MANAGEMENT'S DISCUSSION AND ANALYSIS

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

Delphi Energy Corp. ("Delphi" or the "Company") is an oil and natural gas company based in Calgary, Alberta, focused on the exploration, development, and production of crude oil, natural gas and natural gas liquids from properties located in Western Canada. Delphi's operations are concentrated in the Deep Basin of Northwest Alberta. The Company's common shares, senior secured notes, and warrants are listed on the Toronto Stock Exchange ("TSX") under the symbol "DEE", "DEE.NT", and "DEE.WT", respectively. Additional information about Delphi is available on the Canadian Securities Administrators' System for Electronic Distribution and Retrieval (SEDAR) at www.sedar.com and at the Company's website at www.delphienergy.ca.

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, 2018 and 2017 and should be read in conjunction with the audited consolidated financial statements and accompanying notes for the years ended December 31, 2018 and 2017. 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 12, 2019.

FOURTH QUARTER AND 2018 HIGHLIGHTS

- Successfully executed a twelve (7.80 net) well drilling program and various infrastructure projects to support future growth and further diversify the natural gas processing options for the Company;
- Increased production from 8,401 barrels of oil equivalent per day ("boe/d") in 2017 to 9,774 boe/d in 2018 and increased the liquids yield from 103 barrels per million cubic feet ("bbls/mmcf") to 113 bbls/mmcf;
- Shifted production mix to higher value commodities with a 29 percent increase in field condensate production versus a 12 percent increase in natural gas and natural gas liquids ("NGL") production, resulting in field condensate comprising 26 percent of total production on a boe basis versus 23 percent in 2017;
- Although production in the fourth quarter of 9,444 boe/d decreased two percent in comparison to the fourth quarter of 2017, field condensate production increased by eleven percent, comprising of 28 percent of total production on a boe basis compared to 25 percent in the fourth quarter of 2017;
- Completed construction of and commissioned the amine processing facility which has reduced operating costs and diversified Delphi's natural gas processing options;
- Operating expenses per barrel of oil equivalent ("boe") were $7.33 and $8.38 in the three and twelve months ended December 31, 2018, down 31 percent and 13 percent, respectively, in comparison to the same periods in 2017;
- Improved the operating netback before risk management by 35 percent in 2018 compared to 2017, primarily as a result of improvements in benchmark commodity prices and reductions to operating and transportation expenses;
- Realized a natural gas price of $3.53 per thousand cubic feet ("mcf") and $3.45 per mcf, including risk management and marketing income, in the three and twelve months ended December 31, 2018, more than double the average price for AECO benchmark for the same respective periods;
- The cash netback before risk management in the fourth quarter of 2018 decreased eight percent from the fourth quarter of 2017 to $13.62 per boe, primarily due to a lower average price for field condensate due to an historically wide Edmonton condensate to WTI discount;
- Realized a cash netback before risk management of $16.54 per boe in 2018 compared to a cash netback of $10.96 per boe before risk management in 2017. The increase in cash netback is principally due to a combination of higher production and stronger realized prices of field condensate and NGLs as well as cost reductions in operating, transportation and general and administrative expenses; and
- Continued to build a strong hedge book with commodity risk management contracts valued at $26.6 million as at December 31, 2018, providing protection in 2019 and into 2020 against the volatile commodity price environment.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

	Three months ended December 31			Twelve months ended December 31		
	2018	2017	% Change	**2018**	2017	% Change
Financial						
($ thousands, except per share)						
Crude oil and natural gas revenues	**26,786**	30,896	(13)	**127,254**	101,836	25
Net earnings (loss)	**(17,318)**	(1,764)	882	**(26,366)**	6,902	(482)
Per share – basic and diluted	**(0.09)**	(0.01)	800	**(0.14)**	0.04	(450)
Cash flow from operating activities	**9,428**	9,490	(1)	**54,128**	31,044	74
Per share – basic and diluted(1)	**0.05**	0.05	-	**0.29**	0.18	61
Adjusted funds flow(1)	**8,890**	14,144	(37)	**46,615**	36,670	27
Per share – basic and diluted(1)	**0.05**	0.08	(38)	**0.25**	0.21	19
Net debt(1)	**181,985**	136,421	33	**181,985**	136,421	33
Capital expenditures, net of dispositions	**26,942**	42,156	(36)	**90,834**	117,292	(23)
Weighted average shares (000s)						
Basic	**185,547**	185,472	-	**185,547**	173,171	7
Diluted	**185,547**	185,472	-	**185,547**	173,975	7
Operating						
(boe conversion – 6:1 basis)						
Production:						
Field condensate (bbls/d)	**2,644**	2,374	11	**2,542**	1,968	29
Natural gas liquids (bbls/d)	**1,289**	1,315	(2)	**1,411**	1,250	13
Natural gas (mcf/d)	**33,063**	35,391	(7)	**34,925**	31,098	12
Total (Boe/d)	**9,444**	9,588	(2)	**9,774**	8,401	16
Average realized sales prices, before financial instruments						
Field condensate ($/bbl)	**42.66**	64.20	(34)	**66.96**	59.14	13
Natural gas liquids ($/bbl)	**38.87**	47.34	(18)	**44.88**	35.42	27
Natural gas ($/mcf)	**3.71**	3.39	9	**3.23**	3.78	(14)
Netbacks ($/boe)						
Crude oil and natural gas revenues	**30.83**	35.03	(12)	**35.68**	33.22	7
Marketing income (1)	**1.61**	1.63	(1)	**1.41**	0.58	141
Realized gain (loss) on financial instruments	**(3.38)**	1.25	(370)	**(3.47)**	1.00	(445)
Revenue, after realized financial instruments	**29.06**	37.91	(23)	**33.62**	34.80	(4)
Royalties	**(1.72)**	(2.26)	(24)	**(2.08)**	(2.35)	(11)
Operating expense	**(7.33)**	(10.59)	(31)	**(8.38)**	(9.60)	(13)
Transportation expense	**(4.43)**	(4.62)	(4)	**(4.86)**	(5.67)	(14)
Operating netback (1)	**15.58**	20.44	(24)	**18.30**	17.18	6
General and administrative expenses	**(1.61)**	(1.54)	5	**(1.61)**	(2.08)	(23)
Interest	**(3.80)**	(3.02)	26	**(3.53)**	(3.08)	15
Foreign exchange gains (losses)	**0.26**	0.15	73	**0.10**	(0.06)	-
Settlement of unutilized take-or-pay contract	**(0.19)**	-	-	**(0.19)**	0	-
Cash netback (1)	**10.24**	16.03	(36)	**13.07**	11.96	9

(1) Refer to non–GAAP measures

2018 DRILLING AND COMPLETIONS OPERATIONS

Well Location	Gross	Net	Drilled (Rig Released)	Completed	On-stream
100/15-19-059-23W5	1.0	0.65	Q4 2017	Q4 2017	Q1 2018
102/14-10-059-23W5	1.0	0.65	Q4 2017	Q1 2018	Q1 2018
102/16-07-060-23W5	1.0	0.65	Q4 2017	Q1 2018	Q1 2018
100/16-11-060-23W5	1.0	0.65	Q1 2018	Q1 2018	Q1 2018
100/16-19-059-23W5	1.0	0.65	Q1 2018	Q1 2018	Q2 2018
102/14-18-060-22W5	1.0	0.65	Q1 2018	Q1 2018	Q2 2018
100/16-10-060-24W5	1.0	0.65	Q1 2018	Q1 2018	Q2 2018
102/16-31-059-23W5	1.0	0.65	Q3 2018	Q3 2018	Q3 2018
100/13-18-060-22W5	1.0	0.65	Q3 2018	Q3 2018	Q3 2018
100/15-10-060-24W5	1.0	0.65	Q3 2018	Q4 2018	Q4 2018
102/15-19-059-23W5	1.0	0.65	Q3 2018	Q4 2018	Q4 2018
103/16-31-059-23W5	1.0	0.65	Q4 2018	Q4 2018	Q4 2018
102/15-10-060-24W5	1.0	0.65	Q4 2018	-	-
100/14-10-060-24W5	1.0	0.65	Q4 2018	-	-
100/12-10-060-24W5	1.0	0.65	Q4 2018	-	-
Total on-stream	12.0	7.8			
Success rate (%)	100	100			

In 2018, Delphi drilled twelve (7.80 net) wells in the Montney formation at Bigstone. In comparison, Delphi drilled 17 (11.05 net) wells in 2017 which were also focused on the Bigstone Montney formation.

CAPITAL EXPENDITURES

	Three Months Ended December 31			Twelve Months Ended December 31		
	2018	2017	% Change	**2018**	2017	% Change
Drilling, completions and equipping	**22,984**	39,640	(42)	**71,842**	98,610	(27)
Facilities	**3,236**	4,492	(28)	**16,567**	15,032	10
Land	**35**	49	(29)	**125**	2,196	(94)
Capitalized expenses	**604**	528	14	**2,276**	2,670	(15)
Other	**125**	66	89	**181**	379	(52)
Capital invested	**26,984**	44,775	(40)	**90,991**	118,887	(23)
Disposition of properties	**(42)**	(2,619)	(98)	**(157)**	(2,445)	(94)
Net capital invested	**26,942**	42,156	(36)	**90,834**	116,442	(22)
Acquisition of properties	**-**	-	-	**-**	850	-
Total capital	**26,942**	42,156	(36)	**90,834**	117,292	(23)

During the fourth quarter of 2018 Delphi invested $27.0 million of which 85 percent was for drilling, completion and equipping operations. Delphi completed and brought on-stream three (1.95 net) wells, two of which had been drilled in the third quarter and one of which was drilled in the fourth quarter. In addition, Delphi commenced operations on a four-well pad in West Bigstone, drilling three (1.95 net) of the four (2.60 net) wells. Delphi also completed construction of a 60,000 cubic metre frac water storage cell to help facilitate and reduce capital on future completion operations in West Bigstone and built a pipeline for tie-in of the four-well pad to the battery. The fourth well on the four-well pad was drilled in the first quarter of 2019 and completion operations on the pad were commenced, with the wells scheduled to be tied-in and brought on-stream in the second quarter of 2019.

