Delphi Energy Corp.

THIRD QUARTER
For the nine months ended September 30, 2009

STRATEGY. EXECUTION. RESULTS.
DELPHI DELIVERS.

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Third Quarter 2009 Highlights

- Achieved average production of 6,773 barrels of oil equivalent per day (boe/d) with an average of 200 boe/d shut-in during the quarter for facility turnarounds and low commodity prices.
- Generated funds from operations of $12.6 million ($0.16 per basic share) in the quarter, up from $12.4 million ($0.16 per basic share) in the second quarter of 2009.
- Attained a ten percent reduction in operating costs to $9.46 per boe in the third quarter, down from $10.49 per boe in the third quarter of 2008.
- Realized a 60 day average production rate of 430 boe/d from a successful Doe Creek horizontal oil well at Hythe. Initiated horizontal drilling operations on the first of seven follow-up drilling locations.
- Reduced net debt to $93.7 million from $104.1 million at the end of the second quarter, resulting in a net debt to annualized cash flow ratio of 1.9:1.
- Acquired strategic natural gas infrastructure and production of approximately 400 boe/d in the Wapiti/Gold Creek area of North West Alberta for $11.8 million.
- Extended the Company's natural gas hedge positions through March 31, 2011 with April to October 2010 now hedged 45 percent at $6.08 per mcf and November 2010 to March 2011 hedged 22 percent at $6.31 per mcf.

Financial Highlights ($ thousands except per unit amounts)

	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	**2009**	2008	% Change
Petroleum and natural gas sales	**24,433**	34,461	(29)	**71,867**	105,242	(32)
Per boe	**39.21**	59.09	(34)	**38.82**	61.72	(37)
Funds from operations	**12,635**	18,160	(30)	**35,023**	55,184	(37)
Per boe	**20.28**	31.45	(36)	**18.92**	32.36	(42)
Per share – Basic	**0.16**	0.24	(33)	**0.44**	0.77	(43)
Per share – Diluted	**0.16**	0.23	(30)	**0.44**	0.76	(42)
Net earnings (loss)	**(3,278)**	6,744	-	**(9,415)**	6,053	-
Per boe	**(5.26)**	12.09	-	**(5.10)**	3.55	-
Per share – Basic	**(0.04)**	0.09	-	**(0.12)**	0.08	-
Per share – Diluted	**(0.04)**	0.09	-	**(0.12)**	0.08	-
Capital invested	**7,810**	27,132	(71)	**25,504**	61,119	(58)
Disposition of properties	**(9,728)**	(5,500)	77	**(9,953)**	(8,450)	18
Net capital invested	**(1,918)**	21,632	-	**15,551**	52,669	(70)
Acquisition of properties	**19,669**	34,096	(42)	**19,451**	37,946	(49)
Total capital	**17,751**	55,728	(68)	**35,002**	90,615	(61)

	Sep. 30 2009	Dec. 31 2008	% Change
Debt plus working capital deficiency [(1)]	**93,711**	109,237	(14)
Total assets	**358,028**	364,538	(2)
Shares outstanding (000's)			
Basic	**92,314**	79,067	17
Diluted	**99,706**	83,798	19

(1) excludes risk management asset/liability and the related current future income tax liability/asset.

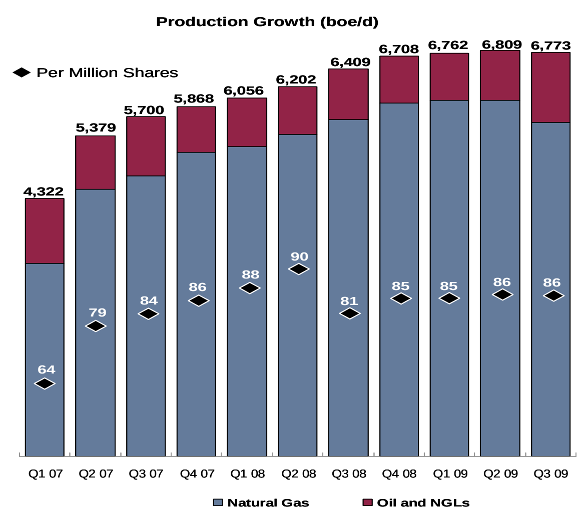
Operational Highlights

	Three Months Ended September 30			Nine Months Ended September 30		
Production	**2009**	2008	% Change	**2009**	2008	% Change
Natural gas (mcf/d)	**33,628**	33,691	-	**34,690**	32,460	7
Crude oil (bbls/d)	**624**	372	68	**490**	376	30
Natural gas liquids (bbls/d)	**544**	421	29	**509**	436	17
Total (boe/d)	**6,773**	6,409	6	**6,781**	6,223	9

MESSAGE TO SHAREHOLDERS

Although natural gas prices continued their downward trend in the third quarter, Delphi generated strong financial and operational results remaining well positioned for sustainable, long-term organic growth. The Company achieved third quarter cash flow stronger than in the second quarter, maintained quarterly production volumes on a limited field capital program and had the financial resources to complete a strategic acquisition at Gold Creek/Wapiti in North West Alberta. At the end of the third quarter, the Company had increased its financial flexibility to $31.3 million available on its production credit facility.

Production during the third quarter of 2009 averaged 6,773 boe/d, an increase of six percent compared to 6,409 boe/d in the third quarter of 2008. The increased light oil production at Hythe changed the production mix in the quarter to 17 percent liquids (83 percent natural gas) from 13 percent liquids (87 percent natural gas) in the second quarter. The change in production mix to higher netback liquids contributed to the strong third quarter cash flow.



Delphi's natural gas production continues to receive a premium to AECO pricing 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 $7.38 per mcf in the third quarter, resulting in a gain on natural gas contracts of $8.0 million. The hedging gains resulted in a realized natural gas price of $5.77 per mcf representing a premium of 96 percent to average AECO pricing.

Funds from operations in the third quarter of 2009 were $12.6 million ($0.16 per basic share) compared to $18.2 million ($0.24 per basic share) in the third quarter of 2008. Significantly lower average oil and natural gas prices were partially offset by increased production volumes and reduced royalty rates. A ten percent reduction in operating costs per boe was offset by slightly higher transportation, general and administrative and interest costs per boe resulting in an overall two percent reduction in cash costs per boe compared to the same quarter in 2008.

During the quarter, the Company completed a common share offering for gross proceeds of $16.5 million by issuing 13.2 million shares at an average price of $1.25 per share.

At September 30, 2009, the Company had reduced net debt to $93.7 million from $109.2 million at December 31, 2008. Delphi's field capital program for the first nine months of 2009 was $25.5 million or 73 percent of the cash flow generated. The remaining cash flow was used to partially fund the Company's strategic acquisition in the Gold Creek/Wapiti area of North West Alberta. The Company's net debt to cash flow ratio on an annualized cash flow basis was reduced to 1.9:1 at the end of the third quarter. Net debt includes bank debt plus working capital deficiency excluding the risk management asset/liability and the related current future income taxes liability/asset.

The scheduled semi-annual credit review by the Company's lenders is underway. The Company's lenders are currently National Bank of Canada and Bank of Nova Scotia. Delphi has syndicated its credit facilities to an expanded group of lenders as part of its strategic long-term growth plan. The semi-annual review and syndication will be completed by late-November. The Company expects to renew its revolving $125.0 million production credit facility upon completion of syndication with all other terms of the credit facilities remaining largely unchanged from the current arrangements.

OPERATIONAL UPDATE

During the third quarter, the Company executed a limited field capital program by drilling and completing one horizontal oil well (1.0 net) and completing one vertical gas well (1.0 net). Delphi was also active in the merger and acquisition market closing one asset acquisition and announcing two additional acquisitions that will close in the fourth quarter. In aggregate, the three transactions will result in initial production gains of 1,100 boe/d, an increase in proven plus probable reserves of 4.0 million boe's, ownership in over 500 kilometres of gas gathering infrastructure and six gas processing plants with a combined processing capacity in excess of one billion cubic feet per day of raw gas.

Hythe

At Hythe, the Company drilled and completed one horizontal oil well (1.0 net) as a follow up to two previous successful oil recompletions in vertical wells. The horizontal section was approximately 1,000 metres in length and completion operations consisted of six intervals being fracture stimulated using a combination of multi stage fracture technology and gelled liquid petroleum gas as the frac fluid. The 60 day average production rate was 390 barrels of light oil per day and 300 mcf/d of associated gas for a total of 430 boe/d. Based on a cost of $2.5 million this project resulted in finding and development costs of approximately $14.00 per boe, a recycle ratio in excess of 4.0 and a payout period of approximately 8 months. The oil pool has been mapped over 5,000 acres, of which Delphi controls 88 percent, with internal estimates of original oil in place in excess of 18 million barrels. A mature analog pool on trend is projected to ultimately recover 29 percent of the original oil in place. Delphi has commissioned a detailed reservoir simulation of the pool with preliminary results indicating a recovery factor of approximately 33 percent or an expected ultimate recovery of 5.2 million barrels of oil net to Delphi's working interest. Preliminary modeling indicates up to seventeen horizontal producers and seven water injectors would be required for full field development. Delphi is currently drilling the first of two horizontal wells (1.4 net) scheduled for the fourth quarter of 2009 and is planning up to five additional wells (4.4 net) in 2010.

