Crescent Point Announces Year-End 2017 Results With Strong Cash Flows, Record Reserves of Over 1 Billion Boe and 152 Percent Organic Replacement of Production

CALGARY, Alberta, March 01, 2018 (GLOBE NEWSWIRE) -- Crescent Point Energy Corp. ("Crescent Point" or the "Company") (TSX:**CPG**) (NYSE:**CPG**) is pleased to announce its operating and financial results for the year ended December 31, 2017.

KEY HIGHLIGHTS

- Exceeded production guidance and achieved exit production growth of approximately 10 percent per share.
- Increased fourth quarter 2017 funds flow from operations by 17 percent per share and reduced net debt by $111.0 million.
- Transacted over $320 million of non-core dispositions since the beginning of 2017. Currently marketing larger disposition packages, with potential proceeds providing increased balance sheet strength.
- Organically replaced 152 percent of 2017 production, with technical revisions and additions contributing to Proved Plus Probable ("2P") reserves growth of over four percent per share and total 2P reserves of more than 1 billion boe.
- Finding and Development ("F&D") costs of $18.56 per boe generated a recycle ratio of 1.6 times. Waterflood reserves accounted for 18 percent of total organic 2P additions and supported F&D costs of $10.24 per boe in the Viewfield Bakken.
- Generated 2P Net Asset Value ("NAV") of $24.44 per share based on independent engineering escalated pricing as of December 31, 2017 and $14.39 per share based on flat WTI pricing of US$55.00 per barrel.
- Advanced new play development in 2017, resulting in over 1,000 net new internally identified risked drilling locations.

"Crescent Point had a strong year operationally and remained disciplined financially," said Scott Saxberg, president and CEO of Crescent Point. "We exceeded our production guidance, achieved significant reserves growth and increased our growth potential."

OPERATIONAL HIGHLIGHTS

- Crescent Point achieved fourth quarter 2017 average production of 178,975 boe/d and annual average production of 176,013 boe/d, exceeding guidance. The Company achieved exit production of over 183,000 boe/d, resulting in year-over-year growth of approximately 10 percent per share.
- In the Uinta Basin, Crescent Point continued horizontal development with a combination of one-mile and two-mile wells. Following a successful one-mile Wasatch well drilled earlier in 2017, the Company completed another one-mile Wasatch well in fourth quarter, which flowed at an average 30-day initial production ("IP30") rate of over 1,350 boe/d and was comprised of over 90 percent oil and liquids. Crescent Point continues to delineate its western lands across multiple zones and has recently initiated multi-well pad drilling within its eastern lands to further enhance efficiencies.
- In the Williston Basin and southwest Saskatchewan resource plays, Crescent Point's development strategy included a combination of low-risk, high-return infill development, step-out drilling to expand economic play boundaries, down-spacing to identify new locations and waterflood advancement. Additional infrastructure to accommodate future growth in the Flat Lake resource play within the Williston Basin is expected to be completed during first quarter 2018.
- The Company's successful new play development contributed to the addition of over 1,000 net new internally identified risked drilling locations during 2017. The Company's total corporate drilling inventory includes approximately 8,100 net risked and 14,000 net unrisked locations.
- Crescent Point further enhanced its current position as a leader in emissions reduction by building new gas conservation facilities and implementing new technologies, including solar power generation and field automation. Based on most recent data from the National Energy Board, Crescent Point's emissions intensity was approximately 40 percent less than its Canadian peers.
- As part of its waterflood program, the Company had installed 50 Injection Control Device ("ICD") waterflood systems by the end of 2017, which resulted in improved water injectivity and production rates. Crescent Point's Viewfield Bakken waterflood program continues to expand and the Company remains on track to fully unitize two of the remaining original four units during 2018. Several additional units have also been identified for continued future waterflood growth.

"In 2017, we increased our growth potential through new drilling locations and a 70 percent increase in our productive capacity," said Saxberg. "Our emissions intensity is approximately 40 percent less than our peers and we continue to implement new technologies to further enhance our leadership in emissions reductions."

FINANCIAL HIGHLIGHTS

- Funds flow from operations totaled $494.7 million, or $0.90 per share diluted, in fourth quarter 2017. This represents an increase of approximately 17 percent per share over fourth quarter 2016 and highlights the Company's strong netbacks of $34.43 per boe. Crescent Point paid cash dividends of $0.09 per share during the quarter, resulting in a payout ratio of 10 percent. For the year ended December 31, 2017, Crescent Point's funds flow from operations totaled $1.73 billion, or $3.16 per share diluted.

- Total development capital expenditures in 2017, excluding land acquisitions, were $1.63 billion. This compared to guidance of $1.55 billion, as the Company advanced new play development and initiated its first quarter 2018 program in December 2017. During fourth quarter 2017, Crescent Point spent $104.5 million on land acquisitions and successfully reduced its net debt by $111.0 million, mainly driven by proceeds from non-core dispositions.

- The Company executed over $320 million of non-core dispositions since the beginning of 2017, of which approximately $20 million closed in first quarter 2018. Crescent Point is also marketing larger disposition packages during 2018, with potential proceeds providing increased balance sheet strength.

- As part of its risk management program, Crescent Point has hedged 18.8 million barrels of oil since third quarter 2017. As at February 23, 2018, the Company had 50 percent of its liquids production, net of royalty interest, hedged for first half of 2018 at a weighted average market value price of approximately CDN$73.00/bbl. For the second half of 2018 and the first half of 2019, Crescent Point had 41 percent and 17 percent of its liquids production hedged, respectively, at a weighted average market value price of approximately CDN$72.00/bbl each. The Company's commodity hedges extend through 2019 and include a significant amount of natural gas production hedged at a weighted average price of CDN$2.79 per GJ.

- Crescent Point retains a significant amount of liquidity with no material near-term debt maturities. As at December 31, 2017, cash and unutilized credit capacity was approximately $1.5 billion.

"Our NAV of over $14 per share at US$55 WTI and funds flow of $3.16 per share in 2017 both highlight the inherent value of our asset base," said Saxberg. "Our year-end NAV only reflects booked locations, which account for 43 percent of our risked inventory, and does not reflect the significant growth potential in our Uinta Basin and Flat Lake resource plays."

