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THIRD QUARTER 2005 **Nine Months Ended September 30, 2005** DEE – TSX

Third Quarter 2005 Highlights

- Increased production 137 percent to 4,152 barrels of oil equivalent per day (boe/d) in the third quarter of 2005 from 1,749 boe/d in the same period of 2004.
- Increased cash flow from operations before change in non-cash working capital by 187 percent to $10,198,584 ($0.20 per share) compared to $3,556,762 ($0.14 per share) in the previous year.
- Earned $1,190,221 in the third quarter of 2005, up 39 percent from $854,227 in the third quarter of 2004.
- Completed drilling operations on 8 wells at Bigstone, Alberta in the third quarter of 2005 with an 88 percent net success rate.
- Increased the Company's credit facility to $82 million syndicated with two Canadian chartered banks.

Operational and Financial Information

	Three Months Ended September 30			Nine Months Ended September 30		
	2005	2004	Change (%)	**2005**	2004	Change (%)
Average Daily Production						
Natural gas (mcf/d)	**19,580**	5,353	266	**18,817**	5,554	239
Crude oil (bbl/d)	**584**	812	(28)	**629**	646	(3)
Natural gas liquids (bbl/d)	**305**	45	578	**246**	44	459
Total (boe/d)	**4,152**	1,749	137	**4,011**	1,616	148
Financial Highlights ($)						
Petroleum and natural gas revenue	**20,606,426**	6,232,569	231	**51,919,740**	17,016,807	205
Per boe	**53.95**	38.73	39	**47.41**	38.57	23
Cash flow from operations	**10,198,584**	3,556,762	187	**24,093,572**	9,376,706	157
Per boe	**26.71**	22.02	21	**22.01**	21.21	4
Per share – basic	**0.20**	0.14	43	**0.49**	0.37	32
Per share – diluted	**0.20**	0.14	43	**0.48**	0.36	33
Net earnings	**1,190,221**	854,227	39	**252,359**	2,631,423	(90)
Per boe	**3.12**	5.30	(41)	**0.24**	5.96	(96)
Per share – basic and diluted	**0.02**	0.03	(33)	**0.01**	0.10	(90)
Capital expenditures	**16,184,629**	11,196,923	45	**32,043,507**	22,693,927	41

	September 30 2005	December 31 2004	Change (%)
Debt plus working capital deficit	**76,246,039**	61,274,113	24
Total assets	**207,109,014**	171,946,974	20
Shares outstanding			
Basic	**50,794,991**	47,703,775	6
Diluted	**53,424,691**	49,598,858	8

Message to Shareholders

The Company's production increased 137 percent to 4,152 boe/d in the third quarter of 2005, compared to 1,749 in the third quarter of 2004. For the nine months ended September 30, 2005, Delphi has produced an average of 4,011 boe/d versus 1,616 boe/d in 2004. The Company's current production is approximately 4,800 boe/d with an additional 800 boe/d expected to be on-stream by the end of November.

OPERATIONS REVIEW

In the third quarter of 2005, Delphi focused its drilling activities on Bigstone in North West Alberta and in the Company's Exploration Joint Venture area in North West Alberta and North East British Columbia. Delphi drilled nine wells (6.9 net) in the third quarter, achieving an 87 percent net success rate. The Company also completed multiple reactivation and optimization projects in Bigstone, East Central Alberta, and as part of its Development Joint Venture in the greater Grande Prairie, Alberta area, lifting Delphi's current production to 4,800 boe/d.

Bigstone, North West Alberta

Delphi was very active in the third quarter of 2005 in the Bigstone area. The Company drilled eight wells (6.8 net), cased six gas wells (6.0 net), and elected not to participate in casing two non-operated wells (0.8 net), for a net success rate of 88 percent. In addition, Delphi continued an optimization program on the existing well base to increase run times and production volumes. These activities resulted in net expenditures of $12.4 million in the quarter and have increased current production levels on the Bigstone operated asset base to 1,900 boe/d, up 58 percent since Delphi acquired the property in February 2005. This success has warranted the continued development of these low-risk opportunities. Since the end of the third quarter, an additional five wells (5.0 net) have been drilled and cased and Delphi is currently drilling its 14th well.

Since Delphi initiated its Bigstone drilling program, four wells have been tied in and six of the remaining seven cased wells have been tested. The six wells are expected to be on line by the end of November, adding production of 800 boe/d. Through to the end of the year, Delphi plans to drill three additional infill and step-out locations in Bigstone, targeting the Dunvegan and Lower Cretaceous formations. The three planned wells, the 14th well currently drilling, and the remaining cased well are expected to be tied in through the end of the fourth quarter and into the first quarter of 2006. The primary focus of the drilling program in Bigstone has been downspacing in the Dunvegan formation based on a reservoir study indicating the original wells would only recover approximately 65 percent of the gas in place. The increased well density should allow recoveries in the range of 85 to 90 percent. In addition, two wells that were deepened to the Lower Cretaceous interval were both successful and have generated additional drilling locations.

Just west of Bigstone, on Delphi's Berland River and Placid lands, the Company has identified eight step-out locations targeting the same producing intervals being developed at Bigstone -- the Dunvegan and Lower Cretaceous. The Company is currently licensing these locations and will take advantage of the rig currently in Bigstone to drill these wells toward the end of the fourth quarter and into the first quarter of 2006. Delphi has identified six additional locations in these focus areas that are contingent on the results of the current drilling program.

Delphi also completed three optimization projects in Bigstone in the third quarter of 2005, resulting in production gains of 125 boe/d. In addition, there are six identified tie-in/reactivation projects that will be completed through the end of 2005 and into the first quarter of 2006 as surface access allows for equipment mobilization.

East Central Alberta

The recent strength of product prices has justified a continued reactivation and optimization program on Delphi's primarily oil properties in East Central Alberta. In the third quarter, Delphi spent $0.7 million on a maintenance project to successfully stabilize production rates. In the Thompson Lake area, Delphi has received approval for a downspacing application, which will allow the drilling of up to five Ellerslie wells in the fourth quarter of 2005 and the first quarter of 2006.

2005 Development Joint Venture, North West Alberta

Progress continues on Delphi's Development Joint Venture in North West Alberta. Under the terms of the arrangement, Delphi has agreed to re-enter and complete or abandon 26 standing cased wells in order to earn a 100 percent working interest in the wells and the lands. Delphi's working interest is subject to a 15 percent convertible overriding royalty which the farmor may convert to a 50 percent working interest.

At the end of the third quarter of 2005, two wells were on production as a result of the Development Joint Venture. Subsequent to the end of the third quarter, an additional well has been brought on production. Of the remaining wells, two are awaiting regulatory approval prior to proceeding with tie-in, four are being evaluated for potential, three are scheduled for abandonment, three have been abandoned and 11 have been turned back to the farmor. Net third quarter expenditures for this project were $1.6 million. Total expenditures are anticipated to be $4.5 million, achieving 350 boe/d net to Delphi.

North East British Columbia

Third quarter operational activities in North East British Columbia were limited to minor maintenance as most of the Company's properties in the area are accessible only during the winter. During the third quarter, Delphi initiated a property trade that culminated in the disposition of a non-operated working interest in one well and various non-operated working interests in several sections of undeveloped land in exchange for a non-operated working interest in three producing wells. The transaction has resulted in a net acquisition of approximately 175 boe/d to Delphi effective October 1, 2005.

In addition, Delphi is finalizing plans for the 2005/2006 winter program by obtaining the regulatory approvals and services required to tie-in seven standing wells (2.5 net) and drill and/or tie-in 17 wells (5.7 net). The identified projects are primarily on operated properties.

Fontas, North West Alberta

As the Fontas area is accessible only during the winter, third quarter operational activities were limited to minor maintenance in preparation for an active 2005/2006 winter drilling program. The Fontas working interest owners have continued the technical evaluation of the property, resulting in a development plan for 2005/2006 that is similar to the 2004/2005 winter program in terms of capital, drilling and well work. This includes drilling 12 to 15 wells and performing a similar number of well workovers and optimizations. Delphi has a 20 percent working interest in this asset.

2005 Exploration Joint Venture, North West Alberta – North East British Columbia

In the third quarter of 2005, Delphi initiated drilling on three of the four wells in the 2005 Exploration Joint Venture, resulting in net expenditures of $0.9 million. The first well was abandoned while the second and third wells are currently drilling.