The Company also completed one vertical gas well (1.0 net), that was drilled in the second quarter which had a seven day average production rate of 960 mcf/d (160 boe/d).

In the fourth quarter, the Company is continuing to advance the resource-type plays at Hythe with the drilling of a horizontal gas well targeting the Bluesky formation and a recompletion program targeting up to thirteen intervals in six wells that are currently either standing or low rate producers.

Bigstone

At Bigstone, the Company will drill one vertical gas well (0.5 net) prior to year end. The proposed well offsets a Company operated well completed in the first quarter that had a 90 day average production rate of 4,500 mcf/d (750 boed). The Company continues to monitor industry activity targeting oil in the Cardium formation on lands directly offsetting and on trend with the Bigstone field. In preparation for the upcoming winter program the Company is licensing three vertical gas wells and three horizontal oil wells targeting the Cardium formation.

LAND ACQUISITIONS

During the third quarter, the Company successfully participated in several Crown land sales acquiring 2,400 gross acres, in the Hythe and Gold Creek areas, at an average working interest of 71 percent. In combination with previous 2009 Crown land sales and the three asset acquisitions, Delphi has increased its undeveloped land position by 47,000 net acres to 172,000 net acres, an increase of 38 percent from December 31, 2008.

ASSET ACQUISITIONS

During the second half of 2009, the Company will complete three independent transactions comprised of an asset acquisition, an asset exchange/acquisition and a corporate acquisition. These transactions will result in a net gain of approximately 1,100 boed, 4.0 million boe's of proven plus probable reserves, ownership in significant gas processing and gathering systems and an increase in undeveloped land of 34,000 net acres.

Composite reserve and production acquisition costs are as follows (excludes undeveloped land costs and includes Future Development Costs):

Proved reserves	$14.49 per boe
Proved plus Probable Reserves	$10.05 per boe
Production Addition Costs	$29,100 per boe/d

The acquired assets are located in the Deep Basin and will expand the Company's core asset base in North West Alberta. The primary producing intervals are the Cretaceous sands that the Company has been successfully developing in the Hythe and Bigstone areas through the use of existing and emerging technologies such as horizontal drilling, multi-stage fracture stimulations and gelled liquid petroleum gas fracturing. At Hythe and in the Gold Creek/Wapiti area, the acquired lands provide an increased working interest and expanded land base in the developing light oil play, the conventional Cretaceous gas development and the resource-type Nikanassin play. In 2010, the Company will recomplete two wells (0.8 net) and drill up to six wells (2.9 net); primary targets will be the Nikanassin and Gething with secondary potential in the Bluesky and Dunvegan intervals.

Delphi continues to build on a strategy of capital efficient growth and inventory expansion by acquiring underdeveloped, multi-zone natural gas assets in the Deep Basin of North West Alberta with significant low risk conventional and resource-type development potential. Development of the large original gas in place identified on these assets through the use of conventional and emerging technologies provide scale and repeatability for visible long-term capital efficient growth. Operational control of production, land and capital programs coupled with ownership in natural gas processing and gathering infrastructure are essential to controlling operating and capital cost efficiencies.

OUTLOOK

The Company will continue to be disciplined in its capital spending focusing on its core areas of Bigstone, Hythe and the recently acquired Gold Creek/Wapiti asset. Operational risk, capital efficiencies and continued inventory generation were the driving factors in selecting projects for the winter and 2010 field capital program.

The field capital program for the fourth quarter is estimated to be $12.0 to $14.0 million with two rigs drilling through the end of the year in conjunction with the on-going recompletion program. Cash flow for 2009 is now forecast to be between $45.0 million and $47.0 million compared to the original guidance of $38.0 million to $43.0 million. Increased cash flow for 2009 has been generated by reduced cash costs, higher crude oil prices and a change in the production mix. The Company has approximately 49 percent of its natural gas production hedged at $7.29 per mcf for the remainder of 2009.

The Company's planned 2010 capital program of approximately $65.0 million is expected to result in production volumes of 7,500 boe/d to 8,000 boe/d. A drill ready inventory in excess of $120.0 million was utilized to generate the 2010 capital program. The program consists of a broad range of projects including up to 24 drill wells (17.6 net), well and infrastructure optimization projects, recompletions, pipeline and facility projects.

The Company's 2010 cash flow forecast of $60.0 million to $65.0 million is based on an average AECO price of $5.70 per mcf and a WTI price of U.S. $75.00 per barrel. Net debt at December 31, 2010 is expected to be approximately $95.0 million to $100.0 million with a resultant net debt to cash flow ratio of 1.6:1. As in prior years, the Company's risk management program provides stability to the Company's cash flow, ensuring a defined level of capital spending. The Company has the following hedges in place:

	Jan - Mar 2010	Apr - Oct 2010	Nov 2010 - Mar 2011
Volume Hedged (mcf/d)	10,436	16,129	7,875
Price (Cdn $/mcf)	7.81	6.08	6.31
Percentage Hedged *	29%	45%	22%

* based on 36,000 mcf/d.

Effective October 16, 2009, Henry Lawrie resigned from the Board of Directors for personal health reasons. Mr Lawrie has been the Chairman of the Audit & Reserves Committee and was a valuable advisor to fellow members of the Board and the Delphi Team on accounting, financial and governance matters. We are very appreciative of his efforts and wish him and his family well.

In addition, on behalf of the Board of Directors and all the employees of Delphi, I would like to thank our shareholders for their continued support. The Delphi Team continues to expand and remains focused on sustainable, capital efficient growth while maintaining the financial strength and flexibility to take advantage of strategic opportunities in this transaction-oriented environment.

On behalf of the Board,

David J. Reid,
President and Chief Executive Officer
November 3, 2009

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 nine months ended September 30, 2009 and 2008 and should be read in conjunction with the audited financial statements and accompanying notes for the years ended December 31, 2008 and 2007. The discussion and analysis has been prepared as of November 3, 2009.

OPERATIONAL AND FINANCIAL HIGHLIGHTS

Delphi's third quarter production averaged 6,773 barrels of oil equivalent per day (boe/d), representing a six percent increase over the comparative period in 2008. Year to date, the Company increased production volumes nine percent over 2008. Natural gas production represented 83 percent of the Company's average production in the third quarter compared to 87 percent in the second quarter of 2009. The change in production mix was a result of the increased light oil production at Hythe, Alberta. Third quarter production volumes were also affected by scheduled facility maintenance which resulted in an average 200 boe/d shut in for the quarter. Despite the scheduled downtime, Delphi is pleased with its ability to show year over year organic growth in an unstable commodity price environment. The Company has undertaken a minimal field capital program in 2009, opting to maintain production at approximately 6,800 boe/d for the first three quarters of the year as a result of the significant drop in natural gas prices over that time. The Company has used its financial strength and cash flow in excess of capital invested to acquire strategic production and infrastructure in North West Alberta and expand its inventory of growth opportunities.

Funds flow from operations in the third quarter of 2009 was $12.6 million or $0.16 per basic share, compared to $18.2 million or $0.24 per basic share in 2008, primarily as a result of lower average oil and natural gas prices for the quarter offset by the growth in production volumes, reduced royalty rates and a two percent reduction in cash operating costs per boe as compared to the same quarter in 2008. Delphi's risk management program continued to contribute to funds from operations providing the Company with $8.0 million in realized hedging gains in the quarter.

Delphi's financial position continued to remain strong in the third quarter of 2009, providing financial flexibility to execute the remainder of its 2009 capital program. At September 30, 2009, the Company had net debt of $93.7 million on a production credit facility of $125.0 million, providing excess financial capacity of approximately $31.3 million. On an annualized cash flow basis, the Company's net debt to cash flow ratio was 1.9:1 as of September 30, 2009.

Delphi has been actively pursuing property and corporate acquisitions in its core area of North West Alberta. On August 31, 2009, Delphi closed the property and infrastructure acquisition in the Gold Creek/Wapiti areas of North West Alberta. In addition, on August 21, 2009, Delphi announced the acquisition of Fairmount Energy Inc. which is expected to close in the fourth quarter of 2009. On September 30, 2009, Delphi announced a property and infrastructure acquisition at Hythe, Alberta which closed on November 3, 2009. These strategic acquisitions provide production, land and infrastructure within the Company's core area of focus.

BUSINESS ENVIRONMENT

Benchmark Prices

	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	**2009**	2008	% Change
Natural Gas						
NYMEX (US $/mmbtu)	**3.16**	9.91	(68)	**3.81**	9.62	(60)
AECO (CDN $/mcf)	**2.94**	7.73	(62)	**3.78**	8.64	(56)
Crude Oil						
West Texas Intermediate (US $/bbl)	**68.29**	117.97	(42)	**57.13**	113.29	(50)
Edmonton Light (CDN $/bbl)	**71.49**	121.85	(41)	**62.47**	115.14	(46)
Foreign Exchange						
Canadian to US dollar	**1.10**	0.96	15	**1.17**	0.98	19
US to Canadian dollar	**0.91**	1.04	(13)	**0.86**	1.02	(16)

Natural Gas

United States natural gas prices are commonly referenced to the New York Mercantile Exchange Henry Hub in Louisiana (NYMEX) while Canadian natural gas prices are typically referenced to the Canadian Alberta Energy Company interconnect with the TransCanada Alberta system (AECO). Natural gas prices are influenced more by North American supply and demand than global fundamentals, however, with the growth in natural gas liquefaction and regasification facilities around the world this North American supply and demand balance is subject to disruption from time to time. The increase in capacity of natural gas liquefaction and regasification facilities has resulted in natural gas in North America becoming a global commodity, more so through the winter heating season than the summer cooling season, with influences from world weather conditions and global supply in the form of liquefied natural gas (LNG) delivered to the United States.

