DELPHI ENERGY CORP.
300, 500 – 4 Avenue SW, Calgary, Alberta T2P 2V6 | t: (403) 265-6171 | f: (403) 265-6207 | e: info@delphienergy.ca | www.delphienergy.ca | TSX Symbol: DEE

Press Release

DELPHI ENERGY REPORTS RECORD PRODUCTION OF 8,035 BOE/D FOR SECOND QUARTER 2010

CALGARY, ALBERTA – July 28, 2010 – Delphi Energy Corp. ("Delphi" or the "Company") is pleased to announce its results for the quarter ended June 30, 2010.

Second Quarter 2010 Highlights

- achieved record production in the second quarter with average daily volumes of 8,035 barrels of oil equivalent per day (boe/d), an increase of 18 percent compared to the second quarter of 2009 and up five percent from the first quarter of 2010;
- increased oil and natural gas liquids production by 86 percent to 1,612 bbls/d compared to 869 bbls/d in the second quarter of 2009, changing the production mix to approximately 20 percent crude oil and natural gas liquids in the second quarter of 2010;
- generated funds from operations (cash flow) of $13.0 million, an increase of five percent from the comparative quarter of 2009;
- reduced operating costs by 20 percent to $7.99 per boe in the second quarter of 2010 from $9.96 per boe in the second quarter of 2009 and achieved an operating netback of $22.01 per boe in the quarter;
- realized $4.3 million in hedging gains on natural gas commodity contracts, providing stability to cash flow and balance sheet strength;
- completed an equity offering of 11.0 million common shares at $2.75 per share for gross proceeds of $30.3 million;
- renewed the Company's credit facilities at $135.0 million, an increase of $10.0 million; and
- reduced bank debt plus working capital (net debt) to $79.2 million at the end of the second quarter resulting in a net debt to annualized cash flow ratio of approximately 1.4:1.

Operational Highlights

	Three Months Ended June 30			Six Months Ended June 30		
Production	**2010**	2009	% Change	**2010**	2009	% Change
Natural gas (mcf/d)	**38,540**	35,641	8	**38,445**	35,229	9
Crude oil (bbls/d)	**1,074**	371	189	**910**	423	115
Natural gas liquids (bbls/d)	**538**	498	8	**523**	491	7
Total (boe/d)	**8,035**	6,809	18	**7,841**	6,786	16

Financial Highlights ($ thousands except per unit amounts)

	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	% Change	**2010**	2009	% Change
Petroleum and natural gas sales	**29,125**	23,229	25	**58,644**	47,434	24
Per boe	**39.83**	37.49	6	**41.32**	38.62	7
Funds from operations	**12,988**	12,371	5	**28,145**	22,388	26
Per boe	**17.77**	19.97	(11)	**19.84**	18.23	9
Per share – Basic	**0.12**	0.16	(25)	**0.27**	0.28	(4)
Per share – Diluted	**0.12**	0.16	(25)	**0.27**	0.28	(4)
Net earnings (loss)	**(2,742)**	(2,817)	(3)	**518**	(6,137)	-
Per boe	**(3.75)**	(4.54)	(17)	**0.37**	(4.99)	-
Per share – Basic	**(0.03)**	(0.04)	25	**0.01**	(0.08)	-
Per share – Diluted	**(0.03)**	(0.04)	25	**-**	(0.08)	-
Capital invested	**8,061**	3,602	124	**43,565**	17,694	146
Disposition of properties	**(251)**	(74)	239	**(251)**	(225)	12
Net capital invested	**7,810**	3,528	104	**43,314**	17,469	148
Acquisition of properties	**(307)**	(218)	41	**385**	(218)	-
Total capital	**7,503**	3,310	127	**43,699**	17,251	153

	Jun. 30 2010	Dec. 31 2009	% Change
Debt plus working capital deficiency [1]	**79,217**	92,538	(14)
Total assets	**379,555**	361,698	5
Shares outstanding (000's)			
Basic	**112,682**	101,166	11
Diluted	**120,494**	108,594	11

[1] excludes risk management asset and the related current future income taxes.

MESSAGE TO SHAREHOLDERS

Production during the second quarter of 2010 averaged 8,035 boe/d, an increase of 18 percent compared to 6,809 boe/d in the second quarter of 2009. The increased light oil production at Hythe and Bigstone changed the production mix in the quarter to 20 percent liquids (80 percent natural gas) from 13 percent liquids (87 percent natural gas) in the second quarter of 2009.

Delphi's natural gas production continued to receive a premium to AECO pricing, $1.42 per mcf in the second quarter, due to marketing arrangements, heating content and natural gas hedges. Approximately 58 percent of the Company's natural gas production was hedged at an average price of $6.00 per mcf in the second quarter, resulting in a gain on natural gas contracts of $4.3 million. These pricing premiums resulted in a realized natural gas price of $5.30 per mcf representing a premium of 36 percent to average AECO pricing during the second quarter.

Delphi continues to improve operating efficiencies as a result of production growth and owned infrastructure within the Company's concentrated core areas. In the second quarter of 2010, operating costs were $7.99 per boe, compared to $9.96 per boe in the second quarter of 2009 and $8.71 per boe in the first quarter of 2010.

Delphi's financial position remains strong at the end of the second quarter of 2010. In the second quarter, the Company's lenders completed their annual credit review. As a result, the Company's credit facilities were increased by $10.0 million to $135.0 million. At June 30, 2010, Delphi had net debt of $79.2 million. On a first half annualized funds from operations basis, Delphi's net debt to cash flow ratio was 1.4:1. Net debt includes bank debt plus working capital deficiency excluding the risk management asset/liability and the related current future income taxes.

OPERATIONS

Field operations in the second quarter were limited as a result of typical spring break-up conditions. The Company completed the final stages of its winter capital program, including the majority of a 15 kilometre gas gathering system extension in the Wapiti area. Delphi was also active at Crown land sales during the second quarter with an acquisition strategy focused within the Company's core areas. Delphi also initiated drilling activities on two wells of a planned 17 well second half capital program. During the first six months of 2010, Delphi drilled 16 (10.7 net) wells with capital expenditures totalling $43.7 million.

Second Half 2010 Capital Program

The focus of the remaining 2010 capital program will be directed towards the Company's three core areas of Bigstone, Hythe and Wapiti/Gold Creek.

- The Company plans to drill up to 17 gross (9.8 net) wells in the second half of 2010 and currently has five drilling rigs active in the field;
- The locations of the planned wells are as follows: seven (4.2 net) at Hythe, six (2.3 net) at Bigstone and four (3.3 net) at Wapiti/Gold Creek;
- Fifty-five percent of the 9.8 net wells drilled will be horizontal wells with multi-stage frac completions; and
- Forty-five percent of the 9.8 net wells drilled will target light oil and the remaining wells will target natural gas with an average NGL content of 50 bbls/mmcf.

Bigstone

Cardium Light Oil Horizontal Well Program

At Bigstone, the Company will participate in up to six wells (2.3 net) targeting Cardium light oil; five wells will be drilled horizontally and one will be a vertical well.

The vertical well has been drilled, cased and is scheduled for completion operations during August. Based on core data and electric logs, the reservoir quality appears similar to the wells drilled during the 2009/2010 winter program. The Company is preparing to spud the first of two operated horizontal wells with the second well being drilled immediately after the first. The Company also has plans to participate in three non-operated horizontal wells during the second half of 2010.

This six well program is on trend with two wells drilled during the 2009/2010 winter program. The 90 day average production rates for these two wells were 170 and 340 boe/d. Delphi controls approximately 17 net sections of prospective Cardium acreage in the Bigstone area.

Hythe

Doe Creek Light Oil Horizontal Well Program

At Hythe, the Company will participate in up to four horizontal wells (1.9 net) targeting Doe Creek light oil.

One well has been drilled and cased with completion operations ongoing. A second operated well is currently drilling and a third well will be drilled immediately after the second well. A fourth non-operated well will be drilled later in the third quarter. Two wells drilled in the 2009/2010 winter program had 90 day average production rates of 170 and 305 boe/d. Delphi controls approximately 11 net sections of prospective Doe Creek acreage in the Hythe area.

Falher and Bluesky Horizontal Well Program

Also at Hythe, the Company will participate in three horizontal wells (2.3 net) targeting natural gas in the Bluesky and Falher formations.

One well targeting the Bluesky formation has been drilled and cased with completion operations ongoing. Two additional wells targeting the Falher formation are currently drilling. The horizontal Bluesky and Falher wells drilled during the

2009/2010 winter program had 90 day average production rates of 160 and 335 boe/d, respectively. Delphi controls in excess of 100 net sections of prospective Bluesky and Falher acreage in the Hythe area.

Wapiti/Gold Creek

Gething/Nikanassin Vertical Well Program

At Wapiti/Gold Creek, the Company will participate in up to four vertical wells (3.3 net) targeting liquids rich natural gas in the Gething and Nikanassin formations.

The first well targeting the Nikanassin has been drilled, cased and is scheduled for completion operations during August. Based on core data and electric logs, the reservoir quality appears similar to the wells drilled during the 2009/2010 winter program. A second well is currently drilling and the Company is preparing to move in another rig to drill the third well in the program during August with a potential fourth well to be drilled in September.

Average 60 day production rates for two of the wells drilled in the 2009/2010 winter program were 300 and 420 boe/d. A third well had an initial test rate of 620 boe/d and will be brought on line in the next week through the recently constructed 15 kilometre gathering system that ensures takeaway capacity into Company owned infrastructure. Delphi controls in excess of 100 net sections of prospective Nikanassin acreage in the Hythe and Wapiti/Gold Creek areas.

LAND ACQUISITIONS

During the first half of 2010, the Company has been active in Crown and private land sales, acquiring 71,600 net acres (112 sections) of various mineral rights. A total of 21,400 net acres (33 sections) are located in the Company's core fairway from Hythe to Bigstone and are prospective for various Cretaceous formations including the Dunvegan, Falher, Bluesky, Gething and Nikanassin. The remaining 50,200 net acres (79 sections) target the Duvernay shale.

SHALE OIL

The Company is in the early stages of evaluating two distinct and separate shale oil plays where a significant land position has been established. One play is targeting the Second White Specks at Bigstone and the other play is targeting the Duvernay shale in the Sturgeon Lake area.

At Bigstone, the Company has stabilized production of 34 barrels of oil per day from an unstimulated well in the Second White Specks. A reservoir characterization study is ongoing to determine the depositional environment, hydrocarbon in place estimates, well productivity and stimulation options. In addition to the producing well, the Company is in the process of working over several wells to assist in determining reservoir extent, continuity and homogeneity. Delphi controls approximately 13,200 net acres (21 sections) in the Second White Specks at Bigstone.

In the Sturgeon Lake area, the Company participated in two Crown land sales during the first half of 2010 and acquired various mineral rights, including the Duvernay shale, on 52,200 net acres (79 sections) of land. A reservoir characterization study including the analysis of cores, cuttings, geochemistry and petrophysical properties is ongoing to determine the depositional environment, reservoir fluid type, key reservoir attributes and ultimately hydrocarbon in place estimates and recovery factors. Existing geochemistry analysis of several wells offsetting the Company's land position indicates the Duvernay shale is in the oil window and this analysis is supported by limited Duvernay oil tests in the area as well as oil production above and below the Duvernay section in the Sturgeon Lake area. Upon completion of the reservoir study, the Company will be high grading potential locations with the expectation of drilling a well in 2011.

