BIRCHCLIFF ENERGY

18-01 February 14, 2018

BIRCHCLIFF ENERGY LTD. ANNOUNCES UNAUDITED 2017 YEAR-END AND FOURTH QUARTER RESULTS, 2017 RESERVES HIGHLIGHTS AND 2018 CAPITAL PROGRAM

Calgary, Alberta – Birchcliff Energy Ltd. ("Birchcliff") (TSX: BIR) is pleased to announce its unaudited 2017 year-end and fourth quarter financial and operational results, highlights from its independent reserves evaluations effective December 31, 2017 and its 2018 capital expenditure program. Birchcliff is also pleased to provide an operational overview and update.

Message to Shareholders

Birchcliff achieved record quarterly average production of 80,103 boe/d and funds flow from operations of $97.0 million in the fourth quarter of 2017 and record annual average production of 67,963 boe/d and funds flow from operations of $317.7 million in 2017. We sold high-cost producing properties and replaced the production with the drill bit, adding low-cost oil and natural gas production in Gordondale and Pouce Coupe. In addition, we brought our 80 MMcf/d Phase V expansion of our Pouce Coupe gas plant on-stream in the third quarter of 2017. As a result, our per boe operating costs in the fourth quarter of 2017 were 10% lower than the third quarter of 2017 and 17% lower than the second quarter of 2017. Our production per share was up 31% in the fourth quarter of 2017 as compared to the fourth quarter of 2016. We were successful at adding profitable production with positive recycle ratios. Our proved developed producing reserves at December 31, 2017 increased to 197,955.1 Mboe from 165,507.0 Mboe at December 31, 2016, reflecting our drilling success and production additions. Lastly, we began paying a quarterly dividend to our common shareholders in 2017 at an annual rate of $0.10 per share. We accomplished all of the foregoing while keeping our total debt flat at approximately $598 million.

In light of current economic conditions and what we believe to be a disconnect between the value of our business and our stock price, we are dedicated to strict capital discipline and are in a position to generate free funds flow from operations in 2018 while also providing strong annual average production growth. Our board of directors has approved a capital expenditure budget of $255 million for 2018 which targets an annual average production rate of 76,000 boe/d to 78,000 boe/d in 2018 (approximately 20% oil and NGLs). We expect that our 2018 capital expenditures will be less than our funds flow from operations during 2018. Our 2018 capital program is designed to maintain a prudent pace of development, protect our balance sheet and provide for the payment of a sustainable quarterly dividend to our shareholders. Of the $255 million budgeted for 2018, approximately $149.9 million has been allocated for drilling and development and $66.9 million for facilities and infrastructure. Our drilling program will focus on drilling liquids-rich natural gas and oil wells and our low-decline, low-cost producing assets are expected to generate a profitable return at a low commodity price.

We have executed on our business plan despite poor economic conditions. We are positioning Birchcliff for future growth while we protect our balance sheet. We thank all of our stakeholders and our staff for their support.

2017 Fourth Quarter Highlights

Highlights of the fourth quarter of 2017 include the following:

- Record quarterly average production of 80,103 boe/d, a 32% increase from 60,750 boe/d in the fourth quarter of 2016. Production consisted of approximately 80% natural gas, 7% light oil and 13% NGLs as compared to 79% natural gas, 8% light oil and 13% NGLs in the fourth quarter of 2016.
- Quarterly funds flow from operations of $97.0 million, or $0.36 per basic common share, a 35% increase and a 33% increase, respectively, from $71.8 million and $0.27 per basic common share in the fourth quarter of 2016.

- Birchcliff recorded net income to common shareholders of $24.8 million ($0.09 per basic common share), as compared to net income to common shareholders of $11.1 million ($0.04 per basic common share) in the fourth quarter of 2016.
- Operating costs of $3.86/boe, a 15% decrease from $4.54/boe in the fourth quarter of 2016.
- General and administrative expense of $1.28/boe, an 8% increase from $1.19/boe in the fourth quarter of 2016.
- Interest expense of $0.97/boe, a 31% decrease from $1.40/boe in the fourth quarter of 2016.
- Net capital expenditures of $18.7 million.
- Birchcliff drilled a total of 2 (2.0 net) wells in the fourth quarter of 2017, both of which were Montney/Doig horizontal natural gas wells in the Pouce Coupe area.
- In addition to Birchcliff's oil drilling at Gordondale, Birchcliff recently drilled a four-well pad at Pouce Coupe which came on-stream in November 2017. This pad has shown strong production rates on an IP60 day basis. The four well average IP60 production rate was 1,280 boe/d (6.2 MMcf/d of raw natural gas, 239 bbls/d of 54° API condensate (condensate gas ratio of approximately 38 bbls/MMcf)) with an average flowing casing pressure on day 60 of 11.6 MPa.

For further information, please see *"2017 Unaudited Fourth Quarter Financial and Operational Results"* in this press release.

2017 Year-End Highlights

Highlights of the year ended December 31, 2017 include the following:

- Record annual average production 67,963 boe/d, a 38% increase from 49,236 boe/d in 2016. Production consisted of approximately 79% natural gas, 9% light oil and 12% NGLs as compared to 83% natural gas, 8% light oil and 9% NGLs in 2016.
- Funds flow from operations of $317.7 million, or $1.20 per basic common share, a 115% increase and a 62% increase, respectively, from $147.4 million and $0.74 per basic common share in 2016.
- Birchcliff recorded a net loss to common shareholders of $51.0 million ($0.19 per basic common share), as compared to the net loss to common shareholders of $28.3 million ($0.14 per basic common share) in 2016. Included in the net loss for 2017 is an after-tax book loss of $132.3 million resulting from the sale of Birchcliff's Worsley Charlie Lake Light Oil Pool which closed on August 31, 2017.
- Operating costs of $4.45/boe, a 6% increase from $4.18/boe in 2016.
- General and administrative expense of $1.07/boe, a 10% decrease from $1.19/boe in 2016.
- Interest expense of $1.14/boe, a 32% decrease from $1.68/boe in 2016.
- Net capital expenditures of $276.1 million and total capital expenditures of $416.8 million in 2017.
- Total debt at December 31, 2017 was $598.2 million, as compared to $600.0 million at December 31, 2016.
- Birchcliff drilled a total of 54 (54.0 net) wells in 2017, consisting of 16 (16.0 net) Montney horizontal oil and natural gas wells in the Gordondale area, 37 (37.0 net) Montney/Doig horizontal natural gas wells in the Pouce Coupe area and 1 (1.0 net) Montney/Doig vertical science and technology well in the Pouce Coupe area. Birchcliff brought a total of 61 (61.0 net) wells on production during 2017.
- The 80 MMcf/d Phase V expansion of Birchcliff's 100% owned and operated natural gas processing plant in Pouce Coupe (the "**Pouce Coupe Gas Plant**") was successfully brought on-stream in the third quarter of 2017, increasing the total processing capacity of the plant to 260 MMcf/d from 180 MMcf/d.
- During 2017, Birchcliff completed asset sales for total proceeds of approximately $148 million (before adjustments), including the disposition of its Worsley Charlie Lake Light Oil Pool for total proceeds of approximately $100 million (before adjustments) ($90 million in cash; $10 million in securities) which closed in the third quarter of 2017.
- During 2017, Birchcliff reduced its exposure to pricing at AECO and diversified the natural gas markets it sells to. Birchcliff entered into agreements for the firm service transportation of an aggregate of 175,000 GJ/d (approximately 152 MMcf/d) of natural gas on TCPL's Canadian Mainline for a 10-year term, whereby natural gas is transported to the Dawn trading hub located in Southern Ontario. The first tranche of this service

(120,000 GJ/d) became available to Birchcliff on November 1, 2017, with additional tranches becoming available on November 1, 2018 (35,000 GJ/d) and November 1, 2019 (20,000 GJ/d).

- Birchcliff began paying a quarterly dividend to its common shareholders during 2017 in the amount of $0.10 per share per year ($0.025 per share per quarter).

For further information, please see *"2017 Unaudited Year-End Financial and Operational Results"* in this press release.

2018 Capital Expenditure Program and 2018 Guidance

- Birchcliff's board of directors has approved a capital expenditure budget for 2018 of $255 million. Approximately $149.9 million has been allocated for drilling and development, $66.9 million for facilities and infrastructure and $17.1 million for sustaining and optimization.
- Highlights of Birchcliff's 2018 capital expenditure program (the "**2018 Capital Program**") include the following:
    - The program contemplates the drilling, completing, equipping and bringing on production of a total of 27 (27.0 net) wells during 2018 and targets an annual average production rate for 2018 in the range of 76,000 to 78,000 boe/d.
    - The 2018 Capital Program is expected to be fully funded from Birchcliff's 2018 funds flow from operations, based on the assumptions contained herein.
    - A continued focus on oil and NGLs production and field delineation of the Montney D1 and D2 intervals in Gordondale and further exploration and delineation of liquids-rich trends in the Montney D1, D2 and C intervals in Pouce Coupe.
    - A continued commitment to science and technology to drive operational excellence and further Birchcliff's learnings on field development planning.
    - Completion of the 80 MMcf/d Phase VI expansion of the Pouce Coupe Gas Plant and other strategic infrastructure projects to provide for future growth. Approximately $25.7 million has been allocated towards the completion of Phase VI which is expected to come on-stream in October 2018. In addition, Phases V and VI of the plant are being re-configured to allow for shallow-cut capability to remove propane plus ("**C3+**") liquids from the natural gas stream.

For further information, please see *"2018 Capital Program"* and *"Outlook and Guidance".*

2017 Year-End Reserves Highlights

- The following table summarizes the estimates of Birchcliff's gross reserves at December 31, 2017 and December 31, 2016, as estimated by Birchcliff's independent qualified reserves evaluators using the forecast price and cost assumptions in effect at the applicable reserves evaluation date:

Reserves Category	December 31, 2017 *(Mboe)*	December 31, 2016 *(Mboe)*	Change from December 31, 2016
Proved Developed Producing	197,955.1	165,507.0	20%
Total Proved	664,480.5	548,523.8	21%
Probable	308,034.8	331,940.0	(7%)
Total Proved Plus Probable	972,515.3	880,463.8	10%

- Birchcliff added 65,974.3 Mboe of proved developed producing reserves during 2017, a 40% increase from December 31, 2016, after excluding the effects of acquisitions and dispositions and adding back 2017 actual production of 24,806.3 Mboe.
- Birchcliff added 2.7 boe of proved developed producing reserves for each boe that was produced in 2017, after excluding the effects of acquisitions and dispositions and adding back 2017 actual production.
- The increases in the proved and proved plus probable reserves volumes is primarily attributable to: (i) the success of Birchcliff's 2017 drilling program which resulted in more potential future drilling locations to which reserves were assigned; and (ii) positive technical revisions as a result of improved well performance. Birchcliff achieved increases in its proved and proved plus probable reserves at December 31, 2017, notwithstanding

the various dispositions completed during 2017 and economic factors resulting from a lower commodity price forecast.

- The estimated net present value at December 31, 2017 (before taxes, discounted at 10%) was $1.9 billion for Birchcliff's proved developed producing reserves ($1.9 billion at December 31, 2016) and $5.1 billion ($5.8 billion at December 31, 2016) for its proved plus probable reserves, notwithstanding a lower commodity price forecast and the various dispositions Birchcliff completed during 2017.
- Reserves life index of 7.0 years on a proved developed producing basis, 23.6 years on a proved basis and 34.6 years on a proved plus probable basis, based on a forecast production rate of 77,000 boe/d (which represents the mid-point of Birchcliff's annual average production guidance range for 2018).
- The following table sets forth Birchcliff's reserves per common share:

Reserves Per Common Share(1)	**December 31, 2017** ***(boe/1,000 shares)***	**December 31, 2016** ***(boe/1,000 shares)***	**Increase from December 31, 2016**
Proved Developed Producing	744.8	626.8	19%
Total Proved	2,500.0	2,077.4	20%
Total Proved Plus Probable	3,658.9	3,334.6	10%

(1) Please see *"Advisories – Oil and Gas Metrics"* for a description of the methodology used to calculate reserves per common share.

For further information, please see *"2017 Year-End Reserves"* in this press release.

2017 F&D Costs, FD&A Costs and Recycle Ratios

- The following table sets forth Birchcliff's 2017 F&D and FD&A costs for proved developed producing, proved and proved plus probable reserves:

Excluding FDC *($/boe)*(1)	**2017**
F&D – Proved Developed Producing	$6.29
F&D – Proved	$2.53
F&D – Proved Plus Probable	$2.54
FD&A – Proved Developed Producing	$4.79
FD&A – Proved	$1.95
FD&A – Proved Plus Probable	$2.35
Including FDC *($/boe)*(1)(2)	
F&D – Proved	$8.14
F&D – Proved Plus Probable	$7.27
FD&A – Proved	$7.16
FD&A– Proved Plus Probable	$5.37

(1) Please see *"Advisories – Oil and Gas Metrics"* for a description of the methodology used to calculate F&D and FD&A costs.

(2) Includes the 2017 increase in FDC from 2016 of $732.9 million on a proved basis and $352.9 million on a proved plus probable basis.

- The following table sets forth Birchcliff's 2017 operating netback and funds flow netback recycle ratios for proved developed producing, proved and proved plus probable reserves:

	Operating Netback Recycle Ratio(1)	**Funds Flow Netback Recycle Ratio**(1)
Excluding FDC		
F&D – Proved Developed Producing	2.2	2.0
FD&A – Proved Developed Producing	2.9	2.7
F&D – Proved	5.5	5.1
FD&A – Proved	7.2	6.6
F&D – Proved Plus Probable	5.5	5.0
FD&A – Proved Plus Probable	6.0	5.5
Including FDC		
F&D – Proved	1.7	1.6
FD&A – Proved	2.0	1.8
F&D – Proved Plus Probable	1.9	1.8
FD&A – Proved Plus Probable	2.6	2.4

(1) Birchcliff's operating netback and funds flow netback for 2017 were $13.97/boe and $12.81/boe, respectively. Please see *"Advisories – Oil and Gas Metrics"* for a description of the methodology used to calculate F&D costs, FD&A costs and recycle ratios.

This press release contains forward-looking information within the meaning of applicable securities laws. Such forward-looking information is based upon certain expectations and assumptions and actual results may differ materially from those expressed or implied by such forward-looking information. For further information regarding the forward-looking information contained herein, please see "Advisories – Forward-Looking Information". In addition, this press release contains references to "funds flow from operations", "funds flow per common share", "free funds flow from operations", "operating netback", "estimated operating netback", "funds flow netback", "operating margin", "total cash costs", "adjusted working capital deficit" and "total debt", which do not have standardized meanings prescribed by GAAP. For further information regarding these non-GAAP measures, including reconciliations to the most directly comparable GAAP measure where applicable, please see "Non-GAAP Measures". All financial and operating information for the fourth quarter and year ended December 31, 2017 is unaudited. See "Advisories – Unaudited Information".