In the third quarter of 2009, the U.S. Northeast and Midwest and Central Canada experienced below average seasonal temperatures resulting in reduced average demand for natural gas for electrical generation with industrial demand remaining significantly reduced due to the continuing economic slowdown. Downward pressure on natural gas prices began early in 2009 and continued through most of the third quarter as natural gas storage numbers continued to grow over the five year average levels. AECO gas prices hit a low of $2.02 per mcf early in September but have since recovered to over $4.25 per mcf at the end of October, 2009. AECO averaged $2.94 per mcf in the third quarter. The drop in natural gas prices has had a significant effect on the active drilling rig count in both Canada and the United States.

For internal forecasting purposes, Delphi continues to expect a challenging natural gas market for the remainder of 2009 and anticipates AECO to average between $3.75 and $4.25 per mcf for the year. Delphi continues to monitor the variables affecting the price of natural gas in order to ensure its capital program is in line with expected funds flow from operations.

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 US/CDN dollar exchange rate.

Through the third quarter of 2009, the price for crude oil was reasonably stable between U.S. $65.00 and $75.00 per barrel. Crude oil supplies continued to grow in the quarter as demand remained reduced due to the slowdown in global economies and use of energy. WTI averaged U.S. $68.29 per barrel for the quarter compared to U.S. $117.97 per barrel for the same quarter in the prior year, a decrease of 42 percent. The average price of U.S. $68.29 per barrel was, however, 15 percent higher than the second quarter average of U.S. $59.62 per barrel.

In the third quarter of 2009, the value of the Canadian dollar increased against its U.S. counterpart as the demand for the United States dollar as a safe haven in these uncertain economic times decreased. This negative effect to the price of oil for Canadian producers was compounded by a widening basis differential between U.S. and Canadian markets. In the third quarter of 2009, Canadian crude oil prices averaged $71.49 per barrel compared to $121.85 per barrel for the same quarter in the prior year, a decrease of 41 percent.

Prices for heavy oil and other lesser quality crude oils trade at a discount or differential to light crude oil due to the additional costs involved in the refining process. The average differential in the third quarter of 2009 was $6.21 per barrel compared to $16.43 per barrel in 2008. The decrease in the average differential, offset by lower light oil prices, resulted in Bow River crude prices averaging $65.29 per barrel compared to $105.42 per barrel in the third quarter of 2008.

For internal forecasting purposes, Delphi anticipates WTI to average between U.S. $65.00 and $75.00 per barrel for the remainder of 2009 with the Canadian dollar to remain between $1.00 and $1.05 per U.S. dollar.

Industry Cost of Services

The drop in commodity prices in the latter half of 2008 and through 2009 so far have had a significant negative effect on cash flow available for capital programs and hence drilling and field activity. Drilling contractors and oilfield service companies have had to reduce the rates charged for equipment and labour in order to remain competitive and as active as possible, but at a much slower pace than in previous years. The overall uncertainty in the economy has also led to reduced demand for oilfield services and equipment as many companies have been unable to raise external sources of funding to pursue capital programs.

FINANCIAL STRATEGY

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. Delphi's program involves executing numerous contracts over a period of time to take advantage of the volatility in the natural gas market. The strategy takes advantage of the upward swings in natural gas prices as a result of a) the changes in demand/supply fundamentals and/or b) the movement of significant financial assets invested in the natural gas market as a pure commodity play. The transactions are generally undertaken for contract terms 12 to 24 months in advance with financially strong counterparties and predominantly executed on a physical basis with the Company's natural gas marketer. Delphi's risk management program consists of fixed price contracts, costless collars, participating swaps and puts and calls which provide downside protection along with the opportunity to share in the upside if market prices increase above the floor price for the costless collar, participating swaps and puts. 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 49 percent of its before-royalty natural gas production at a predominantly AECO based average floor price of $7.29 per mcf for the remainder of 2009. This compares to the forward strip commodity price for AECO of $5.74 per mcf as of September 30, 2009. The following natural gas hedges are in place to support the Company's cash flow.

	Oct 2009	Nov-Mar 2009/2010	Apr-Dec 2010	Oct-Dec 2009	Jan-Dec 2010
Production hedged (mmcf/d)	19.0	13.1	15.2	17.7	14.0
Percentage of natural gas production *	53%	36%	42%	49%	39%
Price floor (Cdn $/mcf)	$7.38	$7.51	$6.13	$7.29	$6.44

* based on 36 mmcf/d

The fair value of the outstanding contracts is estimated to be approximately $6.9 million as of September 30, 2009.

As the Company's financial condition improves and/or natural gas demand/supply fundamentals move toward equilibrium or reduced supply, Delphi will manage its hedging program accordingly to take advantage of exposure to higher natural gas commodity prices.

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 strong operating netbacks per boe through the risk management program 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.

The annual net capital expenditure program in the field will continue to be slightly less than forecast funds from operations. 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.

Delphi continues to be focused on reducing its leverage and improving its financial flexibility through net debt reduction or increasing funds flow growth resulting in a lower net debt to annualized quarterly funds from operations ratio. The Company continues to be focused on achieving its internal target range for this ratio of 1.3 to 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 flow.

SELECTED INFORMATION

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

	Sept. 30 2009	Jun. 30 2009	Mar. 31 2009	Dec. 31 2008	Sept. 30 2008	Jun. 30 2008	Mar. 31 2008	Dec. 31 2007
Production								
Natural gas (mcf/d)	**33,628**	35,641	34,813	35,545	33,691	31,898	31,777	30,610
Oil (bbl/d)	**624**	371	475	431	372	368	387	346
Natural gas liquids (bbl/d)	**544**	498	485	353	421	517	372	420
Barrels of oil equivalent (boe/d)	**6,773**	6,809	6,762	6,708	6,409	6,202	6,056	5,868
Financial								
($ thousands except per unit amounts)								
Petroleum and natural gas revenue	**24,433**	23,229	24,205	30,160	34,461	38,569	32,212	26,632
Funds from operations	**12,635**	12,371	10,017	13,473	18,160	19,965	17,059	13,747
Per share – basic	**0.16**	0.16	0.13	0.18	0.24	0.29	0.25	0.20
Per share – diluted	**0.16**	0.16	0.13	0.18	0.23	0.28	0.25	0.20
Net earnings (loss)	**(3,278)**	(2,817)	(3,320)	(959)	6,743	49	(739)	1,732
Per share – basic	**(0.04)**	(0.04)	(0.04)	(0.01)	0.09	-	(0.01)	0.03
Per share – diluted	**(0.04)**	(0.04)	(0.04)	(0.01)	0.09	**-**	(0.01)	0.03

Production for the last eight consecutive quarters reflects the following events: In 2007, success at Bigstone, Alberta throughout the year and Noel, British Columbia in the third quarter complemented the mid-year start up of production at Tower Creek, Alberta resulting in consistent quarter over quarter production growth. 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 the first nine months of 2009, production growth was achieved with drilling success at Bigstone and Hythe, Alberta. Revenue and funds from operations reflect the cycle of natural gas prices and production volumes.

Natural gas prices over the past two years have generally reflected the cyclical nature of demand. Higher prices in the winter months, reflecting demand for heating, weaken 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, natural gas prices decreased significantly and then stabilized in the fourth quarter. In 2009, reduced heating demand and industrial demand due to the economic crisis caused natural gas prices to decrease further as a result of concerns over excess supply. 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. For the nine months ended September 30, 2009, the Company has recorded cash flow of $35.0 million, during a period of weak commodity pricing. The strong 2009 cash flow is attributed to an increase in production volumes, reduced cost structure and a successful risk management program.

DRILLING RESULTS

	Three Months Ended September 30, 2009		Nine Months Ended September 30, 2009	
	Gross	**Net**	**Gross**	**Net**
Natural gas wells	**-**	**-**	**6.0**	**4.8**
Oil wells	**1.0**	**1.0**	**1.0**	**1.0**
Total wells	**1.0**	**1.0**	**7.0**	**5.8**
Success rate (%)	**100**	**100**	**100**	**100**

The Company had a successful quarter with the drill bit resulting in a drilling success rate of 100 percent. The Company has in excess of one hundred drilling locations identified within its core areas of operations.