OUTLOOK

The capital program through the first half of 2010 has resulted in record production levels and has successfully advanced numerous development projects, further increasing the Company's drill-ready inventory. Delphi's significant inventory of liquids-rich natural gas and light oil projects, low-cost structure and strong financial position strategically positions the Company for long term sustainable growth even in a low natural gas price environment.

Upon completion of a common share offering in the second quarter for gross proceeds of $30.3 million, the Company has expanded its capital program and expects to spend an estimated $90.0 to $100.0 million in 2010. The field capital program for the second half of 2010 will be directed towards drilling and recompletion opportunities in the Bigstone, Hythe and Wapiti/Gold Creek core areas. The planned capital program is expected to result in average 2010 production volumes of 7,900 to 8,200 boe/d, with fourth quarter 2010 production volumes of 9,000 boe/d.

Delphi is forecasting weak natural gas prices through the second half of 2010 with moderate improvements into 2011. The Company is assuming 2010 AECO natural gas prices will average between Cdn $3.75 and $4.25 per mcf for forecast purposes. The Company is hedged with approximately 53 percent of its natural gas production protected at an average floor price of $6.08 per mcf for the remainder of the year. This represents a 47 percent premium to the 2010 strip price of $4.14 per mcf. In addition, Delphi has 200 bbls/d of light oil production hedged at approximately current market prices. The higher production guidance offset by lower natural gas prices and increased royalty rates from increased oil and NGL production is expected to result in cash flow for 2010 of $57.0 to $62.0 million. Bank debt including working capital is estimated to be between $95.0 and $100.0 million at December 31, 2010.

The Company continues to improve its operating cost structure, having achieved a 20 percent reduction in second quarter operating costs to $7.99 per boe, placing the Company in the top quartile among its peers for operating costs and cash netbacks. Delphi is targeting a further 10 to 15 percent reduction in corporate operating costs over the next 12 months. The Company's low-cost core operating areas of Bigstone, Hythe and Wapiti/Gold Creek continue to demonstrate cost structure improvements on a per unit basis as a result of the production growth achieved to date through existing Company owned infrastructure. All three core areas generate field netbacks in excess of $20.00 per boe in the current commodity price environment. The disposition of less efficient non-core assets will contribute to continued cost structure efficiencies and cash netback optimization.

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 remain focussed on sustainable, capital efficient growth of the Company's production and reserve base while maintaining the financial strength and flexibility to take advantage of strategic opportunities.

CONFERENCE CALL

A conference call is scheduled for 9:00 a.m. Mountain Time (11:00 a.m. Eastern Time) on Thursday, July 29, 2010. The conference call number is 1-800-355-4959 or 416-695-6617. A brief presentation by David Reid, President and CEO and Brian Kohlhammer, VP Finance & CFO will be followed by a question and answer period.

If you are unable to participate in the conference call, a taped broadcast will be available until August 5, 2010. To access the replay, dial 1-800-408-3053 or 416-695-5800. The passcode is 2856255. Delphi's second quarter 2010 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:

DELPHI ENERGY CORP.
300, 500 – 4 Avenue S.W.
Calgary, Alberta
T2P 2V6
Telephone: (403) 265-6171 Facsimile: (403) 265-6207
Email: info@delphienergy.ca Website: www.delphienergy.ca

DAVID J. REID
President & CEO

BRIAN P. KOHLHAMMER
V.P. Finance & CFO

***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" 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.*

MANAGEMENT DISCUSSION AND ANALYSIS

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

The management discussion and analysis 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 results of the Company based upon accounting principles generally accepted in Canada. Its focus is primarily a comparison of the financial performance for the three and six months ended June 30, 2010 and 2009 and should be read in conjunction with the audited consolidated financial statements and accompanying notes for the years ended December 31, 2009 and 2008. The discussion and analysis has been prepared as of July 27, 2010.

DELPHI'S BUSINESS

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

Delphi Energy Corp. is a publicly-traded company, listed on the Toronto Stock Exchange, primarily engaged in the acquisition, exploration for and development and production of crude oil, natural gas and natural gas liquids from properties located in Western Canada. Delphi's operations are principally concentrated in North West Alberta, representing 76 percent of its production in 2009 and growing to 87 percent in the first six months of 2010. The Company has four primary core areas in the deep basin of North West Alberta located at Bigstone, Hythe, Wapiti/Gold Creek and Tower Creek.

OPERATIONAL AND FINANCIAL HIGHLIGHTS

What were the highlights of Delphi's operational and financial results in the second quarter of 2010?

With spring break-up occurring in the second quarter, field operations were very limited until the summer capital program was kicked off late in the quarter. Delphi Energy Corp. enjoyed an increase in production over the first quarter on the heels of a successful winter drilling program further contributing to growth in long-term value for its shareholders.

The accomplishments of the second quarter of 2010 are as follows:

- achieved record quarterly production in the second quarter of 2010 with average daily volumes of 8,035 barrels of oil equivalent per day (boe/d), an increase of 18 percent compared to the second quarter of 2009 and up five percent from the first quarter of 2010;
- increased oil and natural gas liquids production by 86 percent to 1,612 bbls/d compared to 869 bbls/d in the second quarter of 2009, changing the production mix to approximately 20 percent crude oil and natural gas liquids in the second quarter of 2010;
- generated funds from operations (cash flow) of $13.0 million, an increase of five percent from the comparative quarter of 2009;
- reduced operating costs by 20 percent to $7.99 per boe in the second quarter of 2010 from $9.96 per boe in the second quarter of 2009;
- realized $4.3 million in hedging gains on natural gas commodity contracts, providing stability to cash flow and balance sheet strength;
- completed an equity offering of 11.0 million common shares at $2.75 per share for gross proceeds of $30.3 million;
- renewed the Company's credit facilities at $135.0 million, an increase of $10.0 million; and
- reduced bank debt plus working capital (net debt) to $79.2 million at the end of the second quarter resulting in a net debt to annualized cash flow ratio of approximately 1.4:1.

Cash flow in the second quarter of 2010 was $13.0 million or $0.12 per basic share, compared to $12.4 million or $0.16 per basic share in the second quarter of 2009. Cash flow was five percent higher as a result of higher production volumes, higher crude oil prices and lower operating costs.

Delphi's financial position continues to remain strong at the end of the second quarter of 2010. At June 30, 2010, the Company had net debt of $79.2 million on total credit facilities of $135.0 million as capital expenditures were reduced due to spring break-up and the Company closed a $30.3 million equity offering. On an annualized six month funds from operations basis, Delphi's net debt to cash flow ratio was 1.4:1. Net debt includes bank debt plus working capital deficiency excluding the risk management asset/liability and the related current future income taxes. The Company's lenders completed their annual review in the quarter, resulting in an increase in the credit facilities to $135.0 million, up $10.0 million from the previous review late in 2009.

BUSINESS ENVIRONMENT

How has the benchmark pricing of Delphi's production and economic parameters changed from the previous year?

The Company is exposed to the volatility in commodity price markets and the change in the foreign exchange rate between the Canadian and United States dollar for pricing of its production volumes. 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 June 30			Six Months Ended June 30		
	2010	2009	% Change	**2010**	2009	% Change
Natural Gas						
NYMEX (US $/mmbtu)	**4.32**	3.71	16	**4.73**	4.14	14
AECO (CDN $/mcf)	**3.89**	3.47	12	**4.42**	4.21	5
Crude Oil						
West Texas Intermediate (US $/bbl)	**77.99**	59.62	31	**78.39**	51.46	52
Edmonton Light (CDN $/bbl)	**75.13**	65.88	14	**77.59**	57.88	34
Foreign Exchange						
Canadian to US dollar	**1.03**	1.17	(12)	**1.03**	1.21	(15)
US to Canadian dollar	**0.97**	0.86	13	**0.97**	0.83	17

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 over the past several years have been influenced more by North American supply and demand than global natural gas fundamentals. The increase in capacity of natural gas liquefaction and regasification facilities for LNG deliveries to the U.S. can influence North America natural gas prices but primarily in periods of short supply in the U.S.; not over supply as has been the situation the past several years.

In the second quarter of 2010, natural gas prices began to decrease as winter heating demand decreased and natural gas production was placed into storage to meet next winter's heating demand. Industrial demand continues to be reduced due to the current economic slowdown. Canadian natural gas prices in the second quarter varied from a high of Cdn $4.44 per mcf to a low of Cdn $3.53 per mcf. For the second quarter, the average price for AECO was Cdn $3.89 per mcf, $0.42 per mcf higher than the average for the same quarter in 2009.

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 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 85 million barrels per day to meet the global requirement for energy.

Through the second quarter of 2010, the price for crude oil traded between U.S. $67.00 and U.S. $80.00 per barrel as the global demand for oil, while reasonably stable, continued to experience volatility due to concerns over the global economic recovery in light of government deficits throughout parts of Europe. The U.S. based price for crude oil was also affected by the decline in the value of the U.S. dollar compared to the currency of most of its major trading partners. In the second quarter of 2010, WTI averaged U.S. $77.99 per barrel, 31 percent higher than the same quarter of the previous year.

In 2010 so far, the general trend for the value of the Canadian dollar against its U.S. counterpart was that of a stronger Canadian dollar. As a producer of crude oil, a stronger Canadian dollar has a negative effect on the price received for production. The Cdn/US exchange rate varied from slightly less than parity to a high of $1.08 in the quarter. In the second quarter of 2010, Canadian crude oil prices averaged $75.13 per barrel compared to $65.88 per barrel in the second quarter of 2009, a 14 percent increase over the comparative quarter.

Prices for heavy oil and other lesser quality crude oils trade at a discount or differential to light crude oil due to the additional costs involved in the refining process. The average differential in the second quarter of 2010 was $8.31 per barrel compared to $3.54 per barrel in 2009. The increase in the average differential and higher light oil prices resulted in Bow River crude prices averaging $66.83 per barrel in the second quarter of 2010 compared to $62.34 per barrel in the comparative quarter of 2009.

What does the Company expect in 2010 as it relates to these external factors?

For forecasting purposes, Delphi continues to expect a challenging natural gas market for 2010 as the industrial demand in the United States returns at a slow pace and the U.S. rig count increases, particularly horizontal drilling into the shale gas plays. The Company currently anticipates AECO will average between Cdn $3.75 and $4.25 per mcf in 2010.

While crude oil suffers from a similar concern of oversupply in the short term, the demand for crude oil is still relatively strong as the world's largest source of energy required on a daily basis. Delphi anticipates WTI to average between U.S. $70.00 and $80.00 per barrel for 2010.

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 financial markets tolerance for risk and need for financial security in the form of holding U.S dollars will also have a significant effect on the value of the Canadian dollar against the U.S. dollar. Delphi believes the Canadian dollar will remain quite strong in 2010 as global economies recover from the recent slowdown. The Canadian dollar is expected to trade in the $0.95 to $1.05 range against the U.S. dollar.

Delphi continues to monitor 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.

FINANCIAL STRATEGY

From a financial point of view, what strategies does the Company employ to achieve its results and meet forecast expectations?

The Company maintains an active risk management program as an integral part of its overall financial strategy to mitigate volatility in cash flow resulting from fluctuating commodity prices. Delphi's risk management program consists of fixed price contracts, costless collars, participating swaps and puts and calls which provide downside protection. Costless collars, participating swaps and puts also provide the opportunity to share in the upside if market prices increase above the floor price. If market prices are above fixed price contracts or the ceiling price of costless collars and calls, the Company would continue to achieve its downside protection while realizing losses on these hedging contracts.