In 2018, Delphi invested $91.0 million, drilling twelve (7.80 net) wells, investing in infrastructure and bringing on new production from twelve (7.80 net) wells, of which three (1.95 net) wells were drilled in the fourth quarter of 2017. In 2018, Delphi constructed an amine processing facility which is capable of sweetening up to 17 (11.0 net) mmcf/d of gross raw Montney natural gas prior to routing it through its 25 percent owned Bigstone sweet natural gas plant for final processing. The facility was commissioned and operating by May 2018. Initially, the natural gas sales from this processing stream will be sold in the AECO market via shipment on the Nova Gas Transmission system ("NGTL") until such time as the Alliance lateral pipeline at the Bigstone sweet natural gas plant is reactivated, which is expected to occur in mid-2020. With the reactivation of the Alliance lateral pipeline, natural gas sales from this processing stream will be shipped on the Alliance pipeline system ("Alliance") and sold in the Chicago market. The purpose of the amine facility is to diversify the Company's natural gas processing options and reduce operating costs through the reduction of third party natural gas processing fees. Until the Alliance lateral pipeline is reactivated, Delphi expects to transport about 60 percent of its natural gas on Alliance and 40 percent on NGTL compared to about 90 percent on Alliance after reactivation of the lateral pipeline. While the greater proportion of natural gas shipped on NGTL in the near-term will result in a lower average realized price for Delphi's natural gas, this will be more than offset by lower natural gas processing costs, lower natural gas transportation costs and an increase in marketing income generated from Delphi's excess capacity on the Alliance system.

In addition, Delphi installed a battery and a chemical natural gas sweetening unit at West Bigstone, allowing marginally sour natural gas production from two of the Montney wells drilled in 2018 to be tied-in and processed at the Company's 100 percent owned Negus sweet gas plant.

As of December 31, 2018, Delphi has a working interest in a total of 118 (76.3 net) sections of undeveloped and partially undeveloped land as part of 148 (97.0 net) sections of total land prospective for liquids-rich natural gas in the Montney formation, situated at its core area of Bigstone.

PRODUCTION

	Three Months Ended December 31			Twelve Months Ended December 31		
	2018	2017	% Change	**2018**	2017	% Change
Field condensate (bbls/d)	**2,644**	2,374	11	**2,542**	1,968	29
Ethane (bbls/d)	**12**	6	100	**11**	8	38
Propane (bbls/d)	**531**	526	1	**596**	552	8
Butane (bbls/d)	**432**	429	1	**449**	398	13
Pentanes & plant condensate (bbls/d)	**314**	354	(11)	**355**	292	22
Total field condensate and natural gas liquids	**3,933**	3,689	7	**3,953**	3,218	23
Natural gas (mcf/d)	**33,063**	35,391	(7)	**34,925**	31,098	12
Total (boe/d)	**9,444**	9,588	(2)	**9,774**	8,401	16

Production volumes in the fourth quarter of 2018 averaged 9,444 boe/d, a two percent decrease over the comparative quarter in 2017. Production volumes from the third well completed during the quarter did not have a significant impact on fourth quarter production as it was brought on-stream in the last few days of December. Production in the fourth quarter of 2017 included 174 boe/d of production from the Company's Tower Creek well which was suspended in October 2018 and did not contribute to production in the fourth quarter of 2018. Delphi completed three (1.95 net) wells in the fourth quarter of 2018 which negatively impacted production on adjacent producing wells, reducing fourth quarter production by about 685 boe/d. In addition, fourth quarter production was curtailed by approximately 410 boe/d due to scheduled and unscheduled facility outages. In an effort to reduce well interference from hydraulic fracturing, Delphi has shifted its focus to drilling multi-well pads and performing frac operations simultaneously.

Production volumes for the twelve months ended December 31, 2018 averaged 9,774 boe/d, a 16 percent increase over the comparative period in 2017. Incremental volumes from the twelve (7.80 net) wells brought on-stream in 2018 were partially offset by natural declines, third party processing plant constraints in the third quarter of 2018 and well interference from frac operations. Due to the suspension of Tower Creek, unscheduled third party plant restrictions and well interference in 2018, production volumes were reduced by approximately 718 boe/d. Field condensate and natural gas liquids volumes increased 23 percent in 2018 compared to 2017, increasing the liquids yield from 103 bbls/mmcf to 113 bbls/mmcf.

The composition of production in the fourth quarter of 2018 shifted to higher value field condensate with an 11 percent increase in field condensate production and a 6 percent decline in combined natural gas and NGL production over the comparative period in 2017. Delphi's production portfolio for the fourth quarter of 2018 was weighted 28 percent to field condensate, 14 percent to natural gas liquids and 58 percent to natural gas. This compares to a production portfolio for the comparative quarter in 2017 weighted 25 percent to field condensate, 13 percent to natural gas liquids and 62 percent to natural gas.

BUSINESS ENVIRONMENT

Benchmark Prices and Economic Parameters

	Three Months Ended December 31			Twelve Months Ended December 31		
	2018	2017	% Change	**2018**	2017	% Change
Natural Gas						
NYMEX (US $/mmbtu)	**3.65**	2.94	24	**3.08**	3.11	(1)
Chicago City Gate MI (US $/mmbtu)	**3.62**	2.92	24	**3.05**	3.04	-
Chicago City Gate DI (US $/mmbtu)	**3.67**	2.91	26	**3.02**	2.83	7
AECO 5A (CDN $/mcf)	**1.56**	1.69	(8)	**1.50**	2.15	(30)
AECO 7A (CDN $/mcf)	**1.90**	2.58	(26)	**1.53**	2.05	(25)
Crude Oil						
West Texas Intermediate (US $/bbl)	**58.78**	55.41	6	**64.76**	50.93	27
West Texas Intermediate (Cdn$/bbl)	**77.57**	70.44	10	**83.92**	66.08	27
Edmonton condensate to WTI Differential (CDN $/bbl)	**(17.98)**	(0.03)	-	**(5.04)**	(0.04)	-
Foreign Exchange						
Canadian to U.S. dollar	**0.76**	0.79	(4)	**0.77**	0.77	-
U.S. to Canadian dollar	**1.32**	1.27	4	**1.30**	1.30	-

Natural Gas

After commissioning of the amine processing facility during the second quarter of 2018, Delphi now ships approximately 60 percent of its natural gas production through the Alliance pipeline system into the Chicago market. Chicago City Gate is the primary benchmark for Delphi's natural gas sales in the United States. The remainder of Delphi's natural gas production is sold in Alberta on the NGTL system. The AECO 5A price is the primary benchmark for the Company's natural gas sales in Alberta.

The Chicago City Gate benchmark natural gas prices for the three months ended December 31, 2018 increased in comparison to the same period in 2017 as demand for natural gas increased for heating purposes as the United States Midwest experienced colder weather. The Chicago City Gate benchmark natural gas prices in 2018 increased marginally in comparison to 2017 as increased supply into the Chicago market outpaced demand for natural gas. The average AECO benchmark natural gas prices weakened in the three and twelve months ended December 31, 2018 primarily due to growing natural gas supplies from Western Canada relative to the limited transportation capabilities to move natural gas out of Western Canada.

Crude Oil

Global crude oil prices weakened in November and December of 2018, after experiencing stronger than expected global demand for crude oil and production curtailments by OPEC and non-OPEC producers earlier in the year. The West Texas Intermediate ("WTI") benchmark declined in the fourth quarter of 2018 from the third quarter of 2018 largely due to rising concerns over slowing global economic growth, increased output of crude oil in the United States and Russia and rising inventories.

The majority of Delphi's condensate production is delivered to various terminals in Fox Creek, Alberta. The price that Delphi receives for its condensate is primarily driven by the price of WTI, adjusted for changes in foreign exchange rates, transportation costs and quality differentials. During September to December 2018, Edmonton condensate experienced widening discounts to WTI principally due to full storage in Edmonton and infrastructure constraints. The Edmonton condensate to WTI discount increased to $17.98 per bbl in the fourth quarter of 2018 compared to $0.03 per bbl in the same period in 2017. The outlook for condensate prices in Alberta remains positive as local demand for condensate as a diluent exceeds current and forecasted local supply.

Natural Gas Liquids

Natural gas liquids, including ethane, propane, butane, pentane and plant condensate, are generally priced off light oil and natural gas prices. Ethane prices are correlated to natural gas prices while propane and butane prices trade at a discount to light oil prices depending on supply and demand conditions. Natural gas liquids pricing in 2018 was generally supported by improvements in WTI crude oil prices.

Canadian/United States Exchange Rate

The value of the Canadian dollar against its U.S. counterpart averaged U.S. $0.76 for the three months ended December 31, 2018, a four percent decrease in comparison to the same period in 2017. The value of the Canadian dollar against its U.S. counterpart averaged U.S $0.77 for the twelve months ended December 31, 2017 and 2018. As a producer of natural gas sold in the United States, an increase in the Canadian dollar relative to its U.S. counterpart has a negative effect on the price received for production.

