# DELPHI ENERGY CORP.

Q3 FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2010

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**Third Quarter 2010 Highlights**

- achieved record quarterly production in the third quarter of 2010 with average daily volumes of 8,114 barrels of oil equivalent per day (boe/d), an increase of 20 percent compared to the third quarter of 2009;
- increased oil and natural gas liquids production by 32 percent to 1,541 bbls/d compared to 1,168 bbls/d in the third quarter of 2009, maintaining the production mix at approximately 19 percent crude oil and natural gas liquids in the third quarter of 2010;
- achieved production growth in the third quarter consistent with the Company's market guidance for average annual production in 2010 of 7,900 to 8,200 boe/d which was established in early 2010;
- generated funds from operations (cash flow) of $15.1 million, an increase of 20 percent from the comparative quarter of 2009;
- reduced operating costs by 21 percent to $7.45 per boe in the third quarter of 2010 from $9.46 per boe in the third quarter of 2009;
- maintained an operating netback in the $22.00 to $24.00 per boe range and a cash netback of $20.25 per boe in the third quarter;
- realized $4.9 million in hedging gains on crude oil and natural gas commodity contracts and executed additional natural gas hedging contracts to approximately 20 percent of expected 2011 natural gas production at a price of $6.04 per mcf providing stability to cash flow and balance sheet strength; and
- drilled 12.0 gross (8.3 net) wells in the third quarter with a 100 percent success rate.

**Financial Highlights** ($ thousands except per unit amounts)

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| | **2010** | 2009 | % Change | **2010** | 2009 | % Change |
| Petroleum and natural gas sales | **28,080** | 24,433 | 15 | **86,724** | 71,867 | 21 |
| Per boe | **37.62** | 39.21 | (4) | **40.04** | 38.82 | 3 |
| Funds from operations | **15,120** | 12,635 | 20 | **43,265** | 35,023 | 24 |
| Per boe | **20.25** | 20.28 | - | **19.98** | 18.91 | 6 |
| Per share – Basic | **0.13** | 0.16 | (19) | **0.40** | 0.44 | (9) |
| Per share – Diluted | **0.13** | 0.16 | (19) | **0.40** | 0.44 | (9) |
| Net earnings (loss) | **(1,566)** | (3,278) | (52) | **(1,048)** | (9,415) | (89) |
| Per boe | **(2.11)** | (5.26) | (60) | **(0.49)** | (5.10) | (91) |
| Per share – Basic | **(0.01)** | (0.04) | (75) | **(0.01)** | (0.12) | (92) |
| Per share – Diluted | **(0.01)** | (0.04) | (75) | **(0.01)** | (0.12) | (92) |
| Capital invested | **43,912** | 7,810 | 462 | **87,477** | 25,504 | 243 |
| Disposition of properties | **4** | (9,728) | - | **(247)** | (9,953) | (98) |
| Net capital invested | **43,916** | (1,918) | - | **87,230** | 15,551 | 461 |
| Acquisition of properties | **2** | 19,669 | (100) | **387** | 19,451 | (98) |
| Total capital | **43,918** | 17,751 | 147 | **87,617** | 35,002 | 150 |

| | Sept. 30 2010 | Dec. 31 2009 | % Change |
|---|---|---|---|
| Debt plus working capital deficiency [(1)] | **107,933** | 92,538 | 17 |
| Total assets | **404,645** | 361,698 | 12 |
| Shares outstanding (000's) | | | |
| Basic | **112,698** | 101,166 | 11 |
| Diluted | **120,462** | 108,594 | 11 |

(1) excludes risk management asset and the related current future income taxes.

**Operational Highlights**

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| **Production** | **2010** | 2009 | % Change | **2010** | 2009 | % Change |
| Natural gas (mcf/d) | **39,439** | 33,628 | 17 | **38,780** | 34,690 | 12 |
| Crude oil (bbls/d) | **831** | 624 | 33 | **884** | 490 | 80 |
| Natural gas liquids (bbls/d) | **710** | 544 | 31 | **586** | 509 | 15 |
| Total (boe/d) | **8,114** | 6,773 | 20 | **7,933** | 6,781 | 17 |

## MESSAGE TO SHAREHOLDERS

Production during the third quarter of 2010 averaged 8,114 boe/d, an increase of 20 percent compared to 6,773 boe/d in the third quarter of 2009. The increased light oil production at Hythe and Bigstone changed the production mix in the quarter to 19 percent liquids (81 percent natural gas) from 17 percent liquids (83 percent natural gas) in the third quarter of 2009.

Delphi's natural gas production continued to receive a premium to AECO, $1.74 per mcf in the quarter, due to marketing arrangements, heating content and natural gas hedges. Approximately 53 percent of the Company's natural gas production was hedged at an average price of $6.00 per mcf in the third quarter, resulting in a gain on natural gas contracts of $4.7 million. These pricing premiums resulted in a realized natural gas price of $5.28 per mcf representing a premium of 49 percent to average AECO pricing during the third 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 third quarter of 2010, operating costs were $7.45 per boe, compared to $9.46 per boe in the third quarter of 2009 and $8.71 per boe in the first quarter of 2010. The third quarter of 2010 also benefitted from the disposition of the Company's high operating cost East Central Alberta properties late in the second quarter.

Delphi's financial position remains strong at the end of the third quarter of 2010. At September 30, 2010, Delphi had net debt of $107.9 million. The Company has a credit facility of $135.0 million which is currently being reviewed by its lenders as part of its scheduled semi-annual review. On a nine month annualized funds from operations basis, Delphi's net debt to cash flow ratio was 1.9:1. Net debt includes bank debt plus working capital deficiency excluding the risk management asset/liability and the related current future income taxes.

**Operational Highlights:**

Delphi's third quarter drilling program continued to focus on liquids-rich, natural gas development in the Nikanassin and upper Cretaceous sands at Wapiti/Gold Creek, the light oil plays in the Cardium at Bigstone and the Doe Creek at Hythe and the resource style natural gas plays in the Bluesky and Falher formations at Hythe.

Highlights include:

- At Wapiti/Gold Creek, the Company drilled three vertical natural gas wells (2.3 net) with gross initial test rates ranging from 1,000 to 3,200 mcf/d of liquids-rich natural gas. Subsequent to the end of the third quarter, an exploration well (1.0 net) tested two different zones at final test rates of 900 and 8,125 mcf/d (165 and 1,350 boe/d) respectively;

- At Bigstone, the Company drilled two horizontal Cardium oil wells (1.1 net) and one vertical Cardium oil well (1.0 net) with the horizontal wells having a gross, combined seven day average production rate of 705 bbls/d and 2,500 mcf/d of associated gas (1,120 boe/d). Currently Cardium light oil production at Bigstone is approximately 900 boe/d (54 percent oil) net to Delphi;

- At Hythe, the Company drilled three horizontal Doe Creek oil wells (1.5 net) during the third quarter with gross, combined seven day average production rates of 435 bbls/d and 510 mcf/d of associated gas (520 boe/d). Currently Doe Creek light oil production at Hythe is approximately 600 boe/d (81 percent oil) net to Delphi;

- Also at Hythe, the Company drilled three horizontal natural gas wells (2.3 net) with gross seven day average production rates ranging from 670 to 3,850 mcf/d (110 to 660 boe/d);

**Wapiti/Gold Creek**

Gething/Nikanassin Liquids-Rich Natural Gas Program

At Wapiti/Gold Creek, the Company drilled and completed three vertical wells (2.3 net) targeting liquids-rich natural gas in the Gething and Nikanassin formations during the third quarter. Two wells were completed in the Nikanassin with initial test rates of 1,000 mcf/d (210 boe/d) and 3,200 mcf/d (735 boe/d) resulting in 825 boe/d net to Delphi. These two wells have been tied-in and will be on production during the first half of November. The third well was completed in multiple intervals including the Gething, Bluesky and Falher with an initial, commingled test rate of 2,000 mcf/d (435 boe/d) resulting in 218 boe/d net to Delphi. This well is being tied-in and should be on stream by the end of the year.

