FINANCIAL AND OPERATING SUMMARY

($000s except per share amounts)

	Three Months Ended			Years Ended December 31,		
	Dec 31, 2019	Sep 30, 2019	% Change	**2019**	2018[2]	% Change
Financial highlights						
Oil sales	**86,905**	93,818	(7)%	**376,238**	285,378	32 %
NGL sales	**2,076**	1,958	6 %	**8,109**	11,022	(26)%
Natural gas sales	**2,808**	1,250	125 %	**10,002**	8,147	23 %
Total oil, natural gas, and NGL revenue	**91,789**	97,026	(5)%	**394,349**	304,547	29 %
Cash flow from operating activities	**34,474**	40,228	(14)%	**149,417**	121,907	23 %
Per share - basic ($)	**0.11**	0.13	(15)%	**0.47**	0.50	(6)%
Adjusted funds flow[1]	**38,881**	41,513	(6)%	**172,988**	113,651	52 %
Per share - basic ($)[1]	**0.12**	0.13	(8)%	**0.55**	0.46	20 %
Net loss	**(143,801)**	(4,269)	3,268 %	**(158,664)**	(71,533)	122 %
Per share basic ($)	**(0.44)**	(0.01)	4,300 %	**(0.50)**	(0.29)	72 %
Total exploration and development expenditures	**30,760**	22,247	38 %	**119,465**	120,552	(1)%
Total acquisitions & dispositions	**2,458**	12,077	(80)%	**(42,438)**	327,765	(113)%
Total capital expenditures	**33,218**	34,324	(3)%	**77,027**	448,317	(83)%
Net debt[1], end of period	**382,309**	377,409	1 %	**382,309**	461,187	(17)%
Operating highlights						
Production:						
Oil (bbls per day)	**16,441**	17,170	(4)%	**17,127**	13,992	22 %
NGLs (bbls per day)	**630**	769	(18)%	**692**	623	11 %
Natural gas (mcf per day)	**19,521**	19,668	(1)%	**20,135**	20,658	(3)%
Total (boe per day) (6:1)	**20,325**	21,217	(4)%	**21,175**	18,058	17 %
Average realized price (excluding hedges):						
Oil ($ per bbl)	**57.46**	59.39	(3)%	**60.19**	55.88	8 %
NGL ($ per bbl)	**35.84**	27.69	29 %	**32.09**	48.51	(34)%
Natural gas ($ per mcf)	**1.56**	0.69	126 %	**1.36**	1.08	26 %
Netback ($ per boe)						
Petroleum and natural gas revenue	**49.09**	49.71	(1)%	**51.02**	46.21	10 %
Realized gain (loss) on commodity and FX contracts	**0.13**	(0.86)	(115)%	**(0.61)**	(1.67)	(63)%
Royalties	**(7.00)**	(7.12)	(2)%	**(6.71)**	(6.55)	2 %
Net operating expenses[1]	**(14.91)**	(13.93)	7 %	**(14.50)**	(14.76)	(2)%
Transportation expenses	**(1.40)**	(1.42)	(1)%	**(1.54)**	(1.50)	3 %
Operating netback[1]	**25.91**	26.38	(2)%	**27.66**	21.73	27 %
G&A expense	**(1.95)**	(1.81)	8 %	**(1.85)**	(2.01)	(8)%
Interest expense	**(3.16)**	(3.31)	(5)%	**(3.45)**	(2.47)	40 %
Adjusted funds flow[1]	**20.80**	21.26	(2)%	**22.36**	17.25	30 %
Common shares outstanding, end of period	**326,330**	324,215	1 %	**326,330**	309,286	6 %
Weighted average basic shares outstanding	**324,836**	318,076	2 %	**316,639**	246,252	29 %
Stock option dilution	**—**	—	— %	**—**	—	— %
Weighted average diluted shares outstanding	**324,836**	318,076	2 %	**316,639**	246,252	29 %

1 This is a non-GAAP financial measure which is defined in the Non-GAAP Financial Measures section of this document.
2 IFRS 16 was adopted January 1, 2019 using the modified retrospective approach and as such, comparative information for 2018 that may have been impacted has not been restated. Refer to the Changes in Accounting Policies section of this MD&A for additional information.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") of the consolidated financial position and results of operations of Surge Energy Inc. ("Surge" or the "Company"), which includes its subsidiaries and partnership arrangements, is for the three months and years ended December 31, 2019 and 2018. For a full understanding of the financial position and results of operations of the Company, the MD&A should be read in conjunction with the documents filed on SEDAR, including historical financial statements, MD&A and the Annual Information Form ("AIF"). These documents are available at www.sedar.com.

Surge's management is responsible for the integrity of the information contained in this report and for the consistency between the MD&A and financial statements. In the preparation of these financial statements, estimates are necessary to make a determination of future values for certain assets and liabilities. Management believes these estimates have been based on careful judgments and have been properly presented. The financial statements have been prepared using policies and procedures established by management and fairly reflect Surge's financial position and results of operations. Surge's financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS").

Surge's Board of Directors and Audit Committee have reviewed and approved the financial statements and MD&A. This MD&A is dated March 9, 2020.

DESCRIPTION OF BUSINESS

Surge is a Calgary based exploration & production company that is engaged in the business of acquiring and developing operated oil-weighted properties. Surge will continue to identify and actively pursue strategic acquisitions with synergistic characteristics such as existing long life producing assets or opportunities with significant, low risk upside potential. Surge's common shares are traded on the Toronto Stock Exchange ("TSX") under the symbol SGY.

CASH FLOW FROM OPERATING ACTIVITIES AND ADJUSTED FUNDS FLOW

	Three Months Ended			Years Ended	
($000s except per share and per boe)	**Dec 31, 2019**	Sep 30, 2019	Dec 31, 2018	**Dec 31, 2019**	Dec 31, 2018
Cash flow from operating activities	**34,474**	40,228	26,770	**149,417**	121,907
Per share - basic ($)	**0.11**	0.13	0.09	**0.47**	0.50
Per share - diluted ($)	**0.11**	0.13	0.09	**0.47**	0.50
$ per boe	**18.44**	20.61	13.82	**19.33**	18.50
Adjusted funds flow	**38,881**	41,513	6,249	**172,988**	113,651
Per share - basic ($)	**0.12**	0.13	0.02	**0.55**	0.46
Per share - diluted ($)	**0.12**	0.13	0.02	**0.55**	0.46
$ per boe	**20.80**	21.26	3.23	**22.36**	17.24

Cash flow from operating activities and adjusted funds flow for the fourth quarter of 2019 decreased when compared to the immediate preceding quarter primarily due to a decrease in petroleum and natural gas revenue. The increase in cash flow from operating activities and adjusted funds flow for the three months and year ended December 31, 2019 when compared to the same periods of the prior year is primarily due to the increase in petroleum and natural gas revenue and the Mount Bastion Oil & Gas Corp. ("MBOG") acquisition in the fourth quarter of 2018.

See the following Operations section for additional information regarding the cash flow and operating results of the Company for the three months and year ended December 31, 2019 and see the Non-GAAP Financial Measures section of this MD&A for further information regarding adjusted funds flow.

OPERATIONS

Drilling

	Drilling		Success rate (%) net	Working interest (%)
	Gross	Net		
Q1 2019	12.0	11.6	100%	96%
Q2 2019	10.0	10.0	90%	100%
Q3 2019	4.0	4.0	100%	100%
Q4 2019	10.0	10.0	100%	100%
Total	**36.0**	**35.6**	**97%**	**99%**

Surge achieved a 97 percent success rate during the year ended December 31, 2019, drilling 36 gross (35.6 net) wells. During the fourth quarter of 2019, Surge drilled nine gross (9.0 net) wells in southeast Alberta ("Sparky") and one gross (1.0 net) well at Valhalla.

Production

	Three Months Ended			Years Ended	
	Dec 31, 2019	Sep 30, 2019	Dec 31, 2018	**Dec 31, 2019**	Dec 31, 2018
Oil (bbls per day)	**16,441**	17,170	16,578	**17,127**	13,992
NGL (bbls per day)	**630**	769	703	**692**	623
Oil and NGL (bbls per day)	**17,071**	17,939	17,281	**17,819**	14,615
Natural gas (mcf per day)	**19,521**	19,668	22,598	**20,135**	20,658
Total (boe per day) (6:1)	**20,325**	21,217	21,047	**21,175**	18,058
% Oil and NGL	**84%**	85%	82%	**84%**	81%

Surge achieved production of 20,325 boe per day in the fourth quarter of 2019 (84 percent oil and NGLs), a four percent decrease compared to the third quarter of 2019 and a three percent decrease from the average production rate in the fourth quarter of 2018.

During the year ended December 31, 2019, Surge achieved production of 21,175 boe per day (84 percent oil and NGLs), a 17 percent increase when compared to the same period of 2018.

The decrease in production during the fourth quarter of 2019 as compared to the third quarter of 2019 is primarily the result of natural declines more than offsetting production additions from the Company's 2019 drilling program. Additionally, permanent closure of a third party gas processing facility resulted in a 350 boe per day decrease in one of the Company's non-core areas in the fourth quarter of 2019.

The increase in Surge's production for the year ended December 31, 2019 as compared to the same period of the prior year is primarily due to the fourth quarter 2018 acquisition of MBOG in combination with successful 2018 and 2019 drilling programs. Approximately 5,000 boe per day of production is attributable to the MBOG assets for the three months and year ended December 31, 2019 (4,000 boe per day and 1,000 boe per day for the three months and year ended December 31, 2018, respectively). The increase is partially offset by approximately 500 boe per day of sold production associated with a disposition of non-core assets in Northwest Alberta, which closed on March 28, 2019.