Delphi has a strategy of hedging approximately 40 to 50 percent of its natural gas production as long as demand/supply fundamentals indicate volatile markets in the future. Currently, Delphi has hedged approximately 53 percent of its before-royalty natural gas production at a predominantly AECO based average floor price of $6.08 per mcf for the remainder of 2010. This compares to the forward strip commodity price for AECO of $4.14 per mcf for the remainder of 2010 as of July 23, 2010. The following natural gas hedges are in place to support the Company's cash flow.

	Jul-Oct 2010	Nov-Mar 2010/11	Apr - Oct 2011
Production hedged (mmcf/d)	20.9	11.2	2.0
Percentage of natural gas production *	58%	31%	5%
Price floor (Cdn $/mcf)	$6.00	$6.23	$5.97

* based on 36 mmcf/d

The fair value of outstanding contracts is estimated to be approximately $8.3 million as of June 30, 2010.

Delphi continues to direct efforts at maintaining or reducing its controllable costs. Increasing production at its various operating fields through Company owned infrastructure reduces fixed costs on a per boe basis and improves netbacks. Field operators are encouraged to undertake preventative maintenance on field infrastructure and wellsite equipment to minimize production downtime and prevent significant operating costs associated with repairs. The Company strives to achieve improvement in its costs of production and at a minimum maintain current production costs.

Maintaining or improving operating netbacks per boe through the risk management program, production mix and the control of costs associated with production operations, allows the Company to pursue its planned capital program with greater confidence that financial flexibility will be maintained while incurring capital expenditures to grow production volumes. The risk management program has been and will continue to be an integral part of maximizing operating netbacks during periods of price volatility and excess natural gas supply.

As a result of the significant difference in netbacks between crude oil and natural gas, the Company's capital program will continue to be geared more towards oil and liquids-rich natural gas opportunities. By altering the Company's production mix, there is greater certainty of achieving the Company's cash flow expectations due to the higher netback crude oil and liquids production.

The net capital expenditure program in the field will continue to approximate forecast cash flow. Additional capital may be approved as a result of opportunistic acquisitions, incremental cash flow from greater than expected production growth, higher than forecast cash netbacks or other sources of financing. For 2010, an expanded capital program has been approved as a result of the equity offering completed in the second quarter.

Delphi continues to be focused on reducing its leverage and improving its financial flexibility through net debt reduction or increasing cash flow growth resulting in a lower net debt to funds from operations ratio. The Company continues to be focused on achieving its internal target range for this ratio of 1.5 times. In a low price environment, the Company's objective would be to reduce or at least not increase the net debt balance by undertaking a capital program within cash sources.

SELECTED INFORMATION

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

Over the last eight quarters production has grown from 6,409 boe/d to 8,035 boe/d. Production for the last eight quarters reflects the following events. In 2008, the combination of a successful winter and summer capital program and the production increase from the Peace River Arch acquisition resulted in continued production growth quarter over quarter. In 2009, the Company changed its product focus due to the commodity price environment. In the first six months of 2009, production growth was achieved with drilling success at Bigstone and Hythe, Alberta, primarily focused on natural gas opportunities. With crude oil and natural gas prices going in opposite directions through 2009, the capital program in the second half of 2009 was geared toward drilling for crude oil while acquiring strategic natural gas properties and infrastructure. The Company completed four natural gas property and infrastructure acquisitions in the deep basin of North West Alberta in the latter half of 2009. Continued drilling success in 2010 has resulted in first and second quarter volumes of 7,645 and 8,035 boe per day, respectively. For the six months ended June 30, 2010, production volumes of 7,841 boe per day were achieved, representing growth of 16 percent over the first half of 2009.

Over the past two years, the changes in revenue and cash flow from quarter to quarter primarily reflect the production volumes achieved and the volatility of commodity prices over the past two years with the third quarter of 2008 experiencing the tail end of peak prices for both crude oil and natural gas.

Natural gas prices over the past two years have generally reflected the cyclical nature of demand. Higher prices are realized in the winter months, reflecting demand for heating and with lower prices through the summer months as production is placed in storage for the upcoming heating season demand. Natural gas prices in the second quarter of 2008 did not follow the cyclical trend expected, as prices continued to increase coming out of the winter heating season due to concerns over natural gas supply in storage and the continued increase in crude oil prices. Subsequent to the second quarter of 2008, natural gas prices decreased significantly and then stabilized in the fourth quarter. In 2009, reduced heating and industrial demand due to the economic crisis caused natural gas prices to decrease further as a result of concerns over excess supply relative to demand. The average spot price for AECO in 2009 was $3.96 per mcf, the lowest average price in 10 years. Crude oil prices had recovered to over U.S. $80.00 per barrel by the end of 2009 from a low earlier in the year of U.S. $33.98 per barrel. In the first half of 2010, crude oil averaged U.S. $78.39 which was a 52 percent increase over the comparative period in 2009.

The Company achieved record cash flow of approximately $20.0 million in the second quarter of 2008 at the peak of commodity prices. Delphi continues to mitigate the volatility of commodity prices on its cash flow and capital program by undertaking an active risk management program.

Net earnings of the Company are primarily driven by the difference between the cash flow netback realized per boe of production versus the Company's depletion, depreciation and amortization (DD&A) rate of $20.43 per boe. 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 F&D costs of $12.06 per proved boe in 2009 contributed to reduce the overall DD&A rate of the Company.

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

	Jun. 30 2010	Mar. 31 2010	Dec. 31 2009	Sept. 30 2009	Jun. 30 2009	Mar. 31 2009	Dec. 31 2008	Sept. 30 2008
Production								
Natural gas (mcf/d)	**38,540**	38,349	34,626	33,628	35,641	34,813	35,545	33,691
Oil (bbls/d)	**1,074**	745	630	624	371	475	431	372
Natural gas liquids (bbls/d)	**538**	508	487	544	498	485	353	421
Barrels of oil equivalent (boe/d)	**8,035**	7,645	6,888	6,773	6,809	6,762	6,708	6,409
Financial								
($ thousands except per unit amounts)								
Petroleum and natural gas revenue	**29,125**	29,519	26,297	24,433	23,229	24,205	30,160	34,461
Funds from operations (cash flow)	**12,988**	15,157	14,218	12,635	12,371	10,017	13,473	18,160
Per share – basic	**0.12**	0.15	0.14	0.16	0.16	0.13	0.18	0.24
Per share – diluted	**0.12**	0.15	0.14	0.16	0.16	0.13	0.18	0.23
Net earnings (loss)	**(2,742)**	3,260	1,386	(3,278)	(2,817)	(3,320)	(959)	6,743
Per share – basic	**(0.03)**	0.03	0.02	(0.04)	(0.04)	(0.04)	(0.01)	0.09
Per share – diluted	**(0.03)**	0.03	0.02	(0.04)	(0.04)	(0.04)	(0.01)	0.09

On annual basis, how has Delphi performed?

The decrease in revenue and net earnings from 2008 to 2009 was primarily due to the significant drop in natural gas prices. The increase in revenue and net earnings from 2007 to 2008 was due to a combination of higher production volumes and much higher commodity prices.

	2009	2008	2007
Revenue	98,164	135,402	97,933
Net earnings/(loss)	(8,029)	5,094	(10,472)
Total assets	361,698	364,538	311,740
Bank debt plus working capital	92,538	109,237	100,658

DRILLING OPERATIONS

How active was Delphi in its drilling program in the second quarter?

The Company did not drill any wells in the second quarter of 2010. The Company commenced its summer drilling program late in the second quarter. Year to date, Delphi has drilled 16 gross (10.7 net) wells with a success rate of 94 percent. The drilling was primarily focused on the core properties of Bigstone, Wapiti/Gold Creek and Hythe in North West Alberta.

	Three Months Ended June 30, 2010		Six Months Ended June 30, 2010	
	Gross	**Net**	**Gross**	**Net**
Natural gas wells	**-**	**-**	**9.0**	**6.5**
Oil wells	**-**	**-**	**6.0**	**3.9**
Dry wells	**-**	**-**	**1.0**	**0.3**
Total wells	**-**	**-**	**16.0**	**10.7**
Success rate (%)	**-**	**-**	**94**	**97**

What is the Company's drilling plans for the remainder of 2010?

The capital program for the remainder of 2010 consists of a broad range of projects including the drilling of up to 9.8 net wells. The focus of the program will continue to be on light oil and natural gas opportunities in Bigstone and Hythe with several wells being drilled in the Company's newly acquired Wapiti/Gold Creek area pursuing liquids-rich natural gas opportunities. The program will consist of both vertical and horizontal drilling using multi-stage fracturing technology in horizontal wells and multiple completions for commingled production in vertical wells.

CAPITAL INVESTED

How much did the Company spend in the first half of 2010 and where were the capital expenditures incurred?

The Company continued to direct its capital program at its core areas of Bigstone, Hythe, and Wapiti/Gold Creek 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 in the field was $43.6 million, net of drilling credits of $3.3 million, with approximately 64 percent directed at drilling and completion operations and 20 percent incurred on equipping and facility projects.

Delphi also added to its growth potential with the acquisition of 79 net sections of Duvernay shale rights at attractive entry costs targeting natural gas and/or light oil. Delphi's inventory of undeveloped land has increased to approximately 210,293 net acres, up 22 percent from December 31, 2009.

During the second quarter, the Company disposed of its non-core properties in East Central Alberta for $0.3 million. The properties consisted of medium quality oil and natural gas production with operating costs in excess of $30.00 per boe. With the disposition, the Company will benefit from a reduction in total operating costs per boe and the reduction of asset retirement obligations associated with the properties of approximately $1.9 million.

	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	% Change	**2010**	2009	% Change
Land	**1,734**	290	498	**3,833**	556	589
Seismic	**8**	270	(97)	**131**	296	(56)
Drilling and completions	**809**	72	1,024	**27,944**	11,082	152
Equipping and facilities	**3,517**	2,078	69	**8,862**	3,556	149
Capitalized expenses	**1,230**	697	76	**2,025**	1,813	12
Other	**763**	195	291	**770**	391	97
Capital invested	**8,061**	3,602	124	**43,565**	17,694	146
Disposition of properties	**(251)**	(74)	239	**(251)**	(225)	12
Net capital invested	**7,810**	3,528	104	**43,314**	17,469	148
Acquisition of properties	**(307)**	(218)	41	**385**	(218)	-
Total capital invested	**7,503**	3,310	127	**43,699**	17,251	153

PRODUCTION

How has Delphi been able to achieve the significant growth in production compared to 2009?

For the three months ended June 30, 2010, Delphi achieved record production volumes of 8,035 boe/d, representing an increase of 18 percent over the comparative period in 2009. The production growth is highlighted by an 86 percent increase in crude oil and natural gas liquids compared to the same quarter in 2009. Delphi's growth in production volumes is attributed to a successful winter drilling program in the Company's core areas as well as the closing of strategic acquisitions during the latter half of 2009. With the weakness in natural gas pricing, Delphi's winter drilling program targeted opportunities in its crude oil and liquids-rich natural gas inventory to maximize netbacks. The Company's production portfolio for the quarter was weighted 80 percent to natural gas, 13 percent to crude oil and seven percent to natural gas liquids.

