumed production is after February 1, 1993. As well, oil production from eligible new field and new pool wildcat wells and deeper pool test wells spudded or deepened after September 30,1992 is entitled to a 12-month royalty exemption (to a maximum of $1 million). Oil produced from low productivity wells, enhanced recovery schemes (such as injection wells) and experimental projects is also subject to royalty reductions.

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

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

In Alberta, a producer of oil or natural gas is entitled to a credit against the royalties payable to the Crown by virtue of the Alberta Royalty Tax Credit ("ARTC") program. The ARTC rate is based on a price sensitive formula and the ARTC rate varies between 75% at prices at and below $100 per m3 and 25% at prices at and above $210 per m3. The ARTC rate is applied to a maximum of $2,000,000 of Alberta Crown royalties payable for each producer or associated group of producers. Crown royalties on production from producing properties acquired from a corporation claiming maximum entitlement to ARTC will generally not be eligible for ARTC. The rate is established quarterly based on the average "par price", as determined by the Alberta Department of Energy for the previous quarterly period.

Producers of oil and natural gas in the Province of British Columbia are also required to pay annual rental payments in respect of Crown leases and royalties and freehold production taxes in respect of oil and gas produced from Crown and freehold lands, respectively. The amount payable as a royalty in respect of oil depends on the vintage of the oil (whether it was produced from a pool discovered before or after October 31, 1975), the type of oil, the quantity of oil produced in a month and the value of the oil. Generally, the age of oil is based on whether the oil is produced from a pool discovered before October 31, 1975 (old oil) between October 31, 1975 and June 1, 1998 (new oil), or after June 1, 1998 (third tier oil). The formula is applied to determine the royalty payable results in higher royalty rates as well production increases. The royalty rate on old oil is between 0% and 34%, on new oil is between 0% and 25%, and on third tier oil is between 0% and 15%. Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production. The royalty payable on natural gas is determined by a sliding scale based on a reference price which is the greater of the amount obtained by the producer and a prescribed minimum price. As an incentive for the production and marketing of natural gas which may have been flared, natural gas produced in association with oil has a minimum royalty of 8%. The royalty payable on non-conservation natural gas varies between a minimum of 9% and 15%, depending on when the well was spudded and when the oil and gas rights were issued.

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

Some of the financial incentives in the Strategy include:

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

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

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

Environmental Regulation

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

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

Risks

Volatility of Oil and Natural Gas Prices

The results of operations and financial condition of Delphi are dependent to a large extent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are subject to fluctuations in response to relatively minor changes in supply, demand, market uncertainty and other factors that are beyond the Corporation's control. These factors include, but are not limited to, worldwide political instability, foreign supply of oil and natural gas, the level of consumer product demand, government regulations and taxes, the price and availability of alternative fuels and the overall economic environment. Any decline in oil or natural gas prices could have a material adverse effect on Delphi's operations, financial condition, proved reserves and the level of expenditures for the development of its oil and natural gas reserves. No assurance can be given that oil and natural gas prices will be at levels which will generate profits for the Corporation.

Delphi regularly assesses the carrying value of its assets in accordance with Canadian generally accepted accounting principles under the full cost method. If oil and natural gas prices become depressed or decline, the carrying value of Delphi's assets could be subject to downward revision.

Need to Replace Reserves

The future oil and natural gas reserves and production, and therefore the cash flows of the Corporation, are highly dependent upon its success in exploring the current reserve base and acquiring or discovering additional reserves. Without reserve additions through exploration, acquisition or development activities, such reserves and production will decline over time as reserves are exploited. The business of exploring for, developing or acquiring reserves is capital intensive. To the extent cash flows from operations are insufficient and external sources of capital become limited or unavailable, the ability of the Corporation to make the necessary capital investments to maintain and increase its oil and natural gas reserves will be impaired. There can be no assurance that Delphi will be able to find and develop or acquire additional reserves to replace production at acceptable costs.

Operating Hazards and Other Uncertainties

Acquiring, developing and exploring for oil and natural gas involves many risks, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. These risks include, but are not limited to, encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, equipment failures and other accidents, cratering, sour gas releases, uncontrollable flows of oil, natural gas or well fluids, adverse weather conditions, pollution, other environmental risks, fires and spills. Although Delphi maintains insurance in accordance with customary industry practice, it is not fully insured against all of these risks. Losses resulting from the occurrence of these risks could have a material adverse effect on the Corporation. Like other oil and natural gas companies, Delphi attempts to conduct its business and financial affairs so as to mitigate political and economic risks applicable to operations but there can be no assurance that the Corporation will be successful in so protecting itself.

Delphi is also subject to deliverability uncertainties related to the proximity of its reserves to pipeline and processing facilities and the possible inability to secure space on pipelines which deliver oil and natural gas to commercial markets.

Uncertainty of Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of proved reserves, including many factors beyond control of the Corporation. It should not be assumed that the present worth of estimated future cash flows shown in the reserves report (Schedule C) is representative of the fair market value of the reserves. There is no assurance that price and cost assumptions will be attained and variances could be material. The estimates of Delphi's crude oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and NGL reserves may be greater than or less than the estimates provided.

