# DELPHI ENERGY CORP.

**ANNUAL REPORT** 2012

www.delphienergy.ca
TSX **DEE**

Delphi Energy Corp. is a junior oil and gas producer operating in the resource rich, deep basin area of Northwest Alberta. Delphi maintains control of its production and capital operations and owns a working interest in key facilities infrastructure to ensure produced volumes are processed cost efficiently and marketed on a timely basis. Delphi is the field operator for over 90 percent of its production and currently operates all of its drilling operations.

Over the past year and one-half, Delphi has primarily focused on de-risking and the development of its liquids-rich, natural gas Montney resource base at Bigstone near Fox Creek, Alberta. In addition, the Company continues to expand its inventory of opportunities in the Deep Basin through farm-ins and land acquisitions.

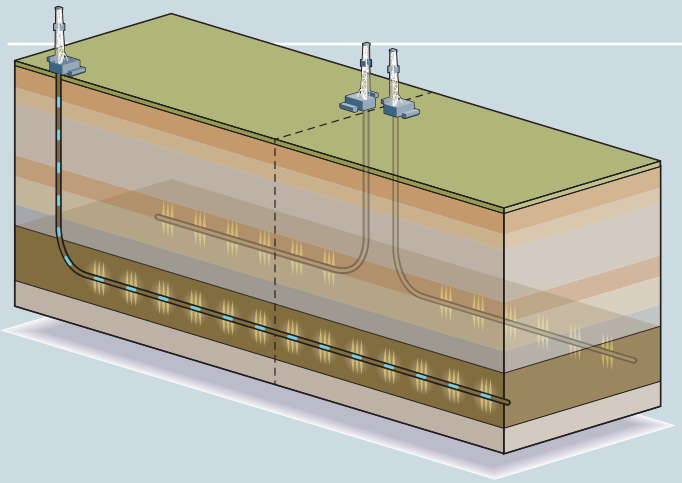
# MONTNEY

## BIGSTONE - THE BIG PLAY

The Montney is an emerging play that continues to be developed with great success. Industry has shown that advancing technologies used in developing the Montney play offers repeatability and has resulted in high rate gas wells that contain substantial amounts of natural gas. Delphi is proud to have such a significant land position with high working interests as well as the technical team and knowledge to fully exploit the resources of this world class asset. Bigstone.... is a Big Story

2012 was a significant year at Bigstone for Delphi as it focused not only on the initial drilling and development of the Montney, but also on adding a substantial amount of high quality lands to complement its existing Montney acreage. By the end of 2012, Delphi had drilled a total of four horizontal Montney wells at East Bigstone and one at West Bigstone. The first three wells at East Bigstone were all brought on stream in 2012 through the Company's 100 percent owned compression and dehydration facility. The facility was constructed during 2012 with an initial capacity of 30 mmcf/d and designed for easy expansion to 60 mmcf/d. With significant infrastructure put in place during 2012, the Company is now able to move forward with the development phase of the Montney at East Bigstone.

The Company is extremely encouraged by the results of the first three East Bigstone wells brought on production during 2012. They not only substantiated the presence of a significant liquids rich resource, the consistent results and performance of the first



## GO LONG!

By developing the Montney with extended reach horizontals, overall development costs can be reduced by approximately 35% compared to single section horizontals.... Go Long.

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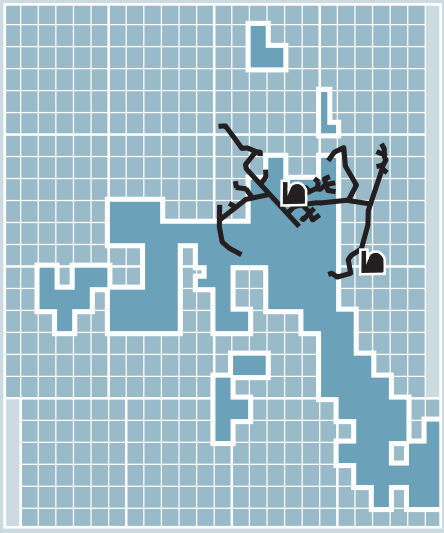
## WHAT MAKES IT BETTER?

# Liquids rich Existing infrastructure Robust economics

three wells verified the large extent of the resource over the Company's land base. Total liquids from the first three wells averaged 65 bbls/mmcf sales in 2012, consisting of 28 bbls/mmcf produced field condensate and an additional 37 bbls/mmcf recovered at the plant. Of this total, field produced and plant recovered condensate accounted for 59 percent or 38 bbls/mmcf sales of total liquids.

Late in 2012, the Company drilled its fourth horizontal Montney well in East Bigstone at 15-10-60-23W5 and in doing so took the first significant step, since drilling the first three wells, toward the enhancement and evolution of the play. The first three wells employed a completion technique very similar to those used in horizontal Montney wells to the east of the Company's lands. They were completed using gelled oil fracs (20 stages in each well) resulting in fracture geometries that can be described as conventional, bi-wing or planar. These completions resulted in very high initial production rates but because of the tight nature of the Montney formation, high initial declines were experienced leading to lower stabilized production rates. To mitigate these high initial decline rates, and after considerable work by the Company's technical team, a new completion technique was designed. A slickwater hybrid frac system was employed in the fourth East Bigstone Montney well at 15-10. The purpose of the new completion technique is to generate a large stimulated rock volume (shatter the rock versus creating one large fracture) in the reservoir and lessen the declines of the wells. The 15-10 well was drilled with a shorter horizontal lateral length (1,424 metres) to assess the new completion liner installed (which is better suited for this completion design compared to what was used on the first three wells) and frac technique. Initial results have not only significantly lessened initial declines, but the enhanced reservoir stimulation has also provided for improved productivity of free reservoir condensate. Although 15-10 is the shortest horizontal well the Company has drilled in the Montney at East Bigstone, it is anticipated, based on initial production data, to outperform the first three horizontal Montney wells the Company drilled in East Bigstone. The new completion technique was also employed at the Company's fifth well in East Bigstone at 10-27-60-23W5. This well was drilled with a longer horizontal lateral (2,407 metres) to test the capability of a 30 stage slickwater hybrid completion, which the Company plans on using in its future drills. Results have followed that of the 15-10 well, significantly surpassing the Company's expectations, both in terms of initial decline and liquid production.



Delphi lands Delphi facilities
Delphi gas gathering system

## DRILLING INVENTORY

140 net 2 section horizontal locations

## LAND POSITION

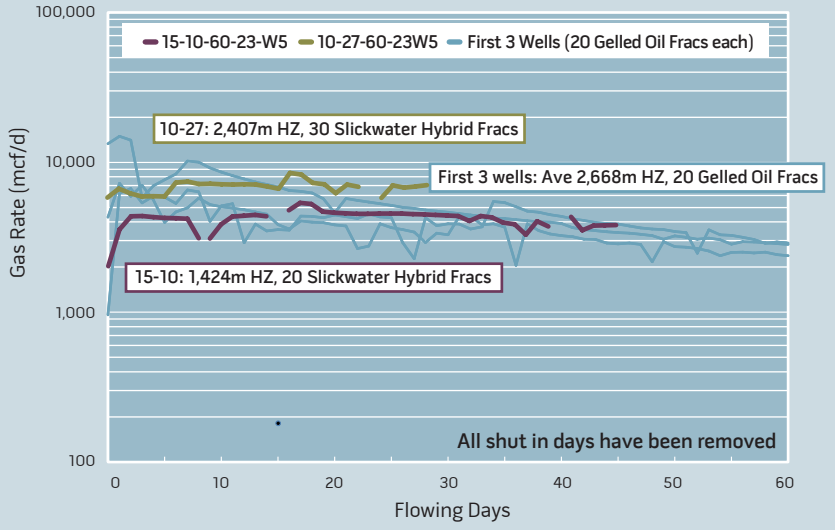
108 gross (93 net) sections

## MITIGATING DECLINES

Quick payout

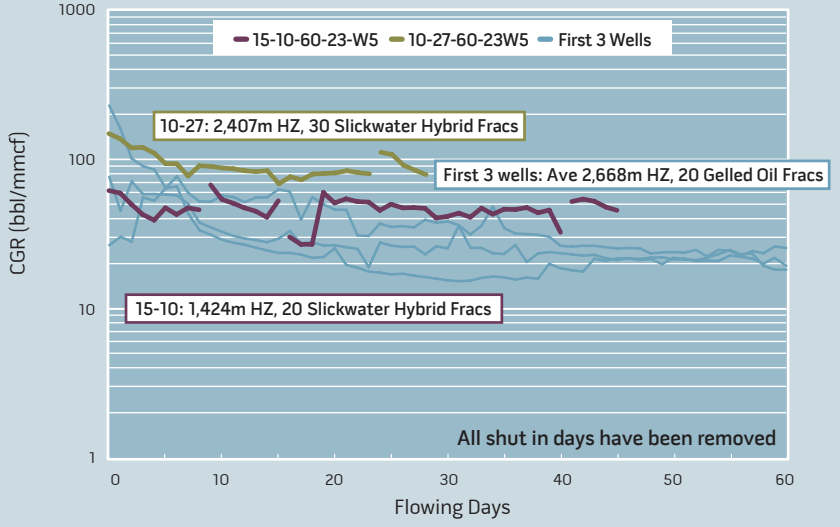
### EAST BIGSTONE HORIZONTAL MONTNEY WELLS

**Gas Rate Normalized to first day of production**




### EAST BIGSTONE HORIZONTAL MONTNEY WELLS

**Field Condensate to Gas Ratio Normalized to first day of production**




Gas plant recovery of natural gas liquids from the gas stream of these two new wells was expected to be similar to that of the first three wells, but the initial combined field produced condensate to gas ratio from the 15-10 and 10-27 wells are more than 2.5 times greater than what has been produced in the first three wells.

The charts show the performance of the two new wells compared to the first three wells the Company drilled. Production data has been normalized and days during which the wells were shut-in have been removed from the plots to appropriately compare gas flow rates and field produced condensate to gas ratio.

The new completion techniques, by mitigating declines and providing for higher field condensate production, have significantly improved the payout rate of return and the net present values of the East Bigstone Montney play.

As the Company has drilled and completed more horizontal Montney wells in Bigstone, capital required to drill and complete each well have been reduced considerably. Drilling time and per stage frac costs have decreased since the drilling and completion of the first Montney well. As the Company advances development of this play, the gained experience and improvements with the drilling and completing of these wells will continue to drive capital costs down and further improve the economics of this already robust play.

Advancement of completion technologies

Maximize efficiencies

Operational discipline to drive down costs

The Company finished its winter drilling season in 2013 at East Bigstone with the 16-23-60-23W5 well, which will be completed with a 30 stage slickwater hybrid frac, after spring break-up. This well is the second longest horizontal Montney well the Company has drilled with a horizontal lateral of 2,809 metres.

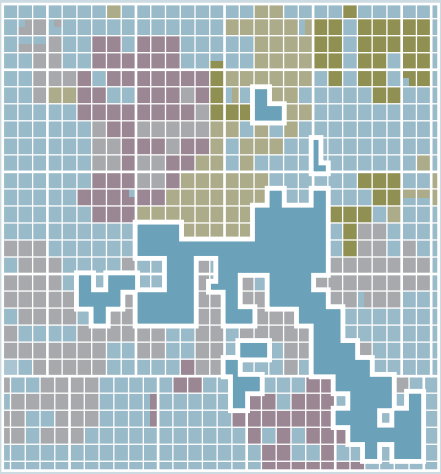
A strategic farm-in near the end of 2012 has the potential, upon earning, to increase the Company's Montney (and Nordegg) land holdings in East Bigstone by as many as 35 gross sections at a WI of 75 percent. Additionally, levering on the results of the new completion techniques and the Company's owned infrastructure, a large and strategic land acquisition was closed in March of 2013. The acquisition consisted of 30 gross sections (27 net) in the heart of the play. Upon full earning of the 2012 farm-in arrangement and including the 2013 land acquisition, the Company will grow its land position by over 130 percent in the Bigstone Montney play from 43 sections (41 net) to 108 sections (94 net).

The Company also drilled a horizontal Montney well on its 27 section block at West Bigstone in 2012. Although initial results from a total production rate perspective are lower than those at East Bigstone, the Company believes that the advancement in completion techniques at East Bigstone are directly applicable to West Bigstone and the significant, potentially light oil, play there.

The next steps in the evolution of the Montney play at Bigstone will include further refinements to completion techniques as production data is analyzed, providing for further improvements to the deliverability of these wells. Applying the learnings from the recent results at East Bigstone to the potentially light oil play at West Bigstone will help unlock the value of that resource. Continued focus on logistics and driving down capital costs will maximize the efficiency of this large scale development.

## IN GOOD COMPANY

We are proud to be neighbours to such notable peers as Encana, Exxon, Chevron and Athabasca.



# HIGHLIGHTS

| Year Ended December 31 | **2012** | 2011 |
|---|---|---|
| **Financial Highlights** | | |
| (thousands of dollars, except per boe and per share amounts) | | |
| Gross petroleum and natural gas sales | **85,754** | 126,887 |
| Per boe | **28.31** | 39.19 |
| Funds from operations | **32,305** | 66,872 |
| Per boe | **10.65** | 20.65 |
| Per share – Basic | **0.24** | 0.57 |
| – Diluted | **0.24** | 0.56 |
| Net earnings (loss) | **(58,030)** | 11,602 |
| Per boe | **(19.18)** | 3.58 |
| Per share – Basic | **(0.43)** | 0.10 |
| – Diluted | **(0.43)** | 0.10 |
| Capital invested | **83,728** | 114,477 |
| Dispositions of properties | **(34,664)** | (12,873) |
| Net capital invested | **49,064** | 101,604 |
| Acquisitions | **139** | 273 |
| Total Capital | **49,203** | 101,877 |
| Debt plus working capital deficit | **92,815** | 95,632 |
| Total assets | **401,649** | 447,073 |
| Shares outstanding (thousands) | | |
| Basic | **153,049** | 131,000 |
| Diluted | **162,104** | 141,591 |

| Year Ended December 31 | **2012** | 2011 |
|---|---|---|
| **Operational Highlights** | | |
| Average daily production | | |
| Natural gas (mcf/d) | **37,589** | 37,992 |
| Percentage of total production | **76%** | 71% |
| Oil and natural gas liquids (bbls/d) | **2,010** | 2,538 |
| Percentage of total production | **24%** | 29% |
| Total (boe/d) | **8,276** | 8,870 |
| | | |
| Realized selling prices | | |
| Natural gas ($/mcf) | **2.87** | 4.55 |
| Oil ($/bbl) | **90.38** | 91.56 |
| Natural gas liquids ($/bbl) | **46.24** | 51.13 |
| Total oil equivalent ($/boe) | **29.50** | 40.47 |
| | | |
| Wells drilled (net) | **6.5** | 23.8 |
| | | |
| Undeveloped land | | |
| Gross acres | **311,771** | 408,471 |
| Net acres | **196,543** | 239,186 |
| Average working interest (%) | **63%** | 59% |
| | | |
| Proved plus probable reserves (P+P) | | |
| Natural gas (mmcf) | **195,795** | 185,862 |
| Oil and natural gas liquids (mbbls) | **10,429** | 9,205 |
| Total oil equivalent (mboe) | **43,062** | 40,182 |
| | | |
| Finding and development costs (P+P) | **16.35** | 12.98 |
| Finding, development and acquisition (P+P) | **18.03** | 12.37 |
| Reserve life index (P+P) | **14.2** | 12.4 |

# TO OUR SHAREHOLDERS

2012 was an exciting year for Delphi as the Company initiated its development of the East Bigstone Montney project and began the transition to a condensate-rich natural gas resource based growth platform, mitigating an ongoing challenging natural gas pricing environment.

## YEAR IN REVIEW

During 2012, Delphi made significant progress in advancing its condensate-rich Montney play at East Bigstone. Since commissioning its 100 percent owned compression and dehydration facility in May 2012, the Company averaged approximately 1,200 barrels of oil equivalent per day, (30 percent or 68 barrels per million cubic feet natural gas liquids) from the three Montney horizontal wells drilled during the year. Condensate represented 62 percent of the total NGL production. Subsequent to year end, Delphi has drilled an additional three Montney wells, two of which have already been completed and are now on production. Current production over the first two weeks of March from the five wells on production averaged approximately 3,850 boe/d (37 percent or 95 bbls/mmcf NGL's). The optimization of the Company's drilling and completions techniques resulting in significantly enhanced production performance will have a positive impact on the play economics and overall corporate performance.

Production during the fourth quarter 2012 of 7,229 boe/d and full year 2012 production of 8,276 boe/d were negatively impacted by the property dispositions during the year. Disposition production volumes totalled approximately 667 boe/d (54 percent light oil).

The total capital program in 2012 was $83.7 million with approximately 75 percent of the expenditures directed to the Montney development project at Bigstone, drilling four gross (3.75 net) wells and constructing the required facility and major gathering system infrastructure. The Company directed approximately $24.3 million or 29 percent of its capital expenditures to new facility and pipeline construction. In total the Company drilled seven gross (6.5 net) wells, including one net well that was drilled in the fourth quarter of 2012 but not completed. This compares to 30 gross (23.8 net) wells drilled in 2011. Strategic non-core asset disposition proceeds of $34.7 million were utilized to partially fund the capital program, resulting in net capital expenditures in 2012 of $49.2 million.

Delphi achieved finding and development costs including changes in future development costs of $16.35 per boe for total proved plus probable reserves, replacing 2012 production by 2.0 times with total proved plus probable reserve additions of 11.9 million boe and dispositions and revisions of 5.9 million boe. Total proved plus probable reserves increased by seven percent to 43.0 million boe compared to 2011, while total proved reserves decreased by five percent compared to 2011. Petroleum and natural gas reserve additions from the capital program increased the Company's reserve life index to 14.2 years. Bigstone Montney total proved plus probable reserves increased by 233 percent to 11.0 million boe compared to 3.3 million boe in 2011.

Financial results in 2012 were also affected by lower commodity prices, particularly lower natural gas prices, with Canadian benchmark natural gas prices decreasing 34 percent to average $2.39 per million cubic feet in 2012. Funds from operations decreased 52 percent to $32.3 million for 2012 as a result of a seven percent decline in average production and a 27 percent reduction in the realized sales price per boe as compared to 2011.

At December 31, 2012, unutilized credit available on the Company's $125.0 million banking facilities was nearly $32.1 million (26 percent of available bank facilities), providing support for the Q1 2013 capital program.

In December 2012, Delphi also increased its exposure in its Bigstone Montney area with an industry farm-in agreement to earn up to a 75 percent working interest in 35 sections of Montney and Nordegg petroleum and natural gas rights. Upon full earning, the Company will grow its land position by nearly 60 percent from 41.7 net sections to approximately 66.2 net sections. The farm-in nearly doubles the East Bigstone low-risk development drilling inventory in the proven upper and middle Montney formations.

Delphi's undeveloped land position at December 31, 2012, a measure of its future growth prospect inventory, was 196,543 net acres (307 sections). The Company has regulatory approval to drill up to four natural gas wells per pool per section on its lands at its three core properties of Bigstone, Hythe and Wapiti. Delphi increased its land holdings in 2012 (including the farm-in lands) on its East Bigstone Montney play to 78.5 gross (66.2 net) sections.

## OUTLOOK

The low natural gas price environment of 2012 had a significant effect on the Company's natural gas revenues in 2012. Looking forward through 2013 and beyond, the Company is forecasting a steady gradual improvement in the natural gas price environment. With the Company's growing condensate-rich Montney production combined with improved natural gas prices, Delphi remains confident in achieving its long term growth targets.

The Company is taking a measured approach to its 2013 capital program with 2013 net capital expenditures estimated to be $50.0 - $55.0 million. Historically, Delphi executes a winter capital program in excess of first quarter cash flow followed by at least one quarter of minimal activity prior to returning to the field with an active fall program.

Delphi has hedged approximately 51 percent of its 2013 natural gas production at $3.27 per mcf to support funds from operations and the Company's ability to pursue its planned capital program.

The Company's recent success at East Bigstone has increased its current production capability in March to approximately 9,200 to 9,400 boe/d (28 percent NGL's and light oil) with the final Montney horizontal well of the winter program not yet completed.

Subsequent to December 31, 2012 the Company closed a strategic acquisition of 30 gross (27 net) sections of undeveloped Montney lands for $13.65 million, putting the final piece of the Bigstone area Montney project puzzle in place, creating one large contiguous land position covering over 100 sections of land. Delphi's land position now ranks the third largest in the area and now boosts over $1.2 billion of development drilling opportunities creating an inventory of economic growth well into the future.

The recent results of the Montney program proves the robust economics of the play and with the large development inventory assembled, the Company is positioned with an asset capable of long term sustainable growth. Field netbacks of the East Bigstone Montney production are estimated to be $28.00 - $30.00 per boe in 2013, more than twice the corporate field netback achieved in 2012.

In 2013 and beyond, we believe the Company will return to the low-cost reserve additions achieved over the previous three years with the major infrastructure build-out at East Bigstone in place and the production performance now being achieved. Our growing condensate and natural gas liquids production is providing a natural hedge against low natural gas prices.

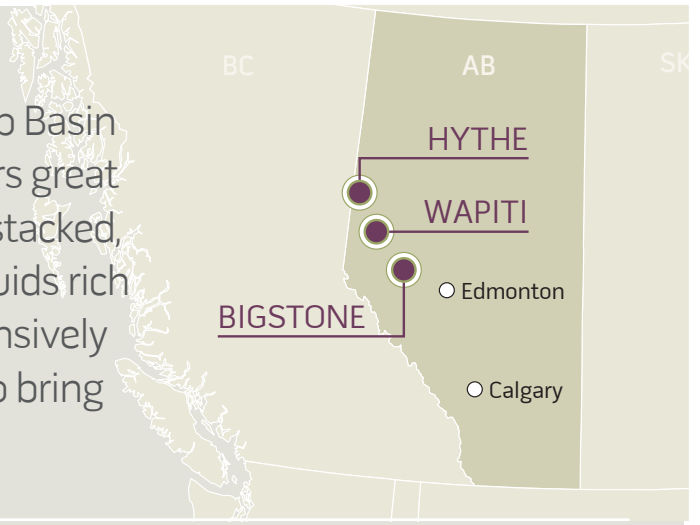
On behalf of the Board of Directors and all the employees of Delphi, we would like to thank our shareholders for their continued support.

On behalf of the Board,

**David J. Reid,**
**President and Chief Executive Officer**

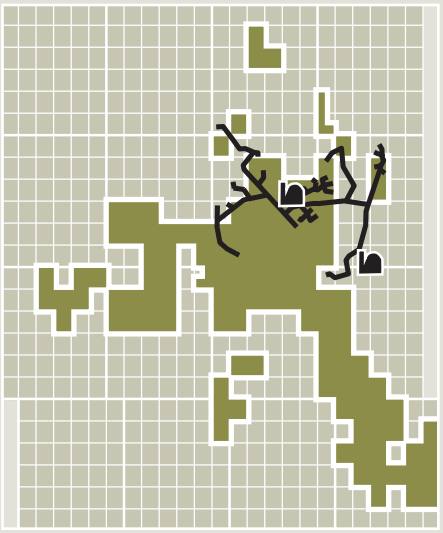
March 19, 2013

Delphi's core operating area is in the Deep Basin of northwestern Alberta. This area garners great attention in the industry because of the stacked, multi-zone opportunities that contain liquids rich natural gas and oil. The area is also extensively covered by the infrastructure required to bring hydrocarbon products to market.




## OPERATIONS OVERVIEW

Our three core assets: Bigstone, Hythe and Wapiti, all possess the important components that make the Deep Basin such a desirable place for oil and gas companies to conduct their business.