CAPITAL INVESTED

	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	**2009**	2008	% Change
Land	**427**	130	228	**983**	130	656
Seismic	**84**	719	(88)	**380**	722	(47)
Drilling and completions	**4,442**	21,329	(79)	**15,524**	44,390	(65)
Equipping and facilities	**2,035**	3,599	(43)	**5,591**	12,847	(56)
Capitalized expenses	**810**	767	6	**2,623**	2,434	8
Other	**12**	588	(98)	**403**	596	(32)
Capital invested	**7,810**	27,132	(71)	**25,504**	61,119	(58)
Disposition of properties	**(9,728)**	(5,500)	77	**(9,953)**	(8,450)	18
Net capital invested	**(1,918)**	21,632	-	**15,551**	52,669	(70)
Acquisition of properties	**19,669**	34,096	(42)	**19,451**	37,946	(49)
Total capital	**17,751**	55,728	(68)	**35,002**	90,615	(61)

The Company continues to focus its capital program towards its core areas of Bigstone and Hythe to take advantage of the multi-zone nature of these assets, low operating costs and quick on-stream capability associated with owned gathering and processing infrastructure. Year to date, the Company has directed capital towards drilling, completion and tie-in of five wells at Hythe, Alberta, one well at Bigstone, Alberta and one well at Noel, British Columbia. In the third quarter of 2009, the Company closed an acquisition of predominantly natural gas producing properties with significant infrastructure in North West Alberta for cash consideration of $19.7 million. Upon closing the acquisition, the Company immediately disposed of 40 percent of the acquired working interest in the properties for cash proceeds of $7.9 million. In addition, the Company disposed of two non-core minor working interest natural gas properties for cash proceeds of $1.8 million.

PRODUCTION

	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	**2009**	2008	% Change
Natural gas (mcf/d)	**33,628**	33,691	-	**34,690**	32,460	7
Crude oil (bbls/d)	**624**	372	68	**490**	376	30
Natural gas liquids (bbls/d)	**544**	421	29	**509**	436	17
Total (boe/d)	**6,773**	6,409	6	**6,781**	6,223	9

Production for the three months ended September 30, 2009 averaged 6,773 boe/d representing an increase of six percent over the comparative period primarily due to the successful drilling and optimization programs at Bigstone and Hythe. The success of the 2009 capital program has allowed the company to increase production volumes nine percent over the comparative period in 2008. This is a testament to the quality of the asset base and technical expertise of the staff and management. A significant undeveloped land base, multi-zone potential and the successful application of emerging technologies continue to provide material growth opportunities in existing and new play concepts. Third quarter production volumes were affected by scheduled facility maintenance which resulted in an average 200 boe/d shut in for the quarter. The Company’s production portfolio for the quarter was weighted 83 percent to natural gas, nine percent to crude oil and eight percent to natural gas liquids. The change in production mix to 17 percent crude oil and natural gas liquids from 13 percent in the second quarter of 2009 was a contributing factor to the third quarter’s strong cash flow.

Crude oil production was 68 percent higher for the three months ended September 30, 2009 over the comparative quarter. The increase in oil production is due to the successful drilling and optimization program targeting the Doe Creek light oil discovery at Hythe, Alberta.

Natural gas liquids were 29 percent higher for the three months ended September 30, 2009, as compared to the comparative period in 2008 due to the increased natural gas liquids production at Progress, Alberta.

REALIZED SALES PRICES

	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	**2009**	2008	% Change
AECO ($/mcf)	**2.94**	7.73	(62)	**3.78**	8.64	(56)
Heating content and marketing ($/mcf)	**0.26**	0.57	(54)	**0.26**	0.53	(51)
Gain (loss) on physical contracts ($/mcf)	**2.22**	(0.05)	-	**1.66**	(0.20)	-
Gain (loss) on financial contracts ($/mcf)	**0.35**	0.03	1,076	**0.34**	(0.01)	-
Realized natural gas price ($/mcf)	**5.77**	8.28	(30)	**6.04**	8.96	(33)
Realized oil price ($/bbl)	**68.47**	111.34	(39)	**59.79**	103.54	(42)
Realized natural gas liquids price ($/bbl)	**51.29**	93.26	(45)	**47.11**	94.94	(50)
Total realized sales price ($/boe)	**39.21**	59.09	(34)	**38.82**	61.72	(37)

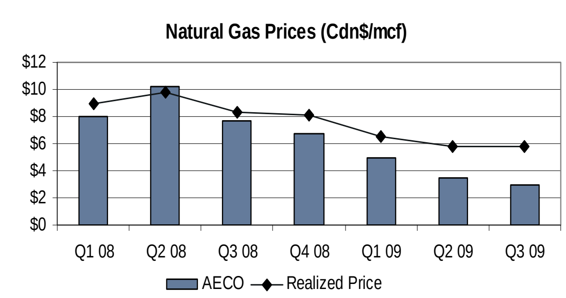
For the three and nine months ended September 30, 2009, Delphi's risk management program realized a gain of $8.0 million and $19.0 million, respectively. For the quarter, the realized gain was $2.57 per mcf with physical contracts contributing a gain of $2.22 per mcf and financial contracts contributing a gain of $0.35 per mcf. For the nine months ended September 30, 2009, the average realized natural gas price was 33 percent less than the comparative period due to a 56 percent decrease in the AECO spot price offset by significant realized hedging gains.

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 3,500 million British thermal units (mmbtu) per day on the Alliance pipeline which is priced at the Chicago Monthly Index.

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

	Sept. 30 2009	Jun. 30 2009	Mar. 31 2009	Dec. 31 2008	Sept. 30 2008	Jun. 30 2008	Mar. 31 2008	Dec. 31 2007
Natural Gas Price								
Delphi realized ($/mcf)	**5.77**	5.81	6.55	8.14	8.28	9.66	8.91	7.61
AECO average ($/mcf)	**2.94**	3.47	4.95	6.70	7.73	10.22	7.97	6.15
Premium (discount) to AECO	**96%**	67%	32%	21%	7%	(5%)	12%	24%
Hedging gain (loss) ($000's)	**7,973**	6,997	3,991	1,985	(67)	(3,153)	1,371	2,996

Delphi's oil production is a mix of light and medium oil; therefore the Company's average price fluctuates with the change in the benchmark crude oil prices and the quality differential. Increased production of light oil at Bigstone and Hythe continues to high grade the Company's quality of crude oil resulting in pricing more reflective of light oil. Year to date, the Company's realized crude oil and natural gas liquids prices were significantly lower than the comparative quarter in the previous year as a result of the significant drop in benchmark prices.



RISK MANAGEMENT ACTIVITIES

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. Delphi makes a concerted effort to hedge production volumes at prices greater than the upper limit of the historical three to five year AECO price range of $5.25 to $8.40 per mcf and is quick to react to price aberrations such as those experienced at the end of 2005 and the summer of 2008. Another component of the risk management program is to layer in contracts over a period of time, as opposed to locking in a significant portion of volumes at any one point in time, to take advantage of unexpected price spikes. For natural gas production, Delphi has hedged approximately 49 percent of its before-royalty natural gas production at a predominately AECO based average floor price of $7.29 per mcf for the remainder of 2009.

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. The changes in the fair value of the United States dollar denominated physical contracts are also classified as unrealized gains and losses in the statement of operations.

The Company recognized an unrealized non-cash loss on its financial contracts and United States dollar denominated physical contracts of $1.9 million for the first nine months of 2009. 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 has fixed the price applicable to future production through the following contracts.

Time Period	Commodity	Type of Contract	Quantity Contracted	Contract Price ($/unit)
April 2009 – October 2009	Natural Gas	Physical	1,000 GJ/d	$7.08 fixed
April 2009 – October 2009	Natural Gas	Physical	2,000 GJ/d	$8.25 floor/$10.00 ceiling
April 2009 – October 2009	Natural Gas	Physical	1,000 mmbtu/d	U.S. $8.18 fixed
April 2009 – October 2009	Natural Gas	Physical	2,000 GJ/d	$8.59 fixed
April 2009 – October 2009	Natural Gas	Physical	2,000 GJ/d	$6.70 floor plus 50% > $6.70
April 2009 – March 2010	Natural Gas	Physical	3,000 GJ/d	$7.52 fixed
April 2009 – March 2010	Natural Gas	Physical	2,000 GJ/d	$6.80 floor plus 50% > $6.80
November 2009 – March 2010	Natural Gas	Physical	2,000 GJ/d	$7.75 floor/$8.70 ceiling
November 2009 – March 2010	Natural Gas	Physical	2,000 GJ/d	$7.26 floor plus 50% > $7.26
November 2009 – March 2010	Natural Gas	Physical	2,000 GJ/d	$7.65 floor plus 50% > $7.65
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 – October 2010	Natural Gas	Financial	2,000 GJ/d	$5.53 fixed
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
February 2009 – December 2009*	Natural Gas	Financial	3,500 GJ/d	$6.00 Put
March 2009 – December 2009*	Natural Gas	Physical	3,500 GJ/d	$6.00 Put
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
April 2010 – October 2010**	Natural Gas	Financial	2,500 GJ/d	$4.75 Put
January 2011 – December 2011**	Natural Gas	Financial	2,500 GJ/d	$7.14 Call
January 2010 – December 2010	Crude Oil	Financial	100 bbls/d	Cdn. $86.40 fixed
January 2010 – December 2010	Crude Oil	Financial	100 bbls/d	Cdn. $72.20 floor/$100.00 ceiling

* The Company has acquired two natural gas put contracts at $6.00 per gigajoule on 3,500 gigajoules per day each for the periods February 1, 2009 through December 31, 2009, and March 1, 2009 through December 31, 2009, respectively. These puts were paid for with the sale of natural gas calls on 7,000 gigajoules per day at an average price of $7.28 per gigajoule for the period January 1, 2010 through December 31, 2010.