Petroleum and Natural Gas Revenue, Realized Prices and Benchmark Pricing

	Three Months Ended			Years Ended	
($000s except per amount)	**Dec 31, 2019**	Sep 30, 2019	Dec 31, 2018	**Dec 31, 2019**	Dec 31, 2018
Petroleum and Natural Gas Revenue					
Oil	**86,905**	93,818	51,424	**376,238**	285,378
NGL	**2,076**	1,958	2,477	**8,109**	11,022
Oil and NGL	**88,981**	95,776	53,901	**384,347**	296,400
Natural gas	**2,808**	1,250	4,226	**10,002**	8,147
Total petroleum and natural gas revenue	**91,789**	97,026	58,127	**394,349**	304,547
Realized Prices					
Oil ($ per bbl)	**57.46**	59.39	33.72	**60.19**	55.88
NGL ($ per bbl)	**35.84**	27.69	38.28	**32.09**	48.51
Oil and NGL ($ per bbl)	**56.66**	58.04	33.90	**59.09**	55.57
Natural gas ($ per mcf)	**1.56**	0.69	2.03	**1.36**	1.08
Total petroleum and natural gas revenue before realized commodity and FX contracts ($ per boe)	**49.09**	49.71	30.02	**51.02**	46.21
Benchmark Prices					
WTI (US$ per bbl)	**56.96**	56.45	58.81	**57.03**	64.77
CAD/USD exchange rate	**1.32**	1.32	1.32	**1.33**	1.30
WTI (C$ per bbl)	**75.19**	74.51	77.63	**75.85**	84.20
Edmonton Light Sweet (C$ per bbl)	**67.97**	68.20	42.76	**69.04**	69.37
WCS (C$ per bbl)	**54.30**	58.39	25.37	**58.78**	49.69
AECO Daily Index (C$ per mcf)	**2.48**	0.91	1.56	**1.76**	1.50

Total petroleum and natural gas revenue for the fourth quarter of 2019 decreased five percent as compared to the third quarter of 2019. The decrease is primarily due a four percent decrease in production and a slight widening of the WCS crude oil differential throughout the period resulting in a three percent decrease in average realized oil prices. This decrease correlates to the seven percent decrease in WCS during the same period.

Total petroleum and natural gas revenue for the fourth quarter of 2019 increased 58 percent when compared to the same period of 2018. The increase is primarily due to a 70 percent increase in average realized oil price as the result of narrowing differentials when compared to the fourth quarter of 2018. This increase correlates to the 59 percent increase in Edmonton light sweet and 114 percent increase in WCS compared to the same period of 2018. The average realized price increase was partially offset by the three percent decrease in production compared to the fourth quarter of 2018.

Total petroleum and natural gas revenue for the year ended December 31, 2019 increased 29 percent when compared to the same period of 2018. The increase is primarily due to a 17 percent increase in production during the period and an eight percent increase in average realized oil prices. The increase in average realized oil prices correlates to the 18 percent increase in WCS benchmark pricing, while Edmonton light sweet remained consistent when compared to 2018, which aligns with the Company's 2019 production weighting as approximately 50 percent of Surge's oil production is sold at the WCS price and 50 percent at Edmonton light sweet. Additionally, the Company realized a 26 percent increase in average natural gas prices during the period as a result of the Company’s ability to secure firm transport on the Alliance pipeline to Chicago.

ROYALTIES

	Three Months Ended			Years Ended	
($000s except per boe)	**Dec 31, 2019**	Sep 30, 2019	Dec 31, 2018	**Dec 31, 2019**	Dec 31, 2018
Royalties	**13,096**	13,892	7,478	**51,837**	43,203
% of petroleum and natural gas revenue	**14%**	14%	13%	**13%**	14%
$ per boe	**7.00**	7.12	3.86	**6.71**	6.55

As royalties are sensitive to both commodity prices and production levels, the corporate royalty rates will fluctuate with commodity prices, well production rates, production decline of existing wells, and performance and geographic location of new wells drilled.

Royalties as a percentage of revenue for the three months ended December 31, 2019 is comparable to the immediate preceding quarter. Royalties as a percentage of revenue for the three months ended December 31, 2019 increased slightly compared to the same period of the prior year primarily as a result of the disposal of a 1.7 percent gross overriding royalty ("GORR") at the end of the second quarter of 2019. This increase was partially offset by a royalty credit earned under the Saskatchewan Petroleum Research Incentive program for gas conservation projects of which a combined $1.0 million was recognized in the third and fourth quarters of 2019.

Royalties as a percentage of revenue for the year ended December 31, 2019 decreased as compared to the same periods of the prior year. In an increasing crude oil pricing environment, the decrease is primarily due to lower royalties on new production, which qualified for various royalty incentives, along with the Saskatchewan royalty credit as noted above.

NET OPERATING EXPENSES

	Three Months Ended			Years Ended	
($000s except per boe)	**Dec 31, 2019**	Sep 30, 2019	Dec 31, 2018	**Dec 31, 2019**	Dec 31, 2018
Operating expenses	**29,448**	28,680	30,985	**116,338**	100,108
Less processing and other income	**(1,564)**	(1,483)	(575)	**(4,303)**	(2,818)
Net operating expenses	**27,884**	27,197	30,410	**112,035**	97,290
$ per boe	**14.91**	13.93	15.70	**14.50**	14.76

Net operating expenses per boe for the fourth quarter of 2019 increased seven percent when compared to the immediate preceding quarter. The increase is primarily attributable to a four percent decrease in production in addition to higher repairs and maintenance costs incurred in anticipation of colder weather throughout the Company's operating areas in the first quarter of 2020.

Net operating expenses per boe during the three months and year ended December 31, 2019 decreased five percent and two percent, respectively, when compared to the same periods of the prior year, however, 2019 includes the impact of adopting IFRS 16. During the three months and year ended December 31, 2019, approximately $2.5 million and $8.5 million, respectively, of equipment rental payments were classified as leases under IFRS 16 and no longer included in net operating expenses. For comparability purposes, excluding the impact of IFRS 16, net operating expenses per boe would have been approximately $16.24 and $15.59 during the three months and year ended December 31, 2019.

Excluding the impact of IFRS 16, net operating expenses per boe during the three months and year ended December 31, 2019 increased three percent and six percent, respectively, when compared to the same periods of the prior year. The increase is primarily attributable to the acquisition of MBOG during the fourth quarter of 2018. The acquired operating fields historically averaged greater than $17.00 per boe. The increase in net operating expenses per boe was partially offset by additional processing income earned following the acquisition of a gas processing plant in the Company's Sparky core area in the third quarter of 2019.

TRANSPORTATION EXPENSES

	Three Months Ended			Years Ended	
($000s except per boe)	**Dec 31, 2019**	Sep 30, 2019	Dec 31, 2018	**Dec 31, 2019**	Dec 31, 2018
Transportation expenses	**2,624**	2,763	2,971	**11,866**	9,878
$ per boe	**1.40**	1.42	1.53	**1.54**	1.50

Transportation expenses per boe for the fourth quarter of 2019 is comparable to the immediate preceding quarter and decreased eight percent when compared to the same period of the prior year as a result of the Company's continued focus of its drilling program in areas with existing pipeline infrastructure.

Transportation expenses per boe during the year ended December 31, 2019 increased three percent when compared to the same period of the prior year due to additional costs associated with a firm transportation commitment to ship a portion of Surge's associated gas production on the Alliance pipeline to Chicago that commenced in the fourth quarter of 2018.

GENERAL AND ADMINISTRATIVE EXPENSES (G&A)

	Three Months Ended			Years Ended	
($000s except per boe)	**Dec 31, 2019**	Sep 30, 2019	Dec 31, 2018	**Dec 31, 2019**	Dec 31, 2018
G&A expenses	**4,805**	4,787	4,948	**19,445**	18,672
Recoveries and capitalized amounts	**(1,165)**	(1,262)	(1,397)	**(5,158)**	(5,444)
Net G&A expenses	**3,640**	3,525	3,551	**14,287**	13,228
Net G&A expenses $ per boe	**1.95**	1.81	1.83	**1.85**	2.01

Net G&A expenses per boe for the fourth quarter of 2019 increased eight percent as compared to the third quarter of 2019 and increased seven percent compared to the same period of the prior year. The increase in net G&A per boe is primarily attributable to the decrease in production.

Net G&A expenses per boe for the year ended December 31, 2019 decreased eight percent when compared to the prior year. The decrease in net G&A expenses per boe is primarily the result of the synergistic acquisition of MBOG in the fourth quarter of 2018 in which the Company had appropriate staff and systems in place to absorb the acquired production in addition to moderately lower rent expense due to the adoption of IFRS 16.

TRANSACTION AND OTHER COSTS

	Three Months Ended			Years Ended	
($000s except per boe)	**Dec 31, 2019**	Sep 30, 2019	Dec 31, 2018	**Dec 31, 2019**	Dec 31, 2018
Transaction and other costs	**(1,200)**	481	3,504	**173**	5,288
$ per boe	**(0.64)**	0.25	1.81	**0.02**	0.80

During the year ended December 31, 2019, the Company incurred transaction and other costs related to an asset acquisition in Southeast Alberta that closed in August 2019, a non-core asset disposition in Northwest Alberta that closed in March 2019 and a disposal of a 1.7 percent GORR that closed in the second quarter of 2019, in addition to severance costs. During the fourth quarter of 2019, the Company unwound an other long term obligation that resulted in a $1.3 million gain recognized in transaction and other costs.

