STRATEGY EXECUTION RESULTS

DELPHI DELIVERS

DELPHI ENERGY CORP.
2008

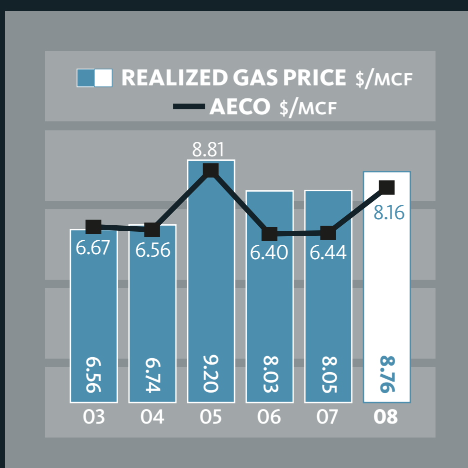
CORPORATE PROFILE

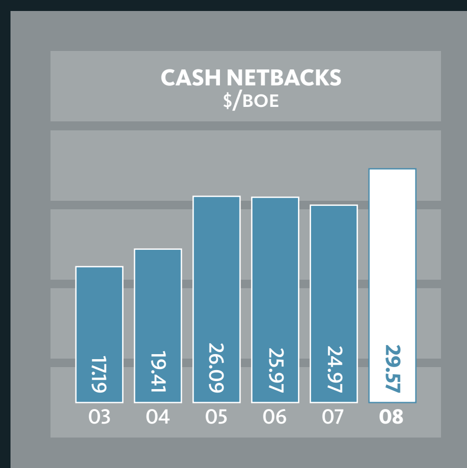
Delphi Energy Corp. is a public company primarily engaged in the acquisition, exploration for and development and production of crude oil, natural gas and natural gas liquids from properties located in Western Canada. Delphi's operations, producing approximately 6,700 boe/d, are principally concentrated in three core regions: (i) northwest Alberta, (ii) northeast British Columbia, and (iii) east central Alberta, with an overall focus on natural gas production. The Company has three primary core areas at Bigstone, Hythe and Tower Creek, all located in northwest Alberta, which comprise over 5,000 boe/d of production.

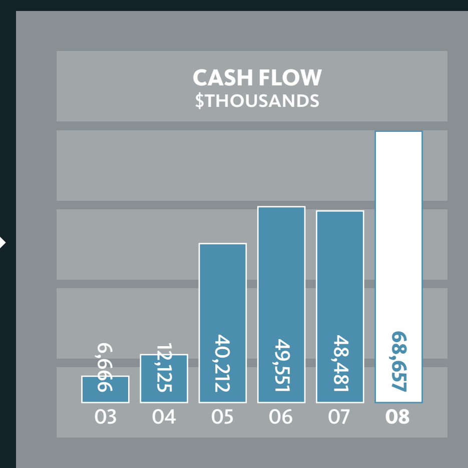
The Company is focused on conventional multi-zone vertical well opportunities blended with complementary horizontal well resource plays to generate a balance between the superior flowing barrel efficiency of conventional drilling with the more attractive finding and development costs of resource plays.

STRATEGY ON TRACK

Delphi's strategy of creating shareholder value through sustainable growth in production and reserves remains on track. Operatorship and control of our assets and our capital program remains a cornerstone to our value-creation strategy. Organic growth from internally generated drilling opportunities focused within core technical strengths continues to deliver top quartile capital efficient metrics. We continue to increase our inventory of drilling opportunities on existing Company lands providing defined long term growth as well as increasing our undeveloped land position for continued prospect generation. Our disciplined financial strategy of internally funding capital expenditures and mitigating the volatility in cash flow resulting from fluctuating commodity prices ensures long term financial strength and flexibility.

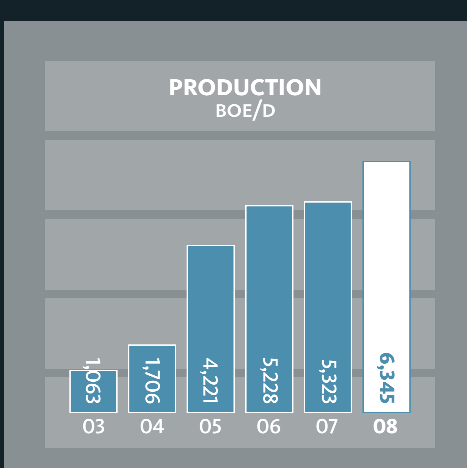


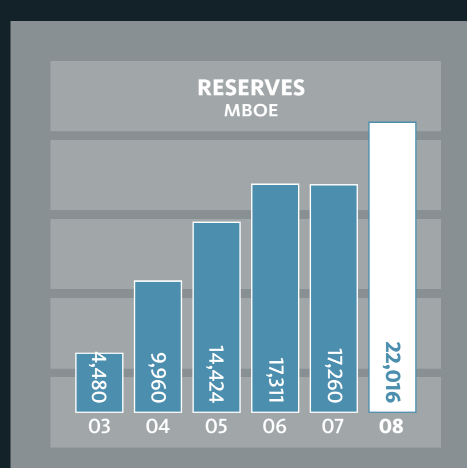


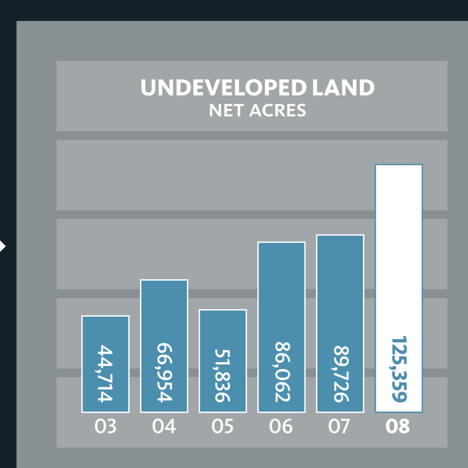


EXECUTION SUCCESSFUL

Successful execution of our operational and financial strategies requires confidence, discipline, and precision. Our team has the required core technical competency, think like owners, and are empowered in their recommendations. Our integrated approach to producing asset and capital project management generates predictable and repeatable results on time and on budget while maintaining operational and financial flexibility. 2008 results demonstrate our successful execution.








RESULTS
SPEAK FOR
THEMSELVES

FINANCIAL HIGHLIGHTS

	Year Ended December 31	
	2008	2007
Financial Highlights		
($ thousands except per boe and per share amounts)		
Gross petroleum and natural gas sales	**135,402**	97,933
Per boe	**58.31**	50.41
Funds from operations	**68,657**	48,481
Per boe	**29.57**	24.97
Per share – Basic	**0.94**	0.72
– Diluted	**0.93**	0.72
Net earnings (loss)	**5,094**	(10,472)
Per boe	**2.19**	(5.38)
Per share – Basic	**0.07**	(0.16)
– Diluted	**0.07**	(0.16)
Capital invested	**76,779**	51,924
Disposition of properties	**(8,450)**	(15,502)
Net capital invested	**68,329**	36,422
Acquisition of properties	**38,120**	10,871
Total capital	**106,449**	47,293
Debt plus working capital deficiency (1)	**109,237**	100,658
Total assets	**364,538**	311,740
Shares outstanding (thousands)		
Basic	**79,067**	68,070
Diluted	**83,798**	73,551

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

OPERATING HIGHLIGHTS

	Year Ended December 31	
	2008	2007
Operating Highlights		
Average Daily Production		
Natural gas (mcf/d)	**33,236**	26,886
Percentage of total production	**87%**	84%
Oil and natural gas liquids (bbl/d)	**806**	842
Percentage of total production	**13%**	16%
Total (boe/d)	**6,345**	5,323
Realized selling prices		
Natural gas ($/mcf)	**8.76**	8.05
Oil ($/bbl)	**89.88**	61.28
Natural gas liquids ($/bbl)	**80.49**	62.28
Total oil equivalent ($/boe)	**58.31**	50.41
Wells drilled (net)	**16.7**	8.1
Undeveloped land		
Gross acres	**315,479**	251,963
Net acres	**125,359**	89,726
Average working interest (%)	**40%**	36%
Proved plus probable reserves (P+P)		
Natural gas (mmcf)	**116,809**	91,108
Oil and natural gas liquids (mbbls)	**2,548**	2,076
Total oil equivalent (mboe)	**22,016**	17,260
Finding and development costs (P+P)	**20.15**	13.11
Finding, development and net acquisition costs (P+P)	**20.70**	21.49
Reserve life index (P+P)	**9.5**	8.9

DELPHI DELIVERS

Delphi has positioned itself to deliver long term sustainable growth. The Company's undeveloped land position increased 40 percent to 125,400 net acres during 2008. The high quality concentrated producing assets and undeveloped land base focused at Hythe and Bigstone in northwest Alberta continue to deliver predictable economic production and reserve growth. Conventional vertical well opportunities blended with complementary horizontal well resource plays continue to provide an effective balance between superior flowing barrel capital efficiencies of conventional opportunities with typically more attractive finding and development costs of resource style plays. Technological advances such as multi-stage fracs in horizontal wells and gas fracing techniques are being applied successfully to these multi-zone areas improving production rates, ultimate reserve recoveries and significantly increasing the drilling inventory for future growth. Delphi has also been active at Crown land sales over the past several months. The Company views the current business environment as an opportunistic entry point to accumulate strategic undeveloped land further strengthening Delphi's long term growth inventory.

STRATEGY

MESSAGE TO OUR SHAREHOLDERS

Delphi enjoyed another successful year in 2008, accomplishing its goals of delivering operational and financial growth, maintaining financial flexibility and ensuring the Company remains well positioned for sustainable long term organic growth in any business environment.

These are challenging times as the global recession deepens and commodity prices remain under pressure. Delphi is well positioned to operate effectively in these challenging times. The Company has entered this recession in a position of strength and will come out the other side with momentum for continued and accelerated growth. It is Delphi's employees with their skill and untiring dedication, management with their leadership and years of experience and the Board of Directors with their stewardship and support that make the difference.

Operational results in 2008 are highlighted by record production volumes and record reserve growth. Production during 2008 averaged 6,345 barrels of oil equivalent per day (boe/d), representing a 19 percent increase from 5,323 boe/d in 2007. The Company also achieved record production and seven consecutive quarters of production growth during the fourth quarter of 2008 averaging 6,708 boe/d. Total proved reserves increased by 33 percent to 15.1 million barrels of oil equivalent and total proved plus probable reserves by 28 percent to 22.0 million barrels of oil equivalent. The net asset value increased by 22 percent to $3.16 per share based on the before tax net present value of total proved plus probable reserves discounted at ten percent.

Financial results in 2008 are highlighted by record funds flow from operations (cash flow), strong earnings and increased financial flexibility. The Company reported record cash flow of $68.7 million ($0.94 per basic share) and earnings of $5.1 million ($0.07 per basic share) during 2008. Financial flexibility increased again during 2008 with debt and working capital improving to 78 percent of available bank facilities at December 31, 2008. Unutilized credit available on the Company's $140.0 million banking facilities increased to $30.8 million at year-end 2008, $6.5 million greater than at year-end 2007. The debt to trailing cash flow ratio at December 31, 2008 improved to 1.6 times from 2.1 at December 31, 2007.

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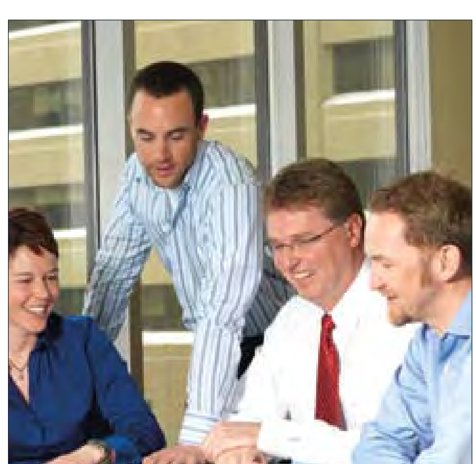
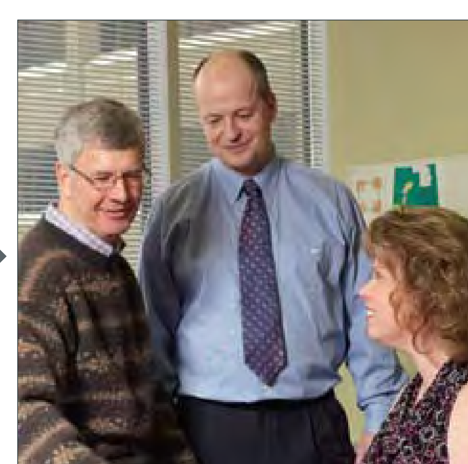




Delphi maintains a competitive advantage within its core areas with operatorship and control of over 84 percent of its production, field gathering and processing infrastructure. Synergies exist between all of the core areas and amongst the operational and technical expertise of the team. The Company's producing assets can be characterized as natural gas focused with medium to long life deep basin production profiles and a low cost structure resulting in economic netbacks and recycle ratios.

YEAR IN REVIEW

Crude oil and natural gas prices were on a rollercoaster in 2008. Early in July, West Texas Intermediate (WTI) reached an all-time high of U.S. $145.29 per barrel. The continuing increase in crude oil prices to the beginning of the third quarter also had a positive affect on natural gas prices. AECO reached a high of $11.83 per mcf before descending to a low of $5.79 per mcf at the end of the third quarter. By the end of the year, with widespread concern over the crisis in the credit and capital markets and the significant uncertainty over a global recession, WTI had collapsed to a low of U.S. $33.87 per barrel. AECO pricing stabilized in the fourth quarter to average $6.70 per mcf in anticipation of normal withdrawals of natural gas from storage to meet winter heating demand. Ongoing demand destruction associated with a slowing U.S. economy has continued to put downward pressure on natural gas prices into 2009.

During 2008, Delphi completed a net field capital program of $68.3 million, drilling 23 (16.7 net) wells with a 96 percent success rate. The Company operated over 90 percent of its capital program. The program was funded entirely from internally generated cash flow from operations of $68.7 million, consistent with the previous year and the Company's strategy.

On July 17, 2008, the Company closed an equity offering of 6,316,000 common shares at $2.85 per share and 3,530,000 flow-through common shares at $3.40 per share for proceeds of approximately $30.0 million (net proceeds of $28.0 million).

In July 2008, the Company completed the acquisition of crude oil and natural gas properties producing approximately 650 boe/d for $38.0 million, after closing adjustments, in the Peace River Arch area of northwest Alberta and northeast British Columbia. The acquisition was funded by the net proceeds of the equity offering and the Company's credit facilities. At the time, the Company's revolving credit facility was increased to the current limit of $130.0 million, an increase of $15.0 million, as a result of the incremental borrowing base attributable to the acquired properties.

Finding and development costs on proved and probable reserve additions, inclusive of future development capital, was $20.15 per boe generating a recycle ratio based on operating netbacks of 1.7 times. All-in finding, development and net acquisition costs on proved plus probable reserve additions for Delphi's total net capital program of $106.4 million, was $20.70 per boe with a very similar recycle ratio. The Company achieved a reserve replacement ratio of 212 percent during 2008 and increased its reserve life index to a robust 9.5 years.

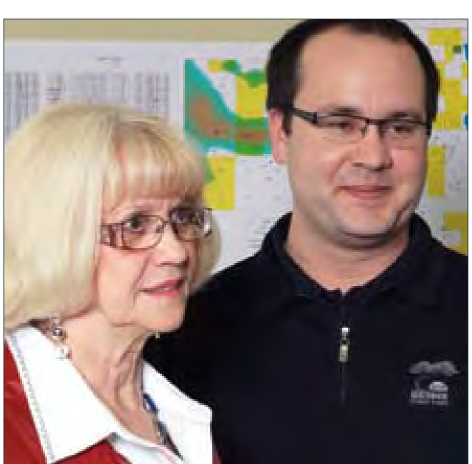
Delphi's operational success during 2008 was a result of a continued focus on its large inventory of growth opportunities in the multi-zone core areas of Bigstone and Hythe, Alberta. With minimal infrastructure dollars required due to ownership in processing facilities and excess capacity, Delphi was able to direct 71 percent of its capital program towards drilling and completion operations to increase production and reserves.

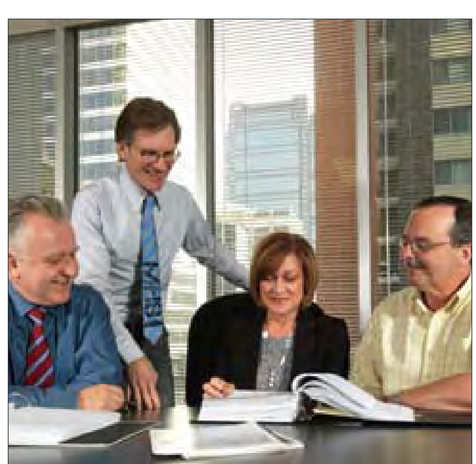
The inventory of conventional vertical and resource-style horizontal drilling locations continues to increase with positive results through the first quarter 2009 drilling program. Continued drilling, recompletion and optimization success at Hythe, Alberta has resulted in production growth of this core area to over 2,000 boe/d, up 400 percent from 400 boe/d at the time of acquisition in September 2007.

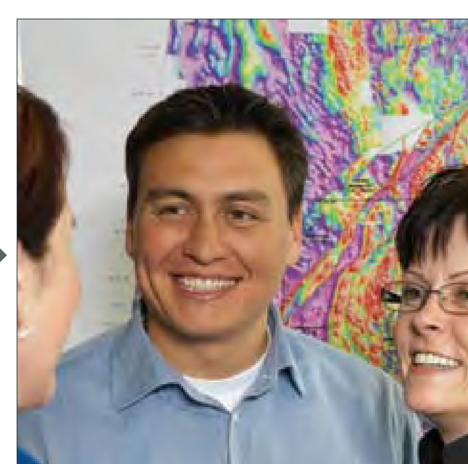
OUTLOOK

In 2009, Delphi will proceed cautiously and prudently with respect to executing a growth plan funded from expected cash flow in this environment of weak commodity prices driven by the ongoing global recession and financial turmoil. Maintaining operational and financial flexibility while expanding the Company's long term growth inventory in a low-cost environment will be key drivers in the capital spending decision process throughout 2009.

Since 2006, Delphi has successfully mitigated downside commodity price risk with an active natural gas hedging program. During 2009, the Company has again hedged approximately 50 percent of its natural gas production. An average floor price of $7.42 per mcf for these hedged natural gas volumes during 2009 represents a 64 percent premium to the current 2009 forward strip price of $4.54 per mcf.