RESERVES HIGHLIGHTS

- On a 2P basis, Crescent Point replaced 152 percent of 2017 production and achieved record reserves of over 1 billion boe (89 percent oil and liquids), representing growth of over four percent per share. The Company generated 2P F&D costs of $18.56 per boe in 2017, excluding changes in Future Development Capital ("FDC"), for a recycle ratio of 1.6 times, based on an operating netback of $29.42 per boe.

- Crescent Point added 97.6 million boe ("MMboe") of organic 2P reserves in 2017 driven by successful new play development in its core areas. This growth compares to organic 2P reserves additions of 66.4 MMboe in 2016, an increase of 47 percent.

- Approximately 18 percent of total organic 2P reserves additions, or 17.3 MMboe, were attributed to waterflood projects. Crescent Point has added over 40 MMboe of 2P waterflood reserves across the Company since 2013, marking the fifth consecutive year independent evaluators have recognized tight rock waterflood additions.

- Crescent Point generated a before-tax 2P NAV of $24.44 per fully diluted share, discounted at 10 percent, based on the independent engineering escalated price forecast as of December 31, 2017.

- On a Proved ("1P") basis, Crescent Point replaced 136 percent of 2017 production and increased reserves to 631.3 MMboe (89 percent oil and liquids), representing approximately five percent growth per share. Excluding changes in FDC, 1P F&D costs totaled $20.76 per boe, for a recycle ratio of 1.4 times. Overall, 1P reserves accounted for 63 percent of total 2P reserves.

- On a Proved Developed Producing ("PDP") basis, Crescent Point replaced 143 percent of 2017 production and increased PDP reserves to 393.3 MMboe (89 percent oil and liquids), representing over seven percent growth per share. PDP F&D costs totaled $19.79 per boe, excluding changes in FDC, representing a recycle ratio of 1.5 times.

"Approximately 18 percent of our total organic 2P reserves additions in 2017 were attributed to our waterflood programs," said Saxberg. "We see waterflood reserves as a leading indicator of lower corporate declines and F&D costs."

OUTLOOK

Crescent Point had an excellent fourth quarter and full year operationally. The Company grew production and reserves on a per share basis and internally identified new drilling locations with significant productive capacity for future growth. Crescent Point also remained financially disciplined by layering additional commodity hedges to protect cash flows and executing non-core dispositions.

"Our technical expertise, coupled with our strategy of focusing on large oil-in-place resource pools, allowed us to generate technical revisions and development reserves for the sixteenth consecutive year," said Saxberg. "These results generated strong recycle ratios and per share growth, reflecting a successful drilling program, waterflood advancement and the implementation of new technologies."

Crescent Point's 2018 guidance remains unchanged with capital expenditures of $1.8 billion, excluding land acquisitions, annual average production guidance of 183,500 boe/d and exit production of 195,000 boe/d. The Company's Williston Basin and southwest Saskatchewan resource plays are expected to generate funds flow from operations in excess of capital expenditures in 2018, supporting continued growth in its Uinta Basin resource play. Crescent Point remains disciplined with its capital spending and expects to direct any excess funds flow from operations realized at higher commodity prices toward debt reduction.

"We remain well-positioned to meet or exceed our 2018 targets," said Saxberg. "Our light-oil weighted asset base is expected to generate strong annual cash flows driven by top-quartile netbacks that have a limited impact from the recent widening of WCS differentials. We are also layering additional commodity hedges as part of our risk management program to further protect our expected cash flows."

The Company remains committed to maintaining a strong financial position and continues to market non-core asset packages. Since 2017, Crescent Point has executed on over $320 million of non-core dispositions.

OPERATIONS AND RESERVES REVIEW

Summary of Drilling Results

The following table summarizes Crescent Point’s drilling results for the three months and year ended December 31, 2017:

Three months ended December 31, 2017	**Gas**	**Oil**	**D&A(4)**	**Service**	**Standing**	**Total**	**Net**	**% Success(3)**
Williston Basin(1)	-	85	-	3	-	88	64.7	100
Southwest Saskatchewan	-	56	-	2	-	58	43.4	100
Uinta Basin(1)	-	22	1	-	-	23	12.7	96
Other	-	3	-	-	-	3	0.6	100
Total(2)	-	166	1	5	-	172	121.4	99

Year ended December 31, 2017	**Gas**	**Oil**	**D&A(4)**	**Service**	**Standing**	**Total**	**Net**	**% Success(3)**
Williston Basin(1)	-	404	-	4	-	408	344.3	100
Southwest Saskatchewan	-	287	-	2	-	289	248.7	100
Uinta Basin(1)	-	73	1	-	-	74	36.2	99
Other	-	23	-	-	-	23	19.9	100
Total(2)	-	787	1	6	-	794	649.1	100

(1) The net well count is subject to final working interest determination

(2) Numbers may not add due to rounding

(3) % success based on total wells

(4) Following an operational issue, which resulted in partial abandonment of a well, an adjacent well was successfully drilled and completed by the Company

Similar to prior years, Crescent Point's 2017 capital program focused on a balanced approach based on economic returns and long-term growth objectives, including new play development. The Company also continued to test new technologies, such as ICD waterflood systems, to maximize ultimate recoveries and value throughout its asset base.

In the Williston Basin and southwest Saskatchewan, Crescent Point generated organic 2P reserves growth through a combination of drilling and development, technical revisions and the advancement of waterflood programs. This is the fifth consecutive year independent evaluators have recognized reserves attributed to tight-rock waterfloods, which contributed to the Company's attractive 2P F&D costs, excluding FDC, of $10.24 per boe in the Viewfield Bakken resource play.

In the Flat Lake area, Crescent Point successfully expanded the economic boundary for the Torquay/Three Forks play and executed eight wells per section spacing in its Ratcliffe development program. The Company is focused on building on this success during 2018 and is currently adding new infrastructure to accommodate future production growth expected from this area.

In the Uinta Basin, 2P reserves grew by approximately 40 percent year-over-year, highlighting the success in the Company's new play development. During fourth quarter 2017, Crescent Point advanced one-mile and two-mile horizontal development across multiple zones with strong results. The Company's second one-mile Wasatch well, which was completed during fourth quarter, flowed at an impressive IP30 rate of over 1,350 boe/d and was comprised of over 90 percent oil and liquids. This horizontal well follows a successful one-mile Wasatch well drilled earlier in 2017, which has already produced over 300,000 boe after only 245 days, and is comprised of over 90 percent oil and liquids. The Company's focus for 2018 includes increased two-mile development, multi-well pad drilling for improved efficiencies, multi-zone development including continued advancement of Wasatch and Uteland Butte zones and the delineation of its lands on the western portion of the basin.