The Ferrier prospect targeting gas in the Banff formation was drilled and abandoned during the third quarter. Delphi was responsible for 17.5 percent of the capital costs associated with this well.

The Valhalla prospect is a 3,400 metre test targeting gas condensate in the Wabamun formation. The well was spud during the first week of October and is currently drilling below 2,700 metres. The Company anticipates reaching total depth in two to three weeks. Delphi will earn an 18 percent working interest in the well and surrounding lands by paying 30 percent of the cost to drill and complete the well. A successful well would begin production during the first quarter of 2006. Wabamun producers on trend typically have initial production rates of between 8 to 10 million cubic feet per day (mmcf/d) with estimated ultimate recoveries of 10 billion cubic feet (bcf) per well.

The Cutbank prospect is a 2,300 metre test targeting gas condensate in several Cretaceous aged formations. The well is expected to reach total depth in late November. Delphi will earn a 60 percent working interest in the well and surrounding lands by paying 100 percent of the cost to drill and complete the well. Delphi's partner is a senior oil and gas company with extensive experience in the area. It is not uncommon for Cretaceous producers along this trend to have initial production rates in the range of 3 to 5 mmcf/d with estimated ultimate recoveries of 3 to 5 bcf per well.

The Brazeau prospect is a 3,900 metre test targeting gas condensate in the Nisku formation. Delphi will earn a 36 percent working interest in the well and surrounding lands by paying 60 percent of the cost to drill and complete the well. Delphi is the operator of the well and is in the final stages of obtaining the necessary regulatory approvals. Delphi intends to utilize the rig that is currently drilling the Valhalla prospect. If successful, initial production is expected in the first or second quarter of 2006. Many of the Nisku producers along this trend have initial production rates in excess of 10 mmcf/d with estimated ultimate recoveries in excess of 30 bcf per well.

FINANCIAL REVIEW

Delphi's cash flow from operations continued increasing to $10.2 million ($0.20 per share) in the third quarter of 2005 and $24.1 million ($0.49 per share) for the nine months ended September 30, 2005. This represents an increase of 187 percent and 157 percent over the comparable periods of 2004. Cash flow netbacks were up $5.90 per boe or 28 percent compared to the second quarter of 2005 despite inflationary pressure on costs and incremental costs due to wet weather conditions in the field. Delphi's cost structure is expected to continue improving through the fourth quarter as production volumes are added from the Company's low operating cost Bigstone area. At current prices, an improving cost structure and the Company's growing production volumes, cash flow from operations is expected to exceed $5 million per month going forward. Net earnings for the third quarter of 2005 and year-to-date were $1.2 million ($0.02 per share) and $0.3 million ($0.01 per share), respectively.

Delphi invested $16.3 million in the third quarter of 2005, with the majority of the expenditures at Bigstone, Alberta. The capital program was funded by cash flow from operations before change in non-cash working capital of $10.2 million, $0.4 million from proceeds on the exercise of stock options and an increase in debt plus working capital of $5.7 million. The Company expects to fund its remaining 2005 capital program through cash flow from operations and available credit lines.

During the third quarter, the Company received an increase in its credit facilities to $82 million, syndicated amongst two Canadian chartered banks.

OUTLOOK

Although wet weather continued to delay some activities, the planning and diligent efforts of the Delphi team resulted in a continuous three rig drilling program from the beginning of August through the end of the third quarter. This level of activity has continued into the fourth quarter. Delphi currently has two operated rigs drilling and anticipates having a third operated rig drilling in the next few weeks. Through the fourth quarter and into the first quarter of 2006 these three drilling rigs will continue to execute on low to medium risk development drilling in the Bigstone and Thompson Lake areas, as well as the high impact Exploration Joint Venture program.

Delphi's third quarter capital program has been focused on low-risk development drilling at Bigstone and reactivation and optimization projects in the Bigstone, East Central Alberta and Development Joint Venture areas. Tested wells currently being tied in are expected to take the Company's production levels through 5,000 boe/d by mid November from current production of 4,800 boe/d and to approximately 5,500 boe/d by the end of November. The wells currently drilling, those planned for the remainder of 2005, and several tie-in opportunities in winter access areas provide the basis for Delphi's current projections of a 2005 exit rate of 6,000 boe/d. Any production volumes from a successful well or wells within Delphi's Exploration Joint Venture program would generate volumes in excess of these forecasts.

As weather conditions permit, Delphi will also be ramping up operations on its winter access properties. In Fontas, Delphi and its partners plan to drill 12 to 15 gross wells and perform a similar number of well workovers and optimizations. On the North East British Columbia properties, Delphi will participate in drilling up to 17 wells and tie-in up to seven standing wells that have the potential to add up to 1,000 boe/d.

Our business strategy remains focused and on track, delivering the significant low-risk growth potential within our asset base. We're confident that in addition to achieving our forecast exit rate for 2005, we will also achieve our targeted average rate for 2006 of 6,500 boe/d and a 2006 exit rate approaching 7,500 boe/d. With the acquisitions in northeast B.C. and Bigstone exceeding our expectations, we will continue to pursue significant growth potential on our existing land base into 2006.

On behalf of the Board,

David J. Reid
President and Chief Executive Officer
November 4, 2005

Management's Discussion and Analysis

The following discussion and analysis has been prepared by management and reviewed and approved by the Board of Directors of Delphi Energy Corp ("Delphi" or the "Company"). The discussion and analysis is a review of the financial results of the Company based upon accounting principles generally accepted in Canada. Its focus is primarily a comparison of the financial performance for the three and nine months ended September 30, 2005 and 2004 and should be read in conjunction with the unaudited financial statements and accompanying notes included in this report and the audited financial statements and accompanying notes for the year-ended December 31, 2004 included in the Company's 2004 Annual Report.

NON GAAP Measures. 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.

Cash flow from operations before change in non-cash working capital is not a recognized measure under Canadian generally accepted accounting principles. Management uses cash flow from operations before change in non-cash working capital 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 Company's reconciliation between net earnings (loss) and cash flow from operations before change in non-cash working capital is disclosed subsequently in management's discussion and analysis. Cash flow from operations before change in non-cash working capital has been defined by the Company as net earnings (loss) plus the addback of non-cash items (depletion, depreciation and accretion, stock-based compensation, future income taxes and unrealized risk management activities) and excludes the change in non-cash working capital related to operating activities. Delphi's determination of cash flow from operations before change in non-cash working capital may not be comparable to that reported by other companies. The Company also presents cash flow from operations before change in non-cash working capital per share whereby amounts per share are calculated using weighted average shares outstanding consistent with the calculation of earnings per share.

Forward-Looking Statements. Certain information regarding Delphi Energy Corp. set forth in this document, including management's assessment of the Company's future plans and operations, contains forward-looking statements that involve substantial known and unknown risks and uncertainties. These forward-looking statements are subject to numerous risks and uncertainties, certain of which are beyond the Company's control, including the effects of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other oil and gas companies, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from both internal and external sources. The Company's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements, and accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur.

The discussion and analysis has been prepared as of November 4, 2005.

Production

	Three Months Ended September 30		Change (%)	Nine Months Ended September 30		Change (%)
	2005	2004		**2005**	2004	
Natural gas (mcf/d)	**19,580**	5,353	266	**18,817**	5,554	239
Crude oil (bbl/d)	**584**	812	(28)	**629**	646	(3)
Natural gas liquids (bbl/d)	**305**	45	578	**246**	44	459
Total (boe/d)	**4,152**	1,749	137	**4,011**	1,616	148

Production for the three months ended September 30, 2005 averaged 4,152 boe/d comprised of 19,580 mcf/d of natural gas, 584 bbls/d of crude oil and 305 bbls/d of natural gas liquids. Average production volumes increased 137 percent on a quarter-over-quarter basis in 2005 compared to 2004 primarily as a result of capital programs undertaken in the first nine months of 2005 and the corporate acquisition of Tercero Energy Inc. (Tercero) and the liquids rich natural gas property acquisition at Bigstone, Alberta. The wet weather during the quarter, particularly in northwest Alberta, hampered the Company's ability to tie-in many of the wells drilled in the third quarter until recently. At the end of the quarter Delphi had tied in two wells at Bigstone. Despite the delays due to weather, Delphi's production is still on track to exit the year at 5,800 – 6,000 boe/d.

Natural gas production increased 266 percent during the third quarter of 2005 compared to the same quarter of 2004, primarily as a result of increased production from North East British Columbia associated with the Tercero acquisition, acquired natural gas production at Bigstone, Alberta and a successful optimization and drilling program during the first nine months of 2005.

