This is Delphi.

DELPHI ENERGY CORP. | PRESS RELEASE

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DELPHI ENERGY REPORTS FOURTH QUARTER AND YEAR END RESULTS

CALGARY, ALBERTA – March 14, 2012 – Delphi Energy Corp. ("Delphi" or the "Company") is pleased to announce its financial and operational results for the quarter and year ended December 31, 2011.

2011 Highlights

- achieved record average production in 2011 with volumes of 8,870 barrels of oil equivalent per day (boe/d), an increase of ten percent compared to 2010;
- increased the liquids percentage of production to approximately 29 percent crude oil and natural gas liquids in 2011, up from 20 percent in 2010 and offsetting a two percent decline in natural gas production;
- generated funds from operations of $66.9 million, an increase of 11 percent from the previous year;
- achieved a cash flow netback of $20.65 per boe, unchanged from the prior year;
- reduced operating costs by an additional eight percent to $6.84 per boe in 2011 from 7.44 per boe in 2010;
- increased total proved reserves by ten percent to 25.1 million boe and increased total proved plus probable reserves by 16 percent to 40.2 million boe;
- drilled 30 (23.8 net) wells with a success rate of 100 percent;
- achieved average finding, development, acquisitions and dispositions costs of $18.28 per proved boe and $12.37 per proved plus probable boe;
- generated a recycle ratio of 2.0 times on an operating netback of $24.25 per boe;
- increased the Company's credit facilities to $145.0 million in May of 2011; and
- reduced net debt per boe at December 31, 2011 on a proved and proved plus probable basis for the fifth year in a row to $3.81 and $2.38 per boe, respectively.

Operational Highlights

	Three Months Ended December 31			Year Ended December 31		
Production	**2011**	2010	% Change	**2011**	2010	% Change
Natural gas (mcf/d)	**38,973**	38,918	-	**37,992**	38,816	(2)
Crude oil (bbls/d)	**1,436**	1,147	25	**1,321**	950	39
Natural gas liquids (bbls/d)	**1,405**	906	55	**1,217**	667	82
Total (boe/d)	**9,337**	8,539	9	**8,870**	8,086	10

Financial Highlights ($ thousands except per unit amounts)

	Three Months Ended December 31			Year Ended December 31		
	2011	2010	% Change	**2011**	2010	% Change
Petroleum and natural gas sales	**33,115**	29,729	11	**126,887**	113,772	12
Per boe	**38.55**	37.92	2	**39.19**	38.55	2
Funds from operations	**17,081**	17,868	(4)	**66,872**	60,412	11
Per boe	**19.89**	22.74	(13)	**20.65**	20.46	1
Per share – Basic	**0.14**	0.16	(13)	**0.57**	0.56	2
Per share – Diluted	**0.14**	0.16	(13)	**0.56**	0.56	-
Net earnings (loss)	**825**	1,744	(53)	**11,602**	(16,984)	-
Per boe	**0.96**	2.22	(57)	**3.58**	(5.77)	-
Per share – Basic	**0.01**	0.02	(50)	**0.10**	(0.16)	-
Per share – Diluted	**0.01**	0.02	(50)	**0.10**	(0.16)	-
Capital invested	**37,282**	18,195	105	**114,477**	104,950	9
Disposition of properties	**(4,835)**	-	-	**(12,873)**	(246)	5,133
Net capital invested	**32,447**	18,195	78	**101,604**	104,704	(3)
Acquisition of properties	**56**	(369)	-	**273**	18	1,417
Total capital invested	**32,503**	17,826	82	**101,877**	104,722	(3)

	December 31, 2011	December 31, 2010	% Change
Debt plus working capital deficiency [1]	**95,632**	108,054	(11)
Total assets	**447,073**	386,737	16
Shares outstanding (thousands)			
Basic	**131,000**	112,825	16
Diluted	**141,591**	120,601	17

[1] excludes fair value of financed instruments.

MESSAGE TO SHAREHOLDERS

2011 was another solid year for Delphi, as the Company achieved record operational results and strong financial results in an environment where increased oil and natural gas liquids ("NGL's") pricing offset a 17 percent reduction in natural gas prices.

The Company achieved production growth of ten percent, while cash flow increased 11 percent and reserves were up 16 percent. Light oil and NGL production growth in 2011 of 57 percent more than offset a two percent decrease in natural gas production. Both light oil and NGL production have tripled over the past three years while natural gas production has only grown 14 percent. Corporate average NGL yields have increased to over 35 bbls/mmcf in 2011 compared to 12.5 bbls/mmcf just three years ago. Continued cost structure improvements also contributed to the eleven percent increase in cash flow and another year of top quartile cash netbacks. Solid operating efficiencies are critical to maintaining sufficient cash generating capability to execute an economic growth plan.

Year in Review

The Company's concentrated high working interest, mostly operated asset base strategically supported by ownership in significant gathering and processing infrastructure continues to deliver growth achieving 100 percent drilling success on a 30 well (23.8 net) drilling program in 2011. Strong reserve additions from the capital program replaced production in 2011 by 2.75 times and increased the Company's reserve life index to 12.4 years. Total proved reserves increased in 2011 by 10 percent, with total proved plus probable reserves increasing by 16 percent.

Delphi achieved top quartile finding, development and net acquisition cost ("FD&A") for 2011 on proved and probable reserve additions, inclusive of future development capital ("FDC") of $12.37 per boe. Operating netbacks were $24.25 per boe in 2011, generating a recycle ratio of 2.0 times. Delphi's recycle ratio continues to be a reliable measure of the Company's economic growth defined by superior netbacks and top quartile finding and development costs. The future drilling locations booked in Delphi's year end 2011 GLJ Engineering Report (the "GLJ Report") increased from 43 locations to 48, with FDC increasing approximately six percent to $143.1 million. Future drilling locations associated with the Company's Bigstone Montney play in the GLJ Report consisted of only two gross (1.7 net) wells.

Financial results in 2011 are highlighted again by a high quality revenue stream and an efficient cost structure, yielding continued growth in cash flow. Revenue increased by 12 percent as a result of increased light oil and NGL production coupled with higher prices and offset by marginally lower natural gas production and 17 percent lower realized natural gas prices. Cash flow increased in 2011 to $66.9 million with hedging gain contributions decreasing to 12 percent of cash flow compared to 27 percent in 2010.

Corporate cash netbacks, including hedging, remained relatively flat at $20.65 per boe compared to $20.46 per boe in 2010. The successful growth of the Company's cash generating capabilities through commodity mix change and cost structure improvements continues to successfully displace less predictable hedging gains as a material component of historically solid cash netbacks in a low natural gas price environment. However, the Company's past track record of $20.00 per boe cash netbacks is expected to be under pressure in 2012 given the much weaker current and anticipated natural gas price environment.

The capital program in 2011 was $114.8 million with net capital expenditures of $101.9 million after taking into account $12.9 million of non-core dispositions.

At December 31, 2011, unutilized credit available on the Company's $145.0 million banking facilities was nearly $50 million (34 percent of available bank facilities), providing support for our Q1 2012 capital program which historically is the quarter in which the majority of Delphi's capital expenditures are incurred.

Delphi's undeveloped land position at December 31, 2011, which is a reliable measure of its future growth prospect inventory, remained relatively flat at 239,186 net acres (374 sections). The Company has regulatory approval to drill up to four natural gas wells per pool per section on its lands at its three core properties of Bigstone, Hythe and Wapiti. Delphi also increased its land holdings in 2011 on its Bigstone Montney play to 45 gross (41.5 net) sections.

Delphi has a number of initiatives in the ongoing capital program that we believe will provide continued growth of our light oil, condensate, and NGL production and reserves.

Bigstone Montney Program

The Company has now successfully drilled and completed three gross (2.75 net) horizontal wells on its Montney lands in Bigstone. All three wells have been drilled using "extended-reach" drilling techniques with horizontal lengths as long as 3,005 metres and completed using multi-stage fracturing technology.

The previously released results of the first Bigstone East 16-30 well with a surface location at 1-19-60-22 W5M, flow tested at an average rate of 12.5 million cubic feet per day of natural gas over the final 24 hours of the four day flow period with approximately 770 barrels per day of condensate (62 bbls/mmcf) at the end of the test. Shallow-cut plant recoveries of NGL's are expected to yield an additional 30 to 35 bbls/mmcf. On a subsequent multi-rate flow test with the well producing at a restricted rate of 2.75 mmcf/d, the wellhead condensate yield increased to 152 bbls/mmcf. These initial flow test results have exceeded Delphi's expectations.

A second Bigstone East 4-2 well, located three miles (five kilometres) south west of the first well is currently on flow test, with initial flow data indicating another favourable result. Flow test results are expected to be released within the next two weeks. After testing operations and well site facility construction is completed, the drilling rig will move back on to the 4-2 surface location to commence drilling operations on the next "extended-reach" Montney well at Bigstone East.

The 100 percent Delphi owned gathering system and 30 mmcf/d facility at Bigstone East is expected to be commissioned for start-up by mid-April.

The results of the 16-4 horizontal well located on the Bigstone West land block remain confidential at this time.

Bigstone Gething Program

The first Gething horizontal well at 13-16 has also been drilled and completed with a 10 stage fracture program successfully placed over an 879 metre horizontal section. The well is currently on flow test, with results also expected to be released within the next two weeks. The pipeline tie-in to Delphi's existing sweet natural gas infrastructure is expected to be completed by mid-April. The well is expected to produce NGL yields of approximately 25 bbls/mmcf based on existing Gething production in the area.

Wapiti Nikanassin / Multi-zone Program

The development of multiple Cretaceous targets utilizing vertical wells has continued through the first quarter of 2012. Two wells were drilled and will be completed after spring break-up. The Wapiti area production has increased from 300 boe/d at the time of acquisition in 2009, to a current rate of almost 3,000 boe/d today with an average NGL yield of 80 bbls/mmcf. The application of horizontal drilling and multi-stage fracturing technology to the producing formations at Wapiti is a natural progression of the development at Wapiti as the delineation of the targets are matured with vertical wells. Operational success with the Bigstone Gething program will also assist with a horizontal Wapiti program.

Outlook

The continued softening of the natural gas price environment cannot be ignored and is expected to have a significant effect on the Company's natural gas revenues in 2012. Our track record of finding and developing oil and gas reserves in the deep basin at top quartile input costs, yielding solid cash netbacks gives confidence to our sustainable growth model. In this environment, however, aggressive growth plans must give way to conservative cash flow and balance sheet management.

Delphi is presently not in a position to provide 2012 guidance due to the current lack of production performance data available for both the Bigstone Montney and Bigstone Gething programs. Some production history is required to appropriately forecast both natural gas production performance and wellhead condensate yields.

Delphi continues to rationalize certain non-core assets with proceeds being redeployed into the 2012 capital program. During the first quarter of 2012, the Company completed the sale of non-core producing assets for net proceeds of $11.5 million and is targeting a further $25.0 million to $35.0 million in dispositions by the end of 2012. The Company is targeting net debt at December 31, 2012 to be between $105.0 million and $115.0 million.

Also, the Company has hedged approximately 20 percent of its 2012 natural gas production at $3.03 per mcf, potentially generating gains of $3.2 million and increasing the cash netback by approximately $1.00 per boe.

The Company expects to maintain 2012 net capital expenditures to within $10.0 million of cash flow. Historically, Delphi executes a winter capital program in excess of first quarter cash flow followed by at least one quarter of minimal activity prior to returning to the field with an active fall program. With the success of the Montney program thus far, the current plan is to continue drilling through spring break-up then reassess the environment, the disposition program and Montney well results prior to making firm plans with respect to a second half of 2012 capital program.

Delphi has never been in a better position to deliver long term sustainable growth with a production mix that yields a high quality revenue stream. The Company's low cost structure maximizes cash generating margins to re-invest into our significant inventory of drilling opportunities. In this weak natural gas price environment, the Wapiti and Bigstone Montney programs offer significant inventory to grow the Company's condensate and NGL production far beyond the current yield of 35 bbls/mmcf, while Hythe offers further light oil opportunities.

We believe the low-cost reserve additions achieved over the past three years are repeatable on our existing large undeveloped and under-developed contiguous land bases within our core areas. Our growing natural gas liquids and light oil production base is providing a natural hedge against low natural gas prices.

On behalf of the Board of Directors and all the employees of Delphi, we would like to thank our shareholders for their continued support as we move forward with confidence and enthusiasm.

CONFERENCE CALL AND WEBCAST

A conference call and webcast to review 2011 results is scheduled for 9:00 a.m. Mountain Time (11:00 a.m. Eastern Time) on Thursday, March 15, 2012. The conference call number is 1-800-355-4959 or 416-695-6616. A brief presentation by David Reid, President and CEO and Brian Kohlhammer, Senior VP Finance & CFO, will be followed by a question and answer period. The conference call will also be broadcast live on the internet and may be accessed through the Delphi Energy website at www.delphienergy.ca

A taped rebroadcast will be available until 6:00 p.m. Mountain Time, Thursday, March 22, 2012. To access the rebroadcast, dial 1-800-408-3053 or 905-694-9451. The passcode is 6254417. Delphi's annual and fourth quarter 2011 financial statements and management's discussion and analysis are available on Delphi's website at www.delphienergy.ca and will be available on SEDAR at www.sedar.com within 24 hours.

Delphi Energy is a Calgary-based company that explores, develops and produces oil and natural gas in Western Canada. The Company is managed by a proven technical team. Delphi trades on the Toronto Stock Exchange under the symbol DEE.

FOR FURTHER INFORMATION PLEASE CONTACT:

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Forward-Looking Statements*. This management discussion and analysis contains forward-looking statements and forward-looking information within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", may", "will", "should", believe", "intends", "forecast", "plans", "guidance" and similar expressions are intended to identify forward-looking statements or information.*

More particularly and without limitation, this management discussion and analysis contains forward looking statements and information relating to the Company's risk management program, petroleum and natural gas production, future funds from operations, capital programs, commodity prices, costs and debt levels. The forward-looking statements and information are based on certain key expectations and assumptions made by Delphi, including expectations and assumptions relating to prevailing commodity prices and exchange rates, applicable royalty rates and tax laws, future well production rates, the performance of existing wells, the success of drilling new wells, the capital availability to undertake planned activities and the availability and cost of labour and services.

Although the Company believes that the expectations reflected in such forward-looking statements and information are reasonable, it can give no assurance that such expectations will prove to be correct. Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results may differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, the risks associated with the oil and gas industry in general such as operational risks in development, exploration and production, delays or changes in plans with respect to exploration or development projects or capital expenditures, the uncertainty of estimates and projections relating to production rates, costs and expenses, commodity price and exchange rate fluctuations, marketing and transportation, environmental risks, competition, the ability to access sufficient capital from internal and external sources and changes in tax, royalty and environmental legislation. Additional information on these and other factors that could affect the Company's operations or financial results are included in reports on file with the applicable securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com). The forward-looking statements and information contained in this press release are made as of the date hereof for the purpose of providing the readers with the Company's expectations for the coming year. The forward-looking statements and information may not be appropriate for other purposes. Delphi undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

Basis of Presentation*. For the purpose of reporting production information, reserves and calculating unit prices and costs, natural gas volumes have been converted to a barrel of oil equivalent (boe) using six thousand cubic feet equal to one barrel. A boe conversion ratio of 6:1 is based upon an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This conversion conforms with the Canadian Securities Administrators' National Instrument 51-101 when boes are disclosed. Boes may be misleading, particularly if used in isolation.*

Non-GAAP Measures*. The MD&A contains the terms "funds from operations", "funds from operations per share", "net debt", "cash operating costs" and "netbacks" which are not recognized measures under Canadian generally accepted accounting principles. The Company uses these measures to help evaluate its performance. Management considers netbacks an important measure as it demonstrates its profitability relative to current commodity prices. Management uses funds from operations to analyze performance and considers it a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future capital investments and to repay debt. Funds from operations is a non-GAAP measure and has been defined by the Company as net earnings plus the addback of non-cash items (depletion, depreciation and accretion, stock-based compensation, future income taxes and unrealized gain/(loss) on risk management activities) and excludes the change in non-cash working capital related to operating activities and expenditures on asset retirement obligations and reclamation. The Company also presents funds from operations per share whereby amounts per share are calculated using weighted average shares outstanding consistent with the calculation of earnings per share. Delphi's determination of funds from operations may not be comparable to that reported by other companies nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. The Company has defined net debt as the sum of long term debt plus working capital excluding the current portion of future income taxes and risk management asset/liability. Net debt is used by management to monitor remaining availability under its credit facilities. Cash operating costs have been defined as the sum of operating expenses, transportation expenses, general and administrative expenses and interest costs. Operating netbacks have been defined as revenue less royalties, transportation and operating costs. Cash flow netbacks have been defined as operating netbacks less interest and general and administrative costs. Netbacks are generally discussed and presented on a per boe basis.*

For the calculation of finding and development cost and recycle ratio, refer to the Company's press release of crude oil and natural gas reserves information dated February 29, 2012.

MANAGEMENT'S DISCUSSION AND ANALYSIS

(All tabular amounts are stated in thousands of dollars, except per unit amounts)

Management's discussion and analysis ("MD&A") has been prepared by management and reviewed and approved by the Board of Directors of Delphi Energy Corp. ("Delphi" or "the Company"). The discussion and analysis is a review of the financial position and results of operations of the Company. Its focus is primarily a comparison of the financial performance for the three and twelve months ended December 31, 2011 and 2010 and should be read in conjunction with the audited consolidated financial statements and accompanying notes for the years ended December 31, 2011 and 2010. The audited consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). The reporting currency is the Canadian dollar. The discussion and analysis has been prepared as of March 13, 2012.

For the purpose of reporting production information, reserves and calculating unit prices and costs, natural gas volumes have been converted to a barrel of oil equivalent ("boe") using six thousand cubic feet equal to one barrel. A boe conversion ratio of 6:1 is based upon an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This conversion conforms to the Canadian Securities Administrators' National Instrument 51-101 when boes are disclosed. Boes may be misleading, particularly if used in isolation.

This MD&A contains the terms "funds from operations", "funds from operations per share", "net debt", "cash operating costs" and "netbacks" which are not recognized measures under IFRS. The Company uses these measures to help evaluate its performance. Management considers netbacks an important measure as it demonstrates its profitability relative to current commodity prices. Management uses funds from operations to analyze performance and considers it a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future capital investments and to repay debt. Funds from operations is a non-IFRS measure and has been defined by the Company as cash flow from operating activities before accretion on long-term debt, decommissioning expenditures and changes in non-cash working capital. The Company also presents funds from operations per share whereby amounts per share are calculated using weighted average shares outstanding consistent with the calculation of earnings per share. Delphi's determination of funds from operations may not be comparable to that reported by other companies nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS. The Company has defined net debt as the sum of long term debt plus/minus working capital excluding the current portion of the fair value of financial instruments. Net debt is used by management to monitor remaining availability under its credit facilities. Cash operating costs have been defined as the sum of operating expenses, transportation expense, general and administrative expenses and cash finance costs. Operating netbacks have been defined as revenue less royalties, transportation and operating costs. Cash netbacks have been defined as operating netbacks less interest and general and administrative costs. Netbacks are generally discussed and presented on a per boe basis.

DELPHI'S OPERATIONS

What is the nature of Delphi's business and where are its operations?

Delphi is a publicly-traded company with its corporate office in Calgary, Alberta, Canada. Delphi is engaged in the exploration for, development and production of crude oil and natural gas from properties and assets located in Western Canada in which it holds an interest. The Company's operations are primarily concentrated in the Deep Basin of North West Alberta, representing in excess of 90 percent of the Company's production. The Company has three primary core areas in the Deep Basin located at Bigstone, Hythe and Wapiti.

2011 ACCOMPLISHMENTS

What were the highlights of Delphi's operational and financial results in 2011?

In 2011, the Company achieved the following:

- achieved average production of 8,870 barrels of oil equivalent per day ("boe/d"), an increase of ten percent compared to 2010;
- increased the liquids percentage of production to approximately 29 percent crude oil and natural gas liquids in 2011, up from 20 percent in 2010;
- generated funds from operations of $66.9 million, an increase of 11 percent from 2010;
- achieved a cash netback of $20.65 per boe, maintaining the Company's objective of achieving a cash netback of at least $20.00 per boe;
- reduced operating costs by eight percent to $6.84 per boe in 2011 from $7.44 per boe in 2010;
- realized $9.2 million in commodity risk management gains on natural gas physical and financial contracts while incurring $1.3 million of commodity risk management losses on a financial crude oil call option;
- drilled 30 gross (23.8 net) wells as part of the Company's capital program; and
- issued 10.0 million common shares and 6.1 million common shares on a flow-through basis for total combined gross proceeds of $38.9 million.

Funds from operations in 2011 were $66.9 million or $0.57 per basic share ($0.56 per diluted share), compared to $60.4 million or $0.56 per basic share and diluted share in 2010. The growth in funds from operations in 2011 over 2010 was primarily a result of higher production, change in production mix towards higher netback crude oil and natural gas liquids and the increase in realized liquids prices offset by the decrease in realized natural gas prices.

