Crescent Point Energy is one of Canada’s largest light and medium oil producers, based in Calgary, Alberta. The Company is focused on growing its significant resource base in the Williston Basin, Southwest Saskatchewan and the Uinta Basin in Utah.
Outperforming 2017 Budget and Upwardly Revised Guidance

- Executing organic growth plan
  - Q2 average production of 175,615 boe/d, exceeded average production target by over 8,000 boe/d or 5%
  - 2017 average production guidance upwardly revised to 174,500 boe/d from 172,000 boe/d

- Strong horizontal drilling results in Uinta Basin and increased land position
  - Advanced Castle Peak horizontal program by testing 2-mile horizontals and increased tonnage per stage
    - IP 30 rates of ~1,000 boe/d in comparison to 620 boe/d generated under current 1-mile type well
    - Testing new zones as part of 2017 program (Uteland Butte and Wasatch)
      - Recent 1-mile Wasatch well completed late Q2/17 currently producing ~2,000 boe/d after approximately 60 days
    - Consolidated ~80,000 net acres of undeveloped land in Uinta providing operating control in a new area of the basin with multi-zone potential

- Advancement of waterflood and Injection Control Device (“ICD”) waterflood system
  - The Innes Unit within the Viewfield Bakken became effective during the quarter
  - 40 ICD systems currently installed throughout the Company’s resource plays with ~10 additional installations planned during the remainder of 2017

- Disposition update
  - Currently marketing or in negotiations to dispose of ~$180 million of certain non-core assets and expect to transact on the majority of these during H2/17
  - Plans to market additional non-core assets of similar value later in 2017

- Credit Renewal
  - Renewed covenant-based, unsecured credit facilities totaling $3.6 billion, with a maturity date extension to June 2020
  - Significant financial flexibility with unutilized credit capacity of approximately $1.5 billion
Business Strategy and 2017 Priorities

Develop & Enhance
Increase recovery factors through infill drilling, waterflood optimization and improved technology

Growth
Acquire high-quality, large resource-in-place pools with production and reserves upside

Manage Risk
Maintain strong balance sheet, significant unutilized bank line capacity and 3 ½ - year hedging program

2017 Priorities

- Execute organic exit production growth of 10%
- Advance resource plays including new play development in Williston and Uinta basins
- Test new technologies including the ICD waterflood system
- Ongoing cost reduction initiatives

2017 Priorities

- Review non-core asset disposition opportunities
- Target new play advancement through a successful step-out and down-spacing programs

2017 Priorities

- Ongoing disciplined hedging program
- Maintain balance sheet strength with significant financial flexibility

● Proven Management Team  ● Excellent Balance Sheet  ● High-Quality Asset Base
Focused Growth: High Quality, Low-Cost Producer With Scale

- 174,500 boe/d 2017 production
- 12 years risked drilling inventory
- 958 MMboe (2P reserves)
- >23 billion barrels OOIP

2P reserves as of December 31, 2016 as independently evaluated by GLJ Petroleum Consultants Ltd. and Sproule Associates Limited. Drilling inventory years based on risked inventory of ~8,085 internally identified locations and 2017 guidance of approximately 670 net wells.

See “Definitions / Non-GAAP Financial Measures” for details on OOIP definition.
Technology and Innovation: Driving Sustainable Growth

• Experience / Big Data Analytics
  - Drilled ~5,000 horizontal wells since inception and applied numerous leading edge technologies
  - #1 driller in Canada and among the largest in North America based on meters drilled
  - Transfer of knowledge across asset base (completions, fluids, waterflood, etc.)

• Knowledge First: Culture Driven by Innovation and Science
  - Disciplined approach in developing assets using strategic and long-term planning
  - Pioneer in advancing new technology (microseismic, self suspended proppant, cemented liner, closeable sliding sleeves, fiber optics in producing wells & injectors, ICD, etc.)
  - Testing additional methods to further increase recovery factors
  - Implementing green energy initiatives (i.e. solar, cogeneration power, etc.)
Significant Growth Potential Supported by Strong Well Economics

Independent Ranking of North American Light/Medium Oil Plays
(Based on Internal Rates of Return at US $50 WTI)

1st: SE Sask Conventional, Tower Montney, Viewfield Bakken, Gordondale Montney, Shaunavon
3rd: Karnes Trough Eagle Ford
4th: Ferguson Bakken/Exshaw
6th: Karr Dunvegan
10th: Flat Lake, East Pembina Cardium, Permian Midland, STACK Maramec/Woodford, Permian Regan/Upton, SCOOP Woodford

~70% of 2017 drilling budget expected to payout in 2 years or less at US $50 WTI

Sourced from Scotiabank GBM September 2016 “The Playbook”. CPG Shaunavon IRR is an average of the Upper and Lower zones.
Major Resource Plays – Growth by Area