Crude oil production was 28 percent lower for the three months ended September 30, 2005 averaging 584 bbls/d compared to 812 bbls/d for the comparative quarter of 2004. The Company continues to optimize its East Central assets to maintain production with minimal capital investment. During the third quarter, production was affected by the wet weather conditions and occasional road bans.

Natural gas liquids production, primarily condensate, has increased significantly as a result of the high yield of liquids associated with the increased natural gas production at Bigstone, Alberta.

Commodity Prices and Risk Management

Benchmark Prices

	Three Months Ended September 30		Change (%)	Nine Months Ended September 30		Change (%)
	2005	2004		**2005**	2004	
Natural gas						
New York Mercantile Exchange (US $/mmbtu)	**10.10**	5.84	73	**7.72**	5.83	32
AECO (CDN $/mcf)	**9.30**	6.67	39	**7.85**	6.69	17
Crude oil						
West Texas Intermediate (US $/bbl)	**63.19**	43.88	44	**55.40**	39.11	42
Edmonton Light (CDN $/bbl)	**76.34**	56.29	36	**67.94**	50.82	37
Foreign exchange rate						
Canadian to US dollar	**1.2026**	1.3071	(8)	**1.2245**	1.3280	(8)
US to Canadian dollar	**0.8315**	0.7650	9	**0.8166**	0.7530	8

Natural Gas

United States natural gas prices are commonly referenced to the New York Mercantile Exchange Henry Hub, Louisiana (NYMEX) index price while Canadian natural gas prices are typically referenced to the AECO Hub in Alberta (AECO). Natural gas prices are influenced more by North American supply and demand than global fundamentals. Recent record hurricane activity has had, and continues to have, an effect on the supply and demand balance creating volatile natural gas prices. Natural gas prices also benefited from an extremely warm summer pushing cooling demands to near record levels. During the three month period ended September 30, 2005 AECO natural gas price averaged $9.30/mcf compared to $6.67/mcf for the same period in 2004. In the first nine months of 2005, the AECO natural gas price averaged $7.85/mcf compared to $6.69/mcf in 2004.

Crude Oil

West Texas Intermediate at Cushing, Oklahoma (WTI) is the benchmark reference for North American crude oil prices. Canadian crude oil prices are based upon postings, primarily at Edmonton, Alberta, and represent the WTI price adjusted for quality and transportation differentials as well as the CDN/US dollar exchange rate. During the three and nine months ended September 30, 2005, WTI averaged US $63.19/bbl and US $55.40/bbl compared to US $43.88/bbl and US $39.11/bbl in 2004. Crude oil prices continued to show sustained strength during the third quarter of 2005 due to increasing demand for gasoline and market uncertainty whether this demand could be satisfied due to a lack of refining capacity, especially in light of damage to oil production and refining infrastructure located along the U.S. Gulf Coast.

The prices received for crude oil are related to the price of crude oil in world markets. Prices for heavy oil and other lesser quality crudes trade at a discount or differential to light crude oil due to the additional processing costs. Heavy oil differentials improved from $24.28/bbl during the second quarter of 2005 to $20.70 in the third quarter. The wide differential has been mainly due to an increase in heavy and medium grade sour crude types entering the North American market and a lack of refining capacity to process this heavier quality crude.

During the three and nine months ended September 30, 2005, Canadian crude oil prices were negatively affected as a result of the strengthening Canadian dollar relative to its US counterpart averaging CDN/US $1.20 and $1.22 compared to CDN/US $1.31 and CDN/US $1.33 during the comparable periods in 2004, respectively.

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.

The Company is required to mark-to-market its outstanding financial fixed price contracts and record any unrealized gain or loss. The estimated fair value of unrealized derivative instruments is reported on the balance sheet with any change in the unrealized positions charged to earnings. The fair values of these instruments are based on an approximation of the amounts that would have been paid to or received from counterparties to settle the instruments outstanding at September 30, 2005 with reference 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 incurred an unrealized non-cash loss on risk management activities for the three months ended September 30, 2005 of $1,847,896 and an unrealized non-cash loss of $3,292,580 for the nine months ended September 30, 2005.

During the three and nine month period ended September 30, 2005, Delphi recorded a realized loss on commodity contracts relating to financial contracts of $1,082,403 and $1,453,073, respectively.

Realized Sales Prices

	Three Months Ended September 30		Change (%)	Nine Months Ended September 30		Change (%)
	2005	2004		**2005**	2004	
Natural gas ($/mcf)	**9.57**	6.25	53	**8.22**	6.52	26
Gain/(loss) on risk management activities ($/mcf)	**(0.27)**	-	-	**(0.05)**	-	-
Realized gas price ($/mcf)	**9.30**	6.25	49	**8.17**	6.52	25
Crude oil ($/bbl)	**56.36**	39.72	42	**46.10**	38.24	21
Gain/(loss) on risk management activities ($/bbl)	**(11.11)**	0.09	-	**(6.87)**	(0.41)	-
Realized oil price ($/bbl)	**45.25**	39.81	14	**39.23**	37.83	4
Natural gas liquids ($/bbl)	**50.79**	43.94	16	**47.76**	37.36	28
Total ($/boe)	**53.95**	38.73	39	**47.41**	38.57	23

The Company's average realized sales price per boe increased 39 percent in the third quarter of 2005 versus the comparative period of 2004. The average crude oil sales price before hedging losses increased 42 percent, consistent with the upward trend of the benchmark WTI over the same period offset by the strengthening of the Canadian dollar and widening light-heavy differentials. The realized sales price for crude oil in the third quarter of 2005, after hedging losses, increased 14 percent versus the comparative quarter of 2004. The Company continues to receive higher than the AECO spot price on natural gas sales due to the high heating content of natural gas production and the sale of approximately 26 percent of the Company's production being priced at Chicago from sales on the Alliance Pipeline for the quarter ended September 30, 2005. Realized natural gas prices increased 49 percent in the third quarter of 2005 compared to an increase in AECO of 39 percent for the same period. Realized natural gas liquids prices have increased significantly due to the increase in the price received for condensate.

Revenue

	Three Months Ended September 30		Change (%)	Nine Months Ended September 30		Change (%)
($)	**2005**	2004		**2005**	2004	
Natural gas	**17,238,464**	3,076,794	460	**42,246,227**	9,892,125	327
Crude oil	**3,029,623**	2,966,845	2	**7,916,333**	6,746,448	17
Natural gas liquids	**1,420,742**	182,083	680	**3,210,253**	450,243	613
Gain/(loss) on risk management activities	**(1,082,403)**	6,847	-	**(1,453,073)**	(72,009)	-
Total	**20,606,426**	6,232,569	231	**51,919,740**	17,016,807	205

Quarter-over-quarter total revenue increased $14,373,857 or 231 percent in 2005 as compared to 2004 primarily due to increased production volumes from the acquisition of Tercero Energy Inc. and the natural gas and natural gas liquids producing property in Bigstone and high commodity prices. The increase in revenue can be attributed to a 39 percent increase in the Company's average realized sales price and a 137 percent increase in production volumes. Revenue for the nine months ended September 30, 2005 increased 205 percent due to a 23 percent increase in the Company's average realized sales price and a 148 percent increase in production. Of the increase in total revenue, 93 percent is attributable to natural gas sales which increased 327 percent over 2004.

Royalties

	Three Months Ended September 30		Change (%)	Nine Months Ended September 30		Change (%)
($)	**2005**	2004		**2005**	2004	
Crown	**4,144,878**	788,791	425	**10,385,218**	2,367,029	339
Freehold and gross overriding	**289,154**	222,236	30	**883,911**	598,423	48
Total	**4,434,032**	1,011,027	339	**11,269,129**	2,965,452	280
Royalty credits	**(621,134)**	(337,252)	84	**(1,479,533)**	(1,200,623)	23
Net	**3,812,898**	673,775	466	**9,789,596**	1,764,829	454
Per boe	**9.98**	4.19	138	**8.94**	4.01	123
Percent of total revenue	**18**	11	64	**18**	10	80

The Company pays royalties to provincial governments, freeholders, which can be individuals or companies, and other oil and gas operators, who own surface or mineral rights. The Company also receives the Alberta Royalty Tax Credit (ARTC), a tax rebate received from the Alberta government for eligible crown royalties paid in the year. Royalty rates are calculated on a sliding scale based on commodity prices and individual well production rates. Royalty rates can change due to price increases or due to an increase in production volumes on a well by well basis. During the third quarter of 2005, total royalties increased 138 percent compared to 2004, as a result of increased production of natural gas and higher natural gas prices. Royalty credits in the third quarter of 2005 are higher versus the comparative period due to the acquisition of the Bigstone property and capital being spent on natural gas infrastructure which has resulted in an increase to the Gas Cost Allowance (GCA) credit. Royalties as a percentage of revenue increased 64 percent for the quarter ended September 30, 2005 compared to 2004, primarily due to properties acquired having royalty rates consistent with industry norms, however, higher than the Company's average royalty rate otherwise. For the remainder of 2005, the Company expects royalty rates to be approximately 18 to 20 percent of gross oil and gas revenue.