REALIZED SALES PRICES

	Three Months Ended December 31			Twelve Months Ended December 31		
Chicago	**2018**	2017	% Change	**2018**	2017	% Change
Chicago City Gate MI (Cdn$/mcf)	**4.80**	3.71	29	**3.97**	3.95	1
Heating content and marketing ($/mcf)	**0.06**	0.06	-	**(0.06)**	0.06	(200)
Realized price before risk management contracts ($/mcf)	**4.86**	3.77	29	**3.91**	4.01	(2)
AECO						
AECO 5A ($/mcf)	**1.56**	1.69	(7)	**1.50**	2.15	(30)
Heating content and marketing ($/mcf)	**0.22**	(0.04)	-	**0.05**	0.24	(79)
Realized price before risk management contracts ($/mcf)	**1.78**	1.65	8	**1.55**	2.39	(35)
Combined Natural Gas						
Realized natural gas price before risk management contracts ($/mcf)	**3.71**	3.39	9	**3.23**	3.78	(14)
Realized gain (loss) on financial contracts ($/mcf)	**(0.64)**	0.47	(237)	**(0.17)**	0.27	(163)
Realized natural gas price ($/mcf)	**3.07**	3.86	(20)	**3.06**	4.05	(24)
Marketing income ($/mcf) (1)	**0.46**	0.44	5	**0.39**	0.16	144
Natural gas price including marketing income ($/mcf)	**3.53**	4.30	(18)	**3.45**	4.21	(18)
Field Condensate						
WTI (Cdn$/bbl)	**77.57**	70.44	10	**83.92**	66.08	27
Edmonton condensate to WTI Differential ($/bbl)	**(17.98)**	(0.03)	-	**(5.04)**	(0.04)	-
Edmonton condensate	**59.59**	70.41	(15)	**78.88**	66.04	19
Differential and marketing ($/bbl)	**(16.93)**	(6.21)	(173)	**(11.92)**	(6.90)	73
Realized price before risk management contracts ($/bbl)	**42.66**	64.20	(34)	**66.96**	59.14	13
Realized loss on financial contracts ($/bbl)	**(4.10)**	(1.89)	117	**(10.94)**	(0.01)	-
Realized field condensate price ($/bbl)	**38.56**	62.31	(38)	**56.02**	59.13	(5)
Natural Gas Liquids						
Realized natural gas liquids price ($/bbl)	**38.87**	47.34	(18)	**44.88**	35.42	27
Total realized sales price ($/boe)	**27.45**	36.28	(24)	**32.21**	34.22	(6)

(1) Refer to non–GAAP measures

Delphi sells natural gas in the Chicago market through the Alliance pipeline system and in the AECO market though the NGTL system. Prior to commissioning the amine facility in May 2018, approximately 90 percent of the Company's natural gas was sold in the Chicago market. Since commissioning the amine facility, sweetened Montney natural gas from the facility has been processed at Delphi's 25 percent owned Bigstone sweet natural gas plant and shipped on NGTL. As a result, the proportion of natural gas sold in the Chicago market was 63 percent and 72 percent in the three and twelve months ending December 31, 2018 respectively. With reactivation of the Alliance lateral pipeline at the Bigstone sweet natural gas plant (expected in mid-2020), the proportion of natural gas sold in Chicago is expected to return to about 90 percent of total natural gas sales. All of the Company's natural gas, with the exception of natural gas processed at Delphi's 100 percent owned Negus sweet gas plant in West Bigstone, will be processed at facilities that are connected to both the Alliance and NGTL pipeline systems.

Delphi generally receives a higher price for its natural gas per mcf due to its high heat content. Differentials for marketing are caused by differences between the daily and monthly benchmark price indices. The majority of the natural gas volumes that were shipped on the Alliance pipeline system were sold with reference to the monthly index and the remainder of the volumes were sold with reference to the daily index. The majority of natural gas volumes shipped on NGTL are sold with reference to AECO 5A index and the remainder with reference to AECO 7A.

For the three months ended December 31, 2018, Delphi's realized natural gas price before risk management contracts increased ten percent in comparison to the same period in 2017 primarily due to an increase in Chicago City Gate benchmarks and a decrease in the value of the Canadian dollar against its U.S. counterpart partially offset by an increase in the proportion of natural gas sales in Alberta coupled with a decrease in AECO benchmark prices. Delphi's realized natural gas price before risk management contracts decreased 14 percent for the year ended December 31, 2018 compared to the same period in 2017 primarily due to an increase in the proportion of natural gas being sold in Alberta in combination with a decrease in the AECO benchmark prices.

Realized field condensate prices before risk management contracts were 34 percent lower in the three months ended December 31, 2018 compared to the same period in 2017. The decrease in the realized price before risk management is due to the significant widening of the Edmonton condensate to WTI discount. Although Delphi was able to ship and sell all of its field condensate in the fourth quarter, a portion of condensate volumes were subject to pipeline apportionments in October and November and received a discounted spot price which increased the differential. The Edmonton Condensate to WTI discount has narrowed significantly since the fourth quarter and Delphi's condensate volumes have not been subject to apportionment since November. Realized field condensate prices before risk management contracts increased 13 percent in 2018 compared to 2017 primarily due to an increase in the WTI benchmark partially offset by widening differentials.

Delphi's realized natural gas liquids price for the three months ended December 31, 2018 decreased 18 percent in comparison to the same period in 2017 primarily due to a decrease in the price for propane, pentane and plant condensate. The majority of natural gas liquids are priced off of the WTI benchmark which decreased in the fourth quarter of 2018. The realized natural gas liquids price for 2018 increased 27 percent from 2017 as the price for all natural gas liquids increased, in particular for butane and pentane. The market price for natural gas liquids increased in 2018 as the WTI benchmark gained strength in 2018 compared to 2017.

RISK MANAGEMENT ACTIVITIES

Overall, growing natural gas supply has resulted in high gas storage levels and ongoing price weakness. Concerns over slowing global economic growth and increased supply continues to create a volatile market environment for crude oil. In an effort to mitigate commodity price fluctuations for natural gas, crude oil and natural gas liquids, Delphi enters into financial commodity contracts as part of its risk management program designed to protect cash flows through to simple payout on the drilling and completion portion of its capital program.

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 consolidated statement of earnings (loss).

Natural Gas Contracts

Time Period	Type of Contract	Quantity Contracted	Price ($/unit)	Reference
January 2018 – December 2019	Financial - Swap	2,000 mmbtu/d	$4.018 Cdn	NYMEX
January 2018 – December 2019	Financial - Swap	5,000 mmbtu/d	$3.840 Cdn	NYMEX
January 2019 – June 2019	Financial - Swap	2,500 mmbtu/d	$3.8975 Cdn.	NYMEX
January 2019 – June 2019	Financial - Swap	2,500 mmbtu/d	$3.945 Cdn.	NYMEX
January 2019 – December 2019	Financial - Swap	3,000 mmbtu/d	$3.550 Cdn.	NYMEX
January 2019 – December 2019	Financial - Swap	5,000 mmbtu/d	$3.710 Cdn.	NYMEX
January 2020 – March 2020	Financial - Swap	5,000 mmbtu/d	$3.750 Cdn.	NYMEX
January 2020 – June 2020	Financial - Swap	5,000 mmbtu/d	$3.480 Cdn.	NYMEX

Propane Contracts

Time Period	Type of Contract	Quantity Contracted	Price ($/U.S. gallon)	Reference
January 2019 – December 2019	Financial - Swap	200 bbls/d	$0.800 U.S.	Conway
January 2019 – December 2019	Financial - Swap	200 bbls/d	$0.793 U.S.	Conway
January 2020 – December 2020	Financial - Swap	100 bbls/d	$0.770 U.S.	Conway

Crude Oil Contracts

Time Period	Type of Contract	Quantity Contracted	Price ($/unit)	Reference
January 2017 – December 2019	Financial - Swap	300 bbls/d	$70.00 Cdn	WTI
January 2019 – June 2019	Financial - Swap	400 bbls/d	$74.80 Cdn	WTI
January 2019 – June 2019	Financial - Swap	250 bbls/d	$95.20 Cdn	WTI
January 2019 – June 2019	Financial - Swap	250 bbls/d	$95.30 Cdn	WTI
January 2019 – December 2019	Financial - Swap	300 bbls/d	$56.20 U.S.	WTI
January 2019 – December 2019	Financial - Swap	1,000 bbls/d	$90.00 Cdn	WTI
January 2019 – December 2020	Financial - Swap	250 bbls/d	$90.00 Cdn	WTI
January 2019 – December 2020	Financial - Swap	250 bbls/d	$90.10 Cdn	WTI
July 2019 – December 2019	Financial - Swap	200 bbls/d	$92.63 Cdn	WTI
July 2019 – December 2019	Financial - Swap	200 bbls/d	$92.65 Cdn	WTI
July 2019 – December 2019	Financial - Swap	400 bbls/d	$89.90 Cdn	WTI

Basis Differential Contracts

Delphi ships the majority of its natural gas production through the Alliance pipeline system into the Chicago market. As a result, the Company has entered into Chicago – NYMEX basis differential contracts in order to fix the basis on a portion of its natural gas sales in the Chicago market.

Time Period	Type of Contract	Quantity Contracted	Differential (U.S. $/unit)
April 2018 – March 2019	Financial - Swap	4,000 mmbtu/d	($0.235)
January 2019 – March 2019	Financial - Swap	3,000 mmbtu/d	($0.110)
January 2019 – March 2019	Financial - Swap	3,000 mmbtu/d	($0.105)
January 2019 – December 2019	Financial - Swap	2,500 mmbtu/d	($0.195)
January 2019 – December 2019	Financial - Swap	2,500 mmbtu/d	($0.190)
January 2019 – December 2019	Financial - Swap	4,000 mmbtu/d	($0.1275)
April 2019 – October 2019	Financial - Swap	7,000 mmbtu/d	($0.400)
April 2019 – October 2019	Financial - Swap	3,000 mmbtu/d	($0.390)
November 2019 – March 2020	Financial - Swap	7,000 mmbtu/d	($0.135)
November 2019 – March 2020	Financial - Swap	3,000 mmbtu/d	($0.120)

U.S. Forward Exchange Contracts

Delphi sells the majority of its natural gas in the Chicago market in U.S. dollars. In order to mitigate the U.S. to Canadian dollar fluctuation, Delphi has entered into the following U.S. dollar forward exchange contracts:

Time Period	Average Notional U.S. $	Average Exchange Rate (U.S.$ to Cdn$)
January 2019 – December 2019	500.0	1.2860
January 2019 – December 2019	115.0	1.2965
January 2019 – December 2019	400.0	1.3000
January 2019 – December 2019	200.0	1.3305
January 2020 – December 2020	250.0	1.2920
January 2020 – December 2020	300.0	1.3210

Fair value of Delphi's risk management contracts

The fair value of the financial contracts outstanding as at December 31, 2018 is estimated to be a net asset of $26.6 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 period having regard to forward prices and market values provided by independent sources. Due to the inherent volatility in commodity prices, foreign exchange and interest rates, actual amounts realized may differ from these estimates.