Delphi lands
Delphi facilities
Delphi gas gathering system

### BIGSTONE

The Bigstone property is located 150 kilometres southeast of the city Grande Prairie and was the Company's second largest producing asset in 2012, contributing an average of 2,420 boe/d, of which 25 percent was oil and natural gas liquids. Important infrastructure ownership not only includes the Company's 100 percent Montney compression and dehydration facility, but also a working interest in the Bigstone West gas plant with a gross capacity of 85 mmcf/d. The Company has an average working interest of 78 percent in 50,400 acres of land, of which 23,040 acres (21,706 net) are undeveloped.

In addition to the Montney play, Bigstone offers significant horizontal development potential in the Gething formation with the success the Company's horizontal well at 12-16-60-23W5. Utilizing horizontal wells and multi-frac technology in the Gething formation not only provides for stimulation of tighter sands within the Gething channels, but also enables stimulation of the high permeability sands, providing a connection of these sands to the horizontal well that were traditionally the target of conventional vertical wells. Statistically, drilling a horizontal well and pumping multiple fracs within the horizontal lateral greatly improves the chance of encountering these high permeability sands that were otherwise a one-shot chance with vertical wells. The Company has identified 57 undrilled Gething horizontal locations on its lands.

On the exploration front, both the Second White Specks and the Nordegg formation overlying the Montney provide possible future light oil/gas condensate resource play style opportunities as technology and resource characterization progress.

Top quartile netbacks

One of the largest area land positions

Robust economic returns

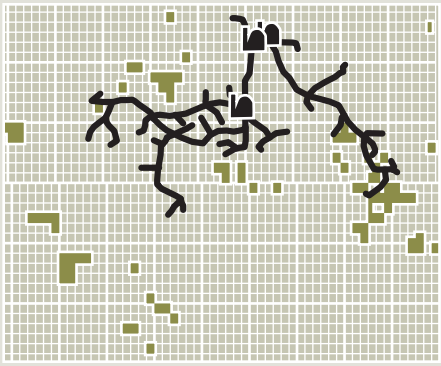
## WAPITI

The Wapiti property is located 50 kilometres south of the city of Grande Prairie and was the Company's third largest producing asset in 2012, contributing an average of 2,274 boe/d, of which 33 percent was oil and natural gas liquids. Important infrastructure ownership includes working interests in three gas plants which includes one with deep cut process. These gas plants have a combined gross processing capacity of 940 mmcf/d. The Company has an average working interest of 58 percent in 61,924 acres of land, of which 26,564 acres (16,481 net) are undeveloped.

In 2012, the Company drilled two vertical wells (2.0 net) including one Nikanassin well and one multi-zone (Gething/Nikanassin) well with a 100 percent success rate.

Rich gas from the multi-zone Cretaceous and Jurassic intervals continue to offer significant value from the liquid volumes that are extracted and sold at premium prices. Wapiti continues to be a growth area with a significant, profitable drilling inventory of over 48 identified net multi-zone locations. The Company is evaluating the potential for drilling horizontal wells with multi-stage fracturing to further enhance the already robust economics of these liquid rich intervals.

The Company's portfolio of strategic infrastructure, including company owned and operated compression and gathering systems, allows for optimization, control of costs and most importantly, dedicated and dependable service which is paramount in maintaining maximum profitability.



Delphi lands Delphi facilities
Delphi gas gathering system

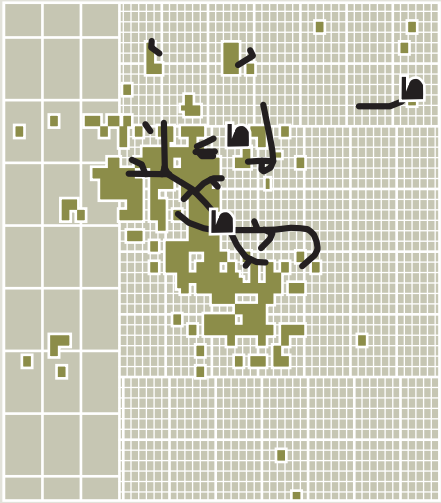
## HYTHE

The Hythe property is located 60 kilometres northwest of the city of Grande Prairie and was the Company's largest producing asset in 2012, contributing an average of 2,788 boe/d, of which 23 percent was oil and natural gas liquids. Important infrastructure ownership includes working interests in three gas plants with a combined gross capacity of over 300 mmcf/d. The Company has an average working interest of 68 percent in 173,219 acres of land, of which 129,952 acres (72,702 net) are undeveloped.

In January 2012, the Company tied in three wells which were drilled earlier that winter, two horizontal multi-fraced Falher wells and one multi-zone vertical well. Performance from the Company's horizontal development program in the Falher formation confirms the extensive inventory of 68 locations currently mapped on existing company lands.

The Company continues to be encouraged by the performance of its Doe Creek horizontal oil wells. The most recent drill at 11-10-73-12W6, which proved to be the best Doe Creek well the Company has drilled, outperformed expectations in 2012 and as a result the Company continues to evaluate drilling more of the eight currently identified locations.

The Hythe property offers many additional multiple stacked targets down to depths of 2,400 metres. The primary natural gas horizons in the area are Dunvegan, Notikewin, Falher, Bluesky, Gething and Nikanassin formations, with the oil horizons being primarily the Doe Creek and Dunvegan. Historically, exploitation of all these formations has been through traditional vertical drilling and completions. Significant oil, gas and natural gas liquids remain to be recovered from these tighter sandstone reservoirs and the Company continues to develop strategies for application of horizontal drilling and multi-stage frac technologies to accomplish this.



Delphi lands Delphi facilities
Delphi gas gathering system

# 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, 2012 and prepared a reserves report in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" and with the Canadian Oil and Gas Evaluation Handbook. Full and complete disclosure information as required by NI 51-101 can be referenced in the Company's Annual Information Form (AIF).

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 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 and AIF.

## RESERVES RECONCILIATION

The reconciliation of the Company's proved, probable and proved plus probable reserves for December 31, 2012 is as follows:

## RECONCILIATION OF COMPANY INTEREST RESERVES (1)(2)(3)

| | Light and Medium Oil | | | Associated and Non-Associated Gas | | | Natural Gas Liquids | | | Barrels of Oil Equivalent | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Factors | Proved (mbbls) | Probable (mbbls) | Proved + Probable (mbbls) | Proved (mmcf) | Probable (mmcf) | Proved + Probable (mmcf) | Proved (mbbls) | Probable (mbbls) | Proved + Probable (mbbls) | Proved (mboe) | Probable (mboe) | Proved + Probable (mboe) |
| December 31, 2011 | 1,913 | 765 | 2,678 | 114,791 | 71,072 | 185,862 | 4,029 | 2,498 | 6,527 | 25,074 | 15,108 | 40,182 |
| Extensions and Improved Recovery | - | - | - | 19,598 | 29,670 | 49,268 | 1,525 | 2,183 | 3,707 | 4,791 | 7,128 | 11,919 |
| Technical Revisions | 52 | (56) | (4) | 1,393 | (8,317) | (6,924) | 27 | (83) | (56) | 311 | (1,526) | (1,215) |
| Discoveries | - | - | - | - | - | - | - | - | - | - | - | - |
| Acquisitions | - | - | - | - | - | - | - | - | - | - | - | - |
| Dispositions | (1,018) | (382) | (1,400) | (7,590) | (2,273) | (9,863) | (138) | (43) | (182) | (2,421) | (804) | (3,225) |
| Economic Factors | (1) | (1) | (2) | (5,066) | (3,724) | (8,790) | (86) | (18) | (103) | (931) | (639) | (1,570) |
| Production | (255) | - | (255) | (13,758) | - | (13,758) | (481) | - | (481) | (3,029) | - | (3,029) |
| December 31, 2012 | 691 | 326 | 1,017 | 109,368 | 86,427 | 195,795 | 4,876 | 4,536 | 9,412 | 23,796 | 19,267 | 43,062 |

(1) Company interest reserves represent the Company's interest before deducting royalties and including any royalty interest of the Company.
(2) Reserves are estimated using forecast prices and costs.
(3) 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 and including Company royalty interest) basis. Proved plus probable reserves increased seven percent and proved reserves decreased by five percent as compared to 2011. Proved producing reserves account for 32 percent of the Company's total proved plus probable reserves.

| Company Interest Reserves (1)(2)(3) | **2012** | 2011 | % change |
|---|---|---|---|
| Proved Developed Producing | | | |
| Light and medium crude oil (mbbls) | **520** | 1,307 | (60) |
| Natural gas liquids (mbbls) | **2,433** | 2,266 | 7 |
| Natural gas excluding natural gas liquids (mmcf) | **65,923** | 69,297 | (5) |
| Total (mboe) | **13,941** | 15,123 | (8) |
| Proved Developed Non-Producing Reserves | | | |
| Light and medium crude oil (mbbls) | **-** | 132 | (100) |
| Natural gas liquids (mbbls) | **236** | 378 | (38) |
| Natural gas excluding natural gas liquids (mmcf) | **5,283** | 11,390 | (54) |
| Total (mboe) | **1,117** | 2,409 | (54) |
| Proved Undeveloped Reserves | | | |
| Light and medium crude oil (mbbls) | **171** | 474 | (64) |
| Natural gas liquids (mbbls) | **2,207** | 1,385 | 59 |
| Natural gas excluding natural gas liquids (mmcf) | **38,162** | 34,103 | 12 |
| Total (mboe) | **8,738** | 7,543 | 16 |
| Proved Reserves | | | |
| Light and medium crude oil (mbbls) | **691** | 1,913 | (64) |
| Natural gas liquids (mbbls) | **4,876** | 4,029 | 21 |
| Natural gas excluding natural gas liquids (mmcf) | **109,368** | 114,791 | (5) |
| Total (mboe) | **23,796** | 25,074 | (5) |
| Probable Reserves | | | |
| Light and medium crude oil (mbbls) | **326** | 765 | (57) |
| Natural gas liquids (mbbls) | **4,536** | 2,498 | 82 |
| Natural gas excluding natural gas liquids (mmcf) | **86,427** | 71,072 | 22 |
| Total (mboe) | **19,267** | 15,108 | 28 |
| Proved Plus Probable Reserves | | | |
| Light and medium crude oil (mbbls) | **1,017** | 2,678 | (62) |
| Natural gas liquids (mbbls) | **9,412** | 6,527 | 44 |
| Natural gas excluding natural gas liquids (mmcf) | **195,795** | 185,862 | 5 |
| Total (mboe) | **43,062** | 40,182 | 7 |

(1) Company interest reserves represent the Company's interest before deducting royalties and including any royalty interest of the Company.
(2) Reserves are estimated using forecast prices and costs.
(3) Tables may not add due to rounding.

## FORECAST PRICES

The following table sets forth a summary of GLJ's January 1, 2013 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 (Cdn$/mmbtu) | Exchange Rate (US$/Cdn$) | Inflation (%) |
|---|---|---|---|---|---|
| 2013 | 90.00 | 85.00 | 3.38 | 1.000 | 2.0 |
| 2014 | 92.50 | 91.50 | 3.83 | 1.000 | 2.0 |
| 2015 | 95.00 | 94.00 | 4.28 | 1.000 | 2.0 |
| 2016 | 97.50 | 96.50 | 4.72 | 1.000 | 2.0 |
| 2017 | 97.50 | 96.50 | 4.95 | 1.000 | 2.0 |
| 2018 | 97.50 | 96.50 | 5.22 | 1.000 | 2.0 |
| 2019 | 98.54 | 97.54 | 5.32 | 1.000 | 2.0 |
| 2020 | 100.51 | 99.51 | 5.43 | 1.000 | 2.0 |
| 2021 | 102.52 | 101.52 | 5.54 | 1.000 | 2.0 |
| 2022 | 104.57 | 103.57 | 5.64 | 1.000 | 2.0 |
| Thereafter (1) | +2.0%/yr | +2.0%/yr | +2.0%/yr | 1.000 | 2.0 |

(1) Percentage change of 2.00% represents the change in future prices each year after 2022 to the end of the reserve life.

The Company's weighted average historical prices for 2012, before hedging impacts, were $2.61 per mcf for natural gas and $86.36 per bbl for its crude oil blend.

## NET PRESENT VALUE OF RESERVES – FORECAST PRICING (1)

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

| ($ millions) (1) | 0% | 5% | 10% | 15% | 20% |
|---|---|---|---|---|---|
| Proved | | | | | |
| Developed Producing | 248.6 | 196.8 | 163.3 | 140.1 | 123.2 |
| Developed Non-Producing | 17.0 | 10.7 | 7.4 | 5.5 | 4.2 |
| Undeveloped | 132.7 | 73.3 | 41.4 | 22.6 | 10.9 |
| Total Proved | 398.3 | 280.8 | 212.1 | 168.2 | 138.3 |
| Probable | 443.3 | 240.4 | 150.8 | 103.3 | 74.8 |
| Total Proved Plus Probable | 841.6 | 521.2 | 362.9 | 271.5 | 213.1 |

(1) The estimated future net revenues are before the deduction of estimated future site restoration costs but are reduced for estimated future abandonment costs for reserve wells and estimated capital for future development associated with the reserves. The estimated values disclosed do not necessarily represent fair market value.

## FINDING AND DEVELOPMENT COSTS

The Company has presented its finding and development costs for its exploration and development program in accordance with NI 51-101.

| | **2012** | | 2011 | | 2010-2012 | |
|---|---|---|---|---|---|---|
| | **Proved** | **Proved Plus Probable** | Proved | Proved Plus Probable | Proved | Proved Plus Probable |
| Capital **($ thousands)** | | | | | | |
| Exploration and Development ("E&D") Costs | **83,728** | **83,728** | 114,477 | 114,477 | 303,155 | 303,155 |
| Change in Future Development Costs ("FDC") related to E&D | **31,644** | **65,642** | 1,473 | 10,112 | 65,995 | 121,800 |
| Total E&D Costs | **115,372** | **149,370** | 115,950 | 124,589 | 369,150 | 424,955 |
| Acquistion Costs | **139** | **139** | 273 | 273 | 431 | 431 |
| Disposition Costs | **(34,664)** | **(34,664)** | (12,873) | (12,873) | (47,783) | (47,783) |
| Change in FDC related to Acquisitions and Dispositions ("A&D") | **(8,299)** | **(8,299)** | (1,162) | (1,935) | (9,638) | (11,491) |
| Total A&D Costs | **(42,823)** | **(42,823)** | (13,762) | (14,535) | (56,991) | (58,843) |
| Total Costs | **72,549** | **106,547** | 102,188 | 110,054 | 312,160 | 366,112 |
| Reserves **(mboe)** | | | | | | |
| Reserve Additions [1] | **4,172** | **9,134** | 5,882 | 9,451 | 17,990 | 29,157 |
| Acquistions and Dispositions | **(2,421)** | **(3,225)** | (291) | (551) | (2,993) | (4,267) |
| Total Reserve Additions | **1,751** | **5,909** | 5,591 | 8,899 | 14,997 | 24,890 |
| Finding and Development Costs **($/boe)** | | | | | | |
| E&D, excluding change in FDC | **20.07** | **9.17** | 19.46 | 12.11 | 16.85 | 10.40 |
| E&D, including change in FDC related to E&D | **27.66** | **16.35** | 19.71 | 13.18 | 20.52 | 14.57 |
| Exploration, Development, Acquisitions and Dispositions, including total change in FDC [2] | **41.44** | **18.03** | 18.28 | 12.37 | 20.81 | 14.71 |

(1) Includes extensions and improved recovery, technical revisions, discoveries, and economic factors.

(2) Includes all extensions and improved recovery, technical revisions, discoveries, economics factors, acquisitions, and dispositions and the total costs (which include the total year over year change in total future development costs).

(3) 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.

(4) BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 mcf : 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

## RESERVE LIFE INDEX

The reserve life index of Delphi has been calculated by dividing year end 2012 reserves by the average 2012 annual production of 8,276 boe/d. The reserve life index is 14.2 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, 2012 | 5,567 | 4,862 | 10,429 | 109,368 | 86,427 | 195,795 | 23,796 | 19,267 | 43,062 |
| Production | 736 | | 736 | 13,758 | | 13,758 | 3,029 | | 3,029 |
| **Reserves life index (years)** | **7.6** | | **14.1** | **7.9** | | **14.2** | **7.9** | | **14.2** |

## RESERVES PER OUTSTANDING COMMON SHARE

The proved plus probable reserves per 1,000 common shares of the Company at December 31, 2012 decreased to 281.4 compared to 306.7 the previous year including an increase to outstanding common shares of 17 percent.

| | **2012** | 2011 |
|---|---|---|
| December 31 proved plus probable reserves (mboe) | **43,062** | 40,182 |
| December 31 common shares outstanding | **153,047,798** | 130,999,798 |
| Proved plus probable boe reserves per 1,000 shares | **281.4** | 306.7 |

## PRODUCTION PER OUTSTANDING COMMON SHARE

2012 average daily production per 1,000,000 common shares of the Company at December 31, 2012 was 54.1 compared to 67.7 the previous year including an increase to outstanding common shares of 17 percent.

| | **2012** | 2011 |
|---|---|---|
| Production, boe/d | **8,276** | 8,870 |
| December 31 common shares outstanding | **153,047,798** | 130,999,798 |
| Production per 1,000,000 shares | **54.1** | 67.7 |

## ACREAGE SUMMARY

The Company's total and undeveloped landholdings by province as at December 31, 2012 are outlined below.

| | Total | | Undeveloped | | Net Fair Market |
|---|---|---|---|---|---|
| December 31, 2012 (acres) | Gross | Net | Gross | Net | Value [1] |
| Alberta | 459,629 | 264,690 | 261,056 | 170,336 | $ 58,063,941 |
| British Columbia | 77,707 | 38,553 | 50,715 | 26,207 | $ 7,255,515 |
| Total acreage | 537,336 | 303,243 | 311,771 | 196,543 | $ 65,319,456 |

(1) Undeveloped land value was determined by independent land valuation report by Seaton-Jordan & Associates Ltd. effective December 31, 2012.

## RECYCLE RATIO

Recycle ratio is calculated by dividing the finding and development costs for total capital invested by the Company's operating netback[1].

| Year ended December 31 | | 2012 | | 2011 |
|---|---|---|---|---|
| Operating netback ($/boe) [1] | $ | 14.57 | $ | 24.25 |
| Proved plus probable reserves F&D costs ($/boe) [2] | $ | 18.03 | $ | 12.37 |
| **Proved plus probable recycle ratio** | | **0.81** | | 1.96 |

(1) Operating netback is calculated by subtracting royalties, operating costs and transportation costs from revenues and dividing by total production for the year.

(2) Includes extensions and improved recovery, technical revisions, discoveries, economic factors, acquisitions and dispositions, and the total costs (which include changes in future development costs).

## RESERVE REPLACEMENT

Reserve replacement ratio is calculated by dividing reserve additions by total Company production.

| | Proved | Proved + Probable |
|---|---|---|
| Total reserves adds (mboe)[1] | 1,751 | 5,909 |
| 2012 production (mboe) | 3,029 | 3,029 |
| **Total reserve replacement ratio** | **0.58** | **1.95** |

(1) Includes extensions and improved recovery, technical revisions, discoveries, economic factors, acquisitions and dispositions.

## NET ASSET VALUE

The net asset value of the Company at December 31, 2012, using the net present value of future net revenue discounted at a rate of 10 percent before deducting future income tax expenses, is summarized below.

| ($ thousands except share count and per share value) | |
|---|---|
| Estimated future net revenues of proved plus probable reserves [1] | 362,860 |
| Undeveloped land [2] | 65,319 |
| Mark-to-market value of hedging contracts | (3,789) |
| In-the-money option proceeds [3] | 573 |
| Total assets value | 424,963 |
| Bank debt plus working capital deficiency | (92,815) |
| Net asset value | 332,148 |
| Common shares outstanding and in-the-money options | 153,896,798 |
| Net asset value per share | 2.16 |

(1) Discounted at 10 percent and before deducting future income tax expenses and reclamation costs.

(2) Undeveloped land value was determined by an independent land valuation report by Seaton-Jordan & Associates Ltd.

(3) In-the-money option proceeds are based on the closing December 31, 2012 share price of $1.14.

(4) The Company estimates it has approximately $315 million of tax deductions available to offset future taxable income.

# MANAGEMENT'S DISCUSSION AND ANALYSIS

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

*Management's discussion and analysis ("MD&A") 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 position and results of operations of the Company. Its focus is primarily a comparison of the financial performance for the three and twelve months ended December 31, 2012 and 2011 and should be read in conjunction with the audited consolidated financial statements and accompanying notes for the years ended December 31, 2012 and 2011. The audited consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). The reporting currency is the Canadian dollar. The discussion and analysis has been prepared as of March 19, 2013.*

*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 to the Canadian Securities Administrators' National Instrument 51-101 when boes are disclosed. Boes may be misleading, particularly if used in isolation.*

*This MD&A contains the terms "funds from operations", "funds from operations per share", "net debt", "operating netbacks", "cash netbacks" and "netbacks" which are not recognized measures under IFRS. 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-IFRS measure and has been defined by the Company as cash flow from operating activities before accretion on long-term debt, decommissioning expenditures and changes in non-cash working capital. 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 IFRS. The Company has defined net debt as the sum of long term debt plus/minus working capital excluding the current portion of the fair value of financial instruments. Net debt is used by management to monitor remaining availability under its credit facilities. Operating netbacks have been defined as revenue less royalties, transportation and operating costs. Cash netbacks have been defined as operating netbacks less interest and general and administrative costs. Netbacks are generally discussed and presented on a per boe basis.*

## DELPHI'S OPERATIONS

### What is the nature of Delphi's business and where are its operations?

Delphi is a publicly-traded company with its corporate office in Calgary, Alberta, Canada. Delphi is engaged in the exploration for, development and production of crude oil and natural gas from properties and assets located in Western Canada in which it holds an interest. The Company's operations are primarily concentrated in the Deep Basin of North West Alberta, from which in excess of 90 percent of the Company's production is obtained. The Company has three primary core areas in the Deep Basin located at Bigstone, Hythe and Wapiti.

## 2012 ACCOMPLISHMENTS

### What were the highlights of Delphi's operational and financial results in 2012?

In 2012, the Company achieved the following:

- produced an average of 8,276 barrels of oil equivalent per day ("boe/d");
- maintained its average corporate NGL ("natural gas liquid") and field condensate yield of 35 barrels per million cubic feet ("bbls/mmcf");
- completed construction and start-up of the Company's East Bigstone compression/dehydration facility and gathering system to handle Delphi and third-party Montney production in the area;
- closed the disposition of its non-operated light oil interests in the Hythe area for net proceeds of $11.0 million with proceeds directed toward the 2012 capital program;

- closed the disposition of the Company's Cardium oil assets at Bigstone representing 450 boe/d for net proceeds of $22.4 million with proceeds applied against bank debt;
- realized $3.6 million in financial commodity risk management gains and $1.6 million in physical commodity risk management gains;
- drilled 7 gross (6.5 net) wells as part of the Company's capital program;
- issued 17.2 million common shares and 4.6 million common shares on a flow-through basis for total combined net proceeds of $31.1 million; and
- entered into a farm-in agreement to earn up to a 75 percent working interest in 35 sections of Montney and Nordegg petroleum and natural gas rights.

Funds from operations in 2012 were $32.3 million or $0.24 per basic share ($0.24 per diluted share), compared to $66.9 million or $0.57 per basic share and $0.56 per diluted share in 2011. The decrease in funds from operations from 2011 to 2012 is primarily due to a decrease in natural gas and natural gas liquids pricing, a change in production mix and lower realized gains on commodity risk management contracts. In 2012, Delphi recognized $3.6 million and $1.6 million in realized gains on financial and physical commodity risk management contracts, respectively.

On November 13, 2012, Delphi issued on a bought deal basis, 17.2 million common shares at $1.45 per share and 4.6 million common shares on a flow-through basis at $1.75 per share for net proceeds of approximately $31.1 million. The net proceeds from this financing have initially been used to temporarily reduce the Company's net debt and will subsequently be directed towards the Company's capital program.