Operating Expenses

	Three Months Ended September 30		Change (%)	Nine Months Ended September 30		Change (%)
($)	**2005**	2004		**2005**	2004	
Total	**3,666,099**	1,495,724	145	**9,517,920**	3,775,555	152
Per boe	**9.60**	9.29	3	**8.69**	8.56	2
Percent of total revenue	**17**	24	(29)	**18**	22	(18)

Operating expenses on a per boe basis for the three and nine months ended September 30, 2005 increased 3 percent and 2 percent over the comparative prior periods, respectively. The increases in third quarter operating costs are due to strong inflationary pressures for services and additional operating costs incurred due to wet weather conditions. The inflationary pressures are a result of the rates charged by oilfield service providers and the high level of industry activity creating tight service markets. Delphi's growth platform is predominantly focused on lower operating cost natural gas opportunities in North West Alberta and North East British Columbia, therefore, corporate operating costs are expected to trend downward during the fourth quarter of 2005 and continue into the first quarter of 2006.

Transportation Expenses

	Three Months Ended September 30		Change (%)	Nine Months Ended September 30		Change (%)
($)	**2005**	2004		**2005**	2004	
Total	**1,223,893**	255,296	379	**3,475,403**	680,009	411
Per boe	**3.20**	1.59	101	**3.17**	1.54	106
Percent of total revenue	**6**	4	50	**7**	4	75

Transportation costs are higher by $968,597, an increase of 379 percent, in the three months ended September 30, 2005 compared to the same period of 2004, primarily due to a 137 percent increase in production volumes in 2005. On a per boe basis, transportation costs increased 101 percent over 2004 primarily due to the transportation costs associated with natural gas production in North East British Columbia and the natural gas production from the Bigstone area.

In British Columbia, there is infrastructure owned by Duke 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.

Approximately 65 percent in the third quarter of 2005 and 71 percent in the nine months ended September 30, 2005 of the Company's natural gas production from the Bigstone area is shipped on the Alliance Pipeline and sold in Chicago. The costs of transmission from the field to Chicago are included in transportation expenses.

General and Administrative and Stock-based Compensation

	Three Months Ended September 30		Change (%)	Nine Months Ended September 30		Change (%)
($)	**2005**	2004		**2005**	2004	
General and administrative costs	**1,210,825**	598,998	102	**3,413,982**	1,998,978	71
Overhead recoveries	**(180,089)**	(323,448)	(44)	**(434,967)**	(555,893)	22
Salary allocations	**(262,457)**	(131,171)	100	**(910,983)**	(419,824)	117
Net	**768,279**	144,379	432	**2,068,032**	1,023,261	102
Per boe	**2.01**	0.98	105	**1.89**	2.35	(20)
Stock-based compensation expense	**265,977**	87,994	202	**1,248,527**	257,700	384
Per boe	**0.70**	0.46	52	**1.14**	0.55	107

On a gross basis, general and administrative ("G&A") expense for the three and nine month period increased 432 percent and 102 percent commensurate with increased staffing and activity levels associated with the Company's growth from corporate and property acquisitions and the Company's extensive capital program. During the three month period ended September 30, 2005, the Company incurred a one-time charge which increased G&A costs by approximately $205,000. On a per boe basis, G&A costs for the three and nine months ended September 30, 2005 increased 126 percent and decreased 19 percent over the comparable period in 2004. Salary allocations have increased by 100 percent and 117 percent due to operating oil and gas properties and increased technical staff efforts toward the Company's capital program. The Company anticipates monthly G&A costs to remain relatively stable for the remainder of the year on a gross basis and decrease on a per boe basis as additional production is brought on-stream.

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 compensation expense for the three and nine months ended September 30, 2005 increased 202 percent and 384 percent. The increase is a function of additional options being granted to new staff to facilitate the significant growth of the Company, with one-third of the options vesting immediately pursuant to the Company's stock option plan and a higher average fair value option price.

Interest

	Three Months Ended September 30		Change (%)	Nine Months Ended September 30		Change (%)
($)	**2005**	2004		**2005**	2004	
Financing	**754,530**	124,723	505	**2,588,287**	367,824	604
Other charges	**92,261**	11,424	708	**242,449**	50,857	377
Interest income	**(1,782)**	-		**(56,053)**	(23,484)	139
Total	**845,009**	136,147	521	**2,774,683**	395,197	602
Per boe	**2.21**	0.85	160	**2.53**	0.90	181

Interest expense on a gross and per boe basis has increased commensurate with higher average debt levels and $10,000,000 mezzanine debt outstanding from December 8, 2004 to February 23, 2005 with an effective interest rate of 15.75 percent used to fund the growth in the Company's operations and to finance the significant property acquisition during the first quarter of 2005. Other charges primarily relate to the Part XII.6 tax associated with the Company's flow-through obligation.

Depletion, Depreciation and Accretion

	Three Months Ended September 30		Change (%)	Nine Months Ended September 30		Change (%)
($)	**2005**	2004		**2005**	2004	
Depletion and depreciation	**6,315,999**	2,112,930	199	**18,239,375**	5,604,755	225
Accretion expense	**133,607**	63,775	109	**359,810**	191,325	88
Total	**6,448,706**	2,176,705	196	**18,599,185**	5,796,080	221
Per boe	**16.88**	13.53	25	**16.98**	13.13	29

Depletion, depreciation and accretion per boe increased 25 percent and 29 percent, respectively, for the three and nine months ended September 30, 2005. This increase is attributable to higher cost proved reserve additions in the year and a larger capital base from acquisitions and increased spending levels. The increase in total depletion, depreciation and accretion versus the comparable periods is a result of increased production levels and a higher per boe 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 3 to 20 years. The Company uses a credit adjusted risk-free rate of 8 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, 2005 was $133,607 and $359,810 representing a 109 percent and 88 percent increase over comparable periods. The increase is due to increased drilling and the major acquisitions at the end of 2004 and during the first quarter of 2005.

Taxes

	Three Months Ended September 30		Change (%)	Nine Months Ended September 30		Change (%)
($)	**2005**	2004		**2005**	2004	
Capital (recovery)	**91,664**	(29,514)	311	**200,534**	1,250	1590
Future	**445,784**	437,836	2	**700,921**	691,503	1
Total	**537,448**	408,322	32	**901,455**	692,753	30

Current tax for the three months and nine months ended September 30, 2005 consists of Federal Large Corporations Tax. Future income tax of $445,784 was recorded for the three months ended September 30, 2005 and $700,921 for the nine months ended September 30, 2005.

Cash Flow from Operations Before Change in Non-Cash Working Capital

	Three Months Ended September 30		Change (%)	Nine Months Ended September 30		Change (%)
($)	**2005**	2004		**2005**	2004	
Net earnings (loss)	**1,190,221**	854,227	39	**252,359**	2,631,423	(90)
Non-cash items						
Depletion, depreciation and accretion	**6,448,706**	2,176,705	196	**18,599,185**	5,796,080	221
Unrealized loss/(gain) on risk management activities	**1,847,896**	-	-	**3,292,580**	-	-
Stock-based compensation expense	**265,977**	87,994	202	**1,248,527**	257,700	384
Future income taxes	**445,784**	437,836	2	**700,921**	691,503	1
Total	**10,198,584**	3,556,762	187	**24,093,572**	9,376,706	157

For the three and nine months ended September 30, 2005 cash flow from operations before change in non-cash working capital was $10,198,584 ($0.20 per basic share) and $24,093,572 ($0.49 per basic share) compared to $3,556,762 ($0.14 per basic share) and 9,376,706 ($0.37 per basic share). The increase in cash flow reflects the effects of increased revenues resulting primarily from higher production volumes and increased realized commodity prices.