An exploration well (1.0 net well) targeting liquids-rich natural gas was drilled subsequent to the third quarter that had multiple zones of interest identified for completion. During clean-up flow, the first zone tested 900 mcf/d (165 boe/d) after recovering seventy percent of the load fluid and was temporarily suspended in order to complete additional intervals. The second zone was fracture stimulated and flowed for twelve hours, after recovering the load fluid, with a final test rate of 8,125 mcf/d (1,350 boe/d) at a flowing wellhead pressure of 890 psi. Several offset locations have been seismically defined on Company lands and further development is planned in the 2010/2011 winter program.

**Bigstone**

Cardium Light Oil Program

At Bigstone, the Company drilled, completed and tied-in two horizontal wells (1.1 net) targeting Cardium light oil and offsetting two successful horizontal wells drilled during the first quarter of 2010. Average production rates of the first quarter wells are performing at or above Company expectations with 30 and 60 day average rates of 247 boe/d and 216 boe/d respectively. Early production rates from the two wells drilled in the third quarter are similar to the best well drilled in the first quarter. Subsequent to the end of the third quarter, the first well of a three well non-operated horizontal program (0.2 net wells) targeting this same light oil pool has begun drilling operations. The following table illustrates the characteristics and productivity of horizontal Cardium wells drilled to date:

| | | | | | | Average boe/d during indicated period (field estimates) | | |
|---|---|---|---|---|---|---|---|---|
| Well | WI (%) | Rig Released | HZ Length (metres) | # of Fracs | Days Produced | 7 Day | 30 Day | 60 Day |
| CARD #1 | 55 | 1Q 2010 | 994 | 8 | 270 | 562 | 387 | 370 |
| CARD #2 | 100 | 1Q 2010 | 221 | 5 | 238 | 158 | 129 | 90 |
| CARD #3 | 49 | 1Q 2010 | 1,050 | 9 | 216 | 276 | 225 | 189 |
| CARD #4 | 55 | 3Q 2010 | 1,112 | 13 | 8 | 515 | - | - |
| CARD #5 | 55 | 3Q 2010 | 1,348 | 16 | 8 | 605 | - | - |
| Average | | | | | | 423 | 247 | 216 |

One vertical Cardium light oil well (1.0 net) was also drilled, completed and tied-in during the third quarter with a 30 day average production rate of 30 boe/d. This well completes a farm-in obligation, earning one section of land, and extends the productive Cardium trend 2.4 kilometres to the southeast of established production.

Delphi controls approximately 17 net sections of prospective Cardium acreage in the Bigstone area.

Land Acquisition

Subsequent to the end of the third quarter, Delphi participated in a Crown land sale and was successful in acquiring mineral rights on 10,700 acres at Bigstone. The mineral rights are for deeper formations including the Montney and Duvernay shale. These lands are adjacent to 6,300 acres of shallow and deep mineral rights acquired at a Crown land sale during the third quarter.

**Hythe**

Doe Creek Light Oil Program

At Hythe, the Company drilled, completed and tied-in three horizontal wells (1.5 net) targeting Doe Creek light oil during the third quarter. Subsequent to the end of the third quarter, two additional horizontal wells (2.0 net) were drilled; one well has been completed and tied in and the second well is awaiting fracture stimulation. One non-operated horizontal well (0.4 net) is scheduled to be drilled in the fourth quarter. Performance of the Doe Creek horizontals continues to be robust with 30 and 60 day average production rates of 262 boe/d and 257 boe/d, respectively.

The Company has transferred the technology of multi-stage fracture stimulation of horizontal wells to a second Doe Creek pool in the Hythe area that was previously developed with vertical wells and initial production results are encouraging. The Company is continuing to evaluate additional opportunities in the area as part of our ongoing efforts to increase the corporate oil weighting. The following table illustrates the characteristics and productivity of horizontal Doe Creek wells drilled to date:

| | | | | | | Average boe/d during indicated period (field estimates) | | |
|---|---|---|---|---|---|---|---|---|
| Well | WI (%) | Rig Released | HZ Length (metres) | # of Fracs | Days Produced | 7 Day | 30 Day | 60 Day |
| DOEC #1 | 100 | 3Q 2009 | 950 | 6 | 443 | 709 | 543 | 482 |
| DOEC #2 | 44 | 4Q 2009 | 1,022 | 7 | 274 | 516 | 295 | 214 |
| DOEC #3 | 100 | 1Q 2010 | 702 | 7 | 227 | 455 | 394 | 334 |
| DOEC #4 | 40 | 3Q 2010 | 809 | 9 | 85 | 122 | 116 | 99 |
| DOEC #5 | 100 | 3Q 2010 | 922 | 10 | 63 | 302 | 158 | 157 |
| DOEC #6 | 13 | 3Q 2010 | 1,076 | 12 | 33 | 151 | 67 | - |
| DOEC #7 | 100 | 4Q 2010 | 933 | 10 | 7 | 221 | - | - |
| DOEC #8 | 100 | 4Q 2010 | 1,001 | Completing | | - | - | - |
| Average | | | | | | 354 | 262 | 257 |

Falher and Bluesky Natural Gas Program

Also at Hythe, the Company has drilled and completed two horizontal Falher wells (2.0 net) and a horizontal Bluesky well (0.3 net). The first Falher well was an offset to a successful horizontal well drilled during the first quarter and was targeting the upper Falher formations. The 30 day average production rate of this well was 3,100 mcf/d (530 boe/d). The second well was targeting a lower Falher interval and had a 30 day average production test rate of 775 mcf/d (130 boe/d). The Bluesky horizontal was drilled 4.2 kilometres to the southeast of the Company's first Bluesky horizontal drilled during the 2009/2010 winter program and had a 30 day average test rate of 680 mcf/d (115 boe/d). The continued success of the horizontal drilling program in these intervals supports the Company's interpretation of a large resource style play in the Hythe area. Delphi is continuing to evaluate and modify stimulation design and frequency in order to optimize initial production rates and reserve recovery.

Delphi controls in excess of 100 net sections of prospective Bluesky and Falher acreage in the Hythe area.

**LAND ACQUISITIONS**

In prior years, Delphi generally acquired its undeveloped land as part of its asset acquisition strategy. In 2010, the Company has been more active at Crown land sales, acquiring undeveloped land in the deep basin of North West Alberta, primarily focused in its core areas of Bigstone, Hythe and Wapiti/Gold Creek. In the first nine months of 2010, Delphi has acquired 31,603 net acres in these areas.

In the Sturgeon Lake area, Delphi added to its growth potential with the acquisition of Duvernay shale rights. 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 development areas with the expectation of 2011 operations to evaluate the Duvernay section for oil potential.

Delphi's inventory of undeveloped land has increased to approximately 223,000 net acres, up 29 percent from December 31, 2009. As of September 30, 2010, the Company had invested $6.5 million on land, primarily at Crown land sales.

**OUTLOOK**

The capital program through the first nine months of 2010 has resulted in record production levels and has successfully advanced numerous development projects, further increasing the Company's drill-ready inventory. The Company expects to spend an estimated $95.0 to $100.0 million in 2010 resulting in 2010 average production volumes of 7,900 to 8,200 boe/d. 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.

Delphi is forecasting weak natural gas prices through the remainder of 2010 with moderate improvements into 2011. The Company is assuming 2010 AECO natural gas prices will average between Cdn $3.75 and $4.00 per mcf for forecast purposes. The Company is hedged with approximately 43 percent of its natural gas production protected at an average floor price of $6.16 per mcf for the remainder of the year. This represents a 69 percent premium to the 2010 strip price of $3.64 per mcf as of November 1, 2010. In addition, Delphi has 500 bbls/d of light oil production hedged at approximately current market prices. Lower natural gas prices are being offset by increased oil and NGL production and reduced operating costs to result in cash flow for 2010 of $57.0 to $60.0 million. Bank debt including working capital is estimated to be between $100.0 and $105.0 million at December 31, 2010.