Transaction and other costs during the year ended December 31, 2018 primarily related to the acquisition of MBOG that closed during the fourth quarter of 2018 and the second quarter 2018 Sparky area asset acquisition, in addition to severance costs.

FINANCE EXPENSES

	Three Months Ended			Years Ended	
($000s except per boe)	**Dec 31, 2019**	Sep 30, 2019	Dec 31, 2018	**Dec 31, 2019**	Dec 31, 2018
Interest on bank debt	**3,778**	4,658	4,281	**19,838**	13,254
$ per boe	**2.02**	2.39	2.21	**2.57**	2.01
Interest on convertible debentures	**1,206**	1,222	640	**4,052**	2,559
$ per boe	**0.64**	0.63	0.33	**0.52**	0.39
Interest on lease and other obligations	**814**	477	118	**2,419**	476
$ per boe	**0.44**	0.24	0.06	**0.31**	0.07
Realized loss on interest contracts	**113**	105	—	**348**	—
$ per boe	**0.06**	0.05	—	**0.05**	—
Total interest expense	**5,911**	6,462	5,039	**26,657**	16,289
$ per boe	**3.16**	3.31	2.60	**3.45**	2.47
Accretion expense	**1,803**	1,704	1,700	**6,750**	5,764
$ per boe	**0.96**	0.87	0.88	**0.87**	0.87
Unrealized loss (gain) on interest contracts	**(1,608)**	(197)	—	**1,556**	—
$ per boe	**(0.86)**	(0.10)	—	**0.20**	—
Total finance expense	**6,106**	7,969	6,739	**34,963**	22,053
$ per boe	**3.27**	4.08	3.48	**4.52**	3.35

Total interest expense for the fourth quarter of 2019 decreased nine percent as compared to the immediate preceding quarter primarily due to a lower average bank debt level during the period, partially offset by an increase in interest on lease and other obligations related to a sale-leaseback arrangement entered into during the third quarter of 2019.

The increase in interest expense for the three months and year ended December 31, 2019 as compared to the same period of 2018 is due to higher average bank debt during the period as a result of the MBOG acquisition and interest expense related to lease obligations following the adoption of IFRS 16. Interest expense for the year ended December 31, 2019 was further impacted by incremental accrued interest related to the second quarter 2019 convertible debenture issuance.

Total finance expense includes accretion, representing the change in the time value of the decommissioning liability, convertible debentures and firm transportation agreements as well as unrealized gains and losses on financial interest contracts. Accretion expense for the fourth quarter of 2019 increased as compared to the third quarter of 2019 and accretion expense for the three months and year ended December 31, 2019 increased as compared to the same periods of 2018 primarily due to the decommissioning liabilities associated with the MBOG acquisition during the fourth quarter of 2018.

NETBACKS

	Three Months Ended			Years Ended	
($ per boe, except production)	**Dec 31, 2019**	Sep 30, 2019	Dec 31, 2018	**Dec 31, 2019**	Dec 31, 2018
Average production (boe per day)	**20,325**	21,217	21,047	**21,175**	18,058
Petroleum and natural gas revenue	**49.09**	49.71	30.02	**51.02**	46.21
Realized gain (loss) on commodity and FX contracts	**0.13**	(0.86)	(1.25)	**(0.61)**	(1.67)
Royalties	**(7.00)**	(7.12)	(3.86)	**(6.71)**	(6.55)
Net operating expenses	**(14.91)**	(13.93)	(15.70)	**(14.50)**	(14.76)
Transportation expenses	**(1.40)**	(1.42)	(1.53)	**(1.54)**	(1.50)
Operating netback	**25.91**	26.38	7.68	**27.66**	21.73
G&A expense	**(1.95)**	(1.81)	(1.83)	**(1.85)**	(2.01)
Interest expense	**(3.16)**	(3.31)	(2.60)	**(3.45)**	(2.47)
Adjusted funds flow	**20.80**	21.26	3.25	**22.36**	17.25

Please refer to the respective sections of the MD&A for a detailed explanation of the changes to the netback as compared to prior periods.

STOCK-BASED COMPENSATION

	Three Months Ended			Years Ended	
($000s except per boe)	**Dec 31, 2019**	Sep 30, 2019	Dec 31, 2018	**Dec 31, 2019**	Dec 31, 2018
Stock-based compensation	**1,749**	5,224	1,743	**10,582**	9,957
Capitalized stock-based compensation	**(678)**	(2,210)	(775)	**(4,303)**	(3,548)
Net stock-based compensation	**1,071**	3,014	968	**6,279**	6,409
Net stock-based compensation $ per boe	**0.57**	1.54	0.50	**0.81**	0.97

Net stock-based compensation expense for the fourth quarter of 2019 decreased 64 percent compared to the immediate preceding quarter and was comparable to the fourth quarter of 2018. The decrease in net stock-based compensation is primarily the result of a $1.6 million PSA performance multiplier adjustment for awards that vested in the third quarter of 2019.

Net stock-based compensation expense for the fourth quarter of 2019 increased $0.1 million when compared to the fourth quarter of 2018.

Net stock-based compensation expense for the year ended December 31, 2019 decreased two percent as compared to the same period of the prior year. The decrease in net stock-based compensation expense for the year ended December 31, 2019 is primarily the result of a stock appreciation rights exercised during the fourth quarter of 2018 with an associated stock-based compensation expense of $0.7 million, partially offset by the $1.6 million PSA performance multiplier adjustment for awards that vested in the third quarter of 2019 as compared to a $1.3 million PSA multiplier adjustment in the third quarter of 2018.

The stock-based compensation recorded in the year ended December 31, 2019 relates to the restricted share awards ("RSAs") and performance share awards ("PSAs") grants. Subject to terms and conditions of the plan, each RSA entitles the holder to an award value not limited to, but typically paid as to one-third on each of the first, second and third anniversaries of the date of grant. Each PSA entitles the holder to an award value to be typically paid on the third anniversary of the date of grant. For the purpose of calculating share-based compensation, the fair value of each award is determined at the grant date using the closing price of the common shares. A weighted average forfeiture rate of 7% for PSAs and 8% for RSAs was used to value all awards granted for the year ended December 31, 2019. The weighted average fair value of awards granted for the year ended December 31, 2019 is $1.04 per PSA and $1.05 per RSA. In the case of PSAs, the award value is adjusted for a payout multiplier which can range from 0.0 to 2.0 and is dependent on the performance of the Company relative to pre-defined corporate performance measures for a particular period.

The number of restricted and performance share awards outstanding are as follows:

	Number of restricted share awards	Number of performance share awards
Balance at December 31, 2018	3,889,902	5,316,079
Granted	3,733,676	3,819,002
Reinvested [(1)]	359,976	477,184
Added by performance factor	—	1,645,004
Exercised	(1,992,880)	(3,202,278)
Forfeited	(215,080)	(452,658)
Balance at December 31, 2019	**5,775,594**	**7,602,333**

(1) Per the terms of the plan, cash dividends paid by the Company are reinvested to purchase incremental awards.

DEPLETION AND DEPRECIATION

	Three Months Ended			Years Ended	
($000s except per boe)	**Dec 31, 2019**	Sep 30, 2019	Dec 31, 2018	**Dec 31, 2019**	Dec 31, 2018
Depletion and depreciation expense	**39,763**	42,093	39,290	**163,450**	114,220
$ per boe	**21.27**	21.57	20.29	**21.15**	17.33

Depletion and depreciation are calculated based on total capital expenditures (including acquisitions and dispositions), production rates and proved plus probable reserves. Deducted from the Company's fourth quarter of 2019 depletion and depreciation calculation are costs associated with salvage values of $61.4 million. Future development costs for proved and probable reserves of $897.3 million have been included in the depletion calculation.

Depletion and depreciation expense for the three months ended December 31, 2019 decreased compared to the third quarter of 2019, primarily due to decreased production and an increase in depletable reserves as a result of the 2019 reserve evaluation. Depletion and depreciation expense for the three months and year ended December 31, 2019 increased as compared to the same period of 2018, primarily due to the MBOG acquisition, resulting in a larger depletable base. Additionally, in relation to the leases recognized upon adoption of IFRS 16, the Company recognized $7.3 million of depreciation charges during the year ended December 31, 2019 (2018 - $nil).

IMPAIRMENT

	Three Months Ended			Years Ended	
($000s except per boe)	**Dec 31, 2019**	Sep 30, 2019	Dec 31, 2018	**Dec 31, 2019**	Dec 31, 2018
Impairment	**180,701**	—	72,174	**180,701**	72,174
$ per boe	**96.64**	—	37.27	**23.38**	10.95

The Company identified six cash generating units ("CGUs") as of December 31, 2019 based on the lowest level at which properties generate cash inflows while applying judgment to consider factors such as shared infrastructure, geographic proximity, petroleum type and similar exposures to market risk and materiality. The Company's CGUs at December 31, 2019 were geographically labeled Northwest Alberta, North Central Alberta, Northeast Alberta, Central Alberta, Southeast Alberta and Southwest Saskatchewan.