Acquisition Risks

Delphi intends to continue acquiring oil and natural gas properties. Although Delphi performs a review of acquired properties that management of Delphi believes is consistent with industry practices, even a detailed review of records and properties may not necessarily reveal every existing or potential problem, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the Corporation often assumes certain environmental and other risks and liabilities in connection with acquired properties. There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and actual future production rates and associated costs with respect to acquired properties, and actual results may vary substantially from those in the estimates.

Environmental Risks

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of international conventions and Canadian federal, provincial and municipal 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 past and current 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. In addition, certain types of operations require the submission and approval of environmental impact assessments. 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. Although the Corporation believes that it is in substantial compliance with all existing material environmental regulations, there can be no assurance that future environmental costs will not have a material adverse effect on Delphi's financial condition and results of operations.

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". The Government of Canada has put forward a Climate Change Plan for Canada which suggests further legislation will set greenhouse gases emission reduction requirements for various industrial activities, including oil and gas exploration and production. Future federal legislation, together with provincial emission reduction requirements such as those proposed in Alberta's Bill 37: Climate Change and Emissions Management, 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.

Competition

The oil and natural gas industry is highly competitive particularly as it pertains to the exploration for and development of new sources of crude oil and natural gas reserves. The industry also competes with other industries in supplying non-petroleum energy products. Delphi actively competes for reserve acquisitions, exploration leases, licences and concessions and skilled industry personnel with a substantial number of other oil and natural gas companies, many of which have significantly greater financial resources than the Corporation.

Governmental Regulation

The oil and natural gas business is subject to regulation and intervention by governments in such matters as the awarding of exploration and production interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of fields (including restrictions on production) and possibly expropriation or cancellation of contract rights. As well, governments may regulate or intervene with respect to prices, taxes, royalties and the exportation of oil and natural gas. Such regulation may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for oil and natural gas, increase costs and have a material adverse effect on the Corporation.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Reference is made to the information filed on SEDAR on March 24, 2005 under the heading "Management's Discussion and Analysis" and included on pages 25 through 39 of the 2004 Annual Report of the Corporation, which information is incorporated herein by reference.

SELECTED CONSOLIDATED FINANCIAL INFORMATION

Reference is made to the information filed on SEDAR on March 24, 2005 under the headings "Consolidated Financial Statements" and included on pages 41 through 54 of the 2004 Annual Report of the Corporation, which information is incorporated herein by reference.

MATTERS RELATING TO THE COMMON SHARES OF THE CORPORATION

Market for Common Shares

The Common Shares of the Corporation are listed and posted for trading on the TSX Venture Exchange 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:

Period	High ($)	Low ($)	Close ($)	Volume (Common Shares)
2004				
January	1.95	1.66	1.90	1,624,500
February	2.13	1.75	2.05	1,396,600
March	2.10	1.75	1.81	1,174,700
April	1.95	1.80	1.92	385,100
May	2.07	1.85	1.98	474,000
June	1.98	1.80	1.85	319,200
July	1.90	1.70	1.89	280,500
August (1)	1.89	1.70	1.85	2,626,200
September	2.05	1.71	2.03	1,947,500
October	2.44	1.96	2.30	2,574,400
November	3.45	2.30	3.10	2,984,400
December	3.80	2.51	3.68	3,125,600

(1) On August 3, 2004, the common shares were delisted from the TSX Venture Exchange and were listed on the TSX.

Description of 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 47,703,775 common shares were outstanding at December 31, 2004. An unlimited number of preferred shares issuable have also been authorized in series of which none are outstanding.

Dividend Record and Policy

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 the Corporation's ability to pay dividends.

DIRECTORS AND OFFICERS

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.

Name and Municipality of Residence	Office or Position with the Corporation	Present and Principal Occupation During the Last Five Years
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 Delphi since June 19, 2003; President and Treasurer of DTE since September 20, 2000; prior thereto, President and Chief Executive Officer of Renata Resources Inc. since October 14, 1998; prior thereto, President and Chief Operating Officer of Renata Resources Inc. since July 1996; prior thereto, Vice President, Operations and Chief Operating Officer of Ballistic Energy Corporation (an oil and gas exploration and production company); prior thereto, Staff Engineer at Amoco Canada Petroleum Company Ltd. (an oil and gas exploration and production company).
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; prior thereto, Vice President, Exploration of Renata Resources Inc. since February 1998; prior thereto, Manager, Exploration of Renata Resources Inc. since October 1996; prior thereto President of Titan Resources Ltd. (a private oil and gas company he co-founded); prior thereto, Director and Vice President, Operations of Prize Energy Inc. (an oil and gas exploration and production company); prior thereto, Senior Exploration Geologist with Shell Canada Limited (an oil and gas exploration and production company).
Robert A. Lehodey, Q.C. [1,2] .... Calgary, Alberta, Canada	Director since June 2003; prior thereto a director of DTE since September 2000.	Partner with the law firm Bennett Jones LLP since November 1997; prior thereto, partner with the law firm MacKimmie Matthews since 1989.
Harry S. Campbell, Q.C. [2] .... Calgary, Alberta, Canada	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] .... Calgary, Alberta, Canada	Director since June 2003; prior thereto a director of DTE since December 2000.	Independent businessman since 1999; prior thereto, Chairman of Starvest Capital Inc. (an oil and gas management company).
Henry R. Lawrie, FCA [1] .... Calgary, Alberta, Canada	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.