The Company continues to improve its operating cost structure, having achieved a further seven percent reduction in third quarter operating costs to $7.45 per boe, placing the Company in the top quartile among its peers for operating costs and cash netbacks. Delphi is targeting a further five to ten 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. The disposition of less efficient non-core assets will continue to contribute to 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.

On behalf of the Board,

**David J. Reid,**
President and Chief Executive Officer
November 8, 2010

# 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 nine months ended September 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 November 8, 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 88 percent in the first nine 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 third quarter of 2010?*

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

- achieved record quarterly production in the third quarter of 2010 with average daily volumes of 8,114 barrels of oil equivalent per day (boe/d), an increase of 20 percent compared to the third quarter of 2009;
- increased oil and natural gas liquids production by 32 percent to 1,541 bbls/d compared to 1,168 bbls/d in the third quarter of 2009, maintaining the production mix at approximately 19 percent crude oil and natural gas liquids in the third quarter of 2010;
- achieved production growth in the third quarter consistent with the Company's market guidance towards average annual production in 2010 of 7,900 to 8,200 boe/d which was established early in 2010;
- generated funds from operations (cash flow) of $15.1 million, an increase of 20 percent from the comparative quarter of 2009;
- reduced operating costs by 21 percent to $7.45 per boe in the third quarter of 2010 from $9.46 per boe in the third quarter of 2009;
- maintained an operating netback in the $22.00 to $24.00 per boe range and a cash netback of $20.25 per boe in the third quarter;
- realized $4.9 million in hedging gains on crude oil and natural gas commodity contracts, providing stability to cash flow and balance sheet strength;
- drilled 12.0 gross (8.3 net) wells in the third quarter with a 100 percent success rate; and
- executed additional natural gas hedging contracts to increase the Company's natural gas hedge position to approximately 20 percent of expected 2011 natural gas production at a price of $6.04 per mcf.

Cash flow in the third quarter of 2010 was $15.1 million or $0.13 per basic share, compared to $12.6 million or $0.16 per basic share in the third quarter of 2009. Cash flow was 20 percent higher primarily as a result of higher production volumes, the change in production mix, higher realized crude oil prices and lower operating costs.

During the quarter, Delphi participated in the drilling of 12.0 gross (8.3 net) wells with a 100 percent success rate, entirely focused in its three core areas of Bigstone, Hythe and Wapiti/Gold Creek. Total capital expenditures for the third quarter were $43.9 million as the Company spent cash flow generated in the third quarter and the net proceeds of the equity raised in the second quarter. Completion and tie-in operations on several of the wells will be undertaken in the fourth quarter due to wet weather conditions late in the third quarter.

Delphi's financial position continues to remain strong at the end of the third quarter of 2010. At September 30, 2010, the Company had net debt of $107.9 million on total credit facilities of $135.0 million. The increase in net debt from the second quarter was a result of a planned, expanded capital expenditure program. Net debt is expected to be slightly lower by year end as fourth quarter capital expenditures are expected to be less than cash flow. On an annualized nine month funds from operations basis, Delphi's net debt to cash flow ratio was 1.9:1 at September 30, 2010. Net debt includes bank debt plus working capital deficiency excluding the risk management asset/liability and the related current future income taxes.

## 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 September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| | **2010** | 2009 | % Change | **2010** | 2009 | % Change |
| **Natural Gas** | | | | | | |
| NYMEX (US $/mmbtu) | **4.30** | 3.16 | 36 | **4.58** | 3.81 | 20 |
| AECO (CDN $/mcf) | **3.54** | 2.94 | 21 | **4.12** | 3.78 | 9 |
| **Crude Oil** | | | | | | |
| West Texas Intermediate (US $/bbl) | **76.17** | 68.29 | 12 | **77.64** | 57.13 | 36 |
| Edmonton Light (CDN $/bbl) | **74.44** | 71.49 | 4 | **76.53** | 62.47 | 23 |
| **Foreign Exchange** | | | | | | |
| Canadian to US dollar | **1.04** | 1.10 | (6) | **1.04** | 1.17 | (11) |
| US to Canadian dollar | **0.96** | 0.91 | 6 | **0.97** | 0.86 | 12 |

### 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 third quarter of 2010, natural gas prices continued to decrease as summer cooling demand for natural gas was more than offset by domestic natural gas production in the United States with excess production placed into storage to meet this winter's heating demand. Industrial demand also continues to be reduced due to the continuing economic slowdown. The potential of natural gas production from the various shale resource plays in North America continued to adversely affect the view of supply and demand fundamentals putting additional downward pressure on natural gas prices in the short to medium term. Canadian prices in the third quarter varied from a high of Cdn $3.98 per mcf to a low of Cdn $3.14 per mcf. For the third quarter, the average price for AECO was Cdn $3.54 per mcf, $0.60 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 third quarter of 2010, the price for crude oil traded between U.S. $70.00 and U.S. $85.00 per barrel as the demand for oil, while reasonably stable, continued to experience volatility due to concerns over the global economic recovery. 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 third quarter of 2010, WTI averaged U.S. $76.17 per barrel, 12 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 $1.07 in the quarter. In the third quarter of 2010, Canadian crude oil prices averaged $74.44 per barrel compared to $71.49 per barrel in the third quarter of 2009, a four percent increase over the comparative quarter.

***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 continues to increase, particularly horizontal drilling into the shale gas plays. The Company currently anticipates AECO will average between Cdn $3.75 and $4.00 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. $75.00 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 43 percent of its before-royalty natural gas production at a predominantly AECO based average floor price of $6.16 per mcf for the remainder of 2010. This compares to the forward strip commodity price for AECO of $3.64 per mcf for the remainder of 2010 as of November 1, 2010. The following natural gas hedges are in place to support the Company's cash flow.

| | Oct 2010 | Nov-Mar 2010/11 | Apr-Dec 2011 |
|---|---|---|---|
| Production hedged (mmcf/d) | 20.9 | 11.2 | 7.9 |
| Percentage of natural gas production * | 52% | 28% | 20% |
| Price floor (Cdn $/mcf) | $6.00 | $6.23 | $5.99 |

* based on 40 mmcf/d

The fair value of outstanding contracts is estimated to be approximately $6.4 million as of September 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 received from crude oil and natural gas 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 6,708 boe/d to 8,114 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, second and third quarter volumes of 7,645, 8,035 and 8,114 boe per day, respectively. For the nine months ended September 30, 2010, production volumes of 7,933 boe per day were achieved, representing growth of 17 percent over the first nine months 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 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 nine months of 2010, crude oil averaged U.S. $77.64, which was a 36 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 $20.69 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.