	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	% Change	**2010**	2009	% Change
Natural gas (mcf/d)	**38,540**	35,641	8	**38,445**	35,229	9
Crude oil (bbls/d)	**1,074**	371	189	**910**	423	115
Natural gas liquids (bbls/d)	**538**	498	8	**523**	491	7
Total (boe/d)	**8,035**	6,809	18	**7,841**	6,786	16

REALIZED SALES PRICES

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

For the three and six months ended June 30, 2010, Delphi's risk management program realized a gain of $4.3 million and $7.2 million, respectively. For the quarter, the realized gain was $1.20 per mcf with physical contracts contributing a gain of $0.90 per mcf and financial contracts contributing a gain of $0.30 per mcf. The average realized natural gas price was nine percent less than the comparative period due to a decrease in hedge gains offset by higher heat content on natural gas volumes.

	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	% Change	**2010**	2009	% Change
AECO ($/mcf)	**3.89**	3.47	12	4.42	4.21	5
Heating content and marketing ($/mcf)	**0.22**	0.19	17	0.32	0.24	35
Gain on physical contracts ($/mcf)	**0.90**	1.80	(50)	0.86	1.38	(38)
Gain on financial contracts ($/mcf)	**0.30**	0.35	(15)	0.16	0.34	(53)
Realized natural gas price ($/mcf)	**5.30**	5.81	(9)	5.77	6.17	(7)
Edmonton Light ($/bbl)	**75.13**	65.88	14	**77.59**	57.88	34
Quality differential ($/bbl)	**2.39**	(3.77)	-	**(0.83)**	(4.75)	(83)
Gain on financial contracts ($/bbl)	**0.62**	-	100	**0.66**	-	100
Realized oil price ($/bbl)	**78.14**	62.11	26	**77.42**	53.13	46
Realized natural gas liquids price ($/bbl)	**54.56**	50.20	8	**57.88**	44.77	29
Total realized sales price ($/boe)	**39.83**	37.49	6	**41.32**	38.62	7

Delphi's oil production is a mix of light and medium oil; therefore the Company's average price fluctuates with the change in the benchmark crude oil prices and the quality differential. 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. The Company's realized crude oil and natural gas liquids prices were significantly higher than the comparative quarter in the previous year as a result of the significant increase in benchmark prices.

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 5,500 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 (discount) Delphi realized on natural gas prices 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 benefited from a premium to AECO.

	Jun. 30 2010	**Mar. 31 2010**	Dec. 31 2009	Sept. 30 2009	Jun. 30 2009	Mar. 31 2009	Dec. 31 2008	Sept.30 2008
Natural Gas Price								
Delphi realized ($/mcf)	**5.30**	6.26	6.15	5.77	5.81	6.55	8.14	8.28
AECO average ($/mcf)	**3.89**	4.96	4.49	2.94	3.47	4.95	6.70	7.73
Premium to AECO	**36%**	26%	37%	96%	67%	32%	21%	7%
Hedging gain (loss) ($000's)	**4,186**	2,941	4,498	7,973	6,997	3,991	1,985	(67)

RISK MANAGEMENT ACTIVITIES

What is Delphi's risk management strategy and what contracts are in place to mitigate the risk of 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 hedged approximately 53 percent of its before-royalty natural gas production at a predominately AECO based average floor price of $6.08 per mcf for the remainder of 2010.

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 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 operations. 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. As at June 30, 2010, the Company did not hold any physical commodity sales contracts based in U.S. dollars.

The Company has fixed the price applicable to future production through the following contracts.

Time Period	Commodity	Type of Contract	Quantity Contracted	Contract Price ($/unit)
January 2010 – March 2011	Natural Gas	Financial	2,000 GJ/d	$5.72 fixed
January 2010 – December 2010*	Natural Gas	Financial	3,500 GJ/d	$7.40 Call
January 2010 – December 2010*	Natural Gas	Physical	3,500 GJ/d	$7.15 Call
January 2010 – December 2010	Crude Oil	Financial	100 bbls/d	$86.40 fixed
January 2010 – December 2010	Crude Oil	Financial	100 bbls/d	$72.20 floor/$100.00 ceiling
January 2010 – March 2011	Natural Gas	Physical	1,500 GJ/d	$5.74 fixed
April 2010 – October 2010**	Natural Gas	Financial	2,500 GJ/d	$4.75 Put
April 2010 – October 2010	Natural Gas	Financial	2,000 GJ/d	$5.53 fixed
April 2010 – October 2010	Natural Gas	Financial	1,500 GJ/d	$4.80 floor plus 50% > $4.80
April 2010 – December 2010	Natural Gas	Physical	3,000 GJ/d	$6.25 floor/$7.47 ceiling
April 2010 – December 2010	Natural Gas	Physical	4,000 GJ/d	$5.93 floor plus 50% > $5.93
April 2010 – March 2011	Natural Gas	Physical	3,000 GJ/d	$6.12 fixed
April 2010 – March 2011	Natural Gas	Physical	2,500 GJ/d	$5.73 fixed
January 2011 – December 2011**	Natural Gas	Financial	2,500 GJ/d	$7.14 Call
April 2011 – October 2011	Natural Gas	Physical	2,000 GJ/d	$5.66 fixed

* The 2010 call contracts were executed in 2009 to obtain a $6.00 put in 2009 on a costless basis.

**The Company has acquired a natural gas put contract at $4.75 per gigajoule on 2,500 gigajoules per day for the period April 1, 2010 through October 31, 2010. This put was paid for with the sale of a natural gas call on 2,500 gigajoules per day at a price of $7.14 per gigajoule for the period January 1, 2011 through December 31, 2011.

The Company recognized an unrealized non-cash gain on its financial contracts of $2.2 million for the first half of 2010. 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 period 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 2010 compare to the same period in 2009 and what factors contributed to the change?

For the three and six months ended June 30, 2010, Delphi generated revenue of $29.1 million and $58.6 million, respectively, representing an increase of 25 percent and 24 percent over the comparative periods. The increase in revenue is a result of an increase in production volumes and an increase in the realized price per boe. Contributing to the increased price per boe is the production increase of crude oil and natural gas liquids.

The risk management program associated with natural gas and crude oil pricing generated revenue of $4.3 million in the second quarter of 2010. For seven consecutive quarters, Delphi has received a premium to AECO pricing due to the success of the risk management program.

	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	% Change	**2010**	2009	% Change
Natural gas	**14,361**	11,856	21	**33,011**	28,377	16
Natural gas physical contract gains	**3,140**	5,851	(46)	**6,018**	8,813	(32)
Crude oil	**7,575**	2,097	261	**12,643**	4,068	211
Natural gas liquids	**2,666**	2,275	17	**5,479**	3,979	38
Sulphur	**227**	4	5,587	**274**	22	1,148
Realized gain on risk management contracts	**1,094**	1,146	(5)	**1,110**	2,175	(49)
Crude oil financial contract gains	**61**	-	100	**108**	-	100
Total	**29,125**	23,229	25	**58,644**	47,434	24

ROYALTIES

What are the types of royalties the Company pays to produce oil and gas?

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 credits 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. Royalties are not affected by gains or losses realized through the Company's risk management program.

What were royalty costs in the second quarter of 2010 and how did they compare to the same period in 2009?

Crown royalties of $4.3 million were partially offset by $0.7 million of royalty credits with the net amount of $3.6 million representing 76 percent of the total royalties paid in the second quarter. The net Crown royalties were significantly higher than the $4.1 million paid in the first six months of 2009 primarily as a result of higher commodity prices in 2010 and the Company's significant increase in crude oil and natural gas liquids production. Royalty credits, in the second quarter of 2010, were less than the comparative quarter as the Company did not receive a significant adjustment related to gas cost allowance. In 2009, the Company received a $0.9 million gas cost allowance adjustment in the second quarter due to newly acquired infrastructure.

Gross overriding royalties represent 25 percent of total royalties in the first six months of 2010 compared to 13 percent in the comparative period of 2009. The increase in gross overriding royalties is a result of the five percent gross overriding royalty granted on the Bigstone property late in 2009 as well as various farm-in transactions undertaken by the Company.

	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	% Change	**2010**	2009	% Change
Crown royalties	**4,296**	2,302	87	**9,028**	7,736	17
Royalty credits	**(693)**	(2,449)	(72)	**(2,817)**	(3,649)	(23)
Crown royalties – net	**3,603**	(147)	-	**6,211**	4,087	52
Freehold royalties	**95**	99	(4)	**166**	185	(10)
Gross overriding royalties	**1,021**	514	99	**2,156**	637	238
Total	**4,719**	466	913	**8,533**	4,909	74
Per boe	**6.45**	0.75	760	**6.01**	4.00	50

What were the average royalty rates paid on production in 2010?

For the three and six months ended June 30, 2010, the Crown royalty rate increased 562 percent and 23 percent over the comparative periods. The higher 2010 Crown royalty rate was primarily due to higher commodity prices in 2010, the change in the Company's product mix and reduced royalty credits. The gross overriding royalty rate increased to four percent in 2010 from three percent in the prior year.

	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	% Change	**2010**	2009	% Change
Crown rate – net of royalty credits	**15%**	(1%)	-	**12%**	11%	8
Gross overriding rate	**4%**	3%	30	**4%**	2%	140
Average rate	**19%**	3%	562	**17%**	13%	23

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

What are the Company's expectations for royalty rates in 2010?

Delphi's average royalty rate for 2010 will ultimately be determined by the production rate of individual wells and commodity prices. Based on the Company's forecast of U.S. $75.00 per barrel of crude oil and an AECO spot price of Cdn $3.75 to $4.25 per mcf, Delphi anticipates its average royalty rate in 2010 to average between 16 and 18 percent. Similar to 2009, for 2010 the Company expects to receive the royalty credits for processing the Crown share of natural gas. The five percent royalty rate on new production in 2010 also is expected to continue to have a positive effect on royalty rates.

What are the highlights of the Alberta Royalty Framework changes announced in March 2010?

On March 11, 2010 the Alberta Government announced further changes to its royalty regime as a result of its "Competitiveness Review". The key changes are: 1) the current incentive program of five percent for the first year of production on new natural gas and conventional wells will become permanent but retain time and volume limits; 2) the maximum royalty rates for conventional oil will be reduced at higher price levels from 50 percent to 40 percent; 3) the maximum royalty rate for conventional and unconventional natural gas will be reduced at higher price levels from 50 percent to 36 percent.

OPERATING EXPENSES

How does the Company continue to reduce its operating expenses in 2010 as compared to 2009?

Operating costs on a per boe basis for the three and six months ended June 30, 2010, decreased 20 percent and 17 percent, respectively, over the comparative periods. The significant decrease in operating costs is attributed to higher production volumes from cost efficient core areas. With the disposition of the East Central Alberta properties and continued growth in production volumes from core areas, the Company's operating costs per boe are expected to continue decreasing.

	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	% Change	**2010**	2009	% Change
Production costs	**6,499**	6,420	1	**13,068**	13,684	(5)
Processing income	**(654)**	(251)	161	**(1,232)**	(1,311)	(6)
Total	**5,845**	6,169	(5)	**11,836**	12,373	(4)
Per boe	**7.99**	9.96	(20)	**8.34**	10.07	(17)

What are the Company's expectations for operating costs in 2010?