The recently announced Alberta royalty incentive plan is a positive development for Delphi. The stimulus program applies to new wells drilled between April 1, 2009 and March 31, 2010 and includes a royalty credit ($200 per metre drilled) based on measured depth drilled. These credits can be used to immediately and directly offset total corporate royalties payable to the Crown. In addition, Crown royalties payable during the twelve month period for these new wells is capped at 5 per cent on the first 500 mmcf of natural gas or 50,000 bbls of crude oil. The calculated impact to Delphi on a typical well drilled in Hythe or Bigstone is approximately $900,000. The affect of this incentive program is material to both project economics and the Company's cash flow. With typical drilling and completion costs averaging approximately $2.5 million per well, the drilling program through the second half of 2009 is anticipated to be positively affected.

The Company expects to spend an estimated $35.0 to $50.0 million in 2009 drilling 10 to 14 net wells compared to 16.7 net wells during 2008. The majority of the capital will again be directed towards drilling and completion activities in the Bigstone and Hythe core areas. Delphi expects to drill and test two additional zones during 2009 using horizontal drilling and multi-stage fracing technologies given the encouraging operational results achieved on the first two horizontal wells drilled in Hythe.

Delphi continues to evaluate and pursue potential property acquisitions and swaps complementary to its existing core assets. The Company continuously evaluates its minor non-core assets for disposition.

Delphi is forecasting weak natural gas prices to persist through to at least the fourth quarter of 2009 and is assuming a 2009 average AECO natural gas price range of $4.25 to $5.50 per mcf. Given the impact of the hedge contracts in place, the Company's 2009 realized natural gas price would be approximately $6.35 to $6.95 per mcf. The planned 2009 capital program executed within forecast cash flow is expected to result in production volumes of approximately 6,500 to 7,000 barrels of oil equivalent per day, and takes into account scheduled facility maintenance outages during the second quarter affecting approximately 330 barrels of oil equivalent per day in the Hythe, Bigstone, and Tower Creek areas.

Bank debt including working capital at the end of 2009 is estimated to be at or below the December 31, 2008 amount of $109.2 million.

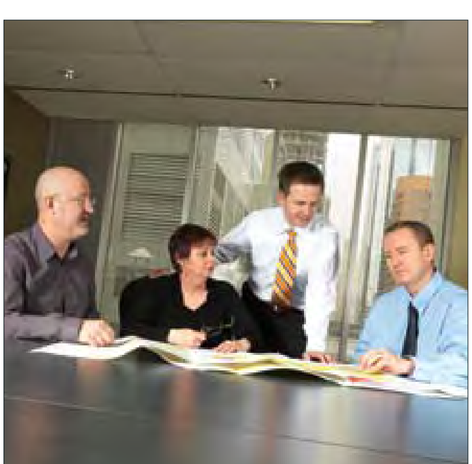
Delphi remains confident in its ability to achieve continued per share growth during these challenging times and is excited about the 2009 drilling program. The expanding inventory of drilling locations and growth prospects being generated gives rise to continued optimism for growth well beyond 2009.

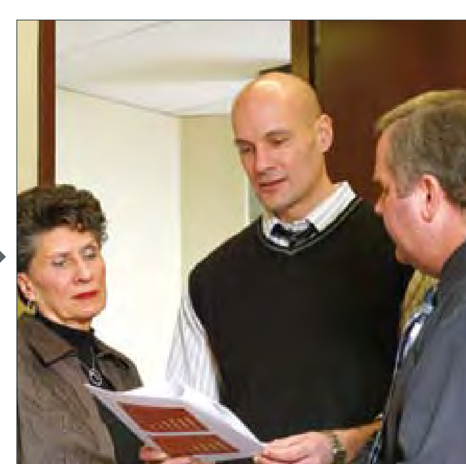
On behalf of the Board of Directors and all the employees of Delphi, I would like to thank our shareholders for their continued support and patience in these very difficult and uncertain economic times. Our team's effort remains focused on sustainable economic growth while maintaining the financial strength and flexibility to take advantage of strategic opportunities which may arise in the coming year.

On behalf of the Board,

David Reid

David J. Reid
President and Chief Executive Officer
March 19, 2009





EXECUTION
REVIEW OF OPERATIONS

During 2008, Delphi continued to expand and exploit a significant inventory of defined and repeatable conventional gas prospects within our core operating areas of west central Alberta and the Peace River Arch. The multi-zone nature of Delphi's assets, the drilling of multiple wells per spacing unit and the ability to commingle multiple zones within one wellbore are key contributors to the Company's success and generation of a large development drilling inventory. The targeted application of emerging technologies are increasing the recoveries of existing hydrocarbons in place and continue to enhance the economics of exploiting untapped hydrocarbon resources within the Company's current land holdings.

PRODUCTION

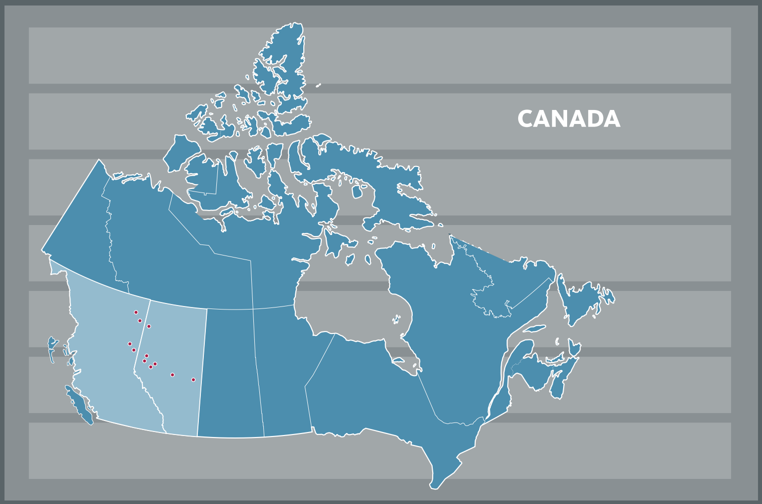
In 2008, production increased 19 percent to 6,345 barrels of oil equivalent per day (boe/d) from 5,323 boe/d in 2007. During the fourth quarter of 2008, production increased 14 percent to 6,708 boe/d from 5,868 boe/d in the fourth quarter of 2007 and increased five percent from 6,409 boe/d in the third quarter of 2008. The record level of production in the fourth quarter of 2008 represents the seventh consecutive quarter of production growth. Fourth quarter and full year production were 88 and 87 percent natural gas, respectively.

The Bigstone and Hythe areas continue to lead the way in production volumes and production growth by contributing approximately 4,200 boe/d or 63 percent of Delphi's fourth quarter volumes. A significant undeveloped land base, multi-zone potential and the successful application of emerging technologies continue to provide material production growth opportunities in existing and new play concepts.

DRILLING

During the year ending December 31, 2008 the Company drilled 23 (16.7 net) wells resulting in 19 (14.0 net) gas wells, two (2.0 net) oil wells, one (0.6 net) potential oil well and one (0.1 net) dry hole for an overall success rate of 96 percent. In the fourth quarter of 2008, Delphi drilled three (2.5 net) gas wells resulting in success rate of 100 percent. Due to the multi-zone nature of the wells, we averaged 2.8 completions per well with as many as nine zones being completed in one wellbore.

Twenty one (15.6 net) of the wells drilled in 2008 were vertical wells and the remaining two (1.1 net) were horizontal wells. In 2009 we will continue to drill vertical wells where appropriate and we will target specific intervals with horizontal laterals and multi-stage fracture stimulations to enhance overall project economics and capital efficiencies. In some cases we will be able to complete some of the horizontal wells in the uphole vertical section to further leverage our drilling capital and increase capital efficiency.

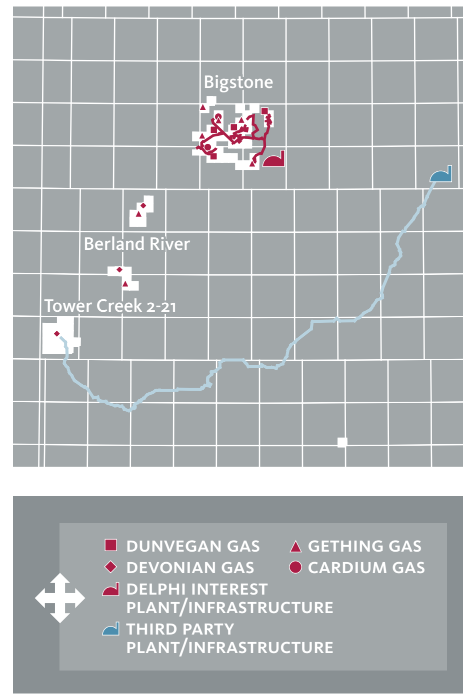


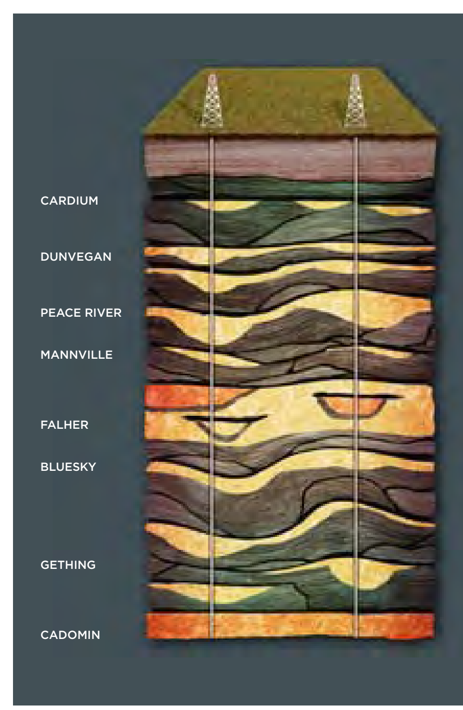
ALBERTA
Bigstone | Fontas | Hythe
Red Rock | Tower Creek | Valhalla

BRITISH COLUMBIA
Noel | Peggo

NORTHWEST ALBERTA
BIGSTONE

The Bigstone property is located 150 kilometres southeast of Grand Prairie and remains the company's single largest producing asset, contributing 2,901 boe/d in 2008. Key attributes of the Bigstone asset include; a large, high working interest, operated land base, multi-zone, liquids rich, sweet gas targets and ownership in an extensive gas infrastructure system.





Delphi's average working interest of 53 percent in 28,000 acres of land and the ability to drill more than one well per spacing unit provides a significant inventory of development drilling opportunities. The operated and high working interest nature of these opportunities allows the Company to efficiently scale a capital program to achieve the objectives of changing internal and external economic conditions. A typical well in the Bigstone area will be drilled to approximately 2,800 metres and has the potential to encounter up to seven intervals in the Cretaceous section with individual productive capabilities ranging from 250 to 3,000 mcf/d. The multi-zone potential is a major factor in drilling success rates approaching 100 percent since acquiring the property in 2005. The sweet gas produced from these intervals is liquids rich with condensate yields approaching 30 barrels per million cubic feet of gas. This rich gas results in premium pricing. Delphi owns an extensive gas gathering system in the Bigstone area which ensures that production can be brought on-line quickly and stay on-line since we are not dependant upon third parties to transport our gas to the processing facility. The ownership in the processing facility once again provides assurance that Delphi gas will not be curtailed due to third party constraints and results in lower operating costs which in turn contribute to higher cash netbacks.

The Company will continue to pursue the repeatable and predictable development projects taking advantage of our extensive land base and owned natural gas infrastructure that has made the Bigstone asset a successful, low cost, high netback and long life producing area.

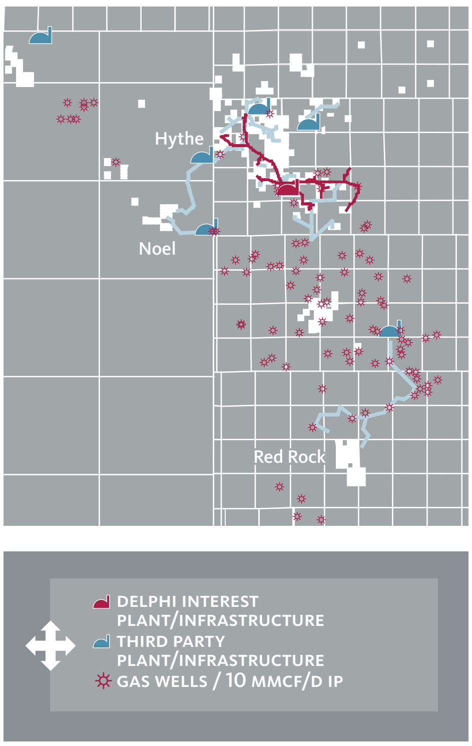
PRODUCTION / DRILLING

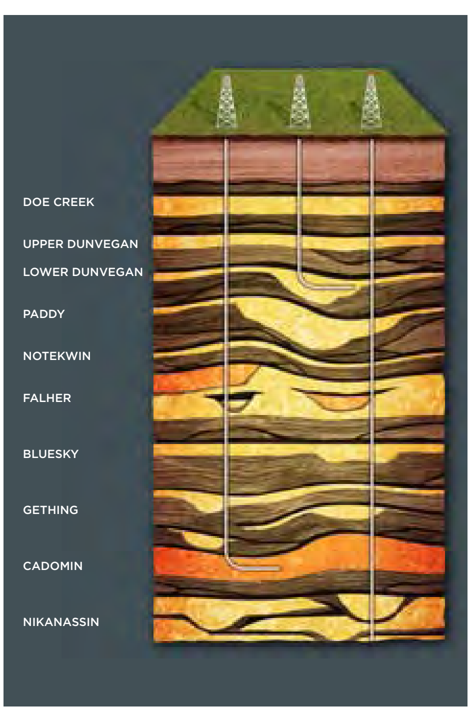
In 2008, average production increased seven percent to 2,901 boe/d from average production of 2,713 boe/d in 2007. During the fourth quarter of 2008, average production decreased ten percent to 2,728 boe/d from average production of 3,042 boe/d in the fourth quarter of 2007.

During the year ending December 31, 2008 the Company drilled nine (5.7 net) wells resulting in seven (4.1 net) gas wells, one (1.0 net) oil well and one (0.6 net) potential oil well for an overall success rate of 100 percent based on completed wells. In the fourth quarter of 2008, Delphi drilled one (0.5 net) gas wells resulting in a success rate of 100 percent.

NORTHWEST ALBERTA
HYTHE

The Hythe property is located 60 kilometres northwest of Grand Prairie and is the Company's second largest producing asset exiting 2008, producing in excess of 1,600 boe/d. Since acquiring the Hythe assets in September 2007, the Company has been focused on unlocking the growth potential on the extensive land base. Delphi has an average working interest of 58 percent on 113,000 acres.





Much like Bigstone, Hythe has the requisite attributes that support a premier growth asset; prolific multi-zone potential, repeatable and predictable development type opportunities, resource type plays and an extensive, underutilized field gathering and processing plant infrastructure in which Delphi owns a working interest. Through the end of 2008, the Company has increased production 300 percent from acquisition rates of approximately 400 boe/d to a stabilized rate of over 1,600 boe/d by drilling new wells, recompleting zones in existing wellbores and optimizing the original wellbores and infrastructure system.

Historically, Hythe has been developed utilizing one vertical well per 640 acre spacing unit with one or two zones completed during the initial stage of development; subsequently additional zones were accessed as the original completions depleted. Recently, emerging technologies such as horizontal wells with mutli-stage fracture stimulations and gas frac stimulations have been utilized in conjunction with traditional drilling and completion methods to enhance production rates, reserve recovery and ultimately capital efficiency. After review of the available data, the Delphi technical team realized that incremental reserves and production volumes could be captured by drilling two wells on the 640 acre spacing units and completing the majority of the productive intervals during the initial completion phase. Subsequently, the Company applied for and received downspacing and commingling approvals from the necessary regulatory agencies for the majority of the Hythe area lands. The first stage of re-development is ongoing and has involved targeting previously identified productive intervals by drilling the second vertical well in producing spacing units and completing up to nine zones during the initial completion operations. These applications are generating low risk capital efficient reserves and production additions that are repeatable and predictable. A second stage of re-development has also been initiated and involves the application of emerging technologies such as horizontal wells with multi-stage fracture stimulations and gas fracture stimulations utilized in conjunction with traditional drilling and completion methods to enhance production rates, reserve recovery and ultimately capital efficiency of existing and emerging play types. Delphi is encouraged by the initial results realized in the second stage of re-development and is continuing to build a multi-year inventory of drilling and recompletion opportunities.

PRODUCTION / DRILLING

In 2008, average production increased 173 percent to 1,010 boe/d from average production of 584 boe/d in 2007. During the fourth quarter of 2008, average production increased 143 percent to 1,467 boe/d from 604 boe/d in the fourth quarter of 2007.

During the year ending December 31, 2008 the Company drilled ten (9.3 net) wells resulting in nine (8.3 net) gas wells and one (1.0 net) oil well for an overall success rate of 100 percent. In the fourth quarter of 2008, Delphi drilled two (2.0 net) gas wells resulting in a success rate of 100 percent.

OTHER PROPERTIES

NORTHWEST AND EAST CENTRAL ALBERTA

In addition to the Bigstone and Hythe areas, Delphi's primary producing assets in Alberta include; the Tower Creek well southwest of Bigstone, the Fontas area in northwest Alberta and several fields in east central Alberta. In 2008, average production for Alberta, excluding Bigstone and Hythe, was 1,796 boe/d and during the fourth quarter of 2008 was 1,751 boe/d. During the year ending December 31, 2008 the Company drilled two (0.2 net) wells resulting in one (0.1 net) gas well and one (0.1 net) dry hole for an overall success rate of 50 percent in these areas.

The Tower Creek well is located 60 kilometres southwest of Bigstone. In 2006, the Company participated in a successful exploration well testing the Devonian Leduc formation at 4,900 metres. The well was brought on-line in June 2007, has been producing in excess of 20,000 mcf/d since first production and has a cumulative production of 10.8 bcf of gas through December 31, 2008. In 2008, Delphi's average production from the Tower Creek well was 737 boe/d.

Fontas is located approximately 300 kilometres north of Grande Prairie. In 2008, average production was 275 boe/d from the Mississippian Debolt/ Elkton and the Cretaceous Detrital formations which are typically less than 800 metres in depth. A combination of sub-surface data, 2-D and 3-D seismic data is used to identify low-risk development wells in the existing pools and medium-risk step-out wells that create development opportunities for the following winter drilling season. At Fontas, Delphi has a 17 percent working interest in a contiguous land base in excess of 110,000 acres, the gathering system and a 40 mmcf/d processing facility that is tied into the Nova pipeline system.

The east central Alberta properties are classified by the Company as low-risk development assets located in Townships 36 to 41, Range 2 - 12 W4. Production is primarily sweet gas and medium gravity crude from shallow Cretaceous intervals with 2008 average production of 280 boe/d.

NORTHEAST BRITISH COLUMBIA

In 2008, average production was 638 boe/d and during the fourth quarter of 2008 was 763 boe/d. During the year ending December 31, 2008 the Company drilled two (1.5 net) gas wells for an overall success rate of 100 percent.