In December 2012, the Company's syndicated credit facility's borrowing base was renewed at $125.0 million, a reduction of $20.0 million from its previous borrowing base. As at December 31, 2012, the Company's net debt was $92.8 million, leaving additional capacity of $32.1 million. On an annualized, fourth quarter funds from operations basis, Delphi's net debt to funds from operations was 3.7:1. Net debt includes bank debt plus working capital deficiency excluding the fair value of financial instruments.

## 2013 OUTLOOK AND FORWARD-LOOKING INFORMATION

*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 MD&A are made as of March 19, 2013 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.*

Delphi's expectations for 2013 are based upon its projection of drilling plans, drilling success, expected completion of wells, expected tie-in of wells and production results and the estimated related revenues and associated costs of royalties, transportation expenses, operating costs, general and administrative expenses and interest costs. Commodity prices used in the determination of forecast revenues are based upon general economic conditions, commodity supply and demand forecasts and publicly available price forecasts. The Company continually monitors its forecast assumptions to ensure the stakeholders are informed of material variances from previously communicated expectations.

## REVENUES

### What does the Company project for crude oil and natural gas prices and the Canadian/United States exchange rate in 2013?

**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 primarily influenced by North American, rather than global, supplies of natural gas versus domestic demand for winter heating and generation of electricity for summer cooling requirements. However, with the growth in natural gas liquefaction and regasification facilities around the world, this North American supply and demand balance is subject to disruption from time to time, primarily in periods of a shortfall in supply. In addition, multi-stage fracturing technology has unlocked significant natural gas resource potential of numerous shale basins in North America which are capable of initially producing very high rates of natural gas.

For forecasting purposes, Delphi continues to expect a challenging natural gas market for the remainder of 2013 as a result of strong natural gas production in the United States. So far in 2013, natural gas storage levels remain high due to growth in natural gas production coupled with another year of warmer than normal average winter temperatures in North America. The Company continues to monitor its cash flow projections in light of this current commodity price environment.

Delphi anticipates AECO to average between $3.00 to $3.25 per mcf in 2013.

**Crude Oil**

West Texas Intermediate at Cushing, Oklahoma ("WTI") is the benchmark reference for North American crude oil prices. Canadian crude oil prices are based upon postings, primarily at Edmonton, Alberta and represent the WTI price adjusted for quality and transportation differentials as well as the Canadian/United States ("Cdn/US") dollar exchange rate. In 2012 and so far in 2013, Canadian prices have also been negatively adjusted for an oversupply of crude oil at Cushing, Oklahoma as pipeline capacity to the Gulf Coast is limited. The fundamental supply/demand equation for crude oil is more balanced on a daily basis than natural gas due to consistent demand for crude oil of approximately 89 million barrels per day to meet the global requirement for energy. The price of crude oil can also be influenced significantly by geopolitical events in the major oil exporting countries of the world and the strength or weakness of the global economies.

Delphi anticipates WTI to average between U.S. $90.00 to $95.00 per barrel in 2013.

**Canadian/United States Exchange Rate**

Both crude oil and natural gas prices in Canada are premised on the U.S. dollar price for each product adjusted for the Cdn/US dollar exchange rate and quality and transportation differentials. The strength or weakness of the Canadian dollar versus the U.S. dollar will largely reflect the global demand for raw materials, particularly metals, minerals and crude oil. The global financial markets tolerance for risk and its need for financial security in the form of holding U.S dollars will also have an effect on the value of the Canadian dollar against the U.S. dollar.

The Canadian dollar continues to trade around parity with the U.S. dollar in 2013. The exchange rate is influenced by many variables which will continue to result in significant volatility. Delphi has assumed an average exchange rate of $1.00 Cdn. to U.S. dollar.

### Has Delphi undertaken any commodity price risk management for 2013 to mitigate the risk of volatility in its product pricing?

In light of the low natural gas prices over the past four years and a future outlook which has resulted in the forward price curve for natural gas to decrease based on the view that there is ample supply of natural gas with the development of the shale gas plays, particularly in the United States, Delphi has become more focused on protecting the downside of prices as opposed to locking in gains to be made on unusually high prices. Currently, Delphi has provided for approximately 51 percent of its natural gas production at a predominantly AECO based average floor price of $3.27 per mcf for 2013. Delphi continually monitors the variables affecting the price of natural gas and crude oil in order to ensure its capital program is in line with expected funds from operations. The following natural gas production is protected by commodity price fluctuations, in order to support the Company's funds from operations:

| | 2013 |
|---|---|
| Production volumes (mmcf/d) | 18.5 |
| Percentage of natural gas production * | 51% |
| Price floor (Cdn $/mcf) | $3.27 |

* based on 36.0 mmcf/d

## ROYALTIES

### What average royalty rate does Delphi expect to pay in 2013?

The Company pays royalties to provincial governments, individuals and companies that own surface and/or mineral rights. These payments take the form of Crown, freehold and overriding royalties. Crown royalty rates for crude oil and natural gas are generally calculated on a sliding scale based on commodity prices and production rates whereas freehold and overriding royalty rates are generally a fixed percentage of revenue. Crown royalty rates can change due to price fluctuations or changes in production volumes on a well by well basis subject to minimum and maximum rates. For natural gas liquids, Crown royalty rates are a fixed percentage of revenue with the rate varying according to the nature of the product. Crown royalty credits are received from the Crown and represent the fee earned by the owners of natural gas processing infrastructure to process the Crown's royalty share of natural gas. Freehold royalties are paid on freehold lands and overriding royalties are generally payable on lands where the Company has earned an interest in the lands through a farm-in, whether the lands are Crown or freehold. Royalties are not affected by gains or losses realized through the Company's risk management program.

For 2013, Delphi expects its royalty rate, after the deduction for royalty credits, will average between 12 to 14 percent of gross revenue, excluding realized and unrealized gains or losses on commodity risk management contracts.

## TRANSPORTATION EXPENSES AND OPERATING COSTS

### Will Delphi be able to further reduce its costs of production in 2013?

Transportation expenses are costs incurred by the Company to transport its production volumes from the wellhead to the point of sales. In British Columbia, infrastructure is owned by Spectra Energy Corp. 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.

Delphi expects its transportation expenses to be approximately $2.70 to $2.90 per boe in 2013. Transportation expenses are subject to the availability of pipeline capacity on an interruptible basis in areas of significant production growth by industry.

The costs of production may be more than expected in periods of very high industry activity causing considerable competition and rising prices for general oilfield services and equipment. With the growth in Montney production as a percentage of total production, operating costs are expected to increase due to sour gas processing. Operating costs in 2013 are expected to average between $8.50 to $8.75 per boe.

## GENERAL & ADMINISTRATIVE AND FINANCE COSTS

### What are the Company's overhead costs for personnel and financing?

In 2013, Delphi anticipates its general and administrative costs, net of capitalized amounts, to be approximately $2.15 to $2.30 per boe. A high level of industry activity may cause an increase in general and administrative expenses due to higher than expected employee retention costs, fees to hire new employees and general cost of inflation.

Interest costs will be dependent on market rates and credit spreads for the oil and gas sector and will be a function of the general economic conditions in Canada. If the economy is viewed as growing too fast, which may result in inflation, interest rates may be increased to slow down the pace of growth in the economy. Interest costs may also increase if funds from operations is less than expected and bank debt is used to fund a larger portion of the capital program than originally anticipated. Interest expense is expected to be approximately $1.75 to $2.00 per boe in 2013.

## CAPITAL PROGRAM AND NET DEBT LEVELS

### What are the Company's forecast capital expenditures and net debt levels for 2013?

The Company expects 2013 capital expenditures to be between $50.0 and $55.0 million, funded from cash flow and bank indebtedness. Historically, Delphi executes a winter capital program in excess of first quarter cash flow followed by at least one quarter of minimal activity prior to returning to the field with an active summer/fall program.

The Company is targeting net debt at December 31, 2013 to be approximately $110.0 million.

## 2012 OPERATIONAL AND FINANCIAL RESULTS

## BUSINESS ENVIRONMENT

### What external factors of the business environment did the Company have to contend with in 2012?

The table below outlines the changes in the various benchmark commodity prices and economic parameters which affect the prices received for the Company's production.

**Benchmark Prices and Economic Parameters**

| | Three Months Ended December 31 | | | Twelve Months Ended December 31 | | |
|---|---|---|---|---|---|---|
| | **2012** | 2011 | % Change | **2012** | 2011 | % Change |
| **Natural Gas** | | | | | | |
| NYMEX (US $/mmbtu) | **3.40** | 3.33 | 2 | **2.75** | 4.00 | (31) |
| AECO (Cdn $/mcf) | **3.21** | 3.20 | - | **2.39** | 3.63 | (34) |
| **Crude Oil** | | | | | | |
| West Texas Intermediate (US $/bbl) | **88.20** | 94.02 | (6) | **94.19** | 95.12 | (1) |
| Edmonton Light (Cdn $/bbl) | **83.97** | 97.31 | (14) | **86.08** | 95.07 | (9) |
| **Foreign Exchange** | | | | | | |
| Canadian to U.S. dollar | **1.01** | 0.98 | 3 | **1.00** | 1.01 | (1) |
| U.S. to Canadian dollar | **0.99** | 1.02 | (3) | **1.00** | 0.99 | 1 |

**Natural Gas**

The level of natural gas production in the United States, despite a significant drop in natural gas drilling, continues to exceed the natural gas demand in North America, leading to an excess supply situation and lower natural gas commodity prices. AECO averaged $3.21 per mcf in the fourth quarter of 2012, no change from the comparative period. For the year ended December 31, 2012, average AECO was 34 percent lower than in 2011.

**Crude Oil**

WTI averaged U.S. $88.20 per barrel in the fourth quarter of 2012, a decrease of six percent over the fourth quarter of 2011. For Canadian prices, the decrease was further reduced by an adjustment for an oversupply of crude oil at Cushing, Oklahoma resulting in Canadian prices being 14 percent lower in the fourth quarter of 2012 over the comparative period of 2011. Edmonton light averaged $83.97 per barrel in the fourth quarter of 2012 versus $97.31 per barrel in 2011.

For 2012, WTI averaged U.S. $94.19 per barrel, a decrease of one percent over the 2011 year. Edmonton light decreased nine percent from the comparative period in 2011.

**Canadian/United States Exchange Rate**

The value of the Canadian dollar against its U.S. counterpart remained strong in 2012. As a producer of crude oil, a stronger Canadian dollar has had a negative effect on the price received for production. The average Cdn/US exchange rate for the three and twelve months ended December 31, 2012 were $1.01 and $1.00, respectively. This negative effect to the price of oil for Canadian producers was further impacted by the differential between U.S. and Canadian markets.

## DRILLING OPERATIONS

### How active was Delphi in its drilling program in 2012?

In 2012, Delphi had a 100 percent success rate in its drilling program that consisted of 7 gross (6.5 net) wells, including 1 gross (1 net) well which was drilled in the fourth quarter of 2012. This compares to a 100 percent success rate achieved in 2011 which resulted in 30 gross (23.8 net) wells, of which 5 gross (4.4 net) wells were drilled in the fourth quarter of 2011.

In light of continued low natural gas prices, the Company focused the majority of its efforts on drilling liquids-rich natural gas opportunities in the Montney formation at Bigstone in North West Alberta.

| | Three Months Ended December 31, 2012 | | Twelve Months Ended December 31, 2012 | |
|---|---|---|---|---|
| | **Gross** | **Net** | **Gross** | **Net** |
| Liquids rich natural gas (>40 bbls/mmcf liquids content) | 1 | 1 | 6.0 | 5.8 |
| Natural gas (>20 bbls/mmcf <40 bbls/mmcf liquids content) | - | - | 1.0 | 0.7 |
| Total | 1 | 1 | 7 | 6.5 |
| Success rate (%) | 100 | 100 | 100 | 100 |

## CAPITAL INVESTED

### How much did the Company spend in 2012 and where were the capital expenditures incurred?

During the year ended December 31, 2012, Delphi invested $83.7 million which was partially funded by proceeds on dispositions of $34.7 million. The capital expenditures were primarily directed toward the Bigstone Montney and Gething drilling, completion and equipping programs (66 percent of capital) and facility expenditures (29 percent of capital), including the construction of the Bigstone Montney facility which has the capacity to handle 30 mmcf/d of natural gas and capacity to store 3,000 barrels of field condensate. Total capital invested during the fourth quarter of 2012 was $11.6 million which was primarily directed toward its Bigstone Montney horizontal drilling program and the completion operations on two Wapiti wells.

As of December 31, 2012, Delphi has a total of 33.3 sections (32.5 net) of undeveloped land on two separate blocks which are prospective for liquids-rich natural gas in the Montney formation, situated at its core area of Bigstone located within the Deep Basin of North West Alberta. In addition, Delphi has entered into a farm-in agreement to earn up to a 75 percent working interest in 35 sections of Montney and Nordegg petroleum and natural gas rights in the Bigstone area. For further details on the farm-in please see the Contractual Obligations section of this MD&A.

During the first quarter of 2012, Delphi closed the disposition of its non-operated light oil interests in the Hythe area and minor offsetting lands for net proceeds of approximately $11.0 million. Production associated with the disposition was approximately 217 boe/d (66 percent light oil), based on fourth quarter 2011 production volumes. Proceeds from the sale were used to fund the ongoing Bigstone Montney development. In the third quarter of 2012, Delphi closed the disposition of its Cardium oil assets and the majority of its non-operated properties in British Columbia for combined net proceeds of approximately $22.9 million. Production associated with the Cardium disposition was approximately 450 boe/d (48 percent light oil).

During the year ended December 31, 2011 Delphi received proceeds on dispositions of $12.9 million, primarily consisting of the sale of certain working interests in Bigstone assets for net proceeds of $4.5 million in the fourth quarter of 2011 and $7.2 million from granting an overriding royalty on certain lands at Hythe in the third quarter of 2011.

| | Three Months Ended December 31 | | | Twelve Months Ended December 31 | | |
|---|---|---|---|---|---|---|
| | **2012** | 2011 | % Change | **2012** | 2011 | % Change |
| Land | **64** | 6,876 | (99) | **408** | 8,816 | (95) |
| Seismic | **10** | 318 | (97) | **61** | 484 | (87) |
| Drilling, completions and equipping | **8,847** | 24,631 | (64) | **55,464** | 81,868 | (32) |
| Facilities | **1,346** | 4,197 | (68) | **24,259** | 19,348 | 25 |
| Capitalized expenses | **1,236** | 1,174 | 5 | **3,435** | 3,824 | (10) |
| Other | **35** | 86 | (59) | **101** | 137 | (26) |
| Capital invested | **11,538** | 37,282 | (69) | **83,728** | 114,477 | (27) |
| Disposition of properties | **(45)** | (4,835) | (99) | **(34,664)** | (12,873) | 169 |
| Net capital invested | **11,493** | 32,447 | (64) | **49,064** | 101,604 | (52) |
| Acquisition of properties | **139** | 56 | 148 | **139** | 273 | (49) |
| Total | **11,632** | 32,503 | (64) | **49,203** | 101,877 | (52) |

## PRODUCTION

### What factors contributed to the production volumes?

Production volumes for the three months ended December 31, 2012 averaged 7,229 boe/d, a 23 percent decrease over the comparative period. Crude oil and natural gas liquids production volumes decreased 43 percent in comparison to the same period in 2011. The decrease in crude oil and natural gas liquids production volumes is primarily due to the disposition of predominantly producing oil properties in the first and third quarters of 2012 partially offset by an increase in field condensate production as a result of the Company's liquids-rich natural gas drilling program. The decrease in total production in the fourth quarter of 2012 is due to natural declines and property dispositions.

Production volumes for the year ended December 31, 2012 averaged 8,276 boe/d, a seven percent decrease over the comparative period. Natural gas volumes decreased by one percent and crude oil and natural gas liquids decreased by 21 percent in the twelve months ended December 31, 2012 in comparison to the same period in 2011. The decrease in crude oil and natural gas liquids production volumes is primarily due to the Hythe and Cardium property dispositions, which were predominantly producing oil properties, and non-operated plant turnarounds in the second quarter of 2012 affecting Wapiti area production. This decrease is partially offset by an increase in field condensate production which is a result of the Company's successful liquids-rich gas drilling program in Bigstone.

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 fourth quarter was weighted six percent to crude oil, two percent to field condensate, 15 percent to natural gas liquids and 77 percent to natural gas. For the year ended December 31, 2012, Delphi's production portfolio was weighted eight percent to crude oil, three percent to field condensate, 13 percent to natural gas liquids and 76 percent to natural gas.

| | Three Months Ended December 31 | | | Twelve Months Ended December 31 | | |
|---|---|---|---|---|---|---|
| | **2012** | 2011 | % Change | **2012** | 2011 | % Change |
| Crude oil **(bbls/d)** | **400** | 1,305 | (69) | **696** | 1,200 | (42) |
| Field condensate **(bbls/d)** | **165** | 131 | 26 | **213** | 121 | 76 |
| Natural gas liquids **(bbls/d)** | **1,055** | 1,405 | (25) | **1,101** | 1,217 | (10) |
| Total crude oil and natural gas liquids | **1,620** | 2,841 | (43) | **2,010** | 2,538 | (21) |
| Natural gas **(mcf/d)** | **33,654** | 38,973 | (14) | **37,589** | 37,992 | (1) |
| Total **(boe/d)** | **7,229** | 9,337 | (23) | **8,276** | 8,870 | (7) |

## REALIZED SALES PRICES

### What were the sales prices realized by the Company for each of its products?

For the three months ended December 31, 2012, Delphi's realized natural gas price decreased by 24 percent in comparison to the same period in 2011. The decrease is primarily due to losses on physical and financial commodity risk management contracts. A loss was realized on the Company's physical and financial commodity risk contracts as natural gas prices improved slightly in the fourth quarter to an average of $3.21 per mcf while the Company's natural gas commodity risk contracts had an average floor price of $2.88 per mcf.

For the year ended December 31, 2012, the Company's realized natural gas price decreased by 37 percent when compared to the same period in 2011. The decrease in realized natural gas prices for the year ended December 31, 2012 is primarily a result of a decrease in the average daily AECO index, a reduction in premiums received for heating content and lower realized gains on physical and financial contracts. For the 2012 year, physical and financial contracts realized gains of $0.12 and $0.14, respectively, per mcf, contributing a total gain of $0.26 per mcf.

Realized crude oil and condensate prices were three percent higher for the three months ended December 31, 2012 compared to the same period in 2011. The increase in realized crude oil and condensate price is primarily due to a gain on financial commodity risk management contracts partially offset by a decrease in Edmonton light and a higher quality differential.

For the year ended December 31, 2012, realized crude oil and condensate prices decreased one percent in comparison to the same period in 2011 due to a decline in Edmonton Light crude prices offset by a gain on financial commodity risk management contracts. For crude oil, Delphi had realized gains of $15.10 and $4.06 per barrel for the three and twelve months ended December 31, 2012, respectively, on its financial commodity contracts.

Natural gas liquids prices for the year ended December 31, 2012 were ten percent lower than in the same period in 2011. The decrease in pricing is primarily a result of a decrease in prices for propane, partially offset by an increase in plant condensate production which receives a higher price in comparison to the other natural gas liquids and realized gains on financial commodity risk management contracts.

| | Three Months Ended December 31 | | | Twelve Months Ended December 31 | | |
|---|---|---|---|---|---|---|
| | **2012** | 2011 | % Change | **2012** | 2011 | % Change |
| AECO ($/mcf) | **3.21** | 3.20 | - | **2.39** | 3.63 | (34) |
| Heating content and marketing ($/mcf) | **0.20** | 0.24 | (17) | **0.22** | 0.25 | (12) |
| Gain (loss) on physical contracts ($/mcf) | **(0.11)** | 0.25 | (144) | **0.12** | 0.28 | (58) |
| Gain (loss) on financial contracts ($/mcf) | **(0.13)** | 0.50 | (126) | **0.14** | 0.39 | (64) |
| Realized natural gas price ($/mcf) | **3.17** | 4.19 | (24) | **2.87** | 4.55 | (37) |
| | | | | | | |
| Edmonton Light ($/bbl) | **83.97** | 97.31 | (14) | **86.08** | 95.07 | (9) |
| Gain (loss) on financial contracts ($/bbl) | **15.10** | (1.47) | - | **4.06** | (2.61) | - |
| Quality differential ($/bbl) | **(1.88)** | (1.24) | 52 | **0.24** | (0.90) | - |
| Realized oil price ($/bbl) | **97.19** | 94.60 | 3 | **90.38** | 91.56 | (1) |
| | | | | | | |
| Realized natural gas liquids price ($/bbl) | **43.15** | 52.69 | (18) | **45.31** | 51.13 | (11) |
| Gain on financial contracts ($/bbl) | **0.22** | - | - | **0.93** | - | - |
| Realized liquids price ($/bbl) | **43.37** | 52.69 | (18) | **46.24** | 51.13 | (10) |
| Total ($/boe) | **28.98** | 40.40 | (28) | **29.50** | 40.47 | (27) |

## RISK MANAGEMENT ACTIVITIES

### What is Delphi's risk management strategy and what contracts are in place to mitigate the risk of price volatility?

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. For natural gas production, Delphi has approximately 51 percent of its before-royalty natural gas production contracted at a predominately AECO based average floor price of $3.27 per mcf for 2013.

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 and crude oil financial contracts on the statement of financial position at each reporting period with the change in the fair value being classified as unrealized gains and losses in the statement of earnings. Natural gas physical commodity sale contracts based in U.S. dollars include an embedded derivative associated with the foreign exchange rate. Due to this derivative, the changes in the fair value of these contracts are also included in the statement of earnings.

The Company has managed the price applicable to production volumes through the following contracts:

**Physical Contracts**

| Time Period | Type of Contract | Quantity Contracted | Price Floor ($/unit) | Price Ceiling ($/unit) |
|---|---|---|---|---|
| April 2012 – December 2013 | Natural Gas - fixed | 2,000 mmbtu/d | $3.21 U.S. | $3.21 U.S. |
| June 2012 – March 2013 | Natural Gas - fixed | 5,000 GJ/d | $2.45 Cdn | $2.45 Cdn |
| January 2013 – December 2013 | Natural Gas - fixed | 1,500 GJ/d | $3.41 Cdn | $3.41 Cdn |
| April 2013 – December 2013 | Natural Gas - fixed | 1,500 GJ/d | $3.42 Cdn | $3.42 Cdn |

**Financial Contracts**

| Time Period | Type of Contract | Quantity Contracted | Price Floor ($/unit) | Price Ceiling ($/unit) |
|---|---|---|---|---|
| August 2012 – March 2013 | Natural Gas - collar | 1,000 GJ/d | $2.50 Cdn | $2.95 Cdn |
| August 2012 – March 2013 | Natural Gas - collar | 1,000 GJ/d | $2.50 Cdn | $3.04 Cdn |
| August 2012 – March 2013 | Natural Gas - collar | 1,000 GJ/d | $2.55 Cdn | $3.07 Cdn |
| April 2012 – December 2014 | Natural Gas - fixed | 6,000 GJ/d | $2.88 Cdn | $2.88 Cdn |
| April 2013 – April 2015 | Natural Gas - fixed | 3,000 GJ/d | $3.535 Cdn | $3.535 Cdn |
| April 2013 – December 2015 | Natural Gas - fixed | 3,000 GJ/d | $3.27 Cdn | $3.27 Cdn |
| April 2013 – December 2016 | Natural Gas - fixed | 3,000 GJ/d | $3.40 Cdn | $3.40 Cdn |
| March 2013 – December 2013 | Crude oil - fixed | 150 bbls/d | $89.65 Cdn | $89.65 Cdn |
| January 2014 – December 2014 (1) | Crude Oil - call option | 600 bbls/d | - | $90.00 U.S. |

(1) The Company acquired a natural gas contract at $5.69 per gigajoule on 6,810 gigajoules per day for the period April 1, 2011 through December 31, 2011. The contract was paid for with the sale of a crude oil call on 600 barrels per day at a price of U.S. $90.00 WTI per barrel for the period January 1, 2012 through December 31, 2012. Delphi has deferred this crude oil call to January 1, 2014 through December 31, 2014.