2017 UNAUDITED FINANCIAL AND OPERATIONAL HIGHLIGHTS

	Three months ended December 31,		Twelve months ended December 31,	
	2017	**2016**	**2017**	**2016**
OPERATING				
Average daily production				
Light oil – *(bbls)*	5,283	4,656	6,004	3,729
Natural gas – *(Mcf)*	385,280	289,587	320,927	247,373
NGLs – *(bbls)*	10,607	7,830	8,471	4,279
Total – boe	**80,103**	**60,750**	**67,963**	**49,236**
Average sales price *($ CDN)* [(1)]				
Light oil – *(per bbl)*	68.58	60.75	61.42	51.40
Natural gas – *(per Mcf)*	2.64	3.31	2.72	2.41
NGLs – *(per bbl)*	40.08	29.50	33.39	31.23
Total – boe	**22.54**	**24.23**	**22.44**	**18.73**
NETBACK AND COST *($/boe)*				
Petroleum and natural gas revenue[(1)]	22.55	24.24	22.45	18.73
Royalty expense	(1.26)	(1.82)	(1.16)	(1.16)
Operating expense	(3.86)	(4.54)	(4.45)	(4.18)
Transportation and marketing expense	(3.52)	(2.42)	(2.87)	(2.38)
Operating netback	**13.91**	**15.46**	**13.97**	**11.01**
General & administrative expense, net	(1.28)	(1.19)	(1.07)	(1.19)
Interest expense	(0.97)	(1.40)	(1.14)	(1.68)
Realized gain (loss) on financial instruments	1.46	(0.02)	1.03	0.04
Interest Income	0.04	-	0.02	-
Funds flow netback	**13.16**	**12.85**	**12.81**	**8.18**
Stock-based compensation expense, net	(0.13)	(0.12)	(0.16)	(0.14)
Depletion and depreciation expense	(7.86)	(7.73)	(7.48)	(8.29)
Accretion expense	(0.08)	(0.15)	(0.12)	(0.14)
Amortization of deferred financing fees	(0.05)	(0.06)	(0.06)	(0.06)
Gain (loss) on sale of assets	1.86	0.17	(7.50)	(0.53)
Unrealized gain (loss) on financial instruments	(1.86)	(1.72)	0.22	(0.52)
Dividends on Series C preferred shares	(0.12)	(0.16)	(0.14)	(0.19)
Income tax recovery (expense)	(1.42)	(0.92)	0.54	0.34
Net income (loss)	**3.50**	**2.16**	**(1.89)**	**(1.35)**
Dividends on Series A preferred shares	(0.14)	(0.18)	(0.17)	(0.22)
Net income (loss) to common shareholders	**3.36**	**1.98**	**(2.06)**	**(1.57)**
FINANCIAL				
Petroleum and natural gas revenue *($000s)* [(1)]	166,149	135,457	556,942	337,586
Funds flow from operations *($000s)*	97,008	71,806	317,680	147,443
Per common share – basic *($)*	0.36	0.27	1.20	0.74
Per common share – diluted *($)*	0.36	0.27	1.19	0.73
Net income (loss) *($000s)*	25,820	12,085	(46,980)	(24,335)
Net income (loss) to common shareholders *($000s)*	24,773	11,085	(51,027)	(28,335)
Per common share – basic *($)*	0.09	0.04	(0.19)	(0.14)
Per common share – diluted *($)*	0.09	0.04	(0.19)	(0.14)
Common shares outstanding *(000s)*				
End of period – basic	265,797	264,042	265,797	264,042
End of period – diluted	282,895	279,881	282,895	279,881
Weighted average common shares for period – basic	265,792	263,396	265,182	199,581
Weighted average common shares for period – diluted	267,619	268,974	267,873	202,686
Dividends on common shares *($000s)*	6,644	-	26,522	-
Dividends on Series A preferred shares *($000s)*	1,047	1,000	4,047	4,000
Dividends on Series C preferred shares *($000s)*	875	875	3,500	3,500
Capital expenditures, net *($000s)*	18,669	62,482	276,125	762,030
Revolving term credit facilities *($000s)*	587,126	572,517	587,126	572,517
Adjusted working capital deficit *($000s)*	11,067	27,495	11,067	27,495
Total debt *($000s)*	598,193	600,012	598,193	600,012

(1) Excludes the effects of hedges using financial instruments but includes the effects of fixed price physical delivery contracts.

2017 UNAUDITED FOURTH QUARTER FINANCIAL AND OPERATIONAL RESULTS

2017 Q4 Production

We achieved record quarterly average production of 80,103 boe/d, which is slightly above the high end of our previous guidance range of 79,000 to 80,000 boe/d. This quarterly average production represents a 23% increase from 65,276 boe/d in the third quarter of 2017 and a 32% increase from 60,750 boe/d in the fourth quarter of 2016. The increase in production is primarily attributable to the success of our 2017 capital program which resulted in incremental production from new horizontal oil wells being brought on production in Gordondale, as well as from new horizontal natural gas wells being brought on production in Pouce Coupe in connection with the start-up of Phase V of the Pouce Coupe Gas Plant.

Production consisted of approximately 80% natural gas, 7% light oil and 13% NGLs in the fourth quarter of 2017, which is in line with our previous guidance of 80% natural gas and 20% oil and NGLs. This compares to 79% natural gas, 8% light oil and 13% NGLs in the fourth quarter of 2016.

2017 Q4 Funds Flow From Operations and Net Income

Funds flow from operations was $97.0 million, or $0.36 per basic common share, a 51% increase and a 50% increase, respectively, from $64.4 million and $0.24 per basic common share in the third quarter of 2017, and a 35% increase and a 33% increase, respectively, from $71.8 million and $0.27 per basic common share in the fourth quarter of 2016. The increase in funds flow from operations from the third quarter of 2017 was largely due to a higher average corporate realized commodity sales price and higher corporate production, partially offset by higher general and administrative expense and increased royalties, operating and transportation and marketing expenses resulting from higher production in the fourth quarter of 2017. The increase in funds flow from operations from the fourth quarter of 2016 was largely due to higher corporate production, a realized cash gain on financial commodity price risk management contracts and lower royalty expense, partially offset by a lower average corporate realized commodity sales price, higher general and administrative expense and increased operating and transportation and marketing expenses primarily resulting from higher production in the fourth quarter of 2017.

We had net income of $25.8 million, as compared to the net loss of $120.7 million in the third quarter of 2017 and net income of $12.1 million in the fourth quarter of 2016. We recorded net income to common shareholders of $24.8 million ($0.09 per basic common share), as compared to the net loss to common shareholders of $121.7 million ($0.46 per basic common share) in the third quarter of 2017 and net income to common shareholders of $11.1 million ($0.04 per basic common share) in the fourth quarter of 2016. The change from the net loss in the third quarter of 2017 to net income in the fourth quarter of 2017 is primarily attributable to the after-tax book loss of $132.3 million on the sale of our Worsley Charlie Lake Light Oil Pool which was recorded in the third quarter of 2017 (see *"2017 Unaudited Year-End Financial Operational Results – Acquisitions and Dispositions"*). The increase in net income as compared to the fourth quarter of 2016 is primarily due to an increase in funds flow from operations, an after-tax gain of $10.0 million on the sale of our Progress Charlie Lake assets (see *"– Acquisitions and Dispositions"*) and partially offset by higher depletion expense resulting from higher production in the fourth quarter of 2017.

2017 Q4 Operating Costs, Transportation and Marketing Expense and General and Administrative Expense

Operating costs were $3.86/boe, which is in line with our previous guidance of less than $4.00/boe. This represents a 10% decrease from $4.27/boe in the third quarter of 2017 and a 15% decrease from $4.54/boe in the fourth quarter of 2016. The decrease in operating costs per boe from the comparative quarters was largely due to an increased percentage of incremental production additions brought on production to Phase V of the Pouce Coupe Gas Plant, the sale of our higher-cost Worsley Charlie Lake Light Oil Pool and various cost reductions and infrastructure optimization initiatives implemented by Birchcliff throughout 2017.

Transportation and marketing expense was $3.52/boe, a 33% increase from $2.65/boe in the third quarter of 2017 and a 45% increase from $2.42/boe in the fourth quarter of 2016. The increase from the comparative quarters was primarily due to firm service transportation tolls for natural gas transported to Dawn between November 1, 2017 and December 31, 2017. See *"Update on Hedging and Market Diversification"* for further information.

General and administrative expense was $1.28/boe, a 56% increase from $0.82/boe in the third quarter of 2017 and an 8% increase from $1.19/boe in the fourth quarter of 2016. The increase from the comparative quarters was primarily due to the additional staff needed to manage the increases in production, reserves and land base associated with our assets in Pouce Coupe and Gordondale and higher general business expenditures.

2017 Q4 Capital Expenditures

Total F&D capital in the fourth quarter of 2017 (which excludes acquisitions, dispositions and administrative assets) was $49.3 million. Of these capital expenditures, approximately $35.5 million was spent on drilling and completions and $9.7 million on facilities and infrastructure.

2017 Q4 Drilling

During the fourth quarter of 2017, we drilled 2 (2.0 net) wells, both of which were Montney/Doig horizontal natural gas wells in the Pouce Coupe area. For further information regarding our drilling activities during 2017, please see *"Operations Overview and Update"* in this press release.

2017 UNAUDITED YEAR-END FINANCIAL AND OPERATIONAL RESULTS

2017 Production

We achieved record annual average production in 2017 of 67,963 boe/d, which is on the high end of our previous guidance range of 67,000 to 68,000 boe/d. This annual average production represents a 38% increase from our 2016 annual average production of 49,236 boe/d. The increase in production is primarily attributable to the success of our 2017 capital program which resulted in incremental production from new horizontal oil wells being brought on production in Gordondale, as well as from new horizontal natural gas wells being brought on production in Pouce Coupe in connection with the start-up of Phase V of the Pouce Coupe Gas Plant.

Production consisted of approximately 79% natural gas, 9% light oil and 12% NGLs in 2017, which is in line with our previous guidance of 79% natural gas and 21% oil/NGLs. This compares to 83% natural gas, 8% light oil and 9% NGLs in 2016.

2017 Market Diversification and Commodity Prices

During 2017, we entered into agreements with TCPL for the firm service transportation of an aggregate of 175,000 GJ/d (approximately 152 MMcf/d) of natural gas on TCPL's Canadian Mainline for a 10-year term, whereby natural gas is transported to the Dawn trading hub located in Southern Ontario. The first tranche of this service (120,000 GJ/d) became available to Birchcliff on November 1, 2017, with additional tranches becoming available later in 2018 and in 2019. In addition, we entered into additional arrangements during 2017 with third party marketers to sell and deliver natural gas into the Alliance pipeline system. See "*Update on Hedging and Market Diversification".*

During 2017, the average benchmark price for WTI oil was US$50.95/bbl, up 18% from US$43.32/bbl during 2016, and the average benchmark price for natural gas sold at AECO stayed flat at $2.16/MMBtu as compared to 2016. The average benchmark price for natural gas sold at Dawn from November 1, 2017 to December 31, 2017 was $3.82/MMBtu. Our average corporate realized commodity sales price during 2017 was $22.44/boe, a 20% increase from $18.73/boe during 2016. At December 31, 2017, approximately 29% of our natural gas production was being sold at the Dawn price, 13% was being sold into the Alliance pipeline system and 58% of was being sold at AECO. After taking into account our oil and NGLs production, approximately 47% of our total corporate production at December 31, 2017 was exposed to AECO pricing, with the remaining 53% of corporate production not exposed to AECO pricing.

2017 Funds Flow From Operations and Net Loss

Funds flow from operations in 2017 was $317.7 million, or $1.20 per basic common share, a 115% increase and a 62% increase, respectively, from $147.4 million and $0.74 per basic common share in 2016. The increase from 2016 was largely due to a higher average corporate realized commodity sales price, higher corporate production, a realized cash gain on financial commodity price risk management contracts and lower interest costs, partially offset by higher royalties, operating and transportation and marketing expenses primarily resulting from higher production during 2017.

We had a net loss of $47.0 million in 2017, as compared to the net loss of $24.3 million in 2016. We recorded a net loss to common shareholders of $51.0 million ($0.19 per basic common share) in 2017, as compared to the net loss to common shareholders of $28.3 million ($0.14 per basic common share) in 2016. The increases in the net losses from 2016 were mainly attributable to an after-tax book loss of $132.3 million resulting from the sale of our Worsley Charlie Lake Light Oil Pool, higher depletion and stock-based compensation costs and an unrealized mark-to-market loss on financial commodity price risk management contracts, partially offset by higher funds flow from operations in 2017.

2017 Operating Costs, Transportation and Marketing Expense and General and Administrative Expense

Operating costs in 2017 were $4.45/boe, a 6% increase from $4.18/boe in 2016. The increase in operating costs per boe from 2016 was largely due to higher operating, processing and service costs associated with our assets in Gordondale (the "**Gordondale Assets**") which were initially acquired on July 28, 2016, partially offset by incremental production additions brought on production to Phase V of the Pouce Coupe Gas Plant, the sale of our higher-cost Worsley Charlie Lake Light Oil Pool and various cost reductions and infrastructure optimization initiatives implemented by Birchcliff throughout 2017. Our Gordondale Assets have a higher cost structure primarily resulting from increased oil and NGLs production weighting and additional fees incurred to process natural gas from the Gordondale area at AltaGas' owned and operated natural gas processing facility located in Gordondale.

Transportation and marketing expense was $2.87/boe, a 21% increase from $2.38/boe in 2016. The increase was primarily due to firm service transportation tolls for natural gas transported from Empress to Dawn between November 1, 2017 and December 31, 2017. See *"Update on Hedging and Market Diversification"* for further information.

General and administrative expense in 2017 was $1.07/boe, a 10% decrease from $1.19/boe in 2016. The decrease on a per unit basis is primarily due to an increase in corporate production, partially offset by additional staff needed to manage the increases in production, reserves and land base associated with our assets and higher general business expenditures.

2017 Interest Expense

Interest expense was $1.14/boe, a 32% decrease from $1.68/boe in 2016. The decrease is primarily due to a combination of higher production and a lower average outstanding bank debt drawn in 2017 as compared to 2016.

2017 Pouce Coupe Gas Plant Netbacks

Approximately 60% of our total corporate natural gas production and 49% of our total corporate production was processed at the Pouce Coupe Gas Plant during 2017 as compared to 68% and 59%, respectively, during 2016. These decreases are primarily due to the increased weighting of liquids-rich production from our Gordondale Assets as a percentage of corporate production. The average plant and field operating cost for production processed through the Pouce Coupe Gas Plant for 2017 was $0.34/Mcfe ($2.07/boe) and the estimated operating netback at the Pouce Coupe Gas Plant was $2.19/Mcfe ($13.12/boe), resulting in an operating margin of 72%.