**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 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

	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	**2009**	2008	% Change
Natural gas	**9,893**	25,824	(62)	**38,270**	81,420	(53)
Natural gas physical contract gains (losses)	**6,882**	(164)	**-**	**15,695**	(1,759)	-
Crude oil	**3,931**	3,769	4	**7,999**	10,667	(25)
Natural gas liquids	**2,567**	3,573	(28)	**6,546**	11,342	(42)
Sulphur	**69**	1,362	(95)	**91**	3,662	(98)
Realized gain on risk management contracts	**1,091**	97	1,025	**3,266**	(90)	-
Total	**24,433**	34,461	(29)	**71,867**	105,242	(32)

The decrease in revenue over the comparative periods is attributed to the decrease in realized sales price per boe offset by the realized gains from the risk management program and the increase in production volumes.

Additionally, during 2008, sulphur prices began their rise as demand for fertilizers increased around the world. Delphi received $3.7 million from the sale of sulphur during the first nine months of 2008, primarily associated with production at its Tower Creek well. As a result of the slowing economies around the world, sulphur prices have fallen significantly resulting in minimal sales year to date in 2009 despite ongoing production at Tower Creek.

ROYALTIES

	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	**2009**	2008	% Change
Total	**1,514**	6,352	(76)	**6,423**	20,560	(69)
Per boe	**2.43**	10.77	(77)	**3.47**	12.06	(71)
Percent of revenue including realized hedges	**6.2**	18.4	(66)	**8.9**	19.5	(54)
Percent of revenue excluding realized hedges	**9.2**	18.4	(50)	**12.1**	19.2	(37)

The Company pays royalties to provincial governments (Crown), freeholders, which can be individuals or companies, and other oil and gas operators that own surface or mineral rights. Crown royalty rates are calculated on a sliding scale based on commodity prices and individual well production rates. Royalty rates can change due to price fluctuations or changes in production volumes on a well by well basis subject to a minimum and maximum rate restriction ascribed by the Crown.

For the three months ended September 30, 2009, royalties as a percentage of revenue decreased over the comparative period due to increased royalty credits associated with the annual capital cost and processing fee deductions. Additionally, the New Royalty Framework (NRF) rates as a percentage of revenue decreased in a low natural gas price environment. Overall, Delphi is expecting royalties as a percentage of revenue, before hedging, to be between 10 and 14 percent in 2009.

On October 25, 2007, the Government of Alberta announced the New Royalty Framework. The NRF established new royalties for oil and natural gas which are based on commodity prices, well production volumes and well depths. The NRF rates apply to both new and existing production and became effective on January 1, 2009. In the fourth quarter of 2008, the Government of Alberta announced royalty relief which provided that for new wells drilled after November 19, 2008, the Company could elect to have the pre-NRF royalty regime apply on those wells. On March 3, 2009, the Alberta Government announced further royalty incentives to promote oilfield activity in light of the current economic environment.

The incentives provided drilling credits based on the depth drilled and a reduced royalty rate of five percent for natural gas production brought on-stream after March 31, 2009. On June 25, 2009 the Alberta Government announced an extension of this incentive program to March 31, 2011 from March 31, 2010.

OPERATING EXPENSES

	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	**2009**	2008	% Change
Total	**5,893**	6,186	(5)	**18,266**	17,507	4
Per boe	**9.46**	10.49	(10)	**9.87**	10.27	(4)

Operating costs on a per boe basis for the three and nine months ended September 30, 2009, decreased ten percent and four percent, respectively, over the comparative periods. The decrease is attributed to lower field operating costs and an increase in production volumes at Hythe which has average operating costs lower than the corporate average. Delphi continues to focus on cost reduction and anticipates lower operating costs per boe as volumes increase at core areas and the industry experiences a further reduction in field costs. Delphi expects operating costs to be $9.50 to $10.00 per boe in 2009.

TRANSPORTATION EXPENSES

	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	**2009**	2008	% Change
Total	**1,651**	1,499	10	**5,240**	4,624	13
Per boe	**2.65**	2.54	4	**2.83**	2.71	4

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.

On a per boe basis, transportation costs for the three and nine months ended September 30, 2009, increased by four percent over the comparative periods. Transportation costs for the nine months ended September 30, 2009 included the reclassification of approximately $0.4 million of natural gas gathering costs reported as operating costs in the first quarter. Effective November 1, 2007 and again on November 1, 2008, Delphi transferred a portion of its excess processing and transmission capacity in North East British Columbia to third parties resulting in reductions in transportation costs. Delphi expects transportation costs to be between $2.60 and $2.90 per boe for the remainder of 2009.

GENERAL AND ADMINISTRATIVE

	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	**2009**	2008	% Change
General and administrative costs	**2,232**	1,989	12	**7,648**	6,975	10
Overhead recoveries	**(155)**	(338)	(54)	**(627)**	(882)	(29)
Salary allocations	**(815)**	(640)	27	**(3,414)**	(2,764)	24
Net	**1,262**	1,011	25	**3,607**	3,329	8
Per boe	**2.02**	1.71	18	**1.95**	1.95	-

On a per boe basis, general and administrative (G&A) costs for the three months ended September 30, 2009 increased 18 percent over the comparative period in 2008 due to an increase in the number of employees and hence salary costs and a reduction in overhead recoveries. Delphi is committed to delivering strong growth and believes a strong technical team is paramount to achieve this goal. For the remainder of 2009, Delphi is expecting G&A per boe to be approximately $1.80 to $2.00 per boe.

STOCK-BASED COMPENSATION

	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	**2009**	2008	% Change
Stock-based compensation	**281**	600	(53)	**1,166**	1,712	(32)
Capitalized costs	**146**	357	(59)	**691**	977	(29)
Net	**135**	243	(44)	**475**	735	(35)
Per boe	**0.22**	0.41	(46)	**0.26**	0.43	(40)

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. The non-cash stock-based compensation expense per boe for the three and nine months ended September 30, 2009, decreased 46 percent and 40 percent, respectively, over the comparative periods. During the nine months ended September 30, 2009, Delphi capitalized $0.7 million of stock-based compensation associated with exploration and development activities.

INTEREST

	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	**2009**	2008	% Change
Total	**1,478**	1,253	18	**3,308**	4,038	(18)
Per boe	**2.37**	2.13	11	**1.79**	2.37	(24)

For the three and nine months ended September 30, 2009, interest expense on a per boe basis increased 11 percent and decreased 24 percent over the comparative periods. The increase over the comparative quarter was due to the increased pricing on the Company's credit agreement established late in the second quarter, reflective of higher market credit spreads. For the nine months ended September 30, 2009, the lower costs reflect higher production volumes and lower benchmark interest rates over the period.

During 2009, the Company converted $80.0 million of its outstanding long term debt from prime-based loans to bankers' acceptances. The bankers' acceptances have terms ranging from 179 to 185 days and a weighted average effective interest rate of 3.9 percent over the term.

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.

DEPLETION, DEPRECIATION AND ACCRETION

	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	**2009**	2008	% Change
Depletion and depreciation	**14,945**	15,895	(6)	**44,635**	45,762	(2)
Accretion expense	**205**	155	32	**599**	450	33
Total	**15,150**	16,050	(6)	**45,234**	46,212	(2)
Per boe	**24.31**	27.22	(11)	**24.44**	27.10	(10)

Depletion, depreciation, and accretion per boe for the three and nine months ended September 30, 2009 decreased 11 and 10 percent over the comparative periods. With continued drilling success at Bigstone and Hythe, Delphi has been able to add proved reserves at metrics 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.

Accretion expense of asset retirement obligations 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 8.0 to 10.0 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, 2009 increased 32 percent and 33 percent respectively over the comparative periods due to the wells acquired in the Peace River Arch acquisition in the third quarter of 2008 and the wells acquired through the property acquisition during the quarter.

INCOME TAXES

	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	**2009**	2008	% Change
Current	**-**	-	-	**-**	-	-
Future (reduction)	**(1,079)**	2,750	-	**(3,140)**	2,230	-
Total	**(1,079)**	2,750	-	**(3,140)**	2,230	-
Per boe	**(1.73)**	4.66	-	**(1.70)**	1.31	-

The provision for income taxes in the financial statements for the three and nine months ended September 30, 2009, was a reduction of $1.1 million and $3.1 million, respectively. Delphi does not anticipate it will be cash taxable before 2011.

FUNDS FROM OPERATIONS

	Three Month Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	**2009**	2008	% Change
Net earnings (loss)	**(3,278)**	6,744	-	**(9,415)**	6,053	-
Non-cash items:						
Depletion, depreciation and accretion	**15,150**	16,050	(6)	**45,234**	46,212	(2)
Unrealized loss (gain) on risk management activities	**1,707**	(7,627)	-	**1,869**	(46)	-
Stock-based compensation expense	**135**	243	(44)	**475**	735	(35)
Future income taxes (reduction)	**(1,079)**	2,750	-	**(3,140)**	2,230	-
Funds from operations	**12,635**	18,160	(30)	**35,023**	55,184	(37)

For the three and nine months ended September 30, 2009, funds from operations were $12.6 million ($0.16 per basic share) and $35.0 million ($0.44 per basic share) compared to $18.2 million ($0.24 per basic share) and $55.2 million ($0.78 per basic share) in the comparative periods. The decrease in funds from operations is a result of a reduction in revenue received per boe being partially offset by an increase in production volumes, reduced royalty rates and a reduction in operating costs per boe.