Delphi's assets in northeast British Columbia produce from various fields and formations, including the shallow Cretaceous sands at Noel, the deeper Permian Mattson at Windlfower, the Mississippian Debolt at Helmet and the deep Devonian Jean Marie and Slave Point carbonates at Helmet North and Missile. The existing northeast British Columbia assets generate positive cash flow and provide a solid base from which to build growth type properties such as Bigstone and Hythe. In addition to the indicated development type plays, Delphi has several land blocks that are on trend with emerging Montney and Horn River Basin shale resource plays.

ACQUISITIONS AND DIVESTITURES

During July 2008 Delphi acquired approximately 650 boe/d with associated proved plus probable reserves of 1.6 mmboe for a total consideration of $38.0 million. The acquired properties are located in west central Alberta and northeast British Columbia with the majority of the assets proximal to the Company's existing land base. The properties are characterized as stable, low decline, high netback production with an acquisition cost, after closing adjustments, of $49,500 per producing barrel and $20.15 per proved plus probable boe, excluding the estimated value of undeveloped land and seismic. In addition to 24,000 net acres of developed land, the acquisition included 35,000 net acres of undeveloped land and 292 kilometres of 2-D seismic. Another key component of the acquisition was the ownership in key natural gas infrastructure including; a 100 percent working interest in the Clayhurst Gas Plant with capacity of 10.0 million cubic feet per day (mmcf/d), a 5.8 percent working interest in the Progress Gas Plant with capacity of 142.0 mmcf/d and ownership in additional field compression and gathering systems throughout the properties.

In 2008, the Company disposed of three non-core assets, for a total consideration of $8.5 million, producing 96 boe/d with associated proved plus probable reserves of 309 mboe, resulting in divestiture metrics of $88,900 per boe/d and $27.47 per proved plus probable boe.

LAND

The current uncertainty in commodity pricing has created an opportunity to acquire land at a fraction of the prices observed in early 2008. Delphi has capitalized on this opportunity and over the past seven months has been successful in acquiring approximately 10,600 net acres of undeveloped land at an average price of $84/acre. The acquired lands are comprised of 7,000 net acres with defined development prospects in the Hythe area and 3,600 net acres on trend with an emerging Doig / Montney play in northeast British Columbia. Combined with a previously established land position, the recent land acquisition targeting the Doig / Montney play has resulted in a contiguous land block of 8,000 gross acres (5,250 net acres). Delphi will continue to pursue a land acquisition strategy that is complementary to our existing conventional development as well as resource type plays. As part of its business strategy of delivering sustainable long term growth, the Company views the current business environment as an opportunity to accumulate strategic undeveloped land.

EXECUTION

OPERATIONAL STATISTICS

RESERVES

GLJ Petroleum Consultants Ltd. (GLJ), an independent petroleum engineering firm, has evaluated the crude oil, natural gas and natural gas liquids reserves of the Company as at December 31, 2008 and prepared a reserves report in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities". GLJ based its evaluation on land data, well and geological information, reservoir studies, estimates of on-stream dates, contract information, operating cost data, capital budgets and future operating plans provided by the Company, information obtained from public records and GLJ's internal non-confidential files and commodity price forecast. The Audit & Reserves Committee, with the mandate of reviewing the independent engineering report, recommended the acceptance of the GLJ reserve estimates and it has been approved by the Board of Directors for the purposes of the Annual Report.

RESERVES RECONCILIATION

The reconciliation of the Company's proved, probable and proved plus probable reserves for December 31, 2008 is as follows:

RECONCILIATION OF COMPANY GROSS RESERVES (1)(2)

	Crude Oil And NGL (mbbls)			Natural Gas (mmcf)			mboe (6:1)		
	Proved	Probable	Total P+P	Proved	Probable	Total P+P	Proved	Probable	Total P+P
December 31, 2007	1,346	730	2,076	60,008	31,100	91,108	11,347	5,913	17,260
Discoveries and Extensions	454	268	722	22,780	5,555	28,336	4,251	1,193	5,444
Technical Revisions	4	(143)	(139)	4,771	(1,820)	2,951	798	(445)	353
Dispositions	(38)	(14)	(52)	(52)	(21)	(74)	(46)	(18)	(64)
Acquisitions	191	45	236	5,510	1,143	6,653	1,109	235	1,344
Sub-Total	1,956	886	2,842	93,017	35,956	128,973	17,459	6,878	24,337
Production	(295)	-	(295)	(12,164)	-	(12,164)	(2,322)	-	(2,322)
December 31, 2008	1,661	886	2,547	80,853	35,956	116,809	15,138	6,879	22,016

(1) Gross reserves represent the Company's interest before deducting royalties and including any royalty interest of the Company.

(2) Tables may not add due to rounding.

SUMMARY OF RESERVES

The following table outlines the oil, natural gas liquids and natural gas reserves of the Company by product type on a Company interest (before royalties) basis. Proved reserves increased 33 percent as compared to 2007 and proved plus probable reserves increased by 28 percent. Proved producing reserves account for 50 percent of the Company's total proved plus probable reserves.

COMPANY GROSS RESERVES (1)	2008	2007	% change
Proved producing oil & NGLs (mbbls)	**1,256**	1,079	16
Proved producing natural gas (mmcf)	**57,952**	47,845	21
Total proved producing (mboe)	**10,914**	9,053	21
Proved oil & NGLs (mbbls)	**1,663**	1,346	24
Proved natural gas (mmcf)	**80,853**	60,008	35
Total proved (mboe)	**15,138**	11,347	33
Probable oil & NGLs (mbbls)	**886**	731	21
Probable natural gas (mmcf)	**35,957**	31,100	16
Total probable (mboe)	**6,879**	5,914	16
Proved plus probable oil & NGLs (mbbls)	**2,548**	2,076	23
Proved plus probable natural gas (mmcf)	**116,809**	91,108	28
Total proved plus probable (mboe)	**22,016**	17,260	28

(1) Gross reserves represent the Company's interest before deducting royalties and including any royalty interest of the Company.

ESCALATED PRICING ASSUMPTIONS

The following table sets forth GLJ's escalated commodity price, currency exchange rate and inflation rate forecasts used in the preparation of the reserve estimates of the Company.

	West Texas Intermediate (US$/BBL)	Edmonton Light (CDN$/BBL)	AECO Spot (CCN$/MMBTU)	Exchange Rate (US$/CDN$)	Inflation (%)
2009	57.50	68.61	7.58	0.825	2.0
2010	68.00	78.94	7.94	0.850	2.0
2011	74.00	83.54	8.34	0.875	2.0
2012	85.00	90.92	8.70	0.925	2.0
2013	92.01	95.91	8.95	0.950	2.0
2014	93.85	97.84	9.14	0.950	2.0
2015	95.73	99.82	9.34	0.950	2.0
2016	97.64	101.83	9.54	0.950	2.0
2017	99.59	103.89	9.75	0.950	2.0
2018	101.59	105.99	9.95	0.950	2.0
Thereafter (1)	+2%/yr	+2%/yr	+2%/yr	0.950	2.0

(1) Percentage change of 2.00% represents the change in future prices each year after 2018 to the end of the reserve life.

NET PRESENT VALUE OF RESERVES – ESCALATED PRICING (1) (2)

The net present values of future net revenue of the Company's reserves at various discount rates on a before income tax basis are outlined below.

($Thousands)	Undiscounted	Discounted at 8%	Discounted at 10%
Proved			
Developed producing	298,580	215,625	202,017
Developed non-producing	45,775	30,914	28,535
Undeveloped	58,732	27,267	22,640
Total proved	**403,087**	**273,806**	**253,192**
Probable	209,435	98,263	84,554
Total proved plus probable	**612,522**	**372,069**	**337,746**

(1) Before income taxes and reclamation costs.

(2) As required by NI 51-101, undiscounted well abandonment costs of $7.8 million for total proved and $9.3 million for total proved plus probable; 8% discounted well abandonment costs of $4.0 million for total proved and $3.8 million for total proved plus probable; 10% discounted well abandonment costs of $3.5 million for total proved and $3.3 million for total proved plus probable are included in the net present value determinations.

FINDING AND DEVELOPMENT COSTS

The Company has presented its finding and development costs in accordance with NI 51-101. The Company has also calculated finding and development costs including acquisitions and dispositions. All-in finding and development cost (including change future development costs) at the Company's key property Hythe, where the Company spent approximately half of its development capital, was $14.25/boe on a proved plus probable basis.

	2008	2007	2006-2008 Average
Capital invested ($000's)			
Land and seismic	**1,508**	611	16,112
Drilling and completion	**53,451**	38,417	215,528
Other	**4,248**	2,261	9,779
Facilities	**17,572**	10,635	112,643
	76,779	51,924	354,062
Change in future development costs			
Proved reserves	**30,949**	(5,971)	38,973
	107,728	45,953	393,035
Probable reserves	**9,066**	(670)	18,295
Total on-stream costs	**116,794**	45,283	411,330
Acquisitions	**38,120**	10,871	101,452
Dispositions	**(8,450)**	(15,502)	(64,732)
Total capital invested	**146,464**	40,652	448,050
Reserve discoveries, extensions and revisions			
Proved (mboe)	**5,049**	2,280	13,835
Proved plus probable reserves (mboe)	**5,797**	3,454	18,277
Reserve acquisitions and dispositions			
Proved (mboe)	**1,063**	(380)	2,255
Proved plus probable reserves (mboe)	**1,280**	(1,563)	1,492
Reserve net additions (1)			
Proved (mboe)	**6,112**	1,901	16,091
Proved plus probable reserves (mboe)	**7,077**	1,892	19,770
Finding and development costs ($/boe) (2)			
On-stream costs excluding future development costs			
Proved	**15.21**	22.77	25.59
Proved plus probable reserves	**13.24**	15.03	19.37
On-stream costs including future development costs			
Proved	**21.34**	20.15	28.41
Proved plus probable reserves	**20.15**	13.11	22.51
Total capital invested			
Proved	**22.48**	21.74	26.71
Proved plus probable reserves	**20.70**	21.49	22.66

(1) Includes discoveries, extensions, revisions, acquisitions and dispositions.

(2) The aggregate of the exploration and development costs incurred in the most recent financial year, included in capital invested, and the change in estimated future development costs, generally will not reflect total finding and development costs related to reserve additions for that year.

RESERVE LIFE INDEX

The reserve life index of Delphi has been calculated by using average 2008 production of 6,345 boe/d. The reserve life index is 9.5 years on a proved plus probable basis.

	Crude Oil and NGL (mbbls)			Natural Gas (mmcf)			Mboe (6:1)		
	Proved	Probable	Total	Proved	Probable	Total	Proved	Probable	Total
Reserves - Dec. 31, 2008	1,661	886	2,547	80,853	35,956	116,809	15,138	6,879	22,016
Production	295		295	12,164		12,164	2,322		2,322
Reserves life index (years)	5.6		8.6	6.6		9.6	6.5		9.5

RESERVES PER OUTSTANDING COMMON SHARE

The proved plus probable reserves per 1,000 common shares of the Company was 278.4 compared to 253.6 in the previous year, an increase of ten percent.

	2008	2007	%Change
Proved and probable reserves (mboe)	**22,016**	17,260	28
Proved and probable boe reserves per 1,000 outstanding common share	**278.4**	253.6	10

ACREAGE SUMMARY

The Company's total and undeveloped landholdings by geographic focus area as at December 31, 2008 are outlined below.

	Total		Undeveloped		
December 31, 2008 (acres)	Gross	Net	Gross	Net	Fair Market Value [1]
Alberta	415,621	163,072	228,960	100,551	$ 10,255,737
British Columbia	153,905	44,399	86,519	24,808	$ 3,934,062
Total	569,526	207,471	315,479	125,359	$ 14,189,799

(1) Undeveloped land value of $14.2 million at December 31, 2008 for undeveloped land based on Seaton-Jordan & Associates Ltd. land valuation report.

RECYCLE RATIO

The recycle ratio is a measure of the effectiveness of the Company's re-investment program. The recycle ratio is a key indicator in the oil and gas industry of efficiency and profitability and is calculated by dividing the finding and development costs for total capital invested into the Company's operating netback.

Year ended December 31	2008	2007
Operating netback ($/boe)	**33.83**	30.76
Proved plus probable reserves F&D costs ($/boe)	**20.70**	21.49
Proved plus probable recycle ratio	**1.63**	1.43

NET ASSET VALUE

The net asset values of the Company for December 31, 2008 at a discount rate of eight and ten percent before taxes are summarized below.

($ thousands except per share value)	8%	10%
Estimated net future revenues of proved plus probable reserves discounted [1]	372,069	337,746
Undeveloped land	14,190	14,190
Mark-to-market value of hedging contracts	7,109	7,109
In-the-money option proceeds [3]	-	-
Total asset value	**393,368**	**359,045**
Bank debt plus working capital deficiency	(109,237)	(109,237)
Net asset value	**284,131**	**249,808**
Common shares outstanding and in-the-money options	79,067,158	79,067,158
Net asset value per share	**3.59**	**3.16**

(1) Before income taxes and reclamation costs.

(2) Undeveloped land and seismic includes value of $14.2 million at December 31, 2008 for undeveloped land based on Seaton-Jordan & Associates Ltd. land valuation report.

(3) In-the-money option proceeds are based on the closing December 31, 2008 share price of $0.99.

(4) The Company estimates it has approximately $200 million of tax deductions available to offset future taxable income.

STRATEGY EXECUTION RESULTS

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)
Independent Businessman

Robert A. Lehodey, Q.C. (2)
Partner
Osler, Hoskin & Harcourt LLP

Andrew E. Osis (1)
Chief Executive Officer and Director
Multiplied Media Corporation

Lamont C. Tolley (1)
Independent Businessman

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

OFFICERS

David J. Reid
President and Chief Executive Officer

Tony Angelidis
Senior Vice President Exploration

Hugo H. Batteke
Vice President Operations

Rod A. Hume
Vice President Engineering

Michael S. Kaluza
Chief Operating Officer

Brian P. Kohlhammer
Vice President Finance and
Chief Financial Officer

CORPORATE OFFICE

300, 500 – 4th Avenue S.W.
Calgary, Alberta
T2P 2V6

Telephone: (403) 265-6171
Facsimile: (403) 265-6207
Email: info@delphienergy.ca
Website: www.delphienergy.ca

AUDITORS

KPMG LLP

BANKERS

National Bank of Canada
The Bank of Nova Scotia

LEGAL COUNSEL

Osler, Hoskin & Harcourt LLP

INDEPENDENT ENGINEERS

GLJ Petroleum Consultants Ltd.

TRANSFER AGENT

Olympia Trust Company

STOCK EXCHANGE LISTING

Toronto Stock Exchange – DEE

ANNUAL GENERAL MEETING

May 21, 2009, Calgary, Alberta

ABBREVIATIONS

bbls	barrels
bbls/d	barrels per day
mbbls	thousand barrels
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
NGL	natural gas liquids
bcf	billion cubic feet
boe	barrels of oil equivalent (6 mcf:1 bbl)
boe/d	barrels of oil equivalent per day
mmboe	million barrels of oil equivalent
GJ	gigajoules

STRATEGY EXECUTION RESULTS DELPHI DELIVERS

DELPHI ENERGY CORP.

2008 MANAGEMENT DISCUSSION & ANALYSIS
AND CONSOLIDATED FINANCIAL STATEMENTS

CORPORATE PROFILE

Delphi Energy Corp. is a public company primarily engaged in the acquisition, exploration for and development and production of crude oil, natural gas and natural gas liquids from properties located in Western Canada. Delphi's operations, producing approximately 6,700 boe/d, are principally concentrated in three core regions: (i) northwest Alberta, (ii) northeast British Columbia, and (iii) east central Alberta, with an overall focus on natural gas production. The Company has three primary core areas at Bigstone, Hythe and Tower Creek, all located in northwest Alberta, which comprise over 5,000 boe/d of production.

The Company is focused on conventional multi-zone vertical well opportunities blended with complementary horizontal well resource plays to generate a balance between the superior flowing barrel efficiency of conventional drilling with the more attractive finding and development costs of resource plays.

RESULTS

MANAGEMENT DISCUSSION AND ANALYSIS

(ALL TABULAR AMOUNTS ARE STATED IN THOUSANDS OF DOLLARS, EXCEPT PER UNIT AMOUNTS)

The management discussion and analysis has been prepared by management and reviewed and approved by the Board of Directors of Delphi Energy Corp. ("Delphi" or "the Company"). The discussion and analysis is a review of the financial results of the Company based upon accounting principles generally accepted in Canada. Its focus is primarily a comparison of the financial performance for the three and twelve months ended December 31, 2008 and 2007, and should be read in conjunction with the audited financial statements and accompanying notes for the years ended December 31, 2008 and 2007. The discussion and analysis has been prepared as of March 17, 2009.

DELPHI'S BUSINESS

Delphi is a public company primarily engaged in the acquisition, exploration for and development and production of crude oil, natural gas and natural gas liquids from properties located in Western Canada. Delphi's operations are principally concentrated in three core regions: (i) northwest Alberta, (ii) northeast British Columbia, and (iii) east central Alberta with an overall focus on natural gas production. The Company has three primary core areas at Bigstone, Hythe and Tower Creek, all located in northwest Alberta which comprise approximately 5,000 boe/d of production.

OPERATIONAL AND FINANCIAL HIGHLIGHTS

Delphi achieved record production in 2008 with average daily volumes of 6,345 barrels of oil equivalent per day (boe/d), an increase of 19 percent compared to 2007. Production volumes increased on a quarter over quarter basis throughout the year from an average of 6,056 boe/d in the first quarter to 6,708 boe/d in the fourth quarter, an increase of 11 percent. Fourth quarter sales volumes represent record production for the Company. Natural gas production comprised 87 percent of the Company's average production.

Several accomplishments were achieved in 2008 through the Company's capital program including:

- the continued growth in production of its core area of Hythe, Alberta to over 1,600 boe/d from 400 boe/d at the time of acquisition in September 2007;
- an increase in total proved reserves of 33 percent to 15.1 million barrels of oil equivalent and an increase in total proved plus probable reserves of 28 percent to 22.0 million barrels of oil equivalent;
- drilling of 23 (16.7 net) wells with an overall success rate of 96 percent and drilling three (2.5 net) natural gas wells resulting in a 100 percent success rate in the fourth quarter;
- an increase in total proved plus probable reserves per basic share outstanding of 10 percent; and
- the acquisition of approximately 650 boe/d and 35,000 net acres of undeveloped land in the Peace River Arch area of northwest Alberta and northeast British Columbia.

Funds flow from operations in 2008 was $68.7 million or $0.94 per basic share, compared to $48.5 million or $0.72 per basic share in 2007, primarily as a result of higher average oil and natural gas prices for the year and growth in production volumes. For the year ended December 31, 2008, the Company recognized approximately $0.1 million in realized gains on financial and physical hedging contracts. For the three months ended December 31, 2008, Delphi recognized approximately $1.6 million in realized gains on Canadian dollar denominated physical contracts, included in natural gas revenue, and recognized a realized gain of approximately $0.4 million on financial contracts and US dollar denominated physical contracts.