Name and Municipality of Residence	Office or Position with the Corporation	Present and Principal Occupation During the Last Five Years
Brian P. Kohlhammer .... Calgary, Alberta, Canada	Vice President, Finance and Chief Financial Officer since December 2004	Vice President, Finance and Chief Financial Officer of Delphi since December 1, 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.
Tim L. Malo..................................... Calgary, Alberta, Canada	Vice President, Corporate Development and Secretary since June 2003	Vice President, Corporate Development of Delphi Energy Corp. since February 2005; prior thereto Vice president, Land since June 18, 2003; prior thereto Senior Vice-President, Rise, prior thereto self employed landman and lawyer, prior thereto Executive Vice President Allied Oil and Gas Corp.
Frank M.Lowe .... Calgary, Alberta, Canada	Vice President, Production since May 2004	Vice President, Production of Delphi Energy Corp. since May 18, 2004; prior thereto self employed operations consultant from April 2000 to May 2004; prior thereto Vice President Operations Cabre Exploration Ltd. from March 1998 to April 2000.
Michael S. Kaluza............................ Calgary, Alberta, Canada	Vice President, Engineering since January 2005	Vice President, Engineering of Delphi Energy Corp. since January 2005; prior thereto Senior Exploitation Engineer of Dominion Exploration and Production from February 2001 to January 2005; prior thereto Senior Reservoir Engineering Specialist of Phillips Petroleum Company from June 1985 to April 2000.

Notes:
(1) Member of the Audit Committee
(2) Member of the Compensation Committee

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

As at March 29, 2005, the directors and executive officers of the Corporation, as a group, beneficially, owned, directly or indirectly, 2,738,343 shares or approximately 5.7% of the issued and outstanding Common Shares and held options to acquire a further 1,684,250 Common Shares. Assuming exercise of all options, the directors and executive officers of the Corporation, as a group, would beneficially own, directly and indirectly, 4,422,593 Common Shares or approximately 8.8% 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.

Certain directors of the Corporation are associated with other companies, which may give rise to conflicts of interest. In accordance with the ABCA, directors who have an interest in a material contract or a material transaction, whether made or proposed, with the Corporation are required, subject to certain exceptions, to disclose the nature and extent of the interest. A director required to disclose such interest shall abstain from voting on any resolution to approve the contract or transaction, except as otherwise permitted by the ABCA. In addition, each director is required to act honestly and in good faith with a view to the best interests of the Corporation.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as set out below, 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.

	Number of Common Shares	Approximate Percentage of Common Shares Owned (undiluted)
Acuity Investment Management Inc., Toronto, Ontario, Canada	5,881,400	12.3 %

TRANSFER AGENT AND REGISTRAR

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

MATERIAL CONTRACTS

The only material contracts which Delphi will be a party to are as follows:

(a) Exploration Joint Venture. See "Other Oil and Gas Information - Exploration Joint Venture" attached in Schedule C;

(b) Development Joint Venture. See "Other Oil and Gas Information – Development Joint Venture" attached in Schedule C;

(c) Credit Agreement. See "Management's Discussion and Analysis – Liquidity and Capital Resources";

(d) Commodity Price Forward Contracts. See "Management's Discussion and Analysis – Business Conditions and Risks"; and

(e) Natural Gas Gathering and Processing Contract. See "Management's Discussion and Analysis – Contractual Obligations".

INTERESTS OF EXPERTS

As at March 30, 2005 KPMG LLP and its partners did not hold any registered or beneficial ownership interests, directly or indirectly, in the securities of the Company or its associates or affiliates.

As at the date hereof, the principals of Gilbert Laustsen Jung Associates Ltd., the independent petroleum consultants of Delphi, as a group owns less than one percent of the Common Shares of Delphi.

As at the date hereof, the principals of Bennett Jones, the legal counsel of Delphi, as a group owns less than one percent of the Common Shares of Delphi.

COMPOSITION OF AUDIT COMMITTEE

The Audit Committee is comprised of Mr. Henry Lawrie, Mr. Lamont Tolley and Mr. Robert Lehodey, Q.C. The Corporation notes that Mr. Lehodey is a Partner of Bennett Jones LLP, legal counsel to the Corporation, but feels, for several reasons, that his relationship with Bennett Jones LLP does not materially interfere with his ability to act in the best interest of the Corporation. Mr. Lehodey is therefore an unrelated director for the purposes of the TSX Companies Manual. However, under Multilateral Instrument 52-110 *Audit Committees* ("MI 52-110"), Mr. Lehodey will be deemed to not be independent of the Corporation because of his relationship with Bennett Jones LLP. The independence requirements of MI 52-110 will take effect for the Corporation following the Corporation's next annual meeting of shareholders, which is scheduled for May 12, 2005.

NON-AUDIT SERVICES

The Corporation has a Non-Audit Services Policy that has been reviewed and approved by the Audit Committee.

For Audit Related, Tax and Other Non-Audit Services the policy allows for pre-approval of services that are recurring or reasonably expected to be provided. The policy provides that for services where the aggregate fees are estimated to be less than or equal to $20,000 the Chief Financial Officer will obtain approval of the Chairman of the Audit Committee. Where the aggregate fees are estimated to be greater than $20,000 the Chief Financial Officer will obtain approval of the entire Audit Committee. The Audit Committee is informed quarterly of the services provided by KPMG LLP.