| | **Sep. 30 2010** | Jun. 30 2010 | Mar. 31 2010 | Dec. 31 2009 | Sept. 30 2009 | Jun. 30 2009 | Mar. 31 2009 | Dec. 31 2008 |
|---|---|---|---|---|---|---|---|---|
| **Production** | | | | | | | | |
| Natural gas (mcf/d) | **39,439** | 38,540 | 38,349 | 34,626 | 33,628 | 35,641 | 34,813 | 35,545 |
| Oil (bbls/d) | **831** | 1,074 | 745 | 630 | 624 | 371 | 475 | 431 |
| Natural gas liquids (bbls/d) | **710** | 538 | 508 | 487 | 544 | 498 | 485 | 353 |
| Barrels of oil equivalent (boe/d) | **8,114** | 8,035 | 7,645 | 6,888 | 6,773 | 6,809 | 6,762 | 6,708 |
| **Financial** | | | | | | | | |
| ($ thousands except per unit amounts) | | | | | | | | |
| Petroleum and natural gas revenue | **28,080** | 29,125 | 29,519 | 26,297 | 24,433 | 23,229 | 24,205 | 30,160 |
| Funds from operations (cash flow) | **15,120** | 12,988 | 15,157 | 14,218 | 12,635 | 12,371 | 10,017 | 13,473 |
| Per share – basic | **0.13** | 0.12 | 0.15 | 0.14 | 0.16 | 0.16 | 0.13 | 0.18 |
| Per share – diluted | **0.13** | 0.12 | 0.15 | 0.14 | 0.16 | 0.16 | 0.13 | 0.18 |
| Net earnings (loss) | **(1,566)** | (2,742) | 3,260 | 1,386 | (3,278) | (2,817) | (3,320) | (959) |
| Per share – basic | **(0.01)** | (0.03) | 0.03 | 0.02 | (0.04) | (0.04) | (0.04) | (0.01) |
| Per share – diluted | **(0.01)** | (0.03) | 0.03 | 0.02 | (0.04) | (0.04) | (0.04) | (0.01) |

***On an 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 third quarter?***

The Company had a successful quarter through the drill bit resulting in a drilling success rate of 100 percent. Year to date, Delphi has drilled 28 gross (19.0 net) wells with a success rate of 96 percent. The drilling was primarily focused on the core properties of Bigstone, Wapiti/Gold Creek and Hythe in North West Alberta.

| | Three Months Ended September 30, 2010 | | Nine Months Ended September 30, 2010 | |
|---|---|---|---|---|
| | **Gross** | **Net** | **Gross** | **Net** |
| Natural gas wells | **6.0** | **4.7** | **15.0** | **11.2** |
| Oil wells | **6.0** | **3.6** | **12.0** | **7.5** |
| Dry wells | **-** | **-** | **1.0** | **0.3** |
| Total wells | **12.0** | **8.3** | **28.0** | **19.0** |
| Success rate (%) | **100** | **100** | **96** | **98** |

## CAPITAL INVESTED

***How much did the Company spend in the third quarter 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 $43.9 million, net of drilling credits of $1.8 million, with approximately 84 percent directed at drilling and completion operations and eight percent incurred on equipping and facility projects.

In prior years, Delphi generally acquired its undeveloped land as part of its asset acquisition strategy. In 2010, the Company has been more active at Crown land sales, acquiring undeveloped land in the deep basin of North West Alberta, primarily focused in its core areas of Bigstone, Hythe and Wapiti/Gold Creek. In the first nine months of 2010, Delphi has acquired 31,603 net acres in these areas. Delphi also added to its growth potential with the acquisition of 52,200 net acres of Duvernay shale rights at an attractive entry cost targeting natural gas and/or light oil. Delphi's inventory of undeveloped land has increased to approximately 223,000 net acres, up 29 percent from December 31, 2009. As of September 30, 2010, the Company had invested $6.5 million on land, primarily at Crown land sales.

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 benefits 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 September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| | **2010** | 2009 | % Change | **2010** | 2009 | % Change |
| Land | **2,310** | 427 | 441 | **6,143** | 983 | 525 |
| Seismic | **215** | 84 | 156 | **346** | 380 | (9) |
| Drilling and completions | **36,890** | 4,442 | 730 | **64,834** | 15,524 | 318 |
| Equipping and facilities | **3,404** | 2,035 | 67 | **12,266** | 5,591 | 119 |
| Capitalized expenses | **987** | 810 | 22 | **3,012** | 2,623 | 15 |
| Other | **106** | 12 | 783 | **876** | 403 | 117 |
| Capital invested | **43,912** | 7,810 | 462 | **87,477** | 25,504 | 243 |
| Disposition of properties | **4** | (9,728) | - | **(247)** | (9,953) | (98) |
| Net capital invested | **43,916** | (1,918) | - | **87,230** | 15,551 | 461 |
| Acquisition of properties | **2** | 19,669 | (100) | **387** | 19,451 | (98) |
| Total capital invested | **43,918** | 17,751 | 147 | **87,617** | 35,002 | 150 |

## PRODUCTION

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

For the three months ended September 30, 2010, Delphi achieved record production volumes of 8,114 boe/d, representing an increase of 20 percent over the comparative period in 2009. Delphi's growth in production volumes is attributed to a successful 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 2010 drilling program is targeting opportunities in its crude oil and liquids-rich natural gas inventory to maximize operating and cash netbacks. For the three and nine months ended September 30, 2010, production growth is highlighted by a 32 percent increase in crude oil and natural gas liquids compared to the same quarter in 2009.

The Company's production portfolio for the quarter was weighted 81 percent to natural gas, 10 percent to crude oil and nine percent to natural gas liquids.

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| | **2010** | 2009 | % Change | **2010** | 2009 | % Change |
| Natural gas (mcf/d) | **39,439** | 33,628 | 17 | **38,780** | 34,690 | 12 |
| Crude oil (bbls/d) | **831** | 624 | 33 | **884** | 490 | 80 |
| Natural gas liquids (bbls/d) | **710** | 544 | 31 | **586** | 509 | 15 |
| Total (boe/d) | **8,114** | 6,773 | 20 | **7,933** | 6,781 | 17 |

**REALIZED SALES PRICES**

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

For the three and nine months ended September 30, 2010, Delphi's risk management program realized a gain of $4.9 million and $12.1 million, respectively. In the quarter for natural gas, the realized gain was $1.29 per mcf with physical contracts contributing a gain of $0.93 per mcf and financial contracts contributing a gain of $0.36 per mcf. The average realized natural gas price was eight percent less than the comparative period due to a decrease in hedge gains offset by higher heat content and marketing arrangements on natural gas volumes.

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| | **2010** | 2009 | % Change | **2010** | 2009 | % Change |
| AECO ($/mcf) | **3.54** | 2.94 | 20 | **4.12** | 3.78 | 9 |
| Heating content and marketing ($/mcf) | **0.45** | 0.26 | 75 | **0.36** | 0.26 | 40 |
| Gain on physical contracts ($/mcf) | **0.93** | 2.22 | (58) | **0.89** | 1.66 | (47) |
| Gain on financial contracts ($/mcf) | **0.36** | 0.35 | 2 | **0.23** | 0.34 | (33) |
| Realized natural gas price ($/mcf) | **5.28** | 5.77 | (8) | **5.60** | 6.04 | (7) |
| | | | | | | |
| Edmonton Light ($/bbl) | **74.44** | 71.49 | 4 | **76.53** | 62.47 | 23 |
| Quality differential ($/bbl) | **(2.46)** | (3.02) | (19) | **(1.33)** | (2.68) | (50) |
| Gain on financial contracts ($/bbl) | **3.07** | - | 100 | **1.42** | - | 100 |
| Realized oil price ($/bbl) | **75.05** | 68.47 | 10 | **76.62** | 59.79 | 28 |
| | | | | | | |
| Realized natural gas liquids price ($/bbl) | **50.48** | 51.29 | (2) | **54.86** | 47.11 | 16 |
| Total realized sales price ($/boe) | **37.62** | 39.21 | (4) | **40.04** | 38.82 | 3 |

Delphi's oil production has changed from a mix of light and medium oil to predominantly light oil therefore the Company's average price for crude oil, since mid 2010, will fluctuate with the change in the benchmark light crude oil price. With the disposition of the East Central Alberta properties in the second quarter of 2010, increased production of light oil at Bigstone and Hythe continues to high grade the Company's quality of crude oil resulting in pricing more reflective of light oil. The Company's realized crude oil and natural gas liquids prices for the nine months ended September 30, 2010 were significantly higher than the comparative period as a result of the increase in benchmark prices, the reduction in quality differential and gains on risk management contracts.