The fair value of the financial contracts outstanding as at December 31, 2012 is estimated to be a loss of approximately $4.0 million. 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 year 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 recognized an unrealized gain on its financial contracts of $0.5 million for the three months ended December 31, 2012 and an unrealized loss of $0.8 million for the twelve months ended December 31, 2012. The unrealized gain and loss recognized for the three and twelve months ended December 31, 2012, respectively, is the difference between the fair value of the commodity risk management contracts outstanding as at December 31, 2012 and that of September 30, 2012 and the fair value of the commodity risk management contracts outstanding as at December 31, 2012 and that of December 31, 2011, respectively.

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

### How do revenues in 2012 compare to 2011 and what factors contributed to the change?

For the three months ended December 31, 2012, Delphi generated revenue of $18.9 million, a 43 percent decrease in comparison to the same period in 2011. For the year ended December 31, 2012, the Company's revenue decreased by 32 percent to $85.8 million compared to the same period in 2011. The reduction in revenues from the year ended December 31, 2011 to that of 2012 is primarily due to a decrease in realized natural gas and natural gas liquids prices, a reduction in crude oil and natural gas liquids production and a decrease in realized gains from physical commodity risk management contracts. For the year ended December 31, 2012, crude oil and natural gas liquids contributed 55 percent of total revenues compared to 54 percent in the same 2011 period.

| | Three Months Ended December 31 | | | Twelve Months Ended December 31 | | |
|---|---|---|---|---|---|---|
| | **2012** | 2011 | % Change | **2012** | 2011 | % Change |
| Natural gas | **10,526** | 12,364 | (15) | **35,916** | 53,814 | (33) |
| Natural gas physical contract gains (loss) | **(330)** | 888 | - | **1,633** | 3,845 | (58) |
| Crude oil | **4,267** | 12,692 | (66) | **28,716** | 45,402 | (37) |
| Natural gas liquids | **4,188** | 6,812 | (39) | **18,257** | 22,712 | (20) |
| Sulphur | **207** | 359 | (42) | **1,232** | 1,114 | 11 |
| Total | **18,858** | 33,115 | (43) | **85,754** | 126,887 | (32) |

## ROYALTIES

### What were royalty costs in 2012?

For the fourth quarter of 2012, royalties totaled $1.6 million compared to $6.3 million for the same period in 2011. The decrease is attributed to prior period adjustments received from the Crown addressing low productivity wells and revenue revisions. Gross overriding royalties in the fourth quarter of 2012 decreased in comparison to the same period in 2011 as a result of declining commodity prices, declining production and a prior period adjustment related to the Tower Creek area.

For the year ended December 31, 2012, royalties totaled $13.4 million compared to $20.7 million for the same period in 2011. The decrease is attributed to lower Crown royalties as a result of weakening natural gas prices and increased production from recently drilled wells which take advantage of the Alberta royalty incentive programs. Gross overriding royalties in the year ended December 31, 2012 decreased in comparison to the same period in 2011 as a result of declining commodity prices and declining production.

| | Three Months Ended December 31 | | | Twelve Months Ended December 31 | | |
|---|---|---|---|---|---|---|
| | **2012** | 2011 | % Change | **2012** | 2011 | % Change |
| Crown royalties | **2,520** | 4,625 | (46) | **14,465** | 19,418 | (26) |
| Royalty credits | **(1,637)** | (1,206) | 36 | **(6,252)** | (5,413) | 15 |
| Crown royalties – net | **883** | 3,419 | (74) | **8,213** | 14,005 | (41) |
| Freehold royalties | **-** | 54 | (100) | **-** | 43 | (100) |
| Gross overriding royalties | **751** | 2,782 | (73) | **5,138** | 6,691 | (23) |
| Total | **1,634** | 6,255 | (74) | **13,351** | 20,739 | (36) |
| Per boe | **2.46** | 7.28 | (66) | **4.41** | 6.41 | (31) |

### What were the average royalty rates paid on production in 2012?

The average royalty rates were lower than the comparative period. For the three and twelve months ended December 31, 2012, Crown royalty rates were 56 percent and six percent lower, respectively, compared to the same periods in 2011. For the three and twelve months ended December 31, 2012, Crown royalty rates decreased as a result of declining commodity prices, prior period adjustments received from the Crown addressing low productivity wells and increased production from recently drilled wells which take advantage of the Alberta royalty incentive programs.

In the fourth quarter of 2012, the gross overriding royalty rate decreased in comparison to the same period in 2011. The decrease is primarily due to a prior period adjustment related to the Tower Creek area. For the year ended December 31, 2012, the gross overriding royalty rate increased by thirteen percent in comparison to the same period in 2011. The increase in the rate is primarily due to the granting of overriding royalties on certain lands in the Hythe area in the third quarter of 2011.

| | Three Months Ended December 31 | | | Twelve Months Ended December 31 | | |
|---|---|---|---|---|---|---|
| | **2012** | 2011 | % Change | **2012** | 2011 | % Change |
| Crown rate – net of royalty credits | **4.6%** | 10.6% | (57) | **9.8%** | 11.4% | (14) |
| Gross overriding rate | **3.9%** | 8.6% | (55) | **6.1%** | 5.4% | 13 |
| Average rate | **8.5%** | 19.4% | (56) | **15.9%** | 16.9% | (6) |

The royalty rate calculations above exclude gains or losses on risk management activities from revenue as the denominator.

## OPERATING EXPENSES

### How do operating expenses in 2012 compare to 2011?

Production costs for the three months ended December 31, 2012 decreased nine percent compared to the same period in 2011 primarily as a result of a reduction in processing fees in the Wapiti area that impacted the production months of April 2011 to November 2012.

Production costs for the year ended December 31, 2012 increased five percent compared to the same period in 2011 primarily due to the new Montney production and facility.

Delphi earns processing income for third party production volumes going through facilities owned by the Company. The processing income represents a reduction of the Company's costs to operate these facilities and hence is deducted in determining operating expenses. Processing income indicates the Company has excess capacity at its facilities which it can access to handle growth in its production volumes. Processing income decreased 27 and eight percent in the three and twelve months ended December 31, 2012, respectively, compared to the same period in 2011.

| | Three Months Ended December 31 | | | Twelve Months Ended December 31 | | |
|---|---|---|---|---|---|---|
| | **2012** | 2011 | % Change | **2012** | 2011 | % Change |
| Production costs | **6,531** | 7,158 | (9) | **26,588** | 25,377 | 5 |
| Processing income | **(778)** | (1,069) | (27) | **(2,979)** | (3,233) | (8) |
| Total | **5,753** | 6,089 | (6) | **23,609** | 22,144 | 7 |
| Per boe | **8.65** | 7.09 | 22 | **7.80** | 6.84 | 14 |

## TRANSPORTATION EXPENSES

### What factors contributed to the change in transportation costs in 2012?

For the three and twelve months ended December 31, 2012, transportation expenses decreased 25 percent and 15 percent, respectively, compared to the same periods in 2011. The reduction in transportation expenses is primarily due to reduced oil emulsion and clean oil trucking as a result of the dispositions in the first and third quarter of 2012 and lower gas gathering and transportation fees.

| | Three Months Ended December 31 | | | Twelve Months Ended December 31 | | |
|---|---|---|---|---|---|---|
| | **2012** | 2011 | % Change | **2012** | 2011 | % Change |
| Total | **1,858** | 2,481 | (25) | **8,232** | 9,630 | (15) |
| Per boe | **2.79** | 2.89 | (3) | **2.72** | 2.97 | (8) |

## GENERAL AND ADMINISTRATIVE

### How do general and administrative costs in 2012 compare to 2011?

General and administrative ("G&A") expenses (after recoveries and allocations) for the three and twelve months ended December 31, 2012 were $2.3 million ($3.43/boe) and $6.8 million ($2.25/boe), respectively, compared to $1.5 million ($1.76/boe) and $6.3 million ($1.96/boe) for the same period in 2011, respectively.

Gross expenses in the fourth quarter in 2012 are 15 percent higher than the comparative period primarily due to higher personnel and consulting costs. Overhead recoveries decreased by 52 percent as a result of a reduced capital program in the fourth quarter of 2012 compared to the same period in 2011. Salary allocations increased by eight percent as a result of higher personnel costs.

Gross expenses for the year ended December 31, 2012 decreased five percent primarily due to lower personnel costs, partially offset by an increase in consulting charges. Overhead recoveries decreased 28 percent over the comparative period as the Company's capital program was reduced in 2012 compared to 2011. Salary allocations have decreased twelve percent as a direct result of a decrease in personnel costs.

Delphi is committed to delivering strong growth and believes a strong team is paramount to achieve this goal.

| | Three Months Ended December 31 | | | Twelve Months Ended December 31 | | |
|---|---|---|---|---|---|---|
| | **2012** | 2011 | % Change | **2012** | 2011 | % Change |
| Gross expenses | **4,185** | 3,648 | 15 | **12,591** | 13,284 | (5) |
| Overhead recoveries | **(319)** | (666) | (52) | **(1,419)** | (1,984) | (28) |
| Salary allocations | **(1,586)** | (1,466) | 8 | **(4,361)** | (4,957) | (12) |
| Total | **2,280** | 1,516 | 50 | **6,811** | 6,343 | 7 |
| Per boe | **3.43** | 1.76 | 95 | **2.25** | 1.96 | 15 |

## SHARE-BASED COMPENSATION

### What is share-based compensation expense?

Share-based compensation expense is the amortization over the vesting period of the fair value of stock options and restricted share units (RSU's) granted to employees, directors and key consultants of the Company. The fair value of RSU's is based on the Company's share price. The fair value of all options granted is estimated at the date of grant using the Black-Scholes option pricing model.

The share-based compensation expense for the three months ended December 31, 2012, decreased seven percent over the comparative period, primarily due to 1.5 million less options outstanding as at December 31, 2012 in combination with a reduced weighted average fair value per option when compared to the same period in 2011. This reduction was partially offset by a decrease in capitalized costs and a $0.1 million increase in expense related to the Company's outstanding RSU's.

For the year ended December 31, 2012, share-based compensation expense increased 54 percent to $1.5 million when compared to the twelve months ended December 31, 2011. The increase is primarily due to the granting of 2.6 million options with a weighted average fair value of $0.50 per option and a $0.1 million increase in expense related to the Company's outstanding RSU's.

During the year ended December 31, 2012, the Company paid out $152 thousand of share-based cash compensation expense related to the Company's outstanding RSU's of which $75 thousand was capitalized to property, plant and equipment.

| | Three Months Ended December 31 | | | Twelve Months Ended December 31 | | |
|---|---|---|---|---|---|---|
| | **2012** | 2011 | % Change | **2012** | 2011 | % Change |
| Share-based compensation | **425** | 716 | (41) | **2,566** | 1,929 | 33 |
| Capitalized costs | **(50)** | (311) | (84) | **(1,034)** | (937) | 10 |
| Net | **375** | 405 | (7) | **1,532** | 992 | 54 |
| Per boe | **0.56** | 0.47 | 20 | **0.51** | 0.31 | 65 |

## FINANCE COSTS

### How do the costs of borrowing compare against the comparative period?

For the fourth quarter of 2012, interest charges increased ten percent compared to the same period in 2011 as a result of a higher average debt balance and higher interest rates charged on the Company's outstanding debt.

For the year ended December 31, 2012, interest charges decreased six percent compared to the same period in 2011 primarily as a result of a lower effective interest rate charged on the Company's outstanding debt.

As at December 31, 2012, Delphi's bankers' acceptances have terms ranging from 61 to 92 days and a weighted average effective interest rate of 4.8 percent over the term.

Accretion and finance lease charges are non-cash and comprised of accretion expense on the Company's decommissioning obligations and the implicit interest rate on the Company's finance lease obligation.

The accretion of decommissioning obligations is an expense that 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 one to 64 years. The decrease in accretion expense is due to a decrease in the average risk free interest rate used for the calculation during the four quarters in 2012 in comparison to the same periods in 2011.

The finance charge on the Company's finance lease is calculated based on the implicit interest rate in the lease.

| | Three Months Ended December 31 | | | Twelve Months Ended December 31 | | |
|---|---|---|---|---|---|---|
| | **2012** | 2011 | % Change | **2012** | 2011 | % Change |
| Interest | **1,413** | 1,279 | 10 | **4,964** | 5,299 | (6) |
| Accretion | **61** | 99 | (38) | **322** | 483 | (34) |
| Finance charge on finance lease obligation | **81** | - | - | **272** | - | - |
| Total | **1,555** | 1,378 | 13 | **5,558** | 5,782 | (4) |
| Interest per boe | **2.12** | 1.49 | 42 | **1.64** | 1.64 | - |
| Accretion per boe | **0.09** | 0.12 | (25) | **0.11** | 0.15 | (27) |
| Finance charge on finance lease obligation per boe | **0.12** | - | - | **0.09** | - | - |

### What has the Company done to protect itself against an increase in interest rates?

Delphi has entered into an interest rate swap transaction on borrowings through bankers' acceptances in the amount of $20.0 million maturing on June 1, 2014. The swap transaction has a fixed interest rate of 1.09 percent. The interest swap is fair valued at each reporting period and included in the fair value of financial instruments in the Company's consolidated statements of financial position. As at December 31, 2012, this contract has a fair value of $55 thousand.

Subsequent to December 31, 2012, Delphi entered into an interest rate swap transaction on borrowings through bankers' acceptances in the amount of $20.0 million maturing on March 1, 2015. The swap transaction has a fixed interest rate of 1.25%.

## DEPLETION, DEPRECIATION AND IMPAIRMENT

### Has the Company's depletion and depreciation rate and expense changed in 2012 compared to 2011?

Depletion and depreciation before impairment loss per boe for the three and twelve months ended December 31, 2012 decreased 22 percent and five percent, respectively, over the comparative period. The depletion and depreciation expense before impairment loss per boe decreased as a result of lower production volumes and a higher reserve base, partially offset by an increase in the cost base.

Impairment tests were carried out at December 31, 2012 due to the decrease in the forward price curve for natural gas as at January 1, 2013 compared to April 1, 2012 when Delphi was last required to test all of its cash-generating units ("CGU's") for impairment. An impairment charge of $36.2 million was recognized in the fourth quarter related to its Hythe, Berland River, Miscellaneous Alberta and North East British Columbia ("NEBC") CGU's. The impairments were based on the difference between the period end carrying value of the CGU's and the recoverable amount. The recoverable amounts were determined using a fair value less costs to sell methodology with the expected future cash flows based on proved and probable reserves using pre-tax discount rates of 10 to 20 percent. Fair value for Delphi's NEBC CGU was determined using the market metrics associated with the Company's disposition in the third quarter of 2012.

In the third quarter of 2012, an impairment test was carried out for the Company's NEBC CGU as indicators of impairment were identified through the disposition of some of Delphi's working interests in NEBC. The recoverable amount was determined using a fair value less costs to sell methodology using the market metrics associated with the Company's recent disposition. An impairment of $2.1 million was recognized and is included in depletion and depreciation expense on the consolidated statement of earnings.

Due to the decrease in the forward price curve for natural gas as at April 1, 2012 compared to January 1, 2012, the Company carried out impairment tests on its CGUs as at March 31, 2012. Delphi recognized an impairment charge of $21.0 million related to its Hythe, Berland River, Miscellaneous Alberta and North East British Columbia CGUs. The impairments were based on the difference between the period end carrying value of the CGU's and the recoverable amount. The recoverable amounts were determined using a fair value less costs to sell methodology with the expected future cash flows based on proved and probable reserves using pre-tax discount rates of 8 to 12 percent.

Impairment tests were carried out at December 31, 2011 due to the decrease in the forward price curve for natural gas as at January 1, 2012 compared to January 1, 2011. The Company recognized an impairment charge of $1.5 million related to the Company's Hythe, Berland River and Miscellaneous Alberta CGUs, which has been included in depletion and depreciation expense on the consolidated statement of earnings. The impairments were based on the difference between the period end carrying value of the CGU's and the recoverable amount. The recoverable amounts were determined using a fair value less costs to sell methodology with the expected future cash flows based on proved and probable reserves using pre-tax discount rates of 8 to 12 percent, as determined by the Company's independent engineers.

| | Three Months Ended December 31 | | | Twelve Months Ended December 31 | | |
|---|---|---|---|---|---|---|
| | **2012** | 2011 | % Change | **2012** | 2011 | % Change |
| Depletion and depreciation | **9,177** | 11,827 | (22) | **43,247** | 45,535 | (5) |
| Impairment loss | **36,238** | 1,500 | 2,315 | **59,366** | 1,500 | 3,857 |
| Total | **45,415** | 13,327 | 241 | **102,613** | 47,035 | 118 |
| Depletion and depreciation per boe | **13.80** | 13.77 | - | **14.28** | 14.06 | 2 |
| Impairment loss per boe | **54.49** | 1.75 | 3,013 | **19.60** | 0.46 | 4,160 |

## INCOME TAXES

### What was the affect on deferred income taxes as a result of the loss for the period?

Delphi recorded a deferred income tax expense recovery of $9.7 million and $18.0 million for the three and twelve months ended December 31, 2012, respectively. Deferred taxes arise from differences between the accounting and tax bases of the Company's assets and liabilities. Delphi does not anticipate it will be cash taxable before 2016.

| | Three Months Ended December 31 | | | Twelve Months Ended December 31 | | |
|---|---|---|---|---|---|---|
| | **2012** | 2011 | % Change | **2012** | 2011 | % Change |
| Deferred expense (recovery) | **(9,687)** | 1,298 | (846) | **(17,972)** | 6,369 | (382) |
| Per boe | **(14.57)** | 1.51 | (1,064) | **(5.93)** | 1.97 | (401) |

## FUNDS FROM OPERATIONS

### What are funds from operations and why is it a key performance measure?

Funds from operations is a non-IFRS measure that has been defined by the Company and is used as a measure to analyze performance. Delphi considers funds from operations 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 calculated as cash flow from operating activities before accretion on long-term debt, decommissioning expenditures and changes in non-cash working capital.

### How do cash flow from operating activities and funds from operations in 2012 compare to 2011?

Delphi's cash flow from operating activities of $9.3 million for the three months ended December 31, 2012 decreased 46 percent from the $17.1 million generated in the same period in 2011. Delphi generated funds from operations of $6.3 million for the three months ended December 31, 2012, down 63 percent from the $17.1 million for the same period in 2011. The decrease in cash flow from operating activities and funds from operations for the fourth quarter of 2012 compared to the fourth quarter of 2011 was primarily the result of lower commodity prices and production volumes and a decrease in realized gains on physical and financial commodity risk management contracts partially offset by a reduction in royalties.

For 2012, Delphi generated cash flow from operating activities of $31.1 million, 54 percent lower than the $68.3 million generated in 2011. Similarly, funds from operations decreased by 52 percent in 2012 compared to the same period in 2011. The decrease in cash flow from operating activities and funds from operations is primarily a result of weakening natural gas sales prices in combination with reduced crude oil and natural gas liquids volumes and a decrease in realized gains on natural gas physical and financial commodity risk management contracts partially offset by a reduction in royalties.

| | Three Months Ended December 31 | | | Twelve Months Ended December 31 | | |
|---|---|---|---|---|---|---|
| | **2012** | 2011 | % Change | **2012** | 2011 | % Change |
| Cash flow from operating activities | **9,273** | 17,134 | (46) | **31,078** | 68,300 | (54) |
| Accretion of long-term debt | **(231)** | (83) | 178 | **107** | 257 | (58) |
| Decommissioning expenditures | **9** | 588 | (98) | **422** | 588 | (28) |
| Change in non-cash working capital | **(2,782)** | (558) | 399 | **698** | (2,273) | - |
| Funds from operations | **6,269** | 17,081 | (63) | **32,305** | 66,872 | (52) |

## NET LOSS

### What factors contributed to the loss in 2012?

For the three months ended December 31, 2012, Delphi recorded a net loss of $29.4 million ($0.21 loss per basic share), down from the $0.8 million ($0.01 per basic share) net earnings recorded in the same period in 2011. The decrease in earnings is primarily due to lower realized sales prices in combination with lower production, a change in the production portfolio, an increase in general and administrative expenses, a decrease in gain on dispositions and higher interest and impairment charges partially offset by a reduction in royalties, operating and transportation expenses, an unrealized gain on commodity risk management contracts and a deferred income tax recovery.

For the twelve months ended December 31, 2012, Delphi recorded a net loss of $58.0 million ($0.43 loss per basic share) compared to net earnings of $11.6 million ($0.10 per basic share) in the same period in 2011. The decrease in earnings in 2012 compared to 2011 is primarily due to lower realized sales prices, particularly for natural gas as Delphi's realized natural gas price for 2012 decreased 37 percent in comparison to the same period in 2011. Other factors were higher general and administrative charges, an increase in share-based compensation expense, a loss on disposition and higher impairment charges partially offset by lower royalties, a reduction in unrealized losses on commodity risk management contracts and a deferred income tax recovery.

## NETBACK ANALYSIS

### How do Delphi's netbacks achieved in 2012 compare to 2011?

Delphi's production is predominantly natural gas, therefore, the Company's operating and cash netbacks are primarily driven by the price received for natural gas. Delphi continues to focus its drilling on liquids-rich natural gas plays in order to mitigate the weakening natural gas price and to strengthen its cash flow netback per boe.

For the three and twelve months ended December 31, 2012, Delphi's cash netback per boe decreased 53 percent and 48 percent, respectively, compared to the same period in 2011, respectively. The decrease is primarily due to lower realized sales prices.

| | Three Months Ended December 31 | | | Twelve Months Ended December 31 | | |
|---|---|---|---|---|---|---|
| | **2012** | 2011 | % Change | **2012** | 2011 | % Change |
| **Barrels of oil equivalent** ($/boe) | | | | | | |
| Realized sales price | **28.98** | 40.40 | (28) | **29.50** | 40.47 | (27) |
| Royalties | **2.46** | 7.28 | (66) | **4.41** | 6.41 | (31) |
| Operating expenses | **8.65** | 7.09 | 22 | **7.80** | 6.84 | 14 |
| Transportation | **2.79** | 2.89 | (3) | **2.72** | 2.97 | (8) |
| Operating netback | **15.08** | 23.14 | (35) | **14.57** | 24.25 | (40) |
| General and administrative expenses | **3.43** | 1.76 | 94 | **2.25** | 1.96 | 15 |
| Paid out restricted share units | **0.10** | - | - | **0.03** | - | - |
| Interest | **2.12** | 1.49 | 43 | **1.64** | 1.64 | - |
| Cash netback | **9.43** | 19.89 | (53) | **10.65** | 20.65 | (48) |
| Unrealized loss (gain) on commodity risk contracts | **(0.75)** | 3.42 | (122) | **0.25** | 0.56 | (55) |
| Stock-based compensation expense | **0.46** | 0.47 | (2) | **0.48** | 0.31 | 54 |
| Loss (gain) on dispositions | **(0.02)** | (2.64) | (99) | **0.95** | (0.58) | - |
| Loss on decommissioning | **-** | 0.53 | - | **-** | 0.14 | - |
| Depletion, depreciation and impairment | **68.29** | 15.52 | 340 | **33.88** | 14.52 | 133 |
| Accretion and finance lease charges | **0.21** | 0.12 | 75 | **0.20** | 0.15 | 33 |
| Deferred income taxes | **(14.57)** | 1.51 | (1,065) | **(5.93)** | 1.97 | (401) |
| Net earnings (loss) | **(44.19)** | 0.96 | (4,703) | **(19.18)** | 3.58 | (636) |

## SELECTED INFORMATION

### Over the past two years, how has Delphi performed and what significant factors contributed to the results?

Over the past two years, the changes in revenue and funds from operations from quarter to quarter primarily reflect the change in production volumes, product mix and the volatility of commodity prices.

In the first quarter of 2011, production decreased to 8,259 boe/d as a result of natural declines in production and an outage at a non-operated processing facility resulting in the shut-in of 550 boe/d for 22 days in the quarter. Record production in the fourth quarter of 2011 of 9,337 boe/d was a result of another successful drilling program.