For the year ended December 31, 2019, due to declines in forward oil and natural gas prices and poor economic performance of certain assets, the Company determined an indication of potential impairment was present in its North Central Alberta, Northwest Alberta, Southwest Saskatchewan and Central Alberta CGUs. As a result, the Company completed an impairment test. Recoverable value was estimated at value in use based on before tax discounted cash flows from oil and gas proved plus probable reserves estimated by the Company's third party reserve evaluators. It was determined that the carrying value of the North Central Alberta CGU exceeded the recoverable amount of $206.9 million, the carrying value of the Southwest Saskatchewan CGU exceeded the recoverable amount of $185.6 million, and the carrying value of the Central Alberta CGU exceeded the recoverable amount of $46.7 million and a $180.7 million impairment was recognized. The before tax discount rate applied in the value in use calculation as at December 31, 2019 was 13 - 25 percent.

As at December 31, 2019, the Company determined there were no indications that impairment losses recognized in prior years no longer exist or have decreased.

The following table outlines forecast commodity prices and exchange rates used in the Company’s CGU impairment tests at December 31, 2019. The forecast commodity prices are consistent with those used by the Company’s external reserve evaluators and are a key assumption in assessing the recoverable amount. The reserve evaluators also include financial assumptions regarding royalty rates, operating costs, and future development capital that can significantly impact the recoverable amount which are assigned based on historic rates and future anticipated activities by Management.

	Medium and Light Crude Oil		Natural Gas	NGL				
Year	Canadian Light Sweet Crude 40˚ API ($/bbl)	Western Canadian Select 20.5˚ API ($/bbl)	AECO Gas Price ($/MMBtu)	Edmonton Condensate ($/bbl)	Edmonton Butane ($/bbl)	Edmonton Propane ($/bbl)	Inflation rates (%/Yr)	Exchange rate ($US/$Cdn)
2020	73.84	59.81	2.04	76.32	37.72	25.07	—	0.76
2021	78.51	63.98	2.27	80.52	43.90	31.84	1.0	0.77
2022	78.73	63.77	2.81	80.00	47.74	32.43	2.0	0.80
2023	80.30	65.04	2.89	81.68	48.69	33.26	2.0	0.80
2024	81.91	66.34	2.98	83.38	49.67	34.12	2.0	0.80
2025	83.54	67.67	3.06	85.13	50.66	34.99	2.0	0.80
2026	85.21	69.02	3.15	86.90	51.67	35.88	2.0	0.80
2027	86.92	70.40	3.24	88.72	52.71	36.78	2.0	0.80
2028	88.66	71.81	3.33	90.57	53.76	37.71	2.0	0.80
2029	90.43	73.25	3.42	92.45	54.84	38.65	2.0	0.80
2030	92.24	74.71	3.51	94.38	55.93	39.61	2.0	0.80

The results of the Company's impairment tests are sensitive to changes in any of the key estimates of which changes could decrease or increase the recoverable amounts of assets and result in additional impairment charges or in the recovery of previously recorded impairment charges.

The Company identified six CGUs as of December 31, 2018 based on the lowest level at which properties generate cash inflows while applying judgment to consider factors such as shared infrastructure, geographic proximity, petroleum type and similar exposures to market risk and materiality. The MBOG acquisition during the year was determined to be a standalone CGU, geographically labeled North Central Alberta and the asset acquisitions in the current year were integrated into existing CGUs based on geographic location. The Company's CGUs at December 31, 2018 were geographically labeled Northwest Alberta, North Central Alberta, Northeast Alberta, Central Alberta, Southeast Alberta and Southwest Saskatchewan.

For the year ended December 31, 2018, due to poor economic performance of certain assets, the Company determined an indication of potential impairment was present in its Southwest Saskatchewan and Central Alberta CGU's. As a result, the Company completed an impairment test. Recoverable value was estimated at value in use based on before tax discounted cash flows from oil and gas proved plus probable reserves estimated by the Company's third party reserve evaluators. It was determined that the carrying value of the Southwest Saskatchewan CGU exceeded the recoverable amount of $268.1 million and the carrying value of the Central Alberta CGU exceeded the recoverable amount of $42.7 million and a $72.2 million impairment was recognized. The before tax discount rate applied in the value in use calculation as at December 31, 2018 was 10 - 20 percent.

As at December 31, 2018, the Company determined there were no indications that impairment losses recognized in prior years no longer exist or have decreased.

The following table outlines forecast commodity prices and exchange rates used in the Company’s CGU impairment tests at December 31, 2018. The forecast commodity prices are consistent with those used by the Company’s external reserve evaluators and are a key assumption in assessing the recoverable amount. The reserve evaluators also include financial assumptions regarding royalty rates, operating costs, and future development capital that can significantly impact the recoverable amount which are assigned based on historic rates and future anticipated activities by Management.

	Medium and Light Crude Oil		Natural Gas	NGL				
Year	Canadian Light Sweet Crude 40˚ API ($/bbl)	Western Canadian Select 20.5˚ API ($/bbl)	AECO Gas Price ($/MMBtu)	Edmonton Condensate ($/bbl)	Edmonton Butane ($/bbl)	Edmonton Propane ($/bbl)	Inflation rates (%/Yr)	Exchange rate ($US/$Cdn)
2019	75.27	59.47	1.95	75.32	40.91	30.27	—	0.77
2020	77.89	62.31	2.44	80.00	50.25	34.51	2.0	0.80
2021	82.25	67.45	3.00	83.75	56.88	38.15	2.0	0.80
2022	84.79	69.53	3.21	85.50	58.01	39.64	2.0	0.80
2023	87.39	71.66	3.30	87.29	59.17	40.62	2.0	0.80
2024	89.14	73.10	3.39	89.11	60.36	41.62	2.0	0.80
2025	90.92	74.56	3.49	90.96	61.56	42.64	2.0	0.80
2026	92.74	76.05	3.58	92.86	62.79	43.68	2.0	0.80
2027	94.60	77.57	3.68	94.79	64.05	44.75	2.0	0.80
2028	96.49	79.12	3.78	96.76	65.33	45.83	2.0	0.80
2029	98.42	80.70	3.88	98.77	66.64	46.94	2.0	0.80

NET LOSS

	Three Months Ended			Years Ended	
($000s except per share)	**Dec 31, 2019**	Sep 30, 2019	Dec 31, 2018	**Dec 31, 2019**	Dec 31, 2018
Net loss	**(143,801)**	(4,269)	(82,473)	**(158,664)**	(71,533)
Per share - basic ($)	**(0.44)**	(0.01)	(0.29)	**(0.50)**	(0.29)
Per share - diluted ($)	**(0.44)**	(0.01)	(0.29)	**(0.50)**	(0.29)

The Company realized a higher net loss and net loss per basic share for the fourth quarter of 2019 as compared to the third quarter of 2019. The loss is primarily due to the impairment expense recognized in the fourth quarter, a four percent decrease in production, along with a three percent decrease in average realized price per barrel of oil, as compared to the immediately preceding quarter.

Net loss and net loss per basic share for the three months and year ended December 31, 2019 increased as compared to the same periods of 2018. The change is primarily due to the recognition of a larger impairment expense during 2019 of $180.7 million (2018 - $72.2 million) and an increase in depletion and depreciation expense due to the MBOG acquisition and adoption of IFRS 16, and a loss on disposal of petroleum and natural gas properties recognized in the second quarter of 2019, partially offset by a lower realized loss on financial contracts.

INCOME TAXES

The estimated tax pools in place at December 31, 2019 are as follows:

($000s)	Total
Canadian oil and gas property expenses	**387,672**
Canadian development expenses	**176,713**
Canadian exploration expenses	**24,587**
Undepreciated capital cost	**125,706**
Non-capital losses	**606,738**
Other	**3,279**
	1,324,695

CAPITAL EXPENDITURES

Capital Expenditure Summary

($000s)	Q1 2019	Q2 2019	Q3 2019	**Q4 2019**	**2019 YTD**	2018 YTD	% Change
Land	310	498	5,750	**237**	**6,795**	3,940	72 %
Seismic	123	(14)	29	**1,137**	**1,275**	2,857	(55)%
Drilling and completions	32,729	18,035	10,264	**19,436**	**80,464**	82,762	(3)%
Facilities, equipment and pipelines	6,761	5,116	4,914	**8,102**	**24,893**	24,205	3 %
Other	1,338	1,562	1,290	**1,848**	**6,038**	6,788	(11)%
Total exploration and development	41,261	25,197	22,247	**30,760**	**119,465**	120,552	(1)%
Acquisitions - cash consideration	273	—	12,077	**2,458**	**14,808**	180,942	(92)%
Acquisitions - share based	—	—	—	**—**	**—**	153,879	(100)%
Property dispositions	(28,080)	(29,166)	—	**—**	**(57,246)**	(7,056)	711 %
Total acquisitions & dispositions	(27,807)	(29,166)	12,077	**2,458**	**(42,438)**	327,765	(113)%
Total capital expenditures	13,454	(3,969)	34,324	**33,218**	**77,027**	448,317	(83)%

During the three months and year ended December 31, 2019, Surge invested a total of $30.8 million and $119.5 million, excluding acquisitions and dispositions.

During the fourth quarter of 2019, Surge invested $2.4 million to complete and bring on stream three gross (3.0 net) wells in the Sparky area that had been spud during the third quarter of 2019. Surge also invested $14.4 million to drill, complete and bring on stream one gross (1.0 net) well at Valhalla and nine gross (9.0 net) wells at Sparky. The Company spent a further $2.6 million optimizing producing wellbores in the Shaunavon and Greater Sawn areas in addition to pre drill costs to prepare for the first quarter 2020 drilling program.

During the fourth quarter of 2019, Surge invested $8.1 million in facilities, pipelines, waterflood expansions and pilots. An additional $3.2 million was spent on land and seismic acquisitions and other capital items during the quarter.