Delphi continues to focus on cost reduction and continues to direct staff to look for potential cost efficiencies. The corporate strategy to improve cost structure is working as the Company anticipates 2010 operating costs in the $7.75 to $8.25 per boe range.

TRANSPORTATION EXPENSES

How are transportation costs different from operating costs?

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 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.

	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	% Change	**2010**	2009	% Change
Total	**2,474**	2,128	16	**4,670**	3,589	30
Per boe	**3.38**	3.43	(1)	**3.29**	2.92	13

What factors contributed to the increase in transportation costs in the first half of 2010 and what are the Company's expectations for the remainder of 2010?

On a per boe basis, transportation costs for the three and six months ended June 30, 2010, decreased by one percent and increased by 13 percent, respectively, over the comparative periods. The increase in transportation costs is attributed to additional transportation capacity acquired in the latter half of 2009 which will be utilized as production volumes grow in core areas and the increased costs of trucking the Company's growth in crude oil volumes. Delphi expects transportation costs to be between $2.75 and $3.25 per boe for 2010.

GENERAL AND ADMINISTRATIVE

	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	% Change	**2010**	2009	% Change
General and administrative costs	**3,468**	2,159	61	**5,901**	5,416	9
Overhead recoveries	**(395)**	(213)	86	**(950)**	(472)	101
Salary allocations	**(1,303)**	(723)	80	**(2,162)**	(2,599)	(17)
Net	**1,770**	1,223	45	**2,789**	2,345	19
Per boe	**2.42**	1.97	23	**1.96**	1.91	3

How do the general and administrative costs in 2010 compare to 2009?

On a per boe basis, general and administrative (G&A) costs for the three and six months ended June 30, 2010 increased 23 percent and three percent over the comparative periods in 2009 due to the timing of compensation adjustments offset by an increase in production volumes. In 2009, annual compensation adjustments were recorded in the first quarter versus the second quarter in 2010. Delphi is committed to delivering strong growth and believes a strong team is paramount to achieve this goal. For 2010, Delphi is expecting G&A per boe to be approximately $2.00 per boe.

STOCK-BASED COMPENSATION

What is stock-based compensation expense?

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

	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	% Change	**2010**	2009	% Change
Stock-based compensation	**430**	393	9	**646**	884	(27)
Capitalized costs	**110**	264	(58)	**221**	544	(59)
Net	**320**	129	148	**425**	340	25
Per boe	**0.44**	0.21	108	**0.30**	0.28	7

The stock based non-cash compensation expense for the three and six months ended June 30, 2010, increased 108 percent and 7 percent over the comparative period. The increase in the second quarter of 2010 is attributed to additional stock options granted during the period. During the three and six months ended June 30, 2010, Delphi capitalized $0.1 million and $0.2 million, respectively, of stock-based compensation associated with exploration and development activities.

INTEREST

How do the costs of borrowing in the first quarter of 2010 compare against the same period in 2009?

For the three and six months ended June 30, 2010, interest expense on a per boe basis increased 29 percent and 26 percent over the comparative periods. The increase over the comparative periods was due to the increased pricing on the Company's credit agreement established late in the second quarter of 2009, reflective of higher market credit spreads.

	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	% Change	**2010**	2009	% Change
Total	**1,329**	872	52	**2,671**	1,830	46
Per boe	**1.82**	1.41	29	**1.88**	1.49	26

During 2009, the Company converted $80.0 million of its outstanding long term debt from prime-based loans to bankers' acceptances. At June 30, 2010, the bankers' acceptances have terms ranging from 90 to 92 days and a weighted average effective interest rate of 4.14 percent over the term.

What has the Company done to protect itself against an increase in interest rates?

The Company has entered into an interest rate swap transaction on borrowings through bankers' acceptances in the amount of $40.0 million maturing on May 4, 2011. The bankers' acceptance rate on the transaction will increase in fixed monthly increments of 4.55 basis points for an average fixed rate over two years of 0.94 percent. The effective interest rate over the two year term on $40.0 million of bankers' acceptances will be 0.94 percent plus the applicable stamping fee. The interest rate swap is fair valued at each reporting date and presented in the risk management asset or liability.

DEPLETION, DEPRECIATION AND ACCRETION

How has the Company's depletion and depreciation rate and expense changed in 2010 as compared to the same periods in 2009?

Depletion and depreciation per boe for the three and six months ended June 30, 2010 decreased 16 percent and 17 percent over the comparative periods. With continued drilling success at Bigstone, Hythe and Wapiti/Gold Creek, Delphi has been able to add proved reserves at a cost below the Company's current depletion rate. The decrease in total depletion and depreciation was a result of the depletion costs associated with increased production being more than offset by the improvement in the depletion rate.

	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	% Change	**2010**	2009	% Change
Depletion and depreciation	**14,836**	15,140	(2)	**28,491**	29,690	(4)
Accretion expense	**253**	151	68	**500**	394	27
Total	**15,089**	15,291	(1)	**28,991**	30,084	(4)
Depletion and depreciation per boe	**20.29**	24.44	(17)	**20.08**	24.17	(17)
Accretion per boe	**0.35**	0.24	42	**0.35**	0.32	10
Total per boe	**20.64**	24.68	(16)	**20.43**	24.49	(17)

What is accretion expense and how did this expense in the first six months of 2010 compare to 2009?

The accretion of asset retirement 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 three to 20 years. The Company uses a credit adjusted risk-free interest rate of eight to ten percent for the purpose of calculating the fair value of its asset retirement obligations and hence the accretion expense. The accretion expense for the three and six months ended June 30, 2010 increased 68 percent and 27 percent, respectively, over the comparative periods.

INCOME TAXES

What was the affect on future income taxes during the first six months of 2010?

The provision for future income taxes in the financial statements for the three months ended June 30, 2010, was a reduction of $0.9 million. Delphi does not anticipate it will be cash taxable before 2012.

	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	% Change	**2010**	2009	% Change
Current	**-**	-	-	**-**	-	-
Future (reduction)	**(878)**	(954)	(8)	**449**	(2,061)	-
Total	**(878)**	(954)	(8)	**449**	(2,061)	-
Per boe	**(1.20)**	(1.54)	(22)	**0.32**	(1.68)	-

FUNDS FROM OPERATIONS

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

Funds from operations is a non-GAAP measure and has been defined by the Company as net earnings (loss) plus the add back 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. Delphi uses funds from operations (cash flow) 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 to grow the Company's value for the shareholders and to repay debt.

What were the funds from operations for the first six months of 2010?

For the three and six months ended June 30, 2010, funds from operations were $13.0 million ($0.12 per basic share) and $28.1 million ($0.27 per basic share) compared to $12.4 million ($0.16 per basic share) and $22.4 million ($0.29 per basic share) in the comparative periods. The increase in funds from operations is a result of an increase in realized prices per boe and production volumes and a reduction in operating costs per boe.

	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	% Change	**2010**	2009	% Change
Net earnings (loss)	**(2,742)**	(2,817)	(3)	**518**	(6,137)	-
Non-cash items:						
Depletion, depreciation and accretion	**15,089**	15,291	(1)	**28,991**	30,084	(4)
Unrealized loss (gain) on risk management activities	**1,199**	722	66	**(2,238)**	162	-
Stock-based compensation expense	**320**	129	148	**425**	340	25
Future income taxes (reduction)	**(878)**	(954)	(8)	**449**	(2,061)	-
Funds from operations	**12,988**	12,371	5	**28,145**	22,388	26

How do funds from operations compare to cash flow from operating activities in the financial statements?

Funds from operations reflect two primary differences from the GAAP term cash flow from operating activities shown on the financial statements. These differences are expenditures incurred for asset retirement obligations and reclamation and changes in non-cash working capital. The following table is a reconciliation of funds from operations to cash flow from operating activities for the periods noted.

	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	% Change	**2010**	2009	% Change
Funds from operations: Non-GAAP	**12,988**	12,371	5	**28,145**	22,388	26
Change in non-cash working capital	**5,796**	89	6,411	**1,768**	(1,415)	-
Cash flow from operating activities: GAAP	**18,784**	12,460	51	**29,913**	20,973	43

NET EARNINGS

What factors contributed to the loss in the second quarter of 2010?

For the three and six months ended June 30, 2010, Delphi recorded a net loss of $2.7 million and net earnings of $0.5 million. Net earnings were affected by non-cash items such as depletion, depreciation and accretion, unrealized gains on risk management activities, stock-based compensation and future income taxes. These non-cash items represent the majority of the significant difference between funds from operations and net earnings.

NETBACK ANALYSIS

How was Delphi able to improve the netbacks in the first quarter of 2010 compared to the prior year?

The Company's netbacks were higher than the comparative quarter due to a higher realized price per boe and a reduction in operating costs per boe. The operating netback and cash netback are higher than the expected cost of finding and developing reserves resulting in a positive recycle ratio.

Delphi's production is predominantly natural gas and therefore Delphi's operating and cash netbacks are primarily driven by the price received for natural gas.

	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	% Change	**2010**	2009	% Change
Barrels of oil equivalent ($/boe)						
Realized sales price	**39.83**	37.49	6	**41.32**	38.62	7
Royalties	**6.45**	0.75	760	**6.01**	4.00	50
Operating expenses	**7.99**	9.96	(20)	**8.34**	10.07	(17)
Transportation	**3.38**	3.43	(1)	**3.29**	2.92	13
Operating netback	**22.01**	23.35	(6)	**23.68**	21.63	9
General and administrative expenses	**2.42**	1.97	23	**1.96**	1.91	3
Interest	**1.82**	1.41	29	**1.88**	1.49	26
Cash netback	**17.77**	19.97	(11)	**19.84**	18.23	9
Unrealized loss (gain) on financial contracts	**1.64**	1.16	41	**(1.58)**	0.13	-
Stock-based compensation expense	**0.44**	0.21	108	**0.30**	0.28	7
Depletion, depreciation and accretion	**20.64**	24.68	(16)	**20.43**	24.49	(17)
Future income taxes (reduction)	**(1.20)**	(1.54)	(22)	**0.32**	(1.68)	-
Net earnings (loss)	**(3.75)**	(4.54)	(17)	**0.37**	(4.99)	-

LIQUIDITY AND CAPITAL RESOURCES

Share Capital

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

At June 30, 2010, the Company had 112.7 million common shares outstanding (December 31, 2009 – 101.2 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 six months ended June 30, 2010.

	Three Months Ended June 30, 2010	Six Months Ended June 30, 2010
Weighted Average Common Shares		
Basic	**104,808**	103,037
Diluted	**104,808**	106,195
Trading Statistics [1]		
High	**2.90**	3.18
Low	**2.51**	1.70
Average daily, volume	**579,205**	678,769

[1] Trading statistics based on closing price

How many common shares and stock options are currently outstanding?

As at July 23, 2010, the Company had 112.7 million common shares outstanding and 7.9 milllion stock options outstanding. The stock options have an average exercise price of $1.57 per share.

Sources and Uses of Funds

	Three Months Ended June 30, 2010	Six Months Ended June 30, 2010
Sources:		
Funds from operations	12,988	28,145
Disposition of petroleum and natural gas properties	251	251
Acquisition of petroleum and natural gas properties	307	-
Issue of common shares	30,250	30,250
Exercise of stock options	269	607
	44,065	59,253
Uses:		
Cash and cash equivalents	10,886	5,755
Capital expenditures	8,061	43,565
Acquisition of petroleum and natural gas properties	-	385
Share issue costs	1,982	1,982
Change in non-cash working capital	23,136	6,466
	44,065	58,153
Increase (decrease) in bank debt	-	(1,100)

Bank Debt plus Working Capital (Net Debt)

How much net debt was outstanding at June 30, 2010?