On July 17, 2008, the Company closed an equity offering of 6,316,000 common shares at $2.85 per share and 3,530,000 flow-through common shares at $3.40 per share for proceeds of approximately $30.0 million (net proceeds of $28.0 million). In late July 2008, the Company completed the acquisition of oil and natural gas properties for $38.0 million, after closing adjustments, in the Peace River Arch area of northwest Alberta and northeast British Columbia. The acquisition was funded by the net proceeds of the equity offering and the Company's credit facilities.

Delphi's financial position continues to remain strong at the end of 2008, providing financial flexibility to execute its 2009 capital program and participate in farm-in, joint venture or acquisition opportunities. At December 31, 2008, the Company had net debt of $109.2 million on total credit facilities of $140.0 million, providing excess financial capacity of approximately $30.8 million. On an annualized fourth quarter funds from operations basis, Delphi's net debt to cash flow ratio was 2.0 times. Net debt includes bank debt plus working capital deficiency excluding the risk management asset/liability and the related current future income taxes.

The current credit facilities were confirmed by the Company's lenders upon completion of their semi-annual review in October, 2008. The annual credit review by the Company's lenders is expected to be completed by May 31, 2009. This detailed review will be based upon the Company's December 31, 2008, reserves engineering report and will take into consideration current production and the results of the winter drilling program. The borrowing base is determined using the Company's year-end engineering report, primarily proved producing reserves, which increased 21 percent over the previous year and the outlook for commodity prices.

BUSINESS ENVIRONMENT

BENCHMARK PRICES

	Three Months Ended December 31			Twelve Months Ended December 31		
	2008	2007	% Change	**2008**	2007	% Change
Natural Gas						
NYMEX (US $/mmbtu)	**6.83**	7.03	(3)	**8.92**	6.91	29
AECO (CDN $/mcf)	**6.70**	6.15	9	**8.16**	6.44	27
Crude Oil						
West Texas Intermediate (US $/bbl)	**58.73**	90.68	(35)	**99.65**	72.31	38
Edmonton Light (CDN $/bbl)	**63.21**	86.42	(27)	**102.16**	76.35	34
Foreign Exchange						
Canadian to US dollar	**1.21**	0.98	23	**1.06**	1.08	(2)
US to Canadian dollar	**0.82**	1.02	(20)	**0.94**	0.93	1

NATURAL GAS

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

While partially influenced by the strength of crude oil price changes, natural gas price changes are predominantly based on supply and demand fundamentals in the North American market. In the first quarter, with global natural gas prices considerably higher than the prices in the United States, LNG imports to the US throughout the winter were less than average and significantly less than the peak imports during the summer of 2007. Cold winter weather persisted to the end of March 2008 in the major natural gas consuming regions of central Canada and the northeast United States. By the end of the natural gas withdrawal season, an increase of over 400 billion cubic feet had been taken out of natural gas storage compared to the previous withdrawal season. Natural gas in storage in the United States had been drawn down below five year average levels, a key measure of supply.

In the second quarter, LNG imports to the United States continued to remain below the historical average, also well below the record injections in the spring of 2007, as world prices for natural gas provided greater economic returns to offshore LNG producers than the US market prices. The continuing increase in crude oil prices through to the end of the second quarter also had a positive effect on the rise in natural gas prices reaching a high of $11.77 per mcf for AECO near the end of the second quarter.

In the third quarter, the collapse of all commodity prices began on the heels of financial and economic turmoil in the credit and capital markets. More specifically in the case of natural gas, hurricane activity in the Gulf of Mexico was minimal, domestic US natural gas production continued to grow thereby increasing storage levels and summer temperatures were moderate resulting in lower demand for the generation of electricity through natural-gas fired power plants to operate air conditioners. During the third quarter, the AECO average daily spot price ranged from a high of $11.83 per mcf early in the quarter to a low of $5.79 per mcf at the end of the third quarter.

In the fourth quarter of 2008, natural gas prices rose from the lows in the third quarter and were between $6.00 and $7.00 per mcf until the end of the year. Prices were stabilizing in anticipation of normal withdrawals of natural gas from storage to meet winter heating demand. The US Midwest and central Canada were experiencing continuous cold weather resulting in reasonable winter heating demand. However, the US Northeast, representing the largest proportion of winter heating demand, experienced above average temperatures and industrial demand was also less than normal due to the economic uncertainty. AECO averaged $6.70 per mcf in the fourth quarter but has been on a steady decline since the end of the year.

For internal forecasting purposes, Delphi is expecting a volatile natural gas market in 2009 and anticipates AECO to average between $4.25 and $5.50 per mcf. Delphi continues to monitor the variables affecting the price of natural gas in order to ensure its capital program is in line with expected funds flow from operations.

CRUDE OIL

West Texas Intermediate at Cushing, Oklahoma (WTI) is the benchmark reference for North American crude oil prices. Canadian crude oil prices are based upon postings, primarily at Edmonton, Alberta and represent the WTI price adjusted for quality and transportation differentials as well as the US/CDN dollar exchange rate.

2008 began as another excellent year for crude oil prices which continued to increase, reaching over US $100.00 per barrel by the end of the first quarter, on continued strong global demand, production disruptions, never ending geopolitical unrest in major producing regions and the devaluation of the US dollar. The outlook for the price of oil was bullish despite its lofty heights.

The second quarter of 2008 maintained the momentum for crude oil prices which continued to increase, approaching US $145.00 per barrel late in the second quarter, for the same reasons as in the previous quarter. The outlook for oil remained strong despite growing concerns over the US and global economies.

Through the third and fourth quarters of 2008 the price for crude oil suffered its free fall as the US banking system imploded and the prospects of a global recession gripped the world, significantly reducing demand for all commodities other than gold. Crude oil experienced a low of US $33.87 on December 19, 2008, a drop of 77 percent from the high in July of US $145.29 per barrel. WTI averaged US $99.65 per barrel for the year and US $58.73 per barrel for the three months ended December 31, 2008. For the year, the average WTI price was 38 percent higher than in 2007 but in the fourth quarter, WTI was 35 percent lower than the comparative quarter in 2007.

For Canadian producers the realized price of light crude oil for most of the year was very similar to the price of West Texas Intermediate due to the Canadian dollar remaining around parity with the US dollar. In the fourth quarter of 2008, however, the value of the Canadian dollar decreased against its US counterpart as the demand for the United States dollar rose significantly as investors viewed the US dollar as a relatively low-risk investment (safe haven) during these uncertain times. This positive effect to the price of oil for Canadian producers was partially offset by a widening basis differential between US and Canadian markets.

Prices for heavy oil and other lesser quality crude oils trade at a discount or differential to light crude oil due to the additional costs involved in the refining process. The average differential in 2008 was $17.76 per barrel compared to $22.83 per barrel in 2007. The decrease in the average differential and higher light oil prices, resulted in Bow River crude prices averaging $84.40 per barrel compared to $53.52 per barrel in 2007.

For internal forecasting purposes, Delphi anticipates WTI to average between US $40.00 to $60.00 per barrel for 2009 with the Canadian dollar to remain between $1.15 and $1.30 per US dollar.

INDUSTRY COST OF SERVICES

For oil and natural gas producers, lower costs of oilfield services were experienced throughout 2008. The drop in commodity prices in the latter half of the year in combination with the New Royalty Framework effective January 1, 2009 have had a significant negative effect on cash flow available for capital programs and hence drilling and field activity. Drilling contractors and oilfield service companies have had to reduce the rates charged for equipment and labour in order to remain competitive. The overall uncertainty in the credit and capital markets has also led to reduced demand for oilfield services and equipment heading into the winter drilling season.

FINANCIAL STRATEGY

The Company maintains an active risk management program as an integral part of its overall financial strategy to mitigate volatility in funds from operations resulting from fluctuating commodity prices. Delphi's program involves executing numerous contracts over a period of time to take advantage of the volatility in the natural gas market. The strategy takes advantage of the upward swings in natural gas prices as a result of a) the changes in demand/supply fundamentals and/or b) the movement of significant financial assets invested in the natural gas market as a pure commodity play. The transactions are generally undertaken for contract terms 12 to 24 months in advance with financially strong counterparties, predominantly executed on a physical basis with the Company's natural gas marketer. Delphi's risk management program consists of fixed price contracts, costless collars, participating swaps and puts and calls which provide downside protection along with the opportunity to share in the upside if market prices increase above the floor price for the costless collar, participating swaps and puts. If market prices are above fixed price contracts or the ceiling price of costless collars and calls, the Company would continue to achieve its downside protection while realizing losses on these hedging contracts.

Delphi has a strategy of hedging approximately 40 to 50 percent of its natural gas production as long as demand/supply fundamentals indicate volatile markets in the future. Currently, Delphi has hedged approximately 50 percent of its before-royalty natural gas production at a predominantly AECO based average floor price of $7.42 per mcf for 2009. This compares to the current forward 2009 strip commodity price for AECO of $4.54 per mcf. The following natural gas hedges are in place to support the Company's cash flow.

	Jan-Mar 2009	Apr-Oct 2009	Nov-Mar 2009/2010	Apr-Dec 2010	2009	2010
Production hedged (mmcf/d)	15.8	19.0	13.1	6.6	17.9	7.6
Percentage of production*	44%	53%	36%	18%	50%	21%
Price floor (CDN $/mcf)	7.66	7.38	7.51	6.39	7.42	6.88

* based on 36 mmcf/d

The fair value of the outstanding hedges is estimated to be approximately $13.2 million as of March 5, 2009.

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

Delphi continues to direct efforts at maintaining or reducing its controllable costs. Increasing production at its various operating fields through Company owned infrastructure reduces fixed costs on a per boe basis and improves netbacks. Field operators are encouraged to undertake preventative maintenance on field infrastructure and wellsite equipment to minimize production downtime and prevent significant operating costs associated with repairs. The Company strives to achieve improvement in its costs of production and at a minimum maintain current production costs.

Maintaining or improving strong operating netbacks per boe through the risk management program and the control of costs associated with production operations, allows the Company to pursue its planned capital program with greater confidence that financial flexibility will be maintained while incurring capital expenditures to grow production volumes. The Company strives to maintain a minimum operating netback per boe in the $29.00 to $31.00 range as it has in the past four years. The risk management program has been and will continue to be an integral part of ensuring operating netbacks in this range during periods of price volatility and excess natural gas supply.

The annual net capital expenditure program will continue to be slightly less than forecast funds from operations. Additional capital may be approved as a result of opportunistic acquisitions, incremental cash flow from greater than expected production growth, higher than forecast cash netbacks or other sources of financing.

Delphi continues to be focused on reducing its leverage and improving its financial flexibility through net debt reduction or increasing funds flow growth resulting in a lower net debt to annualized quarterly funds from operations ratio. The Company continues to be focused on achieving its internal target range for this ratio of 1.3 to 1.5 times. In a low price environment, the Company's objective would be to reduce or at least maintain the net debt balance by undertaking a capital program within cash flow.

SELECTED INFORMATION

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

	Dec. 31 2008	**Sept. 30 2008**	**Jun. 30 2008**	**Mar. 31 2008**	Dec. 31 2007	Sept. 30 2007	Jun. 30 2007	Mar. 31 2007
Production								
Natural gas (mcf/d)	**35,545**	**33,691**	**31,898**	**31,777**	30,610	28,196	26,967	21,658
Oil (bbl/d)	**431**	**372**	**368**	**387**	346	579	423	366
Natural gas liquids (bbl/d)	**353**	**421**	**517**	**372**	420	422	461	346
Barrels of oil equivalent (boe/d)	**6,708**	**6,409**	**6,202**	**6,056**	5,868	5,700	5,379	4,322
Financial								
($ thousands except per unit amounts)								
Petroleum and natural gas revenue	**30,160**	**34,461**	**38,569**	**32,212**	26,632	24,548	24,779	21,974
Funds from operations	**13,473**	**18,160**	**19,965**	**17,059**	13,747	12,600	11,469	10,665
Per share – basic	**0.18**	**0.24**	**0.29**	**0.25**	0.20	0.19	0.17	0.17
Per share – diluted	**0.18**	**0.23**	**0.28**	**0.25**	0.20	0.18	0.17	0.17
Net earnings (loss)	**(959)**	**6,743**	**49**	**(739)**	1,732	(1,348)	797	(11,653)
Per share – basic	**(0.01)**	**0.09**	**-**	**(0.01)**	0.03	(0.02)	0.01	(0.18)
Per share – diluted	**(0.01)**	**0.09**	**-**	**(0.01)**	0.03	(0.02)	0.01	(0.18)

Production for the last eight consecutive quarters reflects the following events: In 2007 success at Bigstone, Alberta throughout the year and Noel, British Columbia in the third quarter complemented the mid-year start up of production at Tower Creek, Alberta resulting in consistent quarter over quarter production growth. In 2008, the combination of a successful winter and summer capital program and the production increase from the acquisition resulted in continued production growth quarter over quarter. Revenue and funds from operations reflect the cycle of natural gas prices and production volumes.

Natural gas prices over the past two years have reflected the cyclical nature of demand. Higher prices in the winter months, reflecting demand for heating, weaken through the summer months as production is placed in storage for the upcoming heating season demand. In the first quarter of 2007, net earnings were significantly reduced by the impairment of goodwill in the amount of $12.1 million. Natural gas prices in the second quarter of 2008 did not follow the cyclical trend expected, as prices continued to increase coming out of the winter heating season due to concerns over natural gas supply in storage and the continued increase in crude oil prices. In 2008, the Company achieved record cash funds flow of $68.7 million or $0.94 per basic share due to continued production growth and increased natural gas and crude oil prices.

	2008	2007	2006
Revenue	**135,402**	97,933	94,189
Net earnings/(loss)	**5,094**	(10,472)	6,903
Total assets	**364,538**	311,740	326,668
Bank debt plus working capital	**109,237**	100,658	118,178

The increase in revenue from 2007 to 2008 was due to production increasing from 5,323 boe/d to 6,345 boe/d as well as high realized prices in the second and third quarters of 2008. The change in net earnings (loss) from 2006 to 2007 was primarily due to the impairment of goodwill recorded in March 2007. The increase in total assets from 2007 to 2008 relates partly to the Peace River Arch aquisition undertaken in July 2008, as well as a successful 2008 capital program.

DRILLING RESULTS

	Three Months Ended December 31, 2008		Twelve Months Ended December 31, 2008	
	Gross	Net	Gross	Net
Natural gas wells	3.0	2.5	20.0	14.6
Oil wells	-	-	2.0	2.0
Dry holes	-	-	1.0	0.1
Total wells	3.0	2.5	23.0	16.7
Success rate (%)	100	100	96	99

The Company had another successful year with the drill bit resulting in a drilling success rate of 96 percent. The Company has in excess of one hundred drilling locations identified within its core areas of operations.

CAPITAL INVESTED

	Three Months Ended December 31			Twelve Months Ended December 31		
	2008	2007	% Change	2008	2007	% Change
Land	612	(26)	-	742	204	264
Seismic	44	(30)	-	766	407	88
Drilling and completions	9,282	13,188	(30)	53,672	38,417	40
Equipping and facilities	4,725	3,693	28	17,572	10,635	65
Capitalized expenses	839	578	45	3,273	2,261	45
Other	158	(412)	-	754	-	100
Capital invested	15,660	16,991	(8)	76,779	51,924	48
Disposition of properties	-	-	-	(8,450)	(15,502)	(45)
Net capital invested	15,660	16,991	(8)	68,329	36,422	88
Acquisition of properties	174	-	100	38,120	10,871	251
Total capital	15,834	16,991	(7)	106,449	47,293	125

In 2008, Delphi's net capital expenditure program was $106.4 million, an increase of 125 percent over 2007 due to an increase in drilling and completions, facility upgrades completed in core areas and the Peace River Arch acquisition which closed mid 2008. The net field capital program of $68.3 million was funded entirely from internally generated cash flow, consistent with prior years and the Company's strategy. Approximately 71 percent of capital invested in 2008 was directed at drilling and completions to increase the Company's production and reserve base.

PRODUCTION

	Three Months Ended December 31			Twelve Months Ended December 31		
	2008	2007	% Change	2008	2007	% Change
Natural gas (mcf/d)	35,545	30,610	16	33,236	26,886	24
Crude oil (bbls/d)	431	346	25	390	429	(9)
Natural gas liquids (bbls/d)	353	420	(16)	416	413	1
Total (boe/d)	6,708	5,868	14	6,345	5,323	19

Production for the twelve months ended December 31, 2008, averaged 6,345 boe/d representing an increase of 19 percent over the comparative period primarily due to the successful drilling and optimization programs at Bigstone and Hythe and the closing of the acquisition in the Peace River Arch area by the end of July, 2008. Delphi continues to achieve steady growth and delivered its seventh consecutive quarter of production growth in the fourth quarter of 2008. The Bigstone and Hythe areas continue to lead the way in production and growth contributing 63 percent of Delphi's fourth quarter volumes. Production at Hythe, Alberta has grown from 400 boe/d at the time of acquisition in September 2007 to over 1,600 boe/d. A significant undeveloped land base, multi-zone potential and the successful application of emerging technologies continue to provide material growth opportunities in existing and new play concepts. The Company's production portfolio for the year was weighted 87 percent to natural gas, six percent to crude oil and seven percent to natural gas liquids. Production for the three months ended December 31, 2008, increased to 6,708 boe/d, 14 percent higher than the comparative period.

Natural gas volumes increased to 33.2 mmcf/d in 2008, representing a 24 percent increase over 2007. Fourth quarter production of natural gas in 2008 was 16 percent greater than the prior year. The increase in natural gas volumes for the quarter and the year were largely as a result of the growth in production volumes at Hythe, Alberta.

Crude oil production for 2008 was nine percent less than the previous year, primarily due to a minor disposition during the year and natural production declines. For the fourth quarter of 2008, crude oil production was 25 percent higher than the comparative period due to oil discoveries at Hythe and Bigstone through the year. Natural gas liquids production remained unchanged from the previous year despite the growth in natural gas production, primarily as a result of increased natural gas production at Hythe, which has a lower liquids-rich content.