The Company continues to focus production growth in its core areas where operating costs were less than $6.00 per boe on a weighted average basis. Delphi's operating costs were reduced by $0.60 per boe to $6.84 per boe in 2011, eight percent lower than the comparative period.

For the 2011 fiscal period, the Company recognized approximately $4.1 million and $3.8 million in realized gains on financial and physical commodity risk management contracts, respectively, providing additional stability to the Company's funds from operations.

On March 24, 2011, Delphi closed an equity offering of 3.2 million flow-through common shares at $2.80 per share for proceeds of approximately $9.0 million. On December 23, 2011, Delphi closed an equity offering of 2.9 million flow-through common shares at $2.75 per share and 10.0 million common shares at $2.20 per share for net proceeds of approximately $28.1 million. The net proceeds from these financings were initially used to temporarily reduce the Company's net debt and subsequently directed towards the Company's capital program.

The combination of the above highlighted items resulted in Delphi's financial position continuing to remain strong at the end of 2011, providing the financial flexibility to pursue its winter drilling program with a significant focus on the Montney formation in the Bigstone area. At December 31, 2011, the Company had net debt of $95.6 million on total credit facilities of $145.0 million, providing excess financial capacity of approximately $49.4 million. On an annualized, fourth quarter funds from operations basis, Delphi's net debt to funds from operations ratio was 1.4:1. Net debt includes bank debt plus working capital deficiency excluding the fair value of financial instruments.

2012 OUTLOOK AND FORWARD-LOOKING INFORMATION

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More particularly and without limitation, this management discussion and analysis contains forward-looking statements and information relating to the Company's risk management program, petroleum and natural gas production, future funds from operations, capital programs, commodity prices, costs and debt levels. The forward-looking statements and information are based on certain key expectations and assumptions made by Delphi, including expectations and assumptions relating to prevailing commodity prices and exchange rates, applicable royalty rates and tax laws, future well production rates, the performance of existing wells, the success of drilling new wells, the capital availability to undertake planned activities and the availability and cost of labour and services.

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Delphi's expectations for 2012 are based upon its projection of drilling plans, drilling success, facilities construction and production results and the estimated related revenues and associated costs of royalties, transportation expenses, operating costs, general and administrative expenses and interest costs. Commodity prices used in the determination of forecast revenues are based upon general economic conditions, commodity supply and demand forecasts and publicly available price forecasts. The Company continually monitors its forecast assumptions to ensure the stakeholders are informed of material variances from previously communicated expectations.

What are the Company's production expectations for 2012?

Delphi is presently not in a position to provide 2012 guidance due to the current lack of production performance data available for both the Bigstone Montney and Bigstone Gething programs. Some production history is required to appropriately forecast both natural gas production performance and wellhead condensate yields.

REVENUES

What does the Company project for crude oil and natural gas prices and the Canadian/United States exchange rate in 2012?

Natural Gas

United States natural gas prices are commonly referenced to the New York Mercantile Exchange Henry Hub in Louisiana ("NYMEX") while Canadian natural gas prices are typically referenced to the Canadian Alberta Energy Company interconnect with the TransCanada Alberta system ("AECO"). Natural gas prices are primarily influenced by North American, rather than global, supplies of natural gas versus domestic demand for winter heating and generation of electricity for summer cooling requirements. However, with the growth in natural gas liquefaction and regasification facilities around the world, this North American supply and demand balance is subject to disruption from time to time, primarily in periods of a shortfall in supply. In addition, multi-stage fracturing technology has unlocked significant natural gas resource potential of numerous shale basins in North America which are capable of initially producing very high rates of natural gas.

For forecasting purposes, Delphi continues to expect a challenging natural gas market for the remainder of 2012 as a result of strong natural gas production in the United States through horizontal drilling using multi-stage fracturing technology into the shale gas plays. So far in 2012, this significant growth in natural gas production has been matched with significantly warmer than normal average winter temperatures in North America. This has resulted in natural gas storage being significantly higher than previous years at this time. During the first quarter of 2012, Canadian natural gas prices have decreased to ten year lows. The Company continues to monitor its cash flow projections in light of this current commodity price environment.

Crude Oil

West Texas Intermediate at Cushing, Oklahoma ("WTI") is the benchmark reference for North American crude oil prices. Canadian crude oil prices are based upon postings, primarily at Edmonton, Alberta and represent the WTI price adjusted for quality and transportation differentials as well as the Canadian/United States ("Cdn/US") dollar exchange rate. The fundamental supply/demand equation for crude oil is more balanced on a daily basis than natural gas due to consistent demand for crude oil of approximately 88 million barrels per day to meet the global requirement for energy. The price of crude oil can also be influenced significantly by geopolitical events in the major oil exporting countries of the world and the strength or weakness of the global economies.

Delphi anticipates WTI to average U.S. $100.00 per barrel in 2012, based on a balanced equation of supply and demand fundamentals supporting strengthening world economies.

Canadian/United States Exchange Rate

Both crude oil and natural gas prices in Canada are premised on the U.S. dollar price for each product adjusted for the Cdn/US dollar exchange rate and quality and transportation differentials. The strength or weakness of the Canadian dollar versus the U.S. dollar will largely reflect the global demand for raw materials, particularly metals, minerals and crude oil. The global financial markets tolerance for risk and its need for financial security in the form of holding U.S dollars will also have an effect on the value of the Canadian dollar against the U.S. dollar.

The Canadian dollar is now expected to trade slightly better than parity with the U.S. dollar in 2012. The exchange rate is influenced by many variables which will continue to result in significant volatility. Delphi has assumed an average exchange rate of $1.00 Cdn. to U.S. dollar.

Has Delphi undertaken any commodity price risk management for 2012 to mitigate the risk of volatility in its product pricing?

In light of the low natural gas prices over the past three years and a future outlook which has resulted in the forward price curve for natural gas to decrease based on the view that there is ample supply of natural gas with the development of the shale gas plays, particularly in the United States, Delphi has become more focused on protecting the downside of prices as opposed to locking in gains to be made on unusually high prices. Currently, Delphi has provided for approximately 20 percent of its natural gas production at a predominantly AECO based average floor price of $3.03 per mcf for 2012. Delphi continually monitors the variables affecting the price of natural gas and crude oil in order to ensure its capital program is in line with expected funds from operations. The following natural gas production is protected by commodity price fluctuations, in order to support the Company's funds from operations:

	2012
Production provided for (mmcf/d)	7.9
Percentage of natural gas production *	20%
Price floor (Cdn $/mcf)	$3.03

* based on 38.5 mmcf/d

ROYALTIES

What average royalty rate does Delphi expect to pay in 2012?

The Company pays royalties to provincial governments, individuals and companies that own surface and/or mineral rights. These payments take the form of Crown, freehold and overriding royalties. Crown royalty rates for crude oil and natural gas are generally calculated on a sliding scale based on commodity prices and production rates whereas freehold and overriding royalty rates are generally a fixed percentage of revenue. Crown royalty rates can change due to price fluctuations or changes in production volumes on a well by well basis subject to minimum and maximum rates. For natural gas liquids, Crown royalty rates are a fixed percentage of revenue with the rate varying according to the nature of the product. Crown royalty credits are received from the Crown and represent the fee earned by the owners of natural gas processing infrastructure to process the Crown's royalty share of natural gas. Freehold royalties are paid on freehold lands and overriding royalties are generally payable on lands where the Company has earned an interest in the lands through a farm-in, whether the lands are Crown or freehold. Royalties are not affected by gains or losses realized through the Company's risk management program.

For 2012, Delphi expects its royalty rate, after the deduction for royalty credits, will average between 12 to 15 percent of gross revenue, excluding realized and unrealized gains or losses on financial instruments.

TRANSPORTATION EXPENSES AND OPERATING COSTS

Will Delphi be able to further reduce its costs of production in 2012?

Transportation expenses are costs incurred by the Company to transport its production volumes from the wellhead to the point of sales. In British Columbia, infrastructure is owned by Spectra Energy Corp. that enables natural gas producers to avoid facility construction in exchange for regulated gathering, processing and transmission fees. This all-in charge is included in transportation expenses.

Delphi expects its transportation expenses to be approximately $2.85 - $3.10 per boe in 2012. Transportation expenses are subject to the availability of pipeline capacity on an interruptible basis in areas of significant production growth by industry.

Operating costs have been trending downward over the past several years as Delphi focuses its capital program and achieves growth in its core areas of Bigstone, Hythe and Wapiti, areas with a weighted average operating cost structure of less than $6.00 per boe. As production grows and fixed area costs are allocated over increased production volumes, the marginal cost of incremental production is expected to be less than field average operating cost.

The costs of production may be more than expected in periods of very high industry activity causing considerable competition and rising prices for general oilfield services and equipment, however, further reductions in operating costs are anticipated resulting in expected operating costs averaging between $6.80 and $7.20 per boe in 2012.

GENERAL & ADMINISTRATIVE AND FINANCE COSTS

What are the Company's overhead costs for personnel and financing?

In 2012, Delphi anticipates its general and administrative costs, net of capitalized amounts, to be approximately $1.90 to $2.00 per boe. A high level of industry activity may cause an increase in general and administrative expenses due to higher than expected employee retention costs, fees to hire new employees and general cost of inflation.

Interest costs will be dependent on market rates and credit spreads for the oil and gas sector and will be a function of the general economic conditions in Canada. If the economy is viewed as growing too fast, which may result in inflation, interest rates may be increased to slow down the pace of growth in the economy. Interest costs may also increase if funds from operations is less than expected and bank debt is used to fund a larger portion of the capital program than originally anticipated. Interest expense is expected to be approximately $1.40 to $1.60 per boe in 2012.

CAPITAL PROGRAM AND NET DEBT LEVELS

What are the Company's forecast capital expenditures and net debt levels for 2012?

The Company expects to maintain 2012 net capital expenditures to within $10.0 million of cash flow. Historically, Delphi executes a winter capital program in excess of first quarter cash flow followed by at least one quarter of minimal activity prior to returning to the field with an active fall program. With the success of the Montney program thus far, the current plan is to continue drilling through spring break-up then reassess the environment, the disposition program and Montney well results prior to making firm plans with respect to a second half of 2012 capital program.

Delphi continues to rationalize certain non-core assets with proceeds being redeployed into the 2012 capital program. During the first quarter of 2012, the Company completed the sale of non-core producing assets for net proceeds of $11.5 million and is targeting a further $25.0 million to $35.0 million in dispositions by the end of 2012. The Company is targeting net debt at December 31, 2012 to be between $105.0 million and $115.0 million.

2011 OPERATIONAL AND FINANCIAL RESULTS

BUSINESS ENVIRONMENT

What external factors of the business environment did the Company have to contend with in 2011?

The price the Company receives for its production volumes is a significant determinant of the Company's funds from operations. The table below outlines the changes in the various benchmark commodity prices and economic parameters which affect the prices received for the Company's production.

Benchmark Prices and Economic Parameters

	Three Months Ended December 31			Twelve Months Ended December 31		
	2011	2010	% Change	**2011**	2010	% Change
Natural Gas						
NYMEX (US $/mmbtu)	**3.33**	3.81	(13)	**4.00**	4.38	(9)
AECO (CDN $/mcf)	**3.20**	3.64	(12)	**3.63**	4.00	(9)
Crude Oil						
West Texas Intermediate (US $/bbl)	**94.02**	85.17	10	**95.12**	79.55	20
Edmonton Light (CDN $/bbl)	**97.31**	80.32	21	**95.07**	77.48	23
Foreign Exchange						
Canadian to U.S. dollar	**0.98**	1.01	(3)	**1.01**	1.03	(2)
U.S. to Canadian dollar	**1.02**	0.99	3	**0.99**	0.97	2

Natural Gas

The growth in natural gas supply continues to exceed the growth in natural gas demand in North America, leading to an excess supply situation and lower natural gas commodity prices. AECO averaged $3.20 per mcf in the fourth quarter of 2011, twelve percent lower than the comparative period. For the year ended December 31, 2011, average AECO was nine percent lower than the same period of 2010.

Crude Oil

WTI averaged U.S. $94.02 per barrel in the fourth quarter of 2011, an increase of ten percent over the fourth quarter of 2010. As a result of the increased price and the narrowing basis differential, Canadian prices were 21 percent higher in the fourth quarter of 2011 over the comparative period of 2010. Edmonton light averaged $97.31 per barrel in the fourth quarter of 2011 versus $80.32 per barrel in 2010.

For 2011, WTI averaged U.S. $95.12 per barrel, an increase of 20 percent over the 2010 year. Edmonton light increased 23 percent to $95.07 from the comparative period in 2010.

Canadian/United States Exchange Rate

The value of the Canadian dollar against its U.S. counterpart continued to strengthen in 2011 as crude oil prices breached U.S. $100.00 per barrel and the concerns over the U.S. government's total debt were raised. As a producer of crude oil, a stronger Canadian dollar has had a negative effect on the price received for production. The average Cdn/US exchange rate for the three and twelve months ended December 31, 2011 were $0.98 and $1.01, respectively. The Cdn/US exchange rate varied from a high of $0.94 to a low of $1.07 in 2011. This negative effect to the price of oil for Canadian producers was offset by a narrowing basis differential between U.S. and Canadian markets.

Industry Cost of Services

The increase in crude oil prices and the demand to drill horizontal oil and natural gas wells using multi-stage fracturing technology has resulted in drilling contractors and oilfield service companies keeping very busy. Natural gas drilling has become more focused on liquids-rich natural gas opportunities with continued strong demand for high deliverability natural gas wells in the Canadian shale gas plays, predominantly the Montney formation. Consequently, there has been pricing pressure on drilling equipment capable of completing these types of operations. The demand for completion services has increased as more horizontal drilling is undertaken with the intention of completing the wells using multi-stage fracturing technology.

DRILLING OPERATIONS

How active was Delphi in its drilling program in 2011?

In 2011, Delphi had a 100 percent success rate in its drilling program that consisted of 30 gross (23.8 net) wells, including 5 gross (4.4 net) wells which were drilled in the fourth quarter of 2011. This compares to a 97 percent success rate achieved in 2010 which resulted in 36 gross (23.3 net) wells, of which 8 gross (4.3 net) wells were drilled in the fourth quarter of 2010.

In light of continued low natural gas prices, the Company focused the majority of its efforts on drilling light oil and liquids-rich natural gas opportunities.

	Three Months Ended December 31, 2011		Twelve Months Ended December 31, 2011	
	Gross	**Net**	**Gross**	**Net**
Crude oil	**1.0**	**0.4**	**9.0**	**6.0**
Liquids rich natural gas (>40 bbl/mmcf NGL content)	**2.0**	**2.0**	**16.0**	**12.8**
Natural gas (<40 bbl/mmcf NGL content)	**2.0**	**2.0**	**5.0**	**5.0**
Total wells	**5.0**	**4.4**	**30.0**	**23.8**
Success rate (%)	**100**	**100**	**100**	**100**

CAPITAL INVESTED

How much did the Company spend in 2011 and where were the capital expenditures incurred?

The Company continued to direct its capital program at its core areas in North West Alberta to take advantage of the multi-zone nature of these assets, low production operating costs and quick on-stream capability associated with owned gathering and processing infrastructure. Total capital invested during the fourth quarter of 2011 was $37.3 million which was primarily directed toward its Bigstone Montney horizontal drilling program. During the year ended December 31, 2011, Delphi invested $114.5 million, of which approximately 72 percent was directed toward drilling and completions and 17 percent was directed toward equipping and facilities. In 2011, the Company invested approximately $8.8 million on undeveloped land, primarily at Crown land sales.

As of December 31, 2011, Delphi has accumulated a total of 45 sections (41.5 net) of undeveloped land prospective for liquids-rich natural gas in the Montney formation, on two separate blocks at its core area of Bigstone located within the Deep Basin of North West Alberta. The Company has increased its Montney rights on the Bigstone East block to 13 sections (11.0 net) through Crown land sales and will earn five gross sections (3.75 net) at Bigstone East through an industry farm-in, with the drilling of its third Montney well. At Bigstone West, the Company holds 27 gross (26.75 net) sections of Montey rights with approximately 56 extended-reach horizontal drilling locations identified.

During the year ended December 31, 2011 Delphi received proceeds on dispositions of $12.9 million, primarily consisting of the sale of certain working interests in Bigstone assets for net proceeds of $4.5 million in the fourth quarter of 2011 and

$7.2 million from granting an overriding royalty on certain lands at Hythe in the third quarter of 2011.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2011	2010	% Change	**2011**	2010	% Change
Land	**6,876**	1,173	486	**8,816**	7,316	21
Seismic	**318**	116	174	**484**	462	5
Drilling and completions	**24,631**	17,228	43	**81,868**	82,061	-
Equipping and facilities	**4,197**	(985)	-	**19,348**	11,281	72
Capitalized expenses	**1,174**	1,349	(13)	**3,824**	3,640	5
Other	**86**	(686)	-	**137**	190	(28)
Capital invested	**37,282**	18,195	105	**114,477**	104,950	9
Disposition of properties	**(4,835)**	-	-	**(12,873)**	(246)	5,133
Net capital invested	**32,447**	18,195	78	**101,604**	104,704	(3)
Acquisition of properties	**56**	(369)	-	**273**	18	1,417
Total capital invested	**32,503**	17,826	82	**101,877**	104,722	(3)

Effective January 16, 2012, Delphi closed the disposition of its non-operated light oil interests in the Hythe area and minor offsetting lands for gross proceeds of $12.0 million. Production associated with the disposition was approximately 217 boe/d (66 percent light oil), based on fourth quarter 2011 production volumes. Proceeds from the sale will be used to fund the ongoing Bigstone Montney development.

PRODUCTION

What factors contributed to the growth in production volumes and the success in growing oil and natural gas liquids volumes?

In 2011, Delphi has focused on exploiting its crude oil and liquids-rich natural gas drilling locations at Bigstone, Hythe and Wapiti. As a direct result of its successful drilling program, production and the weighting toward crude oil and natural gas liquids have increased in comparison to 2010. Production for the three months ended December 31, 2011 increased nine percent averaging 9,337 boe/d. For the year ended December 31, 2011, production averaged 8,870 boe/d, an increase of ten percent when compared to the 8,086 boe/d produced in the same period in 2010.

A significant undeveloped land base, multi-zone potential and the successful application of emerging technologies continue to provide material growth opportunities in existing and new play concepts.

The Company's production portfolio for the fourth quarter was weighted 15 percent to crude oil, 15 percent to natural gas liquids and 70 percent to natural gas. For the year ended December 31, 2011, Delphi's production portfolio was weighted 15 percent to crude oil, 14 percent to natural gas liquids and 71 percent to natural gas.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2011	2010	% Change	**2011**	2010	% Change
Crude oil (bbls/d)	**1,436**	1,147	25	**1,321**	950	39
Natural gas liquids (bbls/d)	**1,405**	906	55	**1,217**	667	82
Total crude oil and natural gas liquids	**2,841**	2,053	38	**2,538**	1,617	57
Natural gas (mcf/d)	**38,973**	38,918	-	**37,992**	38,816	(2)
Total (boe/d)	**9,337**	8,539	9	**8,870**	8,086	10

Crude oil production in the three and twelve months ended December 31, 2011 increased 25 percent and 39 percent, respectively, in comparison to the same period in 2010. The increase in oil production is due to the successful horizontal drilling targeting Cardium light oil at Bigstone and the Doe Creek light oil at Hythe, as well as the significant condensate volumes produced at the wellsite on liquids-rich natural gas wells in the Wapiti area. For the three and twelve months ended December 31, 2011, crude oil volumes include an average of 131 bbls/d and 121 bbls/d, respectively, of field condensate produced from liquids-rich natural gas wells.

Natural gas liquids were 55 percent higher for the fourth of 2011 and 82 percent higher for the year ended December 31, 2011 in comparison to the same respective periods in 2010. The increase in natural gas liquids is primarily due to the successful drilling of multi-zone vertical wells in the Wapiti area, targeting the Nikanassin formation.

The Company's weighting toward crude oil and natural gas liquids production increased from 20 percent in 2010 to 29 percent in 2011 as a direct result of the Company's focus on drilling in crude oil and liquids-rich natural gas locations.

Natural gas production was comparable in the fourth quarter of 2011 to the same period in 2010. For the 2011 year, natural gas production decreased two percent when compared to the same period in 2010, as the company reduced capital spending on natural gas opportunities and focused its capital spending on crude oil and liquids-rich natural gas drilling locations to maximize cash netbacks.

REALIZED SALES PRICES

What were the sales prices realized by the Company for each of its products?