ABBREVIATIONS AND EQUIVALENCIES

The following are abbreviations and definitions 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	mcfe	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

ADDITIONAL INFORMATION

Additional Information regarding 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. Additional financial information is provided in the Consolidated Financial Statements and Management's Discussion and Analysis of the Corporation for the years ended December 31, 2004 and 2003 contained in the 2004 Annual Report.

SCHEDULE 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, 2004. The reserves data consist of the following:

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

   (ii) the related estimated future net revenue; and

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

   (ii) the related estimated future net revenue.

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

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

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

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

Net Present Value of Future Net Revenue
(before income taxes, 10% discount rate, 000's)

Description and Preparation Date of [Evaluation] Report	Location of Reserves (Country or Foreign Geographic Area)	Audited	Evaluated	Reviewed	Total
February 25, 2005	Canada	0	$96,100	0	$96,100

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:

Gilbert Laustsen Jung Associates Ltd., Calgary, Alberta, Canada

Dated March 9, 2005

ORIGINALLY SIGNED BY

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

SCHEDULE B

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

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

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

(ii) the related estimated future net revenue.

An independent qualified reserves evaluator has evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluator 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) *Robert Lehodey*
Robert Lehodey, Q.C.
Director & Member of the Audit Committee

(signed) *Tony Angelidis*
Tony Angelidis
Senior Vice President, Exploration

(signed) *Lamont Tolley*
Lamont Tolley
Director & Member of the Audit Committee

(signed) *Harry Campbell*
Harry Campbell, Q.C.
Director

(signed) *Henry Lawrie*
Henry Lawrie, FCA
Director & Member of the Audit Committee

SCHEDULE C

DELPHI ENERGY CORP.

Reserves Disclosure

The Canadian Securities Administrators ("CSA") have set out disclosure standards for Canadian publicly traded oil and gas companies in National Instrument 51-101 ("NI 51-101"), Standards of Disclosure for Oil and Gas Activities, which came into force on September 30, 2003. NI 51-101 replaces National Policy 2-B ("NP 2-B") "Guide for Engineers and Geologists Submitting Oil and Gas Reports to Canadian Provincial Securities Administrators". NI 51-101 establishes a new standard of disclosure for all Canadian reporting issuers in upstream oil and natural gas activities and new 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 Canada and specifically in the province Alberta.

CAUTIONARY STATEMENT

BOE 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.

INDEPENDENT QUALIFIED RESERVES EVALUATOR AND SCOPE OF EVALUATION

The oil and natural gas reserves of the Corporation were evaluated by Gilbert Laustsen Jung Associates Ltd. (GLJ) with an effective date of December 31, 2004 in a report dated February 25, 2005 (the "Reserves Report"). The Corporation engaged Gilbert Laustsen Jung Associates Ltd. to provide an evaluation of proved and proved plus probable reserves.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION (NI 51-101 F1)

Summary of Oil and Gas Reserves and Net Present Values of Future Net Revenue Constant Prices and Costs as of December 31, 2004.

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]	662	547	366	360	23,548	18,198	85	57	5,038	3,997
Developed non-producing[4]	3	3	70	62	3,964	3,068	21	14	755	591
Undeveloped[5]	-	-	-	-	3,088	2,518	-	-	515	420
Total proved	665	550	436	422	30,600	23,784	106	71	6,308	5,008
Probable[3] [6]	246	197	1,184	1,153	13,044	9,991	49	32	3,653	3,048
Total proved plus probable	911	747	1,620	1,575	43,644	33,775	155	103	9,961	8,056

Net Present Value of Future Net Revenues

($ 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]	95,229	76,007	63,813	55,393	49,215	94,490	75,641	63,622	55,288	49,156
Developed non-producing[4]	13,156	10,263	8,224	6,738	5,625	8,551	6,876	5,656	4,739	4,032
Undeveloped[5]	9,812	6,802	4,991	3,807	2,984	6,377	4,557	3,432	2,677	2,139
Total proved	118,197	93,072	77,028	65,938	57,825	109,418	87,074	72,710	62,704	55,327
Probable[3][6]	45,014	29,725	20,893	15,269	11,445	29,762	19,202	13,131	9,275	6,659
Total proved plus probable	163,211	122,797	97,921	81,207	69,270	139,180	106,276	85,841	71,979	61,986

Total Future Net Revenue

Constant Prices and Costs [8] as of December 31, 2004

($ thousands, undiscounted)	Revenue	Royalties, including ARTC	Operating Costs	Development Costs	Well Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Proved reserves	229,204	43,548	57,429	6,567	3,463	118,197	8,778	109,418
Proved plus probable	342,637	62,919	92,317	20,286	3,904	163,211	24,031	139,180

Future Net Revenue by Production Group

Constant Prices and Costs [8] as of December 31, 2004

Reserve Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year)
		($ thousands)
Proved reserves [3] [6]	Light & medium oil	5,369
	Heavy oil	991
	Natural gas	69,687
	Other revenue and costs	981
	TOTAL	77,028

Summary of Pricing Assumptions

Constant Prices and Costs* [(8)] *as of December 31, 2004

This summary table identifies benchmark reference pricing that applies to the Corporation.