REALIZED SALES PRICES

	Three Months Ended December 31			Twelve Months Ended December 31		
	2008	2007	% Change	**2008**	2007	% Change
AECO ($/mcf)	**6.70**	6.15	9	**8.16**	6.44	27
Heating content and marketing ($/mcf)	**0.83**	0.40	108	**0.59**	0.51	16
Gain (loss) on physical contracts ($/mcf)	**0.50**	0.80	(38)	**(0.01)**	0.95	-
Gain (loss) on financial contracts ($/mcf)	**0.11**	0.26	(58)	**0.02**	0.15	(87)
Realized natural gas price ($/mcf)	**8.14**	7.61	7	**8.76**	8.05	9
Realized oil price ($/bbl)	**54.55**	71.10	(23)	**89.88**	61.28	47
Realized natural gas liquids price ($/bbl)	**28.11**	76.03	(63)	**80.49**	62.28	29
Total realized sales price ($/boe)	**48.87**	49.33	(1)	**58.31**	50.41	16

For the three and twelve months ended December 31, 2008, Delphi's risk management program realized a gain of $2.0 million and $0.1 million, respectively. For the fourth quarter, the realized gain was $0.61 per mcf with physical contracts contributing a gain of $0.50 per mcf and financial contracts contributing a gain of $0.11 per mcf. For the year ended December 31, 2008, the average realized natural gas price was nine percent higher than 2007. This increase was primarily due to the heating content of the Company's natural gas and marketing arrangements.

Excluding hedges, the Company continues to receive higher than the AECO spot price on natural gas sales due to the high heating content of its natural gas production and the sale of approximately 3,500 million British thermal units (mmbtu) per day on the Alliance pipeline which is priced at the Chicago Monthly Index.

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

	Dec. 31 2008	Sept. 30 2008	Jun. 30 2008	Mar. 31 2008	Dec. 31 2007	Sept. 30 2007	Jun. 30 2007	Mar. 31 2007
Natural Gas Price								
Delphi realized ($/mcf)	**8.14**	**8.28**	**9.77**	**8.91**	7.61	7.20	8.20	9.61
AECO average ($/mcf)	**6.70**	**7.73**	**10.22**	**7.97**	6.15	5.14	7.06	7.40
Premium (discount) to AECO	**21%**	**7%**	**(4%)**	**12%**	24%	40%	16%	30%
Hedging gain (loss) ($000's)	**1,985**	**(67)**	**(3,153)**	**1,371**	2,996	3,875	1,130	2,780

Delphi's oil production is slightly better than medium grade oil; therefore the Company's average price fluctuates with the change in the benchmark crude oil prices and the quality differential. Increased production of light oil at Bigstone and Hythe continues to high grade the Company's quality of crude oil resulting in pricing more reflective of light oil. Realized natural gas liquids prices have increased for the year due to the increase in the price received for condensate, the primary component of the Company's natural gas liquids production. In the fourth quarter, the Company's realized crude oil and natural gas liquids prices were significantly lower than the comparative quarter in the previous year as a result of the significant drop in the benchmark crude oil prices.

The average realized price per boe increased 16 percent to $58.31 per boe in 2008 as compared to $50.41 per boe in the previous year. The average realized price per boe for the fourth quarter was virtually unchanged from the comparative period.

RISK MANAGEMENT ACTIVITIES

Delphi enters into both financial and physical commodity contracts as part of its risk management program to manage commodity price fluctuations designed to ensure sufficient cash is generated to fund its capital program particularly when commodity prices are extremely volatile. Delphi makes a concerted effort to hedge production volumes at prices greater than the upper limit of the historical three-to five-year AECO price range of $5.25 to $8.40 per mcf and is quick to react to price aberrations such as those experienced at the end of 2005 and the summer of 2008. Another component of the risk management program is to layer in contracts over a period of time, as opposed to locking in a significant portion of volumes at any one point in time, to take advantage of unexpected price spikes. For natural gas production, Delphi has hedged approximately 50 percent of its before-royalty natural gas production at a predominately AECO based average floor price of $7.42 per mcf for 2009.

With respect to financial contracts, which are derivative financial instruments, management has elected not to use hedge accounting and consequently records the fair value of its natural gas financial contracts on the balance sheet at each reporting period with the change in the fair value being classified as unrealized gains and losses in the statement of earnings. The changes in the fair value of the United States dollar denominated physical contracts are also classified as unrealized gains and losses in the statement of earnings.

The Company recognized an unrealized non-cash gain on risk management activities for the year ended December 31, 2008, of $0.6 million and an unrealized non-cash gain of $0.6 million on financial contracts in the fourth quarter of 2008. The fair values of these contracts are based on an approximation of the amounts that would have been paid to or received from counterparties to settle the contracts outstanding at the end of the period having regard to forward prices and market values provided by independent sources. Due to the inherent volatility in commodity prices, actual amounts realized may differ from these estimates.

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

Time Period	Commodity	Type of Contract	Quantity Contracted	Contract Price ($/unit)
April 2008 – March 2009	Natural Gas	Physical	2,000 GJ/d	$7.30 fixed
November 2008 – March 2009	Natural Gas	Physical	4,000 GJ/d	$7.46 fixed
November 2008 – March 2009	Natural Gas	Financial	2,000 GJ/d	$7.62 fixed
November 2008 – March 2009	Natural Gas	Physical	2,000 GJ/d	$7.00 floor/$8.05 ceiling
November 2008 – March 2009	Natural Gas	Physical	2,000 mmbtu/d	US $9.00 fixed
November 2008 – March 2009	Natural Gas	Financial	1,000 GJ/d	$8.00 floor/$11.07 ceiling
April 2009 – October 2009	Natural Gas	Physical	1,000 GJ/d	$7.08 fixed
April 2009 – October 2009	Natural Gas	Physical	2,000 GJ/d	$8.25 floor/$10.00 ceiling
April 2009 – October 2009	Natural Gas	Physical	1,000 mmbtu/d	US $8.18 fixed
April 2009 – October 2009	Natural Gas	Physical	2,000 GJ/d	$8.59 fixed
April 2009 – October 2009	Natural Gas	Physical	2,000 GJ/d	$6.70 floor plus 50% > $6.70
April 2009 – March 2010	Natural Gas	Physical	3,000 GJ/d	$7.52 fixed
April 2009 – March 2010	Natural Gas	Physical	2,000 GJ/d	$6.80 floor plus 50% > $6.80
November 2009 – March 2010	Natural Gas	Physical	2,000 GJ/d	$7.75 floor/$8.70 ceiling
November 2009 – March 2010	Natural Gas	Physical	2,000 GJ/d	$7.26 floor plus 50% > $7.26
November 2009 – March 2010	Natural Gas	Physical	2,000 GJ/d	$7.65 floor plus 50% > $7.65
April 2010 – December 2010	Natural Gas	Physical	3,000 GJ/d	$6.25 floor/$7.47 ceiling
April 2010 – December 2010	Natural Gas	Physical	4,000 GJ/d	$5.93 floor plus 50% > $5.93
February 2009 – December 2009*	Natural Gas	Financial	3,500 GJ/d	$6.00 Put
March 2009 – December 2009*	Natural Gas	Physical	3,500 GJ/d	$6.00 Put
January 2010 – December 2010*	Natural Gas	Financial	3,500 GJ/d	$7.40 Call
January 2010 – December 2010*	Natural Gas	Physical	3,500 GJ/d	$7.15 Call

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

The Company accounts for its Canadian dollar physical sales contracts, which were entered into and continue to be held for the purpose of delivery of production, in accordance with its expected sale requirements as executory contracts on an accrual basis rather than as non-financial derivatives.

REVENUE

	Three Months Ended December 31			Twelve Months Ended December 31		
	2008	2007	% Change	**2008**	2007	% Change
Natural gas (including physical hedges)	**26,623**	20,696	29	**106,284**	77,495	37
Crude oil	**2,163**	2,263	(4)	**12,830**	9,596	34
Natural gas liquids	**913**	2,769	(67)	**12,255**	9,168	34
Sulphur	**93**	169	(45)	**3,755**	220	1,607
Realized gain on risk management	**368**	735	(50)	**278**	1,454	(81)
Total	**30,160**	26,632	13	**135,402**	97,933	38

The 38 percent increase in revenue for the twelve months ended December 31, 2008, over the comparative period, is attributed to the 19 percent increase in production volumes and the 16 percent increase in realized sales price per boe. For the three months ended December 31, 2008, revenue increased 13 percent over the comparative period due to a 14 percent increase in production volumes and a one percent decrease in the realized sales price per boe. During 2008, sulphur prices soared as demand for fertilizers increased around the world. Delphi received $3.8 million from the sale of sulphur during the year, primarily associated with production at its Tower Creek well. As a result of the slowing economies around the world, sulphur prices have fallen significantly resulting in sales of only $0.1 million in the fourth quarter despite ongoing production at Tower Creek.

ROYALTIES

	Three Months Ended December 31			Twelve Months Ended December 31		
	2008	2007	% Change	**2008**	2007	% Change
Total	**5,267**	4,092	29	**25,827**	14,580	77
Per boe	**8.53**	7.58	13	**11.12**	7.50	48
Percent of revenue including realized hedges	**17.5**	15.4	14	**19.1**	14.9	28
Percent of revenue excluding realized hedges	**18.7**	17.4	7	**19.1**	15.1	26

The Company pays royalties to provincial governments (Crown), freeholders, which can be individuals or companies, and other oil and gas operators that own surface or mineral rights. Crown royalty rates are calculated on a sliding scale based on commodity prices and individual well production rates. Royalty rates can change due to price fluctuations or changes in production volumes on a well by well basis subject to a minimum and maximum rate restriction ascribed by the Crown. For the three months and year ended December 31, 2008, royalties as a percentage of revenue increased over the comparative period due to Tower Creek being off royalty holiday, significant hedge gains in the comparative period on which no royalties were paid and increased commodity prices realized in 2008. Delphi is expecting royalties as a percentage of revenue, before hedging, to be between 17 and 20 percent in 2009.

On October 25, 2007, the Government of Alberta announced the New Royalty Framework (NRF). The NRF established new royalties for oil and natural gas which are based on commodity prices, well production volumes and well depths for natural gas wells. The NRF rates apply to both new and existing production and became effective on January 1, 2009. On March 3, 2009, the Alberta Government announced royalty incentives to promote oilfield activity in light of the current economic environment. The calculated affect to Delphi on a typical well drilled in Hythe or Bigstone is estimated to be approximately $0.9 million, material to both project economics and the Company's cash flow.

OPERATING EXPENSES

	Three Months Ended December 31			Twelve Months Ended December 31		
	2008	2007	% Change	**2008**	2007	% Change
Total	**6,585**	4,477	47	**24,092**	17,464	38
Per boe	**10.67**	8.29	29	**10.37**	8.99	15

Operating expenses on a per boe basis for the twelve months ended December 31, 2008, increased 15 percent over the comparative period due to a high level of workover and maintenance activity and the increase in industry costs experienced throughout most of 2008. In addition, earlier in the year the Company incurred significant cost adjustments for the prior year from the facility operator on the newly acquired Hythe property. Operating expenses on a per boe basis for the three months ended December 31, 2008, increased 29 percent over the comparative period due to higher costs of fuel and power and contract operating fees primarily associated with the acquisition of properties and facilities in the Peace River Arch acquisition.

Delphi is focused on cost reduction and anticipates lower 2009 operating costs per boe as volumes increase at core areas and the industry experiences an expected reduction in field costs. Delphi expects operating costs to be $9.75 to $10.25 per boe in 2009.

TRANSPORTATION EXPENSES

	Three Months Ended December 31			Twelve Months Ended December 31		
	2008	2007	% Change	**2008**	2007	% Change
Total	**2,320**	1,387	67	**6,944**	6,148	13
Per boe	**3.76**	2.57	46	**2.99**	3.16	(5)

In British Columbia, infrastructure is owned by Spectra Energy that enables natural gas producers to avoid facility construction in exchange for regulated gathering, processing and transmission fees. This all-in charge is included in transportation expenses.

On a per boe basis, transportation costs for the twelve months ended December 31, 2008, decreased by five percent over the comparative period due to higher production volumes with fixed firm service fees for production and lower transportation costs at Hythe, Alberta. Effective November 1, 2007 and again on November 1, 2008, Delphi transferred a portion of its excess processing and transmission capacity in northeast British Columbia to third parties resulting in further reductions in transportation costs.

For the three months ended December 31, 2008, transportation costs on a per boe basis increased 46 percent over the same period in 2007. This increase is primarily attributed to a one time payment in the quarter of approximately $0.6 million ($1.04 per boe for the fourth quarter and $0.28 per boe for the year) to transfer excess processing and transmission capacity to a third party. The transfer will save approximately $2.7 million in transportation costs over the next three years and will result in lower transportation costs on a go forward basis. Delphi expects transportation costs to be between $2.50 and $2.75 per boe in 2009.

GENERAL AND ADMINISTRATIVE

	Three Months Ended December 31			Twelve Months Ended December 31		
	2008	2007	% Change	**2008**	2007	% Change
General and administrative costs	**2,377**	2,319	3	**9,352**	6,957	34
Overhead recoveries	**(291)**	(196)	48	**(1,173)**	(711)	65
Salary allocations	**(636)**	(688)	(8)	**(3,400)**	(2,550)	33
Net	**1,450**	1,435	1	**4,779**	3,696	29
Per boe	**2.35**	2.66	(12)	**2.06**	1.90	8

On a per boe basis, general and administrative (G&A) costs for the twelve months ended December 31, 2008, increased eight percent over the comparative period in 2007. The increase is due to additional technical staff hired year over year and additional rental expense for office space. As a result of high levels of activity for Delphi and for the industry as a whole, the costs associated with hiring, compensating and retaining employees and consultants have risen. Delphi is committed to delivering strong growth and believes a strong technical team is paramount to achieve this goal. Delphi expanded its team in 2008 with the addition of two senior exploitation engineers and a new land manager. For 2009, Delphi is expecting G&A per boe to be approximately the same as in 2008.

STOCK-BASED COMPENSATION

	Three Months Ended December 31			Twelve Months Ended December 31		
	2008	2007	% Change	**2008**	2007	% Change
Stock-based compensation	**314**	1,105	(72)	**2,114**	2,649	(20)
Capitalized costs	**(55)**	(553)	(90)	**(1,120)**	(1,352)	(17)
Net	**259**	552	(53)	**994**	1,297	(23)
Per boe	**0.42**	1.02	(59)	**0.43**	0.67	(36)

Stock-based compensation expense is the amortization over the vesting period of the fair value of stock options granted to employees, directors and key consultants of the Company. The fair value of all options granted is estimated at the date of grant using the Black-Scholes option pricing model. The non-cash compensation expense for the twelve months ended December 31, 2008, decreased 23 percent. During the three and twelve months ended December 31, 2008, Delphi capitalized $0.1 million and $1.1 million, respectively, of stock-based compensation associated with exploration and development activities.

INTEREST

	Three Months Ended December 31			Twelve Months Ended December 31		
	2008	2007	% Change	**2008**	2007	% Change
Total	**1,065**	1,491	(29)	**5,103**	7,561	(33)
Per boe	**1.73**	2.76	(38)	**2.20**	3.89	(44)

For the three and twelve months ended December 31, 2008, interest expense on a per boe basis decreased 38 percent and 44 percent over the comparable periods due to lower interest costs from reduced interest rates and higher production volumes. Delphi anticipates interest per boe will continue to decrease in 2009 as average debt levels remain relatively consistent with the prior year, interest rates continue to decline to generate economic growth and additional production is brought on stream. The reduction in interest costs as a result of lower interest rates is expected to be, at least partially, offset by an increase in the Company's credit spread associated with its credit facilities due to the increased cost of funds being incurred by the Company's lenders.

DEPLETION, DEPRECIATION AND ACCRETION

	Three Months Ended December 31			Twelve Months Ended December 31		
	2008	2007	% Change	**2008**	2007	% Change
Depletion and depreciation	**15,333**	13,960	10	**61,095**	48,962	25
Accretion expense	**200**	185	8	**650**	638	2
Total	**15,533**	14,145	10	**61,745**	49,600	24
Per boe	**25.17**	26.20	(4)	**26.59**	25.53	4

Depletion, depreciation, and accretion per boe for the twelve months ended December 31, 2008, increased four percent. With continued success at Bigstone and Hythe, Delphi is in an excellent position to add proved reserves at metrics below the Company's current depletion rate. The Company experienced a decrease in depletion per boe during the fourth quarter of 2008 due to significant reserve additions being recognized in the quarter upon completion of the 2008 engineering report. The increase in total depletion and depreciation versus the comparative periods is a result of increased production levels and a higher per boe rate.

Accretion expense of asset retirement obligations relates to the passing of time until the Company estimates it will retire its assets and restore the asset locations to a condition which meets or exceeds environmental standards. Due to the long term nature of certain assets of the Company, this accretion expense is estimated to extend over a term of three to 20 years. The Company uses a credit adjusted risk-free interest rate of eight percent for the purpose of calculating the fair value of its asset retirement obligations and hence the accretion expense. The accretion expense for the twelve months ended December 31, 2008, remained consistent with the comparative year.

TAXES

	Three Months Ended December 31			Twelve Months Ended December 31		
	2008	2007	% Change	**2008**	2007	% Change
Current	**-**	3	-	**-**	3	-
Future (reduction)	**(798)**	(3,608)	(78)	**1,432**	(3,279)	-
Total	**(798)**	(3,605)	(78)	**1,432**	(3,276)	-
Effective rate						
Per boe	**(1.29)**	(6.68)	(81)	**0.62**	(1.69)	-

The provision for income taxes in the financial statements for the twelve months ended December 31, 2008, was $1.4 million. The significant change in taxes is due to an improvement in earnings before taxes. Delphi does not anticipate it will be cash taxable before 2011.

FUNDS FROM OPERATIONS

	Three Months Ended December 31			Twelve Months Ended December 31		
	2008	2007	% Change	**2008**	2007	% Change
Net earnings (loss)	**(959)**	1,732	-	**5,094**	(10,472)	-
Non-cash items:						
Depletion, depreciation and accretion	**15,533**	14,145	10	**61,745**	49,600	24
Impairment of goodwill	-	-	-	-	12,100	(100)
Unrealized loss on risk management activities	**(562)**	926	-	**(608)**	(765)	(21)
Stock-based compensation expense	**259**	552	(53)	**994**	1,297	(23)
Future income taxes (reduction)	**(798)**	(3,608)	(78)	**1,432**	(3,279)	-
Funds from operations	**13,473**	13,747	(2)	**68,657**	48,481	42

For the three and twelve months ended December 31, 2008, funds from operations were $13.5 million ($0.18 per basic share) and $68.7 million ($0.94 per basic share) compared to $13.7 million ($0.20 per basic share) and $48.5 million ($0.72 per basic share) in the comparative period.

Funds from operations is a non-GAAP measure and has been defined by the Company as net earnings (loss) plus the add back of non-cash items (depletion, depreciation and accretion, impairment provisions, stock-based compensation, future income taxes and unrealized gain (loss) on risk management activities) and excludes the change in non-cash working capital related to operating activities and expenditures on asset retirement obligations and reclamation. Management uses funds from operations to analyze performance and considers it a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future capital investments and to repay debt.