Net Earnings

For the three and nine months ended September 30, 2005, Delphi recorded net earnings of $1,190,221 and $252,359, respectively. Earnings were adversely affected by non-cash items such as depletion, depreciation, accretion; unrealized losses on risk management activities, stock-based compensation and future income taxes.

Netback Analysis

	Three Months Ended September 30		Change (%)	Nine Months Ended September 30		Change (%)
Barrels of oil equivalent ($/boe)	**2005**	2004		**2005**	2004	
Realized sales price	**53.95**	38.73	39	**47.41**	38.57	23
Royalties, net of ARTC	**9.98**	4.19	138	**8.94**	4.01	123
Operating expenses	**9.60**	9.29	3	**8.69**	8.56	2
Transportation	**3.20**	1.59	101	**3.17**	1.54	106
Operating netback	**31.17**	23.66	32	**26.61**	24.46	9
G&A	**2.01**	0.98	105	**1.89**	2.35	(20)
Interest	**2.21**	0.85	160	**2.53**	0.90	181
Current taxes / (recovery)	**0.24**	(0.19)	126	**0.18**	-	-
Cash netback	**26.71**	22.02	21	**22.01**	21.21	4
Unrealized loss (gain) on risk management activities	**4.84**	-	-	**3.01**	-	-
Stock-based compensation expense	**0.70**	0.46	52	**1.14**	0.55	107
Depletion, depreciation and accretion	**16.88**	13.53	25	**16.98**	13.13	29
Future income taxes (recovery)	**1.17**	2.73	(57)	**0.64**	1.57	(59)
Net earnings	**3.12**	5.30	(41)	**0.24**	5.96	(96)

Drilling Results

	Three Months Ended September 30, 2005		Nine Months Ended September 30, 2005	
	Gross	**Net**	**Gross**	**Net**
Natural gas wells	**5.0**	**5.0**	**24.0**	**8.5**
Oil wells	**1.0**	**1.0**	**1.0**	**1.0**
Dry holes	**3.0**	**0.9**	**7.0**	**2.0**
Total wells	**9.0**	**6.9**	**32.0**	**11.5**
Success rate (%)	**66**	**87**	**78**	**83**

Although slowed by wet weather in the quarter, Delphi successfully drilled six operated wells in the Bigstone area with a 100 percent success rate, participated in two (.75 net) non-operated wells which were abandoned and had two other wells still drilling at the end of the quarter, which were successfully completed in early October. During the quarter, the Company abandoned an exploration well at Ferrier, Alberta with a net interest of 17.5 percent.

Capital Invested

($)	Three Months Ended September 30 2005	2004	Change (%)	Nine Months Ended September 30 2005	2004	Change (%)
Land	**-**	100,702	-	**135,248**	586,405	(77)
Seismic	**25,538**	104,064	(75)	**85,537**	202,181	(58)
Drilling and completions	**10,292,297**	4,737,026	117	**17,569,020**	9,838,423	79
Equipping and facilities	**5,595,938**	5,971,067	(6)	**13,324,722**	11,694,111	14
Property acquisition	**95,398**	(36,941)	258	**51,368,580**	596,254	8515
Capitalized expenses	**238,399**	111,347	114	**834,518**	426,159	96
Other	**32,457**	172,717	(81)	**94,462**	(53,352)	177
Capital invested	**16,280,027**	11,159,982	46	**83,412,087**	23,290,181	258
Asset retirement costs	**-**	347,560	-	**1,398,093**	380,234	268
Total capital invested	**16,280,027**	11,507,542	41	**84,810,180**	23,670,415	258

During the third quarter, the Company invested approximately $10,292,297 in drilling and completions and $5,595,938 in equipping and facility operations. Total capital invested in the period was $16,280,027 compared to $11,507,542 in the third quarter of 2004. Approximately 76 percent of the capital invested in the quarter was incurred in the Bigstone area drilling 8.0 (6.75 net) wells with two additional wells still drilling at the end of the quarter. In addition, the Company completed three optimization projects to increase production in the Bigstone area.

The Company completed drilling 1.0 (0.2 net) wells with a second well (0.3 net) currently drilling under the Exploration Joint Venture representing approximately 6 percent of the third quarter capital. Approximately 10 percent of total capital incurred in the third quarter was on four wells in the development joint venture which resulted in two wells being equipped and tied in for production at the end of the third quarter.

Capital invested in the year, including the property acquisition at Bigstone was $83,412,087 compared to $23,290,181 during the comparable period in 2004.

On February 1, 2005, the Company acquired liquids rich natural gas properties at Bigstone in North West Alberta for cash consideration of $51,273,182. The acquisition adds long life natural gas production to this core area of the Company. On January 31, 2005, the Company disposed of non-core properties in Alberta for proceeds on disposition of $5,862,917.

The present value of future asset retirement costs associated with the acquisition of Bigstone and drilling operations, offset by obligations settled due to the dispositions was $1,398,093.

Liquidity and Capital Resources

Funding

	Three months ended September 30, 2005	Nine Months ended September 30, 2005
Sources ($)		
Cash flow from operations before change in non-cash working capital	**10,198,584**	**24,093,572**
Issue of flow-through common shares, net	**-**	**11,143,926**
Exercise of stock options	**394,500**	**632,319**
Proceeds on the disposition of properties	**-**	**5,862,917**
Cash held in trust	**-**	**30,000,007**
Cash on hand	**-**	**1,891,962**
Change in non-cash working capital	**8,286,943**	**8,887,384**
	18,880,027	**82,512,087**
Uses ($)		
Property, plant and equipment additions	**16,184,629**	**32,043,507**
Property acquisition	**95,398**	**51,368,580**
Repayment of mezzanine debt	**-**	**10,000,000**
	16,280,027	**93,412,087**
Increase / (decrease) in bank debt	**(2,600,000)**	**10,900,000**

For the three months ended September 30, 2005, the Company had sources of cash totaling $18,880,027 and uses of cash of $16,280,027 towards capital investments, resulting in a decrease in bank debt of $2,600,000. The Company expects to fund the remainder of its 2005 capital program primarily through internally generated cash flow.

Share Capital

The following table summarizes the common shares issued during the nine months ended September 30, 2005.

	Number of common shares
Balance, December 31, 2004	**47,703,775**
Issue of flow-through common shares for cash	**2,727,500**
Exercise of stock options for cash	**363,716**
Balance September 30, 2005	**50,794,991**

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 month period ended September 30, 2005.

Weighted Average Common Shares	Three months ended September 30, 2005	Nine Months ended September 30, 2005
Basic	50,649,882	49,664,600
Diluted	51,605,986	50,091,156
Trading Statistics		
High	5.35	5.35
Low	3.35	2.63
Close	5.30	5.30
Average daily, volume	169,864	147,952

As at November 4, 2005, the Company had 50,794,991 common shares outstanding and 2,629,700 stock options outstanding.

Bank Debt plus Working Capital Deficit

At September 30, 2005, the Company had $58,300,000 outstanding on its credit facility and a working capital deficit of $14,653,459, excluding the accrued liability of $3,292,580 relating to the unrealized loss on risk management activities, for total debt plus working capital deficit of $72,953,459, up from $67,266,516 at the end of the second quarter of 2005. The Company's anticipated cash flow from operations before change in non-cash working capital is expected to be sufficient to meet the current working capital defiicit. The capital intensive nature of the industry will generally result in the Company having a working capital deficit, however, the Company will maintain total debt plus working capital deficit below the Company's credit facility. At September 30, 2005, the Company had a credit facility of $82,000,000.