During the year ended December 31, 2019, the Company acquired a gas processing plant in Southeast Alberta for cash consideration of $12.1 million. In conjunction with the purchase, the Company elected to early adopt the amendments to IFRS 3 "Business Combinations" which resulted in accounting for the transaction as an asset acquisition. Concurrent with the acquisition, the Company entered into a sale-leaseback arrangement for total cash proceeds of $12.4 million. Refer to notes 5 and 18 in the consolidated financial statements for additional information.

During the year ended December 31, 2019, the Company sold a 1.7 percent gross overriding royalty ("GORR") on the total revenue from the Company's Southwest Saskatchewan, Southeast Alberta and North Central Alberta assets, effective May 1, 2019. Cash consideration received on disposition was $29.1 million. The Company has a drilling commitment on the GORR lands that must be fulfilled by April 30, 2022. In the event that the Company fails to fulfill the drilling commitment, the GORR shall increase from 1.7 percent to 2.7 percent. During 2019, Surge drilled 21 out of the 100 wells that are required to meet the drilling commitment. Per Surge's 2020 capital budget, the Company is expected to drill 56 wells, with the majority of these meeting the requirements set out in the drilling commitment.

During the year ended December 31, 2019 the Company disposed of certain non-core assets in Northwest Alberta for cash proceeds of $28.1 million.

FACTORS THAT HAVE CAUSED VARIATIONS OVER THE QUARTERS

The fluctuations in Surge's revenue and net earnings from quarter to quarter are primarily caused by changes in production volumes, changes in realized commodity prices and the related impact on royalties, realized and unrealized gains or losses on derivative instruments, and changes in impairment expense and non-cash items. The change in production from the first quarter of 2018 through the current quarter is due to Surge's successful drilling programs and acquisitions over that period. Please refer to the Financial and Operating Results section and other sections of this MD&A for detailed discussions on variations during the comparative quarters and to Surge's previously issued interim and annual MD&A for changes in prior quarters.

Share Capital and Option Activity

	Q4 2019	Q3 2019	Q2 2019	Q1 2019
Weighted common shares	**324,835,793**	318,075,528	314,010,237	309,447,717
Dilutive instruments (treasury method)	**—**	—	—	—
Weighted average diluted shares outstanding	**324,835,793**	318,075,528	314,010,237	309,447,717

	Q4 2018	Q3 2018	Q2 2018	Q1 2018
Weighted common shares	288,743,803	231,988,109	230,812,437	233,006,881
Dilutive instruments (treasury method)	—	4,234,451	5,264,860	—
Weighted average diluted shares outstanding	288,743,803	236,222,560	236,077,297	233,006,881

Subsequent to December 31, 2019, the Company issued 8.7 million flow-through shares related to Canadian development expenditures at a price of $1.18 per share for total gross proceeds of $10.3 million. The proceeds will be used to fund the Company's budgeted 2020 drilling program. Including the issuance, on March 9, 2020, Surge had 335,068,916 common shares, 7,724,932 PSAs, and 5,868,734 RSAs outstanding.

Quarterly Financial Information

	Q4 2019	Q3 2019	Q2 2019	Q1 2019
Oil, Natural gas & NGL sales	**91,789**	97,026	107,665	97,868
Net loss	**(143,801)**	(4,269)	(2,611)	(7,983)
Net loss per share ($):				
Basic	**(0.44)**	(0.01)	(0.01)	(0.03)
Diluted	**(0.44)**	(0.01)	(0.01)	(0.03)
Cash flow from operating activities	**34,474**	40,228	45,807	28,908
Cash flow from operating activities per share ($):				
Basic	**0.11**	0.13	0.15	0.09
Diluted	**0.11**	0.13	0.15	0.09
Adjusted funds flow	**38,881**	41,513	50,742	41,851
Adjusted funds flow per share ($):				
Basic	**0.12**	0.13	0.16	0.14
Diluted	**0.12**	0.13	0.16	0.14
Average daily sales				
Oil (bbls/d)	**16,441**	17,170	17,366	17,542
NGL (bbls/d)	**630**	769	727	644
Natural gas (mcf/d)	**19,521**	19,668	20,706	20,663
Barrels of oil equivalent (boe per day) (6:1)	**20,325**	21,217	21,544	21,630
Average sales price				
Natural gas ($/mcf)	**1.56**	0.69	0.86	2.32
Oil ($/bbl)	**57.46**	59.39	66.05	57.72
NGL ($/bbl)	**35.84**	27.69	24.93	41.86
Barrels of oil equivalent ($/boe)	**49.09**	49.71	54.92	50.27

Quarterly Financial Information

	Q4 2018	Q3 2018	Q2 2018	Q1 2018
Oil, Natural gas & NGL sales	58,127	91,036	87,094	68,290
Net income (loss)	(82,473)	9,034	3,015	(1,109)
Net income (loss) per share ($):				
Basic	(0.29)	0.04	0.01	(0.01)
Diluted	(0.29)	0.04	0.01	(0.01)
Cash flow from operating activities	26,770	37,197	33,725	24,215
Cash flow from operating activities per share ($):				
Basic	0.09	0.16	0.15	0.10
Diluted	0.09	0.16	0.14	0.10
Adjusted funds flow	6,249	40,638	38,596	28,169
Adjusted funds flow per share ($):				
Basic	0.02	0.18	0.17	0.12
Diluted	0.02	0.17	0.17	0.12
Average daily sales				
Oil (bbls/d)	16,578	13,560	13,343	12,446
NGL (bbls/d)	703	669	556	560
Natural gas (mcf/d)	22,598	22,797	19,038	18,128
Barrels of oil equivalent (boe per day) (6:1)	21,047	18,029	17,072	16,027
Average sales price				
Natural gas ($/mcf)	2.03	0.71	0.63	0.82
Oil ($/bbl)	33.72	68.89	68.78	57.58
NGL ($/bbl)	38.28	58.46	49.15	48.82
Barrels of oil equivalent ($/boe)	30.02	54.89	56.06	47.34

Annual Financial Information

	Years Ended December 31,		
($000s except per share)	**2019**	2018	2017
Total petroleum and natural gas revenue	**394,349**	304,547	240,908
Net loss	**(158,664)**	(71,533)	(6,673)
Net loss per share ($):			
Basic	**(0.50)**	(0.29)	(0.03)
Diluted	**(0.50)**	(0.29)	(0.03)
Total assets	**1,425,854**	1,566,708	1,232,090
Total long-term financial liabilities	**423,684**	446,566	245,946
Dividends declared	**31,776**	24,637	20,756
Dividends declared per share ($):			
Basic	**0.10**	0.10	90.95
Diluted	**0.10**	0.10	90.95

LIQUIDITY AND CAPITAL RESOURCES

On December 31, 2019, Surge had $316.4 million drawn on its credit facility, $79.0 million principal amount of convertible subordinated unsecured debentures ("Debentures"), and total net debt of $382.3 million, a decrease in total net debt of 17 percent as compared to the same date in 2018. At December 31, 2019, Surge had approximately $33.6 million of borrowing capacity in relation to the $350 million credit facility providing Surge financial flexibility through 2020. The following tables set forth the consolidated capitalization of Surge and the change in the components of the Debentures:

Consolidated Capitalization

($000s)	Outstanding as at December 31, 2019
Shareholder Equity	
Share capital	1,466,506
Common shares outstanding	326,330
Debentures - equity	6,266
Debt	
Credit Facilities	
Total Commitment	350,000
Amount drawn	316,404
Debentures - liability	68,699

Convertible Debentures

	Number of convertible debentures	Liability Component ($000s)	Equity Component ($000s)
Balance at December 31, 2017	44,500	36,715	3,551
Accretion of discount	—	1,258	—
Balance at December 31, 2018	44,500	37,973	3,551
Issuance of convertible debentures	34,500	30,551	3,949
Issue costs	—	(1,776)	(230)
Deferred income tax liability	—	—	(1,004)
Accretion of discount	—	1,951	—
Balance at December 31, 2019	**79,000**	**68,699**	**6,266**

Surge monitors its capital structure and makes adjustments according to market conditions in an effort to meet its objectives. Currently, Surge anticipates that the future capital requirements will be funded through a combination of internal cash flow, divestitures, debt and/or equity financing. Furthermore, the Company's flexible capital program and unused bank line further add to Surge's ability to fund future capital requirements as there is no assurance that debt and equity financing will be available on terms acceptable to the Company to meet its capital requirements.

As crude oil pricing began to stabilize in early 2017, Surge increased the Company's dividend to $0.007080 per share per month, effective February 2017 and following a core area acquisition in April 2017, effective May 2017, the dividend was increased to $0.007917 per share per month. Due to further increases in crude oil prices, effective June 2018, the dividend was increased again, to $0.008333 per share per month. Surge's management and Board will continue to assess the amount of the cash dividend to be paid on the common shares, if any, in light of market conditions and other relevant considerations.

Net Debt

($000s)	As at December 31, 2019
Bank debt	(316,404)
Accounts receivable	41,486
Prepaid expenses and deposits	4,875
Accounts payable and accrued liabilities	(40,848)
Dividends payable	(2,719)
Convertible debentures	(68,699)
Total	**(382,309)**

As at December 31, 2019, the Company had a total commitment of $350 million, being the aggregate of a revolving term credit facility of $300 million and an operating loan commitment of $50 million, with a syndicate of banks. A review and re-determination of the borrowing base will occur semi-annually on or before May 31 and November 30 of each year. The facility is available on a revolving basis until May 31, 2020. On May 31, 2020, at the Company's discretion, the facility is available on a non-revolving basis for a one-year period, at the end of which time the facility would be due and payable. Alternatively, the facility may be extended for a further 364-day period at the request of the Company and subject to the approval of the syndicate. As the available lending limits of the facility are based on the syndicate's interpretation of the Company's reserves and future commodity prices, there can be no assurance that the amount of the available facility will not decrease at the next scheduled review. Interest rates vary depending on the ratio of Net Senior Debt to EBITDA. The facility had an effective interest rate of prime plus 1.25 percent as at December 31, 2019 (December 31, 2018 – prime plus 1.25 percent).