For the three months ended December 31, 2011, Delphi's realized natural gas price decreased by 16 percent. The decrease in realized natural gas prices for the fourth quarter of 2011 in comparison to the same period in 2010 is a result of a twelve percent decrease in the average daily AECO index and a reduction in realized gains on physical contracts. The decrease was partially offset by a higher realized gain on financial contracts as the AECO daily reference price continued to decrease in the fourth quarter of 2011 while the Company's financial contracts had an average floor price of $4.88 per mcf. Overall for the fourth quarter of 2011, the realized gain on natural gas contracts was $0.75 per mcf with physical contracts contributing a gain of $0.25 per mcf and financial contracts contributing a gain of $0.50 per mcf.

For the year ended December 31, 2011, the Company's realized natural gas price decreased by 17 percent when compared to the same period in 2010. The decrease in realized natural gas prices for the year ended December 31, 2011 is primarily a result of a decrease in the average daily AECO index, a reduction in premiums received for heating content and marketing and lower realized gains on physical contracts. The decrease was partially offset by an increase in the gain on financial contracts as natural gas market prices for 2011 were below the Company's financial contracts average floor price of $4.93 per mcf. For the 2011 year, physical and financial contracts realized gains of $0.28 and $0.39, respectively, per mcf, contributing a total gain of $0.67 per mcf.

Realized crude oil prices were 23 and 19 percent higher in the three and twelve months ended December 31, 2011, respectively, compared to the same period in 2010. The increase is primarily due to an increase in Canadian Benchmark crude prices and an upgrade of the Company's crude quality. The increase in realized oil prices for the Company for the year ended December 31, 2011 was partially offset by an increase in realized losses on financial contracts. For crude oil, Delphi lost $1.47 and $2.61 per barrel for the three and twelve months ended December 31, 2011, respectively, on a call option as part of a cross commodity swap. The value of the call, at the time it was undertaken, was used to purchase a higher price on a natural gas contract.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2011	2010	% Change	**2011**	2010	% Change
AECO ($/mcf)	**3.20**	3.64	(12)	**3.63**	4.00	(9)
Heating content and marketing ($/mcf)	**0.24**	0.23	4	**0.25**	0.33	(24)
Gain on physical contracts ($/mcf)	**0.25**	0.92	(73)	**0.28**	0.90	(69)
Gain on financial contracts ($/mcf)	**0.50**	0.21	138	**0.39**	0.22	77
Realized natural gas price ($/mcf)	**4.19**	5.00	(16)	**4.55**	5.45	(17)
Edmonton Light ($/bbl)	**97.31**	80.32	21	**95.07**	77.48	23
Gain (loss) on financial contracts ($/bbl)	**(1.47)**	(0.56)	163	**(2.61)**	0.82	-
Quality differential ($/bbl)	**(1.24)**	(3.18)	61	**(0.90)**	(1.67)	46
Realized oil price ($/bbl)	**94.60**	76.58	23	**91.56**	76.63	19
Realized natural gas liquids price ($/bbl)	**52.69**	51.43	2	**51.13**	53.66	(5)
Total realized sales price ($/boe)	**40.40**	38.79	4	**40.47**	39.71	2

Delphi's oil production has changed from a mix of light and medium oil to predominantly light oil; therefore the Company's average price for crude oil, since mid 2010, will generally fluctuate with the change in the benchmark crude oil prices. Due to field condensate being reported as oil production volumes, Delphi's realized oil price is also affected by the change in condensate prices which are generally priced slightly higher than Edmonton Light prices. With the disposition of the East Central Alberta properties in the second quarter of 2010, increased production of light oil at Bigstone and Hythe continues to high grade the Company's quality of crude oil resulting in pricing more reflective of light oil.

Natural gas liquids prices for the three and twelve months ended December 31, 2011 were two percent higher and five percent lower, respectively, than in the same period in 2010. The fluctuation in pricing is primarily as a result of market prices received for propanes, butanes and condensate extracted from the natural gas stream at the natural gas processing facilities, relative to the comparative period.

How do the realized natural gas prices compare to the benchmark AECO pricing?

Excluding hedges, the Company continues to receive higher than the AECO spot price on natural gas sales due to the high heating content of its natural gas production and the sale of approximately 4.3 million British thermal units (mmbtu) per day on the Alliance pipeline which is priced at the Chicago Monthly Index.

The following table outlines the premium Delphi realized on its natural gas price compared to the average quarterly AECO price due to the risk management program, quality of production and gas marketing arrangements. In years of both high and low commodity price environments, Delphi's realized sales price has been a premium to AECO.

	Dec. 31 2011	Sept. 30 2011	Jun. 30 2011	Mar. 31 2011	Dec. 31 2010	Sept. 30 2010	Jun. 30 2010	Mar. 31 2010
Natural Gas Price								
Delphi realized ($/mcf)	**4.19**	4.64	4.76	4.62	5.00	5.28	5.30	6.26
AECO average ($/mcf)	**3.20**	3.65	3.87	3.80	3.64	3.54	3.89	4.96
Premium to AECO	**31%**	27%	23%	22%	37%	49%	36%	26%
Realized gain on commodity contracts ($000's)	**2,669**	2,306	2,142	2,126	4,045	4,676	4,186	2,941

RISK MANAGEMENT ACTIVITIES

What is Delphi's risk management strategy and what contracts are in place to mitigate the risk of price volatility?

Delphi enters into both financial and physical commodity contracts as part of its risk management program to manage commodity price fluctuations designed to ensure sufficient cash is generated to fund its capital program particularly when commodity prices are extremely volatile. For natural gas production, Delphi has provided for approximately 20 percent of its before-royalty natural gas production at a predominately AECO based average floor price of $3.03 per mcf for 2012.

With respect to financial contracts, which are derivative financial instruments, management has elected not to use hedge accounting and consequently records the fair value of its natural gas and crude oil financial contracts on the balance sheet at each reporting period with the change in the fair value being classified as unrealized gains and losses in the statement of earnings. Natural gas physical commodity sale contracts based in U.S. dollars include an embedded derivative associated with the foreign exchange rate. Due to this derivative, the changes in the fair value of these contracts are included in the statement of earnings.

The Company has fixed the price applicable to production volumes through the following contracts:

Time Period	Commodity	Type of Contract	Quantity Contracted	Contract Price ($/unit)
January 2012 – March 2012	Natural Gas	Physical	1,000 mmbtu/d	U.S. $5.14 fixed
January 2012 – December 2012 (1)	Natural Gas	Physical	2,500 GJ/d	$4.50 call
April 2012 – October 2012	Natural Gas	Physical	1,000 mmbtu/d	U.S. $4.96 fixed
April 2012 – October 2012	Natural Gas	Physical	2,000 GJ/d	$4.06 fixed
January 2012 – December 2012 (2)	Natural Gas	Financial	3,000 GJ/d	$4.50 call
March 2012 – December 2012 (3)	Natural Gas	Financial	7,500 GJ/d	$2.65 fixed
March 2012 – December 2012 (3)	Crude Oil	Financial	500 bbls/d	U.S. $110.00 call
January 2013 – December 2013 (4)	Crude Oil	Financial	600 bbls/d	U.S. $90.00 call

(1) The Company acquired a natural gas contract at $4.12 per gigajoule on 2,500 gigajoules per day for the period January 1, 2011 through December 31, 2011. The contract was paid for with the sale of a natural gas call on 2,500 gigajoules per day at a price of $4.50 per gigajoule for the period January 1, 2012 through December 31, 2012.

(2) The Company acquired a natural gas put contract at $4.00 per gigajoule on 3,000 gigajoules per day for the period January 1, 2011 through December 31, 2011. The put was paid for with the sale of a natural gas call on 3,000 gigajoules per day at a price of $4.50 per gigajoule for the period January 1, 2012 through December 31, 2012.

(3) The Company acquired a natural gas contract at $2.65 per gigajoule on 7,500 gigajoules per day for the period March 1, 2012 through December 31, 2012. The contract was paid for with the sale of a crude oil call on 500 barrels per day at a price of U.S. $110.00 WTI per barrel for the period March 1, 2012 through December 31, 2012.

(4) The Company acquired a natural gas contract at $5.69 per gigajoule on 6,810 gigajoules per day for the period April 1, 2011 through December 31, 2011. The contract was paid for with the sale of a crude oil call on 600 barrels per day at a price of U.S. $90.00 WTI per barrel for the period January 1, 2011 through December 31, 2012. Delphi has deferred this crude oil call to January 1, 2013 through December 31, 2013.

The fair value of the financial contracts outstanding as at December 31, 2011 is estimated to be a loss of approximately $3.2 million, primarily due to the outstanding crude oil contracts. The fair value or mark-to-market of these contracts is based on the estimated amount that would have been received or paid to settle the contacts as at December 31, 2011 and may be different from what will eventually be realized.

The Company recognized an unrealized loss on its financial contracts of $2.9 million and $1.8 million in the three and twelve months ended December 31, 2011, respectively, primarily due to the crude oil call option. The fair values of these contracts are based on an approximation of the amounts that would have been paid to or received from counterparties to settle the contracts outstanding at the end of the year having regard to forward prices and market values provided by independent sources. Due to the inherent volatility in commodity prices, actual amounts realized may differ from these estimates.

The Company accounts for its Canadian dollar physical sales contracts, which were entered into and continue to be held for the purpose of delivery of production, in accordance with its expected sale requirements as executory contracts on an accrual basis rather than as non-financial derivatives.

REVENUE

How do revenues in 2011 compare to 2010 and what factors contributed to the change?

For the three months ended December 31, 2011, Delphi generated revenue of $33.1 million, an eleven percent increase in comparison to the same period in 2010. For the year ended December 31, 2011, the Company's revenue increased by twelve percent to $126.9 million compared to the same period in 2010. The increase in revenues in the fourth quarter and twelve months of 2011 when compared to the same respective periods in 2010 is a result of improved commodity prices for crude oil and natural gas liquids in combination with an increase in the Company's sales weighting toward crude oil and natural gas liquids, partially offset by a decrease in production and commodity prices for natural gas. For the fourth quarter of 2011, crude oil and natural gas liquids contributed to approximately 59 percent of total revenues compared to 42 percent in the same period in 2010. For the year ended December 31, 2011, crude oil and natural gas liquids contributed 54 percent of total revenues compared to 35 percent in the same 2010 period.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2011	2010	% Change	**2011**	2010	% Change
Natural gas	**12,364**	13,848	(11)	**53,814**	61,352	(12)
Natural gas physical contract gains	**888**	3,303	(73)	**3,845**	12,705	(70)
Crude oil	**12,692**	8,140	56	**45,402**	26,287	73
Natural gas liquids	**6,812**	4,287	59	**22,712**	13,063	74
Sulphur	**359**	214	68	**1,114**	365	205
Total	**33,115**	29,792	11	**126,887**	113,772	12

ROYALTIES

What were royalty costs in 2011?

For the fourth quarter of 2011, royalties totaled $6.3 million compared to $2.9 million in the same period in 2010. The increase is primarily a result of higher crown and gross overriding royalties and a reduction in royalty credits. Crown royalties increased by 35 percent primarily as a result of improved crude oil and natural gas liquids commodity prices in combination with the Company's significant increase in crude oil and natural gas liquids production. The Crown royalties were partially offset by royalty credits for processing the Crown's share of natural gas. Gross overriding royalties in the fourth quarter of 2011 increased in comparison to the same period in 2010 primarily as a result of the Company granting an overriding royalty on certain lands in the Hythe area for net proceeds of $7.2 million in the third quarter of 2011.

For the year ended December 31, 2011, total royalties increased 44 percent in comparison to the same period in 2010. The increase is primarily due to higher Crown and gross overriding royalties. Crown royalties of $19.4 million increased 23 percent when compared to the same period in 2010. The increase is primarily due to higher production of crude oil and natural gas liquids in combination with higher commodity prices for crude oil and natural gas liquids. The Company received $5.4 million of royalty credits for processing the Crown's share of natural gas in 2011. For 2011, Crown royalties represent 68 percent of total royalties which is comparable to the 2010 year. Gross overriding royalties increased by 53 percent in 2011 when compared to 2010, primarily as a result of higher crude oil prices and higher production volumes encumbered by gross overriding royalties.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2011	2010	% Change	**2011**	2010	% Change
Crown royalties	**4,625**	3,416	35	**19,418**	15,843	23
Royalty credits	**(1,206)**	(1,589)	(24)	**(5,413)**	(5,963)	(9)
Crown royalties – net	**3,419**	1,827	87	**14,005**	9,880	42
Freehold royalties	**54**	(3)	-	**43**	167	(74)
Gross overriding royalties	**2,782**	1,070	160	**6,691**	4,373	53
Total	**6,255**	2,894	116	**20,739**	14,420	44
Per boe	**7.28**	3.68	98	**6.41**	4.89	31

What were the average royalty rates paid on production in 2011?

The average royalty rates were higher than the comparative period. For the three and twelve months ended December 31, 2011, Crown royalty rates were 54 percent and 16 percent higher, respectively, compared to the same periods in 2010. The increase is primarily due to improved crude oil and natural gas liquids commodity prices which directly impact the Crown royalty rates. Overriding royalty rates increased by 115 percent and 26 percent for the three and twelve months ended December 31, 2011, respectively, as a result of an increase in number of wells encumbered by an overriding royalty.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2011	2010	% Change	**2011**	2010	% Change
Crown rate – net of royalty credits	**10.6%**	6.9%	54	**11.4%**	9.8%	16
Gross overriding rate	**8.6%**	4.0%	115	**5.4%**	4.3%	26
Average rate	**19.4%**	10.9%	78	**16.9%**	14.3%	18

The royalty rate calculations above exclude gains or losses on risk management activities from revenue as the denominator.

OPERATING EXPENSES

How has the Company been able to reduce its operating expenses in 2011 as compared to 2010?

Production costs for the three and twelve months ended December 31, 2011 increased thirty four and four percent, respectively, compared to the same period in 2010. In the fourth quarter of 2011, the Company experienced higher electricity charges, an increase in maintenance costs and excess capacity usage charges as a result of higher production volumes being processed. For 2011, production expenses on a boe basis decreased as a result of an increase in production volumes and increased processing income.

Delphi earns processing income for third party production volumes going through facilities owned by the Company. The processing income represents a reduction of the Company's costs to operate these facilities and hence is deducted in determining operating expenses. Processing income indicates the Company has excess capacity at its facilities which it can access to handle growth in its production volumes. Processing income increased 45 and 27 percent in the three and twelve months ended December 31, 2011, respectively, compared to the same period in 2010.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2011	2010	% Change	**2011**	2010	% Change
Production costs	**7,158**	5,343	34	**25,377**	24,500	4
Processing income	**(1,069)**	(735)	45	**(3,233)**	(2,545)	27
Total	**6,089**	4,608	32	**22,144**	21,955	1
Per boe	**7.09**	5.87	21	**6.84**	7.44	(8)

TRANSPORTATION EXPENSES

	Three Months Ended December 31			Twelve Months Ended December 31		
	2011	2010	% Change	**2011**	2010	% Change
Total	**2,481**	2,089	19	**9,630**	8,908	8
Per boe	**2.89**	2.66	9	**2.97**	3.02	(2)

What factors contributed to the change in transportation costs in 2011?

For the three and twelve months ended December 31, 2011, transportation expenses increased 19 percent and eight percent, respectively, compared to the same periods in 2010. The increase is primarily due to higher trucking activity as the Company's production mix increases for crude oil and natural gas liquids.

LOSS ON DECOMMISSIONING

What does the loss on decommissioning relate to in 2011?

The loss on decommissioning is the difference between decommissioning expenditures incurred in the year and the carrying amount of the Company's decommissioning obligation for those specific assets. In 2011, the Company recorded a loss on decommissioning of $0.5 million associated with several abandonments and reclamations.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2011	2010	% Change	**2011**	2010	% Change
Total	**457**	-	-	**457**	-	-
Per boe	**0.53**	-	-	**0.14**	-	-

GENERAL AND ADMINISTRATIVE

	Three Months Ended December 31			Twelve Months Ended December 31		
	2011	2010	% Change	**2011**	2010	% Change
Gross expenses	**3,648**	3,721	(2)	**13,284**	12,191	9
Overhead recoveries	**(666)**	(497)	34	**(1,984)**	(1,940)	2
Salary allocations	**(1,466)**	(1,509)	(3)	**(4,957)**	(3,822)	30
General and administrative expenses	**1,516**	1,715	(12)	**6,343**	6,429	(1)
Per boe	**1.76**	2.18	(18)	**1.96**	2.18	(10)

How do general and administrative costs in 2011 compare to 2010?

General and administrative ("G&A") expenses (after recoveries and allocations) for the three and twelve months ended December 31, 2011 were $1.5 million ($1.76/boe) and $6.3 million ($1.96/boe), respectively, compared to $1.7 million ($2.18/boe) and $6.4 million ($2.18/boe) for the same period in 2010, respectively. Gross costs in the fourth quarter of 2011 are comparable to the same period in 2010. Gross costs for the year ended December 31, 2011 have increased by nine percent compared to the same period in 2010 as a result of an increase in base costs. On a total basis, recoveries have increased six and 20 percent in the three and twelve months ended December 31, 2011, respectively, in comparison to the same period in 2010. The increase in recoveries is consistent with the increase in the Company's 2011 capital budget. On a per boe basis, G&A expenses have decreased 18 percent and ten percent, respectively, for the three and twelve months ended December 31, 2011, respectively, compared to the same periods in 2010. The decrease on a boe basis is primarily due to a combination of higher recoveries and allocations and higher production volumes. Delphi is committed to delivering strong growth and believes a strong team is paramount to achieve this goal.

SHARE-BASED COMPENSATION

What is share-based compensation expense?

Share-based compensation expense is the amortization over the vesting period of the fair value of stock options and restricted share units granted to employees, directors and key consultants of the Company. The fair value of restricted share units is based on the Company's share price. The fair value of all options granted is estimated at the date of grant using the Black-Scholes option pricing model.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2011	2010	% Change	**2011**	2010	% Change
Share-based compensation	**716**	325	120	**1,929**	1,457	32
Capitalized costs	**(311)**	(126)	147	**(937)**	(430)	118
Net	**405**	199	104	**992**	1,027	(3)
Per boe	**0.47**	0.25	88	**0.31**	0.35	(11)

The share-based non-cash compensation expense for the three months ended December 31, 2011, increased 104 percent over the comparative period, primarily due to the granting of 2.2 million options with a weighted average fair value of $0.72 per option. For the year ended December 31, 2011, the Company granted 5.8 million options with a weighted average fair value of $1.10 per option. During the three and twelve months ended December 31, 2011, Delphi capitalized $0.3 million and $0.9 million of share-based compensation expense.

Included in share-based compensation for the three and twelve months ended December 21, 2011 is $58,000 and $69,000 of expense related to the Company's outstanding restricted share units.

FINANCE COSTS

How do the costs of borrowing compare against the comparative period?

For the fourth quarter of 2011, finance costs decreased four percent when compared to the same period in 2010. Interest costs associated with the Company's long-term debt decreased as a result of lower interest rates charged on the Company's outstanding debt. Accretion for the fourth quarter of 2011 decreased compared to the same period in 2010 as the long-term risk-free interest rates in Canada decreased.

For the year ended December 31, 2011, interest associated with the Company's long-term debt increased slightly as the Company carried a higher average debt balance in comparison to the same period in 2010, partially offset by lower interest rates charged against the long-term debt. Accretion charges in 2011 decreased as a result of lower risk-free long-term interest rates when compared to the same period in 2010.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2011	2010	% Change	**2011**	2010	% Change
Interest	**1,279**	1,301	(2)	**5,299**	5,075	4
Accretion	**99**	134	(26)	**483**	519	(7)
Total finance costs	**1,378**	1,435	(4)	**5,782**	5,594	3
Interest per boe	**1.49**	1.66	(10)	**1.64**	1.72	(5)
Accretion per boe	**0.12**	0.17	(29)	**0.15**	0.18	(17)

As at December 31, 2011, Delphi's bankers' acceptances have terms ranging from 91 to 182 days and a weighted average effective interest rate of 4.08 percent over the term.

What is accretion expense and how did this expense for 2011 compare to 2010?

The accretion of decommissioning obligations is an expense that relates to the passing of time until the Company estimates it will retire its assets and restore the asset locations to a condition which meets or exceeds environmental standards. Due to the long term nature of certain assets of the Company, this accretion expense is estimated to extend over a term of one to 20 years. The Company used a risk-free interest rate of 1.94 percent for the purpose of calculating the fair value of its decommissioning obligations and hence the accretion expense for the three months ended December 31, 2011. On average, the Company has used a risk-free interest rate of 2.64% in 2011 compared to 3.13% in 2010 to value its decommissioning obligations and its accretion expense.

DEPLETION AND DEPRECIATION

Has the Company's depletion and depreciation rate and expense changed in 2011 compared to 2010?

Depletion and depreciation before impairment loss per boe for the three and twelve months ended December 31, 2011 decreased 18 percent and six percent, respectively, over the comparative period. The depletion and depreciation expense before impairment loss per boe decreased as a result of higher production volumes and a higher reserve base, partially offset by an increase in the cost base.