At June 30, 2010, the Company had $80.0 million outstanding in the form of bankers' acceptances and working capital of $0.8 million for total net debt of $79.2 million excluding the financial asset of $1.9 million relating to the unrealized gain on financial commodity contracts and the associated future income tax liability.

What are the Company's credit facilities?

The Company has a revolving credit facility for $135.0 million with a syndicate of Canadian chartered banks. The facility is a 364 day committed revolving facility until May 31, 2011, the term-out date. The term-out date may be extended for a further 364 day period upon approval by the banks. Following the term-out date, the facilities would be available on a non-revolving basis for a one year term. The credit facility bears interest based on a sliding scale pricing grid tied to the Company's trailing debt to cash flow ratio: from a minimum of the bank's prime rate plus 1.75 percent to a maximum of the bank's prime rate plus 4.75 percent or from a minimum of bankers' acceptances rate plus a stamping fee of 2.75 percent to a maximum of bankers' acceptances rate plus a stamping fee of 4.75 percent.

What are the Company's forecast debt levels for the end of 2010?

In 2010, Delphi anticipates a field capital expenditure program equivalent to projected funds from operations and an expanded amount related to the proceeds from the equity offering resulting in net debt levels between $95 and $100 million by the end of 2010. Growth in cash flow to approximately $57.0 to $62.0 million is expected to result in a net debt to cash flow ratio of approximately 1.6-1.7:1 by the end of 2010.

Contractual Obligations

What are the contractual obligations as of June 30, 2010 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.

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

	2010	2011	2012	2013	2014
Gathering, processing and transmission	2,601	4,617	3,624	3,141	3,007
Office and equipment lease	945	1,029	775	390	-
Total	3,546	5,646	4,399	3,531	3,007

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 financial statements, is Delphi required to make estimates or assumptions about future events?

Delphi's financial statements have been prepared in accordance with Canadian generally accepted accounting principles. Certain accounting policies require management to make decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Delphi's management reviews its estimates frequently; however, the emergence of new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates. 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.

The Company's financial and operating results include estimates of the following:

- Depletion, depreciation and accretion and the ceiling test are based on estimates of crude oil and natural gas reserves;
- Revenues, operating expenses and royalties for which accruals have been recorded for actual revenues and costs which have been earned or incurred but have not yet been received;
- Capital expenditures on projects that are in progress;
- Fair value of derivative contracts;
- Asset retirement obligations including estimates of future costs and the timing of the costs.

NEW ACCOUNTING STANDARDS

International Financial Reporting Standards (IFRS)

In February 2008, the Canadian Accounting Standards Board (AcSB) confirmed that Canadian publicly accountable entities will be required to report under International Financial Reporting Standards (IFRS), which will replace Canadian generally accepted accounting principles (GAAP) for years beginning on or after January 1, 2011. Thus, effective January 1, 2011, the Company will be required to prepare its consolidated financial statements in accordance with IFRS, with appropriate comparative figures for the year ended December 31, 2010.

In July 2009, the International Accounting Standards Board (IASB) approved IFRS transitional exemptions that will allow entities to allocate their oil and gas asset balance as determined under full cost accounting to the IFRS categories of exploration and evaluation assets and development and producing properties. Under the exemption, exploration and evaluation assets are measured at the amount determined under an entity's previous GAAP. For assets in the development or production phases, the amount is also measured at the amount determined under an entity's previous GAAP; however, such values must be allocated to the underlying IFRS transitional assets on a pro-rata basis using either reserve values or reserve volumes as of the entity's IFRS transition date. This exemption will relieve entities from significant adjustments resulting from retrospective adoption of IFRS. The Company intends to utilize this exemption. The Company is also evaluating other first-time adoption exemptions and elections available upon initial transition that provide relief from retrospective application of IFRS.

The Company continues to assess the Canadian GAAP and IFRS differences as well as the effects of adoption and finalizing its conversion plan. This work is presently on-going with the objective of having an opening January 1, 2010 balance sheet, prepared in accordance with IFRS. From this point, Delphi will maintain both Canadian GAAP and IFRS compliant financial statements for 2010. The Company's auditors are involved throughout the process to ensure Delphi's policies are in accordance with these new standards.

The conversion from Canadian GAAP to IFRS is significant and may materially affect Delphi's reported financial position and results of operations. At this time, the impact on the Company's financial position and results of operations is not reliably determinable but the identified key differences that will impact the financial statements are as follows:

Impairment testing on oil and gas properties will be performed at a lower level than under Canadian GAAP. Impairment testing will be performed at the level of Cash Generating Units (CGU's) which are considered to be groupings of assets that generate cash inflows that are largely independent of the other asset groups. The Company has completed its initial assessment of its CGU's and there is no indication of impairment.

Depletion and depreciation of property, plant and equipment (PP&E) will be based on significant components. Depletion of resource properties will be undertaken at field area levels calculated using the unit-of-production method rather than one full cost level under Canadian GAAP, Under IFRS, there is an option to deplete resource properties on total proved reserves or total proved plus probable reserves. The Company is currently assessing the impact of this difference and has not made a final determination of its future accounting policy in this regard. Depreciation of all other non-resource assets are not expected to result in material charges to earnings and will continue to be calculated on an appropriate basis over their estimated useful lives.

Oil and gas properties will be classified as either PP&E or Exploration and Evaluation assets (E&E) and will be measured at cost. E&E assets are classified according to the nature of the expenditures and whether or not technical feasibility and commercial viability of extracting oil and gas from a property that has not been established as containing proven reserves. E&E costs will be reclassified to PP&E; to the extent they are not impaired, when proven reserves have been assigned to the property. If proven reserves will not be established and there are no future plans for development, then the E&E expenditures are reviewed for impairment. Future E&E assets are currently being assessed and the impact has not yet been determined.

For stock based compensation expense, the Company will be required to incorporate a forfeiture rate rather than account for forfeitures as they occur. The Company is assessing the impact of this change.

The above is not intended to be a complete disclosure of all the possible significant accounting differences between the Company's current Canadian GAAP accounting policies and those expected under IFRS. Delphi continues to evaluate the impact of all of its IFRS accounting policy choices, including the above noted items, and the effect they will have on its financial statements. The Company will disclose additional information on the impact of the changes throughout 2010.

The Company will continue to monitor any changes in the adoption of IFRS and will update its plan as necessary.

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 its corporate governance policies. 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 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 during the first quarter of 2010.

2010 OUTLOOK

What is the Company's overall strategy and plans for 2010 and beyond?

Corporate Strategy

Delphi emphasizes a full-cycle approach to its business and strives for internally generated development opportunities as a means of enhancing its production base and ultimately creating value for shareholders. Delphi's goal is to become a dominant natural gas developer and explorer focused in the deep basin of North West Alberta with approximately 25 percent of its production being crude oil and natural gas liquids. The objective is to develop an inventory of opportunities and undeveloped land base from which production and reserves can be added independent of acquisition activity.

Capital Activities

With the continuing uncertainty in commodity prices and the economy, Delphi will fund its 2010 field capital program from internally generated cash flow from operations. Delphi has a planned 2010 field capital program ranging between $90.0 and $100.0 million. An expanded capital program in the second half of 2010 will be funded by the proceeds of the equity offering completed in the second quarter.

The capital program for 2010 includes the drilling of up to 17 (9.8 net) wells with the majority of the capital allocated to the Company's three main areas, Bigstone, Hythe and Wapiti/Gold Creek.

Financial Strategy

The Company is well positioned to endure the current weak economic environment with high quality producing assets, increased exposure to light oil and liquids-rich natural gas opportunities, a large inventory of economic projects in numerous play types and a 2010 cash flow stream protected with 53 percent of the Company's current natural gas production hedged at an average price of $6.08 per mcf for the remainder of the year. Maintaining operational and financial flexibility, combined with expanding the Company's long-term growth inventory in a transaction-oriented environment, will be key drivers in the capital spending decision process for 2010 and beyond.

ADDITIONAL INFORMATION

Where is additional information about Delphi available?

Additional information about Delphi 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.

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.

DELPHI ENERGY CORP.
Consolidated Balance Sheets (unaudited)

(Stated in thousands of dollars)	June 30 2010	December 31 2009
Assets		
Current assets		
Cash	**5,616**	-
Accounts receivable	**14,160**	15,630
Prepaid expenses and deposits	**4,197**	6,004
Risk management asset (Note 7)	**1,857**	-
Future income taxes	**-**	112
	25,830	21,746
Property, plant and equipment (Note 3)	**353,725**	339,952
Total assets	**379,555**	361,698
Liabilities		
Current liabilities		
Outstanding cheques	**-**	139
Accounts payable and accrued liabilities	**23,190**	32,933
Risk management liability (Note 7)	**-**	381
Future income taxes	**540**	-
	23,730	33,453
Long term debt (Note 4)	**80,000**	81,100
Future income taxes	**24,882**	23,917
Asset retirement obligations (Note 5)	**10,585**	11,818
	139,197	150,288
Shareholders' equity		
Share capital (Note 6)	**228,162**	200,055
Contributed surplus (Note 6)	**11,371**	11,048
Retained earnings	**825**	307
Total shareholders' equity	**240,358**	211,410
Total liabilities and shareholders' equity	**379,555**	361,698

Commitments (Note 8)

See accompanying notes to the consolidated financial statements.

DELPHI ENERGY CORP.

Consolidated Statements of Earnings (Loss), Comprehensive Income (Loss) and Retained Earnings (unaudited)
For the three and six months ended June 30

	Three Months Ended June 30		Six Months Ended June 30	
(Stated in thousands of dollars, except per share amounts)	**2010**	2009	**2010**	2009
Revenue				
Petroleum and natural gas sales	**27,970**	22,083	**57,426**	45,259
Realized gain on risk management activities (Note 7)	**1,155**	1,146	**1,218**	2,175
	29,125	23,229	**58,644**	47,434
Royalties	**(4,719)**	(466)	**(8,533)**	(4,909)
Unrealized gain (loss) on risk management activities (Note 7)	**(1,199)**	(722)	**2,238**	(162)
	23,207	22,041	**52,349**	42,363
Expenses				
Operating	**5,845**	6,169	**11,836**	12,373
Transportation	**2,474**	2,128	**4,670**	3,589
General and administrative	**1,770**	1,223	**2,789**	2,345
Stock-based compensation (Note 6)	**320**	129	**425**	340
Interest	**1,329**	872	**2,671**	1,830
Depletion, depreciation and accretion	**15,089**	15,291	**28,991**	30,084
	26,827	25,812	**51,382**	50,561
Earnings (loss) before income taxes	**(3,620)**	(3,771)	**967**	(8,198)
Taxes				
Future income taxes (reduction)	**(878)**	(954)	**449**	(2,061)
	(878)	(954)	**449**	(2,061)
Net earnings (loss) and comprehensive earnings (loss)	**(2,742)**	(2,817)	**518**	(6,137)
Retained earnings, beginning of period	**3,567**	5,016	**307**	8,336
Retained earnings, end of period	**825**	2,199	**825**	2,199
Earnings (loss) per share (Note 6)				
Basic	**(0.03)**	(0.04)	**0.01**	(0.08)
Diluted	**(0.03)**	(0.04)	**-**	(0.08)

See accompanying notes to the consolidated financial statements.