The following table details our average daily production and estimated operating netback for wells producing to the Pouce Coupe Gas Plant:

	Twelve months ended December 31, 2017		Twelve months ended December 31, 2016		Twelve months ended December 31, 2015	
Average daily production, net to Birchcliff:						
Natural gas *(Mcf)*		193,417		168,444		163,641
Oil & NGLs *(bbls)*		1,316		960		1,287
Total boe		**33,552**		**29,034**		**28,560**
AECO – C daily *($/MMBtu)*(1)	**$2.16**		**$2.16**		**$2.69**	
Operating netback and cost:	*$/Mcfe*	*$/boe*	*$/Mcfe*	*$/boe*	*$/Mcfe*	*$/boe*
Petroleum and natural gas revenue(2)	3.04	18.24	2.54	15.21	3.17	19.03
Royalty expense	(0.07)	(0.44)	(0.06)	(0.38)	(0.11)	(0.63)
Operating expense(3)	(0.34)	(2.07)	(0.25)	(1.49)	(0.31)	(1.90)
Transportation and marketing expense(4)	(0.44)	(2.61)	(0.33)	(1.96)	(0.31)	(1.88)
Estimated operating netback	**$2.19**	**$13.12**	**$1.90**	**$11.38**	**$2.44**	**$14.62**
Operating margin	**72%**	**72%**	**75%**	**75%**	**77%**	**77%**

(1) $1.00/MMBtu = $1.00/Mcf based on a standard heat value Mcf.

(2) Excludes the effects of hedges using financial instruments but includes the effects of fixed price physical delivery contracts and higher average realized pricing for a portion of natural gas sold at the Dawn price. The average benchmark price for natural gas sold at Dawn from November 1, 2017 to December 31, 2017 was $3.82/MMBtu.

(3) Represents plant and field operating costs.

(4) Includes transportation tolls for a portion of natural gas sold at the Dawn price from November 1, 2017 to December 31, 2017.

2017 Funds Flow Netback and Total Cash Costs

During 2017, we had funds flow netback of $12.81/boe, a 57% increase from $8.18/boe in 2016. The increase from 2016 was largely due to a higher average corporate realized commodity sales price in 2017 and an increase in per unit realized cash gain on financial commodity price risk management contracts during 2017, partially offset by higher per unit operating and transportation and marketing costs due to higher production.

During 2017, we had total cash costs of $10.69/boe, as compared to $10.59/boe in 2016. The increase was primarily due to the acquisition of the higher-cost liquids-rich Gordondale Assets which occurred partway through 2016, partially offset by the disposition of the higher-cost Worsley Charlie Lake Light Oil Pool which closed in the third quarter of 2017.

2017 Capital Activities and Expenditures

In 2017, we had total capital expenditures of $416.8 million and net capital expenditures of $276.1 million, which is 3% above and 5% above, respectively, our previous guidance of $404 million total capital expenditures and $262 million net capital expenditures. Our capital expenditure activities during 2017 were focused on our Montney/Doig Resource Play in our Gordondale and Pouce Coupe areas. Our total F&D capital during 2017 (which excludes acquisitions, dispositions and administrative assets) was $415.0 million, which consisted of $269.1 million on drilling and completions, $132.4 million on facilities and infrastructure, $3.1 million on land and seismic and $10.4 million on other capital expenditures. Of the $132.4 million spent on facilities and infrastructure: (i) approximately $29.7 million was spent on the Phase V expansion of the Pouce Coupe Gas Plant (which came on-stream in the third quarter of 2017) primarily on field construction; and (ii) approximately $26.7 million was spent on the Phase VI expansion of the Pouce Coupe Gas Plant (expected to come on-stream in October 2018) primarily on engineering, procurement and fabrication.

Drilling and Completions

We drilled a total of 54 (54.0 net) wells during 2017. Of the 54 (54.0 net) wells drilled during 2017, 16 (16.0 net) were Montney horizontal oil and natural gas wells drilled in the Gordondale area, 37 (37.0 net) were Montney/Doig horizontal natural gas wells drilled in the Pouce Coupe area and 1 (1.0 net) was a Montney/Doig vertical science and technology well drilled in the Pouce Coupe area. Of these 54 wells, a total of 51 (51.0 net) wells were brought on production during 2017. Of the remaining 3 wells: (i) 1 Montney D1 horizontal natural gas well was drilled in December 2017 and is expected to be brought on production in the second quarter of 2018; (ii) 1 Montney/Doig well drilled in the Pouce Coupe area encountered operational challenges during the completion operation and is now expected to be brought on production in the third quarter of 2018; and (iii) the Montney/Doig vertical science and technology well is not intended to be a producing well. In addition, our 2017 capital program also included the capital associated with the completion, equipping and tie-in of 10 wells drilled in 2016, all of which were brought on production in the first quarter of 2017. Accordingly, a total of 61 (61.0 net) wells were brought on production during 2017, down from our previous guidance of 62 (62.0 net) wells.

All wells drilled in 2017 were drilled on multi-well pads, which allows us to reduce our per well costs and our environmental footprint. In addition, we actively employ the evolving technology utilized by the industry regarding horizontal well drilling and the related multi-stage fracture stimulation technology. For further information regarding our drilling activities during 2017, please see *"Operations Overview and Update"* in this press release.

Acquisitions and Dispositions

During 2017, we completed various asset sales for total proceeds of approximately $148 million (before adjustments) ($138 million in cash; $10 million in securities), representing forecast 2017 average production of approximately 3,600 boe/d. The proceeds from these asset sales were initially used to reduce indebtedness under our credit facilities, which was subsequently redrawn as needed to fund our capital expenditure program and for general corporate purposes. In addition, we also completed various minor acquisitions for total consideration of approximately $1.0 million. See also *"2017 Land"*.

During 2017, we disposed of the vast majority of our assets on our Charlie Lake Light Oil Resource Play pursuant to various transactions so that we could focus on our Montney/Doig Resource Play. In particular, we completed two significant dispositions on August 31, 2017 and October 2, 2017. On August 31, 2017, we completed the sale of our Worsley Charlie Lake Light Oil Pool for total consideration of approximately $100 million (before adjustments) ($90 million in cash; $10 million in securities of affiliates of the purchaser) (the "**Worsley Disposition**"). On October 2, 2017, we completed the disposition of our Progress Charlie Lake assets for total cash consideration of $31.7 million (before adjustments) (the "**Progress Disposition**").

2017 Credit Facilities and Debt

Our extendible revolving credit facilities have an aggregate principal amount of $950 million (the "**Credit Facilities**") and are comprised of an extendible revolving syndicated term credit facility of $900 million (the "**Syndicated Credit Facility**") and an extendible revolving working capital facility of $50 million (the "**Working Capital Facility**"). The maturity date of each of the Syndicated Credit Facility and the Working Capital Facility is May 11, 2020. We may each year, at our option, request an extension to the maturity date of the Syndicated Credit Facility and the Working Capital Facility, or either of them, for an additional period of up to three years from May 11 of the year in which the extension request is made. The Credit Facilities are subject to semi-annual reviews of the borrowing base limit by our syndicate of lenders, which reviews are typically completed in May and November of each year. The Credit Facilities do not contain any financial maintenance covenants.

At December 31, 2017, our long-term bank debt was $587.1 million (December 31, 2016: $572.5 million) from available credit facilities of $950 million (December 31, 2016: $950 million), leaving $343 million of unutilized credit capacity after adjusting for outstanding letters of credit and unamortized interest and fees. Total debt at December 31, 2017 was $598.2 million as compared to $600.0 million at December 31, 2016.

2017 Risk Management

During 2017, we realized a cash gain on financial commodity price risk management contracts of $25.8 million compared to $0.8 million in 2016. We recorded a $5.4 million unrealized gain on financial commodity price risk management contracts in 2017 as compared to a $9.4 million unrealized loss in 2016.

As at December 31, 2017, we had outstanding financial derivative contracts for 4,500 bbls/d of crude oil production from January 1, 2018 to December 31, 2018 at an average WTI price of CDN$71.87. See *"Update on Hedging and Market Diversification".*

2017 Land

Our land base primarily consists of large contiguous blocks of high working interest acreage located near facilities owned and/or operated by Birchcliff or near third party infrastructure. We were very successful with our strategy of focusing on our Montney/Doig Resource Play and disposing of non-core assets during 2017. Our land activities during 2017 included: (i) the acquisition of 51.5 (54.0 net) sections of Crown and third party lands; and (ii) the disposition of 346.3 (309.8 net) sections, including 191.8 (185.3 net) sections of land pursuant to the Worsley Disposition and 45.5 (35.7 net) sections of land pursuant to the Progress Disposition and including 80.8 (73.8 net) sections of land that expired in 2017. Our undeveloped land base at December 31, 2017 was 262,318.4 (238,705.5 net) acres, or 409.9 (373.0 net) sections, with a 91% average working interest.

2018 CAPITAL PROGRAM

Our board of directors has approved a capital expenditure budget of $255 million. Approximately $149.9 million has been allocated for drilling and development and $66.9 million for facilities and infrastructure. We expect that our 2018 capital expenditures will be less than our funds flow from operations during 2018, based on the assumptions contained herein. Details on the expected capital spending allocation are set forth in the table below:

	Gross Wells	Net Wells	Capital *(MM)*
Drilling and Development			
Pouce Coupe – Montney D1 Horizontal Gas Wells	12	12.0	$66.2
Pouce Coupe –Montney D2 Horizontal Gas Wells	1	1.0	$4.9
Pouce Coupe – Montney C Horizontal Gas Wells	1	1.0	$5.1
Gordondale – Montney D2 Horizontal Oil Wells	8	8.0	$42.2
Gordondale – Montney D1 Horizontal Oil Wells	5	5.0	$26.0
2017 Carry Forward Capital(1)	-	-	$5.5
Total Drilling and Development(2)	**27**	**27.0**	**$149.9**
Facilities and Infrastructure			$66.9(3)
Sustaining and Optimization			$17.1
Land and Seismic			$4.6
Other			$16.5
TOTAL CAPITAL(4)			**$255.0**

(1) Primarily completion, equipping and tie-in costs associated with 2 (2.0 net) wells rig released in 2017.

(2) On a drill, case, complete, equip and tie-in basis.

(3) Includes: (i) $25.7 million for the completion of the Phase VI expansion; (ii) $11.2 million for a pipeline twinning project; (iii) $8.3 million for the construction of an additional sales line from the Pouce Coupe Gas Plant; and (iv) $6.0 million for water storage. The remaining capital primarily relates to new pipeline construction and other projects.

(4) Birchcliff makes acquisitions and dispositions in the ordinary course of business. Any acquisitions and dispositions completed during 2018 could have an impact on Birchcliff's capital expenditures, which impact could be material. See *"Advisories – Capital Expenditures"*.

Highlights of the 2018 Capital Program

Our 2018 Capital Program reflects our long-term plan to continue the exploration and development of our low-cost natural gas, crude oil and liquids-rich assets on the Montney/Doig Resource Play. The program will direct capital investment to those projects with the most favourable rates of return, including a combination of liquids-rich natural gas, crude oil and natural gas development opportunities and strategic infrastructure for future growth. In particular, the 2018 Capital Program will focus on the drilling of crude oil wells in Gordondale and a combination of liquids-rich and low-cost natural gas wells in Pouce Coupe to take advantage of the recently improved prices for oil and NGLs.

The objectives of the 2018 Capital Program are to maintain a prudent pace of development and focus on rates of return, while also maintaining balance sheet strength and the payment of a sustainable quarterly dividend to our shareholders. The 2018 Capital Program has been designed with financial and operational flexibility with the potential to accelerate or decelerate capital expenditures throughout the year, depending on commodity prices and economic conditions.

Other highlights of the 2018 Capital Program include the following:

- The program contemplates the drilling, completing, equipping and bringing on production of a total of 27 (27.0 net) wells during 2018 and targets an annual average production rate for 2018 in the range of 76,000 to 78,000 boe/d.
- The 2018 Capital Program is expected to be fully funded from our 2018 funds flow from operations.
- A continued focus on oil and NGLs production and field delineation of the Montney D1 and D2 intervals in Gordondale and further exploration and delineation of liquids-rich trends in the Montney D1, D2 and C intervals in Pouce Coupe.
- A continued commitment to science and technology to drive operational excellence and further our learnings on field development planning.
- Completion of the Phase VI expansion of the Pouce Coupe Gas Plant and other strategic infrastructure projects to provide for future growth. Approximately $25.7 million will be allocated towards the completion of Phase VI which is expected to come on-stream in October 2018. In addition, Phases V and VI of the plant are being re-configured to allow for shallow-cut capability to remove C3+ liquids from the natural gas stream.
- Approximately 35% of the 2018 Capital Program is directed towards our Gordondale area and approximately 56% is directed towards our Pouce Coupe area.

Gordondale Area

We plan to invest approximately $90 million in Gordondale during 2018. Key focus areas for Gordondale in 2018 will be the drilling of crude oil wells, the delineation of the Montney D1 and D2 intervals and continuing to improve on our well results and completion techniques through completion system design and fracturing techniques.

Drilling and Development

We plan to drill 13 (13.0 net) horizontal wells in the Gordondale area, consisting of 8 (8.0 net) Montney D2 horizontal oil wells and 5 (5.0 net) Montney D1 horizontal oil wells, all of which will be drilled on multi-well pads.

Pouce Coupe Area

We plan to invest approximately $142.3 million in Pouce Coupe during 2018. Key focus areas for Pouce Coupe in 2018 will be the drilling of liquids-rich natural gas wells to maximize the recovery of condensate and other liquids, the execution of our multi-well science and technology pad, the exploration of the Montney D2 and C intervals, the completion of the 80 MMcf/d Phase VI expansion of the Pouce Coupe Gas Plant, the addition of shallow-cut capability for Phases V and VI and continuing to improve on our well results and completion techniques.

Drilling and Development

We plan to drill 14 (14.0 net) horizontal wells in our Pouce Coupe area, consisting of 12 (12.0 net) Montney D1 horizontal liquids-rich and low-cost natural gas wells, 1 (1.0 net) Montney D2 horizontal liquids-rich natural gas well and 1 (1.0 net) Montney C horizontal liquids-rich natural gas well, all of which will be drilled on multi-well pads.

Facilities and Infrastructure

We plan to invest $66.9 million in facilities and other strategic infrastructure during 2018, of which approximately $25.7 million will be directed towards the Phase VI expansion of the Pouce Coupe Gas Plant as discussed in further detail below. Once this investment has been made, we expect that our facilities and infrastructure expenditures going forward will decrease significantly until a decision is made to build additional phases of the Pouce Coupe Gas Plant.

Pouce Coupe Gas Plant – Phase VI Expansion and Shallow-Cut Capability

During 2018, we expect to complete the 80 MMcf/d Phase VI expansion of the Pouce Coupe Gas Plant which will increase the processing capacity from 260 MMcf/d to 340 MMcf/d. Field construction commenced in January 2018 and we currently anticipate that Phase VI will be brought on-stream in October 2018. Phase VI will allow for future growth and help us to reduce our operating costs on a per boe basis.

The total estimated cost for the Phase VI expansion is approximately $52.4 million, of which $26.7 million has already been incurred. We estimate that an additional $25.7 million will be required during 2018 to complete construction as the fabrication of the components has been completed and much of the infrastructure that will be utilized by Phase VI was built in connection with Phase V which came on-stream in the third quarter of 2017. In effect, Phase VI is an add-on to Phase V for a relatively low expenditure as the cost of the additional 80 MMcf/d is only $0.655 million per MMcf/d of capacity.