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, impairment provisions, 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. 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.

The following table shows the 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		
	2009	2008	% Change	**2009**	2008	% Change
Funds from operations: Non-GAAP	**12,635**	18,160	(30)	**35,023**	55,184	(37)
Change in non-cash working capital	**(2,039)**	271	-	**(3,454)**	(7,802)	(56)
Cash flow from operating activities: GAAP	**10,596**	18,431	(43)	**31,569**	47,382	(33)

NET EARNINGS

For the three and nine months ended September 30, 2009, Delphi recorded a net loss of $3.3 million and $9.4 million, respectively. Net earnings were affected by non-cash items such as depletion, depreciation and accretion, unrealized gain or loss 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

	Three Months Ended September 30			Nine Months Ended September 30		
	2009	2008	% Change	**2009**	2008	% Change
Barrels of oil equivalent ($/boe)						
Realized sales price	**39.21**	59.09	(34)	**38.82**	61.72	(37)
Royalties	**2.43**	10.77	(77)	**3.47**	12.06	(71)
Operating expenses	**9.46**	10.49	(10)	**9.87**	10.27	(4)
Transportation	**2.65**	2.54	4	**2.83**	2.71	4
Operating netback	**24.67**	35.29	(30)	**22.65**	36.68	(38)
G&A	**2.02**	1.71	18	**1.95**	1.95	-
Interest	**2.37**	2.13	11	**1.79**	2.37	(24)
Cash netback	**20.28**	31.45	(36)	**18.91**	32.36	(42)
Unrealized loss (gain) on financial contracts	**2.74**	(12.93)	-	**1.01**	(0.03)	-
Stock-based compensation expense	**0.22**	0.41	(46)	**0.26**	0.43	(40)
Depletion, depreciation and accretion	**24.31**	27.22	(11)	**24.44**	27.10	(10)
Future income taxes (reduction)	**(1.73)**	4.66	-	**(1.70)**	1.31	-
Net earnings (loss)	**(5.26)**	12.09	-	**(5.10)**	3.55	-

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

LIQUIDITY AND CAPITAL RESOURCES

Funding

	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2009
Sources:		
Funds from operations	**12,635**	35,023
Disposition of petroleum and natural gas properties	**9,728**	9,953
Issue of common shares, net of issue costs	**15,473**	15,473
Exercise of stock options	**32**	32
Change in non-cash working capital	**1,407**	-
	39,275	60,481
Uses:		
Cash and cash equivalents	**5,620**	2,905
Capital expenditures	**7,810**	25,504
Acquisition of petroleum and natural gas properties	**19,669**	19,451
Change in non-cash working capital	**-**	17,221
	33,099	65,081
Increase (decrease) in bank debt	**(6,176)**	4,600

For the period ended September 30, 2009 Delphi funded its field capital program through funds from operations.

Share Capital

At September 30, 2009, the Company had 92.3 million common shares outstanding (December 31, 2008 – 79.1 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, 2009.

	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2009
Weighted Average Common Shares		
Basic	**79,083**	79,072
Diluted	**79,657**	79,398
Trading Statistics (1)		
High	**1.61**	1.61
Low	**0.89**	0.56
Average daily, volume	**488,535**	396,692

(1) Trading statistics based on closing price

As at October 28, 2009, the Company had 96.9 million common shares outstanding and 7.4 milllion stock options outstanding.

Bank Debt plus Working Capital

At September 30, 2009, the Company had $96.0 million outstanding on its credit facility and working capital of $2.3 million for total debt plus working capital of $93.7 million excluding the financial liability of $0.1 million relating to the unrealized loss on financial commodity contracts. The Company's debt to cash flow ratio on an annualized cash flow basis was reduced to 1.9:1 at the end of the third quarter. Delphi anticipates spending less than projected funds from operations on field capital expenditures during 2009 with acquisitions being funded by equity and proceeds on the disposition of assets resulting in a reduction in net debt over the year.

Contractual Obligations

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 are as follows:

	2009	2010	2011	2012	2013
Gathering, processing and transmission	1,095	4,955	4,646	3,637	2,551
Office and equipment lease	252	1,023	1,029	775	390
Total	1,347	5,978	5,675	4,412	2,941

Subsequent Events

On August 21, 2009, the Company announced it had entered into an agreement to acquire all of the outstanding common shares of Fairmount Energy Inc. (Fairmount) on the basis of 0.3571 common shares of Delphi for each share of Fairmount, pursuant to a take-over bid mailed on August 28, 2009 to Fairmount shareholders. As of November 3, 2009, the Company had taken up and paid for 12,915,916 common shares of Fairmount and holds approximately 79.0 percent of the issued and outstanding common shares of Fairmount. Delphi intends to complete a subsequent acquisition transaction prior to the end of November, 2009 to obtain 100.0 percent of the common shares of Fairmount.

On September 30, 2009, the Company announced it has signed an asset exchange agreement to acquire natural gas and light oil assets at Hythe in North West Alberta for cash consideration of $10.0 million and certain non-core producing assets and related infrastructure of the Company. The acquisition closed on November 3, 2009.

On October 23, 2009, Delphi announced an equity financing of 3.0 million flow-through common shares at a price of $2.12 per share for gross proceeds of $6.4 million. The offering is expected to close by November 16, 2009.

GUARANTEES AND OFF-BALANCE SHEET ARRANGEMENTS

Delphi has not entered into any guarantees or off-balance sheet arrangements except for certain lease agreements entered into in the normal course of operations. All leases are operating leases with lease payments charged to operating expenses or general and administrative expenses according to the nature of the lease.

CRITICAL ACCOUNTING ESTIMATES

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 March 2009, the Accounting Standards Board of the Canadian Institute of Chartered Accountants reconfirmed that IFRS will replace Canadian GAAP in 2011 for profit-oriented Canadian publicly accountable enterprises. 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.

The Company has developed a high level changeover plan to assess in detail all aspects of the changeover to IFRS, including appropriate changes to accounting policies and financial disclosures, effects on information systems and processes, changes to internal controls over financial reporting and business activities, in order to complete the transition to IFRS by January 1, 2011. Delphi will update its IFRS changeover plan to reflect new and amended accounting standards issued by the International Accounting Standards Board. As IFRS is expected to change prior to 2011, the effect on the Company's consolidated financial statements is not reasonably determinable at this time.

In July 2009 an amendment to IFRS 1 First Time Adoption of International Reporting Standards was issued that applies to oil and gas assets. The amendment would permit the Company to measure exploration and evaluation assets under IFRS at the carrying amount determined under GAAP at the date of transition to IFRS. In addition, the carrying amount under GAAP of production or development assets could be allocated on a pro rata basis to the underlying assets using either reserve volumes or reserve values at the date of transition. The assets to which this exemption is applied would be required to be tested for impairment at the date of transition under IFRS standards. Delphi anticipates that it will use this exemption.

CORPORATE GOVERNANCE

Overview

The shareholders' interests are a critical factor in the operations and management of Delphi. The Company is committed to maintaining the highest level of investor confidence in the Company through the application of its corporate governance policies. Delphi's Board of Directors consists of five 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 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 quarter.

2009 OUTLOOK

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 North West Alberta. 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. In that regard, the Company's ability to add production through the drill bit creates a competitive advantage over those competitors that rely on acquisitions to build or maintain their production base. Currently, Delphi has identified over one hundred drilling locations, representing three to five years drilling inventory, in its core areas.

Capital Activities

With the current uncertainty in commodity prices and the economy, Delphi will fund the remainder of the 2009 field capital program from internally generated cash flow from operations. The proceeds from the financing in the third quarter are expected to fund the bank debt assumed on the Fairmount acquisition and the capital required for the asset acquisition at Hythe, Alberta. Delphi has a planned fourth quarter field capital program ranging between $12.0 to $14.0 million with the objective of preserving the Company's financial flexibility in these uncertain economic times and maintaining the flexibility to pursue and capture strategic growth opportunities attractively priced in this transaction oriented environment.

The capital program for the last quarter of the year includes the drilling of up to 4 wells with the majority of the capital allocated to the Company's two main areas, Bigstone and Hythe.

Financial Strategy

The Company is well positioned to endure the current weak economic environment with high quality producing assets, a large inventory of economic projects and a 2009 cash flow stream protected with 49 percent of the Company's current natural gas production hedged at an average price of $7.29 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 low-cost environment, will be key drivers in the capital spending decision process for the remainder of 2009.

ADDITIONAL INFORMATION

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 2009**	December 31 2008
Assets		
Current assets		
Cash	**3,829**	1,029
Accounts receivable	**12,823**	14,522
Prepaid expenses and deposits	**5,225**	2,928
Future income taxes	**44**	-
Risk management asset (Note 8)	**-**	1,721
	21,921	20,200
Property, plant and equipment (Note 4)	**336,107**	344,338
Total assets	**358,028**	364,538
Liabilities		
Current liabilities		
Outstanding cheques	**-**	105
Future income taxes	**-**	501
Accounts payable and accrued liabilities	**19,588**	36,211
Risk management liability (Note 8)	**148**	-
	19,736	36,817
Long term debt (Note 5)	**96,000**	91,400
Future income taxes	**34,136**	33,655
Asset retirement obligations (Note 6)	**10,801**	9,730
	160,673	171,602
Shareholders' equity		
Share capital (Note 7)	**187,680**	174,995
Contributed surplus (Note 7)	**10,754**	9,605
Retained earnings (deficit)	**(1,079)**	8,336
Total shareholders' equity	**197,355**	192,936
Total liabilities and shareholders' equity	**358,028**	364,538

Commitments (Note 9)
Subsequent events (Note 10)

See accompanying notes to the interim consolidated financial statements.