In 2011, the Company recorded an impairment loss of $1.5 million compared to $35.5 million in 2010, as a result of declining natural gas prices.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2011	2010	% Change	**2011**	2010	% Change
Depletion and depreciation	**11,827**	13,190	(10)	**45,535**	44,278	3
Impairment loss	**1,500**	-	-	**1,500**	35,500	(96)
Total	**13,327**	13,190	1	**47,035**	79,778	(41)
Depletion and depreciation per boe	**13.77**	16.79	(18)	**14.06**	15.00	(6)
Impairment loss per boe	**1.75**	-	100	**0.46**	12.03	(96)

INCOME TAXES

What was the affect on deferred income taxes as a result of the earnings for the period?

Delphi recorded a deferred income tax expense of $1.3 million and $6.4 million for the three and twelve months ended December 31, 2011, respectively. Deferred taxes arise from differences between the accounting and tax bases of the Company's assets and liabilities. Delphi does not anticipate it will be cash taxable before 2014.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2011	2010	% Change	**2011**	2010	% Change
Deferred expense (recovery)	**1,298**	300	333	**6,369**	(5,189)	-
Per boe	**1.51**	0.38	297	**1.97**	(1.76)	-

FUNDS FROM OPERATIONS

What are funds from operations and why is it a key performance measure?

Funds from operations is a non-IFRS measure that has been defined by the Company and is used as a measure to analyze performance. Delphi considers funds from operations a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future capital investments and to repay debt. Funds from operations is calculated as cash flow from operating activities before accretion on long-term debt, decommissioning expenditures and changes in non-cash working capital.

How do funds from operations in 2011 compare to 2010 and how do funds from operations compare to cash flow from operating activities?

Delphi's cash flow from operating activities of $17.1 million for the three months ended December 31, 2011 decreased ten percent from the $18.9 million generated in the same period in 2010. Delphi generated funds from operations of $17.1 million for the three months ended December 31, 2011, down four percent from the $17.9 million for the same period in 2010. The decrease in cash flow from operating activities and funds from operations for the fourth quarter of 2011 compared to the fourth quarter of 2010 was primarily the result of higher royalties and operating expense partially offset by an increase in realized gains on commodity risk contracts and a decrease in transportation and general and administrative expense.

For 2011, Delphi generated cash flow from operating activities of $68.3 million, 18 percent higher than the $57.9 million generated in 2010. Similarly, funds from operations increased by eleven percent in 2011 compared to the same period in 2010. The increase in cash flow from operating activities and funds from operations is primarily a result of higher realized sales prices as the Company's mix of light oil and natural gas liquids increased and general and administrative expense decreased, partially offset by higher royalties, operating expense and transportation.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2011	2010	% Change	**2011**	2010	% Change
Cash flow from operating activities	**17,134**	18,940	(10)	**68,300**	57,899	18
Accretion of long-term debt	**(83)**	(131)	37	**257**	429	(40)
Decommissioning expenditures	**588**	265	122	**588**	265	122
Change in non-cash working capital	**(558)**	(1,206)	54	**(2,273)**	1,819	-
Funds from operations	**17,081**	17,868	(4)	**66,872**	60,412	11

NET EARNINGS

What factors contributed to the earnings in 2011?

For the three months ended December 31, 2011, Delphi recorded net earnings of $0.8 million ($0.01 per basic share), down from the $1.7 million ($0.02 per basic share) recorded in the same period in 2010. The decrease in net earnings is primarily a result of higher royalties, operating, transportation and deferred income tax expense, partially offset by higher revenues due to improved pricing and production weighting toward crude oil and natural gas liquids, an increase in realized gains on commodity risk contracts and gains on dispositions.

For the twelve months ended December 31, 2011, Delphi's net earnings were $11.6 million ($0.10 per basic share) compared to a net loss of $17.0 million ($0.16 per basic share) in the same period in 2010. The increase in net earnings in 2011 compared to 2010 is primarily due to higher commodity prices for crude oil and natural gas liquids in combination with an increase in production of crude oil and natural gas liquids, a decrease in impairment losses and higher gains on dispositions partially offset by an increase in operating, transportation and deferred income taxes.

NETBACK ANALYSIS

How do Delphi's netbacks achieved in 2011 compare to 2010?

Delphi strives for an operating netback in the range of $22.00 to $25.00 per boe and a cash netback of $20.00 per boe. However, the Company's past track record of $20.00 per boe cash netback is expected to be under pressure in 2012 given the much weaker current and anticipated natural gas price environment.

For the fourth quarter of 2011, Delphi's cash netback per boe was 13 percent lower compared to the same period in 2010. The decrease is primarily due to an increase in royalties, operating expenses and transportation, partially offset by an increase in realized sales price and a decrease in general and administrative expenses and interest charges.

For the year ended December 31, 2011, the Company's cash net back per boe of $20.65 was comparable to the same period in 2010. In 2011, on a boe basis, the Company realized higher sales prices and lower operating, transportation, general and administrative and interest costs which were primarily offset by an increase in royalty expense.

The Company's operating and cash netbacks are primarily driven by the price received for natural gas, as the Company is predominantly a natural gas producer. As a result of the continued weakening of natural gas prices and in order to lower the risk of commodity price volatility, the Company has been focusing on increasing its light oil and natural gas liquids percentage of total production volumes in order to further strengthen its cash netback per boe.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2011	2010	% Change	**2011**	2010	% Change
Barrels of oil equivalent ($/boe)						
Realized sales price	**40.40**	38.79	4	**40.47**	39.71	2
Royalties	**7.28**	3.68	98	**6.41**	4.89	31
Operating expenses	**7.09**	5.87	21	**6.84**	7.44	(8)
Transportation	**2.89**	2.66	9	**2.97**	3.02	(2)
Operating netback	**23.14**	26.58	(13)	**24.25**	24.36	-
General and administrative expenses	**1.76**	2.18	(19)	**1.96**	2.18	(10)
Interest	**1.49**	1.66	(10)	**1.64**	1.72	(5)
Cash netback	**19.89**	22.74	(13)	**20.65**	20.46	1
Unrealized loss on commodity risk contracts	**3.42**	2.99	14	**0.56**	0.36	56
Exploration and evaluation	**-**	(0.06)	100	**-**	0.07	100
Stock-based compensation expense	**0.47**	0.25	88	**0.31**	0.35	(11)
Gain on dispositions	**(2.64)**	-	-	**(0.58)**	-	-
Loss on decommissioning	**0.53**	-	-	**0.14**	-	-
Depletion and depreciation	**15.52**	16.79	(8)	**14.52**	27.03	(46)
Accretion	**0.12**	0.17	(29)	**0.15**	0.18	(17)
Deferred income taxes	**1.51**	0.38	297	**1.97**	(1.76)	-
Net earnings (loss)	**0.96**	2.22	(57)	**3.58**	(5.77)	-

SELECTED INFORMATION

Over the past two years, how has Delphi performed and what significant factors contributed to the results?

Over the last eight quarters, average production has grown from 7,645 boe/d to 9,337 boe/d. In 2009, natural gas prices continued to weaken while crude oil market prices increased. As a result of the commodity price environment, Delphi's capital program in the second half of 2009 targeted drilling for crude oil while acquiring strategic natural gas properties and infrastructure. In the latter half of 2009, Delphi completed four natural gas property and infrastructure acquisitions in the Deep Basin of North West Alberta. In 2010, the Company continued to be successful in its drilling program and focused on light oil and liquids-rich natural gas opportunities. For the 2010 fourth quarter, the company produced an average of 8,539 boe/day, an increase of twenty four percent over the same period in 2009. In the first quarter of 2011, production decreased to 8,259 boe/d as a result of natural declines in production and an outage at a non-operated processing facility resulting in the shut-in of 550 boe/d for 22 days in the quarter. Record production in the fourth quarter of 2011 of 9,337 boe/d is a result of another successful year in the Company's drilling program.

Over the past two years, the changes in revenue and funds from operations from quarter to quarter primarily reflect the increased production volumes achieved, change in production product mix and the volatility of commodity prices.

Natural gas prices over the past two years have generally reflected the cyclical nature of demand. Higher prices have been realized in the winter months, reflecting demand for heating with lower prices through the summer months as production is placed in storage for the upcoming heating season demand. The average spot price for AECO in 2010 was $4.00 per mcf and in 2011, the average spot price for AECO was $3.63 per mcf. In 2010, WTI crude oil averaged U.S. $79.55, while in first half of 2011, crude oil prices increased exceeding U.S. $100 but have withdrawn in the second half of 2011. The average oil price in 2011 was U.S. $95.12.

Net earnings of the Company are primarily driven by the difference between the cash netback realized per boe of production versus the Company's depletion, depreciation and amortization ("DD&A") rate. The Company continues to reduce its DD&A rate by finding and developing reserves at a cost less than the average DD&A rate. Overall finding and development ("F&D") costs were $14.91 per proved plus probable boe in 2010 and $12.46 per proved plus probable reserve in 2011.

The following table sets forth certain information of the Company for the past eight consecutive quarters outlining this performance.

	Dec. 31 2011	Sept. 30 2011	Jun. 30 2011	Mar. 31 2011	Dec. 31 2010	Sep. 30 2010	Jun. 30 2010	Mar. 31 2010
Production								
Oil (bbls/d)	**1,436**	1,395	1,346	1,102	1,147	831	1,074	745
Natural gas liquids (bbls/d)	**1,405**	1,074	1,317	1,072	906	710	538	508
Natural gas (mcf/d)	**38,973**	38,989	37,460	36,509	38,918	39,439	38,540	38,349
Barrels of oil equivalent (boe/d)	**9,337**	8,967	8,906	8,259	8,539	8,114	8,035	7,645
Financial								
($ thousands except per unit amounts)								
Petroleum and natural gas revenue	**33,115**	32,194	32,678	28,900	29,792	26,554	27,970	29,519
Funds from operations	**17,081**	17,213	17,517	15,061	17,868	14,988	12,507	15,049
Per share – basic	**0.14**	0.15	0.15	0.13	0.16	0.13	0.12	0.15
Per share – diluted	**0.14**	0.14	0.15	0.13	0.16	0.13	0.12	0.15
Net earnings (loss)	**825**	4,058	5,757	962	1,744	(20,472)	(131)	1,613
Per share – basic	**0.01**	0.03	0.05	0.01	0.02	(0.18)	-	0.02
Per share – diluted	**0.01**	0.03	0.05	0.01	0.02	(0.18)	-	0.02

On an annual basis, how has Delphi performed?

The annual results for 2010 compared to 2009 were impacted by fluctuating commodity prices and an increase in capital spending. In light of the weak crude oil and natural gas prices in 2009, the Company shifted its drilling program to target opportunities in its crude oil and liquids-rich natural gas inventory to maximize netbacks. In 2010, the Company invested $104.7 million compared to $60.1 million in 2009. As a result of a successful drilling program, production in 2010 increased 19 percent from 2009. The improvement in commodity prices and increased production levels contributed to the higher revenues in 2010 compared to 2009.

In 2011, the Company continued to focus on exploiting its crude oil and liquids-rich natural gas opportunities and invested $101.9 million in net capital. Although natural gas prices continued to weaken in 2011, pricing for crude oil and natural gas liquids improved, allowing the Company to realize higher netbacks for its crude oil and natural gas liquids.

The following table sets forth selected consolidated financial information of the Company for the most recently completed year ended December 31, 2011 and for the years ended 2010 and 2009. The adoption of IFRS as of January 1, 2011 requires restatement for comparative purposes, of the Company's opening balance sheet as at January 1, 2010 and for its year ended December 31, 2010. As a result, 2009 comparative information has not been restated and is in accordance with previous GAAP.

	2011	2010	2009 Previous GAAP
Revenue	**126,887**	113,772	98,164
Net earnings (loss)	**11,602**	(16,984)	(8,029)
Per share – basic	**0.10**	(0.16)	(0.10)
Per share – diluted	**0.10**	(0.16)	(0.10)
Total assets	**447,073**	386,737	361,698
Bank debt plus working capital deficiency [(1)]	**95,632**	108,054	92,538

(1) The Company's calculation of working capital deficiency excludes the fair value of financial instruments.

LIQUIDITY AND CAPITAL RESOURCES

Share Capital

What has been the market activity in the Company's common shares?

At December 31, 2011, the Company had 131.0 million common shares outstanding (December 31, 2010 – 112.8 million). The common shares of Delphi trade on the TSX under the symbol DEE. The following table summarizes outstanding share data for the three and twelve months ended December 31, 2011:

	Three Months Ended December 31	Twelve Months Ended December 31
Weighted Average Common Shares		
Basic	119,252	116,935
Diluted	120,675	118,800
Trading Statistics [(1)]		
High	2.30	2.89
Low	1.43	1.43
Average daily volume	361,878	483,566

(1) Trading statistics based on closing price

How many common shares and stock options are currently outstanding?

As at March 7, 2012, the Company had 131.0 million common shares outstanding and 10.8 milllion share options outstanding. The share options have an average exercise price of $1.90 per option.

Sources and Uses of Funds

	Three Months Ended December 31, 2011	Twelve Months Ended December 31, 2011
Sources:		
Cash and cash equivalents	**5,865**	**22**
Funds from operations	**17,081**	**66,872**
Disposition of petroleum and natural gas properties	**4,835**	**12,873**
Issue of flow-through common shares, net of issue costs	**7,182**	**16,111**
Issue of common shares, net of issue costs	**20,920**	**20,920**
Exercise of stock options	**151**	**2,575**
Change in non-cash working capital	**7,087**	**17,629**
	63,121	**137,002**
Uses:		
Capital expenditures	**(37,282)**	**(114,477)**
Accretion of long term debt	**83**	**(257)**
Acquisition of petroleum and natural gas properties	**(56)**	**(273)**
Expenditures on decommissioning	**(588)**	**(588)**
	(37,843)	**(115,595)**
Change in long term debt	**(25,278)**	**(21,407)**

Bank Debt plus Working Capital Deficiency (Net Debt)

What is liquidity risk and how does the Company manage this risk?

Liquidity risk is the risk that Delphi will not be able to meet its financial obligations as they become due. Delphi actively manages its liquidity through daily and longer-term cash, debt and equity management strategies. Such strategies encompass, among other factors: having adequate sources of financing available through its bank credit facilities, estimating future cash generated from operations based on reasonable production and pricing assumptions, analysis of economic risk management opportunities, and maintaining sufficient cash flows for compliance with financial debt covenants.

As an oil and gas business, Delphi has a declining asset base and therefore relies on ongoing development and acquisitions to replace production and add additional reserves. Future oil and natural gas production and reserves are highly dependent on the success of exploiting the Company's existing asset base and in acquiring additional reserves. To the extent Delphi is successful or unsuccessful in these activities; cash flow could be increased or reduced.

Delphi generally relies on operating cash flows and its credit facilities to fund capital requirements and provide liquidity. Future liquidity depends primarily on cash flow generated from operations, existing credit facilities and the ability to access debt and equity markets. From time to time, the Company accesses capital markets to meet its additional financing needs and to maintain flexibility in funding its capital programs. While Delphi recently completed a $30.0 million offering on a bought deal basis on December 23, 2011, there can be no assurance that future debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to Delphi.

Delphi's results are affected by external market and risk factors, such as fluctuations in the prices of crude oil and natural gas, movements in foreign currency exchange rates and inflationary pressures on service costs. As an added layer of protection of its cash flows, Delphi has fixed financial contracts that provide for approximately 20 percent of its before-royalty natural gas production at predominantly AECO based average floor price of $3.03 per mcf for 2012.

How much bank debt was outstanding on December 31, 2011?

At December 31, 2011, the Company had $79.4 million outstanding in the form of bankers' acceptances, $3.0 million drawn under Canadian-based prime loans and a working capital deficiency of $13.2 million for total net debt of $95.6 million. Net debt is a non-IFRS term. Delphi's calculation of net debt includes long-term debt and the net working capital deficiency (excess) before the current fair value of financial instruments.

What are the Company's credit facilities and when is the next scheduled review of the borrowing base?

The Company has a $145.0 million extendible revolving term credit facility with a syndicate of Canadian chartered banks, subject to the banks' semi-annual valuation of the Company's crude oil and natural gas properties. The facility is a 364 day committed facility available on a revolving basis until May 28, 2012 at which time it may be extended at the lenders' option. If the revolving period is not extended, the undrawn portion of the facility will be cancelled and the amount outstanding will convert to a 365 day non-revolving term facility. The amounts outstanding under the non-revolving facility are required to be repaid at the end of the non-revolving term being May 28, 2013. The non-extension provisions are applicable to the lenders on an individual basis.

Interest payable on amounts drawn under the facility is at the prevailing bankers' acceptance rates plus stamping fees, lenders' prime rate, US base rate or LIBOR plus the applicable margins, depending on the form of borrowing by the Company. The applicable margins and stamping fees are based on a sliding scale pricing grid tied to the Company's trailing debt to annualized quarterly cash flow ratio: from a minimum of the bank's prime rate or US base rate plus 1.25 percent to a maximum of the bank's prime rate or US base rate plus 4.25 percent or from a minimum of bankers' acceptances rate plus a stamping fee of 2.25 percent to a maximum of bankers' acceptances rate plus a stamping fee of 4.25 percent.

Under the terms of the credit facility, the Company covenants that it will maintain a working capital ratio of at least one to one. For the purpose of this ratio, the undrawn portion of the credit facility is added to current assets in the working capital calculation. The credit facility is secured by a $200.0 million demand floating charge debenture and a general security agreement over all assets of the Company. Delphi is in compliance with the covenants of its credit facility as at December 31, 2011.

Contractual Obligations

Does the Company have any contractual obligations as of December 31, 2011 that will require funding in future years?

The Company is committed to future minimum payments for natural gas transmission and processing and operating leases on compression equipment. The Company also has a lease for office space in Calgary, Alberta. As noted above, bank debt is based on a revolving term which is reviewed annually and converts to a 365 day non-revolving term facility if not renewed.

The future minimum commitments over the next five years are as follows:

	2012	2013	2014	2015	2016
Gathering, processing and transmission	6,712	5,403	3,178	3,150	-
Office and equipment lease	811	631	509	509	522
Bank debt	-	83,000	-	-	-
Total	7,523	89,034	3,687	3,659	522

As a result of the flow-through shares issued on December 23, 2011, Delphi is committed to incur approximately $8.0 million in qualifying Canadian exploration expenses on or before December 31, 2012.

As at December 31, 2011, Delphi was committed to drill one well pursuant to an agreement which will allow the Company to earn a 75 percent working interest on five sections of land. Delphi expects to satisfy the drilling commitment at an estimated cost of approximately $8.0 million.

GUARANTEES AND OFF-BALANCE SHEET ARRANGEMENTS

Does Delphi have any outstanding guarantees on behalf of third parties or any off-balance sheet arrangements which could lead to liabilities in the future?

Delphi has not entered into any guarantees or off-balance sheet arrangements. Certain lease agreements entered into in the normal course of operations could be considered off-balance sheet arrangements; however, all leases are operating leases with lease payments charged to operating expenses or general and administrative expenses on a monthly basis according to the lease.

CRITICAL ACCOUNTING ESTIMATES

In preparing the Company's consolidated financial statements, is Delphi required to make estimates or assumptions about future events?

The consolidated financial statements have been prepared in conformity with IFRS which requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, shareholders' equity, revenue and expenses. Actual results may differ from these estimates.

Estimates and their underlying assumptions are reviewed on an ongoing basis. Delphi attempts to mitigate this risk by employing individuals with the appropriate skill set and knowledge to make reasonable estimates, developing internal control systems and comparing past estimates to actual results. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected.

The judgments, estimates and assumptions that have the most significant effect on the amounts recognized in the consolidated financial statements are included in the following:

i) estimated fair values of derivative contracts that are subject to fluctuation depending upon the underlying commodity prices;
ii) estimated depletion, depreciation, and amortization charges that are based on estimates of oil and natural gas reserves that Delphi expects to recover in the future;
iii) estimated value of decommissioning obligations that are dependent upon estimates of future costs and timing of expenditures;
iv) estimated future recoverable value of property, plant and equipment and any associated impairment charges or recoveries;
v) estimated compensation expense under Delphi's share-option plan and the estimate of the inputs for calculating the fair value of options granted; and
vi) estimated deferred income tax assets and liabilities based on current tax interpretations, regulations and legislation that is subject to change.

Estimates of proved plus probable reserves have an effect on a number of the areas referred to above, in particular, the valuation of property, plant and equipment and the calculation of depletion and depreciation.

NEW ACCOUNTING STANDARDS

Are there any new accounting standards which the Company has had to adopt and comply with?

International Financial Reporting Standards ("IFRS")

The Company adopted IFRS effective January 1, 2011. As a result, the Company has prepared its consolidated financial statements for the year ended December 31, 2011 under IFRS and has restated its consolidated financial statements for the year ended December 31, 2010 to comply with IFRS. The financial information presented in this MD&A is derived directly from Delphi's financial statements and as such certain comparative information may differ from what was originally presented by Delphi using previous Canadian generally accepted accounting principles ("previous GAAP").