In 2012, due to the continued deterioration of the natural gas price environment, the Company completed a strategic disposition of its non-operated light oil interests in the Hythe area and minor offsetting lands in order to develop its assets in the Bigstone Montney formation. In the third quarter of 2012, Delphi completed another strategic disposition of its working interests of Cardium oil assets in order to temporarily reduce debt and to fund the Company's ongoing capital program. Despite the dispositions the Company has completed in 2012, production volumes have only decreased seven percent in the twelve months of 2012 when compared to the same period in 2011 as a result of its successful 2012 drilling program.

Natural gas prices over the past two years have generally reflected the cyclical nature of demand. Higher prices are usually realized in the winter months, reflecting demand for heating with lower prices through the summer months as production is placed in storage for the upcoming heating season demand. In 2012, due to higher than normal average winter temperatures in North America and high inventory levels of natural gas, Canadian natural gas prices decreased to ten year lows. The average spot price for AECO in 2011 was $3.63 per mcf and in 2012, the average spot price for AECO was $2.39 per mcf.

Net earnings of the Company are primarily driven by the difference between the cash netback realized per boe of production versus the Company's depletion, depreciation and impairment rate, unrealized losses on commodity risk management contracts and loss on dispositions. Overall finding and development ("F&D") costs were $12.37 per proved plus probable boe in 2011 and $18.03 per proved plus probable boe in 2012.

The following table sets forth certain information of the Company for the past eight consecutive quarters outlining this performance:

| | **Dec. 31 2012** | Sept. 30 2012 | Jun. 30 2012 | Mar. 31 2012 | Dec. 31 2011 | Sept. 30 2011 | Jun. 30 2011 | Mar. 31 2011 |
|---|---|---|---|---|---|---|---|---|
| **Production** | | | | | | | | |
| Oil and field condensate (bbls/d) | **565** | 830 | 1,083 | 1,164 | 1,436 | 1,395 | 1,346 | 1,102 |
| Natural gas liquids (bbls/d) | **1,055** | 1,069 | 1,040 | 1,244 | 1,405 | 1,074 | 1,317 | 1,072 |
| Natural gas (mcf/d) | **33,654** | 38,148 | 39,080 | 39,510 | 38,973 | 38,989 | 37,460 | 36,509 |
| Barrels of oil equivalent (boe/d) | **7,229** | 8,257 | 8,636 | 8,993 | 9,337 | 8,967 | 8,906 | 8,259 |
| **Financial** | | | | | | | | |
| Petroleum and natural gas revenue | **18,858** | 20,878 | 21,875 | 24,143 | 33,115 | 32,194 | 32,678 | 28,900 |
| Funds from operations | **6,269** | 7,881 | 7,181 | 10,974 | 17,081 | 17,213 | 17,517 | 15,061 |
| Per share – basic | **0.04** | 0.06 | 0.05 | 0.08 | 0.14 | 0.15 | 0.15 | 0.13 |
| Per share – diluted | **0.04** | 0.06 | 0.05 | 0.08 | 0.14 | 0.14 | 0.15 | 0.13 |
| Net earnings (loss) | **(29,394)** | (9,190) | (3,531) | (15,915) | 825 | 4,058 | 5,757 | 962 |
| Per share – basic | **(0.21)** | (0.07) | (0.03) | (0.12) | 0.01 | 0.03 | 0.05 | 0.01 |
| Per share – diluted | **(0.21)** | (0.07) | (0.03) | (0.12) | 0.01 | 0.03 | 0.05 | 0.01 |

## On an annual basis, how has Delphi performed?

The annual results for 2011 and 2012 have been impacted by weakening commodity prices, a decrease in 2012 capital spending and an increase in property dispositions.

In 2011, the Company continued to focus on exploiting its crude oil and liquids-rich natural gas opportunities and invested $114.4 million in capital before property dispositions and acquisitions. Although natural gas prices continued to weaken in 2011, pricing for crude oil and natural gas liquids improved, allowing the Company to realize higher netbacks for its crude oil and natural gas liquids.

In 2012, Delphi focused its capital program on drilling liquids-rich natural gas wells and the construction of its Bigstone Montney facility. In the first quarter of 2012, the Company disposed of 217 boe/d (66 percent light oil) and in the third quarter of 2012, the Company disposed of 450 boe/d (48 percent light oil). Total net proceeds of $34.7 million in 2012 for property dispositions were used to temporarily reduce outstanding bank indebtedness and ultimately directed toward the 2012 capital program. Despite the property dispositions, Delphi's production for the year ended December 31, 2012 was only reduced by seven percent compared to the same period in 2011 as the Company's successful drilling program partially offset the sold production and natural declines.

The following table sets forth selected consolidated financial information of the Company for the most recently completed year ended December 31, 2012 and for the years ended 2011 and 2010:

| | **2012** | 2011 | 2010 |
|---|---|---|---|
| Revenue | **85,754** | 126,887 | 113,772 |
| Net earnings (loss) | **(58,030)** | 11,602 | (16,984) |
| Per share – basic | **(0.43)** | 0.10 | (0.16) |
| Per share – diluted | **(0.43)** | 0.10 | (0.16) |
| Total assets | **401,649** | 447,073 | 386,737 |
| Bank debt plus working capital deficiency [1] | **92,815** | 95,632 | 108,054 |

(1) The Company's calculation of working capital deficiency excludes the fair value of financial instruments.

# LIQUIDITY AND CAPITAL RESOURCES

## SHARE CAPITAL

### How many common shares and stock options are currently outstanding?

As at March 19, 2013, the Company had 153.1 million common shares outstanding (December 31, 2011 – 131.0 million) and 10.9 million share options outstanding (December 31, 2011 – 10.8 million). The share options have an average exercise price of $1.66 per option (December 31, 2011 – $1.90 per option).

On November 13, 2012, Delphi issued, on a bought deal basis, 17.2 million common shares at a price of $1.45 per share and 4.6 million common shares on a flow-through basis at a price of $1.75 per common share for total net proceeds of $31.1 million.

### What has been the market activity in the Company's common shares?

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, 2012:

| | Three Months Ended December 31 | Twelve Months Ended December 31 |
|---|---|---|
| Weighted Average Common Shares | | |
| Basic | **142,615** | 133,992 |
| Diluted | **143,021** | 134,386 |
| Trading Statistics [1] | | |
| High | **1.54** | 2.23 |
| Low | **1.09** | 1.09 |
| Average daily volume | **439,434** | 355,139 |

(1) Trading statistics based on closing price.

## SOURCES AND USES OF FUNDS

| | Three Months Ended December 31, 2012 | Twelve Months Ended December 31, 2012 |
|---|---|---|
| **Sources**: | | |
| Cash and cash equivalents | **-** | **4,017** |
| Funds from operations | **6,269** | **32,305** |
| Disposition of petroleum and natural gas properties | **45** | **34,664** |
| Issue of flow-through common shares, net of issue costs | **7,537** | **7,537** |
| Issue of common shares, net of issue costs | **23,535** | **23,535** |
| Exercise of stock options | **-** | **152** |
| | **37,386** | **102,210** |
| **Uses**: | | |
| Capital expenditures | **11,678** | **83,868** |
| Accretion of long term debt | **(231)** | **107** |
| Finance lease obligation | **101** | **372** |
| Expenditures on decommissioning | **9** | **422** |
| Change in non-cash working capital | **(4,260)** | **19,581** |
| | **7,297** | **104,350** |
| Change in long term debt | **(30,089)** | **2,140** |

## BANK DEBT PLUS WORKING CAPITAL DEFICIENCY (NET DEBT)

### What is liquidity risk and how does the Company manage this risk?

As an oil and gas business, Delphi has a declining asset base and therefore relies on oil and gas property development and acquisitions to replace produced reserves. Future oil and natural gas production and growth in reserves are highly dependent on the success of exploiting the Company's existing asset base and/or acquiring additional lands or reserves. To the extent Delphi is successful or unsuccessful in these activities, cash flow could be increased or reduced.

Liquidity risk is the risk that Delphi will not be able to meet its financial obligations as they become due. Delphi actively manages its liquidity through daily, short-term and long-term cash, debt and equity management strategies. Such strategies encompass, among other factors: having adequate sources of financing available through its bank credit facilities, forecasting future cash generated from operations based on reasonable production and pricing assumptions, monitoring economic risk management opportunities and maintaining sufficient cash flows for compliance with financial debt covenants.

Delphi generally relies on operating cash flows and its credit facilities to fund ongoing capital requirements and provide liquidity. Future liquidity depends primarily on cash flow generated from operations, existing credit facilities and the ability to access debt and equity markets. From time to time, the Company accesses capital markets to meet its additional financing needs and to maintain flexibility in funding its capital expenditures program. There can be no assurance that future debt or equity financings, or cash generated from operations will be available or sufficient to meet these requirements or other corporate requirements or, if debt or equity financing is available, that it will be on terms acceptable to Delphi.

Delphi's results are affected by external market and risk factors, such as fluctuations in the prices of crude oil and natural gas, movements in foreign currency exchange rates and inflationary pressures on service costs. Market conditions have resulted in Delphi experiencing primarily downward trends in crude oil pricing for 2012 compared to 2011, and a more significant downward trend in natural gas pricing, although natural gas prices recovered slightly at the end of 2012. As an added layer of cash flow protection, Delphi has fixed financial contracts that provide for approximately 51 percent of its before-royalty natural gas production at predominantly an AECO based average floor price of $3.27 per mcf for 2013.

### How much bank debt was outstanding on December 31, 2012?

At December 31, 2012, the Company had $79.4 million outstanding in the form of bankers' acceptances, $5.0 million drawn under Canadian-based prime loans and a working capital deficiency of $8.4 million for total net debt of $92.8 million. Net debt is a non-IFRS term. Delphi's calculation of net debt includes long-term debt and the net working capital deficiency (excess) before the current fair value of financial instruments.

### What are the Company's credit facilities and when is the next scheduled review of the borrowing base?

The Company's extendible revolving term credit facility with a syndicate of Canadian chartered banks is subject to the banks' semi-annual valuation of the Company's crude oil and natural gas properties. In December 2012, the Company's borrowing base was reduced from $145.0 million to $125.0 million as a result of the banks' semi-annual review.

The facility is a 364 day committed facility available on a revolving basis until May 27, 2013 at which time it may be extended at the lenders' option. If the revolving period is not extended, the undrawn portion of the facility will be cancelled and the amount outstanding will convert to a 365 day non-revolving term facility. The amounts outstanding under the non-revolving facility are required to be repaid at the end of the non-revolving term being May 28, 2014. The non-extension provisions are applicable to the lenders on an individual basis.

Interest payable on amounts drawn under the facility is at the prevailing bankers' acceptance rates plus stamping fees, lenders' prime rate or U.S. base rate plus the applicable margins, depending on the form of borrowing by the Company. The applicable margins and stamping fees are based on a sliding scale pricing grid tied to the Company's trailing debt to annualized quarterly funds from operations ratio: from a minimum of the bank's prime rate or U.S. base rate plus 1.00 percent to a maximum of the bank's prime rate or U.S. base rate plus 2.50 percent or from a minimum of bankers' acceptances rate plus a stamping fee of 2.00 percent to a maximum of bankers' acceptances rate plus a stamping fee of 3.50 percent.

Under the terms of the credit facility, the Company covenants that it will maintain a working capital ratio of at least one to one. For the purpose of this ratio, the undrawn portion of the credit facility is added to current assets in the working capital calculation. The credit facility is secured by a $200.0 million demand floating charge debenture and a general security agreement over all assets of the Company. Delphi is in compliance with the covenants of its credit facility as at December 31, 2012.

## CONTRACTUAL OBLIGATIONS

**Does the Company have any contractual obligations as of December 31, 2012 that will require funding in future years?**

The Company is committed to future minimum payments for natural gas transmission and processing and operating leases on compression equipment. In March of 2012, the Company entered into an arrangement to lease a compressor for one year with a commitment to purchase at the end of the term for $1.6 million. The Company also has a lease for office space in Calgary, Alberta. As noted above, bank debt is based on a revolving term which is reviewed annually and converts to a 365 day non-revolving term facility if not renewed.

The future minimum commitments over the next five years are as follows:

| | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|
| Gathering, processing and transmission | 4,361 | 3,929 | 3,620 | 100 | - |
| Office and equipment lease | 1,932 | 566 | 566 | 579 | 417 |
| Outstanding cheques | 883 | - | - | - | - |
| Accounts payable and accrued liabilities | 24,396 | - | - | - | - |
| Finance lease | 1,642 | - | - | - | - |
| Decommissioning obligations | 420 | - | - | - | - |
| Fair value of financial instruments | 306 | 3,981 | - | - | - |
| Bank debt | - | 84,418 | - | - | - |
| Total | 33,940 | 92,894 | 4,186 | 679 | 417 |

As a result of the flow-through shares issued on December 23, 2012, Delphi is committed to incur approximately $8.0 million in qualifying Canadian exploration expenses on or before December 31, 2013.

Pursuant to a farm-in agreement, Delphi must drill a total of 5 gross wells in 2013 and 2014 of which it has a commitment to pay the farmor's working interest, representing 2.3 net wells. The farm-in agreement will allow Delphi to earn working interests in Montney and Nordegg petroleum and natural gas rights ("PNG rights") in its core area of Bigstone, Alberta. Under this farm-in agreement, Delphi may earn a minimum of a 33 percent working interest in 23.5 sections of PNG rights at an estimated cost of $20.0 million or up to a 75 percent working interest in 35 sections of PNG rights at an estimated cost of $32.5 million. In the event Delphi does not complete their drilling commitments associated with this farm-in agreement, the Company is exposed to a maximum non-performance fee of $4.0 million.

## GUARANTEES AND OFF-BALANCE SHEET ARRANGEMENTS

**Does Delphi have any outstanding guarantees on behalf of third parties or any off-balance sheet arrangements which could lead to liabilities in the future?**

Delphi has not entered into any guarantees or off-balance sheet arrangements. Certain lease agreements entered into in the normal course of operations could be considered off-balance sheet arrangements; however, all leases which are considered operating leases are charged to operating expenses or general and administrative expenses on a monthly basis according to the lease. In March of 2012, the Company entered into a lease agreement that is accounted for as a finance lease. As a result of this arrangement, an asset and an obligation have been recorded on the Company's consolidated statement of financial position as at December 31, 2012.

## CRITICAL ACCOUNTING ESTIMATES

**In preparing the Company's consolidated financial statements, is Delphi required to make estimates or assumptions about future events?**

The consolidated financial statements have been prepared in conformity with IFRS which requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, shareholders' equity, revenue and expenses. Actual results may differ from these estimates.

Estimates and their underlying assumptions are reviewed on an ongoing basis. 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. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected.

The judgments, estimates and assumptions that have the most significant effect on the amounts recognized in the consolidated financial statements are included in the following:

i) Derivatives – the fair value of commodity contracts is estimated, whenever possible, based on published market prices, and if not available, on estimates from third party brokers, as at the balance sheet date and may differ from what will be realized.

ii) Oil and gas reserves – reserves and resources are used in the units of production calculation for depreciation, depletion and amortization and the impairment analysis which affect the net earnings. There are numerous uncertainties inherent in estimating oil and gas reserves. Estimating reserves is very complex, requiring many judgments based on geological, geophysical, engineering and economic data. Changes in these judgments could have a material impact on the estimated reserves. These estimates may change, having either a negative or positive effect on net profit as further information becomes available and as the economic environment changes.

iii) Depletion and depreciation – depletion of petroleum and natural gas properties is provided using the unit-of-production method based on production volumes before royalties in relation to total estimated proved and probable reserves as determined annually by independent engineers and internal reserve evaluations on a quarterly basis in accordance with National Instrument 51-101. Natural gas reserves and production are converted at the energy equivalent of six thousand cubic feet per one barrel of oil equivalent.

   Calculations for depletion and depreciation of production equipment are based on total capitalized costs plus estimated future development costs of proved and probable undeveloped reserves less the estimated net realizable value of production equipment and facilities after the proved reserves are fully produced. The costs of acquiring and evaluating unproved properties are excluded from depletion calculations.

iv) Recoverability of asset carrying values – the Company assesses its oil and gas properties, including exploration and evaluation assets, for possible impairment if there are events or changes in circumstances that indicate that carrying values of the assets may not be recoverable, or at least at every reporting date. The assessment of any impairment of property, plant and equipment is dependent upon estimates of the recoverable amount that take into account factors such as reserves, economic and market conditions, timing of cash flows, the useful lives of assets and their related salvage values.

   Delphi's assets are aggregated into CGU's, for the purpose of calculating impairment, based on their ability to generate largely independent cash flows based on the geography, geology, production profile and infrastructure of its assets. By their nature, these estimates and assumptions are subject to measurement uncertainty and may impact the carrying value of the Company's assets in future periods.

v) Decommissioning obligations – provisions for decommissioning obligations associated with the Company's drilling operations are based on current legal and constructive requirements, technology, price levels and expected plans for remediation. Actual costs and timing of cash outflows can differ from estimates because of changes in laws and regulations, public expectations, prices, discovery and analysis of site conditions and changes in clean up technology.

vi) Share-based compensation – the fair value of stock options granted is measured using a Black-Scholes model. Measurement inputs such as the expected volatility, expected life of the options and a forfeiture rate require management judgment and estimates. The Company estimates volatility based on weighted average historical daily volatility. The expected life of the options is estimated by using an average life for awards based on historical plan records. Management also makes an estimate of the number of options that will forfeit based on historical information. The estimated forfeiture rate is adjusted to reflect actual forfeitures. Dividends are not taken into consideration as the Company does not expect to pay dividends.

vii) Deferred income taxes – deferred tax assets and liabilities are recognized for the estimated tax consequences between amounts included in the financial statements and their tax base using substantively enacted future income tax rates. Timing of future revenue streams and future capital spending changes can affect the timing of the reversal of temporary differences and accordingly affect the amount of the deferred income tax asset or liability calculated at a point in time. These differences could materially impact earnings.

## NEW ACCOUNTING STANDARDS

### Are there any future accounting standards which the Company will have to comply with in the future?

The following new and amended standards have been issued by the International Accounting Standards Board ("IASB"):

- IFRS 9, "Financial Instruments", which is the result of the first phase of the IASB's project to replace IAS 39, "Financial Instruments: Recognition and Measurement". The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value. The effective date for this standard has been deferred to January 1, 2015.

- IFRS 10, "Consolidated Financial Statements" ("IFRS 10"), requires an entity to consolidate an investee when it is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Under existing IFRS, consolidation is required when an entity has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. This standard replaces SIC - 12, "Consolidation – Special Purpose Entities."

- IFRS 11, "Joint Arrangements" ("IFRS 11"), requires a venturer to classify its interest in a joint arrangement as a joint venture or joint operation, each having its own accounting model. Joint ventures will be accounted for using the equity method of accounting whereas for a joint operation the venture will recognize its share of the assets, liabilities, revenue and expenses of the joint operation. The standard provides for a more substance based reflection of joint arrangements by focusing on the rights and obligations of the arrangement, rather than its legal form. The new standard replaces IAS 31, "Interests in Joint Ventures" and SIC – 13, "Jointly Controlled Entities – Non-monetary Contributions by Venturers" and establishes principles for accounting for all joint arrangements.

- IFRS 12, "Disclosure of Interests in Other Entities", which outlines the required disclosures for interests in subsidiaries and joint arrangements. The new disclosures require information that will assist financial statement users to evaluate the nature, risks and financial effects associated with an entity's interests in subsidiaries and joint arrangements.

- IFRS 13, "Fair Value Measurement", which defines fair value, establishes a framework for measuring fair value and sets out disclosure requirements for fair value measurements.

- IAS 28, "Investments in Associates and Joint Ventures", has been amended to conform to the changes made in IFRS 10 and IFRS 11.

Except as noted above, all of the above pronouncements are effective for annual periods beginning on or after January 1, 2013, with early adoption permitted. The Company is currently evaluating the impact of adopting these standards and does not anticipate a material impact to the consolidated financial statements as a result of these new standards.

## CORPORATE GOVERNANCE

### Overview

The shareholders' interests are a critical factor in the operations and management of Delphi. The Company is committed to maintaining the highest level of investor confidence in the Company through the application of its corporate policies and procedures. Delphi's Board of Directors consists of six 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 Company's management, including its President and Chief Executive Officer and Senior 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 Senior Vice President, Finance and Chief Financial Officer have concluded that the Company's internal controls over financial reporting and disclosure controls and procedures are effective and 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. Management's assessment of the Company's internal controls over financial reporting was based on the framework in Internal Control over Financial Reporting – Guidance for Smaller Public Companies issued by the Committee of Sponsoring Organizations.

The Company notes that while it believes the disclosure controls and procedures and internal controls over financial reporting provide a reasonable level of assurance that they are effective, it does not expect that the disclosure controls and procedures and internal controls will prevent all errors and fraud. A control system is designed to provide reasonable, not absolute, assurance that the objectives of the control system are met. There were no changes made to the disclosure controls and procedures or internal controls over financial reporting during the fourth quarter.

## ADDITIONAL INFORMATION

### Where is additional information about Delphi available?

Additional information about Delphi Energy 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.

# MANAGEMENT'S REPORT

The financial statements of Delphi Energy Corp. were prepared by management in accordance with International Financial Reporting Standards. 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 Committee. The Audit 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 Committee has reported its findings to the Board of Directors who have approved the financial statements.

**David J. Reid**
President and Chief Executive Officer

**Brian P. Kohlhammer**
Senior Vice President Finance
and Chief Financial Officer

Calgary, Canada
March 19, 2013

# INDEPENDENT AUDITORS' REPORT

## TO THE SHAREHOLDERS OF DELPHI ENERGY CORP.

We have audited the accompanying consolidated financial statements of Delphi Energy Corp., which comprise the consolidated statements of financial position as at December 31, 2012 and December 31, 2011, the consolidated statements of earnings (loss) and comprehensive earnings (loss), changes in shareholders' equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

### Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

### Auditors' Responsibility

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 comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

### Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Delphi Energy Corp. as at December 31, 2012 and December 31, 2011, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Accountants
March 19, 2013
Calgary, Canada

# Consolidated Statements of Financial Position

| (thousands of dollars) | December 31 2012 | December 31 2011 |
|---|---|---|
| **Assets** | | |
| Current assets | | |
| Cash and cash equivalents | - | 4,017 |
| Accounts receivable (Note 8) | 16,250 | 18,770 |
| Prepaid expenses and deposits | 2,640 | 2,939 |
| Assets held for sale (Note 9) | - | 9,680 |
| Fair value of financial instruments (Note 6) | 285 | 546 |
| | 19,175 | 35,952 |
| Exploration and evaluation (Note 10) | 12,406 | 18,699 |
| Property, plant and equipment (Note 11) | 370,068 | 392,422 |
| Total assets | 401,649 | 447,073 |
| **Liabilities** | | |
| Current liabilities | | |
| Outstanding cheques | 883 | - |
| Accounts payable and accrued liabilities (Note 12) | 24,396 | 47,451 |
| Liabilities held for sale (Note 9) | - | 377 |
| Decommissioning obligations (Note 15) | 420 | 825 |
| Finance lease obligation (Note 13) | 1,588 | - |
| Fair value of financial instruments (Note 6) | 306 | 21 |
| | 27,593 | 48,674 |
| Other liability (Note 17) | 2,651 | 1,334 |
| Long term debt (Note 14) | 84,418 | 82,385 |
| Decommissioning obligations (Note 15) | 35,293 | 19,288 |
| Fair value of financial instruments (Note 6) | 3,981 | 3,772 |
| Deferred income taxes (Note 16) | 6,126 | 23,245 |
| Total liabilities | 160,062 | 178,698 |
| **Shareholders' equity** | | |
| Share capital (Note 17) | 304,816 | 275,682 |
| Contributed surplus | 14,608 | 12,500 |
| Deficit | (77,837) | (19,807) |
| Total shareholders' equity | 241,587 | 268,375 |
| Total liabilities and shareholders' equity | 401,649 | 447,073 |

Commitments (Note 21)

See accompanying notes to the consolidated financial statements.