"We had tremendous operational success in 2017, including our horizontal drilling program in the Uinta Basin," said Saxberg. "Our improved production rates and economics underpin our five-year plan to grow production to 250,000 boe/d to 320,000 boe/d."

Summary of Reserves

The Company’s reserves were independently evaluated by GLJ Petroleum Consultants Ltd. ("GLJ") and Sproule Associates Limited ("Sproule") as at December 31, 2017, and were aggregated by GLJ. The reserves evaluation and reporting was conducted in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook ("COGEH") and - *National Instrument 51-101 Standards for Disclosure of Oil and Gas Activities* ("NI 51-101").

As at December 31, 2017 (1) (2) (3) (4) (5)

	Tight Oil (Mbbls)		**Light and Medium Oil (Mbbls)**		**Heavy Oil (Mbbls)**		**Natural Gas Liquids (Mbbls)**	
Reserves Category	**Company Gross**	**Company Net**	**Company Gross**	**Company Net**	**Company Gross**	**Company Net**	**Company Gross**	**Company Net**
Proved Developed Producing	179,248	162,754	102,943	91,157	24,167	19,075	44,023	39,805
Proved Developed Non-Producing	3,963	3,562	2,961	2,705	177	160	756	681
Proved Undeveloped	140,487	124,353	37,676	34,622	1,991	1,631	24,311	21,444
Total Proved	323,698	290,669	143,580	128,484	26,335	20,866	69,090	61,931
Total Probable	204,252	180,209	84,179	75,096	7,237	5,753	39,039	34,583
Total Proved plus Probable	527,950	470,878	227,759	203,580	33,571	26,619	108,129	96,514

	Shale Gas (MMcf)		**Natural Gas (MMcf)**		**Total (Mboe)**	
Reserves Category	**Company Gross**	**Company Net**	**Company Gross**	**Company Net**	**Company Gross**	**Company Net**
Proved Developed Producing	167,194	151,859	90,142	83,718	393,271	352,054
Proved Developed Non-Producing	5,001	4,339	2,319	2,048	9,077	8,172
Proved Undeveloped	128,064	111,354	18,679	16,939	228,922	203,433
Total Proved	300,259	267,552	111,140	102,704	631,270	563,659
Total Probable	175,023	153,469	54,695	49,477	372,993	329,466
Total Proved plus Probable	475,281	421,021	165,834	152,181	1,004,262	893,125

(1) Based on Sproule’s December 31, 2017, escalated price forecast.

(2) "Gross Reserves" are the total Company’s working-interest share before the deduction of any royalties and without including any royalty interest of the Company.

(3) "Net Reserves" are the total Company's interest share after deducting royalties and including any royalty interest.

(4) Numbers may not add due to rounding.

(5) Detailed reserves and analysis are provided in the Company's Annual Information Form for the year-ended December 31, 2017 (the "AIF").

Summary of Before and After Tax Net Present Values

As at December 31, 2017 (1) (2) (3)

	Before Tax Net Present Value ($ millions)					After Tax Net Present Value ($ millions)				
	Discount Rate					Discount Rate				
Reserves Category	**0%**	**5%**	**10%**	**15%**	**20%**	**0%**	**5%**	**10%**	**15%**	**20%**
Proved Developed Producing	12,839	9,581	7,693	6,467	5,609	12,083	9,147	7,426	6,294	5,492
Proved Developed Non-Producing	256	200	163	137	117	194	156	130	112	99
Proved Undeveloped	5,344	3,441	2,286	1,545	1,047	4,052	2,557	1,647	1,064	672
Total Proved	18,439	13,222	10,141	8,149	6,773	16,328	11,860	9,203	7,470	6,262
Total Probable	14,237	8,095	5,338	3,843	2,926	10,439	5,911	3,874	2,773	2,100
Total Proved plus Probable	32,676	21,317	15,479	11,992	9,699	26,767	17,771	13,078	10,243	8,362

(1) Based on Sproule’s December 31, 2017, escalated price forecast.

(2) Numbers may not add due to rounding.

(3) Detailed Net Present Values and analysis are provided in the AIF.

Before Tax Net Asset Value per Share, Fully Diluted, Utilizing Independent Engineering, Escalated Pricing

	2017 (1) (2) (3)	**2016**	**2015**	**2014**	**2013**	**2012**	**2011**	**2010**	**2009**	**2008**
PV 0%	$55.73	$53.12	$60.55	$75.33	$75.69	$68.39	$71.39	$71.38	$72.01	$80.66
PV 5%	$35.06	$34.18	$38.28	$48.62	$51.04	$46.49	$49.81	$47.65	$46.91	$49.30
PV 10%	$24.44	$24.14	$26.49	$34.74	$38.13	$35.11	$38.42	$36.02	$35.08	$34.97
PV 15%	$18.09	$18.05	$19.37	$26.41	$30.25	$28.15	$31.35	$29.10	$28.27	$26.85

(1) Based on Sproule’s December 31, 2017, escalated price forecast.

(2) Based on 549.4 million shares fully diluted.

(3) Net debt of $4.0 billion as at December 31, 2017.

Reserves Reconciliation

Gross Reserves (1) (2) (3) (4)

	Tight Oil (Mbbls)			Light and Medium Oil (Mbbls)			Heavy Oil (Mbbls)		
Factors	**Proved**	**Probable**	**Proved plus Probable**	**Proved**	**Probable**	**Proved plus Probable**	**Proved**	**Probable**	**Proved plus Probable**
December 31, 2016	298,527	184,814	483,341	159,298	100,034	259,331	22,816	7,329	30,145
Extensions and Improved Recovery	39,322	31,986	71,307	6,345	3,395	9,740	132	(132)	1
Technical Revisions	4,245	(19,855)	(15,610)	7,021	(14,481)	(7,460)	5,136	75	5,211
Acquisitions	15,659	6,077	21,736	585	1,436	2,020	42	8	51
Dispositions	(398)	(500)	(898)	(13,335)	(5,582)	(18,917)	(21)	(63)	(84)
Economic Factors	(1,050)	1,731	680	358	(623)	(265)	30	19	50
Production	(32,607)	-	(32,607)	(16,691)	-	(16,691)	(1,801)	-	(1,801)
December 31, 2017	323,698	204,252	527,950	143,580	84,179	227,759	26,335	7,237	33,571