The facility is secured by a general assignment of book debts, debentures of $1.5 billion with a floating charge over all assets of the Company with a negative pledge and undertaking to provide fixed charges on the major producing petroleum and natural gas properties at the request of the bank.

The credit facility has a financial covenants, whereby the Company's ratio of Net Senior Debt to EBITDA shall not exceed 3.00:1.00 (1.65:1.00 as at December 31, 2019). The EBITDA used in the covenant calculation is net loss and comprehensive loss for the period adjusted for lease payments, non-cash items, non-recurring transaction costs and extraordinary and non-recurring items such as material acquisitions or dispositions. The Net Senior Debt used in the covenant calculation includes bank debt and any working capital deficit. As of December 31, 2019, the Company was compliant with all covenants provided for in the lending agreement. Copies of the Company's credit agreements may be accessed through the SEDAR website (www.sedar.com).

RELATED-PARTY AND OFF-BALANCE-SHEET TRANSACTIONS

Surge was not involved in any off-balance-sheet transactions or related party transactions during the period ended December 31, 2019.

CONTRACTUAL OBLIGATIONS

The Company is contractually obligated under its debt agreements as outlined under liquidity and capital resources.

As at December 31, 2019, Surge had future minimum payments relating to its variable office rent payments and firm transport commitments totaling $34.8 million, as summarized below:

	December 31, 2019
Less than 1 year	$ 11,046
1 - 3 years	13,605
3 - 5 years	4,838
5+ years	5,343
Total commitments	**$ 34,832**

During the year ended December 31, 2019, the Company entered into a three year firm transportation agreement resulting in the recognition of an additional commitment of $15.3 million.

LEASES

The Company has recognized the following lease and other obligations:

	Total
Lease obligations at December 31, 2018	$ 5,871
Additions upon adoption of IFRS 16 at January 1, 2019	29,886
Lease modifications	5,643
Interest expense	2,100
Lease payments	(8,910)
Lease obligations at December 31, 2019	**$ 34,590**
Other obligations	12,094
Lease and other obligations at December 31, 2019	**46,684**
Current portion	8,103
Long term portion	38,581

The Company has recognized during the year ended December 31, 2019, $7.3 million of depreciation charges on ROU assets and $8.9 million of lease payments of which $2.1 million has been recorded as interest expense.

During the year ended December 31, 2019, the Company acquired a gas processing facility in Southeast Alberta. In conjunction with the purchase, the Company entered into a sale-leaseback agreement and recorded a corresponding financial liability in accordance with IFRS 9 "Financial Instruments" (included in "other obligations" in above table). Monthly lease payments will be apportioned between finance expense and a reduction of the outstanding financial liability.

During the year ended December 31, 2019, the Company extended the term of an existing lease resulting in the recognition of an incremental $5.6 million right-of-use asset and lease obligation. The incremental borrowing rate used to revalue the lease was adjusted to reflect changes in market conditions and the revised lease term.

Future minimum payments relating to lease and other obligations at December 31, 2019 are as follows:

	December 31, 2019
Less than 1 year	$ 11,428
1 - 3 years	21,039
3 - 5 years	25,803
5+ years	528
Lease and other obligation payments	**$ 58,798**

FINANCIAL INSTRUMENTS

As a means of managing commodity price, interest rate, and foreign exchange volatility, the Company enters into various derivative financial instrument agreements and physical contracts. The fair value of forward contracts and swaps is determined by discounting the difference between the contracted prices and published forward price curves as at the statement of financial position date, using the remaining contracted oil and natural gas volumes and a risk-free interest rate (based on published government rates). The fair value of options and costless collars is based on option models that use published information with respect to volatility, prices and interest rates. Surge's financial derivative contracts are classified as level two.

The following table summarizes the Company's financial derivatives as at March 9, 2020 by period and by product.

Commodity Contracts

WTI Oil Hedges

Type	Term	bbl/d	Currency	Put Sold (per bbl)	Put Acquired (per bbl)	Call Sold (per bbl)	Swap Price (per bbl)
WTI	Q2 2019 - Q1 2020	250	USD	—	$55.00	$65.00	—
WTI	Q2 2019 - Q1 2020	500	USD	—	—	—	$59.83
WTI	Q3 2019 - Q1 2020	500	USD	—	—	—	$58.80
WTI	Q1 2020	1,750	USD	—	—	—	$57.56
WTI	Q2 2020	1,000	USD	—	—	—	$56.55
WTI	Q3 2020	500	USD	—	—	—	$57.25
WTI	Q3 2019 - Q2 2020	500	USD	—	$58.00	—	—
WTI	Q1 2020	250	USD	—	$45.00	—	—
WTI	1H 2020	3,500	USD	—	$47.61	—	—
WTI	Q2 2020	500	USD	—	$46.00	—	—
WTI	1H 2020	250	USD	—	—	$67.50	—
WTI	Q2 2019 - Q1 2020	250	USD	$45.00	$55.00	$68.50	—
WTI	1H 2020	1,750	USD	$47.14	$55.71	$64.00	—
WTI	Q1 2020 - Q3 2020	1,000	USD	$46.00	$54.00	$64.13	—
WTI	Q2 2020 - Q3 2020	500	USD	$46.00	$54.00	$63.55	—
WTI	Q3 2020	1,500	USD	$47.00	$55.00	$65.00	—
WTI	Q3 2019 - Q4 2020	500	USD	$47.50	$57.50	$71.50	—
WTI	2H 2020	500	USD	$49.00	$57.00	$66.50	—
WTI	Q3 2020 - Q1 2021	500	USD	$44.00	$52.00	$60.00	—

Oil Differential Hedges

Type	Term	bbl/d	Currency	Floor (per bbl)	Ceiling (per bbl)	Swap Price (per bbl)
WCS Swap	1H 2020	1,000	USD	—	—	US$WTI less $16.50
WCS Swap	Q2 2020 - Q3 2020	1,500	USD	—	—	US$WTI less $16.40
WCS Swap	Q3 2020	500	USD	—	—	US$WTI less $16.45
WCS Swap	2H 2020	1,000	USD	—	—	US$WTI less $17.50
MSW Swap	Q2 2020	1,500	USD	—	—	US$WTI less $5.75
MSW Swap	Q2 2020 - Q3 2020	3,500	USD	—	—	US$WTI less $4.94
WCS Collar	Q2 2020 - Q4 2020	1,500	USD	US$WTI less $15.50	US$WTI less $20.00	—
WCS Collar	2020	1,000	USD	US$WTI less $14.60	US$WTI less $19.95	—

Natural Gas Hedges

Type	Term	Volume	Currency	Floor	Ceiling
Chicago Swap	Dec 2019 - Mar 2020	3,000 mmbtu/d	USD	$3.075 per mmbtu	$3.075 per mmbtu
Chicago Swap	Apr 2020 - Oct 2020	3,000 mmbtu/d	USD	$2.045 per mmbtu	$2.045 per mmbtu
Chicago Collar	Nov 2019 - Oct 2020	3,000 mmbtu/d	USD	$2.25 per mmbtu	$2.90 per mmbtu
Chicago Collar	Nov 2020 - Oct 2021	3,000 mmbtu/d	USD	$2.15 per mmbtu	$2.90 per mmbtu
AECO Swap	Nov 2019 - Dec 2020	3,000 gj/d	CAD	$1.975 per gj	$1.975 per gj
AECO Swap	2020	4,000 gj/d	CAD	$1.45 per gj	$1.45 per gj

CAD/USD FX Hedges

Type	Term	Monthly Notional Amount (USD$)	Total Notional Amount (USD$)	Swap Rate (CAD$ per USD$)
Avg Rate Forward	Q2 2020 - Q4 2020	$1,000,000	$9,000,000	$1.3245

Interest Rate Hedges

Type	Term	Notional Amount (CAD$)	Surge Receives	Surge Pays	Fixed Rate SGY Pays
Fixed-to-Floating Rate Swap	Feb 2018 - Feb 2023	$100,000,000	Floating Rate	Fixed Rate	Semi-Annual Step Up • Beginning at 1.786% • Ending at 2.714% • Averaging 2.479%
Fixed Rate Swap	Jul 2019 - Jun 2024	$50,000,000	Floating Rate	Fixed Rate	1.7850%

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Disclosure controls and procedures ("DC&P"), as defined in National Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*, are designed to provide reasonable assurance that information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the Company's management, including its certifying officers, as appropriate to allow timely decisions regarding required disclosure.

There were no changes in the Company's DC&P during the quarter ended December 31, 2019 that materially affected, or are reasonably likely to materially affect, the Company's DC&P.

Internal Controls over Financial Reporting

Internal control over financial reporting ("ICFR"), as defined in National Instrument 52-109, includes those policies and procedures that:

1. pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets of the Company;

2. are designed to provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of the Company are being made in accordance with authorizations of management and Directors of Surge; and

3. are designed to provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company's assets that could have a material effect on the financial statements.