The following table shows the reconciliation of funds from operations to cash flow from operating activities for the periods noted:

	Three Months Ended December 31			Twelve Months Ended December 31		
	2008	2007	% Change	**2008**	2007	% Change
Funds from operations: Non-GAAP	**13,473**	13,747	(2)	**68,657**	48,481	42
Settlement of asset retirement obligations	**(312)**	(93)	235	**(312)**	(550)	(43)
Change in non-cash working capital	**5,646**	7,040	(20)	**(5,022)**	6,777	-
Cash flow from operating activities: GAAP	**18,807**	20,694	(9)	**63,323**	54,708	16

NET EARNINGS

For the three and twelve months ended December 31, 2008, Delphi recorded a net loss of $1.0 million and net earnings of $5.0 million, respectively. Net earnings were affected by non-cash items such as depletion, depreciation and accretion, unrealized gain or loss on risk management activities, stock-based compensation and future income taxes. These non-cash items represent the majority of the significant difference between funds from operations and net earnings.

NETBACK ANALYSIS

	Three Months Ended December 31			Twelve Months Ended December 31		
	2008	2007	% Change	2008	2007	% Change
Barrels of oil equivalent ($/boe)						
Realized sales price	**48.87**	49.33	(1)	**58.31**	50.41	16
Royalties, net of ARTC	**8.53**	7.58	13	**11.12**	7.50	48
Operating expenses	**10.67**	8.29	29	**10.37**	8.99	15
Transportation	**3.76**	2.57	46	**2.99**	3.16	(5)
Operating netback	**25.91**	30.89	(16)	**33.83**	30.76	10
G&A	**2.35**	2.66	(12)	**2.06**	1.90	8
Interest	**1.73**	2.76	(38)	**2.20**	3.89	(44)
Current taxes	**-**	0.01	(100)	**-**	-	-
Cash netback	**21.83**	25.46	(14)	**29.57**	24.97	18
Unrealized loss (gain) on financial contracts	**(0.91)**	1.72	-	**(0.26)**	(0.39)	(33)
Stock-based compensation expense	**0.42**	1.02	(59)	**0.43**	0.67	(36)
Depletion, depreciation and accretion	**25.17**	26.20	(4)	**26.59**	25.53	4
Impairment of goodwill	**-**	-	-	**-**	6.23	(100)
Future income taxes (reduction)	**(1.29)**	(6.68)	(81)	**0.62**	(1.69)	-
Net earnings (loss)	**(1.56)**	3.20	-	**2.19**	(5.38)	-

Approximately 87 percent of Delphi's production is natural gas and therefore Delphi's cash netbacks are primarily driven by the price received for natural gas.

LIQUIDITY AND CAPITAL RESOURCES

FUNDING

	Three Months Ended December 31, 2008	Twelve Months Ended December 31, 2008
Sources:		
Funds from operations	**13,473**	68,657
Disposition of petroleum and natural gas properties	**-**	8,450
Issue of common shares	**-**	18,001
Issue of flow-through common shares	**-**	12,002
Exercise of stock options	**-**	1,532
Change in non-cash working capital	**2,590**	4,461
	16,063	113,103
Uses:		
Cash and cash equivalents	**1,286**	5,282
Share issue costs	**32**	2,010
Capital expenditures	**15,660**	76,779
Acquisition of petroleum and natural gas properties	**173**	38,120
Expenditures on asset retirement obligations	**312**	312
	17,463	122,503
Increase in bank debt	**1,400**	9,400

For the year ended December 31, 2008, Delphi funded its capital program through a combination of funds from operations, the issuance of common shares, the issuance of flow-through common shares and an increase in its bank debt.

SHARE CAPITAL

At December 31, 2008, the Company had 79.1 million common shares outstanding (December 31, 2007 – 68.1 million). The common shares of Delphi trade on the TSX under the symbol DEE. The following table summarizes outstanding share data for the three and twelve months ended December 31, 2008.

	Three Months Ended December 31, 2008	Twelve Months Ended December 31, 2008
Weighted Average Common Shares		
Basic	79,067	73,381
Diluted	79,068	74,024
Trading Statistics [1]		
High	$ 1.67	$ 3.43
Low	$ 0.79	$ 0.79
Average daily, volume	430,637	282,945

(1) Trading statistics based on closing price

As at March 17, 2009, the Company had 79.1 million common shares outstanding and 6.8 milllion stock options outstanding.

BANK DEBT PLUS WORKING CAPITAL DEFICIENCY

At December 31, 2008, the Company had $91.4 million outstanding on its credit facility and a working capital deficiency of $17.8 million for total debt plus working capital deficiency of $109.2 million excluding the financial asset of $1.7 million relating to the unrealized gain on financial commodity contracts and the current future income tax liability of $0.5 million. Delphi anticipates spending less than projected funds from operations on capital expenditures during 2009.

The capital intensive nature of the industry will generally result in the Company having a working capital deficiency. As at March 17, 2009, the Company has a revolving facility for $130.0 million with a syndicate of Canadian chartered banks. The facility is a 364-day committed revolving facility which is available until May 31, 2009, the term-out date. The term-out date may be extended for an additional 364 days upon approval by the banks. Following the term-out date, the facilities would become non-revolving for a one year term, after which time the balance outstanding would be due and payable. The credit facility bears interest based on a sliding scale tied to the Company's trailing debt to funds from operations ratio: from a minimum of the bank's prime rate plus 0.5 percent to a maximum of the bank's prime rate plus 2.0 percent. In addition to the revolving term facility, the Company has a $10.0 million development facility. The pricing grid on the development facility is 0.75 percent higher than the revolving term facility.

The current credit facilities were confirmed by the Company's lenders upon completion of their semi-annual review in October, 2008. The annual credit review by the Company's lenders is expected to be completed by May 31, 2009. This detailed review will be based upon the Company's December 31, 2008, reserves engineering report and will take into consideration current production and the results of the winter drilling program. The borrowing base is determined using the Company's year-end engineering report, primarily proved producing reserves, which increased 21 percent over the previous year and the outlook for commodity prices.

CONTRACTUAL OBLIGATIONS

The Company is committed to future minimum payments for natural gas transmission and processing and operating leases on compression equipment. The Company also has a lease for office space in Calgary, Alberta.

The future minimum commitments are as follows:

	2009	2010	2011	2012	2013
Gathering, processing and transmission	3,484	4,173	3,868	2,833	1,845
Office and equipment lease	1,018	1,023	1,029	775	390
Total	4,492	5,196	4,897	3,608	2,235

GUARANTEES AND OFF-BALANCE SHEET ARRANGEMENTS

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

CRITICAL ACCOUNTING ESTIMATES

Delphi's financial statements have been prepared in accordance with Canadian general accepted accounting principles. Certain accounting policies require management to make decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Delphi's management reviews its estimates frequently, however, the emergence of new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates. Delphi attempts to mitigate this risk by employing individuals with the appropriate skill set and knowledge to make reasonable estimates, developing internal control systems and comparing past estimates to actual results.

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

- Depletion, depreciation and accretion and the ceiling test are based on estimates of crude oil and natural gas reserves;
- Revenues, operating expenses and royalties for which accruals have been recorded for actual revenues and costs which have been earned or incurred but have not yet been received;
- Capital expenditures on projects that are in progress;
- Fair value of derivative contracts; and
- Asset retirement obligations including estimates of future costs and the timing of the costs.

NEW ACCOUNTING STANDARDS

FINANCIAL INSTRUMENTS - DISCLOSURE

Effective January 1, 2008 the Company adopted CICA section 3862 - Financial Instruments – Disclosure which requires additional disclosure about the Company's financial instruments to be included in the financial statements. The recommendations prescribe an increased importance on risk disclosures associated with recognized and unrecognized financial instruments and how such risks are managed. In addition, the recommendations outline revised requirements for the disclosure of qualitative and quantitative information regarding exposure to risks arising from financial instruments. These additional disclosures are included in Note 9 of the Company's audited 2008 annual consolidated financial statements.

Details of the Company's accounting policies for the recognition and measurement of financial instruments and the basis for which revenues and expenses are recognized are disclosed in Note 2 of the Company's audited 2008 annual consolidated financial statements.

CAPITAL MANAGEMENT

Effective December 31, 2007, the Company adopted new disclosure standards with respect to capital management.

INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

In February 2008, the Accounting Standards Board of the Canadian Institute of Chartered Accountants confirmed that IFRS will replace Canadian GAAP in 2011 for profit-oriented Canadian publicly accountable enterprises. Effective January 1, 2011, the Company will be required to prepare its consolidated financial statements in accordance with International Financial Reporting Standards (IFRS), with appropriate comparative figures for the year ended December 31, 2010.

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

The International Accounting Standards Board (IASB) has issued an exposure draft relating to certain amendments to IFRS 1 in response to potential challenges in jurisdictions, including Canada, adopting IFRS for the first time. The IASB is proposing additional optional exemptions, one of which relates to full cost oil and gas accounting, resulting in a reduced administrative transition from the current Canadian full cost accounting for oil and gas activities to IFRS. The exemption would permit the Company to measure exploration and evaluation assets under IFRS at the carrying amount determined under GAAP at the date of transition to IFRS. In addition, the carrying amount under GAAP of production or development assets could be allocated on a pro rata basis to the underlying assets using either reserve volumes or reserve values at the date of transition. The assets to which this exemption has been applied would be required to be tested for impairment at the date of transition under IFRS standards.

CORPORATE GOVERNANCE

OVERVIEW

The shareholders' interests are a critical factor in the operation and management of Delphi. The Company is committed to maintaining the highest level of investor confidence in the Company through the application of its corporate governance policies. Delphi's Board of Directors consists of five independent directors and two officers of the Company who meet regularly to discuss matters of strategy and execution of the business plan. See Delphi's Management Information Circular and Annual Information Form for a listing of committees that oversee specific aspects of the Company's operating and financial strategy.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Disclosure controls and procedures are designed to ensure that information required to be disclosed by the Company is accumulated and communicated to the issuer's management, including its President and Chief Executive Officer and Vice President, Finance and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The Company's President and Chief Executive Officer and Vice President, Finance and Chief Financial Officer have concluded, based on their evaluation as of December 31, 2008 covered by the annual filings, that the Company's disclosure controls and procedures provide a reasonable level of assurance that information required to be disclosed by the Company is recorded, processed, summarized and reported within the time periods specified.

An evaluation and testing was performed under the direction of the President and Chief Executive Officer and the Vice President, Finance and Chief Financial Officer, of the effectiveness of the Company's internal controls over financial reporting as defined in the Multilateral Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings. The assessment was based on the Internal Controls – Integrated Framework issued by the Committee of Sponsoring Organizations. Based on that evaluation, the President and Chief Executive Officer and the Vice President, Finance and Chief Financial Officer have concluded that the design and operation of the Company's internal controls over financial reporting were effective as at December 31, 2008.

The Company notes that while it believes the disclosure controls and procedures and internal controls over financial reporting provide a reasonable level of assurance that they are effective, it does not expect that the disclosure controls and procedures and internal controls will prevent all errors and fraud. A control system is designed to provide reasonable, not absolute, assurance that the objectives of the control system are met.

2009 OUTLOOK

CORPORATE STRATEGY

Delphi emphasizes a full-cycle approach to its business and strives for internally generated development opportunities as a means of enhancing its production base and ultimately creating value for shareholders. Delphi's goal is to become a dominant natural gas developer and explorer focused in northwest Alberta and northeast British Columbia. The objective is to develop an inventory of opportunities and undeveloped land base from which production and reserves can be added independent of acquisition activity. In that regard, the Company's ability to add production through the drill bit creates a competitive advantage over those competitors that rely on acquisitions to build or maintain their production base. Currently, Delphi has identified over 100 drilling locations, three to five years drilling inventory, on its core areas.

CAPITAL ACTIVITIES

With the current uncertainty in commodity prices and the economy, Delphi will fund its capital program from internally generated cash flow from operations. Delphi's Board of Directors have approved a capital program ranging between $17.0 to $22.0 million for the first half of 2009, with the objective of preserving the Company's financial flexibility in these uncertain economic times and maintaining the flexibility to pursue and capture strategic growth opportunities attractively priced in this environment. A larger capital program for the second half of the year is expected, however, that will be dependent upon commodity price expectations at that time. Total capital for the year is expected to be between $35.0 to $50.0 million.

The capital program for the first six months of the year includes the drilling of four wells (3.75 net) with the majority of the capital allocated to the Company's two main areas, Bigstone and Hythe including the drilling of a horizontal well at Hythe utilizing multistage fracturing techniques to enhance production and reserves.

FINANCIAL STRATEGY

The Company is well positioned to endure the current weak economic environment with high quality producing assets, a large inventory of economic projects and a 2009 cash flow stream protected with 50 percent of the Company's current natural gas production hedged at an average floor price 64 percent greater than the current 2009 strip price. Net debt at the end of 2008 is approximately $109.2 million on total credit facilities of $140.0 million, providing excess financial capacity of approximately $30.8 million. Delphi expects to maintain or slightly reduce the net debt by the end of 2009 by spending no more than cash flow from operations. Maintaining operational and financial flexibility, combined with expanding the Company's long-term growth inventory in a low-cost environment, will be key drivers in the capital spending decision process throughout 2009.

ADDITIONAL INFORMATION

Additional information about Delphi is available on the Canadian Securities Administrators' System for Electronic Distribution and Retrieval (SEDAR) at www.sedar.com, at the Company's website at www.delphienergy.ca or by contacting the Company at Delphi Energy Corp. Suite 300, 500 – 4th Avenue S.W., Calgary, Alberta, T2P 2V6 or by e-mail at info@delphienergy.ca.

Forward-Looking Statements. This management discussion and analysis contains forward-looking statements and forward-looking information within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", may", "will", "should", believe", "intends", "forecast", "plans", "guidance" and similar expressions are intended to identify forward-looking statements or information.

More particularly and without limitation, this management discussion and analysis contains forward looking statements and information relating to the Company's risk management program, petroleum and natural gas production, future funds from operations, capital programs, commodity prices, costs and debt levels. The forward-looking statements and information are based on certain key expectations and assumptions made by Delphi, including expectations and assumptions relating to prevailing commodity prices and exchange rates, applicable royalty rates and tax laws, future well production rates, the performance of existing wells, the success of drilling new wells, the capital availability to undertake planned activities and the availability and cost of labour and services.

Although the Company believes that the expectations reflected in such forward-looking statements and information are reasonable, it can give no assurance that such expectations will prove to be correct. Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results may differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, the risks associated with the oil and gas industry in general such as operational risks in development, exploration and production, delays or changes in plans with respect to exploration or development projects or capital expenditures, the uncertainty of estimates and projections relating to production rates, costs and expenses, commodity price and exchange rate fluctuations, marketing and transportation, environmental risks, competition, the ability to access sufficient capital from internal and external sources and changes in tax, royalty and environmental legislation. Additional information on these and other factors that could affect the Company's operations or financial results are included in reports on file with the applicable securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com). The forward-looking statements and information contained in this press release are made as of the date hereof for the purpose of providing the readers with the Company's expectations for the coming year. The forward-looking statements and information may not be appropriate for other purposes. Delphi undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

Basis of Presentation. For the purpose of reporting production information, reserves and calculating unit prices and costs, natural gas volumes have been converted to a barrel of oil equivalent (boe) using six thousand cubic feet equal to one barrel. A boe conversion ratio of 6:1 is based upon an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This conversion conforms with the Canadian Securities Administrators' National Instrument 51-101 when boes are disclosed. Boes may be misleading, particularly if used in isolation.

Non-GAAP Measures. The MD&A contains the terms "funds from operations", "funds from operations per share", "net debt" and "netbacks" which are not recognized measures under Canadian generally accepted accounting principles. The Company uses these measures to help evaluate its performance. Management considers netbacks an important measure as it demonstrates its profitability relative to current commodity prices. Management uses funds from operations to analyze performance and considers it a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future capital investments and to repay debt. Funds from operations is a non-GAAP measure and has been defined by the Company as net earnings plus the addback of non-cash items (depletion, depreciation and accretion, stock-based compensation, future income taxes and unrealized gain/(loss) on risk management activities) and excludes the change in non-cash working capital related to operating activities and expenditures on asset retirement obligations and reclamation. The Company also presents funds from operations per share whereby amounts per share are calculated using weighted average shares outstanding consistent with the calculation of earnings per share. Delphi's determination of funds from operations may not be comparable to that reported by other companies nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. The Company has defined net debt as the sum of long term debt plus working capital excluding the current portion of future income taxes and risk management asset/liability. Net debt is used by management to monitor remaining availability under its credit facilities.

MANAGEMENT'S REPORT

The financial statements of Delphi Energy Corp. were prepared by management in accordance with Canadian generally accepted accounting principles. The financial and operating information presented in this annual report is consistent with that shown in the financial statements.

Management has designed and maintains a system of internal controls to provide reasonable assurance that all assets are safeguarded and to facilitate the preparation of financial statements for reporting purposes. Timely release of financial information sometimes necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. Such estimates are based on careful judgments made by management. External auditors appointed by the shareholders have conducted an independent examination of the Company's accounting records in order to express their opinion on the financial statements.

The Board of Directors is responsible for ensuring that management fulfils its responsibilities for financial and internal control. The Board exercises this responsibility through its Audit & Reserves Committee. The Audit & Reserves Committee, which consists of non-management members, has met with the external auditors and management in order to determine that management has fulfilled its responsibilities in the preparation of the financial statements. The Audit & Reserves Committee has reported its findings to the Board of Directors who have approved the financial statements.

David Reid

David J. Reid
President and Chief Executive Officer

B Kol

Brian P. Kohlhammer
Vice President Finance and Chief Financial Officer

Calgary, Canada
March 17, 2009

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the consolidated balance sheets of Delphi Energy Corp. as at December 31, 2008 and 2007 and the consolidated statements of earnings/(loss), comprehensive income/(loss) and retained earnings and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2008 and 2007, and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Canada
March 17, 2009

DELPHI ENERGY CORP.
CONSOLIDATED BALANCE SHEETS
AS AT DECEMBER 31

(Stated in thousands of dollars)	2008	2007
Assets		
Current assets		
Cash	1,029	5
Accounts receivable	14,522	12,604
Prepaid expenses and deposits	2,928	2,752
Risk management asset (Note 9)	1,721	1,113
	20,200	16,474
Property, plant and equipment (Note 4)	344,338	295,266
Total assets	364,538	311,740
Liabilities		
Current liabilities		
Outstanding cheques	105	4,363
Future income taxes (Note 8)	501	332
Accounts payable and accrued liabilities	36,211	29,656
	36,817	34,351
Long term debt (Note 5)	91,400	82,000
Future income taxes (Note 8)	33,655	27,830
Asset retirement obligations (Note 6)	9,730	7,183
	171,602	151,364
Shareholders' equity		
Share capital (Note 7)	174,995	148,898
Contributed surplus (Note 7)	9,605	8,236
Retained earnings	8,336	3,242
Total shareholders' equity	192,936	160,376
Total liabilities and shareholders' equity	364,538	311,740

Commitments (Note 10)
See accompanying notes to the consolidated financial statements.