In addition, we are currently in the process of re-configuring Phases V and VI to provide for shallow-cut capability when Phase VI comes on-stream. This shallow-cut capability will allow us to remove from the natural gas stream C3+ liquids. As both phases will include shallow-cut capability, the combined 160 MMcf/d facility is expected to provide approximately 600 bbls/d of C3+ based on the current natural gas stream going through the Pouce Coupe Gas Plant. As we increase our focus on liquids-rich drilling opportunities, this will provide for the efficient processing of liquids-rich natural gas. This addition of shallow-cut capability is only expected to cost an additional $3.0 million which is included in the estimated cost for Phase VI.

Given our 2018 drilling program and expected 2018 production levels, we will have excess capacity at the Pouce Coupe Gas Plant when Phase VI comes on-stream. In order to partially fill Phase VI, we currently plan on diverting some of our natural gas that is currently being processed by third-party processors to Phase VI, which will also help us to reduce our operating costs. We believe that we will be able to fill this excess capacity over time as commodity prices improve and as we target liquids-rich natural gas wells.

Funding of the 2018 Capital Program

The 2018 Capital Program is expected to be fully funded from our 2018 funds flow from operations, based on the assumptions contained herein (see *"Outlook and Guidance*"). We are focused on maintaining balance sheet strength and we may choose to use any funds flow from operations in excess of our capital expenditures and dividend payments to pay down indebtedness under our Credit Facilities.

2018 Production Guidance

Based on the 2018 Capital Program, we expect our annual average production in 2018 to be in the range of 76,000 to 78,000 boe/d, comprised of approximately 80% natural gas and 20% oil and NGLs. This represents an increase of 12% to 15% from our 2017 annual average production. We believe that our annual average production target for 2018 represents a prudent level of growth over 2017 given current economic conditions. See *"Outlook and Guidance".*

OUTLOOK AND GUIDANCE

The following table sets forth our guidance and commodity price assumptions for 2018, as well as our 2017 actual unaudited results for comparative purposes:

	2018 Guidance and Assumptions[1]	2017 Annual Actuals
Production		
Annual Average Production (boe/d)	76,000 – 78,000	67,963
% Natural Gas	80%	79%
% Oil and NGLs	20%	21%
Average Expenses *($/boe)*		
Royalty	1.20 – 1.40	1.16
Operating	3.75 – 4.00	4.45
Transportation and Marketing	3.80 – 4.10[2]	2.87[3]
Capital Expenditures *(MM$)*[4]		
Estimated Total Capital	255.0	416.8
Estimated Drilling and Development Capital	149.9	269.1
Estimated Facilities and Infrastructure Capital	66.9	132.4
Natural Gas Market Exposure[5]		
AECO Production as a % of Total Natural Gas Production	66%	58%[6]
Dawn Production as a % of Total Natural Gas Production	30%	29%[6]
Commodity Prices		
Average WTI Oil Price *(US$/bbl)*	61.00	50.95
Average AECO Price *($/MMBtu)*[7]	1.58	2.16
Average Dawn Price *($/MMBtu)*[7]	3.48	3.82[6]
Average Wellhead Natural Gas Price *($/Mcf)*[8]	2.32	2.72[9]

(1) For further information regarding Birchcliff's 2018 guidance, including the assumptions surrounding such guidance, please see *"Advisories – Forward-Looking Information"* in this press release.

(2) Includes transportation tolls for 120,000 GJ/d of natural gas sold at the Dawn price from January 1, 2018 to October 31, 2018 and 155,000 GJ/d from November 1, 2018 to December 31, 2018.

(3) Includes transportation tolls for 120,000 GJ/d of natural gas sold at the Dawn price from November 1, 2017 to December 31, 2017.

(4) Please see *"2018 Capital Program".*

(5) Approximately 13% of total natural gas production was sold via the Alliance pipeline system in 2017. Approximately 4% of total natural gas production is expected to be sold via the Alliance pipeline system in 2018.

(6) For the months of November and December 2017 only as our TCPL-Dawn arrangement did not commence until November 1, 2017.

(7) $1.00 per MMBtu equals $1.00 per Mcf based on a standard heat value of 37.4 MJ/m3 or a heat uplift of 1.055 when converting from $/GJ.

(8) Birchcliff receives premium pricing for its natural gas production due to its high heat content from its properties. The conversion from standard heat value in MMBtu to realized wellhead price in Mcf is based on an expected corporate average realized natural gas heat content value of 40.80 MJ/m3 or a heat uplift of 1.091. The total conversion is $1.00/GJ = $1.15/Mcf at the wellhead.

(9) Includes the effects of any commodity fixed price physical delivery contracts in the period.

The average wellhead natural gas price for 2018 of $2.32/Mcf is based upon an annual average AECO price of $1.58/MMBtu during 2018 ($2.11/MMBtu during the months of January, February, March, November and December and $1.20/MMBtu during the remaining months of 2018) and an annual Dawn price of $3.48/MMBtu during 2018 ($4.22/MMBtu during the months of January and February and $3.33/MMBtu during the remaining months of 2018).

We are currently reviewing our short and long-term growth opportunities and developing a new five year plan to take into account current economic conditions, the 2018 Capital Program and other recent developments. We expect to release our updated five year plan later in 2018.

UPDATE ON HEDGING AND MARKET DIVERSIFICATION

Hedging

Our current hedging strategy for 2018 is to hedge up to 50% of our 2018 forecast annual average production using a combination of financial derivatives and physical delivery sales contracts, depending on our outlook for commodity prices and the availability of hedges on terms acceptable to Birchcliff. At the date hereof, approximately 6% of our 2018 forecast annual average production is hedged.

With respect to crude oil, we have entered into financial derivative contracts for 4,500 bbls/d of crude oil at an average WTI price of CDN$71.87/bbl for the period from January 1, 2018 to December 31, 2018. This represents approximately 31% of our 2018 forecast annual average oil and NGLs production and approximately 6% of our total 2018 forecast annual average production.

With respect to natural gas, we have not entered into any natural gas hedges given the current weak AECO natural gas markets. Given the current strip prices from which to hedge at today, we believe that the downside to AECO has already been priced into the AECO market forward strip and potentially even oversold. Rather than hedge at these current prices, we are continually seeking to diversify away from AECO, but we are doing so prudently, so that we remain profitable in the long-term.

Market Diversification

During 2018, we expect that approximately 34% of our 2018 forecast annual average natural gas production will be sold at prices that are not based on AECO, with 30% being sold at the Dawn daily index price and 4% being marketed via the Alliance pipeline system, as discussed in further detail below. We continue to actively look for further profitable market diversification opportunities. Our market diversification initiatives have helped to reduce our exposure to volatility in commodity prices, including AECO prices which have been extremely volatile in recent months.

During 2017, we entered into agreements with TCPL for the firm service transportation of an aggregate of 175,000 GJ/d (approximately 152 MMcf/d) of natural gas on TCPL's Canadian Mainline for a 10-year term, whereby natural gas is transported from the Empress receipt point in Alberta to the Dawn trading hub located in Southern Ontario. The toll for the Empress to Dawn portion of the service is $0.77/GJ plus fuel. The first tranche of this service (120,000 GJ/d) became available to Birchcliff on November 1, 2017, with additional tranches becoming available on November 1, 2018 (35,000 GJ/d) and November 1, 2019 (20,000 GJ/d). In the fourth quarter of 2017, we entered into agreements with three natural gas marketers whereby we assigned our TCPL service from Empress to Dawn for a one-year term ending November 1, 2018. During this term, the marketers deliver our natural gas to Dawn and pay Birchcliff the Dawn daily index price, less the Empress to Dawn toll and fuel costs. Under these agreements, each marketer has the option to divert the natural gas to a secondary delivery point to optimize the price received for the natural gas. In such instance, Birchcliff will receive between 60% and 80% of the optimized value obtained for the natural gas.

We have sales agreements with a third party marketer to sell and deliver into the Alliance pipeline system: (i) approximately 40 MMcf/d of natural gas under contracts which commenced November 1, 2017 and expire March 31, 2018, 10 MMcf/d of which is sold at Alliance's Trading Pool daily index price and 30 MMcf/d of which is sold at a Chicago index price; and (ii) approximately 5 MMcf/d of natural gas under contracts which commenced April 1, 2017 and expire October 31, 2020, which is sold at Alliance's Trading Pool daily index price.

OPERATIONS OVERVIEW AND UPDATE

Our operations are concentrated within our one core area, the Peace River Arch, which is centred northwest of Grande Prairie, Alberta, adjacent to the Alberta/British Columbia border. Our operations are focused on our established Montney/Doig Resource Play within the Peace River Arch, which is centred approximately 95 kilometres northwest of Grande Prairie, Alberta.

Our strategy is to continue to develop and expand this resource play, while maintaining low capital costs and operating costs. As part of this strategy, we intend to continue to explore and delineate the Montney/Doig Resource Play, both geographically and stratigraphically. The Montney/Doig Resource Play exists in two geological formations, the Montney and the Doig, and we have divided the geologic column in our areas of operation into six drilling intervals from the youngest (top) to the oldest (bottom): (i) the Basal Doig/Upper Montney; (ii) the Montney D4; (iii) the Montney D3; (iv) the Montney D2; (v) the Montney D1; and (vi) the Montney C. At December 31, 2017, we have successfully drilled and cased an aggregate of 348 (342.8 net) Montney/Doig horizontal wells (which includes 87 (81.8 net) wells that were acquired when we initially purchased our Gordondale Assets in 2016), consisting of 75 (73.5 net) wells in the Basal Doig/Upper Montney interval, 12 (12.0 net) wells in the Montney D4 interval, 13 (13.0 net) wells in the Montney D2 interval, 247 (243.3 net) wells in the Montney D1 interval and 1 (1.0 net) well in the Montney C interval.

Gordondale Area

We were active in the Gordondale area during 2017, drilling a total of 16 (16.0 net) Montney horizontal wells (9 Montney D2 oil, 5 Montney D1 oil and 2 Montney D1 liquids-rich natural gas wells), all of which were successful. All of these wells were brought on production in 2017. A large portion of the 2018 Capital Program is directed towards our Gordondale area, including the drilling of 13 (13.0 net) wells (see *"2018 Capital Program"*).

Since we acquired our Gordondale Assets on July 28, 2016, we have drilled, completed and brought on production a total of 22 (22.0 net) wells in Gordondale, consisting of 12 (12.0 net) Montney D2 horizontal oil wells, 5 (5.0 net) Montney D1 horizontal oil wells and 5 (5.0 net) Montney D1 liquids-rich horizontal natural gas wells. When we first acquired our Gordondale Assets, the average production for such assets was approximately 22,000 boe/d at the date of the acquisition. The 22 horizontal wells that we have drilled and brought on production have replaced the natural production declines and have significantly increased the production on our Gordondale Assets (currently approximately 30,000 boe/d).

Update on Gordondale Montney D2 Horizontal Oil Wells

The 12 Montney D2 horizontal wells that we have drilled, completed and brought on production to-date have significantly delineated, de-risked and proven the commerciality of the Montney D2 play. When we initially acquired the Gordondale Assets, only one D2 well had been previously drilled on the play and there was only one offsetting D2 well.

In an effort to continuously improve our well performance and optimize our completions strategy, we have utilized three different completion systems on our Montney D2 wells drilled to-date, including open hole packers, cemented sleeves fracced with coil tubing and plug and perf technology. We continue to evaluate the production results and cost efficiencies of each system in order to optimize field development in Gordondale.

Our Montney D2 horizontal well results are meeting our expectations. In addition, we were able to reduce the average drilling, completion, equipping and tie-in costs of our Montney D2 horizontal wells to approximately $5.3 million during 2017, which is approximately $1 million less than what we had initially budgeted at the time of our acquisition of the Gordondale Assets. This has helped to significantly improve the economics of our Montney D2 wells.

Pouce Coupe Area

We were active in the Pouce Coupe area during 2017, drilling a total of 38 (38.0 net) wells and working towards the expansions of the Pouce Coupe Gas Plant. A large portion of the 2018 Capital Program is directed towards our Pouce Coupe area, including the drilling of 14 (14.0 net) wells and a continued investment in the Pouce Coupe Gas Plant (see *"2018 Capital Program"*). We are continuing to pursue condensate and other liquids in our Pouce Coupe area in several different Montney/Doig Intervals.

Drilling and Development and IP60 Montney D1 Well Results

During 2017, we drilled a total of 37 (37.0 net) Montney/Doig horizontal natural gas wells in Pouce Coupe (27 Montney D1, 7 Basal Doig/Upper Montney and 3 Montney D4 wells). Of these 37 wells, 36 were brought on production in 2017. In addition, we drilled 1 (1.0 net) Montney/Doig vertical science and technology well in the third quarter of 2017.

Our most recent pad at Pouce Coupe, which came on-stream in November 2017 at 16-15-77-12W6, has shown strong production rates on an IP60 day basis. The four well average IP60 production rate was 1,280 boe/d (6.2 MMcf/d of raw natural gas, 239 bbls/d of 54° API condensate (condensate gas ratio of approximately 38 bbls/MMcf)) with an average flowing casing pressure on day 60 of 11.6 MPa.

Update on Pouce Coupe Gas Plant Expansions

During the third quarter of 2017, the 80 MMcf/d Phase V expansion of the Pouce Coupe Gas Plant was successfully brought on-stream, increasing the total processing capacity of the Pouce Coupe Gas Plant to 260 MMcf/d from 180 MMcf/d. A focus for 2018 will be to complete the 80 MMcf/d Phase VI expansion of the plant, which will increase processing capacity from 260 MMcf/d to 340 MMcf/d. Field construction commenced in January 2018 and it is currently expected that Phase VI will be brought on-stream in October 2018.

We had previously commenced the planning and initial work to further expand the processing capacity of the Pouce Coupe Gas Plant by 150 MMcf/d to 490 MMcf/d (Phase VII which was originally expected to come on-stream in 2020) and by 100 MMcf/d to 590 MMcf/d (Phase VIII which was originally expected to come on-stream in 2021). In light of current conditions, we have deferred making a decision on whether we will proceed with Phases VII or VIII. We expect that we will provide a further update to the market in the coming months after a decision has been made.

Update on Science and Technology Multi-Well Pad Program

The purpose of our science and technology multi-well pad program is to collect high quality and high value data from the vertical well and the straddling horizontal wells, which can be used to enhance our technical capabilities and understanding with respect to the drilling, completion and production from a multi-layer resource play.

In the third quarter of 2017, we drilled a vertical science and technology well in Pouce Coupe. The well was drilled to the top of the Montney where we cut a full diameter core through the entire Montney section (approximately 300 metres). The extracted rock core has provided analytical data to increase our knowledge of rock properties, which we have incorporated in our petrophysical models, and helped us to more accurately represent the geology of the area. We are currently compiling all of the lab measurements and analytical data from this well. We are in the early stages of evaluating the data; however, the data we have received to date looks encouraging for the four different intervals to be developed in this area, being our two proven intervals (the Basal Doig/Upper Montney and the Montney D1) and our two relatively new intervals (the Montney D2 and the Montney C).