Delphi's consolidated financial statements as at and for the periods ended December 31, 2011 and 2010 have been prepared in accordance with IFRS 1 – First–time Adoption of International Financial Reporting Standards under IFRS as issued by the International Accounting Standards Board.

For further details on the Company's transition to IFRS, refer to note 22 of the Company's consolidated financial statements for the year ended December 31, 2011.

Are there any future accounting standards which the Company will have to comply with in the future?

The following new and amended standards have been issued by the International Accounting Standards Board ("IASB"):

- IFRS 9, "Financial Instruments", which is the result of the first phase of the IASB's project to replace IAS 39, "Financial Instruments: Recognition and Measurement". The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value. The effective date for this standard has been deferred to January 1, 2015.

- IFRS 11, "Joint Arrangements" ("IFRS 11"), requires a venturer to classify its interest in a joint arrangement as a joint venture or joint operation, each having its own accounting model. Joint ventures will be accounted for using the equity method of accounting whereas for a joint operation the venture will recognize its share of the assets, liabilities, revenue and expenses of the joint operation. The standard provides for a more substance based reflection of joint arrangements by focusing on the rights and obligations of the arrangement, rather than its legal form. The new standard replaces IAS 31, "Interests in Joint Ventures" and SIC – 13, "Jointly Controlled Entities – Non-monetary Contributions by Venturers" and establishes principles for accounting for all joint arrangements.

- IFRS 12, "Disclosure of Interests in Other Entities", which outlines the required disclosures for interests in subsidiaries and joint arrangements. The new disclosures require information that will assist financial statement users to evaluate the nature, risks and financial effects associated with an entity's interests in subsidiaries and joint arrangements.

- IFRS 13, "Fair Value Measurement" which defines fair value, establishes a framework for measuring fair value and sets out disclosure requirements for fair value measurements.

- IAS 28, "Investments in Associates and Joint Ventures" has been amended to conform to the changes made in IFRS 10 and IFRS 11.

Except as noted above, all of the above pronouncements are effective for annual periods beginning on or after January 1, 2013, with early adoption permitted. The Company is currently evaluating the impact of adopting these standards.

CORPORATE GOVERNANCE

Overview

The shareholders' interests are a critical factor in the operations and management of Delphi. The Company is committed to maintaining the highest level of investor confidence in the Company through the application of its corporate policies and procedures. Delphi's Board of Directors consists of six independent directors and two officers of the Company who meet regularly to discuss matters of strategy and execution of the business plan. See Delphi's Management Information Circular and Annual Information Form for a listing of committees that oversee specific aspects of the Company's operating and financial strategy.

Disclosure Controls and Procedures and Internal Controls over Financial Reporting

Disclosure controls and procedures are designed to ensure that information required to be disclosed by the Company is accumulated and communicated to the issuer's management, including its President and Chief Executive Officer and Vice President, Finance and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The Company's President and Chief Executive Officer and Senior Vice President, Finance and Chief Financial Officer have concluded that the Company's disclosure controls and procedures are effective and provide a reasonable level of assurance that information required to be disclosed by the Company is recorded, processed, summarized and reported within the time periods specified.

The Company notes that while it believes the disclosure controls and procedures and internal controls over financial reporting provide a reasonable level of assurance that they are effective, it does not expect that the disclosure controls and procedures and internal controls will prevent all errors and fraud. A control system is designed to provide reasonable, not absolute, assurance that the objectives of the control system are met. There were no changes made to the disclosure controls and procedures or internal controls over financial reporting as a result of the transition to IFRS.

ADDITIONAL INFORMATION

Where is additional information about Delphi available?

Additional information about Delphi Energy is available on the Canadian Securities Administrators' System for Electronic Distribution and Retrieval (SEDAR) at www.sedar.com, at the Company's website at www.delphienergy.ca or by contacting the Company at Delphi Energy Corp. Suite 300, 500 – 4th Avenue S.W., Calgary, Alberta, T2P 2V6 or by e-mail at info@delphienergy.ca.

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Delphi Energy Corp.

We have audited the accompanying consolidated financial statements of Delphi Energy Corp., which comprise the consolidated statements of financial position as at December 31, 2011, December 31, 2010 and January 1, 2010, the consolidated statements of earnings and comprehensive earnings, changes in shareholders' equity and cash flows for the years ended December 31, 2011 and December 31, 2010, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Delphi Energy Corp. as at December 31, 2011, December 31, 2010 and January 1, 2010, and its consolidated financial performance and its consolidated cash flows for the years ended December 31, 2011 and December 31, 2010 in accordance with International Financial Reporting Standards.

(signed) KPMG LLP
Chartered Accountants

Calgary, Canada
March 13, 2012

DELPHI ENERGY CORP.

Consolidated Statements of Financial Position

(thousands of dollars)	**December 31 2011**	December 31 2010	January 1 2010
		(Note 22)	(Note 22)
Assets			
Current assets			
Cash and cash equivalents	**4,017**	4,039	-
Accounts receivable (Note 8)	**18,770**	17,897	15,630
Prepaid expenses and deposits	**2,939**	2,476	5,389
Assets held for sale (Note 9)	**9,680**	-	2,804
Fair value of financial instruments (Note 6)	**546**	2,080	104
	35,952	26,492	23,927
Exploration and evaluation (Note 10)	**18,699**	2,787	315
Property, plant and equipment (Note 11)	**392,422**	357,458	332,938
Total assets	**447,073**	386,737	357,180
Liabilities			
Current liabilities			
Outstanding cheques	**-**	-	139
Accounts payable and accrued liabilities (Note 12)	**47,451**	28,416	32,933
Liabilities held for sale (Note 9)	**377**	-	2,554
Decommissioning obligations (Note 14)	**825**	-	-
Fair value of financial instruments (Note 6)	**21**	-	-
	48,674	28,416	35,626
Other liability (Note 16)	**1,334**	-	960
Long term debt (Note 13)	**82,385**	104,050	80,485
Decommissioning obligations (Note 14)	**19,288**	17,232	15,496
Fair value of financial instruments (Note 6)	**3,772**	3,527	485
Deferred income taxes (Note 15)	**23,245**	16,552	21,144
	178,698	169,777	154,196
Shareholders' equity			
Share capital (Note 16)	**275,682**	236,382	206,382
Contributed surplus	**12,500**	11,987	11,027
Deficit	**(19,807)**	(31,409)	(14,425)
Total shareholders' equity	**268,375**	216,960	202,984
Total liabilities and shareholders' equity	**447,073**	386,737	357,180

Commitments (Note 20)
See accompanying notes to the consolidated financial statements.

Approved on behalf of the Board of Directors:

(signed) "Stephen Mulherin"
Stephen Mulherin
Director

(signed) "Andrew E. Osis"
Andrew E. Osis
Director

DELPHI ENERGY CORP.

Consolidated Statements of Earnings and Comprehensive Earnings
For the years ended December 31, 2011 and 2010

(thousands of dollars, except per share amounts)	2011	2010
		(Note 22)
Revenue		
Crude oil and natural gas sales	**126,887**	113,772
Royalties	**(20,739)**	(14,420)
	106,148	99,352
Realized gain on financial instruments (Note 6)	**4,140**	3,427
Unrealized loss on financial instruments (Note 6)	**(1,800)**	(1,066)
	108,488	101,713
Expenses		
Operating	**22,144**	21,955
Transportation	**9,630**	8,908
Exploration and evaluation	**-**	195
General and administrative	**6,343**	6,429
Share-based compensation (Note 16)	**992**	1,027
Gain on property dispositions	**(1,866)**	-
Loss on decommissioning	**457**	-
Depletion and depreciation (Note 11)	**47,035**	79,778
	84,735	118,292
Finance costs (Note 17)	**(5,782)**	(5,594)
Earnings (loss) before income taxes	**17,971**	(22,173)
Income taxes		
Deferred income taxes (recovery) (Note 15)	**6,369**	(5,189)
Net earnings (loss) and comprehensive earnings (loss)	**11,602**	(16,984)
Net earnings (loss) per share (Note 16)		
Basic	**0.10**	(0.16)
Diluted	**0.10**	(0.16)

See accompanying notes to the consolidated financial statements.

DELPHI ENERGY CORP.

Consolidated Statements of Changes in Shareholders' Equity
For the years ended December 31, 2011 and 2010

(thousands of dollars)	**2011**	2010
		(Note 22)
Share capital		
Common shares		
Balance, beginning of year	**236,382**	206,382
Issued for cash	**22,011**	30,250
Issued for cash on a flow-through basis	**14,801**	-
Issued on exercise of options	**2,575**	775
Transferred on exercise of options	**1,347**	418
Share issue costs, net of tax	**(1,434)**	(1,443)
Balance, end of year	**275,682**	236,382
Contributed surplus		
Balance, beginning of year	**11,987**	11,027
Share-based compensation	**1,860**	1,378
Transferred on exercise of options	**(1,347)**	(418)
Balance, end of year	**12,500**	11,987
Deficit		
Balance, beginning of year	**(31,409)**	(14,425)
Net earnings (loss)	**11,602**	(16,984)
Balance, end of year	**(19,807)**	(31,409)
Total shareholders' equity	**268,375**	216,960

See accompanying notes to the consolidated financial statements.

DELPHI ENERGY CORP.

Consolidated Statements of Cash Flows
For the years ended December 31, 2011 and 2010

(thousands of dollars)	**2011**	2010
		(Note 22)
Cash flow from (used in) operating activities		
Net earnings (loss)	**11,602**	(16,984)
Add non-cash items:		
Depletion and depreciation	**47,035**	79,778
Accretion of decommissioning obligations	**483**	519
Share-based compensation	**992**	1,027
Gain on property dispositions	**(1,866)**	-
Exploration and evaluation expenses	**-**	195
Loss on decommissioning	**457**	-
Unrealized loss on financial instruments	**1,800**	1,066
Deferred income taxes	**6,369**	(5,189)
Accretion of long term debt	**(257)**	(429)
Decommissioning expenditures	**(588)**	(265)
Change in non-cash working capital (Note 21)	**2,273**	(1,819)
	68,300	57,899
Cash flow from (used in) financing activities		
Issue of common shares, net of issue costs	**20,920**	28,284
Issue of flow-through common shares, net of issue costs	**16,111**	-
Exercise of options	**2,575**	775
Increase (decrease) in long term debt	**(21,407)**	23,994
Change in non-cash working capital (Note 21)	**300**	-
	18,499	53,053
Cash flow available for investing activities	**86,799**	110,952
Cash flow from (used in) investing activities		
Additions to exploration and evaluation	**(15,912)**	(2,667)
Additions to property, plant and equipment	**(98,565)**	(102,283)
Disposition of petroleum and natural gas properties	**12,873**	246
Acquisition of petroleum and natural gas properties	**(273)**	(18)
Change in non-cash working capital (Note 21)	**15,056**	(2,052)
	(86,821)	(106,774)
Increase (decrease) in cash and cash equivalents	**(22)**	4,178
Cash and cash equivalents, beginning of year	**4,039**	(139)
Cash and cash equivalents, end of year	**4,017**	4,039
Cash interest paid	**6,021**	5,003

See accompanying notes to the consolidated financial statements.

1) STRUCTURE OF DELPHI

Delphi Energy Corp. ("Delphi" or "the Company") is a publicly-traded company engaged in the exploration for, development and production of crude oil and natural gas from properties and assets located in Western Canada in which it holds an interest. The Company's operations are primarily concentrated in the Deep Basin of North West Alberta, representing in excess of 90 percent of the Company's production. The registered office of the Company is located at Suite 300, 500 – 4th Avenue S.W., Calgary, Alberta, T2P 2V6.

The consolidated financial statements as at and for the year ended December 31, 2011 comprise the accounts of the Company, its wholly-owned subsidiary and a partnership.

2) BASIS OF PRESENTATION

(a) Statement of compliance

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). These are the Company's first consolidated annual financial statements prepared in accordance with IFRS and IFRS 1 *First-time Adoption of International Financial Reporting Standards* has been applied.

Previously, the Company prepared its consolidated annual and consolidated interim financial statements in accordance with Canadian Generally Accepted Accounting Principles ("Previous GAAP"). Previous GAAP differs in some areas from IFRS. An explanation and reconciliations of how the transition to IFRS has affected the previously reported consolidated financial position, financial performance and cash flows of the Company is provided in note 22.

These consolidated financial statements were approved and authorized for issuance by the Board of Directors on March 13, 2012.

(b) Basis of measurement and functional currency

The consolidated financial statements have been prepared on a going concern basis, using historical costs, except for derivative financial instruments which are measured at fair value. The financial statements are presented in Canadian dollars, the Company's functional currency.

(c) Use of estimates and judgments

The preparation of the consolidated financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts in the consolidated financial statements and accompanying notes. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be material. Actual results may differ from these estimates. Estimates and their underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected.

Significant areas of estimation, uncertainty and critical judgments in applying accounting policies that impact the amounts recognized in the consolidated financial statements include:

i) Financial instruments
The fair value of the Company's financial contracts are based on forward curves as at the reporting date which may differ from what will eventually be realized. Changes in the fair value of the financial contracts are recognized in the consolidated statement of earnings. The actual gains or losses realized on eventual cash

settlement can vary due to subsequent fluctuations in commodity prices.

ii) Depreciation and depletion

Management estimates the useful lives of production equipment and other assets based on the period during which the assets are expected to be available for use. For crude oil and natural gas properties, the estimated useful lives are based on proved and probable reserves as determined annually by the Company's independent engineers and internal estimates on a quarterly basis determined in accordance with National Instrument 51-101 ("NI 51-101") and the Canadian Oil and Gas Evaluation Handbook ("COGEH").

Calculations for the depletion of crude oil and natural gas properties are based on total capitalized costs plus estimated future development costs of proved and probable reserves less the estimated net realizable value of production equipment and facilities after the proved reserves are fully produced.

iii) Cash generating unit ("CGU")

The determination of Delphi's CGUs was based on management's judgment and evaluation of the geography, geology, production profile and infrastructure of its assets. The Company's CGUs could change in the future as a result of acquisition or disposition activity.

iv) Recoverability of property, plant and equipment and exploration and evaluation

The Company assesses its oil and gas properties, including exploration and evaluation assets, for possible impairment if there are events or changes in circumstances that indicate that carrying values of the assets may not be recoverable. Determining if there are facts and circumstances present that indicate that carrying values of the assets may not be recoverable requires management's judgment and analysis of the facts and circumstances.

The assessment of any impairment of property, plant and equipment is dependent upon estimates of recoverable amount that take into account factors such as reserves, economic and market conditions, discount rates, timing of cash flows, the useful lives of assets and their related salvage values. In assessing whether oil and gas properties are impaired, each CGUs carrying value is compared to its recoverable amount, defined as the greater of its fair value less costs to sell and value in use.

The recoverable amount of Delphi's CGUs were estimated as their fair value less costs to sell based on the following information:

- the net present value of the after-tax cash flows from oil and gas reserves of each CGU based on reserves estimated by the Company's independent engineers; and
- the fair value of undeveloped land based on estimates provided by Delphi's independent land evaluator.

Key input estimates used in the determination of cash flows from oil and gas reserves include the following:

- Reserves. Assumptions that are valid at the time of reserve estimation may change significantly when new information becomes available. Changes in forward commodity price estimates, production costs or recovery rates may change the economic status of reserves and may ultimately result in reserves being adjusted.

- Oil and gas prices. Forward price estimates of oil and natural gas prices are used in the cash flow model. Commodity prices have fluctuated widely in recent years due to global and regional factors including supply and demand fundamentals, inventory levels, exchange rates, weather, economic and geopolitical factors.

- Discount rate. The discount rate used to calculate the net present value of cash flows is based on estimates of an approximate industry peer group weighted average cost of capital. Changes in the general economic environment could result in significant changes to this estimate.

v) Decommissioning obligations

Provisions for decommissioning obligations associated with the Company's drilling operations are based on current legal and constructive requirements, technology, price levels and expected plans for remediation. Actual costs and timing of cash outflows can differ from estimates because of changes in laws and regulations, public expectations, prices, discovery and analysis of site conditions and changes in clean up technology.

vi) Share-based compensation

The fair value of stock options granted is measured using a Black-Scholes model. Measurement inputs such as the expected volatility, expected life of the options and a forfeiture rate require management judgment and estimates. The Company estimates volatility based on historical share price and the expected life of the options is estimated to correlate with the term of the options. Management also makes an estimate of the number of options that will forfeit and the forfeiture rate is adjusted to reflect actual forfeitures.

vii) Deferred income taxes

Related assets and liabilities are recognized for the estimated tax consequences between amounts included in the financial statements and their tax base using substantively enacted future income tax rates. Timing of future revenue streams and future capital spending changes can affect the timing of the reversal of temporary differences and accordingly affect the amount of the deferred income tax asset or liability calculated at a point in time. These differences could materially impact earnings.

Estimates of recoverable quantities of proved plus probable oil and natural gas reserves have an effect on a number of the areas referred to above, in particular, the valuation of property, plant and equipment and the calculation of depletion and depreciation. There are numerous uncertainties inherent in estimating oil and natural gas reserves. Estimating reserves is very complex, requiring many judgments based on commodity prices, exchange rates, discount rates and production and transportation costs for future cash flows. It also requires interpretation of complex geological and geophysical models in order to make an assessment of the size, shape, depth and quality of reservoirs and their anticipated recoveries. The economic, geological and technical factors used to estimate reserves may change from period to period. Changes in these judgments could have a material impact on the estimated reserves. These estimates may change, having either a negative or positive effect on net earnings as further information becomes available and as the economic environment changes. Reserve estimates are prepared in accordance with NI 51-101 and COGEH and are reviewed by third party reservoir engineers.

3) SIGNIFICANT ACCOUNTING POLICIES

The accounting policies set out below have been applied consistently to all periods presented in these consolidated financial statements and in preparing the opening IFRS statement of financial position at January 1, 2010 for the purposes of the transition to IFRS.

(a) Basis of consolidation

The consolidated financial statements include the accounts of the Company, its wholly-owned subsidiary and a partnership. Any reference throughout these consolidated financial statements refers to the Company and its wholly-owned subsidiary and partnership. All inter-entity transactions and balances have been eliminated.

(b) Jointly controlled operations

Certain of the Company's crude oil and natural gas activities involve jointly controlled operations. The consolidated financial statements reflect the Company's proportionate share of the jointly controlled assets and liabilities and proportionate share of related revenues and costs.

(c) Foreign currency transactions

Transactions in foreign currencies are translated to Canadian dollars at the exchange rate on the date of the transactions. Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars at the period end exchange rate. Foreign currency differences arising on translation are recognized in the consolidated statement of earnings.

(d) Financial instruments

A financial instrument is any contract that gives rise to a financial asset of one entity and a financial liability or equity instrument of another entity. All financial instruments, including all derivatives, are recognized on the balance sheet at fair value at the time the Company becomes a party to the provisions of the contract. Subsequently, all financial assets and liabilities, except financial assets carried at fair value through earnings or loss and available-for-sale, are measured at amortized cost determined using the effective interest method. Financial assets carried at fair value through earnings or loss are measured at fair value with changes in fair value recognized in the consolidated statement of earnings. Available-for-sale financial assets are measured at fair value with changes in fair value recognized in other comprehensive earnings and reclassified to earnings when derecognized or impaired. The Company does not hold any available-for-sale financial assets.

Transaction costs attributable to financial instruments carried at fair value through earnings or loss are expensed as incurred. All other transaction costs related to the Company's financial instruments are recorded as part of the instrument and are amortized using the effective interest method.

Financial assets and liabilities are offset and the net amount presented in the consolidated statement of financial position when, and only when, the Company has the legal right to offset the amounts and intends either to settle on a net basis or to realize the asset and settle the liability simultaneously.

The Company derecognizes a financial asset when the contractual rights to the cash flows from the asset expire or if it transfers the rights to receive the contractual cash flows on the financial asset in a transaction in which substantially all the risk and rewards of ownership of the financial asset are transferred. Any interest in transferred financial assets that is created or retained by the Company is recognized as a separate asset or liability. The Company derecognizes a financial liability when its contractual obligations are discharged, cancelled or expired.

The Company has the following classifications:

Financial Assets and Liabilities	**Category**	**Subsequent Measurement**
Cash and cash equivalents	Loans and receivables	Amortized cost
Accounts receivable	Loans and receivables	Amortized cost
Derivative instruments	Financial assets or liabilities at fair value through earnings or loss	Fair value through earnings or loss
Accounts payable and accrued liabilities	Financial liabilities	Amortized cost
Long-term debt	Financial liabilities	Amortized cost

The Company has a risk management program whereby the commodity price associated with a portion of its future production volumes is fixed in order to mitigate cash flow volatility resulting from fluctuating commodity prices. The Company sells forward a portion of its future production volumes by entering into a combination of physical sale contracts with customers and derivative financial contracts such as fixed price contracts, costless collars and the purchase of floor price options with financial counterparties. These instruments are not used for trading or speculative purposes.