DELPHI ENERGY CORP.

Consolidated Statements of Cash Flows (unaudited)
For the three and six months ended June 30

	Three Months Ended June 30		Six Months Ended June 30	
(Stated in thousands of dollars)	**2010**	2009	**2010**	2009
Cash flow from operating activities				
Net earnings (loss)	**(2,742)**	(2,817)	**518**	(6,137)
Add non-cash items:				
Depletion, depreciation and accretion	**15,089**	15,291	**28,991**	30,084
Stock-based compensation	**320**	129	**425**	340
Unrealized (gain) loss on risk management activities	**1,199**	722	**(2,238)**	162
Future income taxes (reduction)	**(878)**	(954)	**449**	(2,061)
Change in non-cash working capital (Note 9)	**5,796**	89	**1,768**	(1,415)
	18,784	12,460	**29,913**	20,973
Cash flow from (used in) financing activities				
Issue of common shares, net of issue costs	**28,268**	-	**28,268**	-
Exercise of stock options	**269**	-	**607**	-
Increase (decrease) in long term debt	**-**	5,676	**(1,100)**	10,776
	28,537	5,676	**27,775**	10,776
Cash flow available for investing activities	**47,321**	18,136	**57,688**	31,749
Cash flow from (used in) investing activities				
Capital expenditures	**(8,061)**	(3,602)	**(43,565)**	(17,694)
Disposition of petroleum and natural gas properties	**251**	74	**251**	225
Acquisition of petroleum and natural gas properties	**307**	218	**(385)**	218
Change in non-cash working capital (Note 9)	**(28,932)**	(10,221)	**(8,234)**	(17,213)
	(36,435)	(13,531)	**(51,933)**	(34,464)
Increase (decrease) in cash and cash equivalents	**10,886**	4,605	**5,755**	(2,715)
Cash and cash equivalents, beginning of period	**(5,270)**	(6,396)	**(139)**	924
Cash and cash equivalents, end of period	**5,616**	(1,791)	**5,616**	(1,791)
Cash and cash equivalents is comprised of:				
Cash	**5,616**	29	**5,616**	29
Outstanding cheques	**-**	(1,820)	**-**	(1,820)
	5,616	(1,791)	**5,616**	(1,791)
Interest paid	**1,309**	851	**2,705**	2,083

See accompanying notes to the consolidated financial statements.

DELPHI ENERGY CORP.

Notes to the Consolidated Financial Statements (unaudited)
As at and for the periods ended June 30, 2010 and 2009
(All tabular amounts are stated in thousands of dollars, except per share amounts)

NOTE 1: DESCRIPTION OF BUSINESS

Delphi Energy Corp. (“the Company” or “Delphi”) is incorporated under the Business Corporations Act (Alberta) and is a publicly-traded company listed on the Toronto Stock Exchange. Delphi is primarily engaged in the acquisition, exploration for and development and production of crude oil, natural gas and natural gas liquids from properties located in North West Alberta.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES

The unaudited interim consolidated financial statements of Delphi have been prepared by management in accordance with accounting principles generally accepted in Canada and following the same accounting policies and methods of computation as the consolidated financial statements for the year ended December 31, 2009. The disclosures provided below are incremental to those included with the annual financial statements. The unaudited interim consolidated financial statements should be read in conjunction with the audited consolidated financial statements and notes thereto in the Company’s Annual Report for the year ended December 31, 2009. The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results may differ from these estimates.

NOTE 3: PROPERTY, PLANT AND EQUIPMENT

As at June 30, 2010	**Cost**	**Accumulated depletion and depreciation**	**Net book value**
Petroleum and natural gas properties	**480,425**	**243,063**	**237,362**
Production equipment	**154,271**	**38,411**	**115,860**
Furniture, fixtures and office equipment	**1,276**	**773**	**503**
	635,972	**282,247**	**353,725**

As at December 31, 2009	Cost	Accumulated depletion and depreciation	Net book value
Petroleum and natural gas properties	448,619	218,505	230,114
Production equipment	143,813	34,547	109,266
Furniture, fixtures and office equipment	1,277	705	572
	593,709	253,757	339,952

For the six months ended June 30, 2010, the Company capitalized $2.0 million (June 30, 2009 - $1.7 million) of general and administrative costs directly related to exploration and development activities.

As at June 30, 2010, costs in the amount of $11.2 million (December 31, 2009 - $4.2 million) representing unproved properties were excluded from the depletion calculation and estimated future development costs of $48.6 million (December 31, 2009 - $51.3 million) have been included in costs subject to depletion. Ultimate recoverability of these costs will be dependent upon finding proved oil and natural gas reserves.

NOTE 4: LONG TERM DEBT

	June 30, 2010	December 31, 2009
Prime-based loans	**-**	1,100
Bankers' acceptances	**80,000**	80,000
Total debt	**80,000**	81,100

The Company has a revolving credit facility for $135.0 million with a syndicate of Canadian chartered banks. The facility is a 364 day committed revolving facility until May 31, 2011, the term-out date. The term-out date may be extended for a further 364 day period upon approval by the banks. Following the term-out date, the facilities would be available on a non-revolving basis for a one year term. The credit facility bears interest based on a sliding scale pricing grid tied to the Company's trailing debt to cash flow ratio: from a minimum of the bank's prime rate plus 1.75 percent to a maximum of the bank's prime rate plus 4.75 percent or from a minimum of bankers' acceptances rate plus a stamping fee of 2.75 percent to a maximum of bankers' acceptances rate plus a stamping fee of 4.75 percent.

The bankers' acceptances have terms ranging from 90 to 92 days and a weighted average effective interest rate of 4.14 percent over the term.

The facility is secured by a $200.0 million demand floating charge debenture and a general security agreement over all assets of the Company.

NOTE 5: ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations result from working interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations, over the next three to 20 years, is approximately $22.0 million (December 31, 2009 - $25.1 million). A credit-adjusted risk-free rate of 8.0 to 10.0 percent and an inflation rate of 2.5 percent were used to calculate the estimated fair value of the asset retirement obligations.

A reconciliation of the asset retirement obligations is provided below.

	June 30, 2010	December 31, 2009
Balance, beginning of period	**11,818**	9,730
Liabilities incurred	**176**	132
Liabilities disposed	**(1,910)**	(487)
Liabilities acquired	**-**	1,793
Liabilities settled	**-**	(167)
Accretion expense	**501**	817
Balance, end of period	**10,585**	11,818

NOTE 6: SHARE CAPITAL

(a) Authorized

An unlimited number of common shares.

An unlimited number of preferred shares issuable in series.

(b) Common shares issued

	June 30, 2010		December 31, 2009	
	Outstanding shares (000's)	**Amount**	Outstanding shares (000's)	Amount
Balance, beginning of period	**101,166**	**200,055**	79,067	174,995
Issue of common shares	**11,000**	**30,250**	13,200	16,500
Issue of common shares - Fairmount	**-**	**-**	5,835	6,360
Issue of flow-through common shares	**-**	**-**	3,000	6,360
Exercise of stock options	**516**	**607**	64	43
Allocated from contributed surplus	**-**	**324**	-	23
Share issue costs	**-**	**(1,982)**	-	(1,523)
Future tax effect of share issue costs	**-**	**523**	-	405
Tax benefit renounced to shareholders	**-**	**(1,615)**	-	(3,108)
Balance, end of period	**112,682**	**228,162**	101,166	200,055

On November 16, 2009, the Company issued 3.0 million flow-through common shares at a price of $2.12 per share for gross proceeds of $6.4 million. The Company has an obligation to incur qualifying exploration expenditures of $6.4 million by December 31, 2010 to satisfy the terms of the flow-through common shares issued in 2009. As at June 30, 2010, the Company has a remaining requirement to incur approximately $1.8 million of qualifying expenditures to fully satisfy this obligation.

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.

(c) Stock options

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 vested over a two-year period starting on the date of grant. Options granted on September 1, 2009 or later 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. 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 June 30, 2010, there were 7.8 million options to purchase shares outstanding.

The following table summarizes the changes in the number of options outstanding and the weighted average share prices.

	June 30, 2010		December 31, 2009	
	Outstanding options (000's)	**Weighted average exercise price**	Outstanding options (000's)	Weighted average exercise price
Balance, beginning of period	**7,428**	**1.40**	4,731	1.75
Granted	**900**	**2.71**	3,017	0.83
Forfeited	**-**	**-**	(256)	1.31
Exercised	**(516)**	**1.18**	(64)	0.67
Balance, end of period	**7,812**	**1.57**	7,428	1.40
Exercisable, end of period	**5,773**	**1.51**	5,245	1.58

The following table summarizes information about the stock options outstanding and exercisable at June 30, 2010.

	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	**1,804**	**0.66**	**3.67**	**1,165**	**0.66**
$0.98 - $1.54	**712**	**1.20**	**3.92**	**295**	**1.22**
$1.55 - $1.72	**3,736**	**1.67**	**2.42**	**3,686**	**1.67**
$1.73 - $2.15	**440**	**1.82**	**2.30**	**440**	**1.82**
$2.16 - $3.34	**1,120**	**2.80**	**4.45**	**187**	**3.21**
Total	**7,812**	**1.57**	**3.13**	**5,773**	**1.51**

(d) Stock-based compensation

The Company accounts for its stock-based compensation using the fair value method for all stock options. For the six months ended June 30, 2010, Delphi recorded non-cash compensation expense of $0.4 million (June 30, 2009 - $0.3 million). The Company capitalized $0.2 million (June 30, 2009 - $0.5 million) of stock-based compensation directly related to exploration and development activities. The future income tax liability associated with the capitalized stock-based compensation in the amount of $0.1 million (June 30, 2009 - $0.2 million) has also been capitalized for the year.

During the six months ended June 30, 2010, the Company granted 0.9 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 $1.55 per option (June 30, 2009 - $0.40 per option). The assumptions used in the Black-Scholes model to determine fair value were as follows.

For the six months ended June 30	**2010**	2009
Risk-free interest rate (%)	**2.9**	2.0
Expected life (years)	**5.0**	5.0
Expected volatility (%)	**65.9**	64.4

(e) Contributed surplus

The following table outlines the changes in the contributed surplus balance.

	June 30, 2010	December 31, 2009
Balance, beginning of period	**11,048**	9,605
Stock-based compensation expensed	**425**	615
Stock-based compensation capitalized	**222**	851
Reclassification to common shares on exercise of stock options	**(324)**	(23)
Balance, end of period	**11,371**	11,048

(f) Net earnings (loss) per share

Net earnings (loss) per share has been based on the following weighted average common shares.

	Three Months Ended June 30		Six Months Ended June 30	
	2010	2009	**2010**	2009
Basic (000's)	**104,808**	79,067	**103,037**	79,067
Diluted (000's)	**104,808**	79,067	**106,195**	79,067

For the three months ended June 30, 2010, the stock options were anti-dilutive and therefore excluded from the calculation of weighted average common shares. For the six months ended June 30, 2010, the reconciling item between the basic and diluted weighted average common shares outstanding is stock options.

(g) Capital management

The Company considers share capital and net debt, being the sum of long term debt and current liabilities less current assets, as the components of capital to be managed.

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 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 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 expenditures on asset retirement obligations 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.