	Natural Gas Liquids (Mbbls)			Shale Gas (MMcf)			Natural Gas (MMcf)		
Factors	**Proved**	**Probable**	**Proved plus Probable**	**Proved**	**Probable**	**Proved plus Probable**	**Proved**	**Probable**	**Proved plus Probable**
December 31, 2016	57,099	31,714	88,813	247,501	138,953	386,455	127,261	67,441	194,702
Extensions and Improved Recovery	6,501	5,080	11,581	30,692	25,512	56,203	859	1,399	2,257
Technical Revisions	10,141	562	10,703	29,212	(608)	28,604	(1,284)	(16,304)	(17,588)
Acquisitions	2,304	1,565	3,869	22,142	9,539	31,681	437	1,477	1,914
Dispositions	(207)	(152)	(359)	(536)	(806)	(1,342)	(1,600)	(781)	(2,380)

Economic Factors	(86)	269	184	(2,354)	2,433	79	(2,022)	1,463	(560)
Production	(6,661)	-	(6,661)	(26,398)	-	(26,398)	(12,511)	-	(12,511)
December 31, 2017	69,090	39,039	108,129	300,259	175,023	475,281	111,140	54,695	165,834

	Total Oil Equivalent (Mboe)		
Factors	**Proved**	**Probable**	**Proved plus Probable**
December 31, 2016	600,199	358,289	958,489
Extensions and Improved Recovery	57,559	44,814	102,373
Technical Revisions	31,198	(36,517)	(5,320)
Acquisitions	22,352	10,922	33,275
Dispositions	(14,317)	(6,561)	(20,878)
Economic Factors	(1,477)	2,046	569
Production	(64,245)	-	(64,245)
December 31, 2017	631,270	372,993	1,004,262

(1) Based on Sproule's December 31, 2017, escalated price forecast.

(2) "Gross reserves" are the Company's working-interest share before deduction of any royalties and without including any royalty interests of the Company.

(3) Numbers may not add due to rounding.

(4) Detailed descriptions for significant changes in values are included in the AIF.

Finding, Development and Acquisition Costs

	F&D (3)	Change in FDC on F&D	F&D Total (incl. change in FDC)	FD&A (4)	Change in FDC on FD&A	FD&A Total (incl. change in FDC)
Capital ($ millions) (1)						
Total Proved plus Probable	1,812	301	2,113	1,814	370	2,184
Total Proved	1,812	245	2,057	1,814	305	2,119
Reserves Additions (Mboe) (2)						
Total Proved plus Probable	97,622	-	97,622	110,019	-	110,019
Total Proved	87,280	-	87,280	95,315	-	95,315

(1) The capital expenditures include the announced purchase price of corporate acquisitions rather than the amounts allocated to property, plant and equipment for accounting purposes. The capital expenditures also exclude capitalized administration costs and transaction costs.

(2) Gross Company interest reserves are used in this calculation (working interest reserves, before deduction of any royalties and without including any royalty interests of the Company).

(3) F&D costs are calculated by dividing the identified capital expenditures by the applicable reserves additions. F&D costs can include or exclude changes to future development capital costs.

(4) FD&A is calculated by dividing the identified capital expenditures including acquisition costs net of disposition proceeds, by the applicable reserves additions. FD&A can include or exclude changes to future development capital costs.

	Excluding changes in FDC ($/boe, except recycle ratios)			Including changes in FDC ($/boe, except recycle ratios)		
	2017	**2016**	**3 Years Ended Dec. 31, 2017 (Weighted Avg.)**	**2017**	**2016**	**3 Years Ended Dec. 31, 2017 (Weighted Avg.)**
F&D Cost (1)						
Total Proved plus Probable	$18.56	$17.15	$19.70	$21.64	$7.02	$14.05
Total Proved	$20.76	$19.12	$22.90	$23.57	$11.05	$17.34
F&D Recycle Ratio (3)						
Total Proved plus Probable	1.6	1.3	1.3	1.4	3.2	1.8

Total Proved	1.4	1.2	1.1	1.2	2.0	1.5
FD&A Cost (2)						
Total Proved plus Probable	$16.49	$16.21	$17.30	$19.85	$10.87	$17.34
Total Proved	$19.03	$19.63	$22.93	$22.23	$14.47	$21.36
FD&A Recycle Ratio (3)						
Total Proved plus Probable	1.8	1.4	1.5	1.5	2.0	1.5
Total Proved	1.5	1.1	1.1	1.3	1.5	1.2

(1) F&D costs are calculated by dividing the identified capital expenditures by the applicable reserves additions. F&D costs can include or exclude changes to future development capital costs.

(2) FD&A is calculated by dividing the identified capital expenditures including acquisition costs net of disposition proceeds, by the applicable reserves additions. FD&A can include or exclude changes to future development capital costs.

(3) Recycle Ratio is calculated as netback before hedging divided by F&D or FD&A costs. Based on a 2017 netback (before hedging) of $29.42 per boe, a 2016 netback (before hedging) of $22.18 per boe and a three-year weighted average netback (before hedging) of $25.74 per boe.

Future Development Capital

At year-end 2017, FDC for 2P reserves totaled $6.9 billion compared to $6.5 billion at year-end 2016. Net of acquisitions and dispositions, FDC at year-end 2017 increased primarily due to the addition of new drilling locations identified by the Company during 2017.

Company Annual Capital Expenditures ($ millions)

	Canada		**US**		**Total**	
Year	**Total Proved**	**Total Proved + Probable**	**Total Proved**	**Total Proved + Probable**	**Total Proved**	**Total Proved + Probable**
2018	801	1,085	379	553	1,180	1,638
2019	772	1,158	415	591	1,187	1,749
2020	634	914	369	579	1,003	1,492
2021	240	808	215	371	456	1,179
2022	210	405	94	182	304	587
2023	8	12	49	67	57	80
2024	11	9	56	67	66	75
2025	7	7	-	-	7	7
2026	6	7	-	-	6	7
2027	6	6	-	-	6	6
2028	5	8	-	-	5	8
2029	5	6	-	-	5	6
Subtotal (1)	2,706	4,427	1,578	2,409	4,283	6,835
Remainder	68	72	-	-	68	72
Total (1)	2,773	4,499	1,578	2,409	4,351	6,908
10% Discounted	2,275	3,640	1,287	1,955	3,562	5,595

(1) Numbers may not add due to rounding.