Approved on behalf of the Board of Directors:

H.R. Lawrie

Henry R. Lawrie
Director

L. Tolley

Lamont C. Tolley
Director

DELPHI ENERGY CORP.
CONSOLIDATED STATEMENTS OF EARNINGS (LOSS), COMPREHENSIVE INCOME (LOSS) AND RETAINED EARNINGS
YEARS ENDED DECEMBER 31

(Stated in thousands of dollars, except per share amounts)	2008	2007
Revenue		
Petroleum and natural gas sales	**135,124**	96,479
Realized gain on risk management activities (Note 9)	**278**	1,454
	135,402	97,933
Royalties	**(25,827)**	(14,580)
Unrealized gain on risk management activities (Note 9)	**608**	765
	110,183	84,118
Expenses		
Operating	**24,092**	17,464
Transportation	**6,944**	6,148
General and administrative	**4,779**	3,696
Stock-based compensation (Note 7)	**994**	1,297
Interest	**5,103**	7,561
Depletion, depreciation and accretion	**61,745**	49,600
Impairment of goodwill	**-**	12,100
	103,657	97,866
Earnings (loss) before income taxes	**6,526**	(13,748)
Income taxes (Note 8)		
Current	**-**	3
Future (reduction)	**1,432**	(3,279)
	1,432	(3,276)
Net earnings (loss) and comprehensive income (loss)	**5,094**	(10,472)
Retained earnings, beginning of the year	**3,242**	13,714
Retained earnings, end of the year	**8,336**	3,242
Net earnings (loss) per share (Note 7)		
Basic and diluted	**0.07**	(0.16)

See accompanying notes to the consolidated financial statements.

DELPHI ENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
YEARS ENDED DECEMBER 31

(Stated in thousands of dollars)	2008	2007
Cash flow from operating activities		
Net earnings (loss)	**5,094**	(10,472)
Add non-cash items:		
Depletion, depreciation and accretion	**61,745**	49,600
Impairment of goodwill	**-**	12,100
Stock-based compensation	**994**	1,297
Unrealized gain on risk management activities	**(608)**	(765)
Future income taxes (reduction)	**1,432**	(3,279)
Expenditures on asset retirement obligations	**(312)**	(550)
Change in non-cash working capital (Note 11)	**(5,022)**	6,777
	63,323	54,708
Cash flow from (used in) financing activities		
Issue of flow-through common shares	**12,002**	18,007
Issue of common shares	**18,001**	-
Share issue costs	**(2,010)**	(1,208)
Exercise of stock options	**1,532**	83
Increase (decrease) in long term debt	**9,400**	(33,000)
	38,925	(16,118)
Cash flow available for investing activities	**102,248**	38,590
Cash flow from (used in) investing activities		
Capital expenditures	**(76,779)**	(51,924)
Acquisition of petroleum and natural gas properties	**(38,120)**	(10,871)
Disposition of petroleum and natural gas properties	**8,450**	15,502
Change in non-cash working capital (Note 11)	**9,483**	3,588
	(96,966)	(43,705)
Increase (decrease) in cash and cash equivalents	**5,282**	(5,115)
Cash and cash equivalents, beginning of the year	**(4,358)**	757
Cash and cash equivalents, end of the year	**924**	(4,358)
Cash and cash equivalents is comprised of:		
Cash	**1,029**	5
Outstanding cheques	**(105)**	(4,363)
	924	(4,358)
Interest paid	**5,149**	7,087
Taxes paid	**-**	3

See accompanying notes to the consolidated financial statements.

RESULTS

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

AS AT AND FOR THE YEARS ENDED DECEMBER 31, 2008 AND 2007

(All tabular amounts are stated in thousands of dollars, except per share amounts)

NOTE 1: DESCRIPTION OF BUSINESS

Delphi Energy Corp. ("the Company" or "Delphi") is incorporated under the Business Corporations Act (Alberta) and is a public company listed on the Toronto Stock Exchange. Delphi is primarily engaged in the exploration for and development and production of petroleum and natural gas from properties located in northwest Alberta and northeast British Columbia.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of Delphi have been prepared by management in accordance with accounting principles generally accepted in Canada. 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, liabilities, shareholders' equity, revenue and expenses and disclosure of contingent assets and liabilities at the date of the financial statements. Actual results may differ from these estimates.

(A) PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company, its wholly owned subsidiary and a partnership. All inter-entity transactions and balances have been eliminated.

(B) PETROLEUM AND NATURAL GAS OPERATIONS

The Company follows the full cost method of accounting whereby all costs associated with the exploration for and development of petroleum and natural gas reserves are capitalized. Such costs include land acquisition costs, geological and geophysical costs, lease rental costs on non-producing properties, costs of both productive and unproductive drilling and production equipment.

Gains or losses are not recognized upon disposition of petroleum and natural gas properties unless crediting the proceeds against accumulated costs would result in a change in the depletion rate of 20 percent or more.

The accumulated costs, less the costs of acquisition of unproved properties, are depleted using the unit-of-production method based upon total proved reserves before royalties as determined by the Company's independent reserves engineers. Natural gas reserves and production are converted into equivalent barrels of oil at 6:1 based upon the estimated relative energy content.

The costs of acquiring and evaluating unproved properties are initially excluded from depletion calculations. These properties are assessed periodically to ascertain whether impairment has occurred. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of impairment is added to the costs subject to depletion.

The Company is required to perform a ceiling test at least annually to assess the carrying amount of oil and gas assets. The costs are assessed to be recoverable if the sum of the undiscounted cash flows expected from the production of proved reserves using forecast prices and the lower of cost and market of unproved properties exceed the carrying amount of the petroleum and natural gas assets. If the carrying amount of the petroleum and natural gas assets is assessed to not be recoverable, an impairment loss is recognized to the extent that the carrying amount exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves and the lower of cost and market of unproved properties. This approach incorporates risks and uncertainties in the expected future cash flows, which are discounted using a risk-free rate.

Depreciation of furniture and office equipment is provided using the declining balance method based upon estimated useful lives of 20 percent to 50 percent.

(C) JOINT OPERATIONS

Certain of the Company's exploration, development and production activities are conducted jointly with others and accordingly, the financial statements reflect only the Company's proportionate interest in such activities.

(D) GOODWILL

Goodwill, at the time of acquisition, represents the excess of the purchase price of a business over the fair value of the net assets acquired. Goodwill is assessed by the Company for impairment at least each year end. If the fair value of the business is less than the book value, a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the business' assets and liabilities from the fair value of the business to determine the implied fair value of goodwill and comparing that amount to the book value of goodwill. Any excess of the book value of goodwill over the implied fair value is the impairment amount and is charged to earnings in the period of the impairment.

(E) ASSET RETIREMENT OBLIGATIONS

The Company records the future cost associated with removal, site restoration and asset retirement costs of property, plant and equipment. The fair value of the liability for the Company's asset retirement obligation is recorded in the period in which it is incurred, discounted to its present value using the Company's credit adjusted risk-free interest rate and the corresponding amount is recognized by increasing the carrying amount of property, plant and equipment. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. Actual costs incurred upon settlement of the retirement obligation are charged against the obligation to the extent of the liability recorded. The associated asset retirement cost included in property, plant and equipment is amortized to earnings using the unit-of-production method over estimated proved reserves consistent with the depletion and depreciation of the underlying asset.

(F) STOCK-BASED COMPENSATION

The Company records a compensation cost for all stock options granted to employees, directors or key consultants over the vesting period of the options based on the fair value method. The compensation cost is a charge to earnings or is capitalized as a cost of exploration and development activities with an offsetting increase to contributed surplus on the balance sheet. Consideration paid by employees, directors or key consultants upon exercise of the stock options and the amount previously recognized in contributed surplus are recorded as an increase to share capital. The Company has not incorporated an estimated forfeiture rate for stock options that will not vest, rather, the Company accounts for actual forfeitures as they occur.

(G) FUTURE INCOME TAXES

The Company follows the asset and liability method of accounting for income taxes. Under this method, estimated future income tax assets and liabilities are determined based upon differences between the carrying amount as reported on the balance sheet and the tax basis of assets and liabilities and measured using substantively enacted tax rates and laws expected to be in effect when the differences are expected to reverse. The effect on future tax assets and liabilities of a change in tax rates is recognized in earnings in the period in which the change occurs. A valuation allowance is recognized against any future income tax assets if it is considered more likely than not that the asset will not be realized.

(H) FLOW-THROUGH SHARES

The resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share arrangements are renounced to investors in accordance with income tax legislation. To recognize the foregone tax benefits to the Company, the future income tax liability and share capital are adjusted by the estimated cost of the renounced tax deduction on the date of renouncement.

(I) PER SHARE AMOUNTS

Basic per share amounts are computed by dividing the net earnings by the weighted average number of common shares outstanding for the year. Diluted per share amounts reflect the potential dilution that would occur if securities or other contracts to issue common shares were exercised or converted to common shares. Diluted per share information is calculated using the treasury stock method that assumes any proceeds received by the Company upon the exercise of in-the-money stock options, plus the unamortized stock-based compensation cost, would be used to buy back common shares at the average market price for the period. Anti-dilutive options or instruments are not included in the calculation.

(J) FINANCIAL INSTRUMENTS

i) Financial instruments – recognition and measurement

Financial instruments are classified into one of the following five categories: held-for-trading, held-to-maturity, loans and receivables, available-for-sale financial assets or other financial liabilities. All financial instruments, including derivatives and non-financial derivatives are measured in the balance sheet at fair value except for loans and receivables, held-to-maturity investments and other financial liabilities which are measured at amortized cost determined using the effective interest rate method. The accounting for subsequent changes in fair value depends on initial classification, as follows: changes in fair value of held-for-trading financial assets are recognized in net earnings and changes in fair value of available-for-sale financial instruments are recorded in other comprehensive income until the investment is derecognized or impaired at which time the amounts are recorded in net earnings.

The Company classifies its cash as held-for-trading which is measured at fair value. Accounts receivable are classified as loans and receivables and are measured at amortized cost. Accounts payable and long term debt are classified as other financial liabilities and are measured at amortized cost.

ii) Derivatives

All derivative instruments, including embedded derivatives, are recorded on the balance sheet at fair value unless exempt from derivative accounting treatment as a normal purchase and sale. All changes in the fair value of derivative instruments are recorded in earnings unless cash flow hedge accounting is used, in which case changes in fair value are recorded in other comprehensive income. The Company has a risk management program whereby the commodity price associated with a portion of its future production is fixed in order to mitigate cash flow volatility resulting from fluctuating commodity prices. The Company sells forward a portion of its future production by entering into a combination of fixed price physical sale contracts with customers and fixed price financial contracts with financial counterparties. The Company has elected not to use cash flow hedge accounting on its fixed price contracts with financial counterparties resulting in all changes in fair value being recorded in the statement of earnings. The Company has elected to account for its physical commodity sales contracts which were entered into and continue to be held for the purpose of delivery of production in accordance with its expected sale requirements as executory contracts on an accrual basis rather than as non-financial derivatives. Physical commodity sale contracts based in United States dollars include an embedded derivative associated with the foreign exchange rate. Due to this embedded derivative, the change in the fair value of these contracts are included in the statement of earnings.

iii) Other comprehensive income

The Company includes a statement of comprehensive income, which is comprised of net earnings and other comprehensive income which, for the Company, relates to changes in gains or losses on derivatives designated as cash flow hedges. The Company has combined this statement with the statement of earnings.

iv) Transaction costs

Transaction costs attributable to financial instruments classified as other than held-for-trading are included in the recognized amount of the related financial instrument and recognized over the term of the resulting financial instrument.

(K) MEASUREMENT UNCERTAINTY

The amounts recorded for depletion and depreciation of property, plant and equipment are based upon estimates of proved petroleum and natural gas reserves, production rates, commodity prices and future costs. The ceiling test is based upon estimates of proved and, if applicable, probable reserves, production rates, petroleum and natural gas prices, future costs and other assumptions. The asset retirement obligations are based upon future costs, expected inflation rates and other assumptions. The amounts for stock-based compensation are based on estimates of risk-free interest rates, expected lives and volatility. The fair value estimates for derivatives are based on expected future natural gas prices and volatility in those prices. Future income taxes are based on estimates as to timing of the reversal of temporary differences at tax rates substantively enacted in those years. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes to estimates in future periods could be material.

(L) CASH AND CASH EQUIVALENTS

The Company considers deposits in banks less outstanding cheques as cash and cash equivalents.

(M) REVENUE RECOGNITION

Petroleum and natural gas sales are recognized in earnings when the title and risks pass from the Company to its customer.

(N) COMPARATIVE FIGURES

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

NOTE 3: NEW ACCOUNTING STANDARDS

FINANCIAL INSTRUMENTS – DISCLOSURE

Effective January 1, 2008, the Company adopted CICA section 3862 - Financial Instruments – Disclosure which requires additional disclosure about the Company's financial instruments to be included in the financial statements. The recommendations prescribe an increased importance on risk disclosures associated with recognized and unrecognized financial instruments and how such risks are managed. In addition, the recommendations outline revised requirements for the disclosure of qualitative and quantitative information regarding exposure to risks arising from financial instruments. These additional disclosures are included in Note 9.

CAPITAL MANAGEMENT

Effective December 31, 2007, the Company adopted new disclosure standards with respect to capital management.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

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

NOTE 4: PROPERTY, PLANT AND EQUIPMENT

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

As at December 31, 2007	Cost	Accumulated depletion and depreciation	Net book value
Petroleum and natural gas properties	323,305	114,408	208,897
Production equipment	105,713	19,877	85,836
Furniture, fixtures and office equipment	1,003	470	533
	430,021	134,755	295,266

For the year ended December 31, 2008, the Company capitalized $3.3 million (December 31, 2007 - $2.3 million) of general and administrative costs directly related to exploration and development activities.

As at December 31, 2008, costs in the amount of $3.4 million (December 31, 2007 - $10.8 million) representing unproved properties were excluded from the depletion calculation and estimated future development costs of $46.7 million (December 31, 2007 - $15.7 million) have been included in costs subject to depletion. All costs of unproved properties have been capitalized. Ultimate recoverability of these costs will be dependent upon finding proved oil and natural gas reserves.

On July 24, 2008, the Company closed an acquisition of crude oil and natural gas properties in northwest Alberta for total cash consideration of $38.0 million.

The Company performed a ceiling test calculation at December 31, 2008 to assess the recoverable value of property, plant and equipment, which indicated no write down was required. The future commodity prices used in the ceiling test were based on the December 31, 2008 commodity price forecasts of the Company's independent reserve engineers adjusted for differentials specific to the Company's reserves. The following table summarizes the future benchmark prices the Company used in the ceiling test.

	Natural Gas				Crude Oil		
	Henry Hub (US$/mmbtu)	AECO Spot (CDN$/mmbtu)	Delphi Gas (CDN$/mcf)	West Texas Intermediate (US$/bbl)	Edmonton Light (CDN$/bbl)	Bow River Hardisty (CDN$/bbl)	Delphi Oil (CDN$/bbl)
2009	7.00	7.58	7.56	57.50	68.61	51.44	56.49
2010	7.50	7.94	7.92	68.00	78.94	59.21	66.33
2011	8.00	8.34	8.32	74.00	83.54	63.49	70.84
2012	8.75	8.70	8.71	85.00	90.92	69.10	77.16
2013	9.20	8.95	8.98	92.01	95.91	72.89	81.12
2014	9.38	9.14	9.20	93.85	97.84	74.36	82.19
2015	9.57	9.34	9.41	95.73	99.82	75.86	83.36
2016	9.76	9.54	9.63	97.64	101.83	77.39	84.56
2017	9.96	9.75	9.85	99.59	103.89	78.96	91.01
2018	10.16	9.95	10.09	101.59	105.99	80.55	97.19
Thereafter (1)	+2%/yr	+2%/yr		+2%/yr	+2%/yr	+2%/yr	

NOTE 5: LONG TERM DEBT

The Company has a revolving facility for $130.0 million with a syndicate of Canadian chartered banks. The facility is a 364 day committed revolving facility until May 31, 2009, the term out date. The term-out date may be extended for a further 364 day period upon approval by the banks. Following the term-out date, the facilities would be available on a non-revolving basis for a one year term. The credit facility bears interest based on a sliding scale tied to the Company's trailing debt to cash flow ratio: from a minimum of the bank's prime rate plus 0.5 percent to a maximum of the bank's prime rate plus 2.0 percent.

In addition to the revolving term facility, the Company has a $10.0 million development facility with its lenders. The pricing grid on the development facility is 0.75 percent higher than the revolving term facility. As at December 31, 2008, there is no amount drawn under this facility.

The two facilities are secured by a $200.0 million demand floating charge debenture and a general security agreement over all assets of the Company.

NOTE 6: ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations result from working interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations, over the next three to 20 years, is approximately $21.4 million (December 31, 2007 - $16.3 million). A credit-adjusted risk-free rate of 8.0 percent and an inflation rate of 2.5 percent were used to calculate the estimated fair value of the asset retirement obligations.

A reconciliation of the asset retirement obligations is provided below:

As at December 31	2008	2007
Balance, beginning of the year	**7,183**	7,951
Liabilities incurred	**271**	1,017
Liabilities disposed	**(83)**	(1,873)
Liabilities acquired	**2,021**	-
Liabilities settled	**(312)**	(550)
Accretion expense	**650**	638
Balance, end of the year	**9,730**	7,183

NOTE 7: SHARE CAPITAL

(A) AUTHORIZED

An unlimited number of common shares.
An unlimited number of preferred shares issuable in series.

(B) COMMON SHARES ISSUED

	2008		2007	
As at December 31	Outstanding shares (000's)	Amount	shares (000's)	Outstanding Amount
Balance, beginning of the year	68,070	148,898	60,663	139,108
Issue of flow-through common shares	3,530	12,002	7,350	18,007
Issue of common shares	6,316	18,001	-	-
Exercise of stock options	1,151	1,532	57	83
Allocated from contributed surplus	-	745	-	39
Share issue costs	-	(2,010)	-	(1,208)
Future tax effect of share issue costs	-	585	-	369
Tax benefit renounced to shareholders	-	(4,758)	-	(7,500)
Balance, end of the year	79,067	174,995	68,070	148,898

On March 1, 2007, the Company issued 7.35 million flow-through common shares at a price of $2.45 per share for gross proceeds of $18.0 million.

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

The Company has incurred the necessary qualifying exploration expenditures to satisfy the terms of the flow-through common shares issued in 2007. Although the Company believes it has incurred the necessary qualifying expenditures, these amounts may be subject to audit and subsequent interpretation by the Canada Revenue Agency. The Company has an obligation to incur qualifying exploration expenditures of $12.0 million by December 31, 2009 to satisfy the obligation relating to the issuance of flow-through shares in 2008. As at December 31, 2008, the Company had a remaining requirement to incur approximately $4.0 million of qualifying expenditures to fully satisfy this obligation.