Approved on behalf of the Board of Directors:

Stephen Mulherin
Director

Andrew E. Osis
Director

# Consolidated Statements of Earnings (Loss) and Comprehensive Earnings (Loss)

## FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

| (thousands of dollars, except per share amounts) | 2012 | 2011 |
|---|---|---|
| **Revenues** | | |
| Crude oil and natural gas sales | **85,754** | 126,887 |
| Royalties | **(13,351)** | (20,739) |
| | **72,403** | 106,148 |
| Realized gain on financial instruments (Note 6) | **3,595** | 4,140 |
| Unrealized loss on financial instruments (Note 6) | **(755)** | (1,800) |
| | **75,243** | 108,488 |
| **Expenses** | | |
| Operating | **23,609** | 22,144 |
| Transportation | **8,232** | 9,630 |
| General and administrative | **6,811** | 6,343 |
| Share-based compensation (Note 17) | **1,532** | 992 |
| Loss (gain) on property dispositions | **2,890** | (1,866) |
| Loss on decommissioning | **-** | 457 |
| Depletion, depreciation and impairment (Note 11) | **102,613** | 47,035 |
| | **145,687** | 84,735 |
| Finance costs (Note 18) | **5,558** | 5,782 |
| Earnings (loss) before income taxes | **(76,002)** | 17,971 |
| **Income taxes** | | |
| Deferred income taxes (recovery) (Note 16) | **(17,972)** | 6,369 |
| Net earnings (loss) and comprehensive earnings (loss) | **(58,030)** | 11,602 |
| Net earnings (loss) per share (Note 17) | | |
| Basic | **(0.43)** | 0.10 |
| Diluted | **(0.43)** | 0.10 |

See accompanying notes to the consolidated financial statements.

# Consolidated Statements of Changes in Shareholders' Equity

## FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

| (thousands of dollars) | 2012 | 2011 |
|---|---|---|
| **Share capital** | | |
| **Common shares** | | |
| Balance, beginning of year | **275,682** | 236,382 |
| Issued for cash | **25,000** | 22,011 |
| Issued for cash on a flow-through basis | **5,349** | 14,801 |
| Issued on exercise of options | **152** | 2,575 |
| Transferred on exercise of options | **78** | 1,347 |
| Share issue costs, net of deferred tax effect | **(1,445)** | (1,434) |
| Balance, end of year | **304,816** | 275,682 |
| **Contributed surplus** | | |
| Balance, beginning of year | **12,500** | 11,987 |
| Share-based compensation | **2,186** | 1,860 |
| Transferred on exercise of options | **(78)** | (1,347) |
| Balance, end of year | **14,608** | 12,500 |
| **Deficit** | | |
| Balance, beginning of year | **(19,807)** | (31,409) |
| Net earnings (loss) | **(58,030)** | 11,602 |
| Balance, end of year | **(77,837)** | (19,807) |
| Total shareholders' equity | **241,587** | 268,375 |

See accompanying notes to the consolidated financial statements.

# Consolidated Statements of Cash Flows

## FOR THE YEARS ENDED DECEMBER 31, 2012 AND 2011

| (thousands of dollars) | 2012 | 2011 |
|---|---|---|
| **Cash flow from (used in) operating activities** | | |
| Net earnings (loss) | **(58,030)** | 11,602 |
| Adjustments for: | | |
| Depletion, depreciation and impairment | **102,613** | 47,035 |
| Accretion and finance lease charges | **594** | 483 |
| Share-based compensation | **1,455** | 992 |
| Loss (gain) on property dispositions | **2,890** | (1,866) |
| Loss on decommissioning | **-** | 457 |
| Unrealized loss on financial instruments | **755** | 1,800 |
| Deferred income taxes (recovery) | **(17,972)** | 6,369 |
| Accretion of long term debt | **(107)** | (257) |
| Decommissioning expenditures | **(422)** | (588) |
| Change in non-cash working capital (Note 22) | **(698)** | 2,273 |
| | **31,078** | 68,300 |
| **Cash flow from (used in) financing activities** | | |
| Issue of common shares, net of issue costs | **23,535** | 20,920 |
| Issue of flow-through common shares, net of issue costs | **7,537** | 16,111 |
| Finance lease obligation | **(372)** | - |
| Exercise of options | **152** | 2,575 |
| Increase (decrease) in long term debt | **2,140** | (21,407) |
| Change in non-cash working capital (Note 22) | **(212)** | 300 |
| | **32,780** | 18,499 |
| **Cash flow available for investing activities** | **63,858** | 86,799 |
| **Cash flow from (used in) investing activities** | | |
| Additions to exploration and evaluation | **(2,417)** | (15,912) |
| Additions to property, plant and equipment | **(81,312)** | (98,565) |
| Disposition of petroleum and natural gas properties | **34,664** | 12,873 |
| Acquisition of petroleum and natural gas properties | **(139)** | (273) |
| Change in non-cash working capital (Note 22) | **(18,671)** | 15,056 |
| | **(67,875)** | (86,821) |
| Decrease in cash and cash equivalents | **(4,017)** | (22) |
| Cash and cash equivalents, beginning of year | **4,017** | 4,039 |
| Cash and cash equivalents, end of year | **-** | 4,017 |
| Cash interest paid | **5,114** | 6,021 |

See accompanying notes to the consolidated financial statements.

# Notes to the Consolidated Financial Statements

**As at and for the years ended December 31, 2012 and 2011**

(thousands of dollars, except per share amounts)

## 1) STRUCTURE OF DELPHI

Delphi Energy Corp. ("Delphi" or "the Company") is a publicly-traded company engaged in the exploration for, development and production of crude oil and natural gas from properties and assets located in Western Canada in which it holds an interest. The Company's operations are primarily concentrated in the Deep Basin of North West Alberta, representing in excess of 90 percent of the Company's production. The registered office of the Company is located at Suite 300, 500 – 4th Avenue S.W., Calgary, Alberta, T2P 2V6.

The consolidated financial statements as at and for the year ended December 31, 2012 comprise the accounts of the Company, its wholly-owned subsidiary and a partnership.

## 2) BASIS OF PRESENTATION

### (a) Statement of compliance and authorization

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB").

These consolidated financial statements were approved and authorized for issuance by the Board of Directors on March 19, 2013.

### (b) Basis of measurement and functional currency

The consolidated financial statements have been prepared on a going concern basis, using historical costs, except for derivative financial instruments and liabilities for cash-settled share-based payment arrangements which are measured at fair value. The financial statements are presented in Canadian dollars, the Company's functional currency and rounded to the nearest thousand (unless stated otherwise).

### (c) Use of estimates and judgments

The preparation of the consolidated financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts in the consolidated financial statements and accompanying notes. By their nature, these estimates are subject to measurement uncertainty and the effect on the consolidated financial statements of changes in such estimates in future periods could be material. Actual results may differ from these estimates. Estimates and their underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected.

The following are critical judgments that management has made in the process of applying Delphi's accounting policies and that have the most significant effect on the amounts recognized on the consolidated financial statements:

i) Identification of a cash generating unit ("CGU")

Delphi's assets are aggregated into CGUs for the purpose of calculating impairment. A CGU represents the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or group of assets. CGUs have been determined based on similar geological structure, geographical proximity, production profiles and infrastructure of its assets. By nature, these assumptions are subject to management's judgment and may impact the carrying value of the Company's assets in future periods. The Company's CGUs could change in the future as a result of development, acquisition or disposition activity.

ii) Assessment of indicators of impairment

The Company assesses its oil and gas properties, including exploration and evaluation assets, for possible impairment if there are events or changes in circumstances that indicate that carrying values of the assets may not be recoverable. Determining if there are facts and circumstances present that indicate that carrying values of the assets may not be recoverable requires management's judgment and analysis of the facts and circumstances.

For oil and gas properties, management considers changes in assumptions relating to future commodity prices, future costs and significant revisions of estimated recoverable reserves when assessing if indicators of impairment are present. For exploration and development assets, particularly undeveloped land, Delphi considers the expiration date of the leases, management's intention and ability to develop the land and if possible, current market prices. The above does not represent an exhaustive list but rather the most significant factors taken into consideration when assessing for indicators of impairment. An impairment test is performed if it is determined that indicators of impairment are present.

The following are key assumptions concerning the sources of estimation uncertainty at the end of the reporting period:

i) Depreciation and depletion

Management estimates the useful lives of production equipment and other assets based on the period during which the assets are expected to be available for use. For crude oil and natural gas properties, the estimated useful lives are based on proved and probable reserves as determined annually by the Company's independent engineers and internal estimates on a quarterly basis determined in accordance with National Instrument 51-101 ("NI 51-101") and the Canadian Oil and Gas Evaluation Handbook ("COGEH").

Calculations for the depletion of crude oil and natural gas properties are based on total capitalized costs plus estimated future development costs of proved and probable reserves less the estimated net realizable value of production equipment and facilities after the proved reserves are fully produced.

ii) Recoverability of property, plant and equipment and exploration and evaluation

The assessment of any impairment of property, plant and equipment is dependent upon estimates of recoverable amount that take into account factors such as reserves, economic and market conditions, discount rates, timing of cash flows, the useful lives of assets and their related salvage values. In determining whether oil and gas properties are impaired, each CGUs carrying value is compared to its recoverable amount, defined as the greater of its fair value less costs to sell and value in use.

The recoverable amount of Delphi's CGUs were estimated as their fair value less costs to sell based on the following information:

- the net present value, using pre-tax discount rates, of expected future cash flows based on proved and probable reserves as estimated by the Company's independent engineers; and
- the fair value of undeveloped land based on estimates provided by Delphi's independent land evaluator.

Key input estimates used in the determination of cash flows from oil and gas reserves include the following:

- Reserves - Assumptions that are valid at the time of reserve estimation may change significantly when new information becomes available. Changes in forward commodity price estimates, production costs or recovery rates may change the economic status of reserves and may ultimately result in reserves being adjusted.
- Oil and gas prices - Forward price estimates of oil and natural gas prices are used in the cash flow model. Commodity prices have fluctuated widely in recent years due to global and regional factors including supply and demand fundamentals, inventory levels, exchange rates, weather, economic and geopolitical factors.
- Discount rate - The discount rate used to calculate the net present value of cash flows is based on estimates of an approximate industry peer group weighted average cost of capital. Changes in the general economic environment could result in significant changes to this estimate.

iii) Decommissioning obligations

Provisions for decommissioning obligations associated with the Company's drilling operations are based on current legal and constructive requirements, technology, price levels and expected plans for remediation. Actual costs and timing of cash outflows can differ from estimates because of changes in laws and regulations, public expectations, prices, discovery and analysis of site conditions, changes in clean up technology and changes in discount rates.

iv) Share-based compensation

The fair value of stock options granted is measured using a Black-Scholes model. Measurement inputs such as the expected volatility, expected life of the options and a forfeiture rate require management judgment and estimates. The Company estimates volatility based on weighted average historical traded daily volatility. The expected life of the options is estimated by using an average life for awards based on historical plan records. Management also makes an estimate of the number of options that will forfeit based on historical information. The estimated forfeiture rate is adjusted to reflect actual forfeitures. Dividends are not taken into consideration as the Company does not expect to pay dividends.

v) Deferred income taxes

Deferred tax assets and liabilities are recognized for the estimated tax consequences between amounts included in the financial statements and their tax base using substantively enacted future income tax rates. Timing of future revenue streams and future capital spending changes can affect the timing of the reversal of temporary differences and accordingly affect the amount of the deferred income tax asset or liability calculated at a point in time. These differences could materially impact earnings.

Estimates of recoverable quantities of proved plus probable oil and natural gas reserves have an effect on a number of the areas referred to above, in particular, the valuation of property, plant and equipment and the calculation of depletion and depreciation. There are numerous uncertainties inherent in estimating oil and natural gas reserves. Estimating reserves is very complex, requiring many judgments based on commodity prices, exchange rates, discount rates and production and transportation costs for future cash flows. It also requires interpretation of complex geological and geophysical models in order to make an assessment of the size, shape, depth and quality of reservoirs and their anticipated recoveries. The economic, geological and technical factors used to estimate reserves may change from period to period. Changes in these judgments could have a material impact on the estimated reserves. These estimates may change, having either a negative or positive effect on the net loss as further information becomes available and as the economic environment changes.

## 3) SIGNIFICANT ACCOUNTING POLICIES

The accounting policies set out below have been applied consistently to all periods presented in these consolidated financial statements.

### (a) Basis of consolidation

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

### (b) Jointly controlled operations

Certain of the Company's crude oil and natural gas activities involve jointly controlled operations. The consolidated financial statements reflect the Company's proportionate share of the jointly controlled assets and liabilities and proportionate share of related revenues and costs.

### (c) Foreign currency transactions

Transactions in foreign currencies are translated to Canadian dollars at the exchange rate on the date of the transactions. Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars at the period end exchange rate. Foreign currency differences arising on translation are recognized in the consolidated statement of earnings.

### (d) Financial instruments

A financial instrument is any contract that gives rise to a financial asset of one entity and a financial liability or equity instrument of another entity. All financial instruments, including all derivatives, are recognized on the statement of financial position at fair value at the time the Company a party to the provisions of the contract. Subsequently, all financial assets and liabilities, except financial assets carried at fair value through earnings or loss and available-for-sale, are measured at amortized cost determined using the effective interest method. Financial assets carried at fair value through earnings or loss are measured at fair value with changes in fair value recognized in the consolidated statement of earnings. Available-for-sale financial assets are measured at fair value with changes in fair value recognized in other comprehensive earnings and reclassified to earnings when derecognized or impaired. The Company does not hold any available-for-sale financial assets.

Transaction costs attributable to financial instruments carried at fair value through earnings or loss are expensed as incurred. All other transaction costs related to the Company's financial instruments are recorded as part of the instrument and are amortized using the effective interest method.

Financial assets and liabilities are offset and the net amount presented in the consolidated statement of financial position when, and only when, the Company has the legal right to offset the amounts and intends either to settle on a net basis or to realize the asset and settle the liability simultaneously.

The Company derecognizes a financial asset when the contractual rights to the cash flows from the asset expire or if it transfers the rights to receive the contractual cash flows on the financial asset in a transaction in which substantially all the risk and rewards of ownership of the financial asset are transferred. Any interest in transferred financial assets that is created or retained by the Company is recognized as a separate asset or liability. The Company derecognizes a financial liability when its contractual obligations are discharged, cancelled or expired.

The Company has the following classifications:

| Financial Assets and Liabilities | Category | Subsequent Measurement |
|---|---|---|
| Cash and cash equivalents | Loans and receivables | Amortized cost |
| Accounts receivable | Loans and receivables | Amortized cost |
| Derivative instruments | Financial assets or liabilities at fair value through earnings or loss | Fair value through earnings or loss |
| Accounts payable and accrued liabilities | Financial liabilities | Amortized cost |
| Long term debt | Financial liabilities | Amortized cost |

The Company has a risk management program whereby the commodity price associated with a portion of its future production volumes is fixed in order to mitigate cash flow volatility resulting from fluctuating commodity prices. The Company sells forward a portion of its future production volumes by entering into a combination of physical sale contracts with customers and derivative financial contracts such as fixed price contracts, costless collars and the purchase of floor price options with financial counterparties. These instruments are not used for trading or speculative purposes.

The Company has not designated its financial derivative contracts as effective accounting hedges and thus has not applied hedge accounting. As a result, financial derivatives are classified as fair value through earnings or loss and are recorded on the statement of financial position at fair value.

The Company accounts for its commodity sales and purchase contracts, which were entered into and continue to be held for the purpose of receipt or delivery of non-financial items in accordance with its expected purchase, sale or usage requirements as executory contracts. As such, these contracts are not considered to be derivative financial instruments and have not been recorded at fair value on the statement of financial position. Settlements on these physical sales contracts are recognized in crude oil and natural gas sales in the consolidated statement of earnings.

Embedded derivatives are separated from the host contract and accounted for separately if 1) the economic characteristics and risks of the host contract and the embedded derivative are not closely related, 2) a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative and 3) the combined instrument is not measured at fair value through profit or loss. Changes in the fair value of embedded derivatives are recognized in the consolidated statement of earnings.

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares are recognized as a deduction from equity, net of any taxes.

### (e) Exploration and evaluation assets

Costs incurred before acquiring the legal right to explore in a specific area do not meet the definition of an asset and therefore are expensed by the Company as incurred.

Exploration and evaluation costs, including the costs of acquiring licenses and directly attributable general and administrative costs, are initially capitalized as exploration and evaluation assets. The costs are accumulated in cost centres by well, field or exploration area pending determination of technical feasibility and commercial viability.

The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proved plus probable reserves are determined to exist. A review of each exploration license or field is carried out, at each reporting period, to ascertain whether proved plus probable reserves have been discovered. Upon determination of total proved plus probable reserves, exploration and evaluation assets attributable to those reserves are first tested for impairment and then reclassified from exploration and evaluation assets to property, plant and equipment. Assets classified as exploration and evaluation are not subject to depletion and depreciation until they are reclassified to property, plant and equipment.

For exchanges or parts of exchanges that involve only exploration and evaluation assets, the exchange is accounted for at the carrying value of the asset given up and no gain or loss is recognized.

### (f) Property, plant and equipment

i) Recognition and measurement

Items of property, plant and equipment, which include crude oil and natural gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Property, plant and equipment consist of expenditures that are directly attributable to the acquisition of the asset. Within a CGU, when significant parts of property, plant and equipment have different useful lives, the parts are accounted for as separate items (major components) of property, plant and equipment.

ii) Subsequent costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as crude oil and natural gas interests only when it is probable that the costs increase the future economic benefits embodied in the specific asset to which they relate. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved or proved plus probable reserves and bringing on or enhancing production from such reserves and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property, plant and equipment are recognized in the consolidated statement of earnings as incurred.

Property, plant and equipment, including crude oil and natural gas interests, are derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Gains and losses on the disposal of assets are determined by comparing the proceeds from disposition with the carrying amount of the asset and are recognized on a net basis in the consolidated statement of earnings.

iii) Asset exchanges

Exchanges of development and production assets are measured at fair value, unless the exchange transaction lacks commercial substance or the fair value of the assets given up or the assets received cannot be reliably estimated. The cost of the acquired asset is measured at the fair value of the asset given up, unless the fair value of the asset received is more reliable. Where fair value is not used, the cost of the acquired asset is measured at the carrying amount of the asset given up. Any gain or loss on the derecognition of the asset given up is recognized in the consolidated statement of earnings.

iv) Depletion and depreciation

The net carrying amount of development and production assets is depleted using the unit-of-production method by reference to the ratio of production in the period to the related proved plus probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. Future development costs are estimated taking into account the level of development required to produce the reserves. These estimates are reviewed by the Company's independent engineers at least annually and determined in accordance with NI 51-101 and COGEH. For the purpose of this calculation, production and reserves of petroleum and natural gas are converted to a common unit of measure on the basis of their relative energy content, where six thousand cubic feet of natural gas equates to one barrel of oil.

The estimated useful lives for certain production assets for the current and comparative periods are as follows:

| | |
|---|---|
| Facilities | 33 years |
| Crude oil and natural gas properties | Based on reserve life |

For other assets, depreciation is recognized in the consolidated statement of earnings on a declining balance basis over the estimated useful lives of each part of an item of property, plant and equipment. Leased assets are depreciated over the shorter of the lease term and their useful lives unless it is reasonably certain that the Company will obtain ownership by the end of the lease term.

The estimated useful lives for other assets for the current and comparative periods are as follows:

| | |
|---|---|
| Furniture and office equipment | 5 years |
| Leaseholds | Term of the lease |

Depreciation methods, useful lives and residual values are reviewed at each reporting date.

### (g) Finance lease obligation

Leases which effectively transfer substantially all of the risks and rewards of ownership to the Company are classified as finance leases and are accounted for as an acquisition of an asset and an assumption of an obligation at the inception of the lease, measured at the present value of minimum lease payments to a maximum of the asset's fair value. The asset is amortized in accordance with the Company's depletion and depreciation policy.

### (h) Assets held for sale

Non-current assets are classified as held for sale if their carrying amounts will be recovered through a sale transaction rather than through continuing use. This condition is met when the sale is highly probable and the asset is available for immediate sale in its present condition. For the sale to be highly probable, management must be committed to a plan to sell the asset and an active program to locate a buyer and complete the plan must have been initiated. The asset must be actively marketed for sale at a price that is reasonable in relation to its current fair value and the sale should be expected to be completed within one year from the date of classification.

Non-current assets classified as held for sale are measured at the lower of the carrying amount and fair value less costs to sell, with impairments recognized in the consolidated statement of earnings in the period measured. Non-current assets held for sale are presented in current assets and liabilities within the consolidated statement of financial position. Assets held for sale are not depleted, depreciated or amortized.

### (i) Impairment

i) Financial assets

A financial asset not classified at fair value through earnings or loss is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Individually significant financial assets are tested for impairment on an individual basis. Those found not to be individually impaired are then assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in the consolidated statement of earnings.

An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in the consolidated statement of earnings.

ii) Non-financial assets

The carrying amount of property, plant and equipment is reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. Exploration and evaluation assets are assessed for impairment if 1) sufficient data exists to determine technical feasibility and commercial viability and 2) facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of assessing impairment of oil and gas properties, assets are tested at the CGU level. The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell.

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved and probable reserves. Fair value is determined as the amount that would be obtained from the sale of the asset in an arm's length transaction between knowledgeable and willing parties.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in the consolidated statement of earnings. Impairment losses recognized in respect of CGU's are allocated to reduce the carrying amounts of the assets in the unit on a pro rata basis.

Impairment losses in respect of property, plant and equipment and exploration and evaluation assets recognized in prior years are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized.

### (j) Short term employee benefits

Short term employee benefit obligations are measured on an undiscounted basis and are expensed as the related service is provided. A liability is recognized for the amount expected to be paid under short term cash bonus plans if the Company has a present legal or constructive obligation to pay this amount as a result of past service provided by the employee and the obligation can be estimated reliably.

### (k) Share-based compensation

Long term incentives are granted to officers, directors, employees and certain consultants in accordance with the Company's stock option and restricted share unit ("RSU") plan.

i) Equity-settled share-based awards

The fair value of stock options is assessed on the grant date using the Black-Scholes option pricing model. The fair value determined at the grant date of an award is expensed on a graded basis over the vesting period of each respective tranche with a corresponding increase to contributed surplus. In calculating the expense of the stock options, Delphi revises its estimate of the number of equity instruments expected to vest by applying an estimated forfeiture rate for each vesting tranche and subsequently revising this estimate throughout the vesting period, as necessary, with a final adjustment to reflect the actual number of awards that vest. Upon the exercise of the stock options, consideration paid by the stock option holders and the value in contributed surplus pertaining to the exercised stock options are recorded as share capital. In the event that vested stock options expire without being exercised, previously recognized compensation costs associated with such awards are not reversed.

ii) Cash-settled share-based awards

The Company's RSU plan is accounted for as a cash-settled share-based payment plan. The fair value of the amount payable under the RSU plan is recognized as an expense with a corresponding increase in liabilities. The liability is remeasured at each reporting date and at settlement date. Any changes in the fair value of the liability are recognized in the consolidated statement of earnings.

A portion of share-based compensation expense directly attributable to the exploration and development of the Company's assets are capitalized.

### (l) Lease payments

Payments made under operating leases are recognized in the consolidated statement of earnings on a straight-line basis over the term of the lease. Lease incentives received are recognized as an integral part of the total lease expense over the term of the lease.

### (m) Provisions

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability if the risks have not been incorporated into the estimate of cash flows. Provisions are not recognized for future operating losses.