Selected Quarterly Information

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

	Sept. 30 2005	**Jun. 30 2005**	**Mar. 31 2005**	**Dec. 31 2004**	**Sept. 30 2004**	**Jun. 30 2004**	**Mar. 31 2004**	**Dec. 31 2003**
Production								
Oil and NGLs (bbl/d)	**889**	865	872	879	857	726	479	520
Natural gas (mcf/d)	**19,580**	19,961	16,880	6,678	5,353	5,943	5,308	6,081
Barrels of oil equivalent (boe/d)	**4,152**	4,192	3,685	1,991	1,749	1,716	1,364	1,534
Financial								
($000s, except as noted)								
Petroleum and natural gas revenue	**20,606**	17,335	13,978	7,457	6,233	5,860	4,925	4,470
Cash flow	**10,199**	7,937	5,958	2,747	3,557	3,248	2,572	1,925
Basic and Diluted	**0.20**	0.16	0.12	0.09	0.14	0.13	0.10	0.08
Net earnings (loss)	**1,190**	1,004	(1,942)	(679)	854	838	939	1,042
Per share basic & diluted	**0.02**	0.02	(0.04)	(0.02)	0.03	0.03	0.04	0.05
Capital expenditures	**16,280**	7,097	60,036	62,084	11,508	6,979	5,136	6,603
Per unit information								
Natural gas ($/mcf)	**9.30**	7.80	7.28	7.20	6.25	6.50	6.83	5.67
Oil and natural gas liquids ($/bbl)	**47.15**	40.35	37.16	37.57	40.03	35.50	37.25	27.09
Oil equivalent ($/boe)	**53.95**	45.45	42.13	40.70	38.73	37.53	39.67	31.67
Operating netback ($/boe)	**31.17**	24.45	23.83	21.45	23.66	24.42	25.57	18.00

Contractual Obligations

The Company is committed, under contracts of varying lengths, for the utilization of gathering, processing and pipeline capacity on a major natural gas processing and gathering system. The future minimum commitments are as follows:

2005	$ 1,147,032
2006	4,707,351
2007	4,120,345
2008	3,811,868
2009	3,475,958
2010 – 2015	10,778,425

The Company also has a lease rental commitment on office premises from 2005 through 2008 which requires annual payments of $87,000.

As at September 30, 2005, the Company had an obligation to incur qualifying exploration expenditures of approximately $5,500,000 to satisfy terms of the flow-through common shares issued during the previous year and an obligation to incur qualifying exploration expenditures of $12,001,000 by December 31, 2006 to satisfy terms of the flow-through common shares issued during the period.

Business Conditions and Risk

The business of exploration, development and acquisition of oil and gas reserves involves a number of uncertainties and as a result the Company is exposed to certain business risks inherent in the oil and gas industry which affect results. These business risks can generally be grouped into two major areas: operations, including environmental, and financial.

Operationally, the Company faces risks associated with finding, developing and producing oil and gas reserves. The Company attempts to control operating risks by maintaining a disciplined approach to implementation of the exploration and development program. Exploration risks are managed by hiring experienced technical staff and by concentrating the exploration activity on specific core regions where the Company has experience and expertise. The Company also attempts to operate associated projects where its level of ownership is sufficient. Operational control allows the Company to manage costs, timing and sales of production.

Estimates of economically recoverable reserves and the future net cash flow they will generate are based on a number of factors and assumptions, such as commodity prices, projected production and future operating costs. All of these estimates may vary from actual results. The Company has its reserves evaluated annually by an independent engineering firm and reviews their findings with the Audit Committee of the Board of Directors.

Environmental risks are also associated with field operations. The Company has health and safety programs and procedures and an environmental standards policy. These policies and procedures are designed to protect and maintain the environment with respect to all Company operations. The Company performs an annual third party audit of the safety and environmental policies designed to ensure compliance. Delphi also carries environmental liability, property, drilling and general liability insurance.

The Company is also exposed to financial risks in the form of commodity prices, interest rates, the Canadian to U.S. dollar exchange rate and inflation. Delphi manages commodity price risks by focusing its capital program on areas that are expected to generate attractive rates of return even at substantially lower commodity prices than the industry is currently receiving. The Company also conducts a commodity price risk management program designed to mitigate large downward movements in commodity prices.

The Company has the following fixed price contracts applicable to future production outstanding:

Time Period	Commodity	Type of Contract	Quantity Contracted	Canadian Price (Per GJ/bbl)
April 2005 – October 2005	Natural Gas	Financial	2,500 GJ/d	$6.31 fixed
April 2005 – October 2005	Natural Gas	Financial	2,000 GJ/d	$6.00 floor/$6.90 ceiling
July 2005 – October 2005	Natural Gas	Physical	1,000 GJ/d	$7.05 fixed
November 2005 – March 2006	Natural Gas	Financial	2,000 GJ/d	$7.79 fixed
November 2005 – March 2006	Natural Gas	Physical	2,000 GJ/d	$8.00 floor/$8.90 ceiling
November 2005 – March 2006	Natural Gas	Physical	2,000 GJ/d	$7.50 floor/$9.65 ceiling
November 2005 – March 2006	Natural Gas	Physical	1,000 GJ/d	$11.00 floor/$13.40 ceiling
November 2005 – March 2006	Natural Gas	Physical	1,000 GJ/d	$12.66 floor/$14.15 ceiling (1)
April 2006 – October 2006	Natural Gas	Physical	2,000 GJ/d	$9.50 floor/$10.90 ceiling
April 2006 – October 2006	Natural Gas	Physical	2,000 GJ/d	$9.19 fixed
October 2005 – December 2005	Crude Oil	Financial	300 bbl/d	$55.01 fixed

(1) Converted at September 30, 2005 foreign exchange rate of CDN/US $1.1611

As at September 30, 2005, the Company has marked-to-market its financial fixed price contracts resulting in an unrealized loss on risk management activities of $3,292,580 and an obligation of an equivalent amount.

Critical Accounting Estimates

Delphi's financial statements have been prepared in accordance with Canadian general 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 review their 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 individual's with the appropriate skill set and knowledge to make reasonable estimates; developing internal reporting systems; and comparing past estimates to actual results.

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

- Depletion, depreciation and accretion based on estimates of oil and gas reserves;
- Estimated revenues, operating expenses and royalties for which actual revenues and costs have not been received;
- Estimated capital expenditures on projects that are in progress;
- Estimated fair value of derivative contracts; and
- Estimated value of the asset retirement obligation including estimates of future costs and the timing of the costs.

Guarantees and Off-balance Sheet Arrangements

Delphi has not entered into any off-balance sheet arrangements or guarantees.

SEDAR Filing

Additional information about Delphi is available on the Canadian Securities Administrators' System for Electronic Distribution and Retrieval ("SEDAR") at www.sedar.com and at the Company's website at www.delphienergy.ca.

DELPHI ENERGY CORP.
Balance Sheets

		September 30 2005		December 31 2004
Assets		(unaudited)		(audited)
Current assets:				
Cash	**$**	**-**	$	1,891,962
Accounts receivable		**12,029,602**		5,675,468
Prepaid expenses and deposits		**1,289,852**		1,297,865
		13,319,454		8,865,295
Cash in trust		**-**		30,000,007
Property, plant and equipment (Note 3)		**181,689,884**		120,981,996
Goodwill		**12,099,676**		12,099,676
	$	**207,109,014**	$	171,946,974
Liabilities and Shareholders' Equity				
Current liabilities:				
Accounts payable and accrued liabilities	**$**	**27,972,913**	$	12,739,408
Risk management liability (Note 8)		**3,292,580**		-
Mezzanine debt (Note 4)		**-**		10,000,000
Bank debt (Note 5)		**58,300,000**		47,400,000
		89,565,493		70,139,408
Future income taxes		**11,454,280**		7,646,000
Asset retirement obligations (Note 6)		**6,769,620**		5,011,717
Shareholders' equity:				
Share capital (Note 7)		**96,935,743**		87,943,635
Contributed surplus (Note 7)		**1,997,749**		1,072,444
Retained earnings		**386,129**		133,770
		99,319,621		89,149,849
	$	**207,109,014**	$	171,946,974

Commitment (Note 9)

See accompanying notes to the financial statements

DELPHI ENERGY CORP.

Statements of Earnings (unaudited)

		Three months ended September 30				Nine months ended September 30		
		2005		2004		**2005**		2004
Revenue:								
Petroleum and natural gas sales	**$**	**21,688,829**	$	6,225,722	**$**	**53,372,813**	$	17,088,816
Realized gain (loss) on risk management activities		**(1,082,403)**		6,847		**(1,453,073)**		(72,009)
		20,606,426		6,232,569		**51,919,740**		17,016,807
Unrealized loss on risk management activities		**(1,847,896)**		-		**(3,292,580)**		-
Royalties (net of ARTC)		**(3,812,898)**		(673,775)		**(9,789,596)**		(1,764,829)
		14,945,632		5,558,794		**38,837,564**		15,251,978
Expenses:								
Operating		**3,666,099**		1,495,724		**9,517,920**		3,775,555
Transportation		**1,223,893**		255,296		**3,475,403**		680,009
General and administrative		**768,279**		144,379		**2,068,032**		1,023,261
Stock-based compensation		**265,977**		87,994		**1,248,527**		257,700
Interest		**845,009**		136,147		**2,774,683**		395,197
Depletion, depreciation and accretion		**6,448,706**		2,176,705		**18,599,185**		5,796,080
		13,217,963		4,296,245		**37,683,750**		11,927,802
Earnings before taxes		**1,727,669**		1,262,549		**1,153,814**		3,324,176
Taxes:								
Capital		**91,664**		(29,514)		**200,534**		1,250
Future		**445,784**		437,836		**700,921**		691,503
		537,448		408,322		**901,455**		692,753
Net earnings	**$**	**1,190,221**	$	854,227	**$**	**252,359**	$	2,631,423
Net earnings per share (Note 7(f))								
Basic and diluted	**$**	**0.02**	$	0.03	**$**	**0.01**	$	0.10

See accompanying notes to the financial statements

DELPHI ENERGY CORP.