	Light and Medium Oil			Heavy Oil	Natural Gas Liquids			Natural Gas	Inflation Rate	Exchange Rate[(2)]
Pricing assumptions	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										
2000	30.22	44.56	39.91	27.34	32.18	35.60	46.31	5.08	2.7	0.6740
2001	25.97	39.40	31.56	16.94	31.85	31.17	42.48	6.21	2.6	0.6448
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	1.9	0.7734
Forecast										
2005+	43.45	46.54	32.12	18.17	29.79	34.44	48.97	6.79	0.0	0. 8308

Summary of Oil and Gas Reserves and Net Present Values of Future Net Revenue

Forecast Prices and Costs* [(7)] *as of December 31, 2004

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)]	666	550	510	501	23,034	17,800	84	56	5,098	4,073
Developed non-producing[(4)]	3	3	465	452	3,963	3,075	21	14	1,150	982
Undeveloped[(5)]	-	-	-	-	3,080	2,514	-	-	514	419
Total proved	669	553	975	953	30,077	23,389	105	70	6,762	5,474
Probable[(3) (6)]	240	192	763	733	12,886	9,852	48	32	3,199	2,598
Total proved plus probable	909	745	1,738	1,686	42,963	33,241	153	102	9,961	8,072

Net Present Value of Future Net Revenues

($ 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	89,911	73,484	62,790	55,261	49,647	89,911	73,484	62,790	55,261	49,647
Developed non-producing	13,898	11,036	8,976	7,446	6,281	9,717	7,881	6,519	5,479	4,669
Undeveloped	8,165	5,513	3,954	2,952	2,265	5,709	3,937	2,871	2,172	1,684
Total proved	111,974	90,033	75,720	65,659	58,193	105,337	85,302	72,180	62,912	56,000
Probable	42,700	28,621	20,380	15,083	11,453	28,231	18,364	12,612	8,927	6,413
Total proved plus probable	154,674	118,654	96,100	80,742	69,646	133,568	103,666	84,792	71,839	62,413

Total Future Net Revenue

Forecast Prices and Costs [7] as of December 31, 2004

($ thousands, undiscounted)	Revenue	Royalties, including ARTC[4]	Operating Costs	Development Costs	Well Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes[10]	Future Net Revenue After Income Taxes
Proved reserves	235,625	40,848	71,198	7,682	3,923	111,974	6,637	105,337
Proved plus probable	343,644	59,183	104,584	20,577	4,626	154,674	21,108	133,566

Future Net Revenue by Production Group

Forecast Prices and Costs [7] as of December 31, 2004

Reserve Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year)
		($ thousands)
Proved reserves	Light & medium oil	7,863
	Heavy oil	6,068
	Natural gas	60,883
	Other revenue and costs	906
	TOTAL	75,720
Proved plus probable reserves	Light & medium oil	9,248
	Heavy oil	8,469
	Natural gas	76,854
	Other revenue and costs	1,529
	TOTAL	96,100

Summary of Pricing Assumptions

Forecast Prices and Costs [7] as of December 31, 2004

This summary table identifies benchmark reference pricing that applies to the Corporation

	Light and Medium Oil			Heavy Oil	Natural Gas Liquids			Natural Gas	Inflation Rate	Exchange Rate[2]
Pricing assumptions	**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										
2000	30.22	44.56	39.91	27.34	32.18	35.60	46.31	5.08	2.7	0.6740
2001	25.97	39.40	31.56	16.94	31.85	31.17	42.48	6.21	2.6	0.6448
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	35.09	40.49	54.07	6.88	1.9	0.7734
Forecast										
2005	42.00	50.25	43.75	27.50	32.25	37.25	50.75	6.60	2.0	0.8200
2006	40.00	47.75	41.50	28.50	30.50	35.25	48.25	6.35	2.0	0.8200
2007	38.00	45.50	39.50	28.75	29.00	33.75	46.00	6.15	2.0	0.8200
2008	36.00	43.25	37.75	27.25	27.75	32.00	43.75	6.00	2.0	0.8200
2009	34.00	40.75	35.50	25.50	26.00	30.25	41.25	6.00	2.0	0.8200
2010	33.00	39.50	34.25	24.75	25.25	29.25	40.00	6.00	2.0	0.8200
2011	33.00	39.50	34.25	24.75	25.25	29.25	40.00	6.00	2.0	0.8200
2012	33.00	39.50	34.25	24.75	25.25	29.25	40.00	6.00	2.0	0.8200
2013	33.50	40.00	34.75	24.75	25.50	29.50	40.50	6.10	2.0	0.8200
2014	34.00	40.75	35.50	25.50	26.00	30.25	41.25	6.20	2.0	0.8200
2015	34.50	41.25	36.00	25.75	26.50	30.50	41.75	6.30	2.0	0.8200
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	0.8200

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
	(mbbls)			(mbbls)			(mmcf)			(mbbls)			(mboe)		
January 1, 2004	269	58	328	653	406	1,060	9,720	3,554	13,274	81	32	113	2,623	1,089	3,712
Extensions	-	82	82	95	183	278	1,478	844	2,321	4	(2)	2	345	404	748
Improved recovery	127	12	139	61	10	71	-	-	-	-	-	-	188	22	210
Technical revisions	268	(7)	261	(42)	(112)	(154)	(1,005)	(1,202)	(2,207)	(14)	(11)	(26)	44	(331)	(287)
Discoveries	-	-	-	0	0	0	544	229	774	7	3	10	98	41	139
Acquisitions	47	48	95	245	245	490	14,309	6,427	20,736	4	11	15	2,681	1,375	4,056
Economic factors	-	-	-	0	0	0	-	-	-	-	-	-	-	-	-
Production	(160)	-	(160)	(59)	0	(59)	(1,657)	-	(1,657)	(11)	-	(11)	(505)	-	(505)
December 31, 2004	552	192	744	953	733	1,686	23,389	9,852	33,241	71	32	103	5,474	2,599	8,073