We are very excited about the potential identified in the Montney D2 and the C from the vertical well. We have utilized the learnings from the vertical well to finalize the planning on the execution of a science and technology multi-well pad program. Our 2018 Capital Program contemplates drilling four wells from the multi-well pad (one Montney D2 well, one Montney C well and two Montney D1 wells). The Montney D2 well will be the first Montney D2 well drilled in Pouce Coupe and we see significant opportunity to build on the Montney D2 success we have had in Gordondale. The Montney C well will be the second Montney C well we have drilled in Pouce Coupe. The initial

Montney C well that we drilled has been on production for three years and has shown a fairly flat production profile with a condensate ratio of approximately 15 bbls/MMcf. We believe that with our most recent engineered completion design this second Montney C well will outperform the existing Montney C well.

In January 2018, we moved a drilling rig onto the pad and spudded the first of four wells on this pad. The first two wells (the Montney D1 well and a Montney C well) have been rig released and we are currently drilling the third well (the Montney D2 well). We expect that all four wells will be completed in the second quarter of 2018 and brought on production in the third quarter of 2018. During the completion of the four horizontal wells, we intend to utilize the vertical well as a micro-seismic and tilt meter monitoring well to gain further insight into fracture parameters and complexity. In addition to the vertical well, we are planning to install a permanent fiber optic cable within the horizontal portion of one of the Montney D1 horizontal wells, allowing further data to be collected on fracture parameters and ongoing production performance along the horizontal well length.

Potential Future Drilling Opportunities on the Montney/Doig Resource Play

As at December 31, 2017, we held 349.4 sections of land that have potential for the Montney/Doig Resource Play. Of these lands, 348.4 (326.1 net) sections have potential for the Basal Doig/Upper Montney interval, 323.9 (317.0 net) sections have potential for the Montney D1 interval, 325.4 (318.5 net) sections have potential for the Montney D2 interval and 307.9 (301.6 net) sections have potential for the Montney D4 interval. As at December 31, 2017, our total land holdings on these four intervals were 1,305.6 (1,263.2 net) sections. Assuming full development of four horizontal wells per section per drilling interval, we have 5,052.8 net existing horizontal wells and potential net future horizontal drilling locations in respect of the Basal Doig/Upper Montney, Montney D1, Montney D2 and Montney D4 intervals as at December 31, 2017. With 348 (342.8 net) horizontal locations drilled at the end of 2017, there remains 4,710.0 potential net future horizontal drilling locations as at December 31, 2017, down from 5,703.1 at year end 2016. This decrease is primarily attributable to the sale of some non-core Montney/Doig lands that we disposed of during 2017. This does not include any potential net future horizontal drilling locations for the other two prospective Montney intervals, the Montney C and the Montney D3.

Substantial upside exists with respect to the 5,052.8 net existing horizontal wells and potential net future horizontal drilling locations. The 2017 Consolidated Reserves Report attributed proved reserves to 846.0 net existing wells and potential net future horizontal drilling locations (of which 507.2 net wells are potential future drilling locations) and proved plus probable reserves to 1,070.0 net existing wells and potential net future horizontal drilling locations (of which 731.2 net wells are potential future drilling locations). The remaining 3,982.8 potential net future horizontal drilling locations have not yet had any proved or probable reserves attributed to them by our independent qualified reserves evaluators. Please see *“2017 Year-End Reserves”* and *“Advisories – Drilling Locations”.*

Drilling Update

We currently have 5 drilling rigs at work drilling Montney/Doig horizontal wells, 2 rigs in the Gordondale area and 3 in the Pouce Coupe area. In addition to these drilling rigs, we have many other service, facility and pipeline crews working on various projects. We have drilled 10 (10.0 net) wells year-to-date, consisting of 4 (4.0 net) Montney horizontal oil wells in the Gordondale area and 6 (6.0 net) Montney/Doig horizontal natural gas wells in the Pouce Coupe area. All wells were drilled on multi-well pads and none have been completed yet. With 17 wells left to drill under our 2018 Capital Program, we expect to reduce the drilling rigs being utilized after break-up. We anticipate that all 27 wells to be drilled in 2018 will be brought on production by the end of the third quarter of 2018.

We actively employ the evolving technology utilized by the industry regarding horizontal well drilling and the related multi-stage fracture stimulation technology. We are currently utilizing multi-well pad drilling which allows us to reduce our per well costs, as well as our environmental footprint. Industry is continuing to learn about multi-stage fracture stimulation technology and its application to resource plays. The industry trend continues to be toward longer wells, more stages, larger fracs and less inter-well distances, both laterally and vertically.

2017 YEAR-END RESERVES

We retained two independent qualified reserves evaluators, Deloitte LLP ("**Deloitte**") and McDaniel & Associates Consultants Ltd. ("**McDaniel**"), to evaluate and prepare reports on 100% of our light crude oil and medium crude oil (combined), conventional natural gas, shale gas and NGLs reserves. Deloitte evaluated all of our properties other than the Gordondale Assets, representing approximately 75% of the assigned total proved plus probable reserves, and McDaniel evaluated the reserves attributable to the Gordondale Assets, representing approximately 25% of the assigned total proved plus probable reserves.

The reserves data set forth below at December 31, 2017 is based upon the evaluation by Deloitte with an effective date of December 31, 2017 as contained in the report of Deloitte dated February 9, 2018 (the "**2017 Deloitte Reserves Report**") and the evaluation by McDaniel with an effective date of December 31, 2017 as contained in the report of McDaniel dated February 14, 2018 (the "**2017 McDaniel Reserves Report**"), which are contained in the consolidated report of Deloitte with an effective date of December 31, 2017 (the "**2017 Consolidated Reserves Report**"). Deloitte prepared the 2017 Consolidated Reserves Report by consolidating the properties evaluated by Deloitte in the 2017 Deloitte Reserves Report with the properties evaluated by McDaniel in the 2017 McDaniel Reserves Report, in each case using Deloitte's forecast price and cost assumptions effective December 31, 2017 (the "**2017 Deloitte Price Forecast**"). Hedging gains and losses have been incorporated into the 2017 Consolidated Reserves Report.

Deloitte also prepared an evaluation with an effective date of December 31, 2016 as contained in the report of Deloitte dated February 8, 2017 (the "**2016 Deloitte Reserves Report**") and McDaniel prepared an evaluation with an effective date of December 31, 2016 as contained in the report of McDaniel dated February 8, 2017 (the "**2016 McDaniel Reserves Report**"), which are contained in the consolidated report of Deloitte with an effective date of December 31, 2016 (the "**2016 Consolidated Reserves Report**"). Deloitte prepared the 2016 Consolidated Reserves Report by consolidating the properties evaluated by Deloitte in the 2016 Deloitte Reserves Report with the properties evaluated by McDaniel in the 2016 McDaniel Reserves Report, in each case using Deloitte's forecast price and cost assumptions effective December 31, 2016 (the "**2016 Deloitte Price Forecast**").

All of the above-noted reserves reports were prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**") and National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**") in effect at the relevant time.

For additional information regarding the presentation of our reserves disclosure contained herein, please see *"Presentation of Oil and Gas Reserves"* and *"Advisories"* in this press release. The reserves data provided in this press release presents only a portion of the disclosure required under NI 51-101. The disclosure required under NI 51-101 will be contained in our Annual Information Form for the year ended December 31, 2017, which is expected to be filed on the System for Electronic Document Analysis and Retrieval (www.sedar.com) on March 14, 2018. Numbers presented in the tables below may not total due to rounding.

Reserves Summary

The following table summarizes the estimates of our gross reserves at December 31, 2017 and December 31, 2016, using the forecast price and cost assumptions in effect at the applicable reserves evaluation date:

Summary of Gross Reserves
(Forecast Prices and Costs)

Reserves Category	December 31, 2017 *(Mboe)*	December 31, 2016 *(Mboe)*	Change from December 31, 2016
Proved Developed Producing	197,955.1	165,507.0	20%
Total Proved	664,480.5	548,523.8	21%
Probable	308,034.8	331,940.0	(7%)
Total Proved Plus Probable	972,515.3	880,463.8	10%

The following table sets forth our light crude oil and medium crude oil, conventional natural gas, shale gas and NGLs reserves at December 31, 2017, using the 2017 Deloitte Price Forecast:

Summary of Reserves at December 31, 2017
(Forecast Prices and Costs)(1)

	Light Crude Oil and Medium Crude Oil		Conventional Natural Gas		Shale Gas		NGLs		Total Boe	
Reserves Category	*Gross (Mbbls)*	*Net (Mbbls)*	*Gross (MMcf)*	*Net (MMcf)*	*Gross (MMcf)*	*Net (MMcf)*	*Gross (Mbbls)*	*Net (Mbbls)*	*Gross (Mboe)*	*Net (Mboe)*
Proved										
Developed Producing	8,403.9	6,797.3	13,950.1	13,040.2	982,574.8	898,576.8	23,463.6	18,180.4	197,955.1	176,913.8
Developed Non-Producing	0.0	0.5	4,309.1	3,994.8	20,400.5	18,818.3	254.3	183.6	4,372.5	3,986.3
Undeveloped	8,211.8	6,912.3	3,493.2	3,201.6	2,467,406.9	2,187,549.4	42,124.4	34,708.8	462,152.9	406,746.3
Total Proved	16,615.8	13,710.0	21,752.4	20,236.6	3,470,382.2	3,104,944.5	65,842.3	53,072.9	664,480.5	587,646.4
Probable	14,394.0	11,500.2	14,103.2	12,884.0	1,449,379.3	1,241,483.1	49,727.2	39,579.9	308,034.8	260,141.3
Total Proved Plus Probable	31,009.7	25,210.2	35,855.6	33,120.6	4,919,761.5	4,346,427.6	115,569.4	92,652.8	972,515.3	847,787.7

(1) "Gross" means Birchcliff's working interest (operating or non-operating) share before the deduction of royalties and without including any royalty interests of Birchcliff. "Net" means Birchcliff's working interest (operating or non-operating) share after the deduction of royalty obligations, plus Birchcliff's royalty interests in reserves.

Net Present Value of Future Net Revenue

The following table sets forth the net present value of future net revenue attributable to our reserves at December 31, 2017, using the 2017 Deloitte Price Forecast, before deducting future income tax expenses and calculated at various discount rates:

Summary of Net Present Value of Future Net Revenue at December 31, 2017
(Forecast Prices and Costs)

	Before Income Taxes Discounted At (%/year)					
Reserves Category	**0** ***(MM$)***	**5** ***(MM$)***	**10** ***(MM$)***	**15** ***(MM$)***	**20** ***(MM$)***	**Unit Value Discounted at 10%/year** ***($/boe)***
Proved						
Developed Producing	3,542.7	2,469.5	1,871.9	1,504.4	1,259.9	10.58
Developed Non-Producing	71.0	46.0	32.6	24.7	19.6	8.19
Undeveloped	7,484.0	3,603.1	1,827.9	917.9	412.2	4.49
Total Proved	11,097.7	6,118.5	3,732.4	2,447.0	1,691.7	6.35
Probable	6,662.2	2,779.3	1,375.7	764.1	458.7	5.29
Total Proved Plus Probable	17,759.9	8,897.8	5,108.1	3,211.1	2,150.5	6.03

Pricing Assumptions

The following table sets forth the forecast price and cost assumptions used in the 2017 Consolidated Reserves Report:

2017 Deloitte Price Forecast

	Crude Oil		Natural Gas		NGLs					
Year	**WTI at Cushing Oklahoma** ***($US/bbl)***	**Edmonton City Gate** ***($CDN/bbl)***	**Alberta AECO Average Price** ***($CDN/Mcf)***	**Ontario Dawn Reference Point** ***(CDN$/Mcf)***	**Edmonton Ethane** ***($CDN/bbl)***	**Edmonton Propane** ***($CDN/bbl)***	**Edmonton Butane** ***($CDN/bbl)***	**Edmonton Pentanes + Condensate** ***($CDN/bbl)***	**Currency Exchange Rate** ***($CDN/$US)***	**Price and Cost Inflation Rates** ***(%)***
2018	55.00	65.40	2.00	3.85	5.60	39.25	42.50	68.65	0.780	0.0
2019	58.65	68.25	2.30	4.00	6.45	37.55	44.35	71.65	0.800	2.0
2020	62.40	70.65	2.75	4.15	7.70	35.30	45.95	74.20	0.825	2.0
2021	69.00	76.15	2.95	4.40	8.35	34.30	49.50	79.95	0.850	2.0
2022	75.75	84.05	3.20	4.60	8.95	33.60	54.60	88.25	0.850	2.0
2023	77.30	85.75	3.40	4.90	9.60	34.30	55.70	90.05	0.850	2.0
2024	78.85	87.45	3.75	5.25	10.60	34.95	56.80	91.85	0.850	2.0
2025	80.40	89.20	4.10	5.55	11.45	35.65	57.95	93.70	0.850	2.0
2026	82.00	91.00	4.20	5.75	11.85	36.40	59.10	95.55	0.850	2.0
2027	83.65	92.80	4.35	5.90	12.20	37.10	60.30	97.45	0.850	2.0
2028	85.35	94.65	4.45	6.05	12.45	37.85	61.50	99.40	0.850	2.0
2029	87.05	96.55	4.55	6.15	12.70	38.60	62.75	101.40	0.850	2.0
2030	88.80	98.50	4.65	6.30	12.95	39.40	64.00	103.45	0.850	2.0
2031	90.55	100.45	4.70	6.40	13.20	40.15	65.25	105.50	0.850	2.0
2032	92.35	102.45	4.80	6.55	13.45	40.95	66.55	107.60	0.850	2.0
2033	94.20	104.50	4.90	6.65	13.75	41.80	67.90	109.75	0.850	2.0
2034	96.10	106.60	5.00	6.80	14.00	42.60	69.25	111.95	0.850	2.0
2035	98.00	108.75	5.10	6.95	14.30	43.50	70.65	114.20	0.850	2.0
2036	100.00	110.90	5.20	7.05	14.55	44.35	72.05	116.45	0.850	2.0
2037	102.00	113.10	5.30	7.20	14.85	45.25	73.50	118.80	0.850	2.0
2037+	2%/yr	2%/yr	2%/yr	2%/yr	2%/yr	2%/yr	2%/yr	2%/yr	0.850/yr	2.0/yr

In comparison to the 2016 Deloitte Price Forecast, the AECO natural gas price forecast for 2018 decreased by 40% and the Edmonton City Gate oil price forecast decreased by 8%.