**Decommissioning obligations**

The Company's activities give rise to dismantling, decommissioning and site remediation activities. A provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning obligations are measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the statement of financial position date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation as well as changes to the discount rate. The increase in the provision due to the passage of time is recognized as finance costs whereas increases or decreases due to changes in the estimated future cash flows or changes in the discount rate are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established. The difference between the actual costs incurred and the provision established is recorded as a gain or loss in the consolidated statement of earnings.

### (n) Flow-through shares

Delphi may issue flow-through shares to finance a portion of its capital expenditure program. Pursuant to the terms of the flow-through share agreements, the tax deductions associated with the expenditures are renounced to the subscribers. The difference between the value ascribed to flow-through shares issued and the value that would have been received for common shares with no tax attributes is initially recognized as a liability. When the expenditures are incurred, the liability is drawn down, a deferred tax liability is recorded equal to the estimated amount of deferred income tax payable by the Company as a result of the renunciation and the difference is recognized as a deferred tax expense.

### (o) Revenues

Revenues from the sale of crude oil and natural gas are recorded when the significant risks and rewards of ownership of the product are transferred to the buyer which is usually when legal title passes to the external party. This is generally at the time product enters the pipeline.

Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

### (p) Finance costs

Finance costs are comprised of interest expense and stamping fees on borrowings, accretion of the discount on decommissioning obligations and the implicit interest rate on the Company's finance lease obligation.

### (q) Income taxes

Income tax expense comprises current and deferred tax. Income tax expense is recognized in the consolidated statement of earnings except to the extent that it relates to a business combination or items recognized directly in equity or in other comprehensive income.

Current tax is the expected tax payable on the taxable income for the period, using tax rates enacted or substantively enacted at the reporting date and any adjustment to tax payable in respect of previous years.

Deferred taxes are on temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the corresponding tax bases used in the computation of taxable income. Deferred taxes are not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination and that affects neither accounting nor taxable earnings. In addition, deferred taxes are not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred taxes are measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized for unused tax losses, tax credits and deductible temporary differences to the extent that it is probable that future taxable profits will be available against which the temporary differences can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

### (r) Earnings (loss) per share

Basic earnings per share is calculated by dividing the net earnings or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted per share information is calculated giving effect to the potential dilution that would occur if stock options were exercised. The dilutive effect of stock options is calculated with the assumption that proceeds received from the exercise of options, for which the exercise price is less than the market price, plus the unamortized portion of share-based compensation expense are used to repurchase common shares at the average market price for the period. No adjustment to dilutive earnings per share is made if the result of these calculations is anti-dilutive.

### (s) Cash and cash equivalents

Cash and cash equivalents consist of cash balances, call deposits with original maturities of three months or less and outstanding cheques.

Bank overdrafts that are repayable on demand and form an integral part of the Company's cash management are included as a component of cash and cash equivalents for the purpose of the consolidated statement of cash flows.

## 4) DETERMINATION OF FAIR VALUES

A number of the Company's accounting policies and disclosures require the determination of fair value for both financial and non-financial assets and liabilities. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability. Fair values have been determined for measurement and/or disclosure purposes based on the following methods:

### (a) Property, plant and equipment and exploration and evaluation assets:

The fair value of property, plant and equipment and exploration and evaluation assets, with related decommissioning obligations, recognized in a business combination are based on market values. The market value of property, plant and equipment and exploration and evaluation assets is the estimated amount for which the assets could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The market value of crude oil and natural gas interests (included in property, plant and equipment) is estimated with reference to the discounted cash flows expected to be derived from crude oil and natural gas production based on externally prepared reserve reports. The risk-adjusted discount rate is specific to the asset with reference to general market conditions.

The market value of other items of property, plant and equipment are based on the quoted market prices for similar items.

### (b) Cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities and long term debt:

The fair value of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities and long term debt is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At December 31, 2012 and December 31, 2011, the fair value of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities approximated their carrying value due to their short term to maturity. In the case of long term debt, the fair value approximates its carrying value as it bears interest at floating rates and the applicable margin was indicative of the Company's current credit premium.

### (c) Derivatives:

The fair value of forward contracts and swaps is determined by discounting the difference between the contracted prices and published forward price curves as at the reporting date, using the remaining contracted crude oil and natural gas volumes and a risk-free interest rate (based on published government rates). The fair value of options and costless collars is based on option models that use published information with respect to volatility, prices and interest rates. The Company's derivative financial contracts are transacted in active markets. Changes in fair value of the derivatives are recognized in the consolidated statement of earnings. The actual gains and losses realized on eventual cash settlement can vary due to subsequent fluctuations in commodity prices. The contracts are measured at fair values and are classified as Level 2 in accordance with the following hierarchy:

*Level 1* – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

*Level 2* – Valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors which can be substantially observed or corroborated in the marketplace.

*Level 3* – Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

### (d) Share-based compensation:

The fair value of employee stock options is measured using a Black-Scholes option pricing model. Measurement inputs include the share price on measurement date, exercise price of the instrument, expected volatility (based on weighted average historic volatility), weighted average expected life of the instruments (based on historical experience and general option holder behaviour), expected dividends and the risk-free interest rate (based on government bonds).

## 5) FUTURE ACCOUNTING STANDARDS

The following new and amended standards have been issued by the International Accounting Standards Board ("IASB"):

- IFRS 9, "Financial Instruments", which is the result of the first phase of the IASB's project to replace IAS 39, "Financial Instruments: Recognition and Measurement". The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value. The effective date for this standard has been deferred to January 1, 2015.

- IFRS 10, "Consolidated Financial Statements" ("IFRS 10"), requires an entity to consolidate an investee when it is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Under existing IFRS, consolidation is required when an entity has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. This standard replaces SIC - 12, "Consolidation – Special Purpose Entities."

- IFRS 11, "Joint Arrangements" ("IFRS 11"), requires a venturer to classify its interest in a joint arrangement as a joint venture or joint operation, each having its own accounting model. Joint ventures will be accounted for using the equity method of accounting whereas for a joint operation the venture will recognize its share of the assets, liabilities, revenue and expenses of the joint operation. The standard provides for a more substance based reflection of joint arrangements by focusing on the rights and obligations of the arrangement, rather than its legal form. The new standard replaces IAS 31, "Interests in Joint Ventures" and SIC – 13, "Jointly Controlled Entities – Non-monetary Contributions by Venturers" and establishes principles for accounting for all joint arrangements.

- IFRS 12, "Disclosure of Interests in Other Entities", which outlines the required disclosures for interests in subsidiaries and joint arrangements. The new disclosures require information that will assist financial statement users to evaluate the nature, risks and financial effects associated with an entity's interests in subsidiaries and joint arrangements.

- IFRS 13, "Fair Value Measurement" which defines fair value, establishes a framework for measuring fair value and sets out disclosure requirements for fair value measurements.

- IAS 28, "Investments in Associates and Joint Ventures" has been amended to conform to the changes made in IFRS 10 and IFRS 11.

Except as noted above, all of the above pronouncements are effective for annual periods beginning on or after January 1, 2013, with early adoption permitted. The Company is currently evaluating the impact of adopting these standards and does not anticipate a material impact to the consolidated financial statements as a result of these new standards.

## 6) FINANCIAL RISK MANAGEMENT

The Company is exposed to market, credit and liquidity risks from its use of financial instruments. This note provides information about the Company's exposure to each of the above risks and the Company's policies and processes for measuring and managing risk. Risk management policies are ultimately established by the Board of Directors and implemented and monitored by senior management.

### (a) Market risk

Market risk is the risk that changes in market prices, such as commodity prices, foreign exchange rates and interest rates will affect the Company's net earnings or the value of the Company's financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing returns.

**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 crude oil and natural gas are affected not only by world economic events that dictate the levels of supply and demand but also the relationship between the Canadian and United States ("U.S.") dollar, as outlined below. 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 physical sales contracts with customers and derivative financial contracts with financial institutions. The Company's policy is to enter into commodity contracts to a range of 40 – 50 percent of current production volumes when considered appropriate.As at December 31, 2012, the Company had the following derivative financial and physical contracts which were recorded at fair value on the statement of financial position as a current asset of $0.3 million, a current liability of $0.3 million and a long term liability of $4.0 million (December 31, 2011 – current asset of $0.5 million and long term liability of $3.8 million) with changes in fair value included in unrealized loss on financial instruments in the consolidated statement of earnings.

| Time Period | Commodity | Type of Contract | Quantity Contracted | Price Floor ($/unit) | Price Ceiling ($/unit) |
|---|---|---|---|---|---|
| August 2012 – March 2013 | Natural Gas | Financial - collar | 1,000 GJ/d | $2.50 Cdn | $2.95 Cdn |
| August 2012 – March 2013 | Natural Gas | Financial - collar | 1,000 GJ/d | $2.50 Cdn | $3.04 Cdn |
| August 2012 – March 2013 | Natural Gas | Financial - collar | 1,000 GJ/d | $2.55 Cdn | $3.07 Cdn |
| April 2012 – December 2014 | Natural Gas | Financial - fixed | 6,000 GJ/d | $2.88 Cdn | $2.88 Cdn |
| April 2013 – April 2015 | Natural Gas | Financial - fixed | 3,000 GJ/d | $3.535 Cdn | $3.535 Cdn |
| April 2012 – December 2013 | Natural Gas | Physical - fixed | 2,000 mmbtu/d | $3.21 U.S. | $3.21 U.S. |
| January 2014 – December 2014 (1) | Crude Oil | Financial - call | 600 bbls/d | - | $90.00 U.S. |

(1) The Company acquired a natural gas contract at $5.69 per gigajoule on 6,810 gigajoules per day for the period April 1, 2011 through December 31, 2011. The contract was paid for with the sale of a crude oil call on 600 barrels per day at a price of U.S. $90.00 WTI per barrel for the period January 1, 2012 through December 31, 2012. Delphi has deferred this crude oil call to January 1, 2014 through December 31, 2014.

Natural gas physical commodity sale contracts based in U.S. dollars include an embedded derivative associated with the foreign exchange rate. The changes in the fair value of these contracts, which are considered derivatives due to the embedded feature, are included in the unrealized loss on financial instruments in the consolidated statement of earnings.

For the year ended December 31, 2012, the derivative commodity contracts resulted in realized gains of $3.6 million (December 31, 2011 - $4.1 million) that have been included in the consolidated statement of earnings as a realized gain on financial instruments.

As at December 31, 2012, if the future strip prices for crude oil were $1.00 per barrel higher with all variables held constant, the net loss for the year would have been $0.1 million higher. An equal and opposite impact would have occurred had the strip prices for crude oil been lower by the same amount. As at December 31, 2012, if the future strip prices for natural gas were $0.10 per GJ higher with all variables held constant, the net loss for the year would have been $0.5 million higher. An equal and opposite impact would have occurred had the strip prices for natural gas been lower by the same amount.

The Company also has physical sales contracts. The physical sales contracts were entered into and continue to be held for the purpose of delivery of non-financial items as executory contracts and have not been recorded at fair value. As at December 31, 2012, the Company had the following physical sales contracts:

| Time Period | Commodity | Type of Contract | Quantity Contracted | Contract Price ($/unit) |
|---|---|---|---|---|
| June 2012 – March 2013 | Natural Gas | Physical - fixed | 5,000 GJ/d | $2.45 Cdn |
| January 2013 – December 2013 | Natural Gas | Physical - fixed | 1,500 GJ/d | $3.41 Cdn |
| April 2013 – December 2013 | Natural Gas | Physical - fixed | 1,500 GJ/d | $3.42 Cdn |

For the year ended December 31, 2012, the physical contracts resulted in realized gains of $1.6 million (December 31, 2011 - $3.8 million) that have been included in crude oil and natural gas sales.

Subsequent to December 31, 2012, the Company entered into the following financial contracts:

| Time Period | Commodity | Type of Contract | Quantity Contracted | Price Floor ($/unit) | Price Ceiling ($/unit) |
|---|---|---|---|---|---|
| April 2013 – December 2015 | Natural Gas | Financial - fixed | 3,000 GJ/d | $3.27 Cdn | $3.27 Cdn |
| April 2013 – December 2016 | Natural Gas | Financial - fixed | 3,000 GJ/d | $3.40 Cdn | $3.40 Cdn |
| March 2013 – December 2013 | Crude Oil | Financial - fixed | 150 bbls/d | $89.65 Cdn | $89.65 Cdn |

**Currency risk**

Although substantially all of the Company's petroleum and natural gas sales are denominated in Canadian dollars, commodity prices are largely denominated in U.S. dollars and as a result the prices that Canadian producers receive are influenced by the relationship between the Canadian and U.S. dollar. The exchange rate effect cannot be quantified but generally an increase in the value of the Canadian dollar as compared to the U.S. dollar will reduce the prices received by the Company for its crude oil and natural gas sales. At December 31, 2012, the Company did not have any cash in U.S. dollars. The Company had no foreign exchange rate swap or related financial contracts in place as at December 31, 2012.

**Interest rate risk**

Interest rate risk is the risk that future cash flow will fluctuate as a result of changes in market interest rates. Delphi is exposed to interest rate risk as the interest charged on its long term debt is at a floating rate and consequently changes in market interest rates will have an effect on the Company's cash flow.

Interest rate risk is partially mitigated through short term fixed rate borrowings using bankers' acceptances. The Company has also entered into an interest swap transaction on borrowings through bankers' acceptances in the amount of $20.0 million maturing on June 1, 2014. The swap transaction has a fixed interest rate of 1.09 percent. As at December 31, 2012, this contract has a fair value of $51 thousand.

Had the interest rate charged on the Company's long term debt been one percent higher throughout the year ended December 31, 2012, the net loss would have increased by $0.8 million based on the average debt balance outstanding during the period.

Subsequent to December 31, 2012, Delphi entered into an interest rate swap transaction on borrowings through bankers' acceptances in the amount of $20.0 million maturing on March 1, 2015. The swap transaction has a fixed interest rate of 1.25 percent.

## (b) Credit risk

Credit risk represents the risk of financial loss to the Company if customers or counterparties to a financial instrument fail to meet their contractual obligations and arise principally from the Company's receivables from joint interest partners, crude oil and natural gas marketers and financial intermediaries.

All of the Company's accounts receivable are with customers and joint interest partners in the oil and gas industry and are subject to normal industry credit risks. Receivables from joint interest partners are typically collected within one to three months of the joint venture bill being issued. The Company attempts to mitigate the risk related to joint interest receivables by obtaining partner pre-approval of significant capital expenditures prior to expenditure. However, partners are exposed to various crude oil and natural gas industry and market risks that could result in non-collection.

Receivables from crude oil 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 historically has not experienced any collection issues with large purchasers. Concentration of credit risk is mitigated by marketing production to several purchasers under normal industry sale and payment terms.

The Company does not typically obtain collateral from crude oil and 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.

With respect to counterparties to financial commodity contracts, the Company partially mitigates associated credit risk by limiting transactions to counterparties with investment grade credit ratings.

The carrying amount of cash and accounts receivable represents the maximum credit exposure. Delphi sells substantially all of its production to three primary purchasers under standard industry sale and payment terms. Revenues from Delphi's three major purchasers represent approximately $82.3 million of Delphi's total revenues. As at December 31, 2012, the Company's receivables included $6.8 million of receivables from crude oil and natural gas marketers which has been collected subsequent to December 31, 2012. As at December 31, 2012, approximately $4.6 million of the Company's receivables past the due date are due from government agencies and are considered low risk. The Company does not have an allowance for doubtful accounts as at December 31, 2012.

As at December 31, 2012 the Company's aged receivables are as follows:

| | **December 31, 2012** |
|---|---|
| Current (less than 30 days) | **8,896** |
| Past due (31-90 days) | **1,208** |
| Past due (more than 90 days) | **6,146** |
| Total | **16,250** |

### (c) Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet the obligations associated with its financial liabilities. The Company's financial liabilities arise through the cost of operations and capital program in order to maintain or increase production and develop reserves, the acquisition of crude oil and natural gas assets, financial instrument contracts and borrowings under the Company's credit facilities.

The Company generates a certain level of cash flow from operations which is used to partially fund all operating, investing and capital activities. In addition, the Company has a 364 day revolving credit facility in the amount of $125.0 million with a syndicate of Canadian chartered banks with a one year term-out provision (see Note 14).

The following are the contractual maturities of financial liabilities as at December 31, 2012:

| **Financial liabilities** | **Carrying amount** | **< 1 Year** | **1 – 2 Years** | **3 – 5 Years** | **Thereafter** |
|---|---|---|---|---|---|
| Outstanding cheques | 883 | 883 | - | - | - |
| Accounts payable and accrued liabilities | 24,396 | 24,396 | - | - | - |
| Finance lease obligation | 1,588 | 1,642 | - | - | - |
| Fair value of financial instruments | 4,287 | 306 | 3,981 | - | - |
| Long term debt | 84,418 | - | 84,418 | - | - |
| Total | 115,572 | 27,227 | 88,399 | - | - |

## 7) CAPITAL MANAGEMENT

The Company's policy is to ensure a strong capital base so as to maintain investor, creditor and market confidence and to sustain future development of the business. 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 considers share capital and net debt, being the sum of long term debt and current liabilities less current assets (excluding the fair value of financial instruments), as the components of capital to be managed.

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 accretion of long term debt, decommissioning expenditures 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.

Net debt and funds from operations are considered non-IFRS terms.

At December 31, 2012 net debt was $92.8 million and annualized funds from operations based on the fourth quarter was $25.1 million resulting in a net debt to funds from operations ratio of 3.7:1. This ratio may increase at certain times as a result of acquisitions, the timing of capital expenditures or low commodity prices.

In order to facilitate the management of this ratio, the Company prepares annual funds from operations and capital expenditure budgets, which are updated as necessary throughout the year and are reviewed and periodically approved by Delphi's Board of Directors. The Company manages its capital structure by keeping abreast of current and forecast economic conditions and commodity prices, particularly natural gas prices 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 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. There were no changes in the Company's approach to capital management during the period.

The Company's share capital is not subject to external restrictions, however, the Company's credit facilities do contain financial covenants that are outlined in Note 14.

## 8) ACCOUNTS RECEIVABLE

Accounts receivable is comprised as follows:

| | **December 31, 2012** | December 31, 2011 |
|---|---|---|
| Revenue | **7,530** | 10,274 |
| Joint partners | **3,961** | 4,430 |
| Other [1] | **4,759** | 4,066 |
| Total | **16,250** | 18,770 |

(1) As at December 31, 2012, approximately $4.6 million included in this balance is due from a government agency.

## 9) ASSETS AND LIABILITIES HELD FOR SALE

| Assets | Crude oil and natural gas properties | Production equipment | Total |
|---|---|---|---|
| Balance as at December 31, 2011 | 9,680 | - | 9,680 |
| Transfer from property, plant and equipment, net | 24,361 | 1,731 | 26,092 |
| Loss on disposition | (1,380) | (298) | 1,678 |
| Transfer to property, plant and equipment, net | - | (1,433) | (1,433) |
| Dispositions | (32,661) | - | (32,661) |
| Balance as at December 31, 2012 | **-** | **-** | **-** |

| Liabilities | Crude oil and natural gas properties | Production equipment | Total |
|---|---|---|---|
| Balance as at December 31, 2011 | 377 | - | 377 |
| Transfer from decommissioning obligations | 559 | - | 559 |
| Dispositions | (936) | - | (936) |
| Balance as at December 31, 2012 | **-** | **-** | **-** |

During the second quarter of 2012, Delphi entered into an agreement to sell its working interests associated with its proved Cardium assets in the Bigstone cash generating unit ("CGU") for net proceeds of $22.4 million. A loss on sale of $1.4 million was recorded associated with the Cardium disposition. The Company closed the sale on July 24, 2012. In addition to the Cardium assets held for sale, the Company included certain pipe and production equipment as assets held for sale with a carrying value of $1.4 million, of which a $0.3 million loss on sale was recorded. As at December 31, 2012, the pipe and production equipment no longer met the criteria to be classified as assets held for sale and have been reclassified to property, plant and equipment.

In the fourth quarter of 2011, the Company made the decision to market for disposition, certain non-operated interests in its Hythe cash generating unit. The Company completed the sale on January 16, 2012 for net proceeds of $11.0 million and recognized a gain on the disposition of $1.7 million which is included in loss on property dispositions.

## 10) EXPLORATION AND EVALUATION ASSETS

| | Total |
|---|---|
| Balance as at December 31, 2010 | 2,787 |
| Additions | 15,912 |
| Balance as at December 31, 2011 | 18,699 |
| Additions | 5,478 |
| Dispositions | (3,061) |
| Transfer to oil and gas properties | (8,710) |
| Balance as at December 31, 2012 | **12,406** |

Exploration and evaluation assets consist of the Company's exploration projects which are pending the determination of proven and probable reserves. During the fourth quarter of 2012, Delphi swapped undeveloped land in its Bigstone CGU for undeveloped land in the same CGU. The land had a carrying value of $3.1 million and no gain or loss was recognized with this exchange. During the year ended December 31, 2012, $8.7 million was transferred to property, plant and equipment following the successful discovery of proven and probable reserves.

## 11) PROPERTY, PLANT AND EQUIPMENT

| Cost | Crude oil and natural gas properties | Production equipment | Other assets | Total |
|---|---|---|---|---|
| Balance as at December 31, 2010 | 409,087 | 27,528 | 621 | 437,236 |
| Additions | 101,943 | 334 | 137 | 102,414 |
| Acquisitions | 273 | - | - | 273 |
| Dispositions | (14,449) | - | - | (14,449) |
| Reclassification to assets held for sale | (11,826) | - | - | (11,826) |
| Balance as at December 31, 2011 | 485,028 | 27,862 | 758 | 513,648 |
| Additions | 79,167 | 21,669 | 102 | 100,938 |
| Dispositions | (8,165) | - | - | (8,165) |
| Reclassification to assets held for sale | (30,293) | (1,731) | - | (32,024) |
| Reclassification from assets held for sale | - | 1,433 | - | 1,433 |
| Transfer from exploration and evaluation assets | 8,710 | - | - | 8,710 |
| Balance as at December 31, 2012 | 534,447 | 49,233 | 860 | 584,540 |

| Accumulated depletion and depreciation | Crude oil and natural gas properties | Production equipment | Other assets | Total |
|---|---|---|---|---|
| Balance as at December 31, 2010 | (74,066) | (5,583) | (129) | (79,778) |
| Depletion and depreciation | (44,924) | (494) | (117) | (45,535) |
| Dispositions | 3,441 | - | - | 3,441 |
| Reclassification to assets held for sale | 2,146 | - | - | 2,146 |
| Impairment losses | (1,212) | (288) | - | (1,500) |
| Balance as at December 31, 2011 | (114,615) | (6,365) | (246) | (121,226) |
| Depletion and depreciation | (42,450) | (662) | (135) | (43,247) |
| Dispositions | 3,435 | - | - | 3,435 |
| Reclassification to assets held for sale | 5,932 | - | - | 5,932 |
| Impairment losses | (55,006) | (4,360) | - | (59,366) |
| Balance as at December 31, 2012 | **(**202,704**)** | **(**11,387**)** | **(**381**)** | **(214,472)** |
| | | | | |
| Net book value as at December 31, 2012 | **331,743** | **37,846** | **479** | **370,068** |
| Net book value as at December 31, 2011 | 370,413 | 21,497 | 512 | 392,422 |

Delphi's credit facility is secured by a demand floating charge debenture and a general security agreement over all assets.

As at December 31, 2012, the Company has excluded $5.2 million (December 31, 2011 - $8.8 million) for estimated salvage and has included $200.4 million (December 31, 2011 - $143.1 million) estimated future development costs to its costs subject to depletion and depreciation.

For the year ended December 31, 2012, Delphi capitalized $3.5 million (December 31, 2011 - $3.8 million) of general and administrative expenses and $0.9 million (December 31, 2011 - $0.9 million) of share-based compensation expense directly related to exploration and development activities.

During 2012, the Company received $34.7 million for oil and gas properties with a net book value of $37.2 million (including decommissioning obligations), resulting in a loss of $2.5 million. The Company also recognized in loss on dispositions $0.3 million related to equipment that was classified as held for sale during the second and third quarters of 2012.