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	2004 ($ thousands)
Estimated net present value at December 31, 2003	30,518
Oil and gas sales during the period net of production costs and royalties	(14,720)
Net change in prices, production costs and royalties related to future production	3,362
Changes in previously estimated development costs incurred during the period	31,015
Changes in estimated future development costs	(31,098)
Extensions and improved recovery	6,899
Discoveries	2,275
Acquisition of reserves	39,160
Disposition of reserves	-
Net change resulting from revisions in quantity estimates	-
Accretion of discount	3,750
Net change in income taxes	2,662
Changes resulting from technical revisions	(1,052)
Other changes	(61)
Estimated future net revenue at end of year (after income tax)	72,710

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, 2004:

	Light and medium oil(mbbls)	Heavy Oil (mbbls)	Natural gas (mmcf)	Natural gas liquids (mbbls)
Proved undeveloped	-	-	3,080	-

Of the Company's total proved reserves in 2004, only 7.6% were undeveloped. Most of the Company's undeveloped reserves are forecasted to be drilled in 2005 and 2006.

Probable Undeveloped Reserves

The following table sets forth the volumes of probable undeveloped and probable reserves that were attributed to each product type for the year ended December 31, 2004:

	Light and medium oil(mbbls)	Heavy Oil (mbbls)	Natural gas (mmcf)	Natural gas liquids (mbbls)
Probable undeveloped	227	-	3,538	13
Probable	776	-	9,348	35

25.9% of the Corporation's probable reserves are classified as undeveloped and attributed to increased recovery factors from producing wells. The remaining probable reserves for the most part 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 Company'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.

Delphi's reserves are evaluated by an independent engineering firm, Gilbert Laustsen Jung Associates Ltd. ("GLJ"). Reserves are assessed using a discrete value for each parameter in the calculation of reserves, such that the resultant reserve value is consistent with the certainty level associated with the reserve classification. In accordance with NI 51-101, the following definitions are followed by GLJ in their analysis:

- 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 + probable reserves.

Future Development Costs

($ thousands)	**Forecast Prices and Costs[7]**		**Constant Prices and Costs [8]**
Period	**Proved Reserves**	**Proved Plus Probable Reserves**	**Proved Reserves**
2005	**3,029**	**7,478**	**3,029**
2006	4,217	12,251	3,134
2007	164	506	158
2008	-	-	-
2009	137	186	127
Remainder	135	156	119
Total for all years undiscounted	7,682	20,577	6,567
Total for all years discounted at 10% per year	6,835	18,353	5,876

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

Delphi Energy Corp operates in Alberta and British Columbia with operations in three core areas in North East British Columbia, North West Alberta and East Central Alberta. These areas provide a substantial drilling prospect inventory. As well, Delphi's prospects support a defined strategy of balancing low risk development opportunities with high risk/high reward exploration opportunities. In the last quarter of 2004 the Company expanded its asset base to North East British Columbia, closing the corporate acquisition of Tercero Energy Inc. During 2004 Delphi's production averaged 1,706 boe/d, consisting of 5,822 mcf/d of natural gas and 736 bbls/d of crude oil and natural gas liquids. Delphi's production is balanced between the three core areas and weighted approximately 70 percent to natural gas at year-end 2004. Exposure to both oil and natural gas commodities in Delphi's three core areas, strategically mitigates individual project technical and timing risks, as well as commodity pricing volatility risks.

North East British Columbia

Delphi added a third core area on December 9, 2004 with the $57 million acquisition of a private oil and gas company. The acquisition provided Delphi with 21,000 net acres of undeveloped land in North East British Columbia, immediately adding 1,200 boe/d of natural gas production and offering significant growth potential. Delphi has identified numerous drilling, completion and tie-in opportunities on the properties, already believed to hold 4.7 million boe proved plus probable reserves. Most of these opportunities are development in nature and therefore lower risk. The area is typically accessible during the winter months only.

The majority of the assets in this area are located within 160 kilometres of Ft. Nelson, B.C, allowing gas to be gathered into the Duke pipeline system and processed at the Ft. Nelson plant. Natural gas in this area is produced from deeper (2,000 to 3,000 metre) Devonian reservoirs up to shallow (500 metre) Mississippian and Cretaceous reservoirs.

Windflower

Delphi's 8,200 net acres in the Windflower area of North East B.C. are characterized by shallow drill targets focused on structural highs mapped with 2D seismic data. Delphi currently produces about 155 boe/d of gas at Windflower from the Mississippian Matson formation. In 2004, Delphi participated in the drilling of one gross (0.5 net) exploration well, which was not successful.

Missile

The Company currently produces about 265 boe/d of gas form the Devonian Slave Point/Keg River and Jean Marie formations on its 3,800 net acres in Missile in North East British Columbia. A regional 3D seismic survey over Missile has been acquired by one of the Company's partners. This data will be used to define horizontal Jean Marie locations that could be drilled as early as the third quarter of 2005.