The Company has not designated its financial derivative contracts as effective accounting hedges and thus has not applied hedge accounting. As a result, financial derivatives are classified as fair value through earnings or loss and are recorded on the balance sheet at fair value.

The Company accounts for its commodity sales and purchase contracts, which were entered into and continue to be held for the purpose of receipt or delivery of non-financial items in accordance with its expected purchase, sale or usage requirements as executory contracts. As such, these contracts are not considered to be derivative financial instruments and have not been recorded at fair value on the balance sheet. Settlements on these physical sales contracts are recognized in crude oil and natural gas sales in the consolidated statement of earnings.

Embedded derivatives are separated from the host contract and accounted for separately if 1) the economic characteristics and risks of the host contract and the embedded derivative are not closely related, 2) a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative and 3) the combined instrument is not measured at fair value through profit or loss. Changes in the fair value of embedded derivatives are recognized in the consolidated statement of earnings.

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares and share options are recognized as a deduction from equity, net of any taxes.

(e) Property, plant and equipment and exploration and evaluation

i) Recognition and measurement

Costs incurred before acquiring the legal right to explore in a specific area do not meet the definition of an asset and therefore are expensed by the Company as incurred.

Exploration and evaluation costs
Exploration and evaluation costs, including the costs of acquiring licenses and directly attributable general and administrative costs, are initially capitalized as exploration and evaluation assets. The costs are accumulated in cost centres by well, field or exploration area pending determination of technical feasibility and commercial viability.

The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proved plus probable reserves are determined to exist. A review of each exploration license or field is carried out, at least annually, to ascertain whether proved plus probable reserves have been discovered. Upon determination of total proved plus probable reserves, exploration and evaluation assets attributable to those reserves are first tested for impairment and then reclassified from exploration and evaluation assets to property, plant and equipment.

Development and production costs
Items of property, plant and equipment, which include crude oil and natural gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Cost includes expenditures that are directly attributable to the acquisition of the asset. CGUs are defined as the smallest identifiable group of assets that generate cash inflows and are largely independent of the cash inflows from other assets or group of assets. Within a CGU, when significant parts of property, plant and equipment have different useful lives, the parts are accounted for as separate items (major components) of property, plant and equipment.

Gains and losses on the disposition of property, plant and equipment, including crude oil and natural gas interests, are determined by comparing the proceeds from disposition with the carrying amount of the property, plant and equipment and are recognized on a net basis in the consolidated statement of earnings.

ii) Subsequent costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as crude oil and natural gas interests only when it is probable that the costs increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in the consolidated statement of earnings as incurred. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved or proved plus probable reserves and bringing on or enhancing production from such reserves and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property, plant and equipment are recognized in the consolidated statement of earnings as incurred.

iii) Depletion and depreciation

The net carrying amount of development and production assets is depleted using the unit-of-production method by reference to the ratio of production in the period to the related proved plus probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. Future development costs are estimated taking into account the level of development required to produce the reserves. These estimates are reviewed by the Company's independent engineers at least annually and determined in accordance with NI 51-101 and COGEH. For the purpose of this calculation, production and reserves of petroleum and natural gas are converted to a common unit of measure on the basis of their relative energy content, where six thousand cubic feet of natural gas equates to one barrel of oil.

The estimated useful lives for certain production assets for the current and comparative periods are as follows:

Facilities	33 years
Crude oil and natural gas properties	Based on reserve life

For other assets, depreciation is recognized in the consolidated statement of earnings on a declining balance basis over the estimated useful lives of each part of an item of property, plant and equipment. Leased assets are depreciated over the shorter of the lease term and their useful lives unless it is reasonably certain that the Company will obtain ownership by the end of the lease term.

The estimated useful lives for other assets for the current and comparative periods are as follows:

Furniture and office equipment	5 years
Leaseholds	Term of the lease

Depreciation methods, useful lives and residual values are reviewed at each reporting date.

(f) Assets held for sale

Non-current assets are classified as held for sale if their carrying amounts will be recovered through a sale transaction rather than through continuing use. This condition is met when the sale is highly probable and the asset is available for immediate sale in its present condition. For the sale to be highly probable, management must be committed to a plan to sell the asset and an active program to locate a buyer and complete the plan must have been initiated. The asset must be actively marketed for sale at a price that is reasonable in relation to its current fair value and the sale should be expected to be completed within one year from the date of classification.

Non-current assets classified as held for sale are measured at the lower of the carrying amount and fair value less costs to sell, with impairments recognized in the consolidated statement of earnings in the period measured. Non-current assets held for sale are presented in current assets and liabilities within the consolidated balance sheet. Assets held for sale are not depleted, depreciated or amortized.

(g) Impairment

(i) Financial assets

A financial asset not classified at fair value through earnings or loss is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in the consolidated statement of earnings.

An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in the consolidated statement of earnings.

(ii) Non-financial assets

The carrying amount of property, plant and equipment is reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. Exploration and evaluation assets are assessed for impairment if 1) sufficient data exists to determine technical feasibility and commercial viability and 2) facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of assessing impairment of oil and gas properties, assets are tested at the CGU level. The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell.

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved and probable reserves.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in the consolidated statement of earnings. Impairment losses recognized in respect of CGU's are allocated to reduce the carrying amounts of the assets in the unit on a pro rata basis.

Impairment losses in respect of property, plant and equipment and exploration and evaluation assets recognized in prior years are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized.

(h) Short term employee benefits

Short term employee benefit obligations are measured on an undiscounted basis and are expensed as the related service is provided. A liability is recognized for the amount expected to be paid under short term cash bonus plans if the Company has a present legal or constructive obligation to pay this amount as a result of past service provided by the employee, and the obligation can be estimated reliably.

(i) Share-based compensation

Long term incentives are granted to officers, directors, employees and certain consultants in accordance with the Company's stock option plan.

The fair value of stock options is assessed on the grant date using the Black-Scholes option pricing model. The fair value is subsequently recognized as share-based compensation over the vesting period with a corresponding increase in contributed surplus. Upon exercise of the options, consideration paid by the stock option holders and the value in contributed surplus pertaining to the exercised options are recorded as share capital.

A forfeiture rate is estimated on the grant date with the difference between the estimated and actual forfeitures adjusted through share-based compensation.

(j) Restricted share unit plan

The Company's restricted share unit ("RSU") plan is accounted for as a cash settled share-based payment plan. The fair value of the amount payable under the RSU plan is recognized as an expense with a corresponding increase in liabilities. The liability is remeasured at each reporting date and at settlement date. Any changes in the fair value of the liability are recognized in the consolidated statement of earnings.

(k) Lease payments

Payments made under operating leases are recognized in the consolidated statement of earnings on a straight-line basis over the term of the lease. Lease incentives received are recognized as an integral part of the total lease expense over the term of the lease.

(l) Provisions

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability if the risks have not been incorporated into the estimate of cash flows. Provisions are not recognized for future operating losses.

Decommissioning obligations

The Company's activities give rise to dismantling, decommissioning and site remediation activities. A provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning obligations are measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the balance sheet date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as finance costs whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established. The difference between the actual costs incurred and the provision established is recorded as a gain or loss in the consolidated statement of earnings.

(m) Flow-through shares

Resource expenditures for income tax purposes related to exploration and development activities funded by flow-through share arrangements are renounced to investors in accordance with income tax legislation. A liability is recognized for the premium on the flow-through shares, being the difference in price over a common share with no tax attributes and is subsequently reversed as the Company incurs qualifying expenditures. Any difference between the deferred liability set up for the premium on the flow-through shares and the tax effect on the qualifying expenditures incurred is recognized in deferred income tax expense in the consolidated statement of earnings.

(n) Revenues

Revenues from the sale of crude oil and natural gas are recorded when the significant risks and rewards of ownership of the product are transferred to the buyer which is usually when legal title passes to the external party. This is generally at the time product enters the pipeline.

Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

(o) Finance income and costs

Finance costs are comprised of interest expense and stamping fees on borrowings and accretion of the discount on provisions and decommissioning obligations.

(p) Income tax

Income tax expense comprises current and deferred tax. Income tax expense is recognized in the consolidated statement of earnings except to the extent that it relates to a business combination or items recognized directly in equity, in which case it is recognized in equity or other comprehensive income.

Current tax is the expected tax payable on the taxable income for the period, using tax rates enacted or substantively enacted at the reporting date and any adjustment to tax payable in respect of previous years.

Deferred taxes are recognized using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred taxes are not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination and that affects neither accounting nor taxable earnings. In addition, deferred taxes are not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred taxes are measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized for unused tax losses, tax credits and deductible temporary differences to the extent that it is probable that future taxable profits will be available against which the temporary differences can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

(q) Earnings per share

Basic earnings per share is calculated by dividing the net earnings or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted earnings per share is determined by adjusting the net earnings or loss attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments such as options granted to employees.

(r) Cash and cash equivalents

Cash and cash equivalents consist of cash balances, call deposits with original maturities of three months or less and outstanding cheques.

Bank overdrafts that are repayable on demand and form an integral part of the Company’s cash management are included as a component of cash and cash equivalents for the purpose of the consolidated statement of cash flows.

4) DETERMINATION OF FAIR VALUES

A number of the Company’s accounting policies and disclosures require the determination of fair value for both financial and non-financial assets and liabilities. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability. Fair values have been determined for measurement and/or disclosure purposes based on the following methods:

(a) Property, plant and equipment and intangible exploration assets:

The fair value of property, plant and equipment and exploration and evaluation assets recognized in a business combination are based on market values. The market value of property, plant and equipment and exploration and evaluation assets is the estimated amount for which the assets could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The market value of crude oil and natural gas interests (included in property, plant and equipment) is estimated with reference to the discounted cash flows expected to be derived from crude oil and natural gas production based on externally prepared reserve reports. The risk-adjusted discount rate is specific to the asset with reference to general market conditions.

The market value of other items of property, plant and equipment are based on the quoted market prices for similar items.

(b) Cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, decommissioning obligations and long term debt:

The fair value of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities and long term debt is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At December 31, 2011 and December 31, 2010, the fair value of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities approximated their carrying value due to their short term to maturity. In the case of long term debt, the fair value approximates its carrying value as it bears interest at floating rates and the applicable margin was indicative of the Company's current credit premium. The fair value of decommissioning obligations approximates its carrying value as the obligation is re-measured each reporting date using the risk-free interest rate in effect at that time.

(c) Derivatives:

The fair value of forward contracts and swaps is determined by discounting the difference between the contracted prices and published forward price curves as at the reporting date, using the remaining contracted crude oil and natural gas volumes and a risk-free interest rate (based on published government rates). The fair value of options and costless collars is based on option models that use published information with respect to volatility, prices and interest rates. The Company's derivative financial contracts are transacted in active markets. Changes in fair value of the derivatives are recognized in the consolidated statement of earnings. The actual gains and losses realized on eventual cash settlement can vary due to subsequent fluctuations in commodity prices. The contracts are measured at fair values and are classified as Level 2 in accordance with the following hierarchy:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors which can be substantially observed or corroborated in the marketplace.

Level 3 – Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

(d) Share-based compensation:

The fair value of employee stock options is measured using a Black-Scholes option pricing model. Measurement inputs include the share price on measurement date, exercise price of the instrument, expected volatility (based on weighted average historic volatility), weighted average expected life of the instruments (based on historical experience and general option holder behaviour), expected dividends and the risk-free interest rate (based on government bonds).

5) FUTURE ACCOUNTING STANDARDS

The following new and amended standards have been issued by the International Accounting Standards Board ("IASB"):

- IFRS 9, "Financial Instruments", which is the result of the first phase of the IASB's project to replace IAS 39, "Financial Instruments: Recognition and Measurement". The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value. The effective date for this standard has been deferred to January 1, 2015.

- IFRS 11, “Joint Arrangements” (“IFRS 11”), requires a venturer to classify its interest in a joint arrangement as a joint venture or joint operation, each having its own accounting model. Joint ventures will be accounted for using the equity method of accounting whereas for a joint operation the venture will recognize its share of the assets, liabilities, revenue and expenses of the joint operation. The standard provides for a more substance based reflection of joint arrangements by focusing on the rights and obligations of the arrangement, rather than its legal form. The new standard replaces IAS 31, “Interests in Joint Ventures” and SIC – 13, “Jointly Controlled Entities – Non-monetary Contributions by Venturers” and establishes principles for accounting for all joint arrangements.

- IFRS 12, “Disclosure of Interests in Other Entities”, which outlines the required disclosures for interests in subsidiaries and joint arrangements. The new disclosures require information that will assist financial statement users to evaluate the nature, risks and financial effects associated with an entity’s interests in subsidiaries and joint arrangements.

- IFRS 13, “Fair Value Measurement” which defines fair value, establishes a framework for measuring fair value and sets out disclosure requirements for fair value measurements.

- IAS 28, “Investments in Associates and Joint Ventures” has been amended to conform to the changes made in IFRS 10 and IFRS 11.

Except as noted above, all of the above pronouncements are effective for annual periods beginning on or after January 1, 2013, with early adoption permitted. The Company is currently evaluating the impact of adopting these standards.

6) FINANCIAL RISK MANAGEMENT

The Company is exposed to credit, market and liquidity risks from its use of financial instruments. This note provides information about the Company’s exposure to each of the above risks and the Company’s policies and processes for measuring and managing risk. Risk management policies are ultimately established by the Board of Directors and implemented and monitored by senior management.

(a) Commodity price risk

Commodity price risk is the risk that the future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for crude oil and natural gas are affected not only by world economic events that dictate the levels of supply and demand but also the relationship between the Canadian and United States (“U.S.”) dollar, as outlined below. The Company has a commodity price risk management program in place whereby the commodity price associated with a portion of its future production is fixed. The Company sells forward a portion of its future production by entering into a combination of fixed price physical sales contracts with customers and derivative financial contracts. The Company’s policy is to enter into commodity contracts to a range of 40 – 50 percent of current production volumes when considered appropriate.

As at December 31, 2011, the Company had the following derivative financial contracts which were recorded at fair value on the balance sheet as a net current asset of $0.5 million and a long term liability of $3.8 million (December 31, 2010 – current asset of $2.1 million and long term liability of $3.5 million) with changes in fair value included in unrealized loss on financial instruments in the consolidated statement of earnings:

Time Period	Commodity	Type and Reference	Quantity Contracted	Contract Price ($/unit)
January 2012–December 2012[1]	Natural Gas	Financial – AECO	3,000 GJ/d	$4.50 call
January 2013–December 2013[2]	Crude Oil	Financial – WTI	600 bbls/d	U.S. $90.00 call
January 2012 – March 2012	Natural Gas	Physical - AECO	1,000 mmbtu/d	U.S. $5.14 fixed
April 2012 – October 2012	Natural Gas	Physical - AECO	1,000 mmbtu/d	U.S. $4.96 fixed

[1] The Company acquired a natural gas put contract at $4.00 per gigajoule on 3,000 gigajoules per day for the period January 1, 2011 through December 31, 2011. The put was paid for with the sale of a natural gas call on 3,000 gigajoules per day at a price of $4.50 per gigajoule for the period January 1, 2012 through December 31, 2012.

[2] The Company acquired a natural gas contract at $5.69 per gigajoule on 6,810 gigajoules per day for the period April 1, 2011 through December 31, 2011. The contract was paid for with the sale of a crude oil call on 600 barrels per day at a price of U.S. $90.00 WTI per barrel for the period January 1, 2011 through December 31, 2012. Delphi has deferred this crude oil call to January 1, 2013 through December 31, 2013.

Natural gas physical commodity sale contracts based in U.S. dollars include an embedded derivative associated with the foreign exchange rate. The changes in the fair value of these contracts, which are considered derivatives due to the embedded feature, are included in the unrealized loss on financial instruments in the consolidated statement of earnings.

For the year ended December 31, 2011, the financial contracts resulted in realized gains of $4.1 million (December 31, 2010 - $3.4 million) that have been included in the consolidated statement of earnings as a realized gain on financial instruments.

As at December 31, 2011, if the future strip prices for crude oil were $1.00 per barrel higher with all variables held constant, the net earnings for the year would have been $0.1 million lower. An equal and opposite impact would have occurred had the strip prices for crude oil been lower by the same amount. As at December 31, 2011, if the future strip prices for natural gas were $0.10 per mcf higher with all variables held constant, the net earnings for the year would have been $4,000 lower. An equal and opposite impact would have occurred had the strip prices for natural gas been lower by the same amount.

In February 2012, Delphi acquired a natural gas contract at $2.65 per gigajoule on 7,500 gigajoules a day for the period March 1, 2012 through December 31, 2012. The contract was paid for with the sale of a crude oil call on 500 barrels per day at a price of U.S. $110.00 WTI per barrel for the period March 1, 2012 through December 31, 2012.

The Company also has physical sales contracts. The physical sales contracts were entered into and continue to be held for the purpose of delivery of non-financial items as executory contracts and have not been recorded at fair value. As at December 31, 2011, the Company had the following physical sales contracts:

Time Period	Commodity	Type and Reference	Quantity Contracted	Contract Price ($/unit)
January 2012 – December 2012[1]	Natural Gas	Physical - AECO	2,500 GJ/d	$4.50 call
April 2012 – October 2012	Natural Gas	Physical - AECO	2,000 GJ/d	$4.06 fixed

[1] The Company acquired a natural gas contract at $4.12 per gigajoule on 2,500 gigajoules per day for the period January 1, 2011 through December 31, 2011. The contract was paid for with the sale of a natural gas call on 2,500 gigajoules per day at a price of $4.50 per gigajoule for the period January 1, 2012 through December 31, 2012.

For the year ended December 31, 2011, the physical contracts resulted in realized gains of $3.8 million (December 31, 2010 - $12.7 million) that have been included in crude oil and natural gas sales.

(b) Credit risk

Credit risk represents the risk of financial loss to the Company if customers or counterparties to a financial instrument fail to meet their contractual obligations and arise principally from the Company's receivables from joint interest partners, crude oil and natural gas marketers and financial intermediaries.

All of the Company's accounts receivable are with customers and joint interest partners in the oil and gas industry and are subject to normal industry credit risks. Receivables from joint interest partners are typically collected within one to three months of the joint venture bill being issued. The Company attempts to mitigate the risk related to joint interest receivables by obtaining partner pre-approval of significant capital expenditures prior to expenditure. However, partners are exposed to various crude oil and natural gas industry and market risks that could result in non-collection.

Receivables from crude oil and natural gas marketers are normally collected on the 25th day of the month following production. The Company's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large purchasers. The Company historically has not experienced any collection issues with large purchasers. Concentration of credit risk is mitigated by marketing production to numerous purchasers under normal industry sale and payment terms.

The Company does not typically obtain collateral from crude oil and natural gas marketers or joint interest partners, however, the Company does have the ability to request pre-payment of certain major capital expenditures and withhold production from joint interest partners in the event of non-payment.

With respect to counterparties to financial commodity contracts, the Company partially mitigates associated credit risk by limiting transactions to counterparties with investment grade credit ratings.

The carrying amount of cash and accounts receivable represents the maximum credit exposure. Delphi sells substantially all of its production to three primary purchasers under standard industry sale and payment terms. Revenues from Delphi's three major purchasers represent approximately $121.2 million of Delphi's total revenues. As at December 31, 2011, the Company's receivables included $9.9 million of receivables from crude oil and natural gas marketers which has substantially been collected subsequent to December 31, 2011. The Company does not have an allowance for doubtful accounts as at December 31, 2011.

As at December 31, 2011 the Company's aged receivables are as follows.

	December 31, 2011
Current (less than 30 days)	**11,696**
Past due (31-90 days)	**2,469**
Past due (more than 90 days)	**4,605**
Total	**18,770**

(c) Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet the obligations associated with its financial liabilities. The Company's financial liabilities arise through the cost of operations and capital program in order to maintain or increase production and develop reserves, the acquisition of crude oil and natural gas assets, financial instrument contracts and borrowings under the Company's credit facilities.

The Company generates a certain level of cash flow from operations which is used to partially fund all operating, investing and capital activities. In addition, the Company has a 364 day revolving credit facility with a syndicate of Canadian chartered banks with a one year term-out provision.

The following are the contractual maturities of financial liabilities as at December 31, 2011:

Financial liabilities	**Carrying amount**	**< 1 Year**	**1 – 2 Years**	**3 – 5 Years**	**Thereafter**
Accounts payable and accrued liabilities	47,451	47,451	-	-	-
Liabilities held for sale	377	377			
Decommissioning obligations	20,113	825	-	-	23,408
Fair value of financial instruments	3,793	21	3,772	-	-
Long term debt	82,385	-	83,000	-	-
Total	154,119	48,674	86,772	-	23,408

(d) Currency risk

Although substantially all of the Company's petroleum and natural gas sales are denominated in Canadian dollars, commodity prices are largely denominated in U.S. dollars and as a result the prices that Canadian producers receive are influenced by the relationship between the Canadian and U.S. dollar. The exchange rate effect cannot be quantified but generally an increase in the value of the Canadian dollar as compared to the U.S. dollar will reduce the prices received by the Company for its crude oil and natural gas sales. At December 31, 2011, the Company had U.S. $0.8 million in cash. The Company had no foreign exchange rate swap or related financial contracts in place as at December 31, 2011.