For the three and twelve months ended December 31, 2018, Delphi recorded an unrealized gain on its risk management contracts of $37.6 million and $25.8 million, respectively. The unrealized gain recognized for the three months ended December 31, 2018 is the difference between the fair values of the risk management contracts outstanding as at December 31, 2018 and the fair values as at September 30, 2018. The unrealized gain recognized for the twelve months ended December 31, 2018 is the difference between the fair values of the risk management contracts outstanding as at December 31, 2018 and the fair values as at December 31, 2017.

For the three and twelve months ended December 31, 2018, the risk management contracts resulted in a realized loss of $2.9 million and $12.4 million, respectively, primarily due to lower average pricing for the Company's crude oil risk management contracts relative to the benchmark commodity prices during the respective periods.

REVENUES

CRUDE OIL AND NATURAL GAS

	Three Months Ended December 31			Twelve Months Ended December 31		
	2018	2017	% Change	**2018**	2017	% Change
Field condensate	**10,378**	14,023	(26)	**62,128**	42,475	46
Natural gas	**11,289**	11,025	2	**41,186**	42,866	(4)
Natural gas liquids	**4,610**	5,726	(19)	**23,114**	16,174	43
Sulphur	**509**	122	317	**826**	321	157
Total	**26,786**	30,896	(13)	**127,254**	101,836	25

For the three and twelve months ended December 31, 2018, Delphi generated $26.8 million and $127.3 million of revenues, respectively, from the sale of its crude oil and natural gas. Field condensate and natural gas liquids contributed 56 percent and 67 percent of total revenues in the three and twelve months ended December 31, 2018, respectively, while making up approximately 40 percent of the Company's production on a boe basis.

Revenues decreased in the fourth quarter of 2018 compared to the same period in 2017 primarily due to a decrease in market prices for field condensate and natural gas liquids. Revenues in 2018 increased $25.4 million in comparison to 2017 primarily due to increased field condensate and natural gas liquids production in combination with higher market prices received for those products, partially offset by a decrease in natural gas revenues due to a lower average price received for Delphi's natural gas.

The impact on revenues due to volumes variance and realized prices before risk management is as follows:

	Three Months Ended December 31			Twelve Months Ended December 31		
	2018	2017	**($000's)**	2018	2017	**($000's)**
Crude oil and natural gas revenues, December 31, 2017			**30,896**			**101,836**
Revenue change due to:						
Field condensate						
Volume (bbl/d)	2,644	2,374	**1,059**	2,542	1,968	**14,029**
Realized price (1) ($/bbl)	42.66	64.21	**(4,704)**	66.96	59.13	**5,624**
Natural gas						
Volume (mcf/d)	33,063	35,391	**(794)**	34,925	31,098	**4,513**
Realized price (1) ($/mcf)	3.71	3.39	**1,058**	3.23	3.78	**(6,193)**
Natural gas liquids						
Volume (bbl/d)	1,289	1,315	**(93)**	1,411	1,250	**2,637**
Realized price (1) ($/bbl)	38.87	47.33	**(1,023)**	44.88	35.45	**4,303**
Sulphur	-	-	**387**	-	-	**505**
Crude oil and natural gas revenues, December 31, 2018			**26,786**			**127,254**

(1) Realized price before gains or losses on commodity price risk management contracts.

MARKETING

Marketing Revenue	Three Months Ended December 31 2018	2017	% Change	Twelve Months Ended December 31 2018	2017	% Change
Sale of purchased natural gas	**1,121**	2,150	(48)	**3,513**	5,327	(34)
Premiums on the assignment of service	**951**	658	45	**3,922**	985	298
Total	**2,072**	2,808	(26)	**7,435**	6,312	18

Marketing Expense	Three Months Ended December 31 2018	2017	% Change	Twelve Months Ended December 31 2018	2017	% Change
Cost of purchased natural gas	**393**	653	(40)	**1,380**	2,813	(51)
Transportation of purchased natural gas	**278**	717	(61)	**1,031**	1,736	(41)
Total	**671**	1,370	(51)	**2,411**	4,549	(47)

Marketing Income (1)	Three Months Ended December 31 2018	2017	% Change	Twelve Months Ended December 31 2018	2017	% Change
Gain (loss) on marketing of purchased natural gas	**450**	780	(42)	**1,102**	778	42
Premium on the assignment of service	**951**	658	45	**3,922**	985	298
Total	**1,401**	1,438	(3)	**5,024**	1,763	185
Per boe	**1.61**	1.63	(1)	**1.41**	0.58	141

(1) *Refer to non–GAAP measures*

Delphi has contracted for approximately 45.8 mmcf/d of firm transportation service and 11.4 mmcf/d of priority interruptible service on the Alliance pipeline system from Alberta to Chicago. This service is fully renewable commencing October 2020. In order to mitigate the cost of transportation service in excess of its needs, Delphi either temporarily assigns the excess service to other shippers or purchases natural gas in Alberta or British Columbia for sale in Chicago. Marketing income increased in 2018, as the Company had additional firm capacity on the Alliance pipeline and a greater portion of natural gas production was shipped on NGTL due to the commissioning of its amine processing facility.

ROYALTIES

	Three Months Ended December 31 2018	2017	% Change	Twelve Months Ended December 31 2018	2017	% Change
Crown royalties	**1,259**	1,375	(8)	**6,495**	4,875	33
Royalty credits	**(549)**	(723)	(24)	**(2,927)**	(2,857)	2
Crown royalties – net	**710**	652	9	**3,568**	2,018	77
Gross overriding royalties	**787**	1,341	(41)	**3,868**	5,197	(26)
Total	**1,497**	1,993	(25)	**7,436**	7,215	3
Per boe	**1.72**	2.26	(24)	**2.08**	2.35	(11)

	Three Months Ended December 31			Twelve Months Ended December 31		
	2018	2017	% Change	**2018**	2017	% Change
Crown rate – before royalty credits	**4.7%**	4.5%	4	**5.1%**	4.8%	6
Crown rate – net of royalty credits	**2.7%**	2.1%	29	**2.8%**	2.0%	40
Gross overriding rate	**2.9%**	4.3%	(33)	**3.0%**	5.1%	(41)
Average rate	**5.6%**	6.4%	(14)	**5.8%**	7.1%	(18)

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

For the three and twelve months ended December 31, 2018, royalties totaled $1.5 million and $7.4 million, respectively, compared to $2.0 million and $7.2 million in the same periods in 2017.

The Crown royalty rate before royalty credits have increased four and six percent in the three and twelve months ended December 31, 2018, respectively, in comparison to the same periods in 2017. Crown royalties are based on provincial reference prices set by the province of Alberta, for each commodity. The price received by Delphi for its commodities may differ from the Alberta reference price ("ARP"), causing a fluctuation in the average Crown royalty rate. In 2017, approximately 90 percent of the Company's natural gas was sold in Chicago allowing Delphi to realize a higher price for its natural gas in comparison to the AECO benchmark. Although Delphi received a higher price for its natural gas, its Crown royalties for natural gas were referenced to an ARP, creating a lower overall Crown royalty rate on natural gas. Since the commissioning of the Company's amine processing facility, Delphi sells approximately 40 percent of its natural gas in Alberta, narrowing the price differential that Crown royalties are based on. The average Crown royalty rate has also increased due to additional production brought on-stream since 2017 which qualify for the Modern Royalty Framework that currently imposes a five percent royalty rate on all products until certain conditions are met. Most of the Company's Montney wells drilled prior to 2017 are under a different royalty incentive program which allows for a zero percent royalty rate on field condensate until certain limitations set out in the framework are met. Crown royalty credits decreased in the fourth quarter of 2018 compared to 2017 and remained consistent year over year. Crown royalty credits are largely based on the amortization of historical capital and operating costs of gas facilities and do not fluctuate based on commodity prices.

Gross overriding royalties decreased in the three and twelve months ended December 31, 2018 as overall production from wells encumbered with a gross overriding royalty decreased due to natural declines. The gross overriding royalty rate decreased 32 percent and 40 percent in the three and twelve months ended December 31, 2018 compared to the respective periods in 2017 as the majority of additional production volumes are not encumbered with a gross overriding royalty.

OPERATING EXPENSES

	Three Months Ended December 31			Twelve Months Ended December 31		
	2018	2017	% Change	**2018**	2017	% Change
Production costs	**6,797**	9,609	(29)	**31,130**	30,491	2
Processing recoveries	**(427)**	(270)	58	**(1,233)**	(1,065)	16
Total	**6,370**	9,339	(32)	**29,897**	29,426	2
Per boe	**7.33**	10.59	(31)	**8.38**	9.60	(13)

Approximately 93 percent of the Company's production volumes are from the Company's Montney properties in Bigstone, while only 85 percent of the Company's operating expenses relate to costs associated with production from the Montney. The remaining operating expenses are associated with non-Montney properties. Production costs in the fourth quarter of 2018 decreased 29 percent due to lower processing fees, water disposal and trucking costs, as well as $1.0 million of cost estimate reductions for the first nine months of 2018, and $0.4 million of recoveries from equalizations. Production costs in 2018 are in line with production costs in 2017 although production volumes have increased by 16 percent. Delphi is realizing the benefit of reduced costs per unit associated with the gas stream that is sweetened at the Company's amine facility and then further processed at its 25 percent owned Bigstone sweet natural gas processing facility. In addition, Delphi experienced cost savings in trucking water and water disposal fees due to the expansion of its water disposal facility in November of 2017 which increased the disposal capacity from 2,200 bbls/d to 6,000 bbls/d. The increase in water disposal capacity allowed more volumes to be trucked to the Company's own water disposal facility instead of third party facilities which are located further away, requiring longer and more costly trucking distances. Operating expenses on a per boe basis decreased 13 percent from 2017 to $8.38 per boe in 2018 as the Company increased production and realized the capital efficiencies from utilizing more of its own infrastructure for processing its product, particularly the amine sweetening facility.

Delphi recovers processing costs on partner production volumes processed at facilities it owns. The processing recoveries represent a reduction of the Company's costs to operate these facilities and hence is deducted in determining operating expenses.