**Uinta**
- Upwards of 25% production CAGR within 5-yr plan
- In process of updating inventory to reflect recent Hz success

**Viewfield**
- Free cash flow stage with stable, low-risk production

**Flat Lake**
- Upwards of 23% production CAGR within 5-yr plan
- Expanding resource play through step-out program

**Shaunavon**
- Entering free cash flow stage
- Upwards of 14% production CAGR within 5-yr plan

Core resource plays provide combination of stable free cash flow and growth potential

Production CAGR’s are based on 5-year plans (2017-2021) disclosed in May 2017 Technical Day. Pricing assumptions range from $50 WTI to $65 WTI. Production forecasted from July 2017 to December 2017.
Crescent Point Energy 5-Year Plan

- High quality, high netback, low-risk assets with strong well economics
- Plans to grow up to 11% CAGR (dependent on oil prices) funded internally
- Large and diverse inventory enables ability to pivot capital allocation to optimize growth and capital returns in different economic environments
- Implementing new technologies and continuing to be an industry leader in innovation
- Forecasts exclude potential upside related to additional waterflood response

<table>
<thead>
<tr>
<th>Capital Allocation</th>
<th>$50 WTI</th>
<th>$55 WTI</th>
<th>$60 WTI</th>
<th>$65 WTI</th>
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<tbody>
<tr>
<td>Williston Basin (%)</td>
<td>54</td>
<td>51</td>
<td>53</td>
<td>52</td>
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<tr>
<td>SW Saskatchewan (%)</td>
<td>16</td>
<td>19</td>
<td>18</td>
<td>18</td>
</tr>
<tr>
<td>Uinta (%)</td>
<td>23</td>
<td>23</td>
<td>22</td>
<td>23</td>
</tr>
<tr>
<td>Other (%)</td>
<td>7</td>
<td>7</td>
<td>7</td>
<td>7</td>
</tr>
<tr>
<td>Total (%)</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
</tr>
</tbody>
</table>

CAGR based on 2017-2021 average production growth
WTI pricing is in USD
Uinta Marketing

- Refining capacity has the ability to increase (scheduled expansions planned prior to downturn)
- Control rail infrastructure outside of Salt Lake City, Utah for additional marketing capacity
- Recent marketing contracts near historical levels (>90% of WTI)
- Improving netbacks as older term contracts mature
- High-quality crude
  - Yellow wax (38 to 50 API)
  - Black wax (28 to 38 API)

Uinta Basin Production

- March 2017 oil rate = ~70,000 bbl/d
- Refinery capacity tight – diffs widened
- Basin production dropped >35,000 bopd – diffs tightening
- ~22,000 bopd of excess capacity

Uinta Basin production based on most recent public data.
Uinta Stacked Pay Comparison vs. Major North American Shale Plays

- **Uinta Basin:**
  - Wolfcamp A
  - Wolfcamp B
  - Wolfcamp C
  - Middle Spraberry
  - Lower Spraberry
  - Lower Black Shale
  - Castle Peak
  - Uleland Butte
  - Wasatch

- **Montney:**
  - Upper
  - Lower

- **Eagle Ford:**
  - Upper
  - Lower
  - 20 - 50 mmbbl/sec

- **Niobrara:**
  - Niobrara A
  - Niobrara B
  - Niobrara C
  - Codell
  - 25 - 50 mmbbl/sec

- **Bakken:**
  - Bakken
  - Three Forks
  - 10 - 20 mmbbl/sec

**Entire Uinta Basin pool equates to 30 billion barrels of OOIP**
Uinta Horizontal Success in the Castle Peak Zone

**Castle Peak Hz Results**

- **Recent Increased Tonnage and 2-mile Hz Programs**
  - **Strong initial production rates:** IP 30’s of ~1,000 boe/d (~60% increase over current 1-mile type well)
  - **Higher NPVs:** Increased tonnage per stage 1-mile well and 2-mile horizontals ~2-3x greater NPV versus type well
  - **Strong economics:** Well payouts of ~1 year or less at $50 WTI based on initial results

<table>
<thead>
<tr>
<th>Type Well (1-mile) Castle Peak Zone</th>
<th>Reserves (mboe)</th>
<th>IP 30 Rate (boe/d)</th>
<th>IP 90 Rate (boe/d)</th>
<th>Well Cost ($M)</th>
<th>Castle Peak $50 WTI</th>
<th>Castle Peak $55 WTI</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>NPV@ 10% ($M)</td>
<td>IRR (%)</td>
</tr>
<tr>
<td>380</td>
<td>620</td>
<td>650</td>
<td></td>
<td>$5.0</td>
<td>$2.2</td>
<td>58</td>
</tr>
</tbody>
</table>