The Chief Executive Officer and Chief Financial Officer are responsible for designing internal controls over financial reporting or causing them to be designed under their supervision in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's Chief Executive Officer and Chief Financial Officer by others, particularly during the period in which the annual filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

The Committee of Sponsoring Organizations of the Treadway Commission ("COSO") 2013 framework provides the basis for management's design of internal controls over financial reporting. Management and the Board work to mitigate the risk of a material misstatement in financial reporting; however, a control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met and it should not be expected that the disclosure and internal control procedures will prevent all errors or fraud.

There were no changes in the Company's ICFR during the quarter ended December 31, 2019 that materially affected, or are reasonably likely to materially affect, the Company's ICFR.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with IFRS requires management to make certain judgments and estimates. Due to the timing of when activities occur compared to the reporting of those activities, management must estimate and accrue operating results and capital spending. Changes in these judgments and estimates could have a material impact on our financial results and financial condition.

Reserves

The process of estimating reserves is critical to several accounting estimates. It requires significant judgments based on available geological, geophysical, engineering and economic data. These estimates may change substantially as data from ongoing development and production activities becomes available, and as economic conditions impacting oil and gas prices, operating costs and royalty burdens change. Reserve estimates impact net income through depletion, the determination of decommissioning liabilities and the application of impairment tests.

Revisions or changes in reserve estimates can have either a positive or a negative impact on net income.

Forecasted Commodity Prices

Management's estimates of future crude oil and natural gas prices are critical as these prices are used to determine the carrying amount of PP&E, assess impairment and determine the change in fair value of financial contracts. Management's estimates of prices are based on the price forecast from our reserve engineers and the current forward market.

Business Combinations

Management makes various assumptions in determining the fair values of any acquired company's assets and liabilities in a business combination. The most significant assumptions and judgments made relate to the estimation of the fair value of the oil and gas properties. To determine the fair value of these properties, we estimate (a) oil and gas reserves in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (''NI 51-101'') and (b) future prices of oil and gas.

Decommissioning Liability

Management calculates the decommissioning liability based on estimated costs to abandon and reclaim its net ownership interest in all wells and facilities and the estimated timing of the costs to be incurred in future periods. The fair value estimate is capitalized to PP&E as part of the cost of the related asset and amortized over its useful life. There are uncertainties related to decommissioning liabilities and the impact on the financial statements could be material as the eventual timing and costs for the obligations could differ from our estimates. Factors that could cause our estimates to differ include any changes to laws or regulations, reserve estimates, costs and technology.

Derivative Financial Instruments

Surge utilizes derivative financial instruments to manage its exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. Fair values of derivative contracts fluctuate depending on the underlying estimate of future commodity prices, foreign currency exchange rates, interest rates and counterparty credit risk.

Stock-based Compensation

Management makes various assumptions in determining the value of stock based compensation. This includes estimating the forfeiture rate, the expected volatility of the underlying security, interest rates and expected life.

Deferred Income Taxes

Management makes various assumptions in determining the value of stock deferred income tax provision, including (but not limited to) future tax rates, accessibility of tax pools and future cash flows.

Leases

The preparation of the consolidated financial statements in accordance with IFRS requires management to make judgments, estimates, and assumptions that affect the reported amount of assets, liabilities, income, and expenses. Actual results could differ significantly from these estimates. Key areas where management has made judgments, estimates, and assumptions related to the application of IFRS 16 include:

- Incremental borrowing rate: The Incremental borrowing rates are based on judgments including economic environment, term, currency, and the underlying risk inherent to the asset. The carrying balance of the right-of-use assets, lease obligations, and the resulting interest and depreciation expense, may differ due to changes in the market conditions and lease term.
- Lease term: Lease terms are based on assumptions regarding extension terms that allow for operational flexibility and future market conditions.

CHANGES IN ACCOUNTING POLICIES

IFRS 16 was issued January 2016 and replaces IAS 17 Leases. The standard introduces a single lessee accounting model for leases with required recognition of assets and liabilities for most leases. On January 1, 2019 the Company adopted IFRS 16 using the modified retrospective approach, whereby the cumulative effect of initially applying the standard was recognized as an increase to right-of-use assets (included in "Petroleum and natural gas properties") with a corresponding increase to lease obligations (the non-current portion recorded in "Long term lease and other obligations" and the current portion recorded in "Current portion of lease and other obligations").

The right-of-use assets recognized were measured at amounts equal to the lease obligations. The weighted average incremental borrowing rate used to determine the lease obligation at adoption was approximately 6%. The right-of-use assets and lease obligations recognized largely relate to the Company's head office lease in Calgary and long-term leases for oil batteries and equipment rentals. The adoption of IFRS 16 included the following elections:

- The Company elected to retain the classification of contracts previously identified as leases under IAS 17 and IFRIC 4;
- The Company elected to use hindsight in determining the lease term where the contract contains terms to extend or terminate the lease;
- The Company elected to not apply lease accounting to certain leases for which the lease term ends within 12 months of the January 1, 2019 adoption;
- The Company elected to not apply lease accounting to certain leases of low value assets;
- The Company elected to apply a single discount rate to a portfolio of leases with similar characteristics.

As a result of this adoption, the Company has revised the description of its accounting policy for leases as follows:

A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. A lease obligation is recognized at the commencement of the lease term at the present value of the lease payments that are not paid at that date. Interest expense is recognized on the lease obligations using the effective interest rate method and payments are applied against the lease obligation. At the commencement date, a corresponding right-of-use asset is recognized at the amount of the lease obligation, adjusted for lease incentives received and initial direct costs. Depreciation is recognized on the right-of-use asset over the lease term.

RISK FACTORS

Additional risk factors can be found under "Risk Factors" in the Company's AIF for the year ended December 31, 2019, which can be found on www.sedar.com. Many risks are discussed below and in the AIF, but these risk factors should not be construed as exhaustive. There are numerous factors, both known and unknown, that could cause actual results or events to differ materially from forecast results.

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of Surge depends on its ability to find, acquire, develop, and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves Surge may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Surge's reserves will depend not only on the Company's ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that further commercial quantities of oil and natural gas will be discovered or acquired by Surge.

Surge's principal risks include finding and developing economic hydrocarbon reserves efficiently and being able to fund the capital program. The Company's need for capital is both short-term and long-term in nature. Short-term working capital will be required to finance accounts receivable, drilling deposits and other similar short-term assets, while the acquisition and development of oil and natural gas properties requires large amounts of long-term capital. Surge anticipates that future capital requirements will be funded through a combination of internal adjusted funds flow, debt and/or equity financing. There is no assurance that debt and equity financing will be available on terms acceptable to the Company to meet its capital requirements. If any components of the Company's business plan are missing, the Company may not be able to execute the entire business plan.

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial, and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil, or water may give rise to liabilities to governments and third parties and may require Surge's operating entities to incur costs to remedy such discharge. Although Surge believes that it is in material compliance with current applicable environmental regulations, no assurance can be given that environment laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect Surge's financial condition, results of operations or prospects.

Surge's involvement in the exploration for and development of oil and natural gas properties may result in Surge becoming subject to liability for pollution, blowouts, property damage, personal injury or other hazards. Although, prior to drilling, Surge will obtain insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liability. In addition, such risks may not, in all circumstances, be insurable or, in certain circumstances, Surge may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds available to Surge. The occurrence of a significant event that was not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on Surge's financial position, results of operations or prospects and will reduce income otherwise used to fund operations.

The Company's financial performance and condition are substantially dependent on the prevailing prices of oil and natural gas which are unstable and subject to fluctuation. Fluctuations in oil or natural gas prices could have an adverse effect on the Company's operations and financial condition and the value and amount of its reserves. Prices for crude oil fluctuate in response to global supply of and demand for oil, market performance and uncertainty and a variety of other factors which are outside the control of the Company including, but not limited, to the world economy and the Organization of the Petroleum Exporting Countries' ability to adjust supply to world demand, government regulation, political stability and the availability of alternative fuel sources. Natural gas prices are influenced primarily by factors within North America, including North American supply and demand, economic performance, weather conditions and availability and pricing of alternative fuel sources.

Decreases in oil and natural gas prices typically result in a reduction of the Company's net production revenue and may change the economics of producing from some wells, which could result in a reduction in the volume of the Company's reserves. Any further substantial declines in the prices of crude oil or natural gas could also result in delay or cancellation of existing or future drilling, development or construction programs or the curtailment of production. All of these factors could result in a material decrease in the Company's net production revenue, cash flows and profitability causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings available to the Company will in part be determined by the Company's borrowing base. A sustained material decline in prices from historical average prices could further reduce such borrowing base, therefore reducing the bank credit available and could require that a portion of its bank debt be repaid.

The Company utilizes financial derivatives contracts to manage market risk. All such transactions are conducted in accordance with the risk management policy that has been approved by the Board of Directors.

BOE PRESENTATION

All amounts are expressed in Canadian dollars unless otherwise noted. Oil, natural gas and natural gas liquids reserves and volumes are converted to a common unit of measure, referred to as a barrel of oil equivalent (boe), on the basis of 6,000 cubic feet of natural gas being equal to one barrel of oil. This conversion ratio is based on an energy equivalency conversion method, primarily applicable at the burner tip and does not necessarily represent a value equivalency at the wellhead. It should be noted that the use of boe might be misleading, particularly if used in isolation.

FORWARD-LOOKING STATEMENTS

This MD&A contains forward-looking statements. The use of any of the words “anticipate”, “continue”, “estimate”, “expect”, “may”, “will”, “project”, “should”, “believe” and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements.