CONFERENCE CALL DETAILS

Crescent Point management will host a conference call on Thursday, March 1, 2018 at 10:00 a.m. MT (12:00 p.m. ET) to discuss the results and outlook for the Company.

Participants can access the conference call by dialing 844-231-0101 or 216-562-0389 and entering the code 1196717. Alternatively, to listen to this event online, please enter **https://edge.media-server.com/m6/p/nt22dij5** into any web browser.

The webcast will be archived for replay and can be accessed on Crescent Point's website at **www.crescentpointenergy.com**. The replay will be available approximately one hour following completion of the call.

Shareholders and investors can also find the Company's most recent investor presentation on Crescent Point's website.

2018 GUIDANCE

The Company's guidance for 2018 is as follows:

Total annual average production (boe/d) % Oil and NGLs	183,500 90%
Exit production (boe/d)	195,000
Capital expenditures [1] Drilling and development ($ millions) Facilities and seismic ($ millions)	 $1,610 $190
Total ($ millions)	$1,800

(1) The projection of capital expenditures excludes property and land acquisitions, which are separately considered and evaluated.

ON BEHALF OF THE BOARD OF DIRECTORS

Scott Saxberg
President and Chief Executive Officer
March 1, 2018

The Company's audited financial statements and management's discussion and analysis for the year ended December 31, 2017, will be available on the System for Electronic Document Analysis and Retrieval ("SEDAR") at **www.sedar.com**, on EDGAR at **www.sec.gov/edgar.shtml** and on Crescent Point's website at **www.crescentpointenergy.com**.

All financial figures are approximate and in Canadian dollars unless otherwise noted. This press release contains forward-looking information and references to non-GAAP financial measures. Significant related assumptions, risk factors, and reconciliations are described under the Non-GAAP Financial Measures and the Forward-Looking Statements sections of this press release, respectively.

FINANCIAL AND OPERATING HIGHLIGHTS

	Three months ended December 31		Year ended December 31	
(Cdn$ millions except per share and per boe amounts)	**2017**	2016	**2017**	2016
Financial				
Cash flow from operating activities	**449.6**	438.5	**1,718.7**	1,524.3
Funds flow from operations [1]	**494.7**	422.0	**1,728.8**	1,572.5
Per share [2]	**0.90**	0.77	**3.16**	3.03
Net income (loss)	**(56.4)**	(510.6)	**(124.0)**	(932.7)
Per share [2]	**(0.10)**	(0.94)	**(0.23)**	(1.81)
Adjusted net earnings (loss) from operations [1]	**(35.1)**	100.6	**100.0**	88.5
Per share [1] [2]	**(0.06)**	0.18	**0.18**	0.17
Dividends declared	**49.5**	49.2	**197.7**	260.3
Per share [2]	**0.09**	0.09	**0.36**	0.50
Payout ratio (%) [1]	**10**	12	**11**	17
Net debt [1]	**4,024.9**	3,677.1	**4,024.9**	3,677.1
Net debt to funds flow from operations [1] [3]	**2.3**	2.3	**2.3**	2.3
Climate change initiatives and asset retirement [4]	**8.3**	10.0	**26.5**	26.8
Weighted average shares outstanding				
Basic	**545.8**	541.7	**545.2**	516.3
Diluted	**546.9**	544.5	**546.8**	519.3
Operating				
Average daily production				
Crude oil (bbls/d)	**140,544**	130,386	**139,996**	133,172
NGLs (bbls/d)	**19,437**	18,083	**18,250**	17,372
Natural gas (mcf/d)	**113,963**	99,765	**106,599**	103,321
Total (boe/d)	**178,975**	165,097	**176,013**	167,764
Average selling prices [5]				
Crude oil ($/bbl)	**64.25**	56.92	**59.04**	48.46
NGLs ($/bbl)	**34.23**	22.02	**27.82**	15.31
Natural gas ($/mcf)	**2.30**	3.23	**2.60**	2.36
Total ($/boe)	**55.63**	49.32	**51.41**	41.50

Netback ($/boe)				
Oil and gas sales	**55.63**	49.32	**51.41**	41.50
Royalties	**(7.44)**	(7.33)	**(7.35)**	(5.93)
Operating expenses	**(12.53)**	(11.89)	**(12.56)**	(11.27)
Transportation expenses	**(2.07)**	(2.09)	**(2.08)**	(2.12)
Netback before hedging	**33.59**	28.01	**29.42**	22.18
Realized gain on derivatives	**0.84**	3.47	**1.58**	7.63
Netback [1]	**34.43**	31.48	**31.00**	29.81
Capital Expenditures				
Capital acquisitions (dispositions), net [6]	**(156.0)**	9.8	**1.8**	226.5
Development capital expenditures [4]				
Drilling and development	**332.9**	350.5	**1,452.3**	950.6
Facilities and seismic	**42.3**	41.8	**172.7**	145.8
Land	**104.5**	18.4	**187.1**	42.5
Total	**479.7**	410.7	**1,812.1**	1,138.9

(1) Funds flow from operations, adjusted net earnings from operations, payout ratio, net debt, net debt to funds flow from operations and netback as presented do not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other entities.

(2) The per share amounts (with the exception of dividends per share) are the per share – diluted amounts.

(3) Net debt to funds flow from operations is calculated as the period end net debt divided by the sum of funds flow from operations for the trailing four quarters.

(4) Climate change initiatives and asset retirement includes environmental emission reduction expenditures, which are also included in development capital expenditures in the table above.

(5) The average selling prices reported are before realized derivatives.

(6) Capital acquisitions (dispositions), net represent total consideration for the transactions, including long-term debt and working capital assumed, and exclude transaction costs.

Non-GAAP Financial Measures

Throughout this press release, the Company uses the terms "funds flow from operations", "funds flow from operations per share - diluted", "adjusted net earnings from operations", "adjusted net earnings from operations per share - diluted", "net debt", "net debt to funds flow from operations", "netback", "payout ratio" and "total payout ratio". These terms do not have any standardized meaning as prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other issuers.