Well cost and NPV are in USD.
Choke managed wells to optimize current infrastructure.
Improving Uinta Castle Peak Economics Through Efficiencies

Based on pricing assumption of US $55 WTI
Well cost and NPV are in USD
Development phase cost for 1-mile well = $4.2 million (down from $5.0 million), 2-mile = $6.5 million (down from $7.5 million)
Progression of Uinta Horizontal Well Results

- Castle Peak (1-mile Hz) Initial Program
- Castle Peak (First 1-mile Hz w. increased tonnage)
- Castle Peak (First 2-mile Hz)
- Wasatch (Recent 1-mile Hz)

Outliers (restricted flowback, collapsed casing and Hz test between existing Vt's)

Strong IP 30 rates from recent wells

Production typically increases after initial 30 days once wells are producing on pump

Cumulative production of >135,000 boe, and still flowing at ~1,800 boe/d after 75 days

Continue to optimize completions process and the delineation of new zones

Choke managed wells to optimize current infrastructure.
Initial Delineation Program of Uteland Butte and Wasatch Zones

- Strong Industry results are being demonstrated in the Uteland Butte and Wasatch Zones in the Uinta basin
- Crescent Point’s 2017 program includes the delineation of new zones beyond the Castle Peak
- Continued success in new zones allows for additional horizontal inventory locations

**2017 Industry Results**

<table>
<thead>
<tr>
<th></th>
<th>Uteland Butte</th>
<th>Wasatch</th>
</tr>
</thead>
<tbody>
<tr>
<td>IP 30 Rate (boe/d)</td>
<td>~1,650</td>
<td>~2,000</td>
</tr>
</tbody>
</table>

Industry IP 30 rates are 2-mile horizontal well results. Crescent Point has participated in 8 Uteland Butte & Wasatch wells with partners in 2017.

Expect CPG Wasatch (1-mile) well to payout <1 year at $50 WTI
Uinta Basin: Step-out Development

- Successful horizontal step-out results in the Randlett area
- Expect to provide updated inventory towards year-end based on recent success (new zones, down-spacing, longer laterals, etc.)
- Proving up operating lands in western portion of the basin during H2/17 (Blacktail Ridge and Lake Canyon)
- Current horizontal inventory of ~200 Castle Peak locations represents only 11% of overall land base (based on one zone and 4 wells/section)
Uinta Basin: Downspacing Potential / Monitoring Microseismic Data

- Data indicates 300 feet $\frac{1}{2}$ length and 150 feet height growth
- Opportunity to materially increase horizontal inventory by down-spacing to 8 wells per section
  - Current inventory assumes 4 wells per section

<table>
<thead>
<tr>
<th>Wells per Section</th>
<th>Recovery Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>4</td>
<td>15%</td>
</tr>
<tr>
<td>6</td>
<td>23%</td>
</tr>
<tr>
<td>8</td>
<td>30%</td>
</tr>
</tbody>
</table>

Recovery Factor example based on 300 mbbl/well (380 mboe) and 8 MMbbl/sec OOIP
Uinta Basin: CPG’s IP Rates and Economics vs. Major US Plays

CPG’s Uinta results vs wells drilled in US plays (IP 30 per 1,000 feet of lateral length*)

- Continual optimization of completions process and expansion into new zones resulting in top-quartile results

% Liquids (IP 30)
- 90% Recent Wasatch 1-mile
- 90% Recent Castle Peak 1-mile (increased tonnage)
- 70% Delaware
- 63% Eagle Ford
- 56% STACK
- 90% Castle Peak 1st gen 1-mile type well
- 90% Recent Castle Peak 2-mile
- 84% Midland
- 81% North Dakota Bakken
- 72% Niobrara

US$ WTI Breakeven

- Castle Peak 1st Gen 1-mile results
- Recent Castle Peak and Wasatch results

Recent Castle Peak is based on initial increased tonnage and 2-mile lateral results

Highly competitive productivity and economics

Source: Based on data from BMO Capital Markets and internal data on Uinta from Crescent Point Energy
Breakeven is defined as the WTI price that equates to a 10% IRR

* Since 2016
Summary

• **Continue to execute operationally** with significant growth potential driven by Uinta Basin and Flat Lake
  - Achieving excellent horizontal well results in the Uinta Basin
  - Flat Lake area continues to expand with step-out drilling and the optimization of completions processes

• **Significant undeveloped resource base** (>23 billion barrels OOIP with only 3% recovered to date)
  - ~8,085 net drilling locations within low cost, high-return basins (~14,850 including unrisked locations)
  - Successfully added ~1,000 new net risked locations per year on average over the last four years supported through new