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

| | **Sep. 30 2010** | Jun. 30 2010 | Mar. 31 2010 | Dec. 31 2009 | Sept. 30 2009 | Jun. 30 2009 | Mar. 31 2009 | Dec. 31 2008 |
|---|---|---|---|---|---|---|---|---|
| Natural Gas Price | | | | | | | | |
| Delphi realized ($/mcf) | **5.28** | 5.30 | 6.26 | 6.15 | 5.77 | 5.81 | 6.55 | 8.14 |
| AECO average ($/mcf) | **3.54** | 3.89 | 4.96 | 4.49 | 2.94 | 3.47 | 4.95 | 6.70 |
| Premium to AECO | **49%** | 36% | 26% | 37% | 96% | 67% | 32% | 21% |
| Hedging gain (loss) ($000's) | **4,676** | 4,186 | 2,941 | 4,498 | 7,973 | 6,997 | 3,991 | 1,985 |

**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 43 percent of its before-royalty natural gas production at a predominately AECO based average floor price of $6.16 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 September 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 |
| September 2010 – December 2010 | Crude Oil | Financial | 300 bbls/d | $84.00 fixed |
| January 2011 – December 2011** | Natural Gas | Financial | 2,500 GJ/d | $7.14 Call |
| January 2011 – December 2012*** | Crude Oil | Financial | 600 bbls/d | U.S. $90.00 Call |
| April 2011 – October 2011 | Natural Gas | Physical | 2,000 GJ/d | $5.66 fixed |
| April 2011 – December 2011*** | Natural Gas | Financial | 6,810 GJ/d | $5.69 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 has acquired a natural gas contract at $5.69 per gigajoule on 6,810 gigajoules per day for the period April 1, 2011 through December 31, 2011. This contract was paid for with the sale of a crude oil call on 600 barrels per day at a price of U.S. $90.00 WTI per barrel for the period January 1, 2011 through December 31, 2012.

The Company recognized an unrealized non-cash gain on its financial contracts of $1.3 million for the first nine months 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 nine months ended September 30, 2010, Delphi generated revenue of $28.1 million and $86.7 million, respectively, representing an increase of 15 percent and 21 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 $4.9 million in the third quarter of 2010. For eight consecutive quarters, Delphi has received a premium to AECO pricing due to the success of the risk management program.

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| | **2010** | 2009 | % Change | **2010** | 2009 | % Change |
| Natural gas | **14,494** | 9,893 | 47 | **47,504** | 38,270 | 24 |
| Natural gas physical contract gains | **3,385** | 6,882 | (51) | **9,402** | 15,695 | (40) |
| Crude oil | **5,504** | 3,931 | 40 | **18,147** | 7,999 | 127 |
| Natural gas liquids | **3,297** | 2,567 | 28 | **8,776** | 6,546 | 34 |
| Sulphur | **(124)** | 69 | - | **151** | 91 | 65 |
| Realized gain on risk management contracts | **1,526** | 1,091 | 40 | **2,744** | 3,266 | (16) |
| Total | **28,080** | 24,433 | 15 | **86,724** | 71,867 | 21 |

## 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 third quarter of 2010 and how did they compare to the same period in 2009?***

Crown royalties of $3.4 million were partially offset by $1.6 million of royalty credits with the net amount of $1.8 million representing 62 percent of the total royalties paid in the third quarter. The net Crown royalties increased in the first nine months of 2010 compared to the first nine 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.

Gross overriding royalties represent 29 percent of total royalties in the first nine 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 September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| | **2010** | 2009 | % Change | **2010** | 2009 | % Change |
| Crown royalties | **3,400** | 3,082 | 10 | **12,427** | 10,819 | 15 |
| Royalty credits | **(1,557)** | (1,825) | (15) | **(4,374)** | (5,475) | (20) |
| Crown royalties – net | **1,843** | 1,257 | 47 | **8,053** | 5,344 | 51 |
| Freehold royalties | **5** | 85 | (94) | **170** | 270 | (37) |
| Gross overriding royalties | **1,145** | 172 | 566 | **3,303** | 809 | 308 |
| Total | **2,993** | 1,514 | 98 | **11,526** | 6,423 | 79 |
| Per boe | **4.01** | 2.43 | 65 | **5.32** | 3.47 | 53 |

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

For the three and nine months ended September 30, 2010, the Crown royalty rate increased 5 percent and 7 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 two percent in the prior year.

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| | **2010** | 2009 | % Change | **2010** | 2009 | % Change |
| Crown rate – net of royalty credits | **8.0%** | 7.6% | 5 | **10.8%** | 10.1% | 7 |
| Gross overriding rate | **4.9%** | 1.0% | 390 | **4.4%** | 1.5% | 193 |
| Average rate | **12.9%** | 9.2% | 40 | **15.5%** | 12.1% | 28 |

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 to $80.00 per barrel of crude oil and an AECO spot price of Cdn $3.75 to $4.00 per mcf, Delphi anticipates its average royalty rate in 2010 to average between 13 and 15 percent for the remainder of the year. Similar to 2009, for 2010 the Company will continue to receive 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 nine months ended September 30, 2010, decreased 21 percent and 19 percent, respectively, over the comparative periods. The significant decrease in operating costs is attributed to higher production volumes from cost efficient core areas and a reduction in absolute costs. Processing income is lower than the comparative periods due to third party volumes being reduced as Delphi's production volumes increase and require processing capacity previously available for third party volumes. 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 but at a more moderate pace.

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| | **2010** | 2009 | % Change | **2010** | 2009 | % Change |
| Production costs | **6,139** | 6,747 | (10) | **19,207** | 20,531 | (6) |
| Processing income | **(578)** | (954) | (39) | **(1,810)** | (2,265) | (20) |
| Total | **5,561** | 5,893 | (6) | **17,397** | 18,266 | (5) |
| Per boe | **7.45** | 9.46 | (21) | **8.03** | 9.87 | (19) |

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

Delphi continues to focus on cost reduction and continues to direct its 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 September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| | **2010** | 2009 | % Change | **2010** | 2009 | % Change |
| Total | **2,149** | 1,651 | 30 | **6,819** | 5,240 | 30 |
| Per boe | **2.88** | 2.65 | 9 | **3.15** | 2.83 | 11 |

***What factors contributed to the increase in transportation costs in the first nine months 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 nine months ended September 30, 2010, increased by nine percent and 11 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 $3.00and $3.25 per boe for 2010.

**GENERAL AND ADMINISTRATIVE**

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| | **2010** | 2009 | % Change | **2010** | 2009 | % Change |
| General and administrative costs | **2,568** | 2,232 | 15 | **8,470** | 7,648 | 11 |
| Overhead recoveries | **(492)** | (155) | 217 | **(1,442)** | (627) | 130 |
| Salary allocations | **(922)** | (815) | 13 | **(3,084)** | (3,414) | (10) |
| Net | **1,154** | 1,262 | (9) | **3,943** | 3,607 | 9 |
| Per boe | **1.55** | 2.02 | (23) | **1.82** | 1.95 | (7) |

***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 nine months ended September 30, 2010 decreased 23 percent and seven percent over the comparative periods in 2009 due to the timing of compensation adjustments offset by an increase in production volumes. 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 $1.80 to $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 September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| | **2010** | 2009 | % Change | **2010** | 2009 | % Change |
| Stock-based compensation | **486** | 281 | 73 | **1,132** | 1,166 | (3) |
| Capitalized costs | **115** | 146 | (21) | **337** | 691 | (51) |
| Net | **370** | 135 | 174 | **795** | 475 | 67 |
| Per boe | **0.50** | 0.22 | 126 | **0.37** | 0.26 | 41 |

The stock-based non cash compensation expense per boe for the three and nine months ended September 30, 2010, increased 126 percent and 41 percent over the comparative period. The increase in the third quarter of 2010 is attributed to additional stock options granted to new employees. During the three and nine months ended September 30, 2010, Delphi capitalized $0.1 million and $0.4 million, respectively, of stock-based compensation associated with exploration and development activities.