Helmet

Delphi holds an interest in 3,500 net acres in the Helmet area of North East B.C., an area characterized by natural gas targets in the Jean Marie, Debolt and Bluesky formations. The Jean Marie target is typically at about 1,500 metres drill depth while the Debolt and Bluesky are at approximately 500 metres drill depth. Delphi has participated in the tie-in of a Bluesky gas well resulting in about 35 boe/d net of new production. Delphi is currently producing 60 boe/d from the Helmet North area. The primary target is the Jean Marie formation.

Clarke Lake

Delphi holds an interest in 6,100 net acres of land in the Clarke Lake area of North East B.C. About 170 boe/d of gas is produced from the Slave Point and Keg River formations at approximately 2,100 metres drill depth. The Company recently participated in the drilling of a development well. Additional development potential exists through the drilling of short radius horizontal wells and the re-entry and recompletion of existing cased wellbores.

North West Alberta

Delphi's North West Alberta region consists of four areas: Fontas, Berland River, Bigstone and Grande Prarie, where we have both a Development Joint Venture and an Exploration Joint Venture. Production in these areas range from shallow, natural gas development plays at Fontas to deep, high-impact Devonian targets at Berland River and Grande Prairie.

Delphi maintains excellent relationships with major oil and gas companies that operate in this area. Delphi is able to reduce the capital and time required to define and capture opportunities by making use of existing 3D seismic surveys and land positions held by major companies. These joint venture relationships also help ensure access to critical gas gathering and processing infrastructure.

Fontas

Fontas offers high-impact development opportunities from five extensive gas accumulations. The property, located about 240 kilometres north of Grande Prairie, Alberta, can be accessed by land during the winter only, limiting the window of opportunity to capitalize on development opportunities. Net production is currently 4 mmcf/d (700 boe/d) of natural gas, mostly from the Mississippian aged Debolt formations and the Cretaceous Detrital zone. Delphi has access to 2D seismic data set over the property to map out the existing pools and identify new prospects. The Company has an average working interest of 20 percent in the area. The area controlled by Delphi and its partners includes a large contiguous land position of 185,000 gross acres. Wells range in depth from 700 metres to 800 metres and require four to seven days to drill. Also included in the Company's 20 percent ownership are an extensive pipeline infrastructure and a 40 mmcf sour gas processing plant that also provides third party processing income. The Fontas gas plant is tied into the Nova pipeline system. The facility includes one water disposal well and a salt-water pipeline.

Berland River

Berland River offers Delphi multi-zone potential with an attractive risk/reward profile. The Company's working interests in the area, approximately 250 kilometers northwest of Edmonton, Alberta, range from eight to 100 percent. The average working interest in the area is 80 percent, 95 percent of which is operated. The Company's 10-22 Devonian exploration well tested up to 10 mmcf/d, has been tied in and is now on production. The 10-22 twin Cadomin test has been drilled and cased. In total, the Berland River area offers some year-round access and produces 1,375 boe/d with 14,000 net undeveloped acres.

Bigstone

At Bigstone in the Berland River area, Delphi currently produces 1,200 boe/d (net), which consists of 6 mmcf/d of sweet gas and 200 bbl/d of NGL, from about 25 wells. Delphi has a mostly 35 percent working interest in 11,000 acres of undeveloped land at Bigstone. Proved plus probable reserves total 3.4 mmboe. The Company also has a 29 percent working interest in an 80 mmcf/d gas plant. Delphi has an 18 percent working interest in a partnership with a major oil and gas producer on four sections of land in Bigstone. As part of the partnership, Delphi drilled three wells over the 2004/2005 winter drilling season. All three wells have been cased and are in the process of being completed and tied-in. Bigstone is noteworthy because no one well is key to the area's success. Production comes from multiple wells and multiple zones. The deeper and tighter nature of the multizone reservoirs at Bigstone provide Delphi with long life, high netback, production from which to build the Company's growth strategy.

Development Joint Venture

A joint venture relationship with a senior industry producer provides Delphi with an enviable opportunity to work with vast amounts of seismic data to select specific locations that are of interest from among a high number of low-risk recompletion and workover opportunities. As part of the Bigstone deal, Delphi is targeting 27 wells for recompletions or bypassed pay in the Grande Prairie area of North West Alberta. The joint venture allows Delphi to earn up to a 100 percent working interest in 19,200 acres subject to a gross overriding royalty. The area features multi-zone targets of sweet gas and light oil. The terms of the joint venture call for Delphi to pay 100 percent of the re-entry costs with the senior producer having the right to elect to convert to a 50 percent interest or maintain a gross overriding royalty.

Exploration Joint Venture

Delphi's 2005 exploration joint venture with a senior industry producer involves a five-well commitment in North West Alberta. As part of the agreement, Delphi pays 100 percent of initial drilling and completion or abandonment costs to earn a 60 percent working interest. Delphi has access to the senior producers extensive 3D seismic as well as pipeline and processing infrastructure. The targets of this exploration joint venture are three Devonian/Wabamun wells and one Mississippian/Banff well in the Ferrier area of Alberta. The final well, as part of the five-well commitment, is a Cadomin well in the Cutbank area. At a cost of $3 million per well, Delphi is in the process of securing partners for this exploration joint venture.