DELPHI ENERGY CORP.

Consolidated Statements of Operations, Comprehensive Income (Loss) and Retained Earnings (Deficit) (unaudited)

For the three and nine months ended September 30

(Stated in thousands of dollars, except per share amounts)	Three Months Ended September 30 **2009**	2008	Nine Months Ended September 30 **2009**	2008
Revenue				
Petroleum and natural gas sales	**23,342**	34,364	**68,601**	105,332
Realized gain (loss) on risk management activities (Note 8)	**1,091**	97	**3,266**	(90)
	24,433	34,461	**71,867**	105,242
Royalties	**(1,514)**	(6,352)	**(6,423)**	(20,560)
Unrealized gain (loss) on risk management activities (Note 8)	**(1,707)**	7,627	**(1,869)**	46
	21,212	35,736	**63,575**	84,728
Expenses				
Operating	**5,893**	6,186	**18,266**	17,507
Transportation	**1,651**	1,499	**5,240**	4,624
General and administrative	**1,262**	1,011	**3,607**	3,329
Stock-based compensation (Note 7)	**135**	243	**475**	735
Interest	**1,478**	1,253	**3,308**	4,038
Depletion, depreciation and accretion	**15,150**	16,050	**45,234**	46,212
	25,569	26,242	**76,130**	76,445
Earnings (loss) before income taxes	**(4,357)**	9,494	**(12,555)**	8,283
Income taxes				
Future (reduction)	**(1,079)**	2,750	**(3,140)**	2,230
	(1,079)	2,750	**(3,140)**	2,230
Net earnings (loss) and comprehensive income (loss)	**(3,278)**	6,744	**(9,415)**	6,053
Retained earnings, beginning of period	**2,199**	2,551	**8,336**	3,242
Retained earnings (deficit), end of period	**(1,079)**	9,295	**(1,079)**	9,295
Earnings (loss) per share (Note 7)				
Basic and diluted	**(0.04)**	0.09	**(0.12)**	0.08

See accompanying notes to the interim 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 **2009**	2008	Nine Months Ended September 30 **2009**	2008
Cash flow from operating activities				
Net earnings (loss) for the period	**(3,278)**	6,744	**(9,415)**	6,053
Add non-cash items:				
Depletion, depreciation and accretion	**15,150**	16,050	**45,234**	46,212
Stock-based compensation	**135**	243	**475**	735
Unrealized loss on risk management activities	**1,707**	(7,627)	**1,869**	(46)
Future income taxes (reduction)	**(1,079)**	2,750	**(3,140)**	2,230
Change in non-cash working capital	**(2,039)**	271	**(3,454)**	(7,802)
	10,596	18,431	**31,569**	47,382
Cash flow from financing activities				
Issue of common shares, net of issue costs	**15,473**	16,206	**15,473**	17,555
Issue of flow-through common shares	**-**	12,002	**-**	12,002
Exercise of stock options	**32**	-	**32**	-
Increase (decrease) in long term debt	**(6,176)**	-	**4,600**	8,000
	9,329	28,208	**20,105**	37,557
Cash flow available for investing activities	**19,925**	46,639	**51,674**	84,939
Cash flow from (used in) investing activities				
Capital expenditures	**(7,810)**	(27,132)	**(25,504)**	(61,119)
Disposition of petroleum and natural gas properties	**9,728**	5,500	**9,953**	8,450
Acquisition of petroleum and natural gas properties	**(19,669)**	(34,096)	**(19,451)**	(37,946)
Change in non-cash working capital	**3,446**	8,910	**(13,767)**	9,672
	(14,305)	(46,818)	**(48,769)**	(80,943)
Increase (decrease) in cash and cash equivalents	**5,620**	(179)	**2,905**	3,996
Cash and cash equivalents, beginning of period	**(1,791)**	(183)	**924**	(4,358)
Cash and cash equivalents, end of period	**3,829**	(362)	**3,829**	(362)
Cash and cash equivalents is comprised of:				
Cash	**3,829**	1,130	**3,829**	1,130
Outstanding cheques	**-**	(1,492)	**-**	(1,492)
	3,829	(362)	**3,829**	(362)
Interest paid	**1,657**	880	**3,492**	3,666

See accompanying notes to the interim consolidated financial statements.

DELPHI ENERGY CORP.

Notes to the Interim Consolidated Financial Statements
As at and for the periods ended September 30, 2009 and 2008 (unaudited)
(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 public company listed on the Toronto Stock Exchange. Delphi is primarily engaged in the exploration for and development and production of petroleum and natural gas from properties located in North West Alberta and North East British Columbia.

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, 2008. 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, 2008. 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.

Certain comparative figures have been reclassified to conform with the current year's presentation.

NOTE 3: NEW ACCOUNTING STANDARDS

International Financial Reporting Standards

Effective January 1, 2011, the Company will be required to prepare its consolidated financial statements in accordance with International Financial Reporting Standards (IFRS), with appropriate comparative figures for the prior year. The Company is currently assessing the differences between Canadian GAAP and IFRS and the effect on the consolidated financial statements.

NOTE 4: PROPERTY, PLANT AND EQUIPMENT

As at September 30, 2009	Cost	Accumulated depletion and depreciation	Net book value
Petroleum and natural gas properties	**434,720**	**207,023**	**227,697**
Production equipment	**140,621**	**32,794**	**107,827**
Furniture, fixtures and office equipment	**1,251**	**668**	**583**
	576,592	**240,485**	**336,107**

As at December 31, 2008	Cost	Accumulated depletion and depreciation	Net book value
Petroleum and natural gas properties	406,455	168,124	238,331
Production equipment	132,887	27,150	105,737
Furniture, fixtures and office equipment	846	576	270
	540,188	195,850	344,338

On August 31, 2009, the Company closed an acquisition of predominantly natural gas producing properties in North West Alberta for cash consideration of $19.7 million. Upon closing the acquisition, the Company immediately disposed of 40 percent of the acquired working interest in the properties for cash proceeds of $7.9 million.

On September 30, 2009, the Company disposed of two non-core minor working interest natural gas properties for cash proceeds of $1.8 million.

For the nine months ended September 30, 2009, the Company capitalized $2.6 million (September 30, 2008 - $2.4 million) of general and administrative costs directly related to exploration and development activities.

As at September 30, 2009, costs in the amount of $3.1 million (December 31, 2008 - $3.4 million) representing unproved properties were excluded from the depletion calculation and estimated future development costs of $44.9 million (December 31, 2008 - $46.7 million) have been included in costs subject to depletion. All costs of unproved properties have been capitalized. Ultimate recoverability of these costs will be dependent upon finding proved oil and natural gas reserves.

NOTE 5: LONG TERM DEBT

	September 30, 2009	December 31, 2008
Prime-based loans	**16,000**	91,400
Bankers' acceptances	**80,000**	-
Total debt	**96,000**	91,400

The Company has a revolving facility for $125.0 million with a syndicate of Canadian chartered banks. The facility is a 364 day committed revolving facility until May 31, 2010, 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 2.0 percent to a maximum of the bank's prime rate plus 5.0 percent or from a minimum of bankers' acceptances rate plus a stamping fee of 3.0 percent to a maximum of bankers' acceptances rate plus a stamping fee of 5.0 percent.

During 2009, the Company has converted $80.0 million of its outstanding long term debt from prime-based loans to bankers' acceptances. The bankers' acceptances have terms ranging from 179 to 185 days and a weighted average effective interest rate of 3.9 percent over the term.

In addition to the revolving term facility, the Company has a $15.0 million development facility with its lenders. The pricing grid on the development facility is 1.50 to 1.75 percent higher than the revolving term facility. As at September 30, 2009, there is no amount drawn under this facility.

The two facilities are secured by a $200.0 million demand floating charge debenture and a general security agreement over all assets of the Company. The scheduled semi-annual review of the credit facilities is expected to be completed by mid-November.

NOTE 6: 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 $22.7 million (December 31, 2008 - $21.4 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, 2009	December 31, 2008
Balance, beginning of period	**9,730**	7,183
Liabilities incurred	**100**	271
Liabilities disposed	**(99)**	(83)
Liabilities acquired	**471**	2,021
Liabilities settled	**-**	(312)
Accretion expense	**599**	650
Balance, end of period	**10,801**	9,730

NOTE 7: 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, 2009		December 31, 2008	
	Outstanding shares (000's)	**Amount**	Outstanding shares (000's)	Amount
Balance, beginning of period	**79,067**	**174,995**	68,070	148,898
Issue of common shares	**13,200**	**16,500**	6,316	18,001
Issue of flow-through common shares	**-**	**-**	3,530	12,002
Exercise of stock options	**47**	**32**	1,151	1,532
Allocated from contributed surplus	**-**	**17**	-	745
Share issue costs	**-**	**(1,027)**	-	(2,010)
Future tax effect of share issue costs	**-**	**271**	-	585
Tax benefit renounced to shareholders	**-**	**(3,108)**	-	(4,758)
Balance, end of period	**92,314**	**187,680**	79,067	174,995

On July 17, 2008, the Company issued 6.32 million common shares at a price of $2.85 per share and 3.53 million flow-through common shares at $3.40 per share for gross proceeds of $30.0 million.