As at June 30, 2010 net debt, excluding risk management assets or liabilities and the associated future income taxes, was \$79.2 million and funds from operations was \$28.1 million resulting in a net debt to annualized funds from operations ratio of 1.4:1. The Company is focused on its internal target for this ratio of approximately 1.5 times.

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.

NOTE 7: FINANCIAL INSTRUMENTS

(a) Risk management overview

The Company is exposed to market risks related to the volatility of commodity prices, foreign exchange rates and interest rates. Risk management is ultimately established by the Board of Directors and is implemented and monitored by senior management. The Company maintains an active risk management program as an integral part of its overall financial strategy to mitigate volatility in funds from operations resulting from fluctuating commodity prices. The strategy is designed to take advantage of the upward swings in natural gas prices as a result of the changes in demand/supply fundamentals and/or the movement of significant financial assets invested in the natural gas market as a pure commodity investment.

(b) Fair value of financial assets and liabilities

The Company's financial instruments recognized on the balance sheet include cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, long-term debt and the risk management asset or liability. The fair value of financial assets and liabilities that are included on the balance sheet, other than the risk management asset or liability, approximate their carrying amounts due to long-term debt being at a floating interest rate and all other financial assets and liabilities having a short term maturity.

(c) Market risk

Market risk is the risk that future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk is comprised of foreign currency exchange rate risk, interest rate risk and commodity price risk. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing returns.

The Company utilizes both financial derivatives and physical delivery contracts to manage market risks.

Foreign currency exchange rate risk

Foreign currency exchange rate risk is the risk that future cash flows will fluctuate as a result of changes in foreign exchange rates. Although substantially all of the Company's petroleum and natural gas sales are denominated in Canadian dollars, the underlying market prices in Canada for petroleum and natural gas are affected by changes in the exchange rate between the Canadian and United States dollar. The exchange rate could affect the values of certain contracts, however, this indirect influence cannot be accurately quantified. The Company had no foreign exchange rate swap or related financial contracts in place as at June 30, 2010.

Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate risk to the extent that bank debt is at a floating rate of interest. If interest rates on prime-based loans had been 100 basis points lower with all other variables held constant, net earnings for the six months ended June 30, 2010 would not have changed due to no outstanding prime-based loans.

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

The Company has also entered into an interest rate swap transaction on borrowings through bankers' acceptances in the amount of $40.0 million maturing on May 4, 2011. The bankers' acceptance rate on the transaction will increase in fixed monthly increments of 4.55 basis points for an average fixed rate over two years of 0.94 percent. The effective interest rate over the two year term on $40.0 million of bankers' acceptances will be 0.94 percent plus the applicable stamping fee according to the pricing grid for bankers' acceptances. The fair value of this contract at June 30, 2010 is a loss of $85,000. If interest rates on bankers' acceptances had been 100 basis points higher with all other variables held constant, net earnings for the six months ended June 30, 2010 would have been higher by $0.1 million.

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 petroleum and natural gas are affected not only by the relationship between the Canadian and United States dollar, as outlined above, but also world economic events that dictate the levels of supply and demand. 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 sale contracts with customers and commodity swap agreements with financial counterparties. The fair values of the forward contracts are subject to market risk from fluctuating commodity prices and foreign exchange rates. The Company's policy is to enter into commodity contracts to a maximum of 40 – 50 percent of current production volumes.

As at June 30, 2010, the Company had the following financial derivative contracts which were recorded at fair value on the balance sheet at an asset of $1.9 million (December 31, 2009 - liability of $0.4 million) with changes in fair value included in unrealized gain (loss) on risk management activities in the statement of earnings.

Time Period	Commodity	Type of Contract	Quantity Contracted	Contract Price ($/unit)
January 2010 – December 2010*	Natural Gas	Financial	3,500 GJ/d	$7.40 Call
January 2010 – March 2011	Natural Gas	Financial	2,000 GJ/d	$5.72 fixed
January 2010 – December 2010	Crude Oil	Financial	100 bbls/d	$86.40 fixed
January 2010 – December 2010	Crude Oil	Financial	100 bbls/d	$72.20 floor/$100.00 ceiling
April 2010 – October 2010	Natural Gas	Financial	2,000 GJ/d	$5.53 fixed
April 2010 – October 2010	Natural Gas	Financial	1,500 GJ/d	$4.80 floor plus 50% > $4.80
April 2010 – October 2010**	Natural Gas	Financial	2,500 GJ/d	$4.75 Put
January 2011 – December 2011**	Natural Gas	Financial	2,500 GJ/d	$7.14 Call

* The 2010 call contract was executed in 2009 to obtain a $6.00 put in 2009 on a costless basis.

**The Company has acquired a natural gas put contract at $4.75 per gigajoule on 2,500 gigajoules per day for the period April 1, 2010 through October 31, 2010. This put was paid for with the sale of a natural gas call on 2,500 gigajoules per day at a price of $7.14 per gigajoule for the period January 1, 2011 through December 31, 2011.

The Company has Canadian dollar physical sales contracts. The Canadian dollar 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 June 30, 2010, the Company had the following physical sales contracts.

Time Period	Commodity	Type of Contract	Quantity Contracted	Contract Price ($/unit)
January 2010 – December 2010*	Natural Gas	Physical	3,500 GJ/d	$7.15 Call
January 2010 – March 2011	Natural Gas	Physical	1,500 GJ/d	$5.74 fixed
April 2010 – December 2010	Natural Gas	Physical	3,000 GJ/d	$6.25 floor/$7.47 ceiling
April 2010 – December 2010	Natural Gas	Physical	4,000 GJ/d	$5.93 floor plus 50% > $5.93
April 2010 – March 2011	Natural Gas	Physical	3,000 GJ/d	$6.12 fixed
April 2010 – March 2011	Natural Gas	Physical	2,500 GJ/d	$5.73 fixed
April 2011 – October 2011	Natural Gas	Physical	2,000 GJ/d	$5.66 fixed

* The 2010 call contract was executed in 2009 to obtain a $6.00 put in 2009 on a costless basis.

For the six months ended June 30, 2010, the Canadian dollar physical contracts resulted in settlement gains of $6.0 million (June 30, 2009 - $8.8 million) that have been included in petroleum and natural gas sales. For the six months ended June 30, 2010, the financial contracts resulted in gains of $1.2 million (June 30, 2009 - $2.2 million) that have been included in the statement of earnings as a realized gain on risk management activities. If natural gas prices had been higher by $0.10 per mcf, with all other variables held constant, the net change in the unrealized gain (loss) on risk management activities in the statement of earnings for the six months ended June 30, 2010 would have been lower by approximately $0.4 million (June 30, 2009 – $0.2 million).

(d) Credit risk

Credit risk represents the financial loss to the Company if counterparties to a financial instrument fail to meet their contractual obligations and arise principally from the Company's receivables from joint interest partners. 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. With respect to counterparties to financial instruments, the Company partially mitigates associated credit risk by limiting transactions to counterparties with investment grade credit ratings.

Receivables from petroleum 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 attempts to mitigate the risk related to joint interest receivables by obtaining partner approval of significant capital expenditures prior to expenditure. However, partners are exposed to various industry and market risks that could result in non-collection. The Company does not typically obtain collateral from 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 of amounts owing.

The carrying amount of cash and accounts receivable represents the maximum credit exposure. The Company does not consider an allowance for doubtful accounts is required as at June 30, 2010. During the quarter, The Company recorded bad debt expense of $0.3 million related to the settlement of disputed processing fees with a joint venture partner.

As at June 30, 2010 the Company's aged receivables are as follows.

	June 30, 2010
Current (less than 30 days)	**10,360**
Past due (31-90 days)	**2,020**
Past due (more than 90 days)	**1,780**
Total	**14,160**

(e) Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's approach to managing liquidity risk is to ensure, to the extent possible, that it will have sufficient cash resources to meet its liabilities when they become due. The Company actively monitors the costs of its operations and capital expenditure program by preparing an annual budget, formally approved by the Board of Directors. On a monthly basis, internal reporting of actual results is compared to the budget in order to modify budget assumptions, if necessary, to ensure liquidity is maintained.

The Company requires sufficient cash to fund its operating costs and capital program that are designed to maintain or increase production and develop reserves, to acquire petroleum and natural gas assets and to satisfy debt obligations. The majority of capital spent will be funded through cash flow from operating activities. The Company enters into risk management contracts designed to improve risk-adjusted returns and to ensure adequate cash flow to fund the Company's capital program and maintain liquidity. The Company uses a combination of both financial and physical commodity price contracts. Contracts are initiated within the guidelines of the Company's risk management program and are not entered into for speculative purposes. The Company also 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 June 30, 2010.

Financial liabilities	< 1 Year	1 – 2 Years	3 – 5 Years	Thereafter
Accounts payable and accrued liabilities	23,190	-	-	-
Long term debt – principal	-	80,000	-	-
Total	23,190	80,000	-	-

NOTE 8: COMMITMENTS

The Company 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: 2010 - $3.5 million; 2011 - $5.6 million; 2012 - $4.4 million; 2013 - $3.5 million; 2014 - $3.0 million.

NOTE 9: CHANGES IN NON-CASH WORKING CAPITAL ITEMS

	June 30, 2010	June 30, 2009
Change in working capital item:		
Accounts receivable	**1,470**	4,087
Prepaid expenses and deposits	**1,807**	(2,202)
Accounts payable and accrued liabilities	**(9,743)**	(20,513)
Total change in non-cash working capital	**(6,466)**	(18,628)
Relating to:		
Operating activities	**1,768**	(1,415)
Investing activities	**(8,234)**	(17,213)
	(6,466)	(18,628)

CORPORATE INFORMATION

DIRECTORS

David J. Reid
President and Chief Executive Officer
Delphi Energy Corp.

Tony Angelidis
Senior Vice President Exploration
Delphi Energy Corp.

Harry S. Campbell, Q.C. (3)
Partner
Burnet, Duckworth & Palmer LLP

Robert A. Lehodey, Q.C. (2) (3)
Partner
Osler, Hoskin & Harcourt LLP

Stephen Mulherin (1)
Partner
Polar Capital Corporation

Andrew E. Osis (1)
Chief Executive Officer and Director
Multiplied Media Corporation

David Sandmeyer (2)
Director
Freehold Royalty Trust

Lamont C. Tolley (1) (2)
Independent Businessman

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

AUDITORS

KPMG LLP

LEGAL COUNSEL

Osler, Hoskin & Harcourt LLP

TRANSFER AGENT

Olympia Trust Company

OFFICERS

David J. Reid
President and Chief Executive Officer

Tony Angelidis
Senior Vice President Exploration

Hugo H. Batteke
Vice President Operations

Michael K. Galvin
Vice President Land

Rod A. Hume
Vice President Engineering

Michael S. Kaluza
Chief Operating Officer

Brian P. Kohlhammer
Vice President Finance and Chief Financial Officer

CORPORATE OFFICE

300, 500 – 4th Avenue S.W.
Calgary, Alberta
T2P 2V6
Telephone: (403) 265-6171
Facsimile: (403) 265-6207
Email: info@delphienergy.ca
Website: www.delphienergy.ca

BANKERS

National Bank of Canada
The Bank of Nova Scotia
Alberta Treasury Branches

INDEPENDENT ENGINEERS

GLJ Petroleum Consultants Ltd.

STOCK EXCHANGE LISTING

Toronto Stock Exchange – DEE

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