TRANSPORTATION EXPENSES

	Three Months Ended December 31			Twelve Months Ended December 31		
	2018	2017	% Change	**2018**	2017	% Change
Transportation	**3,853**	4,073	(5)	**17,335**	17,379	-
Transportation per boe	**4.43**	4.62	(4)	**4.86**	5.67	(14)

The Company's transportation expenses consist of shipping natural gas on the Alliance and NGTL pipeline systems, trucking field condensate to sales terminals and shipping its natural gas liquids through the Pembina pipeline system.

Transportation expenses in the fourth quarter of 2018 decreased five percent in comparison to the same period in 2017 due to lower pipeline transportation costs realized from shipping a greater proportion of natural gas on the NGTL pipeline system which costs approximately $1.00 per mcf less than the cost of shipping on the Alliance pipeline system. Although transportation costs for 2018 remained comparable to 2017, lower transportation costs for the Company's natural gas was offset by additional trucking charges due to an increase in field condensate volumes.

Transportation costs on a per boe basis in the three and twelve months ended December 31, 2018 decreased four percent and 14 percent in comparison to the same periods in 2017.

GENERAL AND ADMINISTRATIVE

	Three Months Ended December 31			Twelve Months Ended December 31		
	2018	2017	% Change	**2018**	2017	% Change
Gross expenses	**1,999**	1,884	6	**8,025**	8,914	(10)
Capitalized	**(604)**	(529)	14	**(2,276)**	(2,545)	(11)
General and administrative expenses	**1,395**	1,355	3	**5,749**	6,369	(10)
Per boe	**1.61**	1.54	5	**1.61**	2.08	(23)

General and administrative expenses for the three months ended December 31, 2018 were comparable to the same period in 2017. General and administrative expenses for the twelve months ended December 31, 2018 were ten percent lower compared to the same period in 2017 largely due to employee termination payments in the first quarter of 2017 and reduced office rent in 2018 since the Company moved offices during the third quarter of 2017. Capitalized general and administrative expenses decreased in 2018 over the comparative period primarily due to reduced expenses.

On a per boe basis, general and administrative expenses have decreased 23 percent in the twelve months of 2018 as compared to the same periods in 2017.

SHARE-BASED COMPENSATION

	Three Months Ended December 31			Twelve Months Ended December 31		
	2018	2017	% Change	**2018**	2017	% Change
Share-based compensation – Options	**381**	400	(5)	**1,176**	1,481	(21)
Share-based compensation – RSUs	**-**	-	-	**-**	(39)	100
Capitalized costs	**(107)**	(114)	(6)	**(330)**	(457)	(28)
Net	**274**	286	(4)	**846**	985	(14)
Per boe	**0.32**	0.32	-	**0.24**	0.32	(25)

Share-based compensation expense is the amortization over the vesting period of the fair value of stock options and restricted share units ("RSUs") granted to employees, directors and key consultants of the Company. The fair value of RSUs is based on the Company's closing share price on the last business day immediately preceding the vesting date or the Company's closing share price on the last business day immediately preceding the statement of financial position date. The fair value of all options granted is estimated at the date of grant using the Black-Scholes option pricing model.

Share-based compensation expense related to the Company's option plan decreased five percent and 21 percent for the three and twelve months ended December 31, 2018 as compared to the same periods in 2017, respectively. The decrease in the share-based compensation expense related to Delphi's option plan is due to a number of outstanding options that are in their second or third year of vesting. Delphi recognizes the expense associated with its options on a graded vesting schedule basis which recognizes the majority of the expense in the first year of vesting. Share-based compensation expense related to the Company's RSUs decreased in the three and twelve months ended December 31, 2018 in comparison to the same periods in 2017 as the remaining restricted share units fully vested during the third quarter of 2017.

Capitalized share-based compensation decreased in the three and twelve months ended December 31, 2018 compared to the same period in 2017 as a result of no expense related to restricted share units and a reduction in expense related to the Company's option plan.

FINANCE COSTS

	Three Months Ended December 31			Twelve Months Ended December 31		
	2018	2017	% Change	**2018**	2017	% Change
Interest	**3,305**	2,678	23	**12,593**	9,453	33
Accretion of decommissioning liabilities	**148**	98	51	**538**	382	41
Finance charges	**472**	442	7	**1,808**	1,647	10
Foreign exchange (gain) loss	**(226)**	(132)	71	**(378)**	180	(310)
Total finance costs	**3,699**	3,086	(20)	**14,561**	11,662	25
Per boe	**4.26**	3.50	22	**4.08**	3.80	7

Interest charges on Delphi's bank debt and senior secured notes in the three and twelve months ended December 31, 2018 increased 23 and 33 percent over the comparative periods in 2017. The increase in interest expense over the comparative periods is due to a higher average bank debt balance and additional senior secured notes. Delphi issued an additional $30.0 million of ten percent senior secured notes during the second quarter of 2017, and an additional $15.0 million of ten percent senior secured notes during the fourth quarter of 2018.

Accretion and finance charges are non-cash and primarily comprised of accretion expense on the Company's decommissioning obligations and the accretion and amortization of the issue costs of the Company's senior secured notes.

The accretion of decommissioning liabilities 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 40 years. The increase in accretion expense in the three and twelve months ended December 31, 2018 compared to the same periods in 2017 is due to the higher risk free interest rates used to calculate the expense and a higher decommissioning obligation as a result of the 2018 capital program.

Finance charges include the amortization of transaction costs related to the issue of senior secured notes and the accretion of the debt to its face value. The increase in finance charges in the three and twelve months ended December 31, 2018 over the comparative periods in 2017 is due to a higher balance of outstanding debt subject to amortization and accretion.

Delphi's foreign exchange gains and losses primarily relate to the conversion of US dollars to Canadian dollars for the settlement of transactions denominated in US dollars, primarily consisting of natural gas sales and pipeline tolls.

DEPLETION AND DEPRECIATION

	Three Months Ended December 31			Twelve Months Ended December 31		
	2018	2017	% Change	**2018**	2017	% Change
Depletion and depreciation	**11,940**	11,980	-	**45,048**	35,854	26
Impairment loss	**51,004**	-	-	**51,004**	-	-
Total	**62,944**	11,980	425	**96,052**	35,854	168
Depletion and depreciation per boe	**13.74**	13.58	1	**12.63**	11.69	8
Impairment loss per boe	**58.71**	-	-	**14.40**	-	-

Depletion and depreciation in the fourth quarter of 2018 is comparable to that of 2017. For the twelve months ended December 31, 2018, Delphi recorded depletion and depreciation of $45.0 million compared to $35.9 million in the twelve months ended December 31, 2017. The increase in depletion and depreciation reflects increased production over the comparative periods in combination with an increase in the depletion rate.

In the fourth quarter of 2018, Delphi identified indicators of impairment, primarily as a result of sustained declines in forecasted commodity prices and a market capitalization deficiency relative to the book value of the Company's shareholders' equity. Delphi performed an impairment test on its Bigstone CGU, based on the recoverable amount estimated using a value in use calculation derived from expected future cash flows generated from proved and probable reserves using a pre-tax discount rate of approximately 12.5 percent plus an estimate of the fair value of the undeveloped land associated with the Bigstone CGU that is not considered exploration and evaluation. The difference between the carrying amount and the estimated recoverable amount resulted in the recognition of a $51.0 million impairment.

INCOME TAXES

Delphi has concluded that it is not probable that the deferred income tax asset will be realized and as a result, it has not been recognized at December 31, 2018. Therefore, no deferred income tax recovery was recorded against the loss for the year ended December 31, 2018.

Delphi does not have current income taxes payable and has estimated tax pools available at December 31, 2018 of $437.8 million (December 31, 2017 – $393.6 million).

ADJUSTED FUNDS FLOW

	Three Months Ended December 31			Twelve Months Ended December 31		
	2018	2017	% Change	**2018**	2017	% Change
Cash flow from operating activities	**9,428**	9,490	(1)	**54,128**	31,044	74
Decommissioning expenditures	**132**	861	(85)	**229**	3,167	(93)
Change in non-cash working capital	**(670)**	3,793	(118)	**(7,742)**	2,459	(415)
Adjusted funds flow(1)	**8,890**	14,144	(37)	**46,615**	36,670	27

(1) Refer to non–GAAP measures

Delphi's cash flow from operating activities and adjusted funds flow decreased in the three months ended December 31, 2018 compared to the same period in 2017. The decrease in cash flow from operating activities and adjusted funds flow is largely attributed to lower realized prices, particularly for field condensate, in combination with slightly lower production volumes and a realized loss on risk management contracts.

For the twelve months ended December 31, 2018, cash flow from operating activities increased 74 percent in comparison to the same period in 2017. Adjusted funds flow increased 27 percent over the same comparative period as realized prices and higher production volumes contributed to higher revenues. Delphi recorded higher marketing income and reduced its general and administrative costs. Partially offsetting the increase in cash flow from operating activities and adjusted funds flow is a realized loss on risk management contracts and an increase in finance costs.

CASH NETBACK AND EARNINGS ANALYSIS

	Three Months Ended December 31			Twelve Months Ended December 31		
	2018	2017	% Change	**2018**	2017	% Change
Net earnings (loss)	**(17,318)**	(1,764)	882	**(26,366)**	6,902	(482)
Per boe	**(19.93)**	(2.01)	892	**(7.39)**	2.27	(426)
Per basic and diluted share	**(0.09)**	(0.01)	800	**(0.14)**	0.04	(450)

Delphi recorded a net loss of $17.3 million ($0.09 per basic and diluted share) in the fourth quarter of 2018, down from the $1.8 million net loss in the fourth quarter of 2017. The increase in net loss is primarily due to a lower adjusted funds flow and a $51.0 million impairment loss partially offset by an unrealized gain on risk management contracts.

In the twelve months ended December 31, 2018, Delphi recorded a net loss of $26.4 million ($0.14 per basic and diluted share) compared to net earnings of $6.9 million in the same period in 2017. The decrease in earnings is primarily due to an impairment loss partially offset by an unrealized gain on risk management contracts and an increase in adjusted funds flow.