Reconciliation of Changes in Reserves

The following table sets forth a reconciliation of our gross reserves at December 31, 2017 set forth in the 2017 Consolidated Reserves Report, using the 2017 Deloitte Price Forecast, to our gross reserves at December 31, 2016 set forth in the 2016 Consolidated Reserves Report, using the 2016 Deloitte Price Forecast:

Reconciliation of Gross Reserves from December 31, 2016 to December 31, 2017
(Forecast Prices and Costs)

Factors	Light Crude Oil and Medium Crude Oil *(Mbbls)*	Conventional Natural Gas *(MMcf)*	Shale Gas *(MMcf)*	NGLs *(Mbbls)*	Oil Equivalent *(Mboe)*
GROSS TOTAL PROVED					
Opening balance December 31, 2016	**31,792.0**	**59,393.8**	**2,741,455.4**	**49,923.6**	**548,523.8**
Discoveries	0.0	0.0	0.0	0.0	0.0
Extensions & Improved Recovery	4,145.7	99.7	700,773.6	15,204.3	136,162.2
Technical Revisions	(120.0)	4,095.0	151,766.1	4,250.2	30,107.0
Acquisitions	0.2	10.1	5,865.6	42.4	1,021.9
Dispositions	(17,275.8)	(37,618.3)	(173.9)	(408.7)	(23,983.2)
Economic Factors	(244.5)	(1,364.6)	(14,195.4)	(107.7)	(2,945.5)
Production(1)	(1,681.8)	(2,863.3)	(115,109.2)	(3,061.8)	(24,405.7)
Closing balance December 31, 2017	**16,615.8**	**21,752.4**	**3,470,382.2**	**65,842.3**	**664,480.5**
GROSS TOTAL PROBABLE					
Opening balance December 31, 2016	**26,655.7**	**62,289.1**	**1,532,149.2**	**39,544.6**	**331,940.0**
Discoveries	0.0	0.0	0.0	0.0	0.0
Extensions & Improved Recovery	2,590.6	54.8	(228,436.8)	1,059.4	(34,413.7)
Technical Revisions	1,077.7	13.2	167,035.2	9,607.0	38,526.1
Acquisitions	0.0	1.7	5,674.5	56.6	1,002.6
Dispositions	(15,817.3)	(48,025.0)	(125.8)	(493.4)	(24,335.8)
Economic Factors	(112.8)	(230.6)	(26,917.0)	(47.0)	(4,684.4)
Production(1)	0.0	0.0	0.0	0.0	0.0
Closing balance December 31, 2017	**14,394.0**	**14,103.2**	**1,449,379.3**	**49,727.2**	**308,034.8**
GROSS TOTAL PROVED PLUS PROBABLE					
Opening balance December 31, 2016	**58,447.7**	**121,682.9**	**4,273,604.6**	**89,468.2**	**880,463.8**
Discoveries	0.0	0.0	0.0	0.0	0.0
Extensions & Improved Recovery	6,736.3	154.5	472,336.8	16,263.7	101,748.6
Technical Revisions	957.7	4,108.2	318,801.3	13,857.1	68,633.1
Acquisitions	0.2	11.8	11,540.1	99.0	2,024.5
Dispositions	(33,093.1)	(85,643.3)	(299.7)	(902.1)	(48,319.0)
Economic factors	(357.3)	(1,595.2)	(41,112.4)	(154.7)	(7,629.9)
Production(1)	(1,681.8)	(2,863.3)	(115,109.2)	(3,061.8)	(24,405.7)
Closing balance December 31, 2017	**31,009.7**	**35,855.6**	**4,919,761.5**	**115,569.4**	**972,515.3**

(1) Represents the independent qualified reserves evaluators' estimates of actual production for the year ended December 31, 2017 before year-end results were available.

With respect to our total corporate reserves, proved reserves increased by 21%, probable reserves decreased by 7% and proved plus probable reserves increased by 10%. The increases in our proved and proved plus probable reserves is primarily attributable to: (i) the success of our 2017 drilling program which resulted in more potential net future drilling locations to which reserves were assigned; and (ii) positive technical revisions as a result of improved well performance. Positive technical revisions accounted for 42% of the proved plus probable reserves additions and 18% of the total proved reserves additions, after excluding the effects of acquisitions and dispositions and adding back in 2017 actual production of 24,806.3 Mboe. These increases were partially offset by the various dispositions we completed during 2017 (including the Worsley Disposition) as well as economic factors as a result of a lower commodity price forecast. The decrease in our probable reserves is primarily attributable to the re-classification of probable reserves as proved reserves in several of our potential net future drilling locations, as well as the dispositions we completed during 2017.

The following sets forth additional information on the reconciliation of our reserves by product type:

- NGLs: Proved reserves increased by 32%, probable reserves increased by 26% and proved plus probable reserves increased by 29%. The increases are primarily attributable to: (i) the success of our 2017 drilling program which resulted in more potential net future drilling locations to which reserves were assigned; and (ii) positive technical revisions as a result of higher NGLs yields at a proposed deep-cut facility at the Pouce Coupe Gas Plant as compared to a third-party facility. These increases were partially offset by the various dispositions we completed during 2017 (including the Worsley Disposition), as well as economic factors as a result of a lower commodity price forecast.

- Shale Gas: Proved reserves increased by 27%, probable reserves decreased by 5% and proved plus probable reserves increased by 15%. The increases are primarily attributable to: (i) the success of our 2017 drilling program which resulted in more potential net future drilling locations to which reserves were assigned; and (ii) positive technical revisions as a result of improved well performance. The decrease in our probable reserves is primarily attributable to the re-categorization of probable reserves as proved reserves in several of our potential net future drilling locations.

- Conventional Natural Gas: Proved reserves decreased by 63%, probable reserves decreased by 77% and proved plus probable reserves decreased by 71%. The decreases are primarily attributable to the Worsley Disposition.

- Light and Medium Crude Oil: Proved reserves decreased by 48%, probable reserves decreased by 46% and proved plus probable reserves decreased by 47%. The decreases are primarily attributable to the Worsley Disposition.

Since we acquired our Gordondale Assets on July 28, 2016, we have drilled, completed and brought on production a total of 22 (22.0 net) wells in Gordondale, consisting of 12 (12.0 net) Montney D2 horizontal oil wells, 5 (5.0 net) Montney D1 horizontal oil wells and 5 (5.0 net) Montney D1 liquids-rich horizontal natural gas wells. All of these wells were brought on production in 2017 and added significant reserves at December 31, 2017 on a proved developed producing basis. On a proved and a proved plus probable basis, we added 16 new proved and 43 new proved plus probable potential net future drilling locations in the largely unbooked Montney D2 interval. The Gordondale Montney D2 drilling and delineation continues to prove the large oil accumulation in the Gordondale area.

Future Development Costs

FDC reflects the independent reserves evaluators' best estimate of what it will cost to bring the proved and proved plus probable reserves on production. Changes in forecast FDC occur annually as a result of development activities, acquisition and disposition activities and capital cost estimates. The following table sets forth the independent reserves evaluators' estimated FDC to bring the proved and proved plus probable reserves on production:

Future Development Costs
(Forecast Prices and Costs)

	Proved *(MM$)*	**Proved Plus Probable** *(MM$)*
2018	247.1	307.7
2019	485.6	528.7
2020	325.3	416.2
2021	502.0	556.0
2022	628.9	701.9
Thereafter	1,045.1	1,992.5
Total undiscounted	**3,234.0**	**4,503.0**

FDC for total proved reserves increased to $3.23 billion at December 31, 2017 from $2.50 billion at December 31, 2016. FDC for total proved plus probable reserves increased to $4.50 billion at December 31, 2017 from $4.15 billion at December 31, 2016. The increases in FDC for both proved and proved plus probable reserves are largely due to: (i) the increase in Montney/Doig potential net future drilling locations added in each category of reserves as a result of our successful 2017 drilling program; (ii) proved potential net future drilling locations added in Pouce Coupe due to increased geological confidence and continued delineation on the Montney/Doig Resource Play; and (iii) the expansion of natural gas processing capacity and related infrastructure capital. The increases in FDC were partially offset by the reserves associated with the assets that were disposed of pursuant to the Worsley Disposition and the associated capital required to develop such reserves ($159 million on a proved basis and $357 million on a proved plus probable basis).

The FDC for both proved and proved plus probable reserves are primarily the capital costs required to drill, complete, equip and tie-in the net undeveloped locations. The estimates of FDC on a proved basis also include approximately $660 million for the expansion of the Pouce Coupe Gas Plant from the existing 260 MMcf/d to 810 MMcf/d of total throughput. Of this 550 MMcf/d of additional capacity, 150 MMcf/d is related to a proposed deep-cut facility that will process the Gordondale gas as a replacement for a third-party facility. The estimates of FDC on a proved plus probable basis include approximately $678 million for the same capacity expansions as the proved case above with additional gathering pipeline requirements. The FDC for the expansions of the Pouce Coupe Gas Plant also include the costs of the related gathering pipelines, sales pipeline expansion and compression.

The following table sets forth the average cost to drill, complete, equip and tie-in a multi-stage fractured horizontal well as estimated by Deloitte and McDaniel:

Average Well Cost, as Estimated by Deloitte or McDaniel	**December 31, 2017** ***(MM$)***	**December 31, 2016** ***(MM$)***
Pouce Coupe(1)	4.6	4.5
Gordondale(2)	5.2	5.7

(1) Estimated by Deloitte. Up slightly compared to 2016 due to increased frac intensity in completions.

(2) Estimated by McDaniel. Down slightly based on actual costs incurred in 2017 and go forward DCCET costs.

Reserves Replacement

The following table sets forth our 2017 reserves replacement ratios:

Reserves Category	**2017 Reserves Replacement, Excluding the Effects of Acquisitions and Dispositions(1)**	**2017 Reserves Replacement, Including the Effects of Acquisitions and Dispositions(1)**
Proved Developed Producing	266%	231%
Proved	660%	567%
Proved Plus Probable	658%	471%

(1) Please see *"Advisories – Oil and Gas Metrics"* for a description of the methodology used to calculate reserves replacement.

Reserves Life Index

The following table sets forth our 2017 reserves life index:

Reserves Category	**2017 Reserves Life Index(1)**
Proved Developed Producing	7.0 years
Total Proved	23.6 years
Total Proved Plus Probable	34.6 years

(1) Based on a forecast production rate of 77,000 boe/d for 2018, which represents the mid-point of Birchcliff's annual average production guidance range for 2018. Please see *"Advisories – Oil and Gas Metrics"* for a description of the methodology used to calculate reserves life index.

Reserves on the Montney/Doig Resource Play

The following table summarizes the estimates of reserves attributable to our horizontal wells on the Montney/Doig Resource Play as contained in the 2017 Consolidated Reserves Report and the number of horizontal wells to which reserves were attributed:

Montney/Doig Resource Play Reserves Data(1)(2)

	Shale Gas *(Bcf)*		Light Crude Oil and Medium Crude Oil Combined *(Mbbls)*		NGLs *(Mbbls)*		Total *(Mboe)*		Existing Horizontal Wells and Potential Future Horizontal Well Locations *(Gross)*		*(Net)*	
Reserves Category	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**
Proved Developed Producing	976.5	764.1	8,323.4	6,036.5	23,066.0	18,572.5	194,145.1	151,964.1	339	281	333.8	275.7
Total Proved	3,464.1	2,734.5	16,318.7	14,400.5	65,348.2	48,808.2	659,029.0	518,965.8	862	736	846.0	721.7
Total Proved Plus Probable	4,911.2	4,274.8	30,428.7	25,307.2	114,869.1	87,687.7	963,836.1	825,454.6	1,103	1,000	1,072.0	974.4

(1) Estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties due to the effects of aggregation.

(2) At December 31, 2017, the estimated FDC for our reserves on our Montney/Doig Resource Play is $0.0 million on a proved developed producing basis (as compared to $0.9 million at December 31, 2016), $3,223.3 million on a proved basis (as compared to $2,277.5 million at December 31, 2016) and $4,480.8 million on a proved plus probable basis (as compared to $3,680.9 million at December 31, 2016).

2017 FINDING AND DEVELOPMENT COSTS

During 2017, our F&D costs were $415.0 million and our FD&A costs were $274.3 million.

The following table sets forth our estimates of our F&D costs per boe and FD&A costs per boe for 2017, 2016 and 2015, excluding and including FDC:

Excluding FDC *($/boe)*(1)	**2017**	**2016**	**2015**	**Three Year Average**
F&D – Proved Developed Producing	$6.29	$6.42	$8.11	$6.78
F&D – Proved	$2.53	$1.57	$3.09	$2.38
F&D – Proved Plus Probable	$2.54	$1.25	$2.06	$1.99
FD&A – Proved Developed Producing	$4.79	$9.32	$7.79	$7.51
FD&A – Proved	$1.95	$3.53	$2.96	$2.91
FD&A – Proved Plus Probable	$2.35	$2.33	$2.02	$2.27
Including FDC *($/boe)*(1)	**2017**(2)	**2016**(3)	**2015**(4)	**Three Year Average**
F&D – Proved	$8.14	$4.89	$2.41	$5.81
F&D – Proved Plus Probable	$7.27	$4.43	$1.55	$4.68
FD&A – Proved	$7.16	$6.73	$2.28	$6.02
FD&A – Proved Plus Probable	$5.37	$5.58	$1.32	$4.62

(1) Please see *"Advisories – Oil and Gas Metrics"* for a description of the methodology used to calculate F&D and FD&A costs.

(2) Includes the 2017 increase in FDC from 2016 of $732.9 million on a proved basis and $352.9 million on a proved plus probable basis.

(3) Includes the 2016 increase in FDC from 2015 of $690.0 million on a proved basis and $1,059.0 million on a proved plus probable basis.

(4) Includes the 2015 decrease in FDC from 2014 of $56.5 million on a proved basis and $85.4 million on a proved plus probable basis.

2017 RECYCLE RATIOS

The following table sets forth our recycle ratios for operating and funds flow netbacks for 2017 and 2016, excluding and including FDC:

	Operating Netback Recycle Ratio[1]		Funds Flow Netback Recycle Ratio[1]	
	2017	**2016**	**2017**	**2016**
Excluding FDC				
F&D – Proved Developed Producing	2.2	1.7	2.0	1.3
FD&A – Proved Developed Producing	2.9	1.2	2.7	0.9
F&D – Proved	5.5	7.0	5.1	5.2
FD&A – Proved	7.2	3.1	6.6	2.3
F&D – Proved Plus Probable	5.5	8.8	5.0	6.6
FD&A – Proved Plus Probable	6.0	4.7	5.5	3.5
Including FDC				
F&D – Proved	1.7	2.3	1.6	1.7
FD&A – Proved	2.0	1.6	1.8	1.2
F&D – Proved Plus Probable	1.9	2.5	1.8	1.8
FD&A – Proved Plus Probable	2.6	2.0	2.4	1.5

(1) Please see *"Advisories – Oil and Gas Metrics"* for a description of the methodology used to calculate F&D costs, FD&A costs and recycle ratios.

During 2017, the average benchmark price for WTI crude oil was US$50.95/bbl and the average benchmark price for natural gas sold at AECO was CDN$2.16/MMBtu. The operating netback was $13.97/boe in 2017, as compared to $11.01/boe in 2016. Funds flow netback was $12.81/boe in 2017, as compared to $8.18/boe in 2016.