East Central Alberta

East Central Alberta offers Delphi 60 potential infill and step-out drilling locations on four key properties: Thompson Lake, Neutral Hills, Horseshoe and Chauvin. Current production from this area is approximately 820 boe/d, consisting of 85 percent oil and 15 percent natural gas. Although Delphi has an abundance of low-cost infill drilling and field optimization opportunities in East Central Alberta, these projects will have to compete economically with the gas opportunities in North West Alberta and North East BC.

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, 2004.

	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	140	128.0	106	35.7	9	9.0	100	75.7	62	21.5	17	4.7
British Columbia	12	2.7	41	7.3	3	.2	7	1.8	53	12.3	-	-

Properties with No Attributed Reserves

The following table sets forth the Company's undeveloped land holdings as at December 31, 2004.

	Undeveloped	
(acres)	**Gross**	**Net**
Northwest Alberta	263,800	34,684
Northeast British Columbia	78,892	21,330
East Central Alberta	20,040	10,940
Total	362,732	66,954

For 2005, Delphi has committed to drill five new farm-in wells with a capital expenditure commitment of approximately $6.5 million. During 2005, approximately 18,691 net acres of the Company'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 of Delphi anticipated at December 31, 2004 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 $5.2 million at December 31, 2004. The Corporation currently anticipates incurring abandonment and reclamation costs on 298.9 net wells.

Abandonment Costs

($ thousands)	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**Remainder**	**Total**	**Discounted at 10%**
Proved producing	344	252	233	316	772	146	1164	3,227	1,961
Total proved	344	252	233	366	571	173	1,984	3,923	2,240
Total proved plus probable	341	159	232	306	352	464	2,771	4,625	2,245

Tax Horizon

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

The Company 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 2005 financial year. Depending mainly on commodity prices, production levels and capital spending, the Corporation estimates that income taxes may become payable in 2006.

Costs Incurred

During 2004 the Corporation incurred the following costs in Canada:

	2004 *($ thousands)*
Property and capital costs – Unproved properties	1,226
Property and capital costs – Proved properties	52,391
Exploration costs [14]	1,313
Development costs [12]	28,460

Exploration and Development Activity

The following table sets forth the number of exploratory and development wells Delphi participated during the year ended December 31, 2004.

	Exploratory Wells[13]		**Development Wells[11]**	
	Gross	**Net**	**Gross**	**Net**
Natural gas wells	2.0	1.0	3.0	1.3
Oil wells	-	-	1.0	0.3
Dry holes	-	-	9.0	1.7
Total wells	2.0	1.0	13.0	3.3

Production Forecasts

The following table sets forth the volume of daily production estimated for the year 2005 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**
Fontas	-	-	4,248	1	709
Northeast British Columbia	13	-	5,586	1	945
Other	419	377	2,753	50	1,305
Total Proved	432	377	12,587	52	2,959

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
Fontas	-	-	4,626	2	772
Northeast British Columbia	13	-	5,736	1	970
Other	453	484	2,974	53	1,487
Total Proved plus Probable	466	484	13,336	56	3,229

Production History

Delphi's 2004 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)	434	694	812	855
Natural gas (mcf/d)	5,308	5,943	5,353	6,849
Natural gas liquids (bbls/d)	45	32	45	49
Total (boe/d)	1,364	1,716	1,749	2,045

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, 2004.

	Light & Medium Oil ($/bbl)			
	Q1	Q2	Q3	Q4
Average prices received	38.74	39.04	44.22	38.78
Royalties	3.06	3.33	3.79	4.93
Operating expenses	19.47	15.57	11.77	17.50
Netback	16.21	20.14	28.66	16.35

	Heavy Oil ($/bbl)			
	Q1	Q2	Q3	Q4
Average prices received	30.40	27.53	30.68	25.82
Royalties	1.18	0.45	0.55	0.49
Operating expenses	22.67	17.16	14.35	21.07
Netback	6.55	9.92	15.78	4.26

	Natural Gas ($/mcf)			
	Q1	Q2	Q3	Q4
Average prices received	6.93	6.60	6.25	7.02
Royalties	0.96	0.66	0.93	0.92
Operating expenses	.59	1.29	1.64	1.90
Netback	5.38	4.65	3.68	4.20

	Natural Gas Liquids ($/bbl)			
	Q1	Q2	Q3	Q4
Average prices received	34.94	42.42	43.94	45.46
Royalties	9.11	10.91	13.28	5.37
Operating expenses	-	-	-	-
Netback	25.83	31.51	30.36	40.09

Notes:

(1) Gross

(a) In relation to the Company's interest in production or reserves, its "company gross reserves", which are the Company's working interest (operating or non-operating) share before deduction of royalties and including any royalty interest of the Company;

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

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

(2) Net

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

In relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company.

(3) Definitions used for reserve categories in the Reserve 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 Company 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 Company.

(8) Constant prices and costs

Prices and costs used in an estimate that are:

The Company'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 Company 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 Company's prices are the posted prices for oil and the spot price for gas, after historical adjustments for transportation, gravity and other factors.

(9) The Alberta royalty tax credit ("ARTC") is included in the cumulative cash flow amounts. ARTC is based on the program announced November 1989 by the Alberta government with modifications effective January 1, 1995.

(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 Company'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.