Funds flow from operations is calculated based on cash flow from operating activities before changes in non-cash working capital, transaction costs and decommissioning expenditures. Funds flow from operations per share - diluted is calculated as funds flow from operations divided by the number of weighted average diluted shares outstanding. Transaction costs are excluded as they vary based on the Company's acquisition activity and to ensure that this metric is more comparable between periods. Decommissioning expenditures are excluded as the Company has a voluntary reclamation fund to fund decommissioning costs. Management utilizes funds flow from operations as a key measure to assess the ability of the Company to finance dividends, operating activities, capital expenditures and debt repayments. Funds flow from operations as presented is not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS.

The following table reconciles cash flow from operating activities to funds flow from operations:

	Three months ended December 31		Year ended December 31	
($ millions)	**2017**	2016	**2017**	2016
Cash flow from operating activities	**449.6**	438.5	**1,718.7**	1,524.3
Changes in non-cash working capital	**35.5**	(23.5)	**(18.7)**	29.9
Transaction costs	**1.4**	0.5	**3.7**	2.3
Decommissioning expenditures	**8.2**	6.5	**25.1**	16.0
Funds flow from operations	**494.7**	422.0	**1,728.8**	1,572.5

Adjusted net earnings from operations is calculated based on net income before amortization of exploration and evaluation ("E&E") undeveloped land, impairment or impairment recoveries on property, plant and equipment ("PP&E"), unrealized derivative gains or losses, unrealized foreign exchange gain or loss on translation of hedged US dollar long-term debt, unrealized gains or losses on long-term investments and gains or losses on capital acquisitions and dispositions. Adjusted net earnings from operations per share - diluted is calculated as adjusted net earnings from operations divided by the number of weighted average diluted shares outstanding. Management utilizes adjusted net earnings from operations to present a measure of financial performance that is more comparable between periods. Adjusted net earnings from operations as presented is not intended to represent net earnings or other measures of financial performance calculated in accordance with IFRS.

The following table reconciles net income to adjusted net earnings from operations:

	Three months ended December 31		Year ended December 31	
($ millions)	**2017**	2016	**2017**	2016
Net income (loss)	**(56.4)**	(510.6)	**(124.0)**	(932.7)
Amortization of E&E undeveloped land	**34.8**	29.2	**134.3**	172.5
Impairment to PP&E	**(102.9)**	611.4	**203.6**	611.4
Unrealized derivative losses	**180.0**	138.7	**163.6**	706.8
Unrealized foreign exchange (gain) loss on translation of hedged US dollar long-term debt	**(53.7)**	44.1	**(201.2)**	(110.6)
Unrealized (gain) loss on long-term investments	**(3.8)**	0.5	**3.4**	(5.5)
(Gain) loss on capital acquisitions / dispositions	**(21.0)**	-	**(31.1)**	15.3
Deferred tax relating to adjustments	**(12.1)**	(212.7)	**(48.6)**	(368.7)
Adjusted net earnings (loss) from operations	**(35.1)**	100.6	**100.0**	88.5

Net debt is calculated as long-term debt plus accounts payable and accrued liabilities, dividends payable and long-term compensation liability, less cash, accounts receivable, prepaids and deposits and long-term investments, excluding the unrealized foreign exchange on translation of US dollar long-term debt. Management utilizes net debt as a key measure to assess the liquidity of the Company.

The following table reconciles long-term debt to net debt:

($ millions)	**2017**	2016
Long-term debt (1)	**4,111.0**	3,820.7
Accounts payable and accrued liabilities	**613.3**	647.2
Dividends payable	**16.8**	16.3
Long-term compensation liability (2)	**22.9**	3.7
Cash	**(62.4)**	(13.4)
Accounts receivable	**(380.2)**	(335.7)
Prepaids and deposits	**(4.5)**	(5.3)
Long-term investments	**(72.6)**	(35.8)
Excludes:		
Unrealized foreign exchange on translation of hedged US dollar long-term debt	**(219.4)**	(420.6)
Net debt	**4,024.9**	3,677.1

(1) Includes current portion of long-term debt.

(2) Includes current portion of long-term compensation liability.

Net debt to funds flow from operations is calculated as the period end net debt divided by the sum of funds flow from operations for the trailing four quarters. The ratio of net debt to funds flow from operations is used by management to measure the Company’s overall debt position and to measure the strength of the Company’s balance sheet. Crescent Point monitors this ratio and uses this as a key measure in making decisions regarding financing, capital spending and dividend levels.

Netback is calculated on a per boe basis as oil and gas sales, less royalties, operating and transportation expenses and realized derivative gains and losses. Netback is a common metric used in the oil and gas industry and is used by management to measure operating results on a per boe basis to better analyze performance against prior periods on a comparable basis. The calculation of netback is shown in the Financial and Operating Highlights section in this press release.

Payout ratio is calculated on a percentage basis as dividends declared divided by funds flow from operations. Payout ratio is used by management to monitor the dividend policy and the amount of funds flow from operations retained by the Company for capital reinvestment.

Total payout ratio is calculated on a percentage basis as development capital expenditures and declared divided by funds flow from operations. Total payout ratio is used by management to monitor the Company's capital reinvestment and dividend policy, as a percentage of the amount of funds flow from operations.

Management believes the presentation of the Non-GAAP measures above provide useful information to investors and shareholders as the measures provide increased transparency and the ability to better analyze performance against prior periods on a comparable basis.

Notice to US Readers

The oil and natural gas reserves contained in this press release have generally been prepared in accordance with Canadian disclosure standards, which are not comparable in all respects of United States or other foreign disclosure standards. For example, the United States Securities and Exchange Commission (the "SEC") generally permits oil and gas issuers, in their filings with the SEC, to disclose only proved reserves (as defined in SEC rules), but permits the optional disclosure of "probable reserves" and "possible reserves" (each as defined in SEC rules). Canadian securities laws require oil and gas issuers, in their filings with Canadian securities regulators, to disclose not only proved reserves (which are defined differently from the SEC rules) but also probable reserves and permits optional disclosure of "possible reserves", each as defined in NI 51-101. Accordingly, "proved reserves", "probable reserves" and "possible reserves" disclosed in this news release may not be comparable to US standards, and in this news release, Crescent Point has disclosed reserves designated as "proved plus probable reserves". Probable reserves are higher-risk and are generally believed to be less likely to be accurately estimated or recovered than proved reserves. "Possible reserves" are higher risk than "probable reserves" and are generally believed to be less likely to be accurately estimated or recovered than "probable reserves". In addition, under Canadian disclosure requirements and industry practice, reserves and production are reported using gross volumes, which are volumes prior to deduction of royalties and similar payments. The SEC rules require reserves and production to be presented using net volumes, after deduction of applicable royalties and similar payments. Moreover, Crescent Point has determined and disclosed estimated future net revenue from its reserves using forecast prices and costs, whereas the SEC rules require that reserves be estimated using a 12-month average price, calculated as the arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. Consequently, Crescent Point's reserve estimates and production volumes in this news release may not be comparable to those made by companies using United States reporting and disclosure standards. Further, the SEC rules are based on unescalated costs and forecasts.