(e) Interest rate risk

Interest rate risk is the risk that future cash flow will fluctuate as a result of changes in market interest rates. Delphi is exposed to interest rate risk as the interest charged on its long term debt is at a floating rate and consequently changes in market interest rates will have an effect on the Company's cash flow.

Interest rate risk is partially mitigated through short term fixed rate borrowings using bankers' acceptances.

Had the interest rate charged on the Company's long term debt been one percent higher throughout the year ended December 31, 2011, net earnings would have decreased by $0.7 million based on the average debt balance outstanding during the period.

7) CAPITAL MANAGEMENT

The Company's policy is to ensure a strong capital base so as to maintain investor, creditor and market confidence and to sustain future development of the business. The Company's objective in managing its capital is to ensure adequate and appropriate sources of capital are available to execute a capital investment program while maintaining a flexible overall capital structure. Maintaining a flexible capital structure is important due to the inherent risks in oil and gas operations and the volatility of commodity prices.

The Company considers share capital and net debt, being the sum of long term debt and current liabilities less current assets (excluding the fair value of financial instruments), as the components of capital to be managed.

The key measure used by the Company to evaluate its capital structure is the ratio of net debt to funds from operations, defined as cash flow from operating activities before accretion of long term debt, decommissioning expenditures and change in non-cash working capital from operating activities. This ratio represents the time period required to repay the Company's net debt from funds generated from operations on the assumption there are no further capital expenditures incurred and funds from operations remain constant. The measure is often calculated on a historic annual basis and on an annualized most recent quarter basis to provide a more current view of the Company's capital structure.

Net debt and funds from operations are considered non-IFRS terms.

At December 31, 2011 net debt was $95.6 million and funds from operations was $66.9 million resulting in a net debt to funds from operations ratio of 1.4:1. This ratio may increase at certain times as a result of acquisitions, the timing of capital expenditures or low commodity prices.

In order to facilitate the management of this ratio, the Company prepares annual funds from operations and capital expenditure budgets, which are updated as necessary throughout the year and are reviewed and periodically approved by Delphi's Board of Directors. The Company manages its capital structure by keeping abreast of current and forecast economic conditions and commodity prices, particularly natural gas prices and the cost of oilfield services. Additionally, the Company establishes internal processes to monitor and estimate planned capital expenditures, forecast funds from operations and current and forecast debt levels.

The Company maintains an active risk management program as an integral part of its capital management strategy to mitigate the volatility in funds from operations resulting from fluctuating commodity prices. The net debt to funds from operations ratio is the key driver in determining whether to maintain or alter the capital structure. To alter the capital structure of the Company, consideration is given to the level of credit available under current banking facilities, the proceeds on disposition of properties, the amount of the planned capital expenditure program and the offering of new common share equity if available on acceptable terms. There were no changes in the Company's approach to capital management during the period.

The Company's share capital is not subject to external restrictions, however, the Company's credit facilities do contain financial covenants that are outlined in note 13.

8) ACCOUNTS RECEIVABLE

Accounts receivable is comprised as follows:

	December 31, 2011	December 31, 2010
Revenue	**10,274**	10,987
Joint partners	**4,430**	4,369
Other	**4,066**	2,541
Total	**18,770**	**17,897**

9) ASSETS AND LIABILITIES HELD FOR SALE

In the fourth quarter of 2011, the Company made the decision to market for disposition, certain non-operated interests in its Hythe CGU. The facts and circumstances necessary to classify non-current assets as held for sale in accordance with IFRS 5, "Non-current Assets Held for Sale" ("IFRS 5"), were satisfied on December 31, 2011. The Company completed the sale on January 16, 2012 for gross proceeds of $12.0 million, subject to adjustments. Proceeds from the sale will be used to fund the ongoing Bigstone Montney development. In accordance with IFRS 5, the Company has measured the assets held for sale at their carrying amount, which is lower than fair value less costs to sell.

In the fourth quarter of 2011, the Company made the decision to market for disposition, certain non-operated interests in its Hythe CGU. The facts and circumstances necessary to classify non-current assets as held for sale in accordance with IFRS 5, "Non-current Assets Held for Sale" ("IFRS 5"), were satisfied on December 31, 2011. The Company completed the sale on January 16, 2012 for gross proceeds of $12.0 million, subject to adjustments. Proceeds from the sale will be used to fund the ongoing Bigstone Montney development. In accordance with IFRS 5, the Company has measured the assets held for sale at their carrying amount, which is lower than fair value less costs to sell.

10) EXPLORATION AND EVALUATION ASSETS

	Total
Balance as at January 1, 2010	315
Additions	2,472
Balance as at December 31, 2010	2,787
Additions	15,912
Balance as at December 31, 2011	**18,699**

Exploration and evaluation assets consist of the Company's exploration projects which are pending the determination of proven and probable reserves. During the year, the Company added undeveloped lands prospective for liquids-rich natural gas in the Montney formation in the Deep Basin of North West Alberta. Also, included in the additions for 2011, is the cost of drilling an exploratory well in the Montney formation.

11) PROPERTY, PLANT AND EQUIPMENT

Cost	Crude oil and natural gas properties	Production equipment	Other assets	Total
Balance as at January 1, 2010	304,838	27,528	572	332,938
Additions	104,478	-	49	104,257
Acquisitions	18	-	-	18
Dispositions	(247)	-	-	(247)
Balance as at December 31, 2010	409,087	27,528	621	437,236
Additions	101,943	334	137	102,414
Acquisitions	273	-	-	273
Dispositions	(14,449)	-	-	(14,449)
Reclassification to assets held for sale	(18,075)	-	-	(18,075)
Balance as at December 31, 2011	478,779	27,862	758	507,399

Accumulated depletion and depreciation	Crude oil and natural gas properties	Production equipment	Other assets	Total
Balance as at January 1, 2010	-	-	-	-
Depletion and depreciation	(43,566)	(583)	(129)	(44,278)
Impairment losses	(30,500)	(5,000)	-	(35,500)
Balance as at December 31, 2010	(74,066)	(5,583)	(129)	(79,778)
Depletion and depreciation	(44,924)	(494)	(117)	(45,535)
Dispositions	3,441	-	-	3,441
Reclassification to assets held for sale	8,395	-	-	8,395
Impairment losses	(1,212)	(288)	-	(1,500)
Balance as at December 31, 2011	(108,366)	(6,365)	(246)	(114,977)
Net book value as at December 31, 2011	**370,413**	**21,497**	**512**	**392,422**
Net book value as at December 31, 2010	335,021	21,945	492	357,458
Net book value as at January 1, 2010	304,838	27,528	572	332,938

Delphi's credit facility is secured by a demand floating charge debenture and a general security agreement over all assets

As at December 31, 2011, the Company has excluded $8.8 million (December 31, 2010 - $8.5 million) for estimated salvage, $nil (December 31, 2010 - $1.6 million) representing work in progress and has included $143.1 million (December 31, 2010 - $134.9 million) estimated future development costs to its costs subject to depletion.

Impairment tests were carried out at December 31, 2011 due to the decrease in the forward price curve for natural gas as at January 1, 2012 compared to January 1, 2011. The Company recognized an impairment charge of $1.5 million related to the Company's Hythe, Berland River and Miscellaneous Alberta CGUs, which has been included in depletion and depreciation expense on the consolidated statement of earnings. The impairments were based on the difference between the period end carrying value of the CGU's and the recoverable amount. The recoverable amounts were determined using a fair value less costs to sell methodology with the expected future cash flows based on proved and probable reserves using pre-tax discount rates of 8 to 12 per cent, as determined by the Company's independent engineers.

During 2010, as a result of decreasing natural gas prices, the Company recognized a $35.5 million impairment relating to several CGU's which predominantly produce natural gas and are outside of the Company's focus area in the Deep Basin. At March 31, 2010, an impairment loss of $5.0 million was recognized and at September 30, 2010 additional impairment losses of $30.5 million were taken and are included in depletion and depreciation expense on the consolidated statement of earnings. The recoverable amount was determined using fair value less cost to sell based on discounted cash flows of proved plus probable reserves using discount rates of 12 to 15 percent.

12) ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

Accounts payable and accrued liabilities is comprised as follows:

	December 31, 2011	December 31, 2010
Trade	**8,517**	2,935
Royalties	**3,452**	5,185
Joint partners	**6,023**	4,773
Accrued capital	**28,851**	14,937
Other	**608**	586
Total	**47,451**	**28,416**

13) LONG TERM DEBT

	December 31, 2011	December 31, 2010	January 1, 2010
Prime-based loans	**3,000**	25,000	1,100
Bankers' acceptances, net of discount	**79,385**	79,050	79,385
Total	**82,385**	104,050	80,485

The Company has a $145.0 million extendible revolving term credit facility with a syndicate of Canadian chartered banks, subject to the banks' semi-annual valuation of the Company's crude oil and natural gas properties. The facility is a 364 day committed facility available on a revolving basis until May 28, 2012 at which time it may be extended at the lenders' option. If the revolving period is not extended, the undrawn portion of the facility will be cancelled and the amount outstanding will convert to a 365 day non-revolving term facility. The amounts outstanding under the non-revolving facility are required to be repaid at the end of the non-revolving term being May 28, 2013. The non-extension provisions are applicable to the lenders on an individual basis.

Interest payable on amounts drawn under the facility is at the prevailing bankers' acceptance rates plus stamping fees, lenders' prime rate or U.S. base rate plus the applicable margins, depending on the form of borrowing by the Company. The applicable margins and stamping fees are based on a sliding scale pricing grid tied to the Company's trailing debt to annualized quarterly funds from operations ratio: from a minimum of the bank's prime rate or U.S. base rate plus 1.25 percent to a maximum of the bank's prime rate or U.S. base rate plus 4.25 percent or from a minimum of bankers' acceptances rate plus a stamping fee of 2.25 percent to a maximum of bankers' acceptances rate plus a stamping fee of 4.25 percent.

The bankers' acceptances outstanding at December 31, 2011 have terms ranging from 91 to 182 days and a weighted average effective interest rate of 4.08 percent over the term.

Under the terms of the credit facility, the Company covenants that it will maintain a working capital ratio of at least one to one. For the purpose of this ratio, the undrawn portion of the credit facility is added to current assets in the working capital calculation. The credit facility is secured by a $200.0 million demand floating charge debenture and a general security agreement over all assets of the Company. Delphi is in compliance with the covenants of its credit facility as at December 31, 2011.

14) DECOMMISSIONING OBLIGATIONS

The Company's decommissioning obligations result from working interests in crude oil and natural gas assets including well sites, gathering systems and processing facilities. The total decommissioning obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future years. The Company estimates the undiscounted total future liability of $24.7 million (December 31, 2010 - $22.7 million) to be settled over the next 20 years with the majority of the costs to be incurred between 2017 and 2023. A risk-free rate of 1.94 percent (December 31, 2010 – 3.1 percent) and an inflation rate of 2.5 percent were used to calculate the estimated fair value of the decommissioning obligations.

A reconciliation of the decommissioning obligations is provided below:

	Year Ended December 31, 2011	Year ended December 31, 2010
Balance, beginning of year	**17,232**	15,496
Liabilities incurred	**1,049**	862
Liabilities disposed	**(89)**	(79)
Liabilities settled	**(131)**	(265)
Accretion expense	**483**	520
Change in estimate	**1,946**	698
	20,490	17,232
Liabilities held for sale (note 9)	**(377)**	-
Current portion	**(825)**	
Balance, end of year	**19,288**	17,232

15) DEFERRED INCOME TAXES

The provision for income taxes differs from the expected amount calculated by applying the combined Federal and Provincial corporate income tax rates to Delphi's earnings (loss) before taxes. This difference results from the following items:

Years ended December 31	**2011**	2010
Earnings (loss) before income taxes	**17,971**	(22,173)
Statutory tax rate	**26.50%**	28.01%
Expected income tax expense (recovery)	**4,763**	(6,211)
Stock-based compensation	**281**	288
Change in deferred income tax rates and other	**(115)**	79
Flow-through common shares	**1,440**	655
Total income tax expense (recovery)	**6,369**	(5,189)

The decrease in the statutory tax rate in 2011 from 2010 was due to a reduction in the Federal income tax rate to 16.5% in 2011 from 18.0% in 2010.

The income tax effect of temporary differences that give rise to significant portions of the deferred income tax assets and liabilities are presented below:

As at December 31	**2011**	2010
Deferred income tax assets:		
Decommissioning obligations	**5,123**	4,308
Attributed Canadian Royalty Income	**361**	361
Non capital losses	**4,093**	4,093
Share issue costs	**951**	1,008
Risk management liability	**811**	383
Deferred income tax liabilities:		
Exploration and evaluation and property, plant and equipment	**(34,584)**	(26,705)
Net deferred income tax liability	**(23,245)**	(16,552)

Non capital losses of $16.4 million will expire by 2028.

Changes in deferred income tax assets and liabilities for the years ended December 31, 2011 and 2010 are as follows:

	Balance January 1, 2011	Recognized in equity	Recognized in net earnings	Other	**Balance December 31, 2011**
Deferred income tax assets:					
Decommissioning obligations	4,308	-	815	-	**5,123**
Attributed Canadian Royalty Income	361	-	-	-	**361**
Non capital losses	4,093	-	-	-	**4,093**
Share issue costs	1,008	476	(533)	-	**951**
Risk management liability	383	-	428	-	**811**
Deferred income tax liabilities:				-	
Exploration and evaluation and property, plant and equipment	(26,705)	-	(7,079)	(800)	**(34,584)**
Net deferred income tax liability	(16,552)	476	(6,369)	(800)	**(23,245)**

	Balance January 1, 2010	Recognized in equity	Recognized in net earnings	Other	Balance December 31, 2010
Deferred income tax assets:					
Decommissioning obligations	4,594	-	(286)	-	4,308
Attributed Canadian Royalty Income	361	-	-	-	361
Non capital losses	4,093	-	-	-	4,093
Share issue costs	998	525	(515)	-	1,008
Risk management liability	112	-	271	-	383
Deferred income tax liabilities:				-	
Exploration and evaluation and property, plant and equipment	(31,302)	-	5,719	(1,122)	(26,705)
Net deferred income tax liability	(21,144)	525	5,189	(1,122)	(16,552)

16) SHARE CAPITAL

Delphi is authorized to issue an unlimited number of common shares. All shares are fully paid and have no par value. The holders of common shares are entitled to receive dividends as declared by the Company and are also entitled to one vote per share.

(a) Issued and outstanding

	December 31, 2011		December 31, 2010	
	Outstanding shares (000's)	**Amount**	Outstanding shares (000's)	Amount
Balance, beginning of year	**112,825**	**236,382**	101,166	206,382
Issue of common shares	**10,005**	**22,011**	11,000	30,250
Issue of flow-through common shares	**6,100**	**14,801**	-	-
Exercise of stock options	**2,070**	**2,575**	659	775
Allocated from contributed surplus	**-**	**1,347**	-	418
Share issue costs, net of deferred tax effect	**-**	**(1,434)**	-	(1,443)
Balance, end of year	**131,000**	**275,682**	112,825	236,382

On March 24, 2011, the Company issued 3.2 million flow-through common shares at a price of $2.80 per share for gross proceeds of $9.0 million. On December 23, 2011, Delphi closed an equity issuance of 10.0 million shares at a price of $2.20 per share and 2.9 million flow-through common shares at a price of $2.75 for total gross proceeds of $30.0 million. A flow-through premium of $1.3 million related to the issuance of the flow-through common shares on December 23, 2011 was recorded as a long term liability on the consolidated statement of financial position. The liability is de-recognized, with a corresponding deferred tax expense, as the Company incurs qualifying exploration expenditures. Delphi has an obligation to incur qualifying exploration expenditures by December 31, 2012 to satisfy the terms of the flow-through common shares issued.

During the last three quarters of 2011, Delphi satisfied its $9.0 million commitment to incur qualifying capital expenditures associated with its March 24, 2011 flow-through shares. As a result, the long term liability associated with these flow-through shares has been de-recognized and a deferred tax expense of $1.4 million was recorded in the consolidated statements of earnings.

On June 3, 2010, the Company issued 11.0 million common shares at a price of $2.75 per share for gross proceeds of $30.3 million.

(b) Share-based compensation

The Company has established a stock option plan under which it has granted options to acquire common shares to certain officers, directors, employees and key consultants. The plan provides for the granting of options up to ten percent of the issued and outstanding common shares of the Company. Options issued under the plan have a term of five years to expiry. Options granted prior to September 1, 2009 vest over a two-year period starting on the date of grant. Options granted between September 1, 2009 and May 31, 2011 vest over a two-year period with one-third vesting six months after the date of grant and one-third on each of the first and second anniversary of the grant date. Options granted on May 31, 2011 or later vest over a four-year period with one-fourth vesting on each of the first, second, third and fourth anniversary of the grant date. The exercise price of each option equals the five day weighted average of the market price of the Company's common shares, immediately preceding the date of the grant. As at December 31, 2011, a total of 13.1 million options to purchase shares were reserved and 10.6 million options to purchase shares were outstanding, leaving an additional 2.5 million available for future grants.

The following table summarizes the changes in the number of options outstanding and the weighted average exercise prices:

	December 31, 2011		December 31, 2010	
	Outstanding options (000's)	**Weighted average exercise price**	Outstanding options (000's)	Weighted average exercise price
Balance, beginning of year	**7,776**	**1.59**	7,428	1.40
Granted	**5,846**	**2.16**	1,074	2.64
Forfeited	**(961)**	**2.48**	(67)	1.50
Exercised	**(2,070)**	**1.24**	(659)	1.18
Balance, end of year	**10,591**	**1.89**	7,776	1.59
Exercisable, end of year	**5,466**	**1.69**	6,116	1.58

The following table summarizes information about the stock options outstanding and exercisable at December 31, 2011.

	Options outstanding			Options exercisable	
Range of exercise price	Outstanding options (000's)	Weighted average exercise price	Weighted average remaining term (years)	Exercisable (000's)	Weighted average exercise price
$0.65 - $0.97	**1,038**	**0.65**	**2.17**	**1,039**	**0.65**
$0.98 - $1.54	**2,231**	**1.48**	**4.58**	**165**	**1.26**
$1.55 - $1.72	**2,760**	**1.68**	**0.95**	**2,760**	**1.68**
$1.73 - $2.15	**705**	**1.93**	**2.29**	**505**	**1.85**
$2.16 - $3.34	**3,857**	**2.61**	**4.02**	**997**	**2.78**
Total	**10,591**	**1.89**	**3.04**	**5,466**	**1.69**

During 2011, a total of 2.1 million options were exercised. The weighted average share trading price for the year ended December 31, 2011 was $2.22 (2010 - $2.49).

The Company accounts for its share-based compensation using the fair value method for all stock options. For the year ended December 31, 2011, Delphi recorded share-based compensation expense of $1.9 million (December 31, 2010 - $1.4 million), of which $0.9 million was capitalized (2010: $0.3 million).

During the year ended December 31, 2011, the Company granted 5.8 million options. The fair values of all options granted during the period are estimated at the date of grant using the Black-Scholes option pricing model. The weighted average fair value of options granted during the period was $1.10 per option (December 31, 2010 - $1.51 per option). The assumptions used in the Black-Scholes model to determine fair value were as follows.

For the years ended December 31,	**2011**	2010
Risk-free interest rate (%)	**1.8**	2.7
Expected life (years)	**3.8**	5.0
Forfeiture rate (%)	**15.0**	3.7
Expected volatility (%)	**67.3**	65.8

Effective May 3, 2011, the Company established a restricted share unit ("RSU") plan. Employees are eligible to receive RSU awards or were able to convert up to 50 percent of their performance bonus into RSU awards. RSU awards received by an employee as a result of conversion, received a 30 percent increase in the number of RSU's received through the conversion. The RSU awards vest on each of the first, second and third anniversary of the award date at which time the employee will receive a cash payment equivalent to the number of RSU's vested multiplied by the Company's closing share price on the business day immediately preceding the vesting date.

For the year ended December 31, 2011, Delphi recorded $70,000 of share-based compensation expense and a corresponding liability related to the Company's outstanding RSU's. The following table summarizes the changes of the RSU's:

For the year ended December 31, 2011	**Outstanding RSU's**
Balance, beginning of year	-
Granted	**374,012**
Forfeited	**(42,075)**
Balance, end of year	**331,937**

(d) Net earnings (loss) per share

Net earnings (loss) per share has been calculated based on earnings of $11.6 million (2010 loss: $17.0 million) and the following weighted average common shares:

For the years ended December 31,	**2011**	**2010**
Weighted average common shares - basic	**116,935**	107,934
Dilutive effect of share options outstanding	**1,865**	-
Weighted average common shares - diluted	**118,800**	107,934

For the year ended December 31, 2011, a total of 8.7 million share options (2010: 7.8 million) were excluded from the calculation as they were anti-dilutive.