ABBREVIATIONS

AECO	physical storage and trading hub for natural gas on the TransCanada Alberta transmission system which is the delivery point for various benchmark Alberta index prices
° API	the measure of the density or gravity of liquid petroleum products derived from a specific gravity
bbl	barrel
bbls	barrels
bbls/d	barrels per day
Bcf	billion cubic feet
boe	barrel of oil equivalent
boe/d	barrel of oil equivalent per day
F&D	finding and development
FD&A	finding, development and acquisition
FDC	future development costs
GAAP	generally accepted accounting principles
GJ	gigajoule
GJ/d	gigajoules per day
m^3	cubic metres
Mbbls	thousand barrels
Mboe	thousand barrels of oil equivalent
Mcf	thousand cubic feet
Mcfe	thousand cubic feet of gas equivalent
MJ	megajoule
MM	millions
MM$	millions of dollars
MMBtu	million British thermal units
MMcf	million cubic feet
MMcf/d	million cubic feet per day
MPa	megapascal
NGLs	natural gas liquids
TCPL	TransCanada PipeLines
WTI	West Texas Intermediate oil at Cushing, Oklahoma, the benchmark for North American crude oil pricing
000s	thousands
$000s	thousands of dollars

NON-GAAP MEASURES

This press release uses "funds flow from operations", "funds flow per common share", "free funds flow from operations", "operating netback", "estimated operating netback", "funds flow netback", "operating margin", "total cash costs", "adjusted working capital deficit" and "total debt". These measures do not have standardized meanings prescribed by GAAP and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. Management believes that these non-GAAP measures assist management and investors in assessing Birchcliff's profitability, efficiency, liquidity and overall performance. Each of these measures is discussed in further detail below.

"Funds flow from operations" denotes cash flow from operating activities before the effects of decommissioning expenditures and changes in non-cash working capital. "Funds flow per common share" denotes funds flow from operations divided by the basic or diluted weighted average number of common shares outstanding for the period. Management believes that funds flow from operations and funds flow per common share assist management and investors in assessing Birchcliff's profitability, as well as its ability to generate the cash necessary to fund future growth through capital investments, pay dividends and repay debt. The following table provides a reconciliation of cash flow from operating activities, as determined in accordance with International Financial Reporting Standards, to funds flow from operations:

	Three months ended December 31,		Twelve months ended December 31,	
($000s)	**2017**	**2016**	**2017**	**2016**
Cash flow from operating activities	88,995	90,574	287,660	140,514
Adjustments:				
Decommissioning expenditures	93	480	794	1,343
Change in non-cash working capital	7,920	(19,248)	29,226	5,586
Funds flow from operations	**97,008**	**71,806**	**317,680**	**147,443**

"Free funds flow from operations" denotes funds flow from operations less net capital expenditures. Management believes that free funds flow from operations assists management and investors in assessing Birchcliff's financial performance and liquidity.

"Operating netback" denotes petroleum and natural gas revenue less royalties, less operating expense and less transportation and marketing expense. "Estimated operating netback" of the Pouce Coupe Gas Plant (and the components thereof) is based upon certain cost allocations and accruals directly attributable to the Pouce Coupe Gas Plant and related wells and infrastructure. "Funds flow netback" denotes petroleum and natural gas revenue less royalties, less operating expense, less transportation and marketing expense, less net general and administrative expense, less interest expense and less any realized losses (plus realized gains) on financial instruments and plus any other cash income sources. All netbacks are calculated on a per unit basis, unless otherwise indicated. Management believes that operating netback, estimated operating netback and funds flow netback assist management and investors in assessing Birchcliff's profitability and its operating results on a per unit basis to better analyze its performance against prior periods on a comparable basis. The following table provides a breakdown of operating netback and funds flow netback:

Twelve Months Ended	December 31, 2017		December 31, 2016	
	$000s	*$/boe*(1)	*$000s*	*$/boe*(1)
Petroleum and natural gas revenue	556,942	22.45	337,586	18.73
Royalty expense	(28,727)	(1.16)	(20,911)	(1.16)
Operating expense	(110,486)	(4.45)	(75,251)	(4.18)
Transportation and marketing expense	(71,224)	(2.87)	(42,989)	(2.38)
Operating Netback	346,505	**13.97**	**198,435**	**11.01**
General & administrative expense, net	(26,504)	(1.07)	(21,489)	(1.19)
Interest expense	(28,374)	(1.14)	(30,305)	(1.68)
Realized gain on financial instruments	25,785	1.03	802	0.04
Other cash income sources	268	0.02	-	-
Funds flow netback	**317,680**	**12.81**	**147,443**	**8.18**

(1) All per boe figures are calculated by dividing each aggregate financial amount by the production (boe) in the respective period.

"Operating margin" for the Pouce Coupe Gas Plant is calculated by dividing the estimated operating netback for the period by the petroleum and natural gas revenue for the period. Management believes that operating margin assists management and investors in assessing the profitability and efficiency of the Pouce Coupe Gas Plant and Birchcliff's ability to generate operating cash flows (equal to petroleum and natural gas revenue less royalties, less operating expense and less transportation and marketing expense).

"Total cash costs" are comprised of royalty, operating, transportation and marketing, general and administrative and interest expenses. Total cash costs are calculated on a per unit basis. Management believes that total cash costs assists management and investors in assessing Birchcliff's efficiency and overall cash cost structure.

"Adjusted working capital deficit" is calculated as current assets minus current liabilities excluding the effects of any financial instruments. Management believes that adjusted working capital deficit assists management and investors in assessing Birchcliff's liquidity. The following table reconciles working capital deficit (current assets minus current liabilities) to adjusted working capital deficit:

As at, *($000s)*	**December 31, 2017**	**December 31, 2016**
Working capital deficit	15,113	36,928
Fair value of financial instruments	(4,046)	(9,433)
Adjusted working capital deficit	**11,067**	**27,495**

"Total debt" is calculated as the revolving term credit facilities plus adjusted working capital deficit. Management believes that total debt assists management and investors in assessing Birchcliff's liquidity. The following table provides a reconciliation of the revolving term credit facilities, as determined in accordance with International Financial Reporting Standards, to total debt:

As at, *($000s)*	**December 31, 2017**	**December 31, 2016**
Revolving term credit facilities	587,126	572,517
Adjusted working capital deficit	11,067	27,495
Total debt	**598,193**	**600,012**

PRESENTATION OF OIL AND GAS RESERVES

Deloitte prepared the 2017 Consolidated Reserves Report, the 2016 Consolidated Reserves Report, the 2017 Deloitte Reserves Report and the 2016 Deloitte Reserves Report. McDaniel prepared the 2017 McDaniel Reserves Report and the 2016 McDaniel Reserves Report. In addition, Deloitte prepared a reserves evaluation in respect of Birchcliff's oil and natural gas properties effective December 31, 2015. Such evaluations were prepared in accordance with the standards contained in NI 51-101 and the COGE Handbook that were in effect at the relevant time. Reserves estimates stated herein are extracted from the relevant evaluation.

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGLs reserves and the future cash flows attributed to such reserves, including many factors beyond the control of Birchcliff. The reserves and associated cash flow information set forth in this press release are estimates only. In general, estimates of economically recoverable oil, natural gas and NGLs reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, initial production rates, production decline rates, ultimate reserve recovery, the timing and amount of capital expenditures, the success of future development activities, future commodity prices, marketability of oil, natural gas and NGLs, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable oil, natural gas and NGLs reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineer at different times, may vary substantially. Birchcliff's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

With respect to the disclosure of reserves contained herein relating to portions of Birchcliff's properties, the estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation. Estimates of future net revenue, whether calculated without discount or using a discount rate, do not represent fair market value. In this press release, all references to "reserves" are to Birchcliff's gross company reserves unless otherwise stated.

The information set forth in this press release relating to the reserves and future net revenues of Birchcliff constitutes forward-looking information which is subject to certain risks and uncertainties. See *"Advisories – Forward-Looking Information"*.

Definitions

Certain terms used herein but not defined are defined in NI 51-101, CSA Staff Notice 51-324 – *Revised Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities* ("**CSA Staff Notice 51-324**") and/or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101, CSA Staff Notice 51-324 and the COGE Handbook, as the case may be.

Reserves Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates:

- "**Proved reserves**" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
- "**Probable reserves**" are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Interest in Reserves, Production, Wells and Properties

"**Gross**" means: (a) in relation to Birchcliff's interest in production or reserves, its "company gross reserves", which are Birchcliff's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of Birchcliff; (b) in relation to wells, the total number of wells in which Birchcliff has an interest; and (c) in relation to properties, the total area of properties in which Birchcliff has an interest.

"**Net**" means: (a) in relation to Birchcliff's interest in production or reserves, Birchcliff's working interest (operating or non-operating) share after deduction of royalty obligations, plus Birchcliff's royalty interests in production or reserves; (b) in relation to Birchcliff's interest in wells, the number of wells obtained by aggregating Birchcliff's working interest in each of its gross wells; and (c) in relation to Birchcliff's interest in a property, the total area in which Birchcliff has an interest multiplied by the working interest owned by Birchcliff.

ADVISORIES

Unaudited Information

All financial and operating information contained in this press release for the fourth quarter and year ended December 31, 2017, such as FD&A costs, F&D costs, recycle ratio, funds flow from operations, capital expenditures, operating costs, total cash costs, total debt and production information, is based on unaudited estimated results. These estimated results are subject to change upon completion of the audited financial statements for the year ended December 31, 2017, and changes could be material. Birchcliff anticipates filing its audited financial statements and related management's discussion and analysis for the year ended December 31, 2017 on SEDAR on March 14, 2018.

Currency

All amounts in this press release are stated in Canadian dollars unless otherwise specified.

Boe and Mcfe Conversions

Boe amounts have been calculated by using the conversion ratio of 6 Mcf of natural gas to 1 bbl of oil and Mcfe amounts have been calculated by using the conversion ratio of 1 bbl of oil to 6 Mcf of natural gas. Boe and Mcfe amounts may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf: 1 bbl and an Mcfe conversion ratio of 1 bbl: 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

MMBtu Pricing Conversions

$1.00 per MMBtu equals $1.00 per Mcf based on a standard heat value Mcf.

Oil and Gas Metrics

This press release contains metrics commonly used in the oil and natural gas industry, including netbacks, reserves life index, reserves per common share, recycle ratio, reserves replacement, F&D costs and FD&A costs. These oil and gas metrics do not have any standardized meanings or standard methods of calculation and therefore may not be comparable to similar measures presented by other companies where similar terminology is used and should not be used to make comparisons. Such metrics have been included herein to provide readers with additional measures to evaluate Birchcliff's performance; however, such measures are not reliable indicators of Birchcliff's future performance and future performance may not compare to Birchcliff's performance in previous periods and therefore such metrics should not be unduly relied upon.

- Reserves life index is calculated by dividing reserves estimated by Birchcliff's independent qualified reserves evaluators at December 31, 2017 by 77,000 boe/d, which production rate represents the mid-point of Birchcliff's annual average production guidance range for 2018. Reserves life index may be used as a measure of a company's sustainability.
- Reserves per common share is calculated by dividing proved developed producing reserves, proved reserves or proved plus probable reserves at the end of the period by basic common shares at the end of the period.
- Recycle ratios are calculated by dividing the average operating netback per boe or funds flow netback per boe, as the case may be, by F&D costs and FD&A costs, as the case may be. Recycle ratios may be used as a measure of a company's profitability.

- Reserves replacement is calculated by dividing proved developed producing reserves, proved reserves or proved plus probable reserves additions, as the case may be, before production by total production in the applicable period. Reserves replacement ratios have been presented both including and excluding the effects of acquisitions and dispositions. Reserves replacement may be used as a measure of a company's sustainability and its ability to replace its proved developed producing reserves, proved reserves or proved plus probable reserves, as the case may be.
- With respect to F&D and FD&A costs disclosed in this press release:
  - F&D costs both including and excluding FDC have been presented herein. F&D costs for each reserves category in a particular period are calculated by taking the sum of: (i) exploration and development costs incurred in the period; and (ii) where FDC has been included, the change during the period in FDC for the reserves category; divided by the additions to the reserves category before production during the period. F&D costs exclude the effects of acquisitions and dispositions. FD&A costs are calculated in the same manner as F&D costs but include the effects of acquisitions and dispositions.
  - In calculating the amounts of F&D and FD&A costs for a year, the changes during the year in estimated reserves and estimated FDC are based upon the evaluations of Birchcliff's reserves prepared by its independent qualified reserves evaluators, effective December 31 of such year.
  - The aggregate of the exploration and development costs incurred in the most recent financial year and any change during that year in estimated FDC generally will not reflect total F&D costs related to reserves additions for that year.
  - F&D and FD&A costs may be used as a measure of a company's efficiency with respect to finding and developing its reserves.
- For information regarding netbacks, please see *"Non-GAAP Measures".*

Drilling Locations

This press release discloses net existing horizontal wells and potential net future drilling locations in four categories: (i) proved locations; (ii) proved plus probable locations; (iii) unbooked locations; and (iv) an aggregate total of (ii) and (iii). Of the 5,052.8 net existing horizontal wells and potential net future horizontal drilling locations identified herein, 846.0 are proved locations, 1,070.0 are proved plus probable locations and 3,982.8 are unbooked locations.

Proved locations and probable locations are proposed drilling locations identified in the 2017 Consolidated Reserves Report that have proved and/or probable reserves, as applicable, attributed to them in the 2017 Consolidated Reserves Report. Unbooked locations are internal estimates based on Birchcliff's prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal technical analysis review. Unbooked locations have been identified by management based on evaluation of applicable geologic, seismic, engineering, production and reserves information. Unbooked locations do not have proved or probable reserves attributed to them in the 2017 Consolidated Reserves Report.

Birchcliff's ability to drill and develop these locations and the drilling locations on which Birchcliff actually drills wells depends on a number of uncertainties and factors, including, but not limited to, the availability of capital, equipment and personnel, oil and natural gas prices, capital and operating costs, inclement weather, seasonal restrictions, drilling results, additional geological, geophysical and reservoir information that is obtained, production rate recovery, gathering system and transportation constraints, the net price received for commodities produced, regulatory approvals and regulatory changes. As a result of these uncertainties, there can be no assurance that the potential future drilling locations that Birchcliff has identified will ever be drilled or if Birchcliff will be able to produce oil, NGLs or natural gas from these or any other potential drilling locations. As such, Birchcliff's actual drilling activities may differ materially from those presently identified, which could adversely affect Birchcliff's business. While certain of the unbooked drilling locations have been de-risked by drilling existing wells in relative close proximity to such unbooked drilling locations, some of the other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional proved or probable reserves, resources or production.

Initial Production (IP) Rates

Any references in this press release to initial production rates (e.g. IP60) are useful in confirming the presence of hydrocarbons; however, such rates are not determinative of the rates at which such wells will continue to produce and decline thereafter and are not indicative of the long-term performance or of the ultimate recovery of such wells. In addition, such rates may also include recovered "load oil" or "load water" fluids used in well completion stimulation. While encouraging, readers are cautioned not to place undue reliance on such rates in calculating the aggregate production for Birchcliff. Such rates are based on field estimates and may be based on limited data available at this time.

Operating Costs

References in this press release to "operating costs" exclude transportation and marketing costs.

Capital Expenditures

Unless otherwise stated, references in this press release to: (i) "net capital expenditures" and "capital expenditures, net" denote F&D costs (which includes land, seismic, workovers, drilling and completions and well equipment and facilities) plus administrative assets, plus acquisition costs, less any dispositions; and (ii) "total capital expenditures" denotes F&D costs plus administrative assets.

Birchcliff's guidance regarding its 2018 capital expenditures has been presented on a total basis. Birchcliff makes acquisitions and dispositions in the ordinary course of business. Any acquisitions and dispositions completed during 2018 could have an impact on Birchcliff's capital expenditures, production and funds flow from operations for 2018, which impact could be material. See also *"Advisories – Forward-Looking Information"* below.