On September 30, 2009, the Company issued 13.2 million common shares at a price of $1.25 per share for gross proceeds of $16.5 million.

As at September 30, 2009, the Company has incurred the necessary qualifying exploration expenditures to satisfy the terms of the flow-through common shares issued in 2008. Although the Company believes it has incurred the necessary qualifying expenditures, these amounts may be subject to audit and subsequent interpretation by the Canada Revenue Agency.

(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, 2009 there were 7.4 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, 2009		December 31, 2008	
	Outstanding options (000's)	**Weighted average exercise price**	Outstanding options (000's)	Weighted average exercise price
Balance, beginning of period	**4,731**	**1.75**	5,481	1.60
Granted	**2,852**	**0.79**	615	2.23
Cancelled	**(144)**	**1.05**	(60)	1.55
Forfeited	**-**	**-**	(154)	1.56
Exercised	**(47)**	**0.68**	(1,151)	1.33
Balance, end of period	**7,392**	**1.40**	4,731	1.75
Exercisable at end of period	**4,415**	**1.55**	2,938	1.72

The following table summarizes information about the stock options outstanding and exercisable at September 30, 2009.

	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 - $1.54	**2,811**	**0.81**	**4.5**	**919**	**0.80**
$1.55 - $1.72	**3,751**	**1.67**	**3.1**	**2,854**	**1.66**
$1.73 - $2.15	**610**	**1.80**	**3.1**	**495**	**1.80**
$2.16 - $3.34	**220**	**3.18**	**3.7**	**147**	**3.17**
Total	**7,392**	**1.40**	**3.7**	**4,415**	**1.55**

(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, 2009, Delphi recorded non-cash compensation expense of $0.5 million (September 30, 2008 - $0.7 million). The Company capitalized $0.9 million (September 30, 2008 - $1.0 million) of stock-based compensation directly related to exploration and development activities.

During the nine month period ended September 30, 2009, the Company granted 2.9 million options. The fair values of all options granted during the period are estimated at the date of grant using the Black-Scholes option pricing model. The weighted average fair value of options granted during the period was $0.66 per option. The assumptions used in the Black-Scholes model to determine fair value were as follows.

	Nine months ended September 30, 2009	Nine months ended September 30, 2008
Risk-free interest rate (%)	**2.5**	5.0
Expected life (years)	**5.0**	5.0
Expected volatility (%)	**64.9**	55.0

(e) Contributed surplus

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

	September 30, 2009	December 31, 2008
Balance, beginning of the period	**9,605**	8,236
Stock-based compensation expensed	**475**	994
Stock-based compensation capitalized	**691**	1,120
Reclassification to common shares on exercise of stock options	**(17)**	(745)
Balance, end of the period	**10,754**	9,605

(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	
	2009	2008	**2009**	2008
Basic	**79,083**	77,222	**79,072**	71,472
Diluted	**79,083**	78,157	**79,072**	72,330

NOTE 8: 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 as at September 30, 2009 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 in the balance sheet, other than the risk management asset or liability, approximate their carrying amounts due to bank debt being at a floating interest rate and all other financial assets and liabilities having a short term maturity.

The fair value of derivative contracts is determined by calculating the present value of the difference between the contracted price and the related published forward price expectations at the balance sheet date, using the remaining contracted volumes.

(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, 2009.

Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in the market interest rates. The Company is exposed to interest rate risk to the extent that bank debt is at a floating rate of interest. If interest rates had been 100 basis points lower with all other variables held constant, net earnings for the nine months ended September 30, 2009 would have been $0.2 million (2008 - $0.2 million) higher, due to lower interest expense.

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, 2009 is a loss of $25,000.

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, 2009, the Company had the following financial derivative and United States dollar physical sales contracts which were recorded at fair value on the balance sheet at a loss of $0.1 million (December 31, 2008 - gain of $1.7 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)
April 2009 – October 2009	Natural Gas	Physical	1,000 mmbtu/d	U.S. $8.18 fixed
February 2009 – December 2009*	Natural Gas	Financial	3,500 GJ/d	$6.00 Put
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
January 2010 – December 2010*	Natural Gas	Financial	3,500 GJ/d	$7.40 Call
January 2011 – December 2011**	Natural Gas	Financial	2,500 GJ/d	$7.14 Call

* The Company has acquired a natural gas put contract at $6.00 per gigajoule on 3,500 gigajoules per day for the period February 1, 2009 through December 31, 2009. This put was paid for with the sale of a natural gas call on 3,500 gigajoules per day at a price of $7.40 per gigajoule for the period January 1, 2010 through December 31, 2010.

**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 both United States and 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, 2009, the Company had the following physical sales contracts.

Time Period	Commodity	Type of Contract	Quantity Contracted	Contract Price ($/unit)
April 2009 – October 2009	Natural Gas	Physical	1,000 GJ/d	$7.08 fixed
April 2009 – October 2009	Natural Gas	Physical	2,000 GJ/d	$8.25 floor/$10.00 ceiling
April 2009 – October 2009	Natural Gas	Physical	2,000 GJ/d	$8.59 fixed
April 2009 – October 2009	Natural Gas	Physical	2,000 GJ/d	$6.70 floor plus 50% > $6.70
April 2009 – March 2010	Natural Gas	Physical	3,000 GJ/d	$7.52 fixed
April 2009 – March 2010	Natural Gas	Physical	2,000 GJ/d	$6.80 floor plus 50% > $6.80
November 2009 – March 2010	Natural Gas	Physical	2,000 GJ/d	$7.65 floor plus 50% > $7.65
November 2009 – March 2010	Natural Gas	Physical	2,000 GJ/d	$7.75 floor/$8.70 ceiling
November 2009 – March 2010	Natural Gas	Physical	2,000 GJ/d	$7.26 floor plus 50% > $7.26
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
March 2009 – December 2009***	Natural Gas	Physical	3,500 GJ/d	$6.00 Put
January 2010 – December 2010***	Natural Gas	Physical	3,500 GJ/d	$7.15 Call

*** The Company has acquired a natural gas put contract at $6.00 per gigajoule on 3,500 gigajoules per day for the period March 1, 2009 through December 31, 2009. This put was paid for with the sale of a natural gas call on 3,500 gigajoules per day at a price of $7.15 per gigajoule for the period January 1, 2010 through December 31, 2010.

For the nine months ended September 30, 2009, the Canadian dollar physical contracts resulted in settlement gains of $15.7 million (September 30, 2008 loss - $1.8 million) that have been included in petroleum and natural gas sales. For the nine months ended September 30, 2009, the financial contracts and U.S. dollar based physical contracts resulted in gains of $3.3 million (September 30, 2008 loss - $0.1 million) that have been included in the statement of earnings as a realized gain on risk management activities. As at September 30, 2009, if natural gas prices had been +/- $0.10 per mcf, with all other variables held constant, the net change in the unrealized gain or loss on risk management activities in the statement of earnings for the year would have been +/- $0.2 million (September 30, 2008 – $0.1 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 25^{th} 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 to be required as at September 30, 2009.

As at September 30, 2009 the Company's aged receivables are as follows.

	September 30, 2009
Current (less than 30 days)	**10,562**
Past due (31-90 days)	**1,046**
Past due (more than 90 days)	**1,215**
Total	**12,823**

(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, 2009.

Financial liabilities	< 1 Year	1 – 2 Years	3 – 5 Years	Thereafter
Accounts payable and accrued liabilities	19,588	-	-	-
Risk management liability	148	-		
Long term debt – principal	-	96,000	-	-
Total	19,736	96,000	-	-

NOTE 9: 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: 2009-$1.3 million; 2010-$6.0 million; 2011-$5.7 million; 2012-$4.4 million; 2013-$2.9 million.

NOTE 10: SUBSEQUENT EVENTS

On August 21, 2009, the Company announced it had entered into an agreement to acquire all of the outstanding common shares of Fairmount Energy Inc. (Fairmount) on the basis of 0.3571 common shares of Delphi for each share of Fairmount, pursuant to a take-over bid mailed on August 28, 2009 to Fairmount shareholders. As of November 3, 2009, the Company had taken up and paid for 12,915,916 common shares of Fairmount and holds approximately 79.0 percent of the issued and outstanding common shares of Fairmount. Delphi intends to complete a subsequent acquisition transaction prior to the end of November, 2009 to obtain 100.0 percent of the common shares of Fairmount.

On September 30, 2009, the Company announced it had signed an asset exchange agreement to acquire natural gas and light oil assets at Hythe in North West Alberta for cash consideration of $10.0 million and certain non-core producing assets and related infrastructure of the Company. The acquisition closed on November 3, 2009.

On October 23, 2009, Delphi announced an equity financing of 3.0 million flow-through common shares at a price of $2.12 per share for gross proceeds of $6.4 million. The offering is expected to close by November 16, 2009.

CORPORATE INFORMATION

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Independent Businessman

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

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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