Impairment tests were carried out at December 31, 2012 due to the decrease in the forward price curve for natural gas as at January 1, 2013 compared to April 1, 2012 when Delphi last tested all of its cash-generating units ("CGU's") for impairment. An impairment charge of $36.2 million was recognized in the fourth quarter related to its Hythe, Berland River, Miscellaneous Alberta and North East British Columbia ("NEBC") CGU's. The impairments were based on the difference between the period end carrying value of the CGU's and the recoverable amount. The recoverable amounts were determined using a fair value less costs to sell methodology with the expected future cash flows based on proved and probable reserves using pre-tax discount rates of 10 to 20 percent, as determined by the Company's independent engineers. Fair value for Delphi's NEBC CGU was determined using the market metrics associated with the Company's disposition in the third quarter of 2012.

In the third quarter of 2012, an impairment test was carried out for the Company's NEBC CGU as indicators of impairment were identified through the disposition of some of Delphi's working interests in NEBC. The recoverable amount was determined using a fair value less costs to sell methodology using the market metrics associated with the Company's recent disposition. An impairment of $2.1 million was recognized and is included in depletion and depreciation expense on the consolidated statement of earnings.

Due to the decrease in the forward price curve for natural gas as at April 1, 2012 compared to January 1, 2012, the Company carried out impairment tests on its CGUs as at March 31, 2012. Delphi recognized an impairment charge of $21.0 million related to its Hythe, Berland River, Miscellaneous Alberta and British Columbia CGUs. The impairments were based on the difference between the period end carrying value of the CGU's and the recoverable amount. The recoverable amounts were determined using a fair value less costs to sell methodology with the expected future cash flows based on proved and probable reserves using pre-tax discount rates of 8 to 12 percent.

Impairment tests were carried out at December 31, 2011 due to the decrease in the forward price curve for natural gas as at January 1, 2012 compared to January 1, 2011. The Company recognized an impairment charge of $1.5 million related to the Company's Hythe, Berland River and Miscellaneous Alberta CGUs, which has been included in depletion and depreciation expense on the consolidated statement of earnings. The impairments were based on the difference between the period end carrying value of the CGU's and the recoverable amount. The recoverable amounts were determined using a fair value less costs to sell methodology with the expected future cash flows based on proved and probable reserves using pre-tax discount rates of 8 to 12 percent, as determined by the Company's independent engineers.

## 12) ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

Accounts payable and accrued liabilities are comprised as follows:

| | **December 31, 2012** | December 31, 2011 |
|---|---|---|
| Trade | **7,820** | 8,517 |
| Royalties | **721** | 3,452 |
| Joint partners | **6,556** | 6,023 |
| Accrued capital | **9,255** | 28,851 |
| Other | **44** | 608 |
| Total | **24,396** | 47,451 |

## 13) FINANCE LEASE OBLIGATION

The Company entered into an agreement in March 2012 to lease a compressor with a commitment to purchase at the end of the lease term. The lease arrangement has resulted in the recognition of an asset and an obligation. The carrying value of the asset under this finance lease at December 31, 2012 totaled $1.6 million.

The following is a schedule of future minimum lease payments including the purchase price for the asset under the finance lease obligation:

| | **Amount** |
|---|---|
| Payments to be made in 2013 | 1,642 |
| Amount representing implicit interest rate at 20.1% | (54) |
| Finance lease obligation | **1,588** |

## 14) LONG TERM DEBT

| | **December 31, 2012** | December 31, 2011 |
|---|---|---|
| Prime-based loans | **5,000** | 3,000 |
| Bankers' acceptances, net of discount | **79,418** | 79,385 |
| Total | **84,418** | 82,385 |

The Company's extendible revolving term credit facility with a syndicate of Canadian chartered banks is subject to the banks' semi-annual valuation of the Company's crude oil and natural gas properties. In December 2012, the Company's borrowing base was reduced from $145.0 million to $125.0 million as a result of the banks' semi-annual review.

The facility is a 364 day committed facility available on a revolving basis until May 27, 2013 at which time it may be extended at the lenders' option. If the revolving period is not extended, the undrawn portion of the facility will be cancelled and the amount outstanding will convert to a 365 day non-revolving term facility. The amounts outstanding under the non-revolving facility are required to be repaid at the end of the non-revolving term being May 28, 2014. The non-extension provisions are applicable to the lenders on an individual basis.

Interest payable on amounts drawn under the facility is at the prevailing bankers' acceptance rates plus stamping fees, lenders' prime rate or U.S. base rate plus the applicable margins, depending on the form of borrowing by the Company. The applicable margins and stamping fees are based on a sliding scale pricing grid tied to the Company's trailing debt to annualized quarterly funds from operations ratio: from a minimum of the bank's prime rate or U.S. base rate plus 1.00 percent to a maximum of the bank's prime rate or U.S. base rate plus 2.50 percent or from a minimum of bankers' acceptances rate plus a stamping fee of 2.00 percent to a maximum of bankers' acceptances rate plus a stamping fee of 3.50 percent.

The bankers' acceptances outstanding at December 31, 2012 have terms ranging from 61 to 92 days and a weighted average effective interest rate of 4.80 percent over the term.

As at December 31, 2012, the Company had outstanding letters of credit in the amount of $64 thousand that reduce the amount otherwise available to be drawn on the syndicated facility.

As at December 31, 2012, Delphi had approximately $40.5 million of unused and available bank credit under its syndicated facility.

A semi-annual review of the Company's $125.0 million extendible revolving term credit facility will be conducted during the second quarter of 2013. The borrowing base of the facilities will be based on the lenders' evaluation of the Company's petroleum and natural gas reserves and commodity prices.

Under the terms of the syndicated credit facility, the Company covenants that it will maintain a working capital ratio of at least one to one. For the purpose of this ratio, the undrawn portion of the credit facility is added to current assets in the working capital calculation. The credit facility is secured by a $200.0 million demand floating charge debenture and a general security agreement over all assets of the Company. Delphi is in compliance with the covenants of its credit facility as at December 31, 2012.

## 15) DECOMMISSIONING OBLIGATIONS

The Company's decommissioning obligations result from working interests in crude oil and natural gas assets including well sites, gathering systems and processing facilities. The total decommissioning obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future years. The Company estimates the undiscounted total future liability of $53.1 million (December 31, 2011 - $24.7 million) to be settled over the next 65 years. A risk-free rate between 1.14 percent to 2.36 percent (December 31, 2011 – 1.94 percent) and an inflation rate of 2.5 percent were used to calculate the estimated fair value of the decommissioning obligations.

The change in estimates in 2012 is primarily due to a review of the Company's obligations using specific information pertaining to the Company's locations as well as a revision of the timing of future expenditures. In addition, several sites in the Company's NEBC CGU have specific attributes that require additional work than originally estimated. Approximately $10.7 million of the changes in estimates in 2012 is related to an upward revision in abandonment and reclamation costs and $5.5 million is due to the change in discount rates used and a revision to the expected time frame of abandonment and reclamation.

A reconciliation of the decommissioning obligations is provided below:

| | **December 31, 2012** | December 31, 2011 |
|---|---|---|
| Balance, beginning of year | **20,490** | 17,232 |
| Liabilities incurred | **609** | 1,049 |
| Liabilities disposed | **(1,515)** | (89) |
| Liabilities settled | **(422)** | (131) |
| Accretion expense | **322** | 483 |
| Change in estimate | **16,229** | 1,946 |
| | **35,713** | 20,490 |
| Liabilities held for sale (**Note 9**) | **-** | (377) |
| Current portion | **(420)** | (825) |
| Balance, end of year | **35,293** | 19,288 |

## 16) DEFERRED INCOME TAXES

The provision for income taxes differs from the expected amount calculated by applying the combined Federal and Provincial corporate income tax rates to Delphi's earnings (loss) before taxes. This difference results from the following items:

| | **December 31, 2012** | December 31, 2011 |
|---|---|---|
| Earnings (loss) before income taxes | **(76,002)** | 17,971 |
| Statutory tax rate | **25%** | 26.50% |
| Expected income tax expense (recovery) | **(19,001)** | 4,763 |
| Stock-based compensation | **369** | 281 |
| Change in deferred income tax rates and other | **-** | (115) |
| Flow-through common shares | **660** | 1,440 |
| Total income tax expense (recovery) | **(17,972)** | 6,369 |

The decrease in the statutory tax rate in 2012 from 2011 was due to a reduction in the Federal income tax rate to 15.0% in 2012 from 16.5% in 2011.

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

| | **December 31, 2012** | December 31, 2011 |
|---|---|---|
| Deferred income tax assets: | | |
| Decommissioning obligations | **8,924** | 5,123 |
| Attributed Canadian Royalty Income | **361** | 361 |
| Non capital losses | **4,093** | 4,093 |
| Share issue costs | **945** | 951 |
| Finance lease obligation | **397** | - |
| Risk management liability | **1,000** | 811 |
| Other | **107** | - |
| Deferred income tax liabilities: | | |
| Exploration and evaluation and property, plant and equipment | **(21,953)** | (34,584) |
| Net deferred income tax liability | **(6,126)** | (23,245) |

Non capital losses of $16.4 million will expire in years through 2028.

Changes in deferred income tax assets and liabilities for the years ended December 31, 2012 and 2011 are as follows:

| | Balance January 1, 2012 | Recognized in equity | Recognized in net loss | Other | **Balance December 31, 2012** |
|---|---|---|---|---|---|
| Deferred income tax assets: | | | | | |
| Decommissioning obligations | 5,123 | - | 3,801 | - | **8,924** |
| Attributed Canadian Royalty Income | 361 | - | - | - | **361** |
| Non capital losses | 4,093 | - | - | - | **4,093** |
| Share issue costs | 951 | 482 | (488) | - | **945** |
| Finance lease obligation | - | - | 397 | - | **397** |
| Risk management liability | 811 | - | 189 | - | **1,000** |
| Other | - | - | 107 | - | **107** |
| Deferred income tax liabilities: | | | | | |
| Exploration and evaluation and property, plant and equipment | (34,584) | - | 13,966 | (1,335) | **(21,953)** |
| Net deferred income tax liability | (23,245) | 482 | 17,972 | (1,335) | **(6,126)** |

| | Balance January 1, 2011 | Recognized in equity | Recognized in net earnings | Other | Balance December 31, 2011 |
|---|---|---|---|---|---|
| Deferred income tax assets: | | | | | |
| Decommissioning obligations | 4,308 | - | 815 | - | 5,123 |
| Attributed Canadian Royalty Income | 361 | - | - | - | 361 |
| Non capital losses | 4,093 | - | - | - | 4,093 |
| Share issue costs | 1,008 | 476 | (533) | - | 951 |
| Risk management liability | 383 | - | 428 | - | 811 |
| Deferred income tax liabilities: | | | | | |
| Exploration and evaluation and property, plant and equipment | (26,705) | - | (7,079) | (800) | (34,584) |
| Net deferred income tax liability | (16,552) | 476 | (6,369) | (800) | (23,245) |

## 17) SHARE CAPITAL

Delphi is authorized to issue an unlimited number of common shares. All shares are issued as fully paid and non-assessable and have no par value. The holders of common shares are entitled to receive dividends as declared by the Company and are also entitled to one vote per share.

### (a) Issued and outstanding

| | **December 31, 2012** | | December 31, 2011 | |
|---|---|---|---|---|
| | **Outstanding shares** (000's) | **Amount** | Outstanding shares (000's) | Amount |
| Balance, beginning of year | **131,000** | **275,682** | 112,825 | 236,382 |
| Issued for cash | **17,242** | **25,000** | 10,005 | 22,011 |
| Issued for cash on a flow-through basis | **4,572** | **5,349** | 6,100 | 14,801 |
| Issued on exercise of stock options | **235** | **152** | 2,070 | 2,575 |
| Transferred on exercise of options | **-** | **78** | - | 1,347 |
| Share issue costs, net of deferred tax effect | **-** | **(1,445)** | - | (1,434) |
| Balance, end of year | **153,049** | **304,816** | 131,000 | 275,682 |

On November 13, 2012, Delphi issued, on a bought deal basis, 17.2 million common shares at a price of $1.45 per share and 4.6 million common shares on a flow-through basis at a price of $1.75 per common share for total gross proceeds of $33.0 million. A premium of $2.7 million related to the issuance of the common shares on a flow-through basis was recorded as a long term liability on the consolidated statement of financial position. The liability is derecognized, with a corresponding deferred tax expense, as the Company incurs qualifying exploration expenditures. Delphi has an obligation to incur $8.0 million in qualifying exploration expenditures by December 31, 2013 to satisfy the terms of this flow-through common share issuance.

On December 23, 2011, Delphi closed an equity issuance of 10.0 million common shares at a price of $2.20 per share and 2.9 million flow-through common shares at a price of $2.75 for total gross proceeds of $30.0 million. A flow-through premium of $1.3 million related to the issuance of the flow-through common shares was recorded as a long term liability on the consolidated statement of financial position. The Company satisfied the commitment associated with this issuance during the first quarter of 2012. As a result, deferred income tax of $2.0 million associated with the renouncement of the expenditures was recorded, the long term liability was derecognized and the difference of $0.7 million was recognized as deferred income tax expense.

On March 24, 2011, the Company issued 3.2 million flow-through common shares at a price of $2.80 per share for gross proceeds of $9.0 million. Delphi satisfied its commitment to incur qualifying exploration expenditures associated with this issuance by December 31, 2011 and as a result recognized a $1.4 million deferred income tax expense.

### (b) Share-based compensation

The Company has established a stock option plan under which it has granted options to acquire common shares to certain officers, directors, employees and key consultants. The plan provides for the granting of options up to ten percent of the issued and outstanding common shares of the Company. Options issued under the plan have a term of five years to expiry. Options granted prior to September 1, 2009 vest over a two-year period starting on the date of grant. Options granted between September 1, 2009 and May 31, 2011 vest over a two-year period with one-third vesting six months after the date of grant and one-third on each of the first and second anniversary of the grant date. Options granted on May 31, 2011 or later vest over a four-year period with one-fourth vesting on each of the first, second, third and fourth anniversary of the grant date. The exercise price of each option equals the five day weighted average of the market price of the Company's common shares, immediately preceding the date of the grant. As at December 31, 2012, a total of 15.3 million options to purchase shares were reserved and 9.1 million options to purchase shares were outstanding, leaving an additional 6.2 million available for future grants.

The following table summarizes the changes in the number of options outstanding and the weighted average exercise prices:

| | **December 31, 2012** | | December 31, 2011 | |
|---|---|---|---|---|
| | **Outstanding options** (000's) | **Weighted average exercise price** | Outstanding options (000's) | Weighted average exercise price |
| Balance, beginning of year | **10,591** | **1.89** | 7,776 | 1.59 |
| Granted | **2,635** | **1.28** | 5,846 | 2.16 |
| Forfeited | **(911)** | **1.99** | (961) | 2.48 |
| Exercised | **(235)** | **0.65** | (2,070) | 1.24 |
| Expired | **(3,025)** | **1.69** | - | - |
| Balance, end of year | **9,055** | **1.81** | 10,591 | 1.89 |
| Exercisable, end of year | **3,538** | **1.94** | 5,466 | 1.69 |

The following table summarizes information about the stock options outstanding and exercisable at December 31, 2012:

| | Options outstanding | | | Options exercisable | |
|---|---|---|---|---|---|
| **Range of exercise price** | **Outstanding options** (000's) | **Weighted average exercise price** | **Weighted average remaining term** (years) | **Exercisable** (000's) | **Weighted average exercise price** |
| $0.65 - $0.97 | **804** | **0.65** | **1.17** | **804** | **0.65** |
| $0.98 - $1.54 | **4,223** | **1.34** | **4.02** | **632** | **1.44** |
| $1.55 - $2.15 | **575** | **2.04** | **3.08** | **285** | **2.03** |
| $2.16 - $3.34 | **3,453** | **2.60** | **3.07** | **1,817** | **2.66** |
| Total | **9,055** | **1.81** | **3.34** | **3,538** | **1.94** |

During 2012, a total of 235 thousand options were exercised. The weighted average share trading price of the Company's common shares at the dates of exercise were $2.18, $1.26 and $1.29.

The Company accounts for its share-based compensation using the fair value method for all stock options. For the year ended December 31, 2012, Delphi recognized share-based compensation expense of $2.2 million (December 31, 2011 - $1.9 million), of which $0.9 million was capitalized (December 31, 2011: $0.9 million).

During the year ended December 31, 2012, the Company granted 2.6 million options (December 31, 2011: 5.8 million). The fair values of all options granted during the period are estimated at the date of grant using the Black-Scholes option pricing model. The weighted average fair value of options granted during the period was $0.50 per option (December 31, 2011 - $1.10 per option). The weighted average of the assumptions used in the Black-Scholes model to determine fair value were as follows:

| **For the years ended December 31,** | **2012** | 2011 |
|---|---|---|
| Risk-free interest rate (%) | **1.3** | 1.8 |
| Expected life (years) | **3.3** | 3.8 |
| Forfeiture rate (%) | **15.1** | 15.0 |
| Expected volatility (%) | **54.3** | 67.3 |

Effective May 3, 2011, the Company established a restricted share unit ("RSU") plan. Employees are eligible to receive RSU awards or were able to convert up to 50 percent of their 2011 performance bonus into RSU awards. RSU awards received by an employee as a result of conversion, received a 30 percent increase in the number of RSU's received through the conversion. The RSU awards vest on each of the first, second and third anniversary of the award date at which time the employee will receive a cash payment equivalent to the number of RSU's vested multiplied by the Company's closing share price on the business day immediately preceding the vesting date.

For the year ended December 31, 2012, Delphi recorded $0.4 million (December 31, 2011: $70,000) of share-based compensation expense, of which $0.2 million was capitalized (December 31, 2011: nil). As at December 31, 2012, Delphi has included $0.3 million (December 31, 2011: $70,000) in accounts payable and accrued liabilities related to the outstanding vested RSU's. The following table summarizes the changes in the number of outstanding RSU's:

| | **December 31, 2012** | December 31, 2011 |
|---|---|---|
| | **Outstanding units** (000's) | Outstanding units (000's) |
| Balance, beginning of year | **332** | - |
| Granted | **1,206** | 374 |
| Forfeited | **(150)** | (42) |
| Redeemed | **(107)** | - |
| Balance, end of year | **1,281** | 332 |

### (d) Net earnings (loss) per share

Net earnings (loss) per share has been calculated based on a net loss of $58.0 million (2011 earnings: $11.6 million) and the following weighted average common shares:

| **For the years ended December 31,** | **2012** | 2011 |
|---|---|---|
| Weighted average common shares - basic | **133,992** | 116,935 |
| Dilutive effect of share options outstanding | **-** | 1,865 |
| Weighted average common shares - diluted | **133,992** | 118,800 |

For the year ended December 31, 2012, a total of 9.1 million share options (2011: 8.7 million) were excluded from the calculation as they were anti-dilutive.

## 18) FINANCE COSTS

Finance costs is comprised of the following:

| **For the years ended December 31,** | **2012** | 2011 |
|---|---|---|
| Interest expense | **4,964** | 5,299 |
| Accretion expense | **322** | 483 |
| Finance charge on finance lease obligation | **272** | - |
| Total | **5,558** | 5,782 |

## 19) NATURE OF EXPENSES

Delphi's consolidated statement of earnings is prepared primarily by nature of expense, with the exception of employee compensation costs which are included in both the operating and general and administrative expense line items. The following table details operating, general and administrative and employee compensation costs:

| **For the years ended December 31,** | **2012** | 2011 |
|---|---|---|
| Operating | **22,718** | 21,100 |
| General and administrative | **3,304** | 3,324 |
| Employee compensation | **4,398** | 4,063 |
| Total | **30,420** | 28,487 |

## 20) KEY MANAGEMENT COMPENSATION

Key management includes senior officers and directors (executive and non-executive) of the Company. The compensation paid or payable to key management is shown below:

| For the years ended December 31, | 2012 | 2011 |
|---|---|---|
| Salaries and other short-term employee benefits | **2,472** | 2,810 |
| Long-term incentive compensation | **267** | 236 |
| Share-based compensation [1] | **1,132** | 459 |
| Total | **3,871** | 3,505 |

(1) Share-based payments are net of amounts capitalized to property, plant and equipment.

## 21) COMMITMENTS

Delphi is committed to future minimum payments for natural gas gathering, processing and transmission, operating leases on compression equipment and office space. Payments required under these commitments for each of the next five years are as follows:

| | 2013 | 2014 | 2015 | 2016 | 2017 | **Total** |
|---|---|---|---|---|---|---|
| Gathering, processing and transmission | 4,361 | 3,929 | 3,620 | 100 | - | **12,010** |
| Office and equipment lease | 1,932 | 566 | 566 | 579 | 417 | **4,060** |
| Total | 6,293 | 4,495 | 4,186 | 679 | 417 | **16,070** |

As a result of the flow-through shares issued on November 13, 2012, Delphi is committed to incur approximately $8.0 million in qualifying Canadian exploration expenses on or before December 31, 2013.

Pursuant to a farm-in agreement, Delphi must drill a total of 5 gross wells in 2013 and 2014 of which it has a commitment to pay the farmor's working interest, representing 2.3 net wells. The farm-in agreement will allow Delphi to earn working interests in Montney and Nordegg petroleum and natural gas rights ("PNG rights") in its core area of Bigstone, Alberta. Under this farm-in agreement, Delphi may earn a minimum of a 33 percent working interest in 23.5 sections of PNG rights at an estimated cost of $20.0 million or up to a 75 percent working interest in 35 sections of PNG rights at an estimated cost of $32.5 million. In the event Delphi does not complete their drilling commitments associated with this farm-in agreement, the Company is exposed to a maximum non-performance fee of $4.0 million.

## 22) SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital are comprised of the following:

| For the years ended December 31, | 2012 | 2011 |
|---|---|---|
| Source (use) of cash | | |
| Accounts receivable | **2,520** | (873) |
| Prepaid expenses and deposits | **299** | (463) |
| Outstanding cheques | **883** | - |
| Accounts payable and accrued liabilities | **(23,283)** | 18,965 |
| Total change in non-cash working capital | **(19,581)** | 17,629 |
| | | |
| Relating to: | | |
| Operating activities | **(698)** | 2,273 |
| Financing activities | **(212)** | 300 |
| Investing activities | **(18,671)** | 15,056 |
| | **(19,581)** | 17,629 |

## 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.** (3)
Partner
Burnet, Duckworth & Palmer LLP

**Robert A. Lehodey, Q.C.** (2) (3)
Partner
Osler, Hoskin & Harcourt LLP

**Stephen Mulherin** (1)
Partner
Polar Capital Corporation

**Andrew E. Osis** (1) (3)
Independent Businessman

**David Sandmeyer** (2)
Director
Freehold Royalty Trust

**Lamont C. Tolley** (1) (2)
Independent Businessman

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

## AUDITORS

KPMG LLP

## LEGAL COUNSEL

Osler, Hoskin & Harcourt LLP

## OFFICERS

**David J. Reid**
President and Chief Executive Officer

**Tony Angelidis**
Senior Vice President Exploration

**Hugo H. Batteke**
Vice President Operations

**Michael K. Galvin**
Vice President Land

**Rod A. Hume**
Senior Vice President Engineering

**Brian P. Kohlhammer**
Senior Vice President Finance and Chief Financial Officer

## CORPORATE OFFICE

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Email: info@delphienergy.ca
Website: www.delphienergy.ca

## BANKERS

National Bank of Canada
The Bank of Nova Scotia
Alberta Treasury Branches

## INDEPENDENT ENGINEERS

GLJ Petroleum Consultants Ltd.

## STOCK EXCHANGE LISTING

Toronto Stock Exchange – **DEE**

## TRANSFER AGENT

Olympia Trust Company

## ABBREVIATIONS

| | |
|---|---|
| bbls | barrels |
| bbls/d | barrels per day |
| bbls/mmcf | barrels per million cubic feet |
| 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 |

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