Payment of Dividends

The declaration of dividends in any quarter and the amount of such dividends, if any, is subject to the discretion of Birchcliff's board of directors and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, the financial condition of Birchcliff, production levels, results of operations, capital expenditure and debt service requirements, contractual restrictions, hedging activities or programs, available investment opportunities, Birchcliff's business plan, strategies and objectives, the satisfaction of the solvency and liquidity tests imposed by the *Business Corporations Act* (Alberta) for the declaration and payment of dividends and other factors that Birchcliff's board of directors may deem relevant. The payment of cash dividends to common shareholders in the future is not assured or guaranteed and dividends may be reduced or suspended. Birchcliff's dividend policy will be periodically reviewed by its board of directors and no assurance or guarantee can be given that Birchcliff will maintain the dividend policy in its current form.

Forward-Looking Information

Certain statements contained in this press release constitute forward-looking statements and information (collectively referred to as "**forward-looking information**") within the meaning of applicable Canadian securities laws. Such forward-looking information relates to future events or Birchcliff's future performance. All information other than historical fact may be forward-looking information. Such forward-looking information is often, but not always, identified by the use of words such as "seek", "plan", "expect", "project", "intend", "believe", "anticipate", "estimate", "forecast", "potential", "proposed", "predict", "budget", "continue", "targeting", "may", "will", "could", "might", "should" and other similar words and expressions. This information involves 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 information. Birchcliff believes that the expectations reflected in the forward-looking information are reasonable in the current circumstances but no assurance can be given that these expectations will prove to be correct and such forward-looking information included in this press release should not be unduly relied upon.

In particular, this press release contains forward-looking information relating to the following: Birchcliff's plans and other aspects of its anticipated future financial performance, operations, focus, objectives, strategies, opportunities, priorities and goals; that Birchcliff is dedicated to strict capital discipline and is in a position to generate free funds flow from operations in 2018 while also providing strong annual average production growth; that Birchcliff is focused on maintaining balance sheet strength and may choose to use any funds flow from operations in excess of its capital expenditures and dividend payments to pay down indebtedness under its Credit Facilities; Birchcliff's guidance regarding its 2018 Capital Program and its proposed exploration and development activities and the timing thereof (including estimates of capital expenditures in 2018, planned capital expenditures and capital allocation, the focus of, the objectives of and the anticipated results from the 2018 Capital Program, the number and types of wells to be drilled and brought on production, Birchcliff's science and technology multi-well pad program, Birchcliff's expectation that the 2018 Capital Program will be fully funded out of funds flow from operations and that its capital expenditures during 2018 will be less than its funds flow from operations during 2018, the financial and operational flexibility of the 2018 Capital Program, the potential to accelerate or decelerate capital expenditures and Birchcliff's expectation that its facilities and infrastructure capital expenditures going forward will decrease significantly until a decision is made to build additional phases of the Pouce Coupe Gas Plant); Birchcliff's other guidance for 2018 (including its estimates of its annual average production and commodity mix in 2018, its estimates of royalty, operating and transportation and marketing expenses and its estimates of AECO and Dawn production levels during 2018 and forecasts of commodity prices); the proposed Phase VI expansion of the Pouce Coupe Gas Plant (including the anticipated processing capacity of the Pouce Coupe Gas Plant after the expansion, the anticipated timing of the expansion, the anticipated cost of the expansion, that Phase VI will allow for future growth and help Birchcliff reduce its operating costs on a per boe basis and statements regarding the excess capacity at the Pouce Coupe Gas Plant and Birchcliff's ability to fill this excess capacity); statements that Birchcliff expects to update the market in the coming months on the Phase VII and VIII expansions of the Pouce Coupe Gas Plant; statements regarding the re-configuring of Phases V and VI to provide for shallow-cut capability (including the timing thereof, the amount of C3+ expected to be provided and the anticipated cost of this shallow-cut capability); estimates of reserves and the net present values of future net revenue associated with Birchcliff's reserves; price forecasts; FDC; reserves life index; decline rates; estimates of future drilling locations and opportunities; the payment of dividends (including the amount of and timing of the payment of dividends and statements regarding the sustainability of dividends); the performance characteristics of Birchcliff's oil and natural gas properties and expected results from its assets (including that its low-decline, low-cost producing assets are expected to generate a profitable return at a low commodity price and the expected performance of certain wells); statements regarding Birchcliff's Credit Facilities (including the timing of semi-annual reviews); Birchcliff's marketing and transportation arrangements (including its expectation that approximately 34% of its 2018 forecast annual average natural gas production will be sold at prices that are not based on AECO, that its market diversification initiatives have helped to reduce its exposure to volatility in commodity prices and that additional tranches of service on TCPL's Canadian Mainline will become available later in 2018 and 2019); Birchcliff's hedging activities, strategy and use of risk management techniques (including that its current hedging strategy for 2018 is to hedge up to 50% of its 2018 forecast average production using a combination of financial derivatives and physical delivery sales contracts and the amount of its 2018 forecast production that is hedged); and Birchcliff's expectation that it will release its audited results for the year ended December 31, 2017 on March 14, 2018 and its updated five year plan later in 2018. Information relating to reserves is forward-looking as it involves the implied assessment, based on certain estimates and assumptions, that the reserves exist in the quantities predicted or estimated and that the reserves can profitably be produced in the future.

With respect to forward-looking information contained in this press release, assumptions have been made regarding, among other things: Birchcliff's ability to continue to develop its assets and obtain the anticipated benefits therefrom; prevailing and future commodity prices and differentials, currency exchange rates, interest rates, inflation rates, royalty rates and tax rates; expected funds flow from operations; Birchcliff's future debt levels; the state of the economy and the exploration and production business; the economic and political environment in which Birchcliff operates; the regulatory framework regarding royalties, taxes and environmental laws; the sources of funding for Birchcliff's capital expenditure programs and other activities; anticipated timing and results of capital expenditures; the sufficiency of budgeted capital expenditures to carry out planned operations; results of future operations; future operating, transportation, marketing and general and administrative costs; the performance of existing and future wells, well production rates and well decline rates; well drainage areas; success rates for future drilling; reserves and resource volumes and Birchcliff's ability to replace and expand oil and gas reserves through acquisition, development or exploration; the impact of competition on Birchcliff; the availability of, demand for and cost of labour, services and materials; Birchcliff's ability to access capital; the ability to obtain financing on acceptable terms; the ability to obtain any necessary regulatory or other approvals in a timely manner; the ability of Birchcliff to secure adequate transportation for its products; Birchcliff's ability to market oil and gas; and the availability of hedges on terms acceptable to Birchcliff. In addition to the foregoing assumptions, Birchcliff has made the following assumptions with respect to certain forward-looking information contained in this press release:

- With respect to statements regarding the 2018 Capital Program (including estimates of 2018 capital expenditures and statements that the 2018 Capital Program will be fully funded from 2018 funds flow from operations), such statements are based on the assumptions set forth in the table under the heading *"Outlook and Guidance"*.
    - With respect to estimates of capital expenditures, such estimates assume that the 2018 Capital Program will be carried out as currently contemplated. See *"Advisories – Capital Expenditures"*.
    - With respect to statements that the 2018 Capital Program is expected to be fully funded out of 2018 funds flow from operations and that 2018 capital expenditures will be less than expected funds flow for 2018, such statements assume that: the 2018 Capital Program will be carried out as currently contemplated; the production targets and commodity price assumptions set forth herein are achieved; and Birchcliff's forecast commodity mix is achieved.
    - The amount and allocation of capital expenditures for exploration and development activities by area and the number and types of wells to be drilled is dependent upon results achieved and is subject to review and modification by management on an ongoing basis throughout the year. Actual spending may vary due to a variety of factors, including commodity prices, economic conditions, results of operations and costs of labour, services and materials. Birchcliff will monitor economic conditions and commodity prices and, where deemed prudent, will adjust the 2018 Capital Program to respond to changes in commodity prices and other material changes in the assumptions underlying the 2018 Capital Program.
- With respect to Birchcliff's production guidance, the key assumptions are that: Birchcliff's capital expenditure program will be carried out as currently contemplated; no unexpected outages occur in the infrastructure that Birchcliff relies on to produce its wells and that any transportation service curtailments or unplanned outages that occur will be short in duration or otherwise insignificant; the construction of new infrastructure meets timing and operational expectations; existing wells continue to meet production expectations; and future wells scheduled to come on production meet timing, production and capital expenditure expectations. In addition, Birchcliff's production guidance may be affected by acquisition and disposition activity and acquisitions and dispositions could occur that may impact expected production.
- With respect to estimates of reserves volumes and the net present values of future net revenue associated with Birchcliff's reserves, the key assumption is the validity of the data used by Deloitte and McDaniel in their independent reserves evaluations.
- With respect to statements of future wells to be drilled and brought on production and estimates of potential future drilling locations and opportunities, the key assumptions are: the continuing validity of the geological and other technical interpretations performed by Birchcliff's technical staff, which indicate that commercially economic volumes can be recovered from Birchcliff's lands as a result of drilling future wells; and that commodity prices and general economic conditions will warrant proceeding with the drilling of such wells.
- With respect to statements regarding the proposed Phase VI expansion of the Pouce Coupe Gas Plant, including the anticipated processing capacity of the Pouce Coupe Gas Plant after such expansion and the anticipated timing of such expansion, the key assumptions are that: future drilling is successful; there is sufficient labour, services and equipment available; Birchcliff will have access to sufficient capital to fund those projects; the key components of the plant will operate as designed; and commodity prices and general economic conditions will warrant proceeding with the construction of such facilities and the drilling of associated wells.

Birchcliff's actual results, performance or achievements could differ materially from those anticipated in the forward-looking information as a result of both known and unknown risks and uncertainties including, but not limited to: the failure to realize the anticipated benefits of acquisitions and dispositions; general economic, market and business conditions which will, among other things, impact the demand for and market prices of Birchcliff's products and Birchcliff's access to capital; an inability to access sufficient capital from internal and external sources; fluctuations in the costs of borrowing; volatility of crude oil and natural gas prices; fluctuations in currency and interest rates; operational risks and liabilities inherent in oil and natural gas operations; the occurrence of unexpected events such as fires, equipment failures and other similar events affecting Birchcliff or other parties whose operations or assets directly or indirectly affect Birchcliff; uncertainties associated with estimating oil and natural gas reserves and resources; the accuracy of oil and natural gas reserves estimates and estimated production levels as they are affected by exploration and development drilling and estimated decline rates; geological, technical, drilling, construction and processing problems; uncertainty of geological and technical data; horizontal drilling and completions techniques and the failure of drilling results to meet expectations for reserves or production; uncertainties related to Birchcliff's future potential drilling locations; changes in tax laws, Crown royalty rates, environmental laws and incentive programs relating to the oil and natural gas industry and other actions by government authorities, including changes to the royalty and carbon tax regimes and the imposition or reassessment of taxes; the cost of compliance with current and future environmental laws; political uncertainty and uncertainty associated with government policy changes; uncertainties and risks associated with pipeline restrictions and outages to third-party infrastructure that could cause disruptions to production; the ability to satisfy obligations under Birchcliff's firm marketing and transportation arrangements; the inability to secure adequate production transportation for Birchcliff's products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures, including delays in the completion of Birchcliff's gas plants and other facilities; stock market volatility; loss of market demand; environmental risks, claims and liabilities; incorrect assessments of the value of acquisitions and exploration and development programs; shortages in equipment and skilled personnel; the absence or loss of key employees; uncertainties associated with the outcome of litigation or other proceedings involving Birchcliff; uncertainty that development activities in connection with its assets will be economical; competition for, among other things, capital, acquisitions of reserves, undeveloped lands, equipment and skilled personnel; uncertainties associated with credit facilities; counterparty credit risk; risks associated with Birchcliff's hedging program and the risk that hedges on terms acceptable to Birchcliff may not be available; risks associated with the declaration and payment of dividends, including the discretion of Birchcliff's board of directors to declare dividends; the failure to obtain any required approvals in a timely manner or at all; unforeseen difficulties in integrating acquired assets into Birchcliff's operations; variances in Birchcliff's actual capital costs, operating costs and economic returns from those anticipated; negative public perception of the oil and natural gas industry, including transportation, hydraulic fracturing and fossil fuels; management of Birchcliff's growth; and the availability of insurance and the risk that certain losses may not be insured.

Readers are cautioned that the foregoing lists of factors are not exhaustive. Additional information on these and other risk factors that could affect results of operations, financial performance or financial results are included in Birchcliff's most recent Annual Information Form and in other reports filed with Canadian securities regulatory authorities.

Any future-orientated financial information and financial outlook information (collectively, "**FOFI**") contained in this press release, as such terms are defined by applicable securities laws, is provided for the purpose of providing information about management's current expectations and plans relating to the future and is subject to the same assumptions, risk factors, limitations and qualifications as set forth in the above paragraphs. FOFI contained in this press release was made as of the date of this press release and Birchcliff disclaims any intention or obligation to update or revise any FOFI contained in this press release, whether as a result of new information, future events or otherwise, unless required by applicable law. Readers are cautioned that any FOFI contained herein should not be used for purposes other than those for which it has been disclosed herein.

Management has included the above summary of assumptions and risks related to forward-looking information provided in this press release in order to provide readers with a more complete perspective on Birchcliff's future operations. Readers are cautioned that this information may not be appropriate for other purposes.

The forward-looking information contained in this press release is expressly qualified by the foregoing cautionary statements. The forward-looking information contained in this press release is made as of the date of this press release. Birchcliff is not under any duty to update or revise any of the forward-looking information except as expressly required by applicable securities laws.

In November 2016, in connection with the disclosure of its 2021 five year plan (the "**2021 Five Year Plan**"), Birchcliff disclosed a targeted exit production rate of approximately 106,000 boe/d for 2018 and an annual average production rate of 91,000 boe/d for 2018. In addition, Birchcliff disclosed various other guidance for 2019 through 2021. Given current economic conditions and commodity prices, Birchcliff has revised its annual average production guidance for 2018 to 76,000 to 78,000 boe/d. Birchcliff is in the process of updating its five year plan for 2022 which is expected to contain updated guidance for the five-year period. Depending on its outlook for commodity prices, Birchcliff expects that some of the growth contemplated by the 2021 Five Year Plan may be delayed. Birchcliff expects to release its updated five year plan later in 2018.

About Birchcliff:

Birchcliff is a Calgary, Alberta based intermediate oil and natural gas company with operations concentrated within its one core area, the Peace River Arch of Alberta. Birchcliff's common shares and cumulative redeemable preferred shares, Series A and Series C are listed for trading on the Toronto Stock Exchange under the symbols "BIR", "BIR.PR.A" and "BIR.PR.C", respectively.

For further information, please contact:

Birchcliff Energy Ltd.
Suite 1000, 600 – 3rd Avenue S.W.
Calgary, Alberta T2P 0G5
Tel: (403) 261-6401
Fax: (403) 261-6424
Email: info@birchcliffenergy.com
www.birchcliffenergy.com

Jeff Tonken, *President and Chief Executive Officer*

Bruno Geremia, *Vice-President and Chief Financial Officer*