## INTEREST

***How do the costs of borrowing in 2010 compare against 2009?***

For the three and nine months ended September 30, 2010, interest expense on a per boe basis decreased 38 percent and three percent over the comparative periods. The decrease is attributed to an increase in production volumes and lower interest costs in the third quarter of 2010.

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| | **2010** | 2009 | % Change | **2010** | 2009 | % Change |
| Total | **1,103** | 1,478 | (25) | **3,774** | 3,308 | 14 |
| Per boe | **1.48** | 2.37 | (38) | **1.74** | 1.79 | (3) |

During 2009, the Company converted $80.0 million of its outstanding long term debt from prime-based loans to bankers' acceptances. At September 30, 2010, the bankers' acceptances have terms ranging from 90 to 182 days and a weighted average effective interest rate of 4.22 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 nine months ended September 30, 2010 decreased 13 percent and 15 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 September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| | **2010** | 2009 | % Change | **2010** | 2009 | % Change |
| Depletion and depreciation | **15,593** | 14,945 | 4 | **44,084** | 44,635 | (1) |
| Accretion expense | **223** | 205 | 9 | **723** | 599 | 21 |
| Total | **15,816** | 15,150 | 4 | **44,807** | 45,234 | (1) |
| Depletion and depreciation per boe | **20.89** | 23.98 | (13) | **20.35** | 24.12 | (16) |
| Accretion per boe | **0.30** | 0.33 | (9) | **0.33** | 0.32 | 3 |
| Total per boe | **21.19** | 24.31 | (13) | **20.69** | 24.44 | (15) |

***What is accretion expense and how does 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 nine months ended September 30, 2010 increased nine percent and 21 percent, respectively, over the comparative periods.

## INCOME TAXES

***What was the affect on future income taxes during 2010?***

The provision for future income taxes in the financial statements for the three months ended September 30, 2010, was a reduction of $0.5 million. Delphi does not anticipate it will be cash taxable before 2014.

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| | **2010** | 2009 | % Change | **2010** | 2009 | % Change |
| Current | **-** | - | - | **-** | - | - |
| Future (reduction) | **(456)** | (1,079) | (58) | **(7)** | (3,140) | (100) |
| Total | **(456)** | (1,079) | (58) | **(7)** | (3,140) | (100) |
| Per boe | **(0.61)** | (1.73) | (65) | **-** | (1.70) | (100) |

## 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 nine months of 2010?***

For the three and nine months ended September 30, 2010, funds from operations were $15.1 million ($0.13 per basic share) and $43.3 million ($0.40 per basic share) compared to $12.6 million ($0.16 per basic share) and $35.0 million ($0.45 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 September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| | **2010** | 2009 | % Change | **2010** | 2009 | % Change |
| Net loss | **(1,566)** | (3,278) | (52) | **(1,048)** | (9,415) | (89) |
| Non-cash items: | | | | | | |
| Depletion, depreciation and accretion | **15,816** | 15,150 | 4 | **44,807** | 45,234 | (1) |
| Unrealized loss (gain) on risk management activities | **956** | 1,707 | (44) | **(1,282)** | 1,869 | (169) |
| Stock-based compensation expense | **370** | 135 | 174 | **795** | 475 | 67 |
| Future income taxes (reduction) | **(456)** | (1,079) | (58) | **(7)** | (3,140) | (100) |
| Funds from operations | **15,120** | 12,635 | 20 | **43,265** | 35,023 | 24 |

***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 September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| | **2010** | 2009 | % Change | **2010** | 2009 | % Change |
| Funds from operations: Non-GAAP | **15,120** | 12,635 | 20 | **43,265** | 35,023 | 24 |
| Change in non-cash working capital | **(4,741)** | (2,039) | 133 | **(2,973)** | (3,454) | (14) |
| Cash flow from operating activities: GAAP | **10,379** | 10,596 | (2) | **40,292** | 31,569 | 28 |

**NET EARNINGS**

***What factors contributed to the loss in the third quarter of 2010?***

For the three and nine months ended September 30, 2010, Delphi recorded a net loss of $1.6 million and a net loss of $1.0 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 nine months of 2010 compared to the prior year?***

The Company's operating netback was lower than the comparative quarter due to a lower realized price per boe and an increase in royalty costs per boe. The Company strives for an operating netback in the $22.00 to $24.00 per boe range and a cash netback of $20.00 per boe. Operating and cash netbacks at these levels are expected to be higher than the 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 September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| | **2010** | 2009 | % Change | **2010** | 2009 | % Change |
| **Barrels of oil equivalent ($/boe)** | | | | | | |
| Realized sales price | **37.62** | 39.21 | (4) | **40.04** | 38.82 | 3 |
| Royalties | **4.01** | 2.43 | 65 | **5.32** | 3.47 | 53 |
| Operating expenses | **7.45** | 9.46 | (21) | **8.03** | 9.87 | (19) |
| Transportation | **2.88** | 2.65 | 9 | **3.15** | 2.83 | 11 |
| **Operating netback** | **23.28** | 24.67 | (6) | **23.54** | 22.65 | 4 |
| General and administrative expenses | **1.55** | 2.02 | (23) | **1.82** | 1.95 | (7) |
| Interest | **1.48** | 2.37 | (38) | **1.74** | 1.79 | (3) |
| **Cash netback** | **20.25** | 20.28 | - | **19.98** | 18.91 | 6 |
| Unrealized loss (gain) on financial contracts | **1.28** | 2.74 | (53) | **(0.59)** | 1.01 | (159) |
| Stock-based compensation expense | **0.50** | 0.22 | 126 | **0.37** | 0.26 | 41 |
| Depletion, depreciation and accretion | **21.19** | 24.31 | (13) | **20.69** | 24.44 | (15) |
| Future income taxes (reduction) | **(0.61)** | (1.73) | (65) | **-** | (1.70) | (100) |
| **Net earnings (loss)** | **(2.11)** | (5.26) | (60) | **(0.49)** | (5.10) | (91) |

## LIQUIDITY AND CAPITAL RESOURCES

### Share Capital

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

At September 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 nine months ended September 30, 2010.

| | Three Months Ended September 30, 2010 | Nine Months Ended September 30, 2010 |
|---|---|---|
| Weighted Average Common Shares | | |
| Basic | **112,698** | 106,293 |
| Diluted | **112,698** | 106,293 |
| Trading Statistics [1] | | |
| High | **2.72** | 3.18 |
| Low | **2.38** | 1.70 |
| Average daily, volume | **230,786** | 528,647 |

[1] Trading statistics based on closing price

***How many common shares and stock options are currently outstanding?***

As at November 1, 2010, the Company had 112.8 million common shares outstanding and 7.8 milllion stock options outstanding. The stock options have an average exercise price of $1.59 per share.

**Sources and Uses of Funds**

| | Three Months Ended September 30, 2010 | Nine Months Ended September 30, 2010 |
|---|---|---|
| **Sources:** | | |
| Funds from operations | 15,120 | 43,265 |
| Disposition of petroleum and natural gas properties | - | 247 |
| Issue of common shares | - | 30,250 |
| Share issue costs | 16 | - |
| Exercise of stock options | 66 | 673 |
| Change in non-cash working capital | 22,985 | 16,519 |
| Cash and cash equivalents | 5,731 | - |
| | 43,918 | 90,954 |
| **Uses:** | | |
| Capital expenditures | 43,912 | 87,477 |
| Acquisition of petroleum and natural gas properties | 2 | 387 |
| Disposition of petroleum and natural gas properties | 4 | - |
| Share issue costs | - | 1,966 |
| Cash and cash equivalents | - | 24 |
| | 43,918 | 89,854 |
| Increase (decrease) in bank debt | - | (1,100) |

**Bank Debt plus Working Capital (Net Debt)**

***How much net debt was outstanding at September 30, 2010?***

At September 30, 2010, the Company had $80.0 million outstanding in the form of bankers' acceptances and a working capital deficiency of $27.9 million for total net debt of $107.9 million excluding the financial asset of $1.4 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 $100.0 and $105.0 million by the end of 2010. Growth in cash flow to approximately $57.0 to $60.0 million is expected to result in a net debt to cash flow ratio of approximately 1.8:1 by the end of 2010.