	Three Months Ended December 31			Twelve Months Ended December 31		
Barrels of oil equivalent ($/boe)	**2018**	2017	% Change	**2018**	2017	% Change
Realized sales price	**30.83**	35.03	(12)	**35.68**	33.22	7
Marketing income (1)	**1.61**	1.63	(1)	**1.41**	0.58	143
Royalties	**(1.72)**	(2.26)	(24)	**(2.08)**	(2.35)	(11)
Operating expenses	**(7.33)**	(10.59)	(31)	**(8.38)**	(9.60)	(13)
Transportation	**(4.43)**	(4.62)	(4)	**(4.86)**	(5.67)	(14)
Operating netback before risk management contracts (1)	**18.96**	19.19	(1)	**21.77**	16.18	34
Realized gain (loss) on risk management contracts	**(3.38)**	1.25	(370)	**(3.47)**	1.00	(447)
Operating netback (1)	**15.58**	20.44	(24)	**18.30**	17.18	7
General and administrative expenses	**(1.61)**	(1.54)	5	**(1.61)**	(2.08)	(23)
Interest	**(3.80)**	(3.02)	26	**(3.53)**	(3.08)	15
Foreign exchange gains (losses)	**0.26**	0.15	73	**0.10**	(0.06)	-
Settlement of unutilized take-or-pay contract	**(0.19)**	-	-	**(0.19)**	-	-
Cash netback (1)	**10.24**	16.03	(36)	**13.07**	11.96	9

(1) Refer to non–GAAP measures

Delphi continues to focus drilling on high margin, liquids-rich natural gas prospects and reducing costs in order to strengthen its operating and cash netback per boe. However, the Company's netback will continue to be impacted by swings in commodity prices and the realized gains or losses on the Company's risk management contracts. In the fourth quarter of 2018, Delphi's cash netback per boe decreased 36 percent primarily due to the significant drop in market prices for field condensate and realized losses on the Company's risk management contracts partially offset by lower royalties, operating and transportation costs. Delphi's cash netback for 2018 increased nine percent in comparison to 2017 as the Company received an overall higher average price for its products, realized higher marketing income and cost reduction initiatives partially offset by realized losses on risk management contracts and higher interest charges.

LIQUIDITY AND CAPITAL RESOURCES

As an oil and natural gas business, Delphi has a declining asset base and therefore relies on oil and natural 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 operations, 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. The Company's financial liabilities arise through the cost of operations and the capital program in order to maintain or increase production and develop reserves, the acquisition of crude oil and natural gas assets, financial instrument contracts, issuance of senior secured notes and borrowings under the Company's credit facilities.

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 adjusted funds flow 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 expenditure programs. There can be no assurance that future debt financings, equity financings or cash generated from operations will be available or sufficient to meet these or other corporate requirements. If debt or equity financing is available, there is no assurance 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 (deflationary) pressures on service costs. Volatility in crude oil and natural gas prices continues to result in a challenging environment for the energy sector. Delphi continuously monitors commodity prices and has an active commodity price risk management program in order to reduce its exposure to fluctuations in commodity prices and protect its future cash flows. On November 9, 2018, Delphi issued $15.0 million principal amount of ten percent senior secured notes (the "Additional Notes"). The Additional Notes were issued under the same indenture as the existing senior secured notes and collectively are treated as a single class of debt securities with identical terms. Proceeds were used to temporarily repay a portion of Delphi's outstanding bank indebtedness, providing Delphi with financial flexibility on its senior credit facility in order to fund a portion of its 2018 and 2019 capital program.

Net Debt

	December 31, 2018	December 31, 2017
Long term debt	**66,742**	26,878
Senior secured notes (1)	**100,099**	83,642
Long term portion of unutilized take-or-pay contract	**217**	867
Working capital deficiency	**14,927**	25,034
Net debt(2)(3)	**181,985**	136,421

(1) $105.0 million principal amount of senior secured notes outstanding as at December 31, 2018.
(2) Net debt excludes $7.5 million and $7.3 million as at December 31, 2018 and December 31, 2017, respectively, of outstanding letters of credit
(3) Refer to non-GAAP measures

As at December 31, 2018, Delphi had $66.7 million outstanding in bank debt, $100.1 million in senior secured notes, $0.2 million in the long term portion of an unutilized take-or-pay contract and a working capital deficit of $15.0 million for net debt of $182.0 million. As at December 31, 2018, Delphi had $30.8 million (net of outstanding letters of credit) available to be drawn on the senior credit facility.

Senior Credit Facility

During the fourth quarter of 2018, Delphi's lenders completed the semi-annual review of the Company's senior credit facility and maintained the borrowing base at $105.0 million. The facility is a 364 day committed facility available on a revolving basis until May 28, 2019 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 would be required to be repaid at the end of the non-revolving term being May 29, 2020. The non-extension provisions are applicable to the lenders on an individual basis. 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 at the time of the review. A decrease in the borrowing base could result in a reduction to the credit facility, which may require a repayment to the lenders within 60 days.

Interest payable on amounts drawn under the facility is at the prevailing bankers' acceptance or LIBOR 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 earnings before interest, taxes, depreciation and amortization ratio: from a minimum of the bank's prime rate or U.S. base rate plus 0.5 percent to a maximum of the bank's prime rate or U.S. base rate plus 2.5 percent or from a minimum of bankers' acceptances or LIBOR rate plus a stamping fee of 1.5 percent to a maximum of bankers' acceptances rate plus a stamping fee of 3.5 percent.

The senior credit facility is secured by a $200.0 million demand floating charge debenture and a general security agreement over all assets of the Company.

The senior credit facility is subject to the following financial covenants:

Financial covenant	Requirement	As at December 31, 2018
Adjusted working capital ratio	$\geq$ 1.0	1.3
Adjusted bank debt to EBITDA ratio	$\leq$ 3.0	1.4
Adjusted debt to EBITDA ratio	$\leq$ 4.0	3.2

Adjusted working capital ratio [1]	As at December 31,2018
Current assets	59,394
Exclusion of the current fair value of financial instruments	(23,784)
Undrawn portion of senior credit facility	30,765
	66,375
Current liabilities	51,347
Exclusion of the current fair value of financial instruments	(810)
	50,537
Adjusted working capital ratio	1.3x

(1) Refer to non-GAAP measures

Adjusted bank debt to EBITDA ratio [1]	As at December 31, 2018
Bank debt	66,742
Unutilized take-or-pay contract	867
Outstanding letters of credit	7,493
Adjusted bank debt	75,102
Annualized EBITDA	54,089
Adjusted bank debt to EBITDA ratio	1.4x

(1) Refer to non-GAAP measures

Adjusted debt to EBITDA ratio [1]	As at December 31, 2018
Bank debt	66,742
Unutilized take-or-pay contract	867
Outstanding letters of credit	7,493
Senior secured notes	100,099
Adjusted debt	175,201
Annualized EBITDA	54,089
Adjusted debt to EBITDA ratio	3.2x

(1) Refer to non-GAAP measures

Delphi was in compliance with all covenants as at December 31, 2018.

Senior Secured Notes

	Senior Secured Notes
Balance as at December 31, 2017	83,642
Issue of senior secured notes	15,000
Issue costs	(328)
Accretion of discount and amortization of issue costs	1,785
Balance, end of year	**100,099**

On November 9, 2018, Delphi issued an additional $15.0 million principal of senior secured notes through a private placement. The senior secured notes were issued under the same indenture as the previously existing senior secured notes and collectively are treated as a single class of debt securities with identical terms.

At December 31, 2018, Delphi had $105.0 million principal amount of ten percent senior secured notes outstanding which mature on July 15, 2021. Interest is payable quarterly in arrears on January 15, April 15, July 15 and October 15 of each year. The senior secured notes are redeemable at the Company's option, in whole or part during the twelve month period beginning on June 15 of the years indicated at the following specified redemption prices (expressed as a percentage of the principal amount): 2019 at 105 percent and 2020 and thereafter at 100 percent.

The senior secured notes are secured on a second-priority basis by substantially all of the Company's assets and are subordinate to indebtedness under the senior credit facility.

The senior secured notes are carried at amortized cost, net of transaction costs and are accreted to their principal balance at maturity using the effective interest rate method.

The senior secured notes have no financial covenants but have an incurrence covenant that limits the Company's ability to (subject to certain exceptions, limitations and qualifications) make certain restricted payments and investments; incur additional debt; create liens; make dividend or other payments; consolidate, merge sell, or otherwise dispose of all or substantially all of its assets; and enter into certain transactions with affiliates.

Share Capital

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, 2018:

	Three Months Ended December 31, 2018	Twelve Months Ended December 31, 2018
Weighted Average Common Shares (in thousands)		
Basic	185,547	185,547
Diluted	185,547	185,547
Trading Statistics (1)		
High	0.83	1.13
Low	0.36	0.36
Average daily volume (in thousands)	220	155

(1) Trading statistics based on closing price

As at March 12, 2019, the Company had 185.5 million common shares outstanding, 9.7 million stock options outstanding, and 14.7 million warrants outstanding. The stock options have an average exercise price of $1.43 per option and the warrants have an exercise price of $1.40 per warrant.

CONTRACTUAL OBLIGATIONS

The Company is committed to future minimum payments for natural gas transmission and processing and operating leases on compression equipment. The Company also has a lease for office space in Calgary, Alberta. As noted above, the senior credit facility is based on a revolving term which is reviewed semi-annually and converts to a 364 day non-revolving term facility if not renewed. The senior secured notes mature in 2021 as discussed in the Liquidity and Capital Resources section.

The future minimum commitments over the next five years ending on December 31 are as follows:

	2019	2020	2021	2022	Thereafter
Gathering, processing and transmission [(1)]	16,074	18,421	1,234	1,234	4,004
Office, equipment and software leases	574	389	397	397	672
Accounts payable and accrued liabilities	49,505	-	-	-	-
Unutilized take or pay	672	225	-	-	-
Risk management	810	350	-	-	-
Decommissioning obligations [(2)]	382	4,847	1,036	2,754	19,490
Interest payments on senior secured notes	10,500	10,500	5,688	-	-
Bank Debt	-	67,000			
Senior secured notes	-	-	105,000	-	-
Total	78,517	101,732	113,355	4,385	24,166

(1) Balances denominated in U.S. dollars have been translated at the December 31, 2018 exchange rate.
(2) Amounts represent the inflated, discounted future abandonment and reclamation expenditures anticipated to be incurred over the life of the Company's properties.