All amounts in the news release are stated in Canadian dollars unless otherwise specified.

Forward-Looking Statements

Any "financial outlook" or "future oriented financial information" in this press release, as defined by applicable securities legislation has been approved by management of Crescent Point. Such financial outlook or future oriented financial information is provided for the purpose of providing information about management's current expectations and plans relating to the future. Readers are cautioned that reliance on such information may not be appropriate for other purposes.

Certain statements contained in this press release constitute "forward-looking statements" within the meaning of section 27A of the Securities Act of 1933 and section 21E of the Securities Exchange Act of 1934 and "forward-looking information" for the purposes of Canadian securities regulation (collectively, "forward-looking statements"). The Company has tried to identify such forward-looking statements by use of such words as "could", "should", "can", "anticipate", "expect", "believe", "will", "may", "intend", "projected", "sustain", "continues", "strategy", "potential", "projects", "grow", "take advantage", "estimate", "well-positioned" and other similar expressions, but these words are not the exclusive means of identifying such statements.

In particular, this press release contains forward-looking statements pertaining, among other things, to the following: the Company's current marketing of disposition packages and the expected use of proceeds from any sales resulting from such efforts; the Company's NAV per share based on flat WTI pricing of US$55.00 assumes a $0.77 USD/CAD exchange; the Company's plans to continue to delineate its western Uinta Basin lands across multiple zones; the expectation that additional infrastructure will be completed in Flat Lake during the first quarter 2018 and the anticipation that such infrastructure will accommodate future growth in the area; the Company's drilling inventory; the planned continued expansion of the Company's Viewfield Bakken waterflood program and the belief that the Company remains on track to fully unitize two of the remaining four units in the area during 2018; the significant growth potential of the Company's Uinta Basin and Flat Lake resource plays; the Company's belief that waterflood reserve additions are a leading indicator of lower corporate declines and F&D costs; the Company's 2018 guidance with respect to capital expenditures, annual average production and exit production; Crescent Point's expectation that its Williston Basin and southwest Saskatchewan resource plays will generate funds flow from operations in excess of capital expenditures in 2018 and the expectation that such excess funds flow from operations will support the continued growth in the Uinta Basin; the expected use of excess cash flows above capital expenditures; Crescent Point being well positioned to meet or exceed its 2018 targets; expected annual cash flows; the anticipated impact of the recent widening of differentials on cash flows; the expected layering of additional commodity hedges to further protect the Company's expected cash flows and netbacks; Crescent Point's 2018 focus on building on its success in Flat Lake; the Company's focus in Uinta for 2018, including increased two-mile development, multi-well pad drilling for improved efficiencies, multi-zone development including continued advancement of Wasatch and Uteland Butte zones and the delineation of its lands on the western portion of the basin; and the Company's five-year plan to grow production to 250,000 boe/d to 320,000 boe/d, which is based on two total payout scenarios of 100 percent and 110 percent. Both scenarios assume WTI prices of approximately US$60.00 per barrel in 2018 and US$55.00 per barrel in 2019-2022.

Statements relating to "reserves" are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future. Actual reserve values may be greater than or less than the estimates provided herein.

Unless otherwise noted, reserves referenced herein are given as at December 31, 2017. Also, estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates and future net revenue for all properties due to the effect of aggregation. All required reserve information for the Company is contained in its Annual Information Form for the year ended December 31, 2017, which is accessible at **www.sedar.com**.

With respect to disclosure contained herein regarding resources other than reserves, there is uncertainty that it will be commercially viable to produce any portion of the resources and there is significant uncertainty regarding the ultimate recoverability of such resources.

All forward-looking statements are based on Crescent Point’s beliefs and assumptions based on information available at the time the assumption was made. Crescent Point believes that the expectations reflected in these forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this report should not be unduly relied upon. By their nature, such forward-looking statements are subject to a number of risks, uncertainties and assumptions, which could cause actual results or other expectations to differ materially from those anticipated, expressed or implied by such statements, including those material risks discussed in the Company’s Annual Information Form for the year ended December 31, 2017 under "*Risk Factors*" and our Management’s Discussion and Analysis for the year ended December 31, 2017, under the headings "*Risk Factors*" and "*Forward-Looking Information*". The material assumptions are disclosed in the Management’s Discussion and Analysis for the year ended December 31, 2017, under the headings "*Capital Expenditures*", "*Liquidity and Capital Resources*", "*Critical Accounting Estimates*", "*Risk Factors*", "*Changes in Accounting Policies*" and "*Outlook*". In addition, risk factors include: financial risk of marketing reserves at an acceptable price given market conditions; volatility in market prices for oil and natural gas; delays in business operations, pipeline restrictions, blowouts; the risk of carrying out operations with minimal environmental impact; industry conditions including changes in laws and regulations and the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; risks and uncertainties related to all oil and gas interests and operations on tribal lands; uncertainties associated with estimating oil and natural gas reserves; economic risk of finding and producing reserves at a reasonable cost; uncertainties associated with partner plans and approvals; operational matters related to non-operated properties; increased competition for, among other things, capital, acquisitions of reserves and undeveloped lands; competition for and availability of qualified personnel or management; incorrect assessments of the value of acquisitions and exploration and development programs; unexpected geological, technical, drilling, construction and processing problems; availability of insurance; fluctuations in foreign exchange and interest rates; stock market volatility; failure to realize the anticipated benefits of acquisitions; general economic, market and business conditions; uncertainties associated with regulatory approvals; uncertainty of government policy changes; uncertainties associated with credit facilities and counterparty credit risk; and changes in income tax laws, tax laws, crown royalty rates and incentive programs relating to the oil and gas industry; and other factors, many of which are outside the control of Crescent Point. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and Crescent Point’s future course of action depends on management’s assessment of all information available at the relevant time.