Statements of Retained Earnings (Deficit) (unaudited)

		Three months ended September 30				Nine months ended September 30		
		2005		2004		**2005**		2004
Retained earnings (deficit), beginning of period	**$**	**(804,092)**	$	(41,556)	**$**	**133,770**	$	(1,150,466)
Changes in accounting policies								
Stock-based compensation		**-**		-		**-**		(668,286)
Net earnings		**1,190,221**		854,227		**252,359**		2,631,423
Retained earnings, end of period	**$**	**386,129**	$	812,671	**$**	**386,129**	$	812,671

See accompanying notes to the financial statements

DELPHI ENERGY CORP.

Statements of Cash Flows (unaudited)

	Three Months Ended September 30		Nine months Ended September 30	
	2005	2004	**2005**	2004
Cash provided by (used in):				
Operations:				
Net earnings	**$ 1,190,221**	$ 854,227	**$ 252,359**	$ 2,631,423
Add non cash items:				
Depletion, depreciation and accretion	**6,448,706**	2,176,705	**18,599,185**	5,796,080
Stock-based compensation	**265,977**	87,994	**1,248,527**	257,700
Unrealized loss on risk management activities	**1,847,896**	-	**3,292,580**	-
Future taxes	**445,784**	437,836	**700,921**	691,503
Expenditures on site restoration and reclamation	**-**	(186,471)	**-**	(186,471)
Funds from operations	**10,198,584**	3,370,291	**24,093,572**	9,190,235
Change in non-cash working capital	**(3,436,588)**	369,456	**(4,066,664)**	(1,902,988)
	6,761,996	3,739,747	**20,026,908**	7,287,247
Financing:				
Issue of shares, net of issue costs	**394,500**	111,498	**11,776,245**	285,239
Repayment of mezzanine debt	**-**	-	**(10,000,000)**	-
Increase in bank debt (repayment)	**(2,600,000)**	4,754,298	**10,900,000**	11,133,495
	(2,205,500)	4,865,796	**12,676,245**	11,418,734
Investing:				
Property, plant and equipment additions	**(16,280,027)**	(11,159,982)	**(32,138,905)**	(23,290,181)
Acquisition of properties	**-**	-	**(51,273,182)**	-
Proceeds on the disposition of properties	**-**	-	**5,862,917**	-
Change in non-cash working capital	**11,723,531**	2,554,439	**12,954,048**	4,584,200
	(4,556,496)	(8,605,543)	**(64,595,122)**	(18,705,981)
Increase (decrease) in cash and cash equivalents	**-**	-	**(31,891,969)**	-
Cash and cash equivalents, beginning of period	**-**	-	**31,891,969**	-
Cash and cash equivalents, end of period	**$ -**	$ -	**$ -**	$ -
Interest paid	**$ 384,951**	$ 214,061	**$ 2,197,806**	$ 537,356
Taxes paid	**$ -**	$ -	**$ 154,811**	$ -

See accompanying notes to the financial statements

DELPHI ENERGY CORP.
Notes to Financial Statements

Nine months ended September 30, 2005 and 2004 (unaudited)

The unaudited interim financial statements of Delphi Energy Corp. (the “Company”) 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, 2004. Certain comparative figures have been reclassified to conform with current period presentation. The disclosures provided below are incremental to those included with the annual financial statements. The interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto in the Company’s Annual Report from the year ended December 31, 2004.

The preparation of financial statements in conformity 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 reported period. Actual results may differ from these estimates.

Note 1: BASIS OF PRESENTATION

The financial statements include the accounts of the Company and Tercero Energy Inc. (“Tercero”), which was acquired on December 9, 2004 and amalgamated with the Company on February 1, 2005. The financial statements are stated in Canadian dollars.

Note 2: ACQUISITIONS

On February 1, 2005, the Company acquired producing natural gas and natural gas liquids properties with associated facilities and undeveloped land for cash consideration of $51,273,182. The Company paid for the acquisition with cash and increased bank debt.

On December 9, 2004, the Company acquired all of the issued and outstanding shares of Tercero, a private company involved in the exploration, development and production of oil and natural gas, for cash consideration of $42,531,777. The transaction was accounted for using the purchase method. The assets and liabilities have been recorded at their fair values. The accounts of the Company include the results of Tercero, which was amalgamated with the Company on February 1, 2005.

Allocated:

Property and equipment	$	52,391,118
Working capital		2,172,974
Goodwill		9,864,680
Bank debt		(14,950,000)
Asset retirement obligations		(1,011,563)
Future income tax liability		(4,850,122)
	$	43,617,087

Purchase price:		
Cash consideration	$	42,531,777
Transaction costs		1,085,310
	$	43,617,087

Note 3: PROPERTY, PLANT AND EQUIPMENT

September 30, 2005		Cost		Accumulated depletion and depreciation		Net book value
Petroleum and natural gas properties	**$**	**176,199,247**	**$**	**31,203,655**	**$**	**144,995,592**
Production equipment		**42,729,972**		**6,267,229**		**36,462,743**
Furniture, fixtures and office equipment		**499,289**		**267,740**		**231,549**
	$	**219,428,508**	**$**	**37,738,624**	**$**	**181,689,884**
December 31, 2004						
Petroleum and natural gas properties	$	110,009,449	$	17,219,756	$	92,789,693
Production equipment		30,066,969		2,067,725		27,999,244
Furniture, fixtures and office equipment		404,827		211,768		193,059
	$	140,481,245	$	19,499,249	$	120,981,996

As at September 30, 2005, costs in the amount of $24,129,767 (December 31, 2004 - $15,600,000) representing unproved properties were excluded from the depletion calculation and future development costs of $8,442,000 (December 31, 2004 - $7,700,000) have been included in costs subject to depletion.

During the nine months ended September 30, 2005, the Company capitalized $834,518 (2004 - $426,160) of general and administrative costs directly related to exploration and development activities.

During the nine months ended September 30, 2005, the Company disposed of two non-core properties for total proceeds of $5,862,917.

Note 4: MEZZANINE DEBT

		September 30, 2005		December 31, 2004
Mezzanine debt	**$**	**-**	$	10,000,000

On February 23, 2005, the maturity date of the mezzanine debt, the Company repaid the entire principal balance and interest payable on the mezzanine debt, including the repurchase of the gross overriding royalty, for a total of $10,332,260. The repayment was funded by proceeds on the disposition of properties and bank debt.

Note 5: BANK DEBT

		September 30, 2005		December 31, 2004
Bank debt	**$**	**58,300,000**	$	47,400,000

At September 30, 2005 the Company had drawn $58,300,000 on its banking facility. The Company has a revolving term facility for $82,000,000 with a syndicate of Canadian chartered banks. The facility may be drawn down or repaid at any time but there are no scheduled repayment terms. The credit facility bears interest based on a sliding scale tied to the Company's trailing debt to cash flow: from a minimum of the bank's prime rate to a maximum of the bank's prime rate plus 1.0%.

At September 30, 2005 the facility bears interest at bank prime rate plus 0.75% payable monthly and is secured by a $100 million demand floating charge debenture and a general security agreement over all assets of the Company.

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 twenty years, is approximately $13,500,000. A credit-adjusted risk-free rate of 8.0% and an inflation rate of 2.5% was used to calculate the fair value of the asset retirement obligations.

A reconciliation of the asset retirement obligations is provided below.

		Amount
Balance, December 31, 2004	$	5,011,717
Liabilities incurred due to operations		44,217
Liabilities incurred due to acquisitions		1,603,876
Liabilities settled due to dispositions		(250,000)
Accretion expense		359,810
Balance, September 30, 2005	**$**	**6,769,620**

Note 7: SHARE CAPITAL

(a) Authorized:

An unlimited number of voting common shares.