GUARANTEES AND OFF-BALANCE SHEET ARRANGEMENTS

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. On January 1, 2019, Delphi will be adopting the new IFRS 16 "Leases" standard which will require the recognition of lease assets and liabilities on the balance sheet for most leases, where the entity is acting as a lessee. See "New Accounting Standards" section of this MD&A for further information.

SELECTED INFORMATION

The following table sets forth selected consolidated financial information of the Company for the most recently completed year ended December 31, 2018 and for the years ended 2017 and 2016:

	2018	2017	2016
Crude oil and natural gas sales	**127,254**	101,836	69,135
Net earnings (loss)	**(26,366)**	6,902	(41,114)
Per share – basic and diluted	**(0.14)**	0.04	(0.26)
Total assets	**418,919**	409,522	303,625
Net debt	**181,985**	136,421	85,945

The following table summarizes the Company's financial and operating results over the past eight quarters:

	Dec 31, 2018	Sep. 30, 2018	June 30, 2018	Mar. 31, 2018	Dec. 31, 2017	Sep. 30, 2017	Jun. 30, 2017	Mar. 31, 2017
Production								
(boe conversion – 6:1 basis)								
Field condensate (bbls/d)	**2,644**	2,196	2,858	2,472	2,374	2,012	1,540	1,940
Natural gas liquids (bbls/d)	**1,289**	1,359	1,575	1,418	1,315	1,367	1,019	1,302
Natural gas (mcf/d)	**33,063**	35,751	37,141	33,747	35,391	35,603	23,551	29,737
Barrels of oil equivalent (boe/d)	**9,444**	9,514	10,623	9,515	9,588	9,313	6,484	8,198
Financial								
($ thousands, except per share)								
Crude oil and natural gas sales	**26,786**	31,399	36,394	32,675	30,896	25,107	20,162	25,671
Net earnings (loss)	**(17,318)**	1,252	(5,834)	(4,466)	(1,764)	(4,010)	4,520	8,156
Per share – basic and diluted	**(0.09)**	0.01	(0.03)	(0.02)	(0.01)	(0.02)	0.03	0.05
Adjusted funds flow(1)	**8,890**	11,600	14,697	11,428	14,144	7,596	6,964	7,970
Per share – basic and diluted(1)	**0.05**	0.06	0.08	0.06	0.08	0.04	0.04	0.05

(1) Refer to non-GAAP measures

Over the past two years, the changes in revenue and funds from operations from quarter to quarter primarily reflect the change in production and the volatility of commodity prices. Production has been impacted by processing plant outages, dispositions, production performance and new wells through successful drilling. Production volumes during the second quarter of 2017 were negatively impacted by plant outages at the SemCams K3 processing facility where the Company processed all of its Montney natural gas.

During the second quarter of 2017, the Company closed a private placement financing on June 7, 2017, that was comprised of 27,559,055 common shares issued at a price of $1.27 per common share and 30,000 senior secured notes, each with a principal amount of $1,000 and a 10% coupon, for gross proceeds of $65.0 million. Delphi used a portion of the proceeds to repay outstanding bank debt.

During the first quarter of 2018, Delphi invested $41.2 million which included the drilling of four (2.60 net) wells, completion operations on six (3.90 net) wells and the construction of its amine processing facility. Production volumes remained comparable to the fourth quarter of 2017 due to lower production declines and additional production from wells brought on-stream late in the quarter partially offsetting scheduled production outages relating to new well completion operations.

During the second quarter of 2018, Delphi's lenders completed the annual review of the Company's senior credit facility and increased the borrowing base to $105.0 million. The Company tied-in and brought on production three (1.95 net) Montney wells in the Bigstone area. Delphi commissioned its newly constructed amine facility during the second quarter which allows the Company to sweeten up to 11 mmcf/d net of Montney raw natural gas in order to process it at its 25 percent owned Bigstone sweet natural gas plant. This allows the Company the flexibility to sell its natural gas into two different natural gas markets and reduce processing fees for the sweetened natural gas. In the third quarter of 2018, Delphi invested $19.3 million, primarily on drilling four (2.60 net) Montney wells and performing completion and tie-in operations on two (1.30 net) wells in Montney.

In the fourth quarter of 2018, Delphi issued an additional $15.0 million of ten percent senior secured notes. The Additional Notes were issued under the same indenture as the existing senior secured notes. Proceeds were used to temporarily repay a portion of outstanding indebtedness. The Company invested $27.0 million in the fourth quarter of 2018, primarily on bringing three (1.95 net) wells on-stream and drilling three (1.95 net) wells of a four (2.60 net) well pad which is expected to be completed during the first quarter of 2019 and brought on production during the second quarter of 2019. As at December 31, 2018, Delphi identified indicators of impairment and performed an impairment calculation on the Company's Bigstone CGU resulting in the recognition of a $51.0 million impairment. The recoverable amount of the Bigstone CGU was based on expected future cash flows generated from proved and probable reserves using a pre-tax discount rate of approximately 12.5% plus an estimate of the fair value of the undeveloped land associated with the Bigstone CGU reserves.

Delphi's commodity risk management program continues to be an integral part of the Company's strategy to protect cash flows through to simple payout of the drilling and completions portion of its capital program.

CRITICAL ACCOUNTING ESTIMATES

The consolidated financial statements have been prepared in accordance 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) Depletion and depreciation – 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 salvage value of production equipment and facilities after the proved and probable reserves are fully produced.

ii) Recoverability of asset carrying values – Delphi's assets are aggregated into CGUs for the purpose of calculating impairment based on their ability to generate largely independent cash inflows. 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.

Management applies judgment in assessing the existence of indicators of impairment and impairment recovery based on various internal and external factors. 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 CGU's carrying value is compared to its recoverable amount, defined as the greater of its fair value less costs to sell and value in use.

In estimating the recoverable amount of a CGU, the following information is incorporated:

- 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 fluctuate widely due to global and regional factors including supply and demand fundamentals, inventory levels, exchange rates, weather, economic and geopolitical factors.
- Discount rate – Estimated future cash flows are discounted to their present value using a discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. 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 option pricing 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 be forfeited 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 income 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 net earnings (loss).

NEW ACCOUNTING STANDARDS

Effective January 1, 2018, Delphi adopted IFRS 9, Financial Instruments ("IFRS 9") replacing IAS 39, Financial Instruments: Recognition and Measurement ("IAS 39"). The adoption of IFRS 9 did not have a material impact on our consolidated financial statements.

Effective January 1, 2018, Delphi adopted IFRS 15, Revenue from Contracts with Customers ("IFRS 15") replacing IAS 11, Construction Contracts, IAS 18, Revenue and several revenue-related interpretations. The adoption of IFRS 15 did not have a material impact on our consolidated financial statements.

Further information about changes to our accounting policies resulting from the adoption of IFRS 9 and IFRS 15 can be found in Note 22 to the condensed consolidated financial statements.

In January 2016, the IASB issued IFRS 16, "Leases" ("IFRS 16"), which replaces IAS 17 Leases and IFRIC 4, "Determining Whether an Arrangement Contains a Lease". IFRS 16 requires the recognition of lease assets and liabilities on the balance sheet for most leases, where the entity is acting as a lessee. For lessees applying IFRS 16, the dual classification model of leases as either operating leases or finance leases no longer exists, effectively treating all leases as finance leases. Certain short-term leases (less than 12 months) and leases of low-value assets can be exempt from the balance sheet recognition requirements, and may continue to be treated as operating leases.

The standard will come into effect for annual periods beginning on or after January 1, 2019. IFRS 16 is required to be adopted either retrospectively or using a modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect of IFRS 16 as an adjustment to opening retained earnings and applies the standard prospectively. Delphi will elect to apply the optional exemptions for short-term and low-value leases.

The adoption of IFRS 16 will increase the Company's assets and liabilities, increase depreciation, depletion and amortization expense, increase finance costs and reduce operating and general and administrative expenses. Total cash payments over the life of the leases will remain the same. Cash payments associated with operating leases are currently presented within cash flows from operating activities. Under IFRS 16, the cash flows will be allocated between financing activities for the repayment of the principal liability and operating activities for the financing expense portion. The overall impact to cash flow will remain unchanged. Based on Delphi's review of identified contracts completed to date, the Company anticipates that it will record approximately $2.0 million of right of use assets and lease liabilities upon adoption of IFRS 16.

CORPORATE GOVERNANCE

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 eight independent directors and one officer 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, as defined in NI 52-109, 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 Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The President and Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, internal controls over financial reporting, as defined in NI 52-109, to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles applicable to the Company. The President and Chief Executive Officer and Chief Financial Officer have concluded that the Company's internal controls over financial reporting and disclosure controls and procedures are effective. The Company's internal controls over financial reporting is based on the framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 Framework).

The Company is required to disclose any change in the Company's internal control over financial reporting that occurred during the period beginning on October 1, 2018 and ended on December 31, 2018 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting. No material changes in the Company's internal control over financial reporting were identified during such period that has materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

2019 OUTLOOK

With the normalizing of the Edmonton Condensate to WTI differential (US$2.37 in February 2019) and a strong hedge book, Delphi expects to modestly grow production while modestly reducing net debt in 2019, based on current strip commodity prices. Net debt will increase in the first quarter but will be reduced to year-end 2018 levels before commencement of the capital program for the second half of 2019. The capital program for the second half will be dependent on both commodity prices and the results of the four-well pad currently being completed.

Capital Program

Delphi's capital program for the first half of 2019 will include the drilling of the fourth well on the four-well pad commenced in the fourth quarter of 2018, the completion and flow back of all four (2.60 net) wells, facility upgrades and pipeline construction to allow for the growth in production from West Bigstone. Capital spending in the first half is forecast to be about $26 million with about 30 percent being spent on facilities and pipelines.