(C) STOCK OPTIONS

The Company has established a stock option plan under which it has granted options to acquire common shares to certain officers, directors, employees and key consultants. The plan provides for the granting of options up to ten percent of the issued and outstanding common shares of the Company. Options issued under the plan have a term of five years to expiry and vest over a two-year period starting on the date of the grant. The exercise price of each option equals the five day weighted average of the closing market price of the Company's common shares, immediately preceding the date of the grant. As at December 31, 2008, there were 4.7 million options to purchase shares outstanding.

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

	2008		2007	
As at December 31	Outstanding options (000's)	Weighted average exercise price	Outstanding options (000's)	Weighted average exercise price
Balance, beginning of the year	5,481	1.60	4,229	3.40
Granted	615	2.23	4,500	1.67
Cancelled	(60)	1.55	(3,070)	4.09
Forfeited	(154)	1.56	(121)	3.92
Exercised	(1,151)	1.33	(57)	1.45
Balance, end of the year	4,731	1.75	5,481	1.60
Exercisable at end of the year	2,938	1.72	2,481	1.52

The following table summarizes information about the stock options outstanding and exercisable at December 31, 2008.

	Options outstanding			Options exercisable	
Range of exercise price	Outstanding options (000's)	Weighted average exercise price	Weighted average remaining term (years)	Exercisable (000's)	Weighted average exercise price
$0.97 - $1.54	100	1.24	4.3	50	1.33
$1.55 - $1.72	3,751	1.67	3.9	2,489	1.67
$1.73 - $2.15	660	1.80	3.9	325	1.79
$2.16 - $3.34	220	3.18	4.5	74	3.18
Total	4,731	1.75	3.9	2,938	1.72

(D) STOCK-BASED COMPENSATION

The Company accounts for its stock-based compensation using the fair value method for all stock options. For the year ended December 31, 2008, Delphi recorded non-cash compensation expense of $1.0 million (December 31, 2007- $1.3 million). The Company capitalized $1.1 million (December 31, 2007 - $1.3 million) of stock-based compensation directly related to exploration and development activities. The future income tax liability associated with the capitalized stock-based compensation in the amount of $0.4 million (2007 - $0.5 million) has also been capitalized for the year.

During the year ended December 31, 2008, the Company granted 0.6 million options. The fair values of all options granted during the period are estimated at the date of grant using the Black-Scholes option pricing model. The weighted average fair value of options granted during the year was $1.13 per option (2007 - $0.96 per option). The assumptions used in the Black-Scholes model to determine fair value were as follows.

Years ended December 31	2008	2007
Risk-free interest rate (%)	4.6	5.0
Expected life (years)	5.0	5.0
Expected volatility (%)	52.0	53.0

(E) CONTRIBUTED SURPLUS

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

As at December 31	2008	2007
Balance, beginning of the year	8,236	5,627
Stock-based compensation expensed	994	1,296
Stock-based compensation capitalized	1,120	1,352
Reclassification to common shares on exercise of stock options	(745)	(39)
Balance, end of the year	9,605	8,236

(F) NET EARNINGS (LOSS) PER SHARE

Net earnings (loss) per share has been based on the following weighted average common shares.

Years ended December 31	2008	2007
Basic	73,381	66,835
Diluted	74,024	66,983

The reconciling item between the basic and diluted weighted average common shares outstanding is stock options. In 2008, the majority of stock options were anti-dilutive and therefore excluded from the diluted weighted average shares outstanding.

(G) CAPITAL MANAGEMENT

The Company considers share capital and net debt, being the sum of long term debt and current liabilities less current assets, as the components of capital to be managed.

The Company's objective in managing its capital is to ensure adequate and appropriate sources of capital are available to execute a capital investment program while maintaining a flexible overall capital structure. Maintaining a flexible capital structure is important due to the inherent risks in oil and gas operations and the volatility of commodity prices.

The Company manages its capital structure by keeping abreast of current and forecast economic conditions and commodity prices, particularly natural gas and the cost of oilfield services. Additionally, the Company establishes internal processes to monitor and estimate planned capital expenditures, forecast funds from operations and current and forecast debt levels.

The key measure used by the Company to evaluate its capital structure is the ratio of net debt to funds from operations, defined as cash flow from operating activities before expenditures on asset retirement obligations and change in non-cash working capital from operating activities. This ratio represents the time period required to repay the Company's net debt from funds generated from operations on the assumption there are no further capital expenditures incurred and funds from operations remain constant. The measure is often calculated on a historic annual basis and on an annualized most recent quarter basis to provide a more current view of the Company's capital structure.

At December 31, 2008; net debt, excluding risk management assets or liabilities, was $109.2 million and funds from operations was $68.7 million resulting in a net debt to funds from operations ratio of 1.6 times, down from 2.1 times at December 31, 2007. On an annualized fourth quarter 2008 basis, funds from operations would be $53.9 million resulting in a net debt to funds from operations ratio of 2.0 times. The Company is focused on achieving its internal target range for this ratio of approximately 1.5 times.

The Company maintains an active risk management program as an integral part of its capital management strategy to mitigate the volatility in funds from operations resulting from fluctuating commodity prices. The net debt to funds from operations ratio is the key driver in determining whether to maintain or alter the capital structure. To alter the capital structure of the Company consideration is given to the level of credit available under current banking facilities, the proceeds on disposition of properties, the amount of the planned capital expenditure program and the offering of new common share equity if available on acceptable terms.

NOTE 8: INCOME TAXES

(A) EXPECTED INCOME TAX RATE

The provision for income taxes in the financial statements differs from the result that would have been obtained by applying the combined federal and provincial income tax rates to the Company's earnings before income taxes.

The difference relates to the following items:

YEARS ENDED DECEMBER 31	2008	2007
Earnings (loss) before income taxes	**6,526**	(13,748)
Statutory tax rate	**29.84%**	32.46%
Expected income tax expense	**1,946**	(4,463)
Stock-based compensation	**297**	421
Reduction in future income tax rates	**(882)**	(3,634)
Impairment of goodwill	**-**	3,928
Other	**71**	472
Total income tax expense (recovery)	**1,432**	(3,276)

(B) FUTURE INCOME TAX LIABILITY

The income tax effect of temporary differences that give rise to significant portions of the future income tax assets and liabilities are presented below:

As at December 31	2008	2007
Future income tax assets:		
Asset retirement obligations	**2,441**	1,885
Attributed Canadian Royalty Income	**270**	270
Non-capital losses	**1,894**	4,142
Share issue costs	**1,067**	1,160
Future income tax liabilities:		
Risk management asset	**(501)**	(332)
Property, plant and equipment	**(39,327)**	(35,287)
Net future income tax liability	**(34,156)**	(28,162)

The non-capital losses expire in the year 2026.

NOTE 9: FINANCIAL INSTRUMENTS

(A) RISK MANAGEMENT OVERVIEW

The Company is exposed to market risks related to the volatility of commodity prices, foreign exchange rates and interest rates. Risk management is ultimately established by the Board of Directors and is implemented and monitored by senior management. The Company maintains an active risk management program as an integral part of its overall financial strategy to mitigate volatility in funds from operations resulting from fluctuating commodity prices. The strategy is designed to take advantage of the upward swings in natural gas prices as a result of the changes in demand/supply fundamentals and/or the movement of significant financial assets invested in the natural gas market as a pure commodity investment.

(B) FAIR VALUE OF FINANCIAL ASSETS AND LIABILITIES

The Company's financial instruments as at December 31, 2008; include cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, long-term debt and risk management asset.

The fair value of financial assets and liabilities that are included in the balance sheet approximate their carrying amounts due to bank debt being at a floating interest rate and all other financial assets and liabilities having a short-term maturity.

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

(C) MARKET RISK

Market risk is the risk that future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk is comprised of foreign currency exchange rate risk, interest rate risk and commodity price risk. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing returns.

The Company utilizes both financial derivatives and physical delivery contracts to manage market risks.

Foreign currency exchange rate risk

Foreign currency exchange rate risk is the risk that future cash flows will fluctuate as a result of changes in foreign exchange rates. Although substantially all of the Company's petroleum and natural gas sales are denominated in Canadian dollars, the underlying market prices in Canada for petroleum and natural gas are affected by changes in the exchange rate between the Canadian and United States dollar. The exchange rate could affect the values of certain contracts, however, this indirect influence cannot be accurately quantified. The Company had no foreign exchange rate swap or related financial contracts in place as at December 31, 2008.

Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in the market interest rates. The Company is exposed to interest rate risk to the extent that bank debt is at a floating rate of interest. The Company had no interest rate swap or related financial contracts in place as at December 31, 2008. If interest rates had been 100 basis points lower with all other variables held constant, net earnings for the year ended December 31, 2008 would have been $0.6 million (2007- $0.3 million) higher, due to lower interest expense.

Commodity price risk

Commodity price risk is the risk that the future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for petroleum and natural gas are affected not only by the relationship between the Canadian and United States dollar, as outlined above, but also world economic events that dictate the levels of supply and demand. The Company has a commodity price risk management program in place whereby the commodity price associated with a portion of its future production is fixed. The Company sells forward a portion of its future production by entering into a combination of fixed price sale contracts with customers and commodity swap agreements with financial counterparties. The fair values of the forward contracts are subject to market risk from fluctuating commodity prices and foreign exchange rates. The Company's policy is to enter into commodity contracts to a maximum of 40 – 50 percent of current production volumes.

As at December 31, 2008, the Company had the following financial derivative sales contracts which were recorded on the balance sheet at fair value of $1.7 million (2007 - $1.1 million) with changes in fair value included in unrealized gain of $0.6 million (2007 - $0.8 million) on risk management activities in the statement of earnings.

Time Period	Commodity	Type of Contract	Quantity Contracted	Contract Price ($/unit)
November 2008 – March 2009	Natural Gas	Financial	2,000 GJ/d	$7.62 fixed
November 2008 – March 2009	Natural Gas	Financial	1,000 GJ/d	$8.00 floor/$11.07 ceiling

The Company has both United States and Canadian dollar physical sales contracts. The Canadian dollar physical sales contracts were entered into and continue to be held for the purpose of delivery of non-financial items as executory contracts and have not been recorded at fair value. The fair value of the United States dollar physical sales contracts are recorded on the balance sheet with changes in fair value included in unrealized gain or loss on risk management activities in the statement of earnings. As at December 31, 2008, the Company had the following physical sales contracts.

Time Period	Commodity	Type of Contract	Quantity Contracted	Contract Price ($/unit)
April 2008 – March 2009	Natural Gas	Physical	2,000 GJ/d	$7.30 fixed
November 2008 – March 2009	Natural Gas	Physical	4,000 GJ/d	$7.46 fixed
November 2008 – March 2009	Natural Gas	Physical	2,000 GJ/d	$7.00 floor/$8.05 ceiling
November 2008 – March 2009	Natural Gas	Physical	2,000 mmbtu/d	US $9.00 fixed
April 2009 – October 2009	Natural Gas	Physical	1,000 GJ/d	$7.08 fixed
April 2009 – October 2009	Natural Gas	Physical	2,000 GJ/d	$8.25 floor/$10.00 ceiling
April 2009 – October 2009	Natural Gas	Physical	1,000 mmbtu/d	US $8.18 fixed
April 2009 – October 2009	Natural Gas	Physical	2,000 GJ/d	$8.59 fixed
April 2009 – October 2009	Natural Gas	Physical	2,000 GJ/d	$6.70 floor plus 50% > $6.70
April 2009 – March 2010	Natural Gas	Physical	3,000 GJ/d	$7.52 fixed
April 2009 – March 2010	Natural Gas	Physical	2,000 GJ/d	$6.80 floor plus 50% > $6.80
November 2009 – March 2010	Natural Gas	Physical	2,000 GJ/d	$7.65 floor plus 50% > $7.65
November 2009 – March 2010	Natural Gas	Physical	2,000 GJ/d	$7.75 floor/$8.70 ceiling
November 2009 – March 2010	Natural Gas	Physical	2,000 GJ/d	$7.26 floor plus 50% > $7.26

For the year ended December 31, 2008, the Canadian dollar physical contracts resulted in a settlement loss of $0.1 million (2007 - gains of $7.1 million) that have been included in petroleum and natural gas sales. If natural gas prices had been +/- $0.10 per mcf, with all other variables held constant, the net change in the unrealized gain or loss on risk management activities in the statement of earnings for the year would have been +/- $0.1 million (2007 – $nil). The sensitivity is higher in 2008 as compared to 2007 because of an increase in financial and US dollar based physical contracts outstanding.

The Company entered into the following contracts subsequent to December 31, 2008:

Time Period	Commodity	Type of Contract	Quantity Contracted	Contract Price ($/unit)
April 2010 – December 2010	Natural Gas	Physical	3,000 GJ/d	$6.25 floor/$7.47 ceiling
April 2010 – December 2010	Natural Gas	Physical	4,000 GJ/d	$5.93 floor plus 50% > $5.93
February 2009 – December 2009*	Natural Gas	Financial	3,500 GJ/d	$6.00 Put
March 2009 – December 2009*	Natural Gas	Physical	3,500 GJ/d	$6.00 Put
January 2010 – December 2010*	Natural Gas	Financial	3,500 GJ/d	$7.40 Call
January 2010 – December 2010*	Natural Gas	Physical	3,500 GJ/d	$7.15 Call

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

(D) CREDIT RISK

Credit risk represents the financial loss to the Company if counterparties to a financial instrument fail to meet their contractual obligations and arise principally from the Company's receivables from joint interest partners. All of the Company's accounts receivable are with customers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks. With respect to counterparties to financial instruments, the Company partially mitigates associated credit risk by limiting transactions to counterparties with investment grade credit ratings.

Receivables from petroleum and natural gas marketers are normally collected on the 25th day of the month following production. The Company's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large purchasers. The Company attempts to mitigate the risk from joint interest receivables by obtaining partner approval of significant capital expenditures prior to expenditure. However, partners are exposed to various industry and market risks that could result in non-collection. The Company does not typically obtain collateral from natural gas marketers or joint interest partners; however, the Company does have the ability to request pre-payment of certain major capital expenditures and withhold production from joint interest partners in the event of non-payment of amounts owing.

The carrying amount of cash and accounts receivable represents the maximum credit exposure. The Company does not consider an allowance for doubtful accounts is required as at December 31, 2008, however, bad debt expense of $0.1 million was recorded during the year.

As at December 31, 2008 the Company's aged receivables are as follows:

As At December 31	2008
Current (less than 30 days)	11,484
Past due (31-90 days)	1,617
Past due (more than 90 days)	1,421
Total	**14,522**

(E) LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's approach to managing liquidity risk is to ensure, to the extent possible, that it will have sufficient cash resources to meet its liabilities when they become due. The Company actively monitors the costs of its operations and capital expenditure program by preparing an annual budget, formally approved by the Board of Directors. On a monthly basis, internal reporting of actual results is compared to the budget in order to modify budget assumptions, if necessary, to ensure liquidity is maintained.

The Company requires sufficient cash to fund its operating costs and capital program that are designed to maintain or increase production and develop reserves, to acquire petroleum and natural gas assets and to satisfy debt obligations. The majority of capital spent will be funded through cash flow from operating activities. The Company enters into risk management contracts designed to improve risk-adjusted returns and to ensure adequate cash flow to fund the Company's capital program and maintain liquidity. The Company uses a combination of both financial and physical commodity price contracts. Contracts are initiated within the guidelines of the Company's risk management program and are not entered into for speculative purposes. The Company also has a 364 day revolving credit facility with a syndicate of Canadian chartered banks with a one year term out provision.

The following are the contractual maturities of financial liabilities as at December 31, 2008.

Financial liabilities	< 1 Year	1 – 2 Years	3 – 5 Years	Thereafter
Outstanding cheques	105	-	-	-
Accounts payable and accrued liabilities	36,211	-	-	-
Long term debt – principal	-	91,400	-	-
Total	36,316	91,400	-	-

NOTE 10: COMMITMENTS

The Company is committed to future minimum payments for natural gas transmission and processing, operating leases on compression equipment and office space. Payments required under these commitments for each of the next five years are: 2009-$4.5 million; 2010-$5.2 million; 2011-$4.9 million; 2012-$3.6 million; 2013-$2.2 million.

NOTE 11: CHANGES IN NON-CASH WORKING CAPITAL ITEMS

Years ended December 31	2008	2007
Change in working capital item:		
Accounts receivable	**(1,918)**	3,493
Prepaid expenses and deposits	**(176)**	(1,292)
Accounts payable and accrued liabilities	**6,555**	8,164
Total change in non-cash working capital	**4,461**	10,365
Relating to:		
Operating activities	**(5,022)**	6,777
Investing activities	**9,483**	3,588
	4,461	10,365

RESULTS
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]
Independent Businessman

Robert A. Lehodey, Q.C. [2]
Partner
Osler, Hoskin & Harcourt LLP

Andrew E. Osis [1]
Chief Executive Officer and Director
Multiplied Media Corporation

Lamont C. Tolley [1]
Independent Businessman

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

OFFICERS

David J. Reid
President and Chief Executive Officer

Tony Angelidis
Senior Vice President Exploration

Hugo H. Batteke
Vice President Operations

Rod A. Hume
Vice President Engineering

Michael S. Kaluza
Chief Operating Officer

Brian P. Kohlhammer
Vice President Finance and
Chief Financial Officer

CORPORATE OFFICE

300, 500 – 4th Avenue S.W.
Calgary, Alberta
T2P 2V6

Telephone: (403) 265-6171
Facsimile: (403) 265-6207
Email: info@delphienergy.ca
Website: www.delphienergy.ca

AUDITORS
KPMG LLP

BANKERS
National Bank of Canada
The Bank of Nova Scotia

LEGAL COUNSEL
Osler, Hoskin & Harcourt LLP

INDEPENDENT ENGINEERS
GLJ Petroleum Consultants Ltd.

TRANSFER AGENT
Olympia Trust Company

STOCK EXCHANGE LISTING
Toronto Stock Exchange – DEE

ANNUAL GENERAL MEETING
May 21, 2009, Calgary, Alberta

ABBREVIATIONS

bbls	barrels
bbls/d	barrels per day
mbbls	thousand barrels
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
NGL	natural gas liquids
bcf	billion cubic feet
boe	barrels of oil equivalent (6 mcf:1 bbl)
boe/d	barrels of oil equivalent per day
mmboe	million barrels of oil equivalent
GJ	gigajoules

DELPHI DELIVERS

Delphi Energy Corp.

300, 500 – 4th Avenue S.W.
Calgary, Alberta
T2P 2V6

Telephone: (403) 265-6171
Facsimile: (403) 265-6207
Email: info@delphienergy.ca

WWW.DELPHIENERGY.CA