An unlimited number of preferred shares issuable in series.

(b) Common shares issued:

	Number of shares		Amount
Balance, December 31, 2004	47,703,775	$	87,943,635
Exercise of stock options	363,716		642,958
Issue of flow through common shares	2,727,500		12,001,000
Allocated from contributed surplus	-		323,222
Share issue costs, net of future tax effect of $295,022	-		(572,691)
Tax benefit renounced to shareholders	-		(3,402,381)
Balance, September 30, 2005	**50,794,991**	**$**	**96,935,743**

The Company issued subscription receipts late in 2004 for total proceeds of $30,000,007. As at December 31, 2004, the proceeds were being held in trust until closing of the acquisition of natural gas and natural gas liquids properties (Note 2 – Acquisitions). Upon closing of the acquisition on February 1, 2005, the receipts were exchanged for common shares of the Company on a 1 for 1 basis.

On March 31, 2005, the Company issued 2,727,500 flow-through common shares at a price of $4.40 per share for gross proceeds of $12,001,000.

As at September 30, 2005, the Company had an obligation to incur qualifying exploration expenditures of approximately $5,500,000 to satisfy terms of the flow-through common shares issued during the previous year and an obligation to incur qualifying exploration expenditures of $12,001,000 by December 31, 2006 to satisfy terms of the flow-through common shares issued during the period.

(c) Stock options:

The Company has established a stock option plan (the “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 equal 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 and vest over a two-year period starting on the date of the grant. The exercise price of each option equals the closing market price of the Company’s common shares immediately preceding the date of the grant. As of September 30, 2005 there were 2,629,700 options to purchase shares outstanding.

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

	Number of options outstanding		Weighted average exercise price
Balance, December 31, 2004	**1,895,083**	**$**	**1.59**
Granted	**1,165,000**		**3.43**
Exercised	**(363,716)**		**1.77**
Cancelled	**(66,667)**		**1.85**
Balance, September 30, 2005	**2,629,700**		**2.37**
Exercisable at September 30, 2005	**1,669,700**	**$**	**1.87**

The following table summarizes information about the stock options outstanding and exercisable at September 30, 2005.

	Options outstanding				Options exercisable		
Range of exercise price	Options outstanding		Weighted average exercise price	Weighted average remaining term	Exercisable		Weighted average exercise price
$0.99	**344,250**	**$**	**0.99**	**2.4**	**344,250**	**$**	**0.99**
$1.45 - 1.61	**843,750**		**1.46**	**2.7**	**823,750**		**1.45**
$1.75 - 1.90	**76,700**		**1.77**	**3.5**	**46,700**		**1.76**
$2.66	**200,000**		**2.66**	**4.1**	**66,667**		**2.66**
$3.25 - $3.77	**1,165,000**		**3.43**	**4.5**	**388,333**		**3.43**
Total	**2,629,700**	**$**	**2.37**	**3.6**	**1,669,700**	**$**	**1.87**

(d) Stock-based compensation:

The Company accounts for its stock-based compensation using the fair value method for all stock options granted since January 1, 2002. For the nine months ended September 30, 2005, Delphi recorded non-cash compensation expense of $1,248,527 (2004 - $257,700).

During the nine month period ended September 30, 2005, the Company granted 1,165,000 (2004 – 390,000) options. The fair values of all options granted during the period are estimated at the date of grant using the Black-Scholes option pricing model. The weighted average fair value of options granted during the period was $1.62 per share (2004 - $0.85). The assumptions used in the Black-Scholes model to determine fair value were as follows:

	Nine months Ended September 30	
	2005	2004
Risk free interest rate (%)	**4.5**	3.9
Expected life (years)	**5**	5
Expected volatility (%)	**48**	47

(e) Contributed surplus:

The following table outlines the changes in the amount of contributed surplus:

		Amount
Balance, December 31, 2004	**$**	1,072,444
Stock-based compensation expense		1,248,527
Reclassification to common shares on exercise		(323,222)
Balance, September 30, 2005	**$**	**1,997,749**

(f) Earnings (loss) per share:

Net earnings per share has been based on the following weighted average common shares:

	Three Months Ended September 30		Nine months Ended September 30	
	2005	2004	**2005**	2004
Basic	**50,649,882**	25,407,676	**49,664,600**	25,314,715
Diluted	**51,605,986**	25,773,693	**50,091,156**	25,714,140

The reconciling item between the basic and diluted weighted average common shares outstanding is stock options.

Note 8: FINANCIAL INSTRUMENTS

(a) Fair value of financial instruments:

The Company's exposure under its financial instruments is limited to financial assets and liabilities, all of which are included in these financial statements. The fair values of financial assets and liabilities that are included in the balance sheet approximate their carrying amounts.

(b) Credit risk:

Substantially all of the Company's accounts receivable are with customers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks.

(c) Foreign currency exchange risk:

The Company is exposed to foreign currency fluctuations as crude oil and natural gas prices are referenced to U.S. dollar denominated prices.

(d) Interest rate risk:

The Company is exposed to interest rate risk to the extent that bank debt is at a floating rate of interest.

(e) Commodity price risk management:

The Company has a price risk management program whereby the commodity price associated with a portion of its future production is fixed. The Company sells forward a portion of its future production and enters into a combination of fixed price sale contracts with customers and commodity swap agreements with financial counterparties. The physical forward contracts are subject to market risk from fluctuating commodity prices and exchange rates. Gains and losses on the contracts are offset by changes in the value of the Company's production which are presently recognized in earnings in the same period as the production revenue.

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

Time Period	Commodity	Type of Contract	Quantity Contracted	Canadian Price (Per GJ/bbl)
April 2005 – October 2005	Natural Gas	Financial	2,500 GJ/d	$6.31 fixed
April 2005 – October 2005	Natural Gas	Financial	2,000 GJ/d	$6.00 floor/$6.90 ceiling
July 2005 – October 2005	Natural Gas	Physical	1,000 GJ/d	$7.05 fixed
November 2005 – March 2006	Natural Gas	Financial	2,000 GJ/d	$7.79 fixed
November 2005 – March 2006	Natural Gas	Physical	2,000 GJ/d	$8.00 floor/$8.90 ceiling
November 2005 – March 2006	Natural Gas	Physical	2,000 GJ/d	$7.50 floor/$9.65 ceiling
November 2005 – March 2006	Natural Gas	Physical	1,000 GJ/d	$11.00 floor/$13.40 ceiling
November 2005 – March 2006	Natural Gas	Physical	1,000 GJ/d	$12.66 floor/$14.15 ceiling (1)
April 2006 – October 2006	Natural Gas	Physical	2,000 GJ/d	$9.50 floor/$10.90 ceiling
April 2006 – October 2006	Natural Gas	Physical	2,000 GJ/d	$9.19 fixed
October 2005 – December 2005	Crude Oil	Financial	300 bbl/d	$55.01 fixed

(1) Converted at September 30, 2005 foreign exchange rate of CDN/US $1.1611

As at September 30, 2005, the Company has marked-to-market its financial fixed price contracts resulting in an unrealized loss on risk management activities of $3,292,580 and an obligation of an equivalent amount.

Note 9: COMMITMENT

The Company is committed, under contracts of varying lengths, for the utilization of gathering, processing and pipeline capacity on a major natural gas processing and gathering system. The future minimum commitments are as follows:

2005	$ 1,147,032
2006	4,707,351
2007	4,120,345
2008	3,811,868
2009	3,475,958
2010 – 2015	10,778,425

CORPORATE INFORMATION

DIRECTORS

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

Tony Angelidis
Senior Vice President Exploration
Delphi Energy Corp.

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Henry R. Lawrie (1)
Independent Businessman

Robert A. Lehodey, Q.C. (2)
Partner
Bennett Jones LLP

Andrew E. Osis (1)
Independent Businessman

Lamont C. Tolley (1)
Independent Businessman

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

OFFICERS

David J. Reid
President and Chief Executive Officer

Tony Angelidis
Senior Vice President Exploration

Michael S. Kaluza
Vice President Engineering

Brian P. Kohlhammer
Vice President Finance and Chief Financial Officer

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Vice President Corporate Development
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TRANSFER AGENT

CIBC Mellon Trust Company

STOCK EXCHANGE LISTING

Toronto Stock Exchange – DEE