## Contractual Obligations

***What are the contractual obligations as of September 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 | 1,203 | 4,375 | 3,963 | 3,089 | 2,958 |
| Office and equipment lease | 472 | 1,029 | 775 | 390 | - |
| Total | 1,675 | 5,404 | 4,738 | 3,479 | 2,958 |

## 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 in 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. 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. IFRS uses a one-step approach for testing and measuring impairment, with asset carrying values compared directly with the higher of fair value less costs to sell and value in use (discounted cash flows). This may potentially result in more frequent write-downs, however, under IFRS impairments may be reversed in the future if circumstances change. This approach may lead to volatility of earnings in future periods. The Company has completed its initial assessment of 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 the determination of the 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. 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. 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. Delphi has a planned 2010 field capital program ranging between $95.0 and $100.0 million. The capital program for 2010 includes the drilling of up to 33 (20.5 net) wells with the majority of the capital allocated to the Company's three main areas at 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 43 percent of the Company's current natural gas production hedged at an average price of $6.16 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) | **September 30 2010** | December 31 2009 |
|---|---|---|
| **Assets** | | |
| Current assets | | |
| Accounts receivable | **17,523** | 15,630 |
| Prepaid expenses and deposits | **3,868** | 6,004 |
| Risk management asset (Note 7) | **901** | - |
| Future income taxes | **-** | 112 |
| | **22,292** | 21,746 |
| Property, plant and equipment (Note 3) | **382,353** | 339,952 |
| Total assets | **404,645** | 361,698 |
| **Liabilities** | | |
| Current liabilities | | |
| Outstanding cheques | **115** | 139 |
| Accounts payable and accrued liabilities | **49,209** | 32,933 |
| Risk management liability (Note 7) | **-** | 381 |
| Future income taxes | **239** | - |
| | **49,563** | 33,453 |
| Long term debt (Note 4) | **80,000** | 81,100 |
| Future income taxes | **24,766** | 23,917 |
| Asset retirement obligations (Note 5) | **10,956** | 11,818 |
| | **165,285** | 150,288 |
| **Shareholders' equity** | | |
| Share capital (Note 6) | **228,281** | 200,055 |
| Contributed surplus (Note 6) | **11,820** | 11,048 |
| Retained earnings (deficit) | **(741)** | 307 |
| Total shareholders' equity | **239,360** | 211,410 |
| Total liabilities and shareholders' equity | **404,645** | 361,698 |

Commitments (Note 8)

See accompanying notes to the consolidated financial statements.

# DELPHI ENERGY CORP.

**Consolidated Statements of Operations, Comprehensive Loss and Deficit (unaudited)**

For the three and nine months ended September 30

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| (Stated in thousands of dollars, except per share amounts) | **2010** | 2009 | **2010** | 2009 |
| **Revenue** | | | | |
| Petroleum and natural gas sales | **26,554** | 23,342 | **83,980** | 68,601 |
| Realized gain on risk management activities (Note 7) | **1,526** | 1,091 | **2,744** | 3,266 |
| | **28,080** | 24,433 | **86,724** | 71,867 |
| Royalties | **(2,993)** | (1,514) | **(11,526)** | (6,423) |
| Unrealized gain (loss) on risk management activities (Note 7) | **(956)** | (1,707) | **1,282** | (1,869) |
| | **24,131** | 21,212 | **76,480** | 63,575 |
| **Expenses** | | | | |
| Operating | **5,561** | 5,893 | **17,397** | 18,266 |
| Transportation | **2,149** | 1,651 | **6,819** | 5,240 |
| General and administrative | **1,154** | 1,262 | **3,943** | 3,607 |
| Stock-based compensation (Note 6) | **370** | 135 | **795** | 475 |
| Interest | **1,103** | 1,478 | **3,774** | 3,308 |
| Depletion, depreciation and accretion | **15,816** | 15,150 | **44,807** | 45,234 |
| | **26,153** | 25,569 | **77,535** | 76,130 |
| Loss before income taxes | **(2,022)** | (4,357) | **(1,055)** | (12,555) |
| **Taxes** | | | | |
| Future income taxes (reduction) | **(456)** | (1,079) | **(7)** | (3,140) |
| | **(456)** | (1,079) | **(7)** | (3,140) |
| Net loss and comprehensive loss | **(1,566)** | (3,278) | **(1,048)** | (9,415) |
| Retained earnings, beginning of period | **825** | 2,199 | **307** | 8,336 |
| Deficit, end of period | **(741)** | (1,079) | **(741)** | (1,079) |
| Loss per share (Note 6) | | | | |
| Basic and diluted | **(0.01)** | (0.04) | **(0.01)** | (0.12) |

See accompanying notes to the consolidated financial statements.

# DELPHI ENERGY CORP.

**Consolidated Statements of Cash Flows (unaudited)**
For the three and nine months ended September 30

| (Stated in thousands of dollars) | Three Months Ended September 30 **2010** | Three Months Ended September 30 2009 | Nine Months Ended September 30 **2010** | Nine Months Ended September 30 2009 |
|---|---|---|---|---|
| **Cash flow from operating activities** | | | | |
| Net loss | **(1,566)** | (3,278) | **(1,048)** | (9,415) |
| Add non-cash items: | | | | |
| Depletion, depreciation and accretion | **15,816** | 15,150 | **44,807** | 45,234 |
| Stock-based compensation | **370** | 135 | **795** | 475 |
| Unrealized (gain) loss on risk management activities | **956** | 1,707 | **(1,282)** | 1,869 |
| Future income taxes (reduction) | **(456)** | (1,079) | **(7)** | (3,140) |
| Change in non-cash working capital (Note 9) | **(4,741)** | (2,039) | **(2,973)** | (3,454) |
| | **10,379** | 10,596 | **40,292** | 31,569 |
| **Cash flow from (used in) financing activities** | | | | |
| Issue of common shares, net of issue costs | **16** | 15,473 | **28,284** | 15,473 |
| Exercise of stock options | **66** | 32 | **673** | 34 |
| Increase (decrease) in long term debt | **-** | (6,176) | **(1,100)** | 4,600 |
| | **82** | 9,329 | **27,857** | 20,105 |
| **Cash flow available for investing activities** | **10,461** | 19,925 | **68,149** | 51,674 |
| **Cash flow from (used in) investing activities** | | | | |
| Capital expenditures | **(43,912)** | (7,810) | **(87,477)** | (25,504) |
| Disposition of petroleum and natural gas properties | **(4)** | 9,728 | **247** | 9,953 |
| Acquisition of petroleum and natural gas properties | **(2)** | (19,669) | **(387)** | (19,451) |
| Change in non-cash working capital (Note 9) | **27,726** | 3,446 | **19,492** | (13,767) |
| | **(16,192)** | (14,305) | **(68,125)** | (48,769) |
| Increase (decrease) in cash and cash equivalents | **(5,731)** | 5,620 | **24** | 2,905 |
| Cash and cash equivalents, beginning of period | **5,616** | (1,791) | **(139)** | 924 |
| Cash and cash equivalents, end of period | **(115)** | 3,829 | **(115)** | 3,829 |
| Cash and cash equivalents is comprised of: | | | | |
| Cash | **-** | 3,829 | **-** | 3,829 |
| Outstanding cheques | **(115)** | - | **(115)** | - |
| | **(115)** | 3,829 | **(115)** | 3,829 |
| Interest paid | **1,133** | 1,657 | **3,838** | 3,492 |

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 September 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 September 30, 2010** | **Cost** | **Accumulated depletion and depreciation** | **Net book value** |
|---|---|---|---|
| Petroleum and natural gas properties | **517,097** | **256,674** | **260,423** |
| Production equipment | **161,809** | **40,363** | **121,446** |
| Furniture, fixtures and office equipment | **1,288** | **804** | **484** |
| | **680,194** | **297,841** | **382,353** |

| 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 nine months ended September 30, 2010, the Company capitalized $3.0 million (September 30, 2009 - $2.6 million) of general and administrative costs directly related to exploration and development activities.