More particularly, this MD&A contains statements concerning: sustainability of production; forecast commodity prices, inflation rates and currency prices; the Company's long term prospects and business plan; Surge's continued pursuit of strategic acquisitions and the characteristics thereof; Surge's assets and the characteristics thereof; underlying causes of the fluctuations in Surge’s revenue and net earnings from quarter to quarter; management’s expectations regarding net operating, transportation and G&A expenses for the remainder of 2020; Surge’s capital program for the remainder of 2020; Surge’s capital budget and production guidance for the remainder of 2020; continued efforts of Surge to monitor and adjust its capital structure; funding of future capital requirements through internal cash flow, divestitures, debt and/or equity financing; future development costs; Surge’s financial flexibility; fair value of forward contracts, swaps, options and costless collars entered into by the Company; expected payments and forfeiture rates of RSAs and PSAs granted under the Company’s Stock Incentive Plan; estimations of the fair value of acquired assets; estimated tax pools; potential impairments of CGUs and the assumptions used to assess such impairments; expectations with respect to its underlying decommissioning liabilities; ability of Surge to increase or maintain its credit facility; the impact of certain new IFRS; continued support of Surge's lenders; the amount of Surge's dividend, if any, and the ongoing assessment of management and the Board of market conditions and other relevant considerations; and expectations on corporate royalty rates applicable to the Company.

The forward-looking statements are based on certain key expectations and assumptions made by Surge, including expectations and assumptions concerning the performance of existing wells and success obtained in drilling new wells, anticipated expenses, cash flow and capital expenditures, the application of regulatory and royalty regimes, prevailing commodity prices and economic conditions, recoverable and carrying value of certain assets, the financial assumptions used by Surge’s reserve evaluators in assessing potential impairment of Surge assets; development and completion activities and the costs relating thereto, the performance of new wells, the successful implementation of waterflood programs, the availability of and performance of facilities and pipelines, the geological characteristics of Surge’s properties and any acquired assets, the successful application of drilling, completion and seismic technology, the determination of decommissioning liabilities, the ability to obtain approval from syndicate to increase credit facility; prevailing weather conditions, exchange rates, licensing requirements, the impact of completed facilities on operating costs and the availability, costs of capital, labour and services, and the creditworthiness of industry partners.

Although Surge believes that the expectations and assumptions on which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because Surge can give no assurance that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, risks associated with the condition of the global economy, including trade, public health (including the impact of COVID-19) and other geopolitical risks; risks associated with the oil and gas industry in general (e.g., operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; inability of Surge to fund its future capital requirements; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production, costs and expenses, and health, safety and environmental risks); commodity price and exchange rate fluctuations and constraint in the availability of services, adverse weather or break-up conditions; uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures; failure to obtain the continued support of the lenders under Surge’s current bank line; or the inability to obtain consent of lenders to increase bank line. Certain of these risks are set out in more detail in this MD&A under the heading ‘Risk Factors’ and in Surge’s AIF, which will be filed on SEDAR before March 31, 2020 and can be accessed at www.sedar.com.

The forward-looking statements contained in this MD&A are made as of the date hereof and Surge 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.

NON-GAAP FINANCIAL MEASURES

Certain secondary financial measures in this document - namely, "adjusted funds flow", "adjusted funds flow per share", “net debt”, and "net operating expenses" are not prescribed by GAAP. These non-GAAP financial measures are included because management uses the information to analyze business performance, cash flow generated from the business, leverage and liquidity, resulting from the Company’s principal business activities and it may be useful to investors on the same basis. None of these measures are used to enhance the Company’s reported financial performance or position. The non-GAAP measures do not have a standardized meaning prescribed by IFRS and therefore are unlikely to be comparable to similar measures presented by other issuers. They are common in the reports of other companies but may differ by definition and application. All non-GAAP financial measures used in this document are defined below.

Adjusted funds flow & Adjusted funds flow per share

The Company adjusts cash flow from operating activities in calculating adjusted funds flow for changes in non-cash working capital, decommissioning expenditures, cash settled transaction and other costs, and cash settled stock-based compensation plans, particularly cash used to settle withholding obligations on stock-based compensation arrangements that are settled in shares. Management believes the timing of collection, payment or incurrence of these items involves a high degree of discretion and as such may not be useful for evaluating Surge’s cash flows.

Changes in non-cash working capital are a result of the timing of cash flows related to accounts receivable and accounts payable, which management believes reduces comparability between periods. Management views decommissioning expenditures predominately as a discretionary allocation of capital, with flexibility to determine the size and timing of decommissioning programs to achieve greater capital efficiencies and as such, costs may vary between periods. Transaction and other costs represent expenditures associated with acquisitions, which management believes do not reflect the ongoing cash flows of the business, and as such reduces comparability. All of the Company’s stock-based compensation plans are equity classified as the Company has the intention of settling all awards with shares. Cash settled stock-based compensation currently represents the statutory tax withholdings required on stock-based compensation awards and is a discretionary allocation of capital. The Company has the option to either require the holder to sell shares earned in the stock-based compensation plan to satisfy tax withholdings, or the Company can issue less shares to the individual and remit a cash payment to satisfy tax withholding requirements. Each of these expenditures, due to their nature, are not considered principal business activities and vary between periods, which management believes reduces comparability.

Adjusted funds flow per share is calculated using the same weighted average basic and diluted shares used in calculating income per share.

The following table reconciles cash flow from operating activities to adjusted funds flow and adjusted funds flow per share:

	Three Months Ended			Years Ended	
($000s except per share)	**Dec 31, 2019**	Sep 30, 2019	Dec 31, 2018	**Dec 31, 2019**	Dec 31, 2018
Cash flow from operating activities	**34,474**	40,228	26,770	**149,417**	121,907
Change in non-cash working capital	**2,876**	(475)	(25,464)	**16,569**	(24,338)
Decommissioning expenditures	**1,425**	1,279	1,439	**5,522**	6,348
Cash settled transaction and other costs	**106**	481	3,504	**1,480**	5,288
Cash settled stock-based compensation	**—**	—	—	**—**	4,447
Adjusted funds flow	**$ 38,881**	$ 41,513	$ 6,249	**$ 172,988**	$ 113,651
Per share - basic	**$ 0.12**	$ 0.13	$ 0.02	**$ 0.55**	$ 0.46

Net Debt

There is no comparable measure in accordance with IFRS for net debt. Net debt is calculated as bank debt plus the liability component of the convertible debentures plus or minus working capital, however, excluding the fair value of financial contracts, lease obligations, decommissioning obligations and other obligations. This metric is used by management to analyze the level of debt in the Company including the impact of working capital, which varies with timing of settlement of these balances.

	As at		
($000s)	**Dec 31, 2019**	Sep 30, 2019	Dec 31, 2018
Bank debt	**(316,404)**	(308,335)	(408,593)
Accounts receivable	**41,486**	40,562	21,084
Prepaid expenses and deposits	**4,875**	6,200	9,222
Accounts payable and accrued liabilities	**(40,848)**	(45,016)	(42,350)
Convertible debentures	**(68,699)**	(68,118)	(37,973)
Dividends payable	**(2,719)**	(2,702)	(2,577)
Total	**(382,309)**	(377,409)	(461,187)

Operating Netback & Adjusted Funds Flow per boe

Operating netback & adjusted funds flow are calculated on a per unit basis as follows:

Operating Netback & Adjusted Funds Flow per boe

	Three Months Ended			Years Ended	
($000s)	**Dec 31, 2019**	Sep 30, 2019	Dec 31, 2018	**Dec 31, 2019**	Dec 31, 2018
Petroleum and natural gas revenue	**91,790**	97,026	58,127	**394,349**	304,547
Processing and other income	**1,563**	1,483	576	**4,303**	2,818
Royalties	**(13,096)**	(13,892)	(7,478)	**(51,837)**	(43,203)
Realized gain (loss) on financial contracts	**248**	(1,674)	(2,430)	**(4,679)**	(11,007)
Operating expenses	**(29,448)**	(28,680)	(30,985)	**(116,338)**	(100,108)
Transportation expenses	**(2,624)**	(2,763)	(2,971)	**(11,866)**	(9,878)
Operating netback	**48,433**	51,500	14,839	**213,932**	143,169
G&A expense	**(3,640)**	(3,525)	(3,551)	**(14,287)**	(13,228)
Interest expense	**(5,911)**	(6,462)	(5,039)	**(26,657)**	(16,289)
Adjusted funds flow	**38,881**	41,513	6,249	**172,988**	113,651
Barrels of oil equivalent (boe)	**1,869,819**	1,951,893	1,936,352	**7,728,923**	6,591,007
Operating netback ($ per boe)	**$ 25.91**	$ 26.38	$ 7.68	**$ 27.66**	$ 21.73
Adjusted funds flow ($ per boe)	**$ 20.80**	$ 21.26	$ 3.25	**$ 22.36**	$ 17.25

Net Operating Expenses

Net operating expenses are determined by deducting processing and other revenue primarily generated by processing third party volumes at processing facilities where the Company has an ownership interest. It is common in the industry to earn third party processing revenue on facilities where the entity has a working interest in the infrastructure asset. Under IFRS this source of funds is required to be reported as revenue. However, the Company's principal business is not that of a midstream entity whose activities are dedicated to earning processing and other infrastructure payments. Where the Company has excess capacity at one of its facilities, it will look to process third party volumes as a means to reduce the cost of operating/owning the facility. As such, third party processing revenue is netted against operating costs in the MD&A.