Marketing Income

In the first half of 2019, Delphi expects to generate marketing income from its excess Alliance service similar to that of the fourth quarter of 2018. Any changes in marketing income will principally be due to changes in the basis between Chicago and AECO prices. Based on current strip prices, Delphi estimates marketing income will be about $1.4 million to $1.5 million per quarter in the first half of 2019.

Production

Production in the first quarter will be lower than the fourth quarter of 2018 as no new wells will have been brought on production since December 2018 and about 500 boe/d of production has been shut-in during the four-well pad completion. The four-well pad is scheduled to be brought on production throughout the first half of the second quarter.

Royalties

The Company pays royalties to provincial governments, individuals and companies that own surface and/or mineral rights and companies that have been granted an overriding royalty. These payments take the form of Crown, freehold and overriding royalties. Royalties are not affected by gains or losses realized through the Company's risk management program.

Delphi pays a gross overriding royalty ("GORR") of between ten and twelve percent on 20 of its Montney wells drilled between April 2013 and January 2016. Production from these wells accounted for about 23 percent of total corporate production in the fourth quarter of 2018, compared to about 40 percent in the fourth quarter of 2017. As production from these wells continue to decrease due to natural declines and new wells are brought on-stream, the proportion of wells and production subject to the GORR will continue to reduce the overall corporate royalty rate.

For the first half of 2019, Delphi expects its royalty rate, after the deduction for royalty credits and inclusion of GORRs, to average between five and six percent of gross revenue, excluding realized and unrealized gains or losses on commodity risk management contracts.

Operating Expenses

In 2019, Delphi will realize the full benefit of the amine sweetening facility which in conjunction with the Bigstone sweet natural gas plant, processes gas for about $0.95 per mcf less than the cost of third-party sour natural gas processing.

Further operating expense reductions are expected to be realized late in the second quarter of 2019 upon commissioning of the Catapult Environmental Inc. water disposal facility which will be pipeline connected to Delphi's compression and dehydration facility at 07-11-60-23W5. The combined tariff for pipeline and water disposal is less than Delphi's current average water trucking cost (a saving of about 45 percent).

Delphi expects operating expense in the first half of 2019 to be between $8.20 and $8.70 per boe.

Transportation Expenses

The contracted rates for pipeline transportation of natural gas and natural gas liquids are fixed and the rate for trucking field condensate is expected to remain unchanged in 2019. The average natural gas transportation cost per mcf is expected to remain at the current level until the Alliance lateral from the Bigstone natural gas plant is reactivated, which is expected in mid-2020, at which time the proportion of total gas sales on the Alliance system will return to approximately 90 percent of total natural gas sales volumes.

Delphi expects transportation expense in the first half of 2019 to be between $4.70 and $5.20 per boe.

General and Administrative and Finance Costs

Delphi expects general and administrative expense to remain flat in the first half of 2019.

Interest costs will increase in the first half of 2019 due to the issuance of $15 million of additional 10 percent senior secured notes on November 9, 2018 and capital spending in excess of adjusted funds flow in the first quarter of 2019.

NON GAAP MEASURES

Management uses certain measures that are not recognized under IFRS to help evaluate the performance of the Company. The following are terms and definitions contained within this MD&A that are not recognized measures under IFRS:

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.

Adjusted bank debt to EBITDA ratio – Adjusted bank debt is defined as amounts outstanding under the senior credit facility, including outstanding letters of credit. EBITDA is calculated based on the terms and definitions set out in the senior credit facility agreement which adjusts net income (loss) for financing costs, certain specific unrealized and non-cash transactions and acquisition and disposition activity. EBITDA is calculated on an annualized basis based on the last two completed quarters. This ratio is used to calculate the Company's compliance with its adjusted bank debt to EBITDA ratio covenant.

Adjusted debt to EBITDA ratio - The calculation of adjusted debt excludes accounts payable and accrued liabilities, decommissioning obligations and the fair value of financial instruments. The calculation includes outstanding letters of credit, the senior credit facility and senior secured notes. EBITDA is calculated as defined above. This ratio is used to calculate the Company's compliance with its adjusted debt to EBITDA ratio covenant.

Adjusted funds flow - cash flow from operating activities before decommissioning expenditures and changes in non-cash working capital from operating activities. Management uses adjusted funds flow 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, abandonment obligations and to repay debt. Delphi's determination of adjusted funds flow 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 (loss) or other measures of financial performance calculated in accordance with IFRS.

Adjusted funds flow per share – adjusted funds flow divided by the number of common shares outstanding calculated using weighted average shares outstanding consistent with the calculation of earnings (loss) per share.

Adjusted working capital – current assets and current liabilities exclude the current portion of the fair value of the financial instruments. This definition is consistent with the definition used in calculating the Company's compliance with its working capital ratio covenant and is used by the Company in determining its net debt.

Adjusted working capital ratio – current assets include the undrawn portion of the senior credit facility, less outstanding letters of credit, and exclude the current portion of the fair value of financial instruments. Current liabilities exclude the current portion of long term debt and the current portion of the fair value of financial instruments. This ratio is used to calculate the Company's compliance with its working capital ratio covenant.

Cash flow from operating activities per share – cash flow from operating activities divided by the number of common shares outstanding calculated using weighted average shares outstanding consistent with the calculation of earnings (loss) per share.

Marketing income - the margin earned on the sale of purchased third party natural gas volumes and premiums received on the assignment of capacity on the Alliance pipeline system to a third party. Management considers marketing income important measures of the Company's ability to mitigate the cost of excess committed capacity.

Net debt – the sum of bank debt, senior secured notes and the long term portion of unutilized take-or-pay contract plus (minus) the adjusted working capital deficit (surplus). Net debt is used by management to monitor the remaining availability under its credit facilities.

Management considers netbacks as an important measure of the cash generating capability of the produced volumes. Netbacks are generally discussed and presented on a per boe basis.

Operating netbacks – crude oil and natural gas sales plus realized gains (losses) on financial instruments and marketing income less royalties, operating and transportation costs. Management considers operating netbacks per boe an important measure of profitability relative to current commodity prices and costs of production.

Cash netbacks - operating netbacks less interest on bank debt and senior secured notes, general and administrative costs, cash costs related to the Company's restricted share units and the settlement of the unutilized take-or-pay contract. Management considers cash netbacks per boe an important measure as it demonstrates the cash realized on each unit of production to be reinvested in future capital investment or repay debt.

FORWARD-LOOKING STATEMENTS

This management discussion and analysis contains forward-looking statements and forward-looking information within the meaning of applicable Canadian securities laws. These statements relate to future events or the Company's future performance and are based upon the Company's internal assumptions and expectations. All statements other than statements of present or historical fact are forward-looking statements. Forward-looking statements are often, but not always, identified by the use of any of the words "expect", "anticipate", "continue", "estimate", "may", "will", "should", "believe", "intends", "forecast", "plans", "guidance", "budget" and similar expressions.

More particularly and without limitation, this management discussion and analysis contains forward-looking statements and information relating to petroleum and natural gas production estimates and weighting, projected crude oil and natural gas prices, future exchange rates, expectations as to royalty rates, expectations as to transportation and operating costs, expectations as to general and administrative costs and interest expense, expectations as to capital expenditures and net debt, planned capital spending, future liquidity and Delphi's ability to fund ongoing capital requirements through operating cash flows and its credit facilities, estimated tax pools and expectations regarding current income taxes payable by Delphi in 2018, supply and demand fundamentals for oil and gas commodities, timing and success of development and exploitation activities, cash availability for the financing of capital expenditures, access to third-party infrastructure, treatment under governmental regulatory regimes and tax laws and future environmental regulations.

Furthermore, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions that the reserves described can be profitable in the future.

The forward-looking statements and information contained in this management discussion and analysis are based on certain key expectations and assumptions made by Delphi. The following are certain material assumptions on which the forward-looking statements and information contained in this management discussion and analysis are based: the stability of the global and national economic environment, the stability of and commercial acceptability of tax, royalty and regulatory regimes applicable to Delphi, exploitation and development activities being consistent with management's expectations, production levels of Delphi being consistent with management's expectations, the absence of significant project delays, the stability of oil and gas prices, the absence of significant fluctuations in foreign exchange rates and interest rates, the stability of costs of oil and gas development and production in Western Canada, including operating costs, the timing and size of development plans and capital expenditures, availability of third party infrastructure for transportation, processing or marketing of oil and natural gas volumes, prices and availability of oilfield services and equipment being consistent with management's expectations, the availability of, and competition for, among other things, pipeline capacity, skilled personnel and drilling and related services and equipment, results of development and exploitation activities that are consistent with management's expectations, the availability of capital, weather affecting Delphi's ability to develop and produce as expected, contracted parties providing goods and services on the agreed timeframes, Delphi's ability to manage environmental risks and hazards and the cost of complying with environmental regulations, the accuracy of operating cost estimates, the accurate estimation of oil and gas reserves, future exploitation, development and production results and Delphi's ability to market oil and natural gas successfully to current and new customers. Additionally, estimates as to expected average annual production rates assume that no unexpected outages occur in the infrastructure that the Company relies on to produce its wells, that existing wells continue to meet production expectations and any future wells scheduled to come on in the coming year meet timing and production expectations.

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.

Financial outlook information contained in this management discussion and analysis about prospective results of operations, financial position or cash flows is based on assumptions about future events, including economic conditions and proposed courses of action, based on management's assessment of the relevant information currently available. This financial outlook is included to provide readers with an understanding of the Company's operations for 2019 and readers are cautioned that such financial outlook information contained in this management discussion and analysis should not be used for purposes other than for which it is disclosed.

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 and such forward-looking statements should not be unduly relied upon. Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent known and unknown risks and uncertainties. Delphi's actual results, performance or achievements could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits Delphi will derive therefrom. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary 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 risks, environmental risks, competition from others for scarce resources, the inability to access sufficient capital from internal and external sources, adverse changes in governmental regulation of the oil and gas industry and adverse 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 the Company's most recent Annual Information Form and other reports on file with the applicable securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com).

Readers are cautioned that the foregoing list of factors is not exhaustive. Furthermore, the forward-looking statements contained in this MD&A are made as of the date of this MD&A 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. The forward-looking statements contained in this management discussion and analysis are expressly qualified in their entirety by this cautionary statement.