As at September 30, 2010, costs in the amount of $6.1 million (December 31, 2009 - $4.2 million) representing unproved properties were excluded from the depletion calculation and estimated future development costs of $48.4 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

| | **September 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 182 days and a weighted average effective interest rate of 4.22 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 $22.5 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.

| | **September 30, 2010** | December 31, 2009 |
|---|---|---|
| **Balance, beginning of period** | **11,818** | 9,730 |
| Liabilities incurred | **325** | 132 |
| Liabilities disposed | **(1,910)** | (487) |
| Liabilities acquired | **-** | 1,793 |
| Liabilities settled | **-** | (167) |
| Accretion expense | **723** | 817 |
| **Balance, end of period** | **10,956** | 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

| | September 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 | **574** | **673** | 64 | 43 |
| Allocated from contributed surplus | **-** | **361** | - | 23 |
| Share issue costs | **-** | **(1,966)** | - | (1,523) |
| Future tax effect of share issue costs | **-** | **523** | - | 405 |
| Tax benefit renounced to shareholders | **-** | **(1,615)** | - | (3,108) |
| **Balance, end of period** | **112,740** | **228,281** | 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 September 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 September 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.

| | September 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 | **954** | **2.71** | 3,017 | 0.83 |
| Forfeited | **(44)** | **1.14** | (256) | 1.31 |
| Exercised | **(574)** | **1.17** | (64) | 0.67 |
| **Balance, end of period** | **7,764** | **1.58** | 7,428 | 1.40 |
| **Exercisable, end of period** | **5,883** | **1.52** | 5,245 | 1.58 |

The following table summarizes information about the stock options outstanding and exercisable at September 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** | **3.41** | **1,165** | **0.66** |
| $0.98 - $1.54 | **610** | **1.21** | **3.63** | **335** | **1.22** |
| $1.55 - $1.72 | **3,736** | **1.67** | **2.17** | **3,686** | **1.67** |
| $1.73 - $2.15 | **440** | **1.82** | **2.04** | **440** | **1.82** |
| $2.16 - $3.34 | **1,174** | **2.80** | **4.22** | **257** | **3.11** |
| **Total** | **7,764** | **1.58** | **2.89** | **5,883** | **1.52** |

**(d) Stock-based compensation**

The Company accounts for its stock-based compensation using the fair value method for all stock options. For the nine months ended September 30, 2010, the Company recorded non-cash compensation expense of $0.8 million (September 30, 2009 - $0.5 million). The Company capitalized $0.4 million (September 30, 2009 - $0.9 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 (September 30, 2009 - $0.2 million) has also been capitalized for the year.

During the nine months ended September 30, 2010, the Company granted 1.0 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 (September 30, 2009 - $0.66 per option). The assumptions used in the Black-Scholes model to determine fair value were as follows.

| **For the nine months ended September 30** | **2010** | 2009 |
|---|---|---|
| Risk-free interest rate (%) | **2.8** | 2.5 |
| Expected life (years) | **5.0** | 5.0 |
| Expected volatility (%) | **65.9** | 64.9 |

**(e) Contributed surplus**

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

| | **September 30, 2010** | December 31, 2009 |
|---|---|---|
| **Balance, beginning of period** | **11,048** | 9,605 |
| Stock-based compensation expensed | **795** | 615 |
| Stock-based compensation capitalized | **338** | 851 |
| Reclassification to common shares on exercise of stock options | **(361)** | (23) |
| **Balance, end of period** | **11,820** | 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 September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2010** | 2009 | **2010** | 2009 |
| Basic and diluted (000's) | **112,698** | 79,083 | **106,293** | 79,072 |

For the three and nine months ended September 30, 2010, the stock options were anti-dilutive and therefore excluded from the calculation of weighted average common shares.

### (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 September 30, 2010 net debt, excluding risk management assets or liabilities and the associated future income taxes, was $107.9 million and funds from operations was $43.3 million resulting in a net debt to annualized funds from operations ratio of 1.9:1. 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 September 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.

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 September 30, 2010 is a loss of $30,000. If interest rates on bankers' acceptances had been 100 basis points higher with all other variables held constant, net loss for the nine months ended September 30, 2010 would have been lower 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 September 30, 2010, the Company had the following financial derivative contracts which were recorded at fair value on the balance sheet at an asset of $0.9 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 |
| September 2010 – December 2010 | Crude Oil | Financial | 300 bbls/d | $84.00 fixed |
| January 2011 – December 2011** | Natural Gas | Financial | 2,500 GJ/d | $7.14 Call |
| January 2011 – December 2012*** | Crude Oil | Financial | 600 bbls/d | U.S. $90.00 Call |
| April 2011 – December 2011*** | Natural Gas | Financial | 6,810 GJ/d | $5.69 fixed |

* 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 acquired a natural gas contract at $5.69 per gigajoule on 6,810 gigajoules per day for the period April 1, 2011 through December 31, 2011. This contract was paid for with the sale of a crude oil call on 600 barrels per day at a price of U.S. $90.00 WTI per barrel for the period January 1, 2011 through December 31, 2012.

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 September 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 nine months ended September 30, 2010, the Canadian dollar physical contracts resulted in settlement gains of $9.4 million (September 30, 2009 - $15.7 million) that have been included in petroleum and natural gas sales. For the nine months ended September 30, 2010, the financial contracts resulted in gains of $2.7 million (September 30, 2009 - $3.3 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 nine months ended September 30, 2010 would have been lower by approximately $0.4 million (September 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 September 30, 2010.

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

| | **September 30, 2010** |
|---|---|
| Current (less than 30 days) | **14,378** |
| Past due (31-90 days) | **1,201** |
| Past due (more than 90 days) | **1,944** |
| **Total** | **17,523** |

**(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 September 30, 2010.

| **Financial liabilities** | < 1 Year | 1 – 2 Years | 3 – 5 Years | Thereafter |
|---|---|---|---|---|
| Outstanding cheques | 115 | - | - | - |
| Accounts payable and accrued liabilities | 49,209 | - | - | - |
| Long term debt – principal | - | 80,000 | - | - |
| Total | 49,324 | 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 - $1.7 million; 2011 - $5.4 million; 2012 - $4.7 million; 2013 - $3.5 million; 2014 - $3.0 million.

**NOTE 9: CHANGES IN NON-CASH WORKING CAPITAL ITEMS**

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2010** | 2009 | **2010** | 2009 |
| Change in working capital item: | | | | |
| Accounts receivable | **(3,363)** | (2,388) | **(1,893)** | 1,699 |
| Prepaid expenses and deposits | **329** | (95) | **2,136** | (2,297) |
| Accounts payable and accrued liabilities | **26,019** | 3,890 | **16,276** | (16,623) |
| Total change in non-cash working capital | **22,985** | 1,407 | **16,519** | 17,221 |
| Relating to: | | | | |
| Operating activities | **(4,741)** | (2,039) | **(2,973)** | (3,454) |
| Investing activities | **27,726** | 3,446 | **19,492** | (13,767) |
| | **22,985** | 1,407 | **16,519** | 17,221 |

## 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
Poynt 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

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### 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

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