Additional information on these and other factors that could affect Crescent Point’s operations or financial results are included in Crescent Point’s reports on file with Canadian and U.S. securities regulatory authorities. Readers are cautioned not to place undue reliance on this forward-looking information, which is given as of the date it is expressed herein or otherwise. Crescent Point undertakes no obligation to update publicly or revise any forward-looking statements, whether as a result of new information, future events or otherwise, unless required to do so pursuant to applicable law. All subsequent forward-looking statements, whether written or oral, attributable to Crescent Point or persons acting on the Company’s behalf are expressly qualified in their entirety by these cautionary statements.

Definitions

Decline rate is the reduction in the rate of production from one period to the next. This rate is usually expressed on an annual basis.

Finding and development (F&D) costs are calculated by dividing the identified capital expenditures by the applicable reserves additions. F&D costs can include or exclude changes to future development capital costs.

Finding, development and acquisitions costs (FD&A) is calculated by dividing the identified capital expenditures including acquisition costs by the applicable reserves additions. FD&A can include or exclude changes to future development capital costs.

Future development capital (FDC) reflects the independent evaluator’s best estimate of the cost required to bring proved undeveloped and probable reserves on production. Changes in FDC can result from acquisition and disposition activities, development plans or changes in capital efficiencies due to inflation or reductions in service costs and/or improvements to drilling and completion methods.

Net asset value (NAV) is a snapshot in time as at year-end, and is based on the Company’s reserves evaluated using the independent evaluators forecast for future prices, costs and foreign exchange rates. The Company’s NAV is calculated on a before tax basis and is the sum of the present value of proved and probable reserves, the fair value for land and seismic, the fair value for the Company’s oil and gas hedges based on Sproule’s December 31, 2017 escalated price forecast, less outstanding net debt. The NAV per share is calculated on a fully diluted basis.

N1 51-101 means "*National Instrument 51-101 - Standards for Disclosure for Oil and Gas Activities*".

Recycle Ratio is calculated as operating netback divided by F&D or FD&A costs. Based on a 2017 netback (before hedging), of $29.42 per boe, a 2016 netback (before hedging) of $22.18 per boe and a three-year weighted average netback (before hedging) of $25.74 per boe.

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. Proved reserves are reserves estimated to have a high degree of certainty of recoverability. Probable reserves are less certain to be recoverable than probable reserves and possible reserves are less certain than probable reserves.

Reserves and Drilling Data

The reserves information contained in this press release has been prepared in accordance with NI 51-101. Complete NI 51-101 reserves disclosure will be included in our Annual Information Form for the year ended December 31, 2017, which will be filed on or before March 1, 2018.

Where applicable, a barrels of oil equivalent ("boe") conversion rate of six thousand cubic feet of natural gas to one barrel of oil equivalent (6Mcf:1bbl) has been used based on an energy equivalent conversion method primarily applicable at the burner tip. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different than the energy equivalency of the 6:1 conversion ratio, utilizing the 6:1 conversion ratio may be misleading as an indication of value.

This press release contains metrics commonly used in the oil and natural gas industry including "netbacks", "F&D costs", "FD&A costs", "FDC", "NAV", "recycle ratio", "decline rate", and "drilling inventory". These terms do not have a standardized meaning and may not be comparable to similar measures presented by other companies and, therefore, should not be used to make such comparisons.

F&D costs, including changes in FDC have been presented in this news release because they provide a useful measure of capital efficiency. F&D costs, including land, facility and seismic expenditures and excluding changes in FDC have also been presented in this news release because they provide a useful measure of capital efficiency.

FD&A costs, including changes in FDC have been presented in this news release because they provide a useful measure of capital efficiency. FD&A costs, including land, facility and seismic expenditures and excluding changes in FDC have also been presented in this news release because they provide a useful measure of capital efficiency.

Management uses recycle ratio for its own performance measurements and to provide shareholders with measures to compare the Company’s performance over time.

Netback is calculated on a per boe basis as oil and gas sales, less royalties, operating and transportation expenses and realized derivative gains and losses. Netback is used by management to measure operating results on a per boe basis to better analyze performance against prior periods on a comparable basis.

Drilling inventory is calculated in years as the Company’s 2017 year-end inventory divided by the number of wells in its 2018 drilling program. Drilling inventory is used by management to assess the amount of available drilling opportunities.

References to the "total corporate productive capacity” are derived from the sum of the 30-day initial production rates of the Company's total drilling inventory, both on a risked and unrisked basis. References to the “potential upside” of asset acquisitions relative to non-core asset dispositions are derived from the before-tax net present value of unrisked drilling locations, discounted at 10 percent, in comparison to the total value of dispositions executed in 2017.

There are numerous uncertainties inherent in estimating quantities of crude oil, natural gas and NGL reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth above are estimates only. In general, estimates of economically recoverable crude oil, natural gas and NGL 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, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially. For these reasons, estimates of the economically recoverable crude oil, NGL and natural gas 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 engineers at different times, may vary. The Company'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.

Individual properties may not reflect the same confidence level as estimates of reserves for all properties due to the effects of aggregation. This press release contains estimates of the net present value of the Company's future net revenue from our reserves. Such amounts do not represent the fair market value of our reserves. The recovery and reserve estimates of the Company's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered.

The reserve data provided in this news release presents only a portion of the disclosure required under National Instrument 51-101. All of the required information will be contained in the Company's Annual Information Form for the year ended December 31, 2017, which will be filed on SEDAR (accessible at **www.sedar.com**) and EDGAR (accessible at **www.sec.gov/edgar.shtml**) on or before March 1, 2018.

In this press release, the: approximately 1,000 new internally identified drilling locations, of which 137 are booked locations and the remaining drilling are locations unbooked; approximately 8,100 total internally identified risked corporate drilling locations and 14,000 total internally identified unrisked drilling locations, include 3,458 booked locations, with the remaining drilling locations unbooked. These unbooked potential drilling opportunities may include infill, lease-edge and undrilled tracts, based on current land holdings, geologic, geophysical and engineering analysis that result in mapped type-well groupings (prepared by qualified reserves evaluators in accordance with the COGEH handbook) and optimized scheduling.

FOR MORE INFORMATION ON CRESCENT POINT ENERGY, PLEASE CONTACT:

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Crescent Point shares are traded on the Toronto Stock Exchange and New York Stock Exchange, under the symbol CPG.

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