delphi energy corp.

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Third Quarter 2004

Nine months ended September 30, 2004

DEE – TSX

Third Quarter 2004 Highlights

- Increased cash flow 147 percent to $3.6 million for the third quarter of 2004 ($0.14/share) compared to $1.4 million ($0.06/share) in 2003.
- Achieved the highest quarterly cash flow in the Company's history, increasing nine percent over the second quarter of 2004 and eight percent on a per share basis.
- Earned $0.9 million ($0.03 per share) compared to a loss of $0.2 million ($0.01 per share) for the same period in 2003.
- Increased average production 41 percent to 1,749 barrels of oil equivalent per day (boe/d), from production of 1,245 boe/d in the third quarter of 2003, a result of successful well reactivations combined with acquisition and development volume additions.
- Accomplished the most active capital program in the Company's history with $11.1 million expended on projects primarily in east central Alberta.
- Graduated from the TSX-V to the Toronto Stock Exchange on August 3, 2004.

Subsequent Events

- Announced the proposed acquisition of a private company ("PrivateCo.") on October 26, 2004 for $56.85 million.
- Announced a $16 million to $20 million financing, scheduled to close on or about November 23, 2004, with proceeds to be used for the acquisition of PrivateCo. Closed a $4 million flow-through share financing on November 10, 2004.

	Three Months Ended September 30			Nine Months Ended September 30		
Financial Highlights (1) ($000s except per boe and per share amounts)	**2004**	2003	% Change	**2004**	2003	% Change
Gross petroleum and natural gas sales	**6,233**	3,893	60	**17,017**	9,835	73
Per boe	**38.73**	33.99	14	**38.57**	38.81	(1)
Cash flow from operations	**3,557**	1,442	147	**9,377**	4,741	98
Per boe	**22.02**	12.58	75	**21.22**	18.71	13
Per share – Basic	**0.14**	0.06	133	**0.37**	0.23	61
Per share – Diluted	**0.14**	0.06	133	**0.36**	0.22	64
Earnings (loss)	**855**	(209)	-	**2,631**	1,092	141
Per boe	**5.30**	(1.84)	-	**5.96**	4.33	38
Per share – Basic & Diluted	**0.03**	(0.01)	-	**0.10**	0.05	100
Capital expenditures	**11,508**	5,029	129	**23,670**	20,261	17
Debt, net				**24,501**	8,685	182
Total assets				**69,330**	40,331	72
Shares outstanding - weighted average (000s)						
Basic				**25,315**	20,984	21
Diluted				**27,714**	21,155	31
Operating Highlights						
Natural gas (mcf/d)	**5,353**	5,779	(7)	**5,554**	4,891	14
Crude Oil (bbl/d)	**812**	244	233	**646**	84	669
Natural gas liquids (bbl/d)	**45**	38	18	**44**	29	52
Total (boe/d)	**1,749**	1,245	40	**1,616**	928	74

(1) Certain amounts for 2003 are restated.

Message to our Shareholders

Third Quarter 2004

Delphi followed a successful third quarter of 2004 with the announcement of a $57-million corporate acquisition. The importance of the proposed transaction is outlined in the Outlook section below. Before announcing the acquisition, Delphi increased its cash flow and earnings in the third quarter of 2004 compared with the same period of 2003 and made considerable progress on its capital program.

Delphi engaged in record levels of activity during the third quarter of 2004, primarily in east central Alberta. The Company spent $11.1 million during the third quarter on recompletions, workovers and facility upgrades compared with $7 million in the previous quarter and $5 million in the same period of 2003. These capital expenditures are expected to decrease the Company's operating costs, increase efficiencies and enhance production levels over the next number of months.

The Company's focus on development projects has proven successful during a time of historically high commodity prices. Delphi achieved record quarterly cash flow for the third quarter of 2004, increasing 147 percent to $3.6 million ($0.14/share) compared with $1.4 million ($0.06 per share) in the same period of 2003. The Company increased its earnings to $855,000 ($0.03 per share) in the third quarter of 2004 compared with a loss in the corresponding period of 2003.

The Company's successful well reactivation program helped increase production volumes for the third quarter of 2004 by 41 percent to 1,749 barrels of oil equivalent per day (boe/d) compared with 1,245 boe/d during the same period of 2003. This increase came despite plant problems and restrictions on a third-party pipeline at Fontas, Alberta that shut in approximately 250 bbls/d, or 14 percent of the Company's overall production. Although Delphi is optimistic the challenges at Fontas will be overcome, the Company expects this production to remain shut-in until the end of 2004 when weather conditions will allow for installation of a hydrocarbon dewpoint facility to remedy the problem. In addition to Delphi's shut-in production, wet weather limited Delphi's production increase in the third quarter compared with the previous quarter.

Outlook

Delphi's operational and financial outlook will be further strengthened on December 9, 2004 when the previously announced corporate acquisition is scheduled to close. The acquisition is accretive on all key measures. Delphi's production will immediately increase by 50 percent to approximately 3,000 boe/d and reserves will jump by 100 percent – an increase of 4.7 million boe. The acquisition provides development upside on 21,000 net acres of undeveloped land and offers at least 12 identified drilling locations for 2005 with several optimization and recompletion projects.

Financing of the acquisition has been designed to maintain a healthy balance sheet. Delphi's decision to fund 38 percent of the acquisition with debt and 62 percent with equity will keep the Company on track to exit 2004 with a debt ratio of 1.4 to 1.6 times annualized cash flow. Delphi's hedging program will help protect the Company's capital program.

Delphi looks forward to an active winter drilling program on its newly acquired assets and on its properties at Berland River and Fontas. At Berland River, a 10-22 Cadomin development well has spud. At Fontas, the Company plans to drill 15 wells (3 net) over the winter. Delphi is well positioned to continue its successful organic growth model while aggressively pursuing opportunities for expansion.

On behalf of the board,

David J. Reid
President and Chief Executive Officer
November 10, 2004

Management's Discussion and Analysis

The following discussion and analysis provided by the management of Delphi Energy Corp. ("Delphi" or the "Company") should be read in conjunction with the unaudited financial statements for the nine months ended September 30, 2004 and 2003 and the audited consolidated financial statements and MD&A for the year ended December 31, 2003 in our annual report, all of which have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The date of this MD&A is November 10, 2004. Additional information relating to the Company is available on SEDAR at http://www.sedar.com.

NON-GAAP MEASURES

MD&A contains the term "cash flow from operations", which should not be considered an alternative to, or more meaningful than, "cash flow from operating activities" as determined in accordance with Canadian generally accepted accounting principles as an indicator of the Company's performance. Delphi's determination of cash flow from operations may not be comparable to that reported by other companies. The reconciliation between net earnings and cash flow from operations can be found in the consolidated statements of cash flows. The Company also presents cash flow from operations per share whereby per share amounts are calculated using weighted average shares outstanding consistent with the calculation of earnings per share.

Production information and reserves are reported in units of barrels of oil equivalent ("boe"). Disclosure provided in respect of boe units may be misleading particularly if used in isolation. Where amounts are stated on a boe basis, gas volumes have been converted to barrels of oil equivalent at a ratio of 6,000 cubic feet of gas to one barrel of oil. This conversion ratio is based upon an energy equivalent method primarily applicable at the burner tip and does not represent value equivalence at the wellhead.

FORWARD-LOOKING INFORMATION

The MD&A contains forward-looking or outlook information with respect to Delphi. Forward-looking statements may include estimates, plans, expectations, opinions, forecasts, projections, guidance or other statements that are not statements of fact. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will prove to have been correct. These statements are subject to certain risks and uncertainties and may be based on assumptions that could cause actual results to differ materially from those anticipated or implied in the forward-looking statements. These statements speak only as of the date of this MD&A.

Production

	Three Months Ended September 30		Change (%)	Nine Months Ended September 30		Change (%)
	2004	2003		**2004**	2003	
Natural gas (mcf/d)	**5,353**	5,779	(7)	**5,554**	4,891	14
Crude oil (bbl/d)	**812**	244	233	**646**	84	669
Natural gas liquids (bbl/d)	**45**	38	18	**44**	29	52
Total (boe/d)	**1,749**	1,245	40	**1,616**	928	74

In the third quarter of 2004 Delphi increased production 40 percent from the same quarter of 2003, primarily a result of successful well reactivation programs in the Company's operated east central Alberta region. The overall production increase was partially offset by decreases in natural gas production due to pipeline curtailments at Fontas.

The seven percent decrease in natural gas production for the three months ended September 30, 2004 compared to the same quarter of last year, was primarily a result of production cutbacks in the Fontas area, offset partially by new gas production coming on stream in east central Alberta late in the third quarter. Plant problems causing shut-in of production, combined with restrictions on a third party pipeline in the area due to failure to meet the quality specifications caused frequent interruptions during the quarter. Current net natural gas production from the Fontas area has been reduced approximately 200 boe/d or 10 percent of the Company's current overall production due to these curtailments. The operator is currently reviewing options for mitigating this production curtailment. The possibility remains, however, that the restriction may continue until the end of 2004 when weather conditions will permit installation of a hydrocarbon dewpoint facility that will rectify the problem.

Oil and liquids production for the three months ended September 30, 2004 increased over the same period in 2003 as substantial progress was made in the quarter on a significant capital program in east central Alberta, involving facility upgrades, workovers and recompletions, and installation of high volume lift pumps. The start up of most of these projects was hampered by the unseasonably wet weather and new production was realized in late September through October..

Production for the nine months ended September 30, 2004 increased 74 percent, compared to the same period in 2003 primarily a result of acquisitions closed throughout the second half of 2003 combined with a successful third quarter capital program. Production for the nine months ended September 30, 2004 consisted of 57 percent natural gas and 43 percent crude oil and natural gas liquids, and was spread fairly evenly between the Company's two core regions of northwest Alberta and east central Alberta.

Average production for the quarter of 1,749 boe/d was two percent higher than in the second quarter of 2004. Oil and liquids production increased 18 percent to 857 bbl/d in the third quarter of 2004 over the 726 bbl/d reported in the second quarter of 2004 largely due to the extensive capital program in the east central Alberta region. Timing of new production, however was delayed, largely due to weather problems encountered in the quarter, combined with slower than expected ramping up of volumes from reactivations in individual fields in east central Alberta and regulatory delays. Optimization of these major facility projects are nearly complete with new production brought on stream in late September and October. Natural gas production decreased 10 percent over the production of 5,943 mcf/d in the second quarter of 2004, primarily due to problems encountered at Fontas.

Commodity Pricing

Benchmark Prices

	Three Months Ended September 30		Change (%)	Nine Months Ended September 30		Change (%)
	2004	2003		**2004**	2003	
Natural gas (AECO daily $/GJ)	**6.32**	5.96	6	**6.34**	6.70	(5)
Crude oil (U.S. WTI $/bbl)	**43.88**	30.20	45	**39.11**	30.99	26
Canadian to US dollar exchange rate	**0.7650**	0.7263	5	**0.7530**	0.6886	9

Average Sales Prices

	Three Months Ended September 30		Change (%)	Nine Months Ended September 30		Change (%)
	2004	2003		**2004**	2003	
Natural gas ($/mcf)	**6.25**	6.12	2	**6.52**	6.74	(3)
Crude oil ($/bbl)	**39.81**	27.45	45	**37.83**	27.73	36
Natural gas liquids ($/bbl)	**43.94**	6.59	567	**37.36**	24.92	50
Total ($/boe)	**38.73**	33.99	14	**38.57**	38.81	(1)

Both natural gas and crude oil benchmark commodity prices remained strong in the third quarter of 2004, with crude oil prices reaching record highs, partially offset by the effect of a stronger Canadian dollar.

North American natural gas prices softened slightly in the third quarter of 2004. The Company's natural gas prices for both the three and nine months ended September 30, 2004 were relatively flat over those realized for the same period in 2003. Natural gas pricing tends to be volatile, a result of periodic imbalances between supply and demand which affects inventory levels. Other factors that affect natural gas pricing include weather conditions, particularly in the eastern United States, pipeline delivery capacity and the availability of other less expensive sources of energy. Cooler than normal summer weather and a strong build up of inventories have caused downward pressure on gas prices earlier in the quarter with some strengthening late in the quarter over shut-ins due to hurricane damage in the Gulf of Mexico.

Crude oil prices have remained strong throughout 2004 but have risen sharply in the third quarter with WTI climbing to a new record high in September, due to world supply concerns combined with a steady increase in world demand for crude oil. Recent increased volatility in crude oil prices seems likely to continue. Supply concerns and speculation around those concerns will likely continue to support higher crude prices for the remainder of 2004. Many factors could affect crude oil prices for the remainder of 2004 not the least of which are, uncertainty around the world, OPEC's actual production levels and concerns around the continuing terrorist threat in the Middle East.

The Company enters into contracts to reduce commodity price volatility, increase cash flow stability and protect acquisition economics.

At September 30, 2004 the Company had the following physical gas sales contracts outstanding:

Year	Time Period	Commodity	Type of Contract	Quantity Contracted	Price
2004	April 2004 – October 2004	Natural Gas	Fixed price	1,000 GJ/d	$5.19 fixed
2004	May 2004 – October 2004	Natural Gas	Fixed price	2,000 GJ/d	$6.33 fixed
2004	Nov 2004 – March 2005	Natural Gas	Fixed price	1,000 GJ/d	$6.88 fixed
2004	Nov 2004 – March 2005	Natural Gas	Fixed price	1,000 GJ/d	$7.70 fixed
2004	October 2004 – December 2004	Crude Oil	Fixed price	100 bbl/d	$45.75 WTI[(1)]

(1) Represents WTI prices converted to Canadian$ at the then current exchange rates at the time the contract was entered into

Revenue

	Three Months Ended September 30		Change (%)	Nine Months Ended September 30		Change (%)
($000s)	**2004**	2003		**2004**	2003	
Natural gas	**3,077**	3,253	(5)	**9,892**	9,001	10
Crude oil	**2,944**	617	337	**6,675**	639	945
Natural gas liquids	**182**	23	691	**450**	195	131
Total	**6,233**	3,893	60	**17,017**	9,835	73

For the three months ended September 30, 2004, revenues increased 60 percent over the same period in 2003. The increase in revenues in the quarter is entirely attributable to crude oil, which saw increases in both volumes and prices. During the nine months ended September 30, 2004 revenues increased 73 percent compared to the same period in 2003 primarily due to higher crude oil production. Quarter-over-quarter total revenues remained flat, as weakened gas prices and volumes offset the gains made by crude oil

Royalties

	Three Months Ended September 30		Change (%)	Nine Months Ended September 30		Change (%)
($000s except per boe amounts)	**2004**	2003		**2004**	2003	
Crown, before royalty rebates	**839**	924	(9)	**2,417**	2,217	9
Royalty credits:						
Alberta royalty tax credit	**(44)**	(90)	(51)	**(107)**	(63)	70
Gas Cost Allowance	**(343)**	(97)	254	**(1,143)**	(97)	1078
Net Crown royalties	**452**	737	(39)	**1,167**	2,057	(43)
Freehold and gross overriding	**222**	172	29	**598**	219	173
Total royalties	**674**	909	(26)	**1,765**	2,276	(55)
Per boe ($)	**4.19**	7.94	(47)	**4.01**	8.97	(55)
Percent of total revenue	**10.8**	23.3	(54)	**10.4**	23.1	(32)

Delphi pays royalties to the provincial government, freeholders, which can be individuals or companies, and other oil and gas operators, who own surface or mineral rights. The Company also receives Gas Cost Allowance ("GCA"), for eligible capital expenditures during the year and Alberta Royalty Tax Credit ("ARTC") tax rebates 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. As prices increase or as there is an increase in higher producing wells royalty rates also increase.

Crown royalties before royalty credits decreased 9 percent on both a dollar and a percentage of revenue basis in the third quarter of 2004 over 2003, due to a higher proportion of crude oil revenue in the third quarter of 2004. Crude oil revenues have lower royalty rates, combined with a high percentage of revenue from non-Crown burdened or royalty free oil wells. Net Crown royalty expense decreased 26 percent, for the third quarter of 2004 compared to 2003, primarily a result of increased GCA rebates for current and prior periods resulting from increased capital spending on gas facilities in northwest Alberta. Freehold and gross overriding royalties increased in the third quarter of 2004 compared to 2003 a result of an increase in the number of freehold encumbered wells on production, combined with higher oil prices in the quarter. Royalties for the nine months ended September 30, 2004 are 22 percent lower than the same period in 2003. This decrease was primarily due to increased GCA credits received in 2004.

Quarter over quarter Crown royalties increased 55 percent due to high GCA rebates booked in the second quarter relating to 2003. Freehold and gross overriding royalties remained flat for the three months ended September 30, 2004 compared to the second quarter of 2004.

Operating Expenses

	Three Months Ended September 30		Change (%)	Nine Months Ended September 30		Change (%)
	2004	2003		**2004**	2003	
Total operating costs ($000s)	**1,496**	941	59	**3,776**	1,709	121
Per boe ($)	**9.29**	8.22	13	**8.56**	6.74	27
Percent of total revenue	**24**	24	-	**22**	17	29

Operating expenses increased $0.6 million for the three months ended September 30, 2004 and $2.1 million for the nine months ended September 30, 2004, compared to the same periods in 2003. A primary factor for the increase in costs was the increase in production in 2004 over the 2003. On a per boe basis third quarter operating costs have increased 13 percent from the same quarter in 2003 and 27 percent for the nine months ended September 30, 2004 compared to the same period in 2003, primarily a result of the acquisition of higher operating cost oil properties in the second half of 2003.

Compared to the second quarter of 2004 operating costs on a boe basis increased 19 percent for the three months ended September 30, 2004, primarily due to higher maintenance costs, higher fuel and water handling costs and the spread of fixed costs over fewer barrels of production. The Company is anticipating reductions in operating costs in the fourth quarter of 2004, both on a cost and a boe basis, as added costs of bringing on recompleted wells and newly commissioned facilities spent in the second and third quarter will be offset by recognition of full production capabilities.

The Company is continually focusing on reduction of operating costs. Total operating costs, on a per unit basis, are expected to decrease as more production volumes are added and the Company continues to create operating synergies in its core areas of operation.

Transportation

	Three Months Ended September 30		Change (%)	Nine Months Ended September 30		Change (%)
	2004	2003		**2004**	2003	
Total transportation costs ($000's)	**255**	169	51	**680**	459	48
Per boe ($)	**1.59**	1.48	7	**1.54**	1.81	(15)
Percent of total revenue	**4**	4	-	**4**	5	(20)

Transportation costs for the three months ended September 30, 2004 are higher than the costs recorded in the same period of 2003 due to an increase in trucked oil volumes in the third quarter of 2004.

Effective January 1, 2004, and consistent with the adoption of the new Canadian accounting standard, transportation costs have been reclassified as an expense in the consolidated statements of earnings and retained earnings for the three months ended September 30, 2004 and 2003. Previously, as was industry practice, transportation costs were deducted from revenue. The adoption of this guideline had no effect on the results of operations or financial position of the Company for the periods ended September 30, 2004 and 2003.

General and Administrative

	Three Months Ended September 30		Change (%)	Nine Months Ended September 30		Change (%)
($000s except per boe amounts)	**2004**	2003		**2004**	2003	
General and administrative costs	**686**	448	53	**2,257**	773	192
Overhead recoveries	**(323)**	(136)	138	**(556)**	(136)	309
Salary reallocations	**(131)**	(99)	32	**(420)**	(202)	108
Net	**232**	213	9	**1,281**	435	194
Per boe ($)	**1.44**	1.86	(23)	**2.90**	1.72	69

The increase in general and administrative costs ("G&A") for the nine months ended September 30, 2004, compared to the same period in 2003, is primarily due to additional staff and higher office rent required as a result of the increased size of the Company's operations and its increased asset base. Additional public company expenses increased G&A costs, a result of the private company becoming public in June 2003. G&A costs for the three months ended September 30, 2004 increased 9 percent compared to the same period in 2003, primarily due to expenses paid to transfer to the TSX. In January 2004, the Company adopted the new accounting policy with respect to the Stock Based Compensation. This new policy resulted in a non-cash expense of $88,000 and $243,000 charged to G&A for the third quarter and the nine months ended September 2004, respectively. Increased overhead recoveries recorded in the third quarter of 2004 are primarily due to the increase of capital activity in the quarter.

G&A costs decreased 64 percent in the third quarter of 2004 over the second quarter of 2004 primarily due to higher annual report costs and costs associated with new staff additions incurred in the second quarter.

The Company's G&A forecast for 2004 is estimated to be approximately $2.75 per boe. This estimate includes higher reserve evaluation costs due to the adoption of National Instrument 51-101, "*Standards of Disclosure for Oil and Gas Activities*", non-cash costs associated with the adoption of the amended Stock Based Compensation disclosures and additional listing fees required to move to the TSX from the TSX-V.

Interest

	Three Months Ended September 30		Change (%)	Nine Months Ended September 30		Change (%)
($000s except per boe amounts)	**2004**	2003		**2004**	2003	
Financing	**131**	73	79	**378**	104	263
Other	**5**	116	(96)	**17**	72	(76)
Total Interest	**136**	189	(28)	**395**	176	124
Per boe ($)	**0.85**	1.65	(48)	**0.90**	0.69	30

Interest expense was higher in the third quarter of 2004 compared to the same period a year ago, a result of increased average debt balances offset slightly by lower interest rates. Net debt has increased $15.9 million from September 30, 2003 to September 30, 2004, a result of an accelerated winter exploration and development program in northwest Alberta, combined with a substantial capital program executed throughout the summer and into the fall in east central Alberta.

Interest expense in the third quarter of 2004 increased 36 percent from the second quarter as net debt increased $7.7 million, a result of the substantial capital program executed throughout the summer and into the fall.

Depletion, Depreciation and Asset Retirement Obligation ("DD&A")(1)

	Three Months Ended September 30		Change (%)	Nine Months Ended September 30		Change (%)
($000s except per boe amounts)	**2004**	2003		**2004**	2003	
Depletion and depreciation	**2,113**	1,514	40	**5,605**	2,879	95
Accretion expense	**64**	9	611	**191**	26	635
Total	**2,177**	1,523	43	**5,796**	2,905	100
Per boe ($)	**13.53**	13.30	2	**13.13**	11.46	15

(1) Amounts for 2003 are restated. Refer to Note 2 to the financial statements.

For the three and nine months ended September 30, 2004 the depletion and depreciation of capital assets and the accretion of the asset retirement obligation increased 43 percent and 100 percent, respectively, compared to the same periods in 2003. The increase is due to higher production and a larger capital base in 2004.

Effective January 1, 2004 the Company retroactively adopted the recommendations of the Canadian Institute of Chartered Accountants ("CICA") Section 3110, "Asset Retirement Obligations" ("AROs"). The standard requires companies to recognize the liability associated with future abandonment and reclamation costs in the financial statements at the time the liability is incurred. Asset retirement obligations are initially measured at fair value in each period and are subsequently adjusted for the accretion of discount and any changes to the underlying cash flows. The asset retirement cost is capitalized as part of property, plant and equipment and amortized to income consistent with the depletion and depreciation of the underlying asset. Upon adoption of CICA Section 3110 effective January 1, 2004 the Company adjusted its future abandonment and reclamation costs retroactively. The effect of the adoption of the ARO standard has resulted in an increase to net property, plant and equipment of $1.5 million, an increase to goodwill of $1.5 million, an increase to the asset retirement obligation of $3.2 million, a decrease to the future tax liability of $337,000 and a reduction to the deficit of $863,000.

Income Taxes

	Three Months Ended September 30		Change (%)	Nine Months Ended September 30		Change (%)
($000s)	**2004**	2003		**2004**	2003	
Current	**(30)**	30	(200)	**1**	39	(97)
Future (recovery)	**438**	128	242	**692**	744	(7)
Total income taxes	**408**	158	158	**693**	783	(11)

The provision for future income taxes was lower in the nine months ended September 30, 2004 compared with the same period of 2003 as a result of a one percent tax rate reduction to the Alberta corporate income tax rate and reductions to the Company's federal tax provision. This tax rate reduction resulted in a $381,000 benefit in which was recognized in the first nine months of 2004. Current taxes for the nine months ended September 30, 2004 are for Federal Large Corporations Tax ("LCT") of $15,000, offset by a refund of federal taxes for 2003 . As at December 31, 2003 the Company had over $45 million in tax pools available for use and will not be cash-taxable in 2004.

Net Income

The Company's net earnings for the third quarter of 2004 were $855,000 or $0.03 per share on a diluted basis, versus a loss of $209,000 or $0.01 per share for the same period in 2003. Earnings in the third quarter were positively affected by higher volumes, commodity prices and royalty rebates. These increases were offset by higher operating expenses and DD&A.

Net earnings for the nine months ended September 30, 2004 increased 141 percent to $2.6 million ($0.10 per share) from $1.1 million ($0.05 per share) during the same period in 2003. The increase was primarily due to higher revenues from increased production and higher royalty rebates received in 2004.

Netback Analysis

Barrels of oil equivalent ($/boe)	Three Months Ended September 30 2004	2003	Change (%)	Nine Months Ended September 30 2004	2003	Change (%)
Sales price after hedging	**38.73**	33.99	14	**38.57**	38.81	(1)
Royalties	**4.19**	7.94	(47)	**4.01**	8.97	(55)
Operating expenses	**9.29**	8.22	13	**8.56**	6.74	27
Transportation	**1.59**	1.48	7	**1.54**	1.81	(15)
Operating netback	**23.66**	16.35	45	**24.46**	21.29	15
G&A	**0.98**	1.86	(47)	**2.35**	1.72	37
Interest	**0.85**	1.65	(48)	**0.90**	0.69	30
Current income taxes	**(0.19)**	0.26	(173)	**-**	0.15	(100)
Cash netback	**22.02**	12.58	75	**21.21**	18.73	13
Stock based compensation	**0.46**	-	100	**0.55**	-	100
Depletion, depreciation and accretion	**13.53**	13.30	2	**13.13**	11.46	15
Future income taxes	**2.73**	1.12	144	**1.57**	2.94	(47)
Net income	**5.30**	(1.84)	103	**5.96**	4.33	38

Liquidity and Capital Resources

Capitalization and Debt

As at ($000s except per share amounts)	**September 2004**
Common shares outstanding	**25,424**
Share price (end of period) ($)	**2.03**
Market value of common shares	**51,611**
Debt including working capital deficit	**24,501**
Total capitalization	**76,112**
Debt as a % of capitalization	**32**

Liquidity

At September 30, 2004 the Company had $20.1 million outstanding on its credit facility and a working capital deficit of $4.4 million, totaling $24.5 million of total net debt. As at September 30, 2004 the Company had accounts receivable of $3.9 million consisting of $2.6 million of revenue receivable, $0.8 million of joint venture receivables and $0.5 million of royalty and tax rebates. Included in the Company's $9.4 million of accounts payable is $1.3 million of operating expenses, $0.7 million of royalty expenses, $6 million of capital expenses and $1.4 million of joint venture expenses. The Company has a $31 million operating credit facility consisting of a $26 million demand revolving operating facility, of which $15.9 million was drawn at September 30, 2004, and a $5 million acquisition and development credit facility.

Operating Activities

Cash flow from operating activities, before site restoration expenses, increased 147 percent to $3.6 million or $0.14 per share in the third quarter of 2004, compared to $1.4 million or $0.06 per share for the same period a year ago. The increase in cash from operating activities in the second quarter of 2004 is primarily due to increased production volumes and commodity pricing, and lower royalties offset by increased operating expenses.

Cash flow from operations increased 96 percent to $9.4 million for the nine months ended September 30, 2004 compared to $4.7 million in the same period in 2003 due to reasons explained above for the third quarter of 2004. On a per boe basis cash flow from operations for the nine months ended September 30, 2004 was $0.36 per share compared to $0.22 per share for the same period in 2003.

Cash flow increased nine percent in the third quarter of 2004 from the second quarter primarily as a result of increased crude oil production and pricing, combined with lower G&A expenses.

Financing Activities

During the third quarter of 2004 cash generated from financing activities amounted to $4.9 million, consisting of an increase to bank debt of $4.76 million and proceeds on the exercise of options totaling $111,000. Cash generated from financing activities in the third quarter of 2003 totaled $2.1 million all from increased bank debt.

Investing Activities

Cash used in investing activities amounted to $8.6 million in the third quarter of 2004 compared with $3.8 million in the third quarter of 2003. Cash invested in the third quarter of 2004 consisted of $11.2 million of capital expenditures, with the remainder due to changes in non-cash working capital.

Drilling Results

During the third quarter of 2004 the Company finished drilling its fourth exploratory joint venture well in the Valhalla area of Northern Alberta. The Company's main focus during the third quarter was on recompleting and reactivating zones in existing wells and facility optimizations.

	Three Months Ended September 30, 2004		**Nine Months Ended September 30, 2004**	
	Gross	**Net**	**Gross**	**Net**
Natural gas wells	**-**	**-**	**8.0**	**1.4**
Oil wells	**-**	**-**	**-**	**-**
Dry holes	**1.0**	**0.1**	**4.0**	**0.7**
Total wells	**1.0**	**0.1**	**12.0**	**2.1**
Success rate (%)	**0**	**0**	**67**	**67**

Capital Invested

	Three Months Ended September 30		Change (%)	Nine Months Ended September 30		Change (%)
($000s)	**2004**	2003		**2004**	2003	
Land	**67**	28	139	**553**	244	127
Seismic	**104**	38	174	**202**	463	(56)
Drilling and completions	**4,992**	2,095	138	**9,838**	4,492	119
Equipping and facilities	**5,971**	116	505	**11,694**	1,946	501
Property acquisitions	**(37)**	2,611	(101)	**596**	12,868	(95)
Capitalized expenses	**111**	99	12	**426**	202	111
Other	**(48)**	42	214	**(53)**	46	(215)
Total cash capital invested	**11,160**	5,029	122	**23,290**	20,261	15
Asset retirement obligation	**348**	-	100	**380**	-	100
Total capital invested	**11,508**	5,029	129	**23,670**	20,261	17

During the third quarter of 2004 the majority of Delphi's capital expenditures were directed towards oil production optimizations and reactivations, combined with extensive facility work, in the east central region of Alberta. Eighty-five percent of the Company's third quarter capital expenditures were directed towards its core region of east central Alberta, where the Company spent $9.6 million. In John Lake $1.3 million was spent on reactivations and winterizing projects. The Company spent a further $4.1 million in the Thompson Lake area on recompletions and facility upgrades to maintain and expand production capacity. Cost structure of services and equipment continues to escalate in this very busy and competitive environment, in addition efforts to work through the inclement weather also increased costs slightly. Most major spending in east central Alberta was completed in early October. In northwest Alberta work began on the development joint venture project in Grande Prairie and the fourth of the exploratory joint venture wells finished drilling in the Valhalla area.

Outstanding Share Data

The common shares of Delphi began trading on the Toronto Stock Exchange on August 3, 2004 under the symbol DEE. The following table summarizes the common shares issued during 2004 and 2003.

(000s)	Number of Shares/Warrants
Class A common shares:	
Balance, December 31, 2002	18,232
Issued for cash pursuant to a private placement	1,836
Issued to DT shareholders with respect to the reverse take-over of Rise	**20,068**
Common shares of Rise at date of acquisition	2,862
Issue of common shares with respect to the acquisition of Murias	358
Issue of common shares with respect to the acquisition of Fish Creek	540
Issue of common shares with respect to asset acquisitions	154
Issue of flow-through common shares for cash	1,136
Exercise of stock options for cash	100
Balance, December 31, 2003	**25,218**
Exercise of stock options for cash	206
Balance, September 30, 2004	**25,424**

(000s except per share price amount)	**Nine Months Ended September 30, 2004**	Year Ended December 31, 2003
Share price ($)		
High	**$2.15**	$1.90
Low	**$1.66**	$1.32
Close at end of period	**$2.03**	$1.75
Weighted average number of common shares outstanding		
Basic	**25,315**	21,711
Diluted	**25,714**	21,897
Number of common shares outstanding	**25,424**	25,218
Number of stock options outstanding	**1,758**	1,852

Critical Accounting Estimates

The preparation of financial statements in accordance with GAAP requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses. The process of estimating reserves is also critical to several accounting estimates and requires judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change, having either a negative or positive effect on net income as further data becomes available, and as the economic environment continues to change.

Changes in Accounting Policies

1. Oil and gas operations:

Effective January 1, 2004 the Company adopted Accounting Guideline 16, "Oil and Gas Accounting - Full Cost" (AcG-16), which modifies how the ceiling test is performed.

The recoverability of a cost centre is tested by comparing the carrying value of the cost centre to the sum of the undiscounted cash flows expected from the cost centre's use and eventual disposition. If the carrying value is unrecoverable the cost centre is written down to its fair value using the expected present value approach. This approach incorporates risks and uncertainties in the expected future cash flows, which are discounted using a credit adjusted risk free rate. The adoption of AcG-16 had no effect on the Company's financial results. An analysis of operating income is completed each quarter, rather than cost of sales or gross profit, in keeping with oil and gas operations.

2. Asset retirement obligations:

Effective January 1, 2004 the Company retroactively adopted CICA section 3110, "Asset Retirement Obligations". The new recommendations require that the recognition of the fair value of obligations associated with the retirement of tangible long-lived assets be recorded in the period in which the liability is incurred, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are statutory, contractual or legal obligations. The liability is accreted over time for changes in the fair value of the liability through charges to accretion expense booked to DD&A. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depreciation, depletion and amortization of the underlying asset. The impact of the adoption of CICA section 3110 on the financial statements is outlined in note 3 of the financial statements.

3. Stock-based compensation plans:

Effective January 1, 2002, the Company retroactively adopted the new accounting policies with respect to accounting for stock options. Compensation expense has been recognized for all stock options granted. Any consideration received on exercise of the stock options is credited to share capital.

4. Transportation

In accordance with CICA Section 1100 GAAP, transportation costs are no longer being netted from sales revenues. All transportation costs have been reclassified and are being reported separately. For comparative purposes prior periods have been restated.

Selected Quarterly Information

	2004			2003				2002
	Q3	**Q2**	**Q1**	Q4	Q3	Q2	Q1	Q4
Production								
Oil and NGLs (bbl/d)	**857**	**726**	**479**	520	282	28	27	43
Natural gas (mcf/d)	**5,353**	**5,943**	**5,308**	5,648	5,779	5,049	3,824	1,131
Barrels of oil equivalent (boe/d)	**1,749**	**1,716**	**1,364**	1,461	1,245	869	664	232
Financial								
($000s, except as noted)								
Petroleum and natural gas revenue	**6,233**	**5,803**	**4,981**	4,500	3,893	3,256	2,686	700
Cash flow from operations	**3,372**	**3,248**	**2,572**	1,924	1,442	1,741	1,560	443
Per share basic ($)	**0.13**	**0.13**	**0.10**	0.08	0.06	0.08	0.08	0.04
Per share diluted ($)	**0.13**	**0.13**	**0.10**	0.08	0.06	0.07	0.08	0.04
Net earnings (loss)	**855**	**838**	**939**	217	(209)	734	568	87
Per share basic & diluted ($)	**0.03**	**0.03**	**0.04**	0.01	(0.01)	0.03	0.03	0.01
Per unit information								
Natural gas ($/mcf)	**6.25**	**6.41**	**6.93**	6.10	6.12	6.89	7.50	5.77
Oil ($/bbl)	**39.81**	**35.53**	**37.70**	27.04	27.45	26.18	43.65	-
Natural gas liquids ($/bbl)	**43.94**	**32.77**	**34.94**	37.11	6.59	37.34	42.90	25.05
Oil equivalent ($/boe)	**38.73**	**37.16**	**40.12**	33.48	33.99	41.16	44.92	32.84
Operating netback ($/boe)	**23.66**	**24.43**	**25.57**	18.00	16.35	23.78	27.37	20.06

DELPHI ENERGY CORP.

Balance Sheets

($000s)		September 30 2004		December 31 2003
Assets		(unaudited)		(audited)
				(restated Note 2)
Current assets:				
Accounts receivable	**$**	**3,932**	$	4,611
Prepaid expenses and deposits		**1,134**		659
		5,066		5,270
Property, plant and equipment (Notes 2,3&4)		**62,029**		43,963
Goodwill (Note 3)		**2,235**		2,235
	$	**69,330**	$	51,468
Liabilities and Shareholders' Equity				
Current liabilities:				
Accounts payable and accrued liabilities	**$**	**9,428**	$	6,951
Bank indebtedness (Note 5)		**20,139**		9,006
		29,567		15,957
Future income taxes (Notes 3&7)		**4,362**		3,670
Asset retirement obligations (Notes 2&3)		**3,575**		3,189
Shareholders' equity:				
Share capital (Note 6)		**30,228**		29,802
Contributed surplus (Notes 2&6)		**785**		-
Retained earnings (deficit) (Note 3)		**813**		(1,150)
		31,826		28,652
	$	**69,330**	$	51,468
Subsequent event – Note 10				

DELPHI ENERGY CORP.

Statements of Earnings and Retained Earnings (unaudited)

($000s)	Three months ended September 30		Nine months ended September 30	
	2004	2003	**2004**	2003
		(restated Note 2)		(restated Note 2)
Revenue:				
Petroleum and natural gas	**6,233**	3,893	**17,017**	9,835
Royalties (net of Alberta Royalty Tax Credit)	**(674)**	(909)	**(1,765)**	(2,276)
	5,559	2,984	**15,252**	7,559
Expenses:				
Operating	**1,496**	941	**3,776**	1,709
Transportation (Note 2)	**255**	169	**680**	459
General and administrative	**232**	213	**1,281**	435
Interest	**136**	189	**395**	176
Depletion, depreciation and accretion	**2,177**	1,523	**5,796**	2,905
	4,296	3,035	**11,928**	5,684
Earnings (loss) before taxes	**1,263**	(51)	**3,324**	1,875
Taxes:				
Current taxes	**(30)**	30	**1**	39
Future income taxes (Notes 3&7)	**438**	128	**692**	744
	408	158	**693**	783
Net earnings (loss) (Note 3)	**855**	(209)	**2,631**	1,092
Deficit, beginning of period	**(42)**	(1,989)	**(1,150)**	(3,290)
Stock based compensation – retroactive adoption (Note 2)	**-**	-	**(668)**	-
Retained earnings (deficit), end of period	**813**	(2,198)	**813**	(2,198)
Earnings per share:				
Basic and diluted	**0.03**	(0.01)	**0.10**	0.05
Weighted average number of common shares outstanding ($000s)				
Basic	**25,408**	23,000	**25,315**	20,984
Diluted	**25,774**	23,098	**25,714**	21,155

DELPHI ENERGY CORP.

Statements of Cash Flows (unaudited)

($000s)	Three months ended September 30		Nine months ended September 30	
	2004	2003	**2004**	2003
Cash provided by (used in):		(restated Note 2)		(restated Note 2)
Operations:				
Net earnings	**855**	(209)	**2,631**	1,092
Add non-cash items:				
Depletion, depreciation and accretion	**2,177**	1,523	**5,796**	2,905
Stock based compensation expense	**88**	-	**258**	-
Future income taxes	**438**	128	**692**	744
Site restoration expenditures	**(186)**	-	**(186)**	-
Funds from operations	**3,372**	1,442	**9,191**	4,741
Change in non-cash working capital (Note 8)	**369**	248	**(1,903)**	278
	3,741	1,690	**7,288**	5,019
Financing:				
Issue of shares, net of share issue costs	**111**	(46)	**285**	1,542
Increase in bank indebtedness	**4,754**	2,182	**11,133**	4,101
	4,865	2,136	**11,418**	5,643
Investing:				
Property, plant and equipment additions	**(11,160)**	(2,506)	**(23,290)**	(10,817)
Change in non-cash working capital (Note 8)	**2,554**	(1,320)	**4,584**	(1,440)
	(8,606)	(3,826)	**(18,706)**	(12,257)
Decrease in cash	**-**	-	**-**	(1,595)
Cash, beginning of period	**-**	-	**-**	1,595
Cash, end of period	**-**	-	**-**	-

DELPHI ENERGY CORP.
Notes to Financial Statements
(Unaudited)

Note 1: ACCOUNTING POLICIES

The interim financial statements of Delphi Energy Corp. ("Delphi" or the "Company") have been prepared by management in accordance with accounting principles generally accepted in Canada. The interim financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements for the year ended December 31, 2003, except as noted below. Certain prior years' amounts have been reclassified to conform with current presentation. The interim financial statements should be read in conjunction with the consolidated financial statements and the notes thereto in the Company's annual report for the year ended December 31, 2003.

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 2: CHANGE IN ACCOUNTING POLICIES

(a) Stock based compensation:

Effective January 1, 2004 the Company adopted the Canadian Institute of Chartered Accountants ("CICA") section 3870, "Stock based Compensation and Other Stock based Payments", retroactively without restatement of prior periods. The Company is required to record a compensation expense for all options granted over the vesting period based on the option's fair value. The compensation expense is included in the Company's general and administrative expenses. This change resulted in a decrease to the deficit of $668,286 and an increase to contributed surplus of the same amount.

(b) Asset Retirement Obligations

Effective January 1, 2004 the Company retroactively adopted the recommendations of CICA Section 3110, "Asset Retirement Obligations" ("AROs"). The standard requires companies to recognize the liability associated with future abandonment and reclamation costs in the financial statements at the time when the liability is incurred. Asset retirement obligations are initially measured at fair value and subsequently adjusted for the accretion of discount and any changes to the estimated underlying cash flows. The asset retirement cost is capitalized as part of property, plant and equipment and amortized to income consistent with the depletion and depreciation of the underlying asset. Note 3 discloses the effect of the adoption of this Section.

(c) Property, Plant and Equipment – Oil and Gas

Effective January 1, 2004 the Company adopted Accounting Guideline 16, "Oil and Gas Accounting – Full Cost" ("AcG-16"), which replaces Accounting Guideline 5, "Full Cost Accounting in the Oil and Gas Industry". AcG-16 modifies how the ceiling test is performed and is consistent with CICA Section 3063, "Impairment of Long-lived Assets". The new standards prescribe the recognition of impairment only if the carrying amount of a long-lived asset is not recoverable from its estimated undiscounted future cash flows. The impairment amount is the difference between the carrying amount and the estimated fair value of the asset. This approach incorporates risks and uncertainties in the expected future cash flows, which are discounted using a risk free rate. The adoption of AcG-16 had no effect on the Company's financial results.

(d) Transportation

Effective January 1, 2004, and consistent with the adoption of new Canadian generally accepted accounting principles ("GAAP"), transportation costs are presented as an expense in the Statement of Earnings and Deficit. The new standard defines the sources of GAAP and effectively eliminates industry practices as a source of GAAP. In 2003, as was industry practice, transportation costs were deducted from revenue and have been reclassified to conform to the presentation adopted in 2004.

Note 3: ASSET RETIREMENT OBLIGATIONS

The Company retroactively adopted the new recommendations on the recognition of the obligations to retire long-lived tangible assets. This change was effective January 1, 2004, with the revisions being applied retroactively. The effects were as follows:

Balance Sheet - As at December 31, 2003	As Reported	Change	As Restated
($000s)			
Assets			
Petroleum and natural gas properties	53,106	1,668	54,774
Accumulated depletion and depreciation	(10,638)	(173)	(10,811)
Net book value	42,468	1,495	43,963
Goodwill	784	1,451	2,235
Liabilities and shareholders' equity			
Asset retirement obligations	-	3,189	3,189
Future abandonment and restoration costs	768	(768)	-
Future income taxes	4,007	(337)	3,670
Deficit	(2,013)	863	(1,150)

Statement of Earnings Three months ended September 30, 2003	As Reported	Change	As Restated
($000s)			
Depletion, depreciation and accretion	1,597	(74)	1,523
Net earnings	(283)	74	(209)

Statement of Earnings Nine months ended September 30, 2003	As Reported	Change	As Restated
($000s)			
Depletion, depreciation and accretion	2,937	(32)	2,905
Net earnings	1,060	32	1,092

At September 30, 2004 the estimated total undiscounted amount required to settle the AROs was $5.4 million. These obligations are to be recognized based on the economic lives of the underlying assets, which currently extend 16 years into the future. This amount has been discounted using a credit adjusted risk free interest rate of eight percent.

Changes to Asset Retirement Obligations	**Nine Months Ended September 30, 2004**
($000s)	
Asset retirement obligation at beginning of period	**3,189**
Liabilities incurred during the period	**381**
Liabilities settled during period	**(186)**
Accretion expense	**191**
Asset retirement obligation at September 30, 2004	**3,575**

Note 4: PROPERTY, PLANT AND EQUIPMENT

September 30, 2004	Cost	Accumulated Depletion and Depreciation	Net book Value
($000s)			
Petroleum and natural gas properties	**60,200**	**14,360**	**45,840**
Production equipment	**15,812**	**1,507**	**14,305**
Asset retirement cost	**2,049**	**354**	**1,695**
Furniture, fixtures and office equipment	**384**	**195**	**189**
	78,445	**16,416**	**62,029**
December 31, 2003			
($000s)			
Petroleum and natural gas properties	42,922	9,925	32,997
Production equipment	9,871	572	9,299
Asset retirement cost	1,668	173	1,495
Furniture, fixtures and office equipment	313	141	172
	54,774	10,811	43,963

As at September 30, 2004, unproved properties with capitalized costs of $6.3 million were not subject to depletion.

During the nine months ended September 30, 2004, the Company capitalized $0.4 million (2003 - $0.2), of general and administrative costs directly related to exploration and development activities.

Adoption of the new guideline for oil and gas accounting using the full cost method, as outlined in Note 2c, had no effect on the Company's financial statements. The future commodity prices used in the ceiling test prepared on initial adoption were based on January 1, 2004 commodity price forecasts of the Company's independent reserve engineers. These prices have been adjusted for commodity price differentials specific to the Company. The following table summarizes the future benchmark prices used in the ceiling test calculation. Based on these assumptions, the undiscounted value of future net revenues from the Company's proved reserves exceeded the carrying value of property, plant and equipment and other assets at September 30, 2004.

	WTI ($US/bbl)	Currency exchange rate $US/$Cdn.	Edmonton reference price ($Cdn/bbl)	AECO-C spot price ($Cdn/mmbtu)
2004	$37.25	$0.75	$49.00	$7.15
2005	32.00	0.75	41.75	6.20
2006	32.00	0.75	37.75	5.65
2007	27.00	0.75	35.25	5.35
2008	26.00	0.75	33.75	5.20
Escalate thereafter at:	1.5%/yr		1.5%/yr	1.5%/yr

Note 5: BANK INDEBTEDNESS

At September 30, 2004 the Company had drawn $15.9 on its banking facility. The Company has a financing commitment with a Canadian chartered bank for a revolving operating demand loan and a non-revolving development demand loan. As at November 2, 2004 the Company had a $60 million operating credit facility consisting of an $55 million demand revolving operating facility, restricted to $26 million pending the close of the proposed acquisition (see Note 10) and a $5 million acquisition and development credit facility. The loans bear interest at bank prime rate plus 0.25 percent% payable monthly and are secured by a $50 million demand floating charge debenture and a general security agreement. The borrowing base is subject to a semi-annual and annual review by the lender.

Note 6: SHARE CAPITAL

(a) Authorized:

An unlimited number of voting common shares.

An unlimited number of preferred shares issuable in series.

(b) Issued:

Common shares/warrants:

	Number of Shares/warrants	Amount
Class A common shares:	(000s)	($000s)
Balance, December 31, 2003	25,218	29,802
Stock based compensation – adoption	-	74
Exercised – options	206	352
Balance, September 30, 2004	**25,424**	**30,228**
Warrants:		
Balance, December 31, 2003	146	50
Cancelled	(146)	(50)
Balance, September 30, 2004	**-**	**-**

(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 and employees. The Plan provides for the granting of options to acquire up to 2,532,600 common shares of the Company. Options granted under the Plan have a term of five years to expiry and vest equally over a three-year period starting on the date of the grant. The exercise price of each option equals the market price of the Company's common shares on the date of the grant.

On September 30, 2004, options for 1,758,416 common shares were outstanding with an exercise price between $0.99 and $1.90, and a weighted average remaining contractual life of 3.74 years.

The following table sets forth a reconciliation of the Plan activity to September 30, 2004.

	Number of options (000s)	Weighted average exercise price
Balance, December 31, 2003	1,852	$1.38
Granted	390	$1.86
Cancelled	(278)	$1.48
Exercised	(206)	$1.45
Balance, September 30, 2004	**1,758**	**$1.46**

(d) Stock Based Compensation

The Company has calculated its stock based compensation expense using the Black-Scholes option pricing model to estimate the fair value of each option granted on the date of grant with weighted average assumptions and resulting values for grants as follows:

	Nine Months Ended September 30, 2004
Assumptions	
Risk-free interest rate (%)	**3.93**
Volatility (%)	**47**
Expected life (years)	**5.00**
Results	
Weighted average fair value of options granted	**0.85**

As described in Note 2a, the Company adopted the fair value based method of accounting for stock based compensation for its stock option plan retroactively without restating prior periods. The deficit at January 1, 2004, was increased by $668,286 with an increase to contributed surplus of the same amount. Beginning January 1, 2004, stock based compensation is being recognized in earnings and included in general and administrative expenses.

(e) Contributed Surplus

Nine Months Ended September 30	**2004**
($000s)	
Contributed surplus at beginning of period	**-**
Stock based compensation adoption	**668**
Stock based compensation expense	**452**
Options exercised	**(141)**
Options cancelled	**(194)**
Contributed surplus at September 30, 2004	**785**

(f) Flow-Through Share Expenditures

Pursuant to the December 18, 2003 flow-through share offering, the Company renounced $2.5 million of qualifying expenditures effective December 31, 2003. All of the total qualifying expenditures renounced, have been expended as at September 30, 2004.

Note 7: INCOME TAXES

The provision for income taxes for the nine months ended September 30, 2004 includes a $254,000 benefit for a one percent reduction in the Alberta corporate income tax rate.

Note 8: CASH FLOWS – CHANGE IN NON-CASH WORKING CAPITAL

	Three Months Ended	Nine Months Ended	Three Months Ended	Nine Months Ended
	September 30, 2004		September 30, 2003	
($000s)				
(a) Change in non-cash working capital was as follows				
Decrease (increase) in non-cash working capital				
Accounts receivable	**(431)**	**679**	(1,502)	(2,685)
Prepaid expenses	**(213)**	**(475)**	(84)	(122)
Accounts payable	**3,567**	**2,477**	515	1,645
Change in non-cash working capital	**2,923**	**2,681**	(1,071)	(1,162)
Relating to:				
Investing activities	**2,554**	**4,584**	(1,320)	(1,440)
Operating activities	**369**	**(1,903)**	249	278
Total non-cash working capital	**2,923**	**2,681**	(1,071)	(1,162)
(b) Other cash flow information:				
Taxes paid	**-**	**-**	-	20
Interest paid	**214**	**537**	114	101

Note 9: FINANCIAL INSTRUMENTS

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 through a combination of fixed price sale contracts with customers and commodity swap agreements with financial counterparts. The forward and futures 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 and recognized in income in the same period and category as the related item.

At September 30, 2004 the Company had the following physical sales contracts outstanding:

Year	Time Period	Commodity	Type of Contract	Quantity Contracted	Price
2004	April 2004 – October 2004	Natural Gas	Fixed price	1,000 GJ/d	$5.19 fixed
2004	May 2004 – October 2004	Natural Gas	Fixed price	2,000 GJ/d	$6.33 fixed
2004	Nov 2004 – March 2005	Natural Gas	Fixed price	1,000 GJ/d	$6.88 fixed
2004	Nov 2004 – March 2005	Natural Gas	Fixed price	1,000 GJ/d	$7.70 fixed
2004	October 2004 – December 2004	Crude Oil	Fixed price	100 bbl/d	$45.75 WTI(1)

(1) Represents WTI prices converted to Canadian dollar at the time the contract was initiated.

Note 10: SUBSEQUENT EVENT

Subsequent to September 30, 2004, the Company entered into an acquisition agreement to acquire all the issued and outstanding securities of a private Alberta oil & gas company ("PrivateCo"). The acquisition is subject to regulatory and other approvals and will be effected by way of take-over bid. The total consideration for PrivateCo is approximately $56.85 million, which includes the assumption of debt. PrivateCo's main asset-base is concentrated in northeast British Columbia with current production of approximately 1,200 boe/d (92 percent gas). PrivateCo's reserves were re-evaluated by the Company and its independent engineers and as at October 1, 2004,were estimated at 4.7 million boe on a proven and probable basis.

Also subsequent to September 30, 2004 the Company entered into a financing agreement with a syndicate of underwriters pursuant to which it has agreed to issue and sell, 1,333,334 flow-through common shares at an issue price of $3 each, resulting in gross proceeds of $4 million. The offering closed November 10, 2004 and the proceeds will be used to incur Canadian exploration expenses in connection with the exploration of the Company's oil and natural gas properties.

On November 2, 2004 the Company entered into a "bought deal" financing agreement with a syndicate of underwriters, to sell 7,272,727 subscription receipts, each subscription receipt being exchangeable without further payment into one common share of the Company upon the completion of the acquisition of PrivateCo. The subscription receipts will be issued at a price of $2.20 each, resulting in gross proceeds of $16 million. In addition Delphi has granted the underwriters an option to increase the size of the offering of subscription receipts by $4 million at the same price.

Corporate Information

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Delphi Energy Corp.

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Former Chief Accountant
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Lamont C. Tolley (1)
Independent Businessman

(1) Member of the Audit Committee
(2) Member of the Compensation Committee

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CIBC Mellon Trust Company

STOCK EXCHANGE LISTING

Toronto Stock Exchange
Stock Symbol: DEE