17) FINANCE COSTS

Finance costs is comprised of the following:

For the years ended December 31,	**2011**	2010
Interest expense	**5,299**	5,075
Accretion expense	**483**	519
Total	**5,782**	5,594

18) NATURE OF EXPENSES

Delphi's consolidated statement of earnings is prepared primarily by nature of expense, with the exception of employee compensation costs which are included in both the operating and general and administrative expense line items. The following table details operating, general and administrative and employee compensation costs:

For the years ended December 31,	**2011**	2010
Production	**21,100**	21,370
General and administrative	**3,324**	3,680
Employee compensation	**4,063**	3,334
Total	**28,487**	28,384

19) KEY MANAGEMENT COMPENSATION

Key management includes senior officers and directors (executive and non-executive) of the Company. The compensation paid or payable to key management is shown below:

For the years ended December 31,	**2011**	2010
Salaries and other short-term employee benefits	**2,810**	2,540
Long-term incentive compensation	**236**	214
Share-based payments [1]	**459**	544
Total	**3,505**	3,298

[1] Share-based payments are net of amounts capitalized to property, plant and equipment.

20) COMMITMENTS

Delphi is committed to future minimum payments for natural gas transmission and processing, operating leases on compression equipment and office space. Payments required under these commitments for each of the next five years are as follows:

	2012	2013	2014	2015	2016	**Total**
Gathering, processing and transmission	6,712	5,403	3,178	3,150	-	**18,443**
Office space	811	631	509	509	522	**2,982**
Total	7,523	6,034	3,687	3,659	522	**21,425**

As a result of the flow-through shares issued on December 23, 2011, Delphi is committed to incur approximately $8.0 million in qualifying Canadian exploration expenses on or before December 31, 2012. As at December 31, 2011, Delphi was committed to drill one well pursuant to an agreement which will allow the Company to earn a 75 percent working interest on five sections of land. Delphi expects to satisfy the drilling commitment at an estimated cost of approximately $8.0 million.

21) SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital are comprised of the following:

For the years ended December 31,	2011	2010
Source/(use) of cash		
Accounts receivable	**(873)**	(2,267)
Prepaid expenses and deposits	**(463)**	2,913
Accounts payable and accrued liabilities	**18,965**	(4,517)
Total change in non-cash working capital	**17,629**	(3,871)
Relating to:		
Operating activities	**2,273**	(1,819)
Financing activities	**300**	-
Investing activities	**15,056**	(2,052)
	17,629	(3,871)

22) FIRST TIME ADOPTION OF INTERNATIONAL FINANCIAL REPORTING STANDARDS

The CICA Accounting Standards Board announced that Canadian public reporting issuers will be required to report under IFRS, replacing Canadian GAAP for years beginning on or after January 1, 2011. The adoption date of January 1, 2011 requires restatement, for comparative purposes, of the Company's opening balance sheet as at January 1, 2010, all interim quarterly periods in 2010 and for year ended December 31, 2010.

Delphi has prepared reconciliations of equity as at January 1, 2010 and December 31, 2010 and reconciliations of total comprehensive earnings (loss) for the year ended December 31, 2010, using the accounting policies in note 3 and the following IFRS 1, "First-time Adoption of International Financial Reporting Standards", ("IFRS 1") exemptions:

Key First Time Adoption Exemptions Applied

IFRS 1 is the standard that governs mandatory exceptions and optional exemptions that an entity may elect for its transition to IFRS in order to assist the entity with the transition process. This standard is only applicable to the opening balance sheet of the entity on the transition date of January 1, 2010. All adjustments made as result of adoption of IFRS are offset against Delphi's January 1, 2010 deficit.

The following exemptions have been applied, allowing the Company to apply the applicable IFRS standards on a prospective basis:

Business Combinations

An exemption under IFRS 1 provides the entity with relief on the restatement of business combinations prior to the transition date. Under IFRS 3, "Business Combinations", the determination of the fair value of share consideration differs from the determination under Canadian accounting standards. Any difference in the fair value calculation would have a resulting impact on the carrying amount of net assets acquired, non-controlling interest and any goodwill. Also, transaction costs on business combinations are expensed as incurred under IFRS, whereas under previous GAAP the transaction costs related to business combinations are capitalized as part of the purchase equation. The Company has taken advantage of this election, allowing Delphi to be exempt from restating business combinations prior to the transition date to IFRS.

Property, Plant and Equipment ("PP&E")

Companies that applied full cost accounting under previous GAAP had the option to measure oil and gas assets at the date of transition to IFRS at the amount previously determined under previous GAAP. Delphi has elected to value its oil and gas assets as previously determined by previous GAAP, subject to a transition date impairment test. The measurement upon transition to IFRS is as follows:

- exploration and evaluation assets were reclassified from the full cost pool to exploration and evaluation ("E&E") assets at the amount that was recorded under previous GAAP; and

- the remaining full cost pool was allocated to development and producing assets on a pro rata basis using reserve values for its proved plus probable company interest reserves.

Upon transition to IFRS, the Company recorded an impairment of $3.9 million related to its East Central Alberta cash generating unit, with an offsetting amount to the January 1, 2010 deficit.

Share-based Payment Transactions

IFRS 1 provides an elective exemption, which the Company has elected, which allows Delphi to apply IFRS 2, “Share-based Payments”, to the unvested options outstanding on transition date.

Decommissioning Obligations

The Company measured decommissioning liabilities as at the transition date in accordance with IAS 37, “Provisions, Contingent Liabilities and Contingent Assets” (“IAS 37”). In accordance with the IFRS 1 exemption applicable to companies that applied full cost accounting, the difference between the obligation under IFRS at January 1, 2010 and the carrying amount under previous GAAP, was recognized directly in equity.

An explanation of how the transition from previous GAAP to IFRS has affected the Company's financial position and financial performance is set out in the following tables:

Opening Consolidated Statement of Financial Position
As at January 1, 2010

(thousands of dollars)	Notes	Previous GAAP	Effect of Transition to IFRS	IFRS
Assets				
Current assets				
Accounts receivable		15,630	-	15,630
Prepaid expenses and deposits	**k)**	6,004	(615)	5,389
Assets held for sale	**a)**	-	2,804	2,804
Fair value of financial instruments	**k)**	-	104	104
Deferred income taxes	**h)**	112	(112)	-
		21,746	2,181	23,927
Exploration and evaluation assets	**b)**	-	315	315
Property, plant and equipment		339,952		332,938
Transfer to exploration and evaluation assets	**b)**		(315)	
Reclassification to assets held for sale	**a)**		(6,699)	
Total assets		**361,698**	**(4,518)**	**357,180**
Liabilities				
Current liabilities				
Outstanding cheques		139	-	139
Accounts payable and accrued liabilities		32,933	-	32,933
Liabilities held for sale	**a)**	-	2,554	2,554
Fair value of financial instruments	**k)**	381	(381)	-
		33,453	2,173	35,626
Other liability	**i)**	-	960	960
Long term debt	**k)**	81,100	(615)	80,485
Decommissioning obligations		11,818		15,496
Reclassification to liabilities held for sale	**a)**		(2,554)	
Transitional adjustment	**e)**		6,232	
Fair value of financial instruments	**k)**	-	485	485
Deferred income taxes	**h)**	23,917	(2,773)	21,144
		150,288	3,908	154,196
Shareholders' equity				
Share capital	**i)**	200,055	6,327	206,382
Contributed surplus	**f)**	11,048	(21)	11,027
Deficit	**j)**	307	(14,732)	(14,425)
Total shareholders' equity		211,410	(8,426)	202,984
Total liabilities and shareholders' equity		**361,698**	**(4,518)**	**357,180**

Consolidated Statement of Financial Position
As at December 31, 2010

(thousands of dollars)	Notes	Previous GAAP	Effect of Transition to IFRS	IFRS
Assets				
Current assets				
Cash and cash equivalents		4,039	-	4,039
Accounts receivable		17,897	-	17,897
Prepaid expenses and deposits	**k)**	3,426	(950)	2,476
Fair value of financial instruments		2,080	-	2,080
		27,442	(950)	26,492
Exploration and evaluation assets	**b)**	-	2,787	2,787
Property, plant and equipment		384,887		357,458
Transfer to exploration and evaluation assets	**b)**		(2,032)	
Reclassification to assets held for sale	**j)**		(4,599)	
Expensing of dry holes	**c)**		(195)	
Decrease in depletion and depreciation	**d)**		15,398	
Impairment losses	**d)**		(35,500)	
Change in decommissioning obligations	**e)**		1,211	
Capitalization of share-based compensation	**f)**		(180)	
Capitalization of directly related overhead	**g)**		(1,532)	
Total assets		**412,329**	**(25,592)**	**386,737**
Liabilities				
Current liabilities				
Accounts payable and accrued liabilities		28,416	-	28,416
Deferred income taxes	**h)**	551	(551)	-
		28,967	(551)	28,416
Long term debt	**k)**	105,000	(950)	104,050
Decommissioning obligations		10,984		17,232
Reclassification to liabilities held for sale	**a)**		(704)	
Transitional adjustment	**e)**		6,232	
Change in decommissioning obligations	**e)**		720	
Fair value of financial instruments		3,527	-	3,527
Deferred income taxes	**h)**	23,860	(7,308)	16,552
		172,338	(2,561)	169,777
Shareholders' equity				
Share capital	**i)**	228,440	7,942	236,382
Contributed surplus	**f)**	12,088	(101)	11,987
Deficit	**j)**	(537)	(30,872)	(31,409)
Total shareholders' equity		239,991	(23,031)	216,960
Total liabilities and shareholders' equity		**412,329**	**(25,592)**	**386,737**

Consolidated Statement of Loss
Year Ended December 31, 2010

(thousands of dollars)	Notes	Previous GAAP	Effect of Transition to IFRS	IFRS
Revenue				
Petroleum and natural gas sales		113,772	-	113,772
Royalties		(14,420)	-	(14,420)
		99,352	-	99,352
Realized gain on financial instruments		3,427	-	3,427
Unrealized loss on financial instruments		(1,066)	-	(1,066)
		101,713	-	101,713
Expenses				
Operating	**g)**	22,013	(58)	21,955
Transportation		8,908	-	8,908
Exploration and evaluation	**c)**	-	195	195
General and administrative	**g)**	5,531	898	6,429
Share-based compensation	**f)**	990	37	1,027
Depletion and depreciation		60,687		79,778
Reclassification of accretion expense	**d)**		(1,011)	
Decrease in depletion and depreciation	**d)**		(15,398)	
Impairment losses	**d)**		35,500	
		98,129	20,163	118,292
Finance costs	**d), e)**	(5,075)	(519)	(5,594)
Earnings before taxes		(1,491)	(20,682)	(22,173)
Taxes				
Deferred income taxes	**h)**	(647)	(4,542)	(5,189)
		(647)	(4,542)	(5,189)
Net loss and comprehensive loss		(844)	(16,141)	(16,984)

Notes to reconciliations:

a) Assets held for sale – Upon transition to IFRS, Delphi recorded an impairment on its East Central Alberta ("ECAB") cash generating unit to a net realizable value of $0.3 million, with the impairment of $3.9 million recognized in the opening deficit as required by IFRS 1. The remaining assets and liabilities were reclassified to assets and liabilities held for sale. The net assets were sold in the second quarter of 2010 for $0.3 million.

Consolidated statement of financial position (thousands)	**As at Jan. 1 2010**
Reclassify assets to held for sale	6,699
Impairment on assets held for sale	(3,895)
	2,804
Reclassify liabilities to held for sale	(2,554)
	250

b) Exploration and evaluation assets ("E&E") – At the transition date to IFRS, Delphi evaluated its existing asset base and reclassified from the full cost pool to E&E assets, the carrying amount for Delphi's undeveloped land that related directly to exploration properties. A total of $0.3 million was reclassified to E&E assets upon transition. For the year ended December 31, 2010, the Company reclassified approximately $1.7 million from PP&E and added approximately $0.8 million of E&E assets in accordance with the Company's accounting policy for E&E.

Consolidated statement of financial position (thousands)	**As at Jan. 1 2010**	**As at Dec. 31 2010**
Reclassification from PP&E	315	2,032
Capitalization of directly related overhead	-	692
Capitalization of share-based compensation	-	63
	315	2,787

c) Property, plant and equipment – In accordance with the Company's accounting policies, Delphi expensed $0.2 million as exploration and evaluation expense for carrying costs associated with an unsuccessful well.

d) Depletion and depreciation expense and impairment – Previous GAAP provided specific guidelines on the depletion calculation for oil and natural gas properties. Depletion was calculated based on proved reserves. Under IFRS, the Company has a choice as to the reserve base to use for its depletion calculations. Delphi has adopted a policy of depleting its oil and natural gas properties using its proved plus probable reserve base. As a result, the 2010 depletion and depreciation expense decreased as compared to its calculation under previous GAAP.

Impairment of PP&E assets – Under previous GAAP, the full cost ceiling test was used to assess impairment of PP&E on the basis of estimated undiscounted future cash flows compared with the asset's carrying amount. If impairment was indicated, discounted cash flows were estimated to quantify the amount of impairment, using a risk-free rate. The impairment test under previous GAAP was done at the cost centre level. Under previous GAAP, Delphi had one cost centre for impairment test purposes.

IFRS requires the impairment test to occur at the asset level or at the cash generating unit level when long-lived assets exist that do not generate largely independent cash inflows. The carrying amount of the asset or CGU is compared to its recoverable amount which is the higher of value in use or fair value less costs to sell.

During 2010, as a result of decreasing natural gas prices, the Company recognized a $35.5 million impairment relating to several CGU's outside the Company's focus area in the Deep Basin which predominantly produce natural gas. The Company has recorded this impairment charge within depletion and depreciation on the consolidated statement of loss.

Consolidated statement of earnings (thousands)	Year Ended Dec. 31, 2010
Decrease in depletion and depreciation	(15,398)
Reclassification of accretion expense	(1,011)
Impairment losses	35,500
Increase in depletion and depreciation	19,091

e) Decommissioning obligations – Under IFRS, Delphi re-measured its liability for asset retirement obligations (now referred to as decommissioning obligations) using a risk-free rate of interest. Under IFRS, a risk-free discount rate is used if the estimated cash flows are risk adjusted. Under previous GAAP, the Company used a credit-adjusted risk free rate. Upon transition to IFRS on January 1, 2010, Delphi's total decommissioning liabilities increased by $6.2 million as the liability was revalued to reflect the estimated risk-free rate of interest of 3.6% as compared to the credit adjusted risk-free rate of 8 – 10% used under previous GAAP. The offset to this increase in the decommissioning obligations was recognized directly in the Company's deficit on January 1, 2010.

Under IFRS, the liability is to be re-measured each reporting period in order to reflect interest rates in effect at that time. As a result of re-measuring the decommissioning liabilities each reporting period, on a cumulative basis in 2010, PP&E and decommissioning liabilities increased $1.2 million for the year ended December 31, 2010. The decrease in discount rates used under IFRS versus previous GAAP caused a decrease of $0.5 million in accretion expense for the year ended December 31, 2010.

Consolidated statement of financial position (thousands)	As at Jan. 1, 2010	As at Dec. 31, 2010
Opening adjustment	6,232	6,232
Change in decommissioning obligations	-	1,211
Decrease in accretion	-	(491)
Reclassification of ECAB decommissioning obligations to liabilities held for sale	(2,554)	(704)
	3,678	6,248

Under IFRS accretion expense is reclassified from depletion and depreciation expense to finance cost.

f) Share-based compensation –Under previous GAAP, the Company accounted for forfeitures as they occurred whereas IFRS requires an estimate of forfeitures to be reflected in the option fair value. As a result of applying a forfeiture rate to the Company's unvested share options outstanding on the transition date, Delphi recorded a decrease of $0.02 million to contributed surplus, with an offsetting entry to the January 1, 2010 deficit. For the year ended December 31, 2010, Delphi recognized a decrease of $0.1 million in contributed surplus as a result of the Company's application of IFRS 2.

Due to differences in the accounting for share-based compensation under previous GAAP and IFRS, adjustments are required in the amount of capitalized share-based compensation. For the year ended December 31, 2010, Delphi capitalized $0.1 million less under IFRS when compared to previous GAAP.

Consolidated statement of earnings (thousands)	Year Ended Dec. 31, 2010
Change to share-based compensation	(80)
Share-based compensation capitalized to PP&E	180
Share-based compensation capitalized to E&E	(63)
	37

g) Capitalized directly related overhead
As a result of IFRS, the Company made re-allocations of previously capitalized overhead and allocations of operating expense to general and administration. In addition, the Company allocated previously capitalized overhead to E&E.

Consolidated statement of financial position (thousands)	**As at Dec. 31, 2010**
Decrease in capitalized directly related overhead	(840)
Capitalized directly related overhead transferred to E&E	(692)
	(1,532)

Consolidated statement of earnings (thousands)	**Year Ended Dec. 31, 2010**
Decrease in capitalized directly related overhead	840
Transfer from operating expense to general and administration	58
	898

h) Deferred income tax – Delphi recorded a decrease of $2.4 million to its deferred tax liability upon transition to IFRS with the offset to opening retained earnings. The decrease in deferred tax liability is primarily due to the adjustments to the opening balances of property, plant and equipment and decommissioning liabilities on transition to IFRS. Under IFRS, deferred income tax assets and liabilities are classified as non-current.

Consolidated statement of financial position (thousands)	**As at Jan. 1, 2010**	**As at Dec. 31, 2010**
Reclassification from current deferred income taxes	(112)	(551)
Deferred income tax related to transition to IFRS	(2,661)	(6,757)
	(2,773)	(7,308)

Consolidated statement of earnings (thousands)	**Year Ended Dec. 31, 2010**
Deferred income tax related to transition to IFRS	(4,542)

i) Share capital - Delphi recorded an increase of $7.4 million to its share capital upon transition to IFRS, with the offset to opening retained earnings, relating to the accounting for flow-through shares. Under previous GAAP, the tax renouncement related to flow-through shares was recorded against share capital whereas under IFRS only the portion related to the flow-through premium is recorded against share capital. The premium is the difference between the proceeds received for the flow-through shares and the market price of the common shares of the Company. As qualifying expenditures are incurred, the related tax liability associated with the renouncement of the tax benefits is recorded and the liability recognized for the premium is reversed. The difference between the deferred tax liability and the liability set up for the premium is recognized as a deferred tax expense. This change is retrospective for all flow-through share issuances.

With respect to flow-through shares issued in 2009, qualifying expenditures were incurred in 2010 and the flow-through premium of $1.0 million was recorded in other liabilities instead of share capital until the qualifying expenditures were incurred, at which point the flow-through premium liability was reversed and a deferred tax expense was recognized.

Also, Delphi recorded a decrease of $0.1 million to its share capital upon transition to IFRS, with the offset to opening retained earnings, for the tax rate changes related to previously recognized tax benefits within share capital for share issue costs under IFRS.

Consolidated statement of financial position (thousands)	**As at Jan. 1, 2010**	**As at Dec. 31, 2010**
Flow-through adjustment	7,409	7,409
Flow-through common shares issued in 2009	(960)	655
Share issue cost adjustment	(122)	(122)
	6,327	7,942

j) Retained earnings (deficit)

Consolidated statement of financial position (thousands)	**As at Jan. 1, 2010**	**As at Dec. 31, 2010**
Decommissioning obligations	(6,232)	(6,496)
Share-based compensation	21	(16)
Flow-through adjustment	(7,409)	(8,064)
ECAB impairment	(3,895)	(3,895)
Share issue cost adjustment	122	122
Deferred income tax	2,661	7,859
Capitalized directly related overhead	-	(840)
Depletion and depreciation	-	15,398
Rate change in decommissioning obligations	-	755
Expensing of dry hole costs	-	(195)
Impairment losses	-	(35,500)
	(14,732)	(30,872)

k) Re-classification of prepaid expenses
The reclassification of prepaid expenses to long-term debt is not an adjustment as a result of the transition to IFRS but rather an adjustment to conform to the current year's presentation.

Consolidated statement of cash flows
There are no material differences between the consolidated statement of cash flows presented under IFRS and the consolidated statement of cash flows under previous GAAP.

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INDEPENDENT ENGINEERS

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STOCK EXCHANGE LISTING

Toronto Stock Exchange – DEE

TRANSFER AGENT

Olympia Trust Company

ABBREVIATIONS

bbls.......barrels
bbls/d.......barrels per day
mbbls.......thousand barrels
mcf.......thousand cubic feet
mcf/d.......thousand cubic feet per day
mmcf.......million cubic feet
mmcf/d.......million cubic feet per day
NGL.......natural gas liquids
bcf.......billion cubic feet
boe.......barrels of oil equivalent (6 mcf:1 bbl)
boe/d.......barrels of oil equivalent per day
mmboe.......million barrels of oil equivalent