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FIRST QUARTER 2005 **Three Months Ended March 31, 2005** DEE – TSX

First Quarter 2005 Highlights

- Production increased 170 percent to 3,685 boe/d from 1,364 boe/d in the first quarter of 2005 and was up 80 percent from the fourth quarter of 2004 with natural gas representing over 75 percent of production.
- Increased cash flow 132 percent to $5,958,222 for the first quarter of 2005 ($0.12 per share) compared to $2,571,897 ($0.10 per share) in 2004.
- Delphi participated in the drilling of 21 gross (4.2 net) wells with a success rate of 81%.
- On February 1, 2005, Delphi acquired liquids-rich natural gas producing properties with associated facilities and undeveloped land at Bigstone, Alberta for cash consideration of $51,249,542.
- On March 31, 2005, the Company closed a private placement of 2,727,500 flow-through common shares at an exercise price of $4.40 per share for gross proceeds of $12,001,000.
- On February 23, 2005, the Company repaid the entire principal balance and interest payable on the mezzanine debt, including the repurchase of an associated gross overriding royalty for a total of $10,332,260.

Operational and Financial Information

	Three Months Ended March 31		
	2005	2004	**% Change**
Average Daily Production			
Natural gas (mcf/d)	**16,880**	5,308	**218**
Percentage of total production	**76.3%**	64.9%	**18**
Crude oil (bbl/d)	**713**	434	**64**
Percentage of total production	**19.3%**	31.8%	**(39)**
Natural gas liquids (bbl/d)	**159**	45	**253**
Percentage of total production	**4.4%**	3.3%	**33**
Total (boe/d)	**3,685**	1,364	**170**
Financial Highlights ($)			
Petroleum and natural gas revenue	**13,977,955**	4,924,735	**184**
Per boe	**42.13**	39.67	**6**
Cash flow from operations	**5,958,222**	2,571,897	**132**
Per boe	**17.96**	20.71	**(13)**
Per share – basic and diluted	**0.12**	0.10	**20**
Net earnings (loss)	**(1,942,272)**	939,073	
Per boe	**(5.85)**	7.56	
Per share – basic and diluted	**(0.04)**	0.04	
Capital expenditures	**60,035,551**	5,135,929	**1,069**

	March 31, 2005	December 31, 2004	
Debt plus working capital deficit	**70,904,522**	61,274,113	**16**
Total assets	**195,152,436**	171,946,974	**13**
Shares outstanding			
Basic	**50,512,358**	47,703,775	**6**
Diluted	**53,036,358**	49,598,858	**7**

Message to Shareholders

Delphi Energy has enjoyed success on its initial development efforts on the more than $108 million in corporate and property acquisitions announced late in 2004. The Company's production increased 170 percent to 3,685 barrels of oil equivalent per day (boe/d) in the first quarter of 2005 compared with 1,364 boe/d in the first quarter of 2004. Delphi is currently producing approximately 4,400 boe/d and expects to exit 2005 above 6,000 boe/d with the 2005 average production rate exceeding 4,800 boe/d. This constitutes a 300 percent growth in production from 2004 to 2005 and a 165 percent increase over the past three years in production per share.

While the acquisitions have provided an immediate and significant increase to the producing asset base, the Company has added approximately 750 boe/d through its $9 million capital program in the first quarter of 2005 at a cost of $12,000 per flowing boe/d. The Company anticipates the capital program through the remainder of the 2005 will yield production growth for less than $18,000 per flowing boe/d. The successful first quarter 2005 capital program focused primarily on low-risk activity, including optimization of existing producing wells, the completion of additional productive zones within existing wells, and development drilling.

OPERATIONS REVIEW

In the first quarter of 2005, Delphi participated in drilling 21 (4.2 net) natural gas wells for a success rate of 81 percent. The Company continues to operate out of three core areas, including North West Alberta, East Central Alberta and North East B.C.

Bigstone, North West Alberta

The Bigstone property acquisition closed February 1, 2005, adding approximately 1,150 boe/d of high netback sweet natural gas and natural gas liquids production to the Company. Delphi moved quickly on several capital projects late in the first quarter of 2005 resulting in a 30% increase in production to current levels of 1,500 boe/d. The incremental 350 boe/d (100% working interest) was achieved through several compressor optimization projects and the completion and tie-in of two existing wells.

The Company has dedicated $8 million to $12 million for its Bigstone capital program for the remainder of 2005. Delphi expects to double its production at Bigstone within the next twelve months through its existing inventory of capital projects. Opportunities at Bigstone include multiple low-risk re-entries, workovers, and up to 20 low-risk development drilling opportunities with an additional three to five step-out locations. Delphi has also identified several more compressor and well optimization projects as well as four to six additional shut-in gas wells to tie-in. The Company has excess plant capacity to handle a three-fold increase in production from the area. The drilling program is expected to begin late in the second quarter and continue through the winter. The area offers good summer and fall access for the development drilling opportunities with winter only access limited more to the step-out drilling project areas. The Company's capital budget for the area has the potential to grow beyond $12 million in 2005 depending on the results of the initial drilling program.

2005 Development Joint Venture, North West Alberta

Delphi has allocated $5 million for its 2005 well development joint venture in North West Alberta, negotiated as part of Delphi's Bigstone acquisition. The joint venture allows Delphi to earn up to a 100 percent working interest in 26 wells (16,640 acres), subject to a convertible gross overriding royalty. The lands covered by the development joint venture offer multi-zone objectives of sweet gas and light oil.

In the first quarter of 2005, five wells were re-entered to evaluate productivity in the area. About 210 boe/d currently awaits tie-in which will be tied in after break-up. The Company expects to recomplete and evaluate another 15 wells during the remainder of 2005.

2005 Exploration Joint Venture, North West Alberta

Delphi has a five-well commitment with a senior industry partner as part of its 2005 exploration joint venture in North West Alberta. Delphi pays 100 percent of initial drilling and completion or abandonment costs to earn a 60 percent working interest in the wells. All five drilling opportunities on the joint venture lands are fully defined on 3D seismic. Delphi has access to both the seismic data of its senior partner as well as pipeline and processing infrastructure.

Delphi expects to spend $10 million as part of its 2005 exploration joint venture. The joint venture targets exploration wells with 25 BCF and deliverability of 5 to 10 mmcf/d per well. At an average cost of $3 million per well, Delphi has secured partners for approximately 35 percent of the exploration program. Through the first quarter of 2005, Delphi worked on licensing the exploration wells. Drilling is expected to commence during the summer. Results are anticipated in the fall.

Fontas, North West Alberta

Delphi and its partners completed another significant winter program at Fontas spending $3.7 million (net) during the first quarter of 2005. Delphi participated in the drilling of 16 wells, 8 of which are tied in and producing. The capital program also included 21 workovers and tie-ins of standing tested wells. In addition, a refrigeration unit installed in the first quarter of 2005, at a cost of $3.2 million ($640,000 net), will ensure natural gas production from the area meets the specified pipeline hydrocarbon dew point levels. The capital program increased production rates 55 percent to current levels of approximately 700 boe/d, at an average cost of $21,000 per flowing boe/d.

No new activity is planned for Fontas until next winter. Delphi has an average working interest of 20 percent in the area, including a contiguous land position of 167,000 gross acres.

North East British Columbia

Current production from Delphi's recently acquired natural gas properties in North East British Columbia is approximately 1,100 boe/d. Delphi added this area on December 9, 2004 with the acquisition of a private company. The acquisition included 21,000 net acres of undeveloped land and offers significant growth potential. During the first quarter of 2005, Delphi tied in one standing well for a production increase of 50 boe/d. Although Delphi had several projects identified for the first quarter of 2005 and obtained the required regulatory approvals, operations were cut short due to an early spring breakup. Delphi estimates more than 150 boe/d were left behind pipe on its lands in North East B.C. when winter ended early and will not be brought on until January 2006.

Delphi has allocated $5 million of its capital program for 2005 to conduct a two to four well summer drilling program and participate in the tie-in of a Slave Point gas well. Delphi is in the process of completing all technical, land, and regulatory work to prepare for an active winter drilling program in 2005/2006, with several tie-in and well optimization projects as well as 15 to 25 development drilling opportunities.

East Central Alberta

East Central Alberta offers significant potential infill and step-out drilling locations at Thompson Lake, Neutral Hills, Horseshoe and Chauvin. Current production is approximately 765 boe/d, consisting of 85 percent oil and 15 percent natural gas. The Company sold non-core assets in the area producing 200 boe/d for net proceeds of $6 million in January 2005.

Delphi has an abundance of low-cost infill drilling and field optimization opportunities in East Central Alberta. Although Delphi has been increasing its weighting to natural gas, strong oil prices make it attractive for Delphi to continue developing these assets with current plans to drill six to eight oil wells in East Central Alberta during 2005. Delphi's $3 million capital program in 2005 for the area will also include continued production and operating cost optimization, well reactivations and workovers. Mature and fully developed assets in the area will continue to be considered for disposition.

FINANCIAL REVIEW

Delphi's activity in the field is being reflected in its financial results. Petroleum and natural gas revenues in the first quarter of 2005 increased 184 percent to $14 million. Delphi increased its cash flow 132 percent to $6 million in the first quarter of 2005 compared with $2.6 million in the first quarter of 2004. For the three months ended March 31, 2005, the net loss was $1.9 million ($0.04 per share), including an unrealized loss on risk management activities of $1.8 million after tax, compared to net earnings of $0.9 million ($0.04 per share) for the comparative period.

Delphi incurred capital of $9 million, excluding acquisitions, and received proceeds on the disposition of two non-core properties of $6 million. These proceeds and increased bank debt were used to fund the repayment of the mezzanine debt of $10 million.

OUTLOOK

Delphi's first quarter operating results provide an indication of the growth potential beginning to be realized. The major corporate and property acquisitions have been integrated into the Company with the expanded Delphi team of highly skilled and motivated individuals. The 2005 capital program is being executed as planned. The success in the first quarter of 2005 demonstrates the high quality and low-risk profile of the opportunities being pursued. Delphi expects the growth profile from our planned capital program to continue to gain momentum through the remainder of 2005 and into 2006.

Delphi plans to spend approximately $28 to $30 million through the remainder of 2005. Ninety percent of the budget will be spent in North West Alberta and North East B.C. Delphi expects to drill an additional 20 wells throughout the remainder of the year. Significant focus will continue on the low-risk tie-in, optimization, workover and recompletion projects identified. The Company estimates it has 400 to 600 boe/d of production awaiting tie-in.

Improved operating efficiencies are already being realized with near-term operating, general and administrative, and interest costs being 10 to 15 percent lower than realized during the first quarter of 2005. Delphi expects this trend to continue through the remainder of 2005. At current production levels of 4,400 boe/d, monthly cash flow is expected to adequately fund the remaining 2005 capital program, with incremental cash flow from production growth being applied to the Company's bank debt as planned. The Company is forecasting cash flow of $40 million to $45 million in 2005, an increase in cash flow per share of 109 percent to $0.80 to $0.90 per share, resulting in a year-end debt to 2005 cash flow ratio of approximately 1.5 times and 1.1 times using annualized 2005 fourth quarter cash flow.

Delphi is gearing up to take full advantage of its significant inventory of opportunities throughout remainder of 2005.

On behalf of the Board,

David J. Reid
President and Chief Executive Officer
May 5, 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 months ended March 31, 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 and 2003 included in the Company's 2004 Annual Report. The discussion and analysis has been prepared as of April 29, 2005.

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 51-101when boes are disclosed. Boes may be misleading, particularly if used in isolation.

Cash flow from operations is not a recognized measure under Canadian generally accepted accounting principles. Management believes that cash flow from operations is a useful measure of financial performance. The Company's reconciliation between net earnings (loss) and cash flow from operations is disclosed subsequently in management's discussion and analysis. Cash flow from operations 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. The change in non cash working capital has been excluded to better reflect the ability of operations to generate cash flow rather than the exact timing of its receipt. Delphi's determination of cash flow from operations may not be comparable to that reported by other companies. The Company also presents cash flow from operations 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.

Production

	Three Months Ended March 31		
	2005	2004	**% Change**
Natural gas (mcf/d)	**16,880**	5,308	**218**
Crude oil (bbls/d)	**713**	434	**64**
Natural gas liquids (bbls/d)	**159**	45	**253**
Total (boe/d)	**3,685**	1,364	**170**

Production for the three months ended March 31, 2005 of 3,685 boe/d is comprised of 76% natural gas, 19% crude oil and 5% natural gas liquids. Average production volumes increased 170% on a quarter-over-quarter basis in 2005 compared to 2004 primarily as a result of capital programs undertaken during 2004 and in the first quarter of 2005 and the recent corporate acquisition of Tercero Energy Inc. (Tercero) and the liquids rich natural gas property acquisition at Bigstone, Alberta.

Natural gas production increased 218% during the first quarter of 2005 compared to the same quarter of 2004, primarily as a result of increased production from northeast British Columbia associated with the Tercero acquisition, natural gas production at Bigstone, Alberta and the installation of a refrigeration facility at Fontas, Alberta.

Crude oil production was 64% higher for the three months ended March 31, 2005 averaging 713 bbls/d compared to 434 bbls/d for the comparative quarter of 2004. This increase is primarily due to the Company's capital program in East Central, Alberta consisting of facility expansion and optimization, recompletion of non-productive wells and the restart of numerous shut-in oil wells undertaken during the second and third quarters of 2004.

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

Commodity Prices

Benchmark Prices

	Three Months Ended March 31		
	2005	2004	**% Change**
Natural gas			
New York Mercantile Exchange (US $/mmbtu)	**6.32**	5.69	**11**
AECO (CDN $/mcf)	**6.86**	6.38	**7**
Crude Oil			
West Texas Intermediate (U.S. $/bbl)	**54.63**	35.76	**53**
Edmonton Light (CDN $/bbl)	**61.68**	46.32	**33**
Foreign exchange rate			
Canadian to U.S. dollar	**1.227**	1.317	**(7)**
U.S. to Canadian dollar	**0.815**	0.759	**7**

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. In the first three months of 2005, the AECO natural gas price averaged $6.86/mcf compared to $6.38/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 Canadian/US dollar exchange rate. In the first three months ended March 31, 2005, WTI averaged US$54.63/bbl compared to US$35.76/bbl in 2004 with volatility throughout the period ranging from approximately US$45.50/bbl to over US$58.00/bbl at its peak in March, 2005.

During the first quarter of 2005, Canadian crude oil prices were negatively affected as a result of the strengthening Canadian dollar relative to its U.S. counterpart. The Canadian dollar averaged CDN/US$1.23 in the first quarter of 2005 compared to CDN/US$1.32 in the first quarter of 2004.

Heavy oil differentials also widened throughout the first three months of 2005. This was particularly noticeable in the latter part of 2004 and has continued into 2005. Differentials began widening in the fourth quarter of 2004, ranging between $20.00 and $25.00 per barrel and have continued to remain at $25.00 or higher in recent months, wider than recent historical averages. The average differential for the first quarter of 2005 was $22.98 per barrel.

Average Sales Prices

	Three Months Ended March 31		
	2005	2004	**% Change**
Natural gas ($/mcf)	**7.02**	6.83	**3**
Crude oil ($/bbl)	**38.34**	37.49	**2**
Natural gas liquids ($/bbl)	**46.40**	34.94	**33**
Realized gain on risk management activities ($/boe)	**0.57**	-	
Total ($/boe)	**42.13**	39.66	**6**

The Company's average realized sales price per boe increased 6% in the first quarter of 2005 versus the comparative period of 2004. The average natural gas sales price increased slightly at 3% matching the trend of AECO benchmark prices. The realized average crude oil sales price increased 2% reflecting the increase in the Canadian dollar relative to the US dollar and the significant widening of light/heavy differentials. Realized natural gas liquids prices have increased significantly due to the increase in the price received for condensate. The Company realized $0.57 per barrel of oil equivalent as a result of its combined natural gas and oil hedging program.

Revenue

	Three Months Ended March 31		
($)	**2005**	2004	**% Change**
Natural gas	**10,660,688**	3,298,924	**223**
Crude oil	**2,461,945**	1,481,526	**66**
Natural gas liquids	**665,141**	144,285	**360**
Realized risk management activities	**190,181**	-	
Total	**13,977,955**	4,924,735	**184**

Quarter-over-quarter total revenues increased $9,053,220 or 184% in 2005 as compared to 2004. Of the increase in total revenue, 81% is attributable to natural gas sales, which increased 223% over 2004 primarily due to increased production volumes. Crude oil revenues increased 66% versus the comparative quarter primarily as a result of increased production volumes. Natural gas liquids revenue increased 360% due to increased volume from the Bigstone properties and the 33% increase in natural gas liquids prices.

Loss on Risk Management Activities

The Company is required to mark-to-market its outstanding financial fixed price contracts and record any unrealized gain or loss. As a result, the Company incurred an unrealized loss on risk management activities of $2,686,834 in the first quarter of 2005 and has established an accrued liability of an equivalent amount. Gains or losses in future periods will be dependent upon the realization or maturity of the fixed price contracts and the change in the future prices of the commodities fixed by the contracts.

Royalties

	Three Months Ended March 31		
($)	**2005**	2004	**% Change**
Crown	**2,563,477**	714,618	**259**
Freehold and gross overriding	**305,972**	148,977	**105**
Total	**2,869,449**	863,595	**232**
Royalty credits	**(410,513)**	(292,056)	**41**
Net	**2,458,936**	571,539	**330**
Per boe	**7.41**	4.60	**61**
Percent of total revenue	**17.6%**	11.6%	**52**

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 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 increase or due to an increase in production volumes on a well by well basis. Total royalties in the first three months ended March 31, 2005 increased 232% compared to 2004, as a result of increased production of natural gas, higher natural gas prices and increased oil and liquids production quarter-over-quarter. Royalties as a percentage of revenue increased 52% for the quarter ended March 31, 2005 compared to 2004, primarily due to properties acquired which have royalty rates higher than the Company's average royalty rate otherwise.

Operating Expenses

	Three Months Ended March 31		
($)	**2005**	2004	**% Change**
Total	**2,642,999**	1,015,823	**160**
Per boe	**7.97**	8.18	**(3)**
Percent of total revenue	**18.9%**	20.6%	**(8)**

Operating expenses increased $1,627,176 in 2005 compared to 2004, primarily due to a 170% increase in production volumes in 2005. On a per boe basis annual operating costs decreased 3% over 2004. This decrease is a result of increased natural gas production from northeast British Columbia and Bigstone, properties which have operating costs less than the corporate average, largely offset by increased oil production with operating costs greater than the corporate average.

Transportation Expenses

	Three Months Ended March 31		
($)	**2005**	2004	**% Change**
Total	**967,140**	163,290	**492**
Per boe	**2.92**	1.32	**121**
Percent of total revenue	**6.9%**	3.3%	**109**

Transportation costs are higher by $803,850, an increase of 492%, in the three months ended March 31, 2005 compared to the same period of 2004, primarily due to a 170% increase in production volumes in 2005. On a per boe basis, transportation costs increased 121% over 2004 primarily due to the transportation costs associated with natural gas production in northeast British Columbia and shipping natural gas production from the Bigstone area.

General and Administrative

	Three Months Ended March 31		
($)	**2005**	2004	**% Change**
General and administrative costs	**1,227,877**	644,801	**90**
Overhead recoveries	**(132,076)**	(67,116)	**97**
Salary reallocations	**(361,060)**	(157,076)	**130**
Net	**734,741**	420,609	**75**
Stock-based compensation expense	**574,803**	(21,962)	
Total	**1,309,544**	398,647	**228**
Per boe	**3.95**	3.21	**23**

General and administrative costs increased 90% in the three months ended March 31, 2005 versus the comparative period of 2004, primarily due to additional staff costs and increased public company expenses required as a result of the increased size of the Company’s operations and its asset base primarily from recent acquisitions. Overhead recoveries increased by 97% in the period due to operating oil and gas properties and the increase in operated capital programs. Salary reallocations have increased by 130% due to increased technical staff efforts toward the Company’s capital program.

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 values of all options granted are estimated at the date of grant using the Black-Scholes option pricing model. The expense for the three months ended March 31, 2005 was $574,803 compared to a reduction in the comparative period of $21,962. During the period, options were granted to five new employees, with one-third of the options vesting immediately pursuant to the Company's stock option plan, resulting in the recording of $384,731 or 67% of the stock-based compensation expense in the period.

Interest

($)	Three Months Ended March 31 2005	2004	% Change
Financing	**1,160,749**	123,289	**841**
Other charges	**21,205**	36,527	**(42)**
Interest income	**(45,686)**	(1,020)	**4,379**
Total	**1,136,268**	158,796	**616**
Per boe	**3.42**	1.28	**167**

Interest expense in the three months ended March 31, 2005 increased $977,472 over 2004, as a result of increased average bank debt balances and $10,000,000 mezzanine debt outstanding from December 8, 2004 until February 23, 2005 with an effective interest rate of 15.75% offset slightly by increased interest income received from cash held in trust during the period. Average bank debt for the three months ended March 31, 2005 was $46,800,000 higher than the average bank debt for the three months ended March 31, 2004.

Depletion, Depreciation and Accretion

($)	Three Months Ended March 31 2005	2004	% Change
Depletion and depreciation	**5,297,600**	1,534,770	**245**
Accretion expense of asset retirement obligations	**95,233**	63,775	**49**
Total	**5,392,833**	1,598,545	**237**
Per boe	**16.26**	12.88	**26**

Depletion and depreciation expense was $5,297,600 in 2005 compared to $1,534,770 in 2004. The quarter-over-quarter increase of 245% was due to production increases of 170% and a 26% increase in the depletion rate per unit-of-production to $16.26 in the quarter up from $12.87 in 2004. This increase is primarily attributable to higher cost proved reserve additions in the year and a larger capital base.

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 accretion expense for the three months ended March 31, 2005 was $95,233 compared to $63,775 in 2004. This 49% increase is primarily due to property, plant and equipment additions over the past year. The Company uses a credit adjusted risk-free rate of 8% for the purpose of calculating the fair value of its asset retirement obligations and hence the accretion expense.

Taxes

($)	Three Months Ended March 31 2005	2004	% Change
Current	**79,649**	22,781	**249**
Future (recovery)	**(753,976)**	56,241	
Total	**(674,327)**	79,022	

Current taxes for the three months ended March 31, 2005 are Federal Large Corporations Tax (LCT) of $79,649 versus the comparative period of $22,781.

Cash Flow from Operations Before Changes in Working Capital

($)	Three Months Ended March 31 2005	2004
Net earnings (loss)	**(1,942,272)**	939,073
Depletion, depreciation and accretion	**5,392,833**	1,598,545
Unrealized loss on risk management activities	**2,686,834**	-
Stock-based compensation expense	**574,803**	(21,962)
Future income taxes	**(753,976)**	56,241
Cash flow from operations	**5,958,222**	2,571,897

For the three months ended March 31, 2005 cash flow from operations was $5,958,222 ($0.12 per basic share) compared to $2,571,897 ($0.10 per basic share) for the comparative period. The increase in cash flow reflects the effects of increased revenues resulting primarily from higher production volumes and increased realized commodity prices.

Net Earnings (Loss)

For the three months ended March 31, 2005, the net loss was $1,942,272 ($0.04 per share), including an unrealized loss on risk management activities of $1,774,923 after tax, compared to net earnings of $939,073 ($0.04 per share) for the three months ended March 31, 2004.

Netback Analysis

	Three Months Ended March 31		
	2005	2004	**% Change**
Barrels of oil equivalent ($/boe)			
Realized sales price	**42.13**	39.66	**6**
Royalties, net of ARTC	**7.41**	4.60	**61**
Operating expenses	**7.97**	8.18	**(3)**
Transportation	**2.92**	1.32	**121**
Operating netback	**23.83**	25.56	**(7)**
G&A	**2.21**	3.39	**(35)**
Interest	**3.42**	1.28	**167**
Current taxes	**0.24**	0.18	**33**
Cash netback	**17.96**	20.71	**(13)**
Unrealized loss on risk management activities	**8.09**	-	
Stock-based compensation expense	**1.74**	(0.18)	
Depletion, depreciation and accretion	**16.26**	12.88	**26**
Future income taxes (recovery)	**(2.28)**	0.45	
Net earnings (loss)	**(5.85)**	7.56	

Drilling Results

	Three Months Ended March 31			
	2005		2004	
	Gross	**Net**	Gross	Net
Natural gas wells	**17**	**3.1**	8	1.4
Oil wells	**-**	**-**	-	-
Dry holes	**4**	**1.1**	3	0.6
Total wells	**21**	**4.2**	11	2.0
Success rate (%)	**81%**		73%	

Capital Invested

	Three Months Ended March 31		
($)	**2005**	2004	**% Change**
Land	**183,374**	356,398	**(49)**
Seismic	**(21,942)**	3,742	
Drilling and completions	**5,755,073**	1,555,301	**270**
Equipping and facilities	**2,478,286**	3,032,652	**(18)**
Property acquisition	**51,249,542**	-	
Capitalized general and administrative expenses	**336,945**	153,453	**120**
Other	**54,273**	34,383	**58**
Capital invested	**60,035,551**	5,135,929	**1,069**
Asset retirement costs	**1,398,093**	48,026	**2,811**
Total capital invested	**61,433,644**	5,183,955	**1,085**

Delphi's capital program, excluding property acquisitions, was $8,786,009 in the three months ended March 31, 2005, 71% higher than the previous year's capital expenditures of $5,135,929. The Company participated in the drilling of 21 gross (4.2 net) wells for an 81% success rate with 16 of the wells being drilled at Fontas, Alberta. At Bigstone, Alberta the Company participated in 4 wells, of which one was not finished drilling until mid-April and in northeast British Columbia, Delphi drilled 2 wells. The Company was also actively pursuing opportunities associated with the development joint venture agreement signed with a major oil and gas producer in the first quarter of 2005. During the quarter, the Company reworked 5 wells under this program of which 3 are expected to be tied in by the end of the second quarter. At Fontas, capital expenditures were $3,614,201, consisting of drilling, completions, equipment and tie in expenditures. Due to the winter access nature of this area all operations were completed before break-up as scheduled with costs as expected. At Bigstone, the Company incurred capital of $2,816,206 towards the participation in 4 wells, equipping and the tie-in of a standing cased well obtained from another producer, and four compression projects resulting in increased production in early April. In northeast British Columbia, the Company incurred capital of $897,437 primarily towards the drilling of 2 gross wells and minor facility upgrades. Approximately 53% of the remaining capital of $1,458,165 was incurred in the core area of northwest Alberta primarily reworking standing cased wellbores.

On February 1, 2005, the Company acquired liquids rich natural gas properties at Bigstone in northwest Alberta for cash consideration of $51,249,542. 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 March 31, 2005
Sources	**($)**
Cash flow from operations	**5,958,222**
Issue of flow-through common shares, net	**11,143,926**
Exercise of stock options	**126,904**
Proceeds on the disposition of properties	**5,862,917**
Cash held in trust	**30,000,007**
	53,091,976
Uses	
Property, plant and equipment additions	**8,786,009**
Property acquisition	**51,249,542**
Repayment of mezzanine debt	**10,000,000**
Change in working capital	**1,556,425**
	71,591,976
Increase in bank debt	**18,500,000**

For the three months ended March 31, 2005, the Company had sources of cash totaling $53,091,976 and uses of cash of $71,591,976, primarily consisting of the repayment of the mezzanine debt of $10,000,000 and a capital program of $60,035,551, resulting in an increase in bank debt of $18,500,000. The Company expects to fund its 2005 capital program primarily through internally generated cash flow.

Share Capital

The common shares of Delphi trade on the TSX under the symbol DEE. The following table summaries the common shares issued during the three months ended March 31, 2005.

	Number of shares
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	**81,083**
Balance, March 31, 2005	**50,512,358**

As at April 29, 2005, the Company has 50,512,358 common shares outstanding and 2,672,333 stock options outstanding.

Bank Debt

At March 31, 2005, the Company had $65,900,000 outstanding on its credit facility and a working capital deficit of $5,004,522, including an accrued liability for the unrealized loss on risk management activities of $2,686,834, for a total of $70,904,522 debt plus working capital. At March 31, 2005 the Company had a $79,500,000 operating credit facility consisting of a $76,000,000 demand revolving operating facility and a $3,500,000 acquisition and development credit facility. The Company's lender is currently reviewing the credit facilities based on the Company's current reserve engineering report.

Selected Quarterly Information

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

	Mar. 31 2005	Dec. 31 2004	Sept. 30 2004	June 30 2004	Mar. 31 2004	Dec. 31 2003	Sept. 30 2003	June 30 2003
Production								
Oil and NGLs (bbl/d)	**872**	904	857	726	479	520	282	28
Natural gas (mcf/d)	**16,880**	6,849	5,353	5,943	5,308	6,081	5,779	5,049
Barrels of oil equivalent (boe/d)	**3,685**	2,045	1,749	1,716	1,364	1,534	1,245	869
Financial								
($000s, except as noted)								
Petroleum and natural gas revenue	**13,978**	7,457	6,233	5,803	4,818	4,470	3,893	3,256
Cash flow	**5,958**	2,747	3,557	3,248	2,572	1,925	1,442	1,741
Per share basic	**0.12**	0.09	0.14	0.13	0.10	0.08	0.06	0.08
Per share diluted	**0.12**	0.09	0.14	0.13	0.10	0.08	0.06	0.07
Net earnings (loss)	**(1,942)**	(679)	855	838	939	1,042	(209)	734
Per share basic & diluted	**(0.04)**	(0.02)	0.03	0.03	0.04	0.05	(0.01)	0.03
Capital expenditures	**60,036**	62,084	11,508	6,979	5,136	6,603	8,628	5,029
Per unit information								
Natural gas ($/mcf)	**7.02**	7.02	6.25	6.60	6.83	5.67	6.12	6.89
Oil and natural gas liquids ($/bbl)	**39.81**	36.51	40.03	36.67	37.25	27.09	24.67	35.32
Oil equivalent ($/boe)	**42.13**	39.63	38.73	38.38	39.67	31.67	33.98	41.15
Operating netback ($/boe)	**23.83**	20.89	23.66	25.23	25.57	18.00	16.35	23.78

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	$	1,268,632
2006		2,231,186
2007		2,230,435
2008		2,093,361
2009		2,124,761
2010		2,156,633
2011		1,818,593

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

As at March 31, 2005, the Company had an obligation to incur qualifying exploration expenditures of $9,194,000 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 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 be generally 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 has 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 towill 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	Price
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
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
April 2005 – June 2005	Crude Oil	Financial	300 bbl/d	$52.34 fixed
July 2005 – September 2005	Crude Oil	Financial	300 bbl/d	$54.66 fixed
October 2005 – December 2005	Crude Oil	Financial	300 bbl/d	$55.01 fixed

As at March 31, 2005, the Company has marked-to-market its financial fixed price contracts resulting in an unrealized loss on risk management activities of $2,686,834 and an obligation of an equivalent amount.

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

		March 31 2005		December 31 2004
Assets		(unaudited)		
Current assets:				
Cash	**$**	**184,396**	$	1,891,962
Accounts receivable		**10,333,158**		5,675,468
Prepaid expenses and deposits		**1,280,083**		1,297,865
		11,797,637		8,865,295
Cash in trust		**-**		30,000,007
Property, plant and equipment (Note 3)		**171,255,123**		120,981,996
Goodwill		**12,099,676**		12,099,676
	$	**195,152,436**	$	171,946,974
Liabilities and Shareholders' Equity				
Current liabilities:				
Accounts payable and accrued liabilities	**$**	**14,115,325**	$	12,739,408
Risk management liability (note 8)		**2,686,834**		
Mezzanine debt (Note 4)		**-**		10,000,000
Bank debt (Note 5)		**65,900,000**		47,400,000
		82,702,159		70,139,408
Future income taxes		**10,003,000**		7,646,000
Asset retirement obligations (Note 6)		**6,505,043**		5,011,717
Shareholders' equity:				
Share capital (Note 7)		**96,157,733**		87,943,635
Contributed surplus (Note 7)		**1,593,003**		1,072,444
Retained earnings (deficit)		**(1,808,502)**		133,770
		95,942,234		89,149,849
	$	**195,152,436**	$	171,946,974

Commitments (Note 9)

DELPHI ENERGY CORP.
Statements of Earnings (unaudited)

	Three Months Ended March 31	
	2005	2004
Revenue:		
Petroleum and natural gas sales	**$ 13,977,955**	$ 4,924,735
Loss on risk management activities	**(2,686,834)**	-
Royalties (net of Alberta Royalty Tax Credit)	**(2,458,936)**	(571,539)
	8,832,185	4,353,196
Expenses:		
Operating	**2,642,999**	1,015,823
Transportation	**967,140**	163,290
General and administrative	**1,309,544**	398,647
Interest	**1,136,268**	158,796
Depletion, depreciation and accretion	**5,392,833**	1,598,545
	11,448,784	3,335,101
Earnings (loss) before taxes	**(2,616,599)**	1,018,095
Taxes:		
Capital	**79,649**	22,781
Future (recovery)	**(753,976)**	56,241
	(674,327)	79,022
Net earnings (loss)	**$ (1,942,272)**	$ 939,073
Net earnings per share (Note 7(f))		
Basic and diluted	**$ (0.04)**	$ 0.04

DELPHI ENERGY CORP.
Statements of Retained Earnings (Deficit) (unaudited)

	Three Months Ended March 31	
	2005	2004
Retained earnings (deficit), beginning of period	**$ 133,770**	$ (1,150,466)
Changes in accounting policies		
Stock-based compensation	**-**	(668,286)
Net earnings (loss)	**(1,942,272)**	939,073
Retained earnings (deficit), end of period	**$ (1,808,502)**	$ (879,679)

DELPHI ENERGY CORP.

Statements of Cash Flows (unaudited)

	Three Months Ended March 31	
	2005	2004
Cash provided by (used in):		
Operations:		
Net earnings (loss)	**$ (1,942,272)**	$ 939,073
Add non cash items:		
Depletion, depreciation and accretion	**5,392,833**	1,598,545
Stock-based compensation	**574,803**	(21,962)
Unrealized loss on risk management activities	**2,686,834**	-
Future taxes (recovery)	**(753,976)**	56,241
Change in non cash working capital	**(4,250,641)**	(3,640,477)
	1,707,581	(1,068,580)
Financing:		
Issue of shares, net of issue costs	**11,270,830**	156,985
Repayment of mezzanine debt	**(10,000,000)**	-
Increase in bank debt	**18,500,000**	2,700,000
Change in non cash working capital	**-**	931,000
	19,770,830	3,787,985
Investing:		
Property, plant and equipment additions	**(8,786,009)**	(5,135,929)
Acquisition of properties	**(51,249,542)**	-
Proceeds on the disposition of properties	**5,862,917**	-
Change in non cash working capital	**986,650**	2,416,524
	(53,185,984)	(2,719,405)
Increase (decrease) in cash and cash equivalents	**(31,707,573)**	-
Cash and cash equivalents, beginning of period	**31,891,969**	-
Cash and cash equivalents, end of period	**$ 184,396**	$ -
Interest paid	**$ 1,213,251**	$ 145,424
Taxes paid	**$ 19,649**	$ 6,628

Three months ended March 31, 2005 (unaudited)

The interim financial statements of Delphi Energy Corp. (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, 2004. Certain prior years' amounts have been reclassified to conform with the current year's presentation. 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 $51,249,542. 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

March 31, 2005		Cost		Accumulated depletion and depreciation		Net book Value
Petroleum and natural gas properties	**$**	**150,256,015**	**$**	**20,690,598**	**$**	**129,565,417**
Production equipment		**41,587,505**		**3,384,725**		**38,202,780**
Asset retirement costs		**3,749,352**		**492,158**		**3,257,194**
Furniture, fixtures and office equipment		**459,100**		**229,368**		**229,732**
	$	**196,051,972**	**$**	**24,796,849**	**$**	**171,255,123**
December 31, 2004						
Petroleum and natural gas properties	$	107,658,190	$	16,848,598	$	90,809,592
Production equipment		30,066,969		2,067,725		27,999,244
Asset retirement costs		2,351,259		371,158		1,980,101
Furniture, fixtures and office equipment		404,827		211,768		193,059
	$	140,481,245	$	19,499,249	$	120,981,996

As at March 31, 2005, costs in the amount of $25,946,000 (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 three months ended March 31, 2005, the Company capitalized $336,945 (2004 - $153,454), of general and administrative costs directly related to exploration and development activities.

During the three months ended March 31, 2005, the Company disposed of two non-core properties for total proceeds of $5,862,917.

Note 4: MEZZANINE DEBT

		March 31, 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

		March 31, 2005		December 31, 2004
Bank debt	**$**	**65,900,000**	$	47,400,000

At March 31, 2005 the Company had drawn $65,900,000 on its banking facility. The Company has a financing commitment with a Canadian chartered bank for a demand loan credit facility of $76,000,000 and a $3,500,000 acquisition and development facility. The operating facility bears interest at bank prime rate plus 0.5%, payable monthly, and is secured by a $100 million demand floating charge debenture and a general security agreement over all assets of the Company. The credit facility is subject to a semi-annual review by the Company's lender.

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.

		March 31, 2005
Balance, beginning of period	**$**	**5,011,717**
Liabilities incurred due to operations		**44,217**
Liabilities incurred due to acquisitions		**1,603,876**
Liabilities settled due to dispositions		**(250,000)**
Accretion expense		**95,233**
Balance, end of period	**$**	**6,505,043**

Note 7: SHARE CAPITAL

(a) Authorized:

An unlimited number of voting common shares.

An unlimited number of preferred shares issuable in series.

(b) Issued:

Common shares:

	Number of shares		Amount
Common shares:			
Balance, December 31, 2004	**47,703,775**	**$**	**87,943,635**
Exercise of stock options	**81,083**		**126,904**
Issue of flow through common shares	**2,727,500**		**12,001,000**
Stock-based compensation expense of options exercised			**54,244**
Share issue costs, net of future tax effect of $291,405			**(565,669)**
Tax benefit renounced to shareholders			**(3,402,381)**
Balance, March 31, 2005	**50,512,358**	**$**	**96,157,733**

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.

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 March 31, 2005, the Company had an obligation to incur qualifying exploration expenditures of $9,194,000 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 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 a fixed number of options to acquire up to 2,532,600 shares, which was ten percent of the issued and outstanding common shares of the Company on May 20, 2004. 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 on the day immediately preceding the date of the grant. As of March 31, 2005 there were 2,524,000 options to purchase shares outstanding.

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

	March 31, 2005		
	Number of Options		Weighted Average Exercise Price
Stock options outstanding, beginning of year	**1,895,083**	**$**	**1.59**
Granted	**710,000**		**3.44**
Exercised	**(81,083)**		**1.57**
Cancelled	**-**		**-**
Stock options outstanding, end of year	**2,524,000**		**2.11**
Exercisable at year-end	**1,396,500**	**$**	**1.78**

The following table summarizes information about the stock options outstanding and exercisable at March 31, 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**	**3.0**	**344,250**	**$**	**0.99**
$1.45 – 1.61	**884,750**		**1.46**	**3.3**	**607,250**		**1.46**
$1.75 – 1.90	**385,000**		**1.86**	**4.2**	**141,667**		**1.85**
$2.66	**200,000**		**2.66**	**4.7**	**66,667**		**2.66**
$3.25 - $3.77	**710,000**		**3.44**	**4.9**	**236,666**		**3.44**
	2,524,000	**$**	**2.11**	**3.6**	**1,396,500**	**$**	**1.78**

(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. Compensation expense recorded for stock options granted totaled $574,803 (2004 - $(21,962)).

The Company granted 710,000 options during the period (2004 – 50,000). 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 - $0.83). The assumptions used in the Black-Scholes model to determine fair value are as follows:

	Three Months Ended March 31	
	2005	2004
Risk free interest rate (%)	**4.5**	3.5
Expected life (years)	**5**	5
Expected volatility (%)	**47**	50
Dividend per share ($)	**-**	-

(e) Contributed surplus:

		March 31, 2005
Beginning of period	$	**1,072,444**
Stock-based compensation expense		**574,803**
Contributed surplus of options exercised		**(54,244)**
End of period	$	**1,593,003**

(f) Weighted average number of shares:

The weighted average number of common shares issued and outstanding used in calculating earnings per share for the three months ended March 31, 2005 and 2004 are as follows. The diluted weighted average shares outstanding include the dilutive effect of the Company's outstanding stock options. In 2005, all stock options were anti-dilutive and therefore excluded from the diluted weighted average shares outstanding. In 2004, 417,191 additional shares were included in the diluted weighted average shares outstanding.

	Three Months Ended March 31	
	2005	2004
Weighted average shares outstanding		
Basic	**47,772,029**	25,263,111
Diluted	**47,772,029**	25,680,302

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 due to the short-term maturity of those instruments.

(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 and 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 and category as the hedged item.

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

Time Period	Commodity	Type of Contract	Quantity Contracted	Price
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
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
April 2005 – June 2005	Crude Oil	Financial	300 bbl/d	$52.34 fixed
July 2005 – September 2005	Crude Oil	Financial	300 bbl/d	$54.66 fixed
October 2005 – December 2005	Crude Oil	Financial	300 bbl/d	$55.01 fixed

As at March 31, 2005, the Company has marked-to-market its financial fixed price contracts resulting in an unrealized loss on risk management activities of $2,686,834 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	$	1,268,632
2006		2,231,186
2007		2,230,435
2008		2,093,361
2009		2,124,761
2010		2,156,633
2011		1,818,593

CORPORATE INFORMATION

DIRECTORS

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

Tony Angelidis
Senior Vice President Exploration
Delphi Energy Corp.

Harry S. Campbell, Q.C. (2)
Partner
Burnet, Duckworth & Palmer LLP

Henry R. Lawrie (1)
Former Chief Accountant
Alberta Securities Commission

Robert A. Lehodey, Q.C. (1) (2)
Partner
Bennett Jones LLP

Lamont C. Tolley (1)
Independent Businessman

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

OFFICERS

David J. Reid
President and Chief Executive Officer

Tony Angelidis
Senior Vice President Exploration

Michael Kaluza
Vice President Engineering

Brian Kohlhammer
Vice President Finance and Chief Financial Officer

Frank M. Lowe
Vice President Production

Tim Malo
Vice President Corporate Development
and Corporate Secretary

CORPORATE OFFICE

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AUDITORS

KPMG LLP

BANKERS

National Bank of Canada

LEGAL COUNSEL

Bennett Jones LLP

INDEPENDENT ENGINEERS

Gilbert Laustsen Jung Associates Ltd.

TRANSFER AGENT

CIBC Mellon Trust Company

STOCK EXCHANGE LISTING

Toronto Stock Exchange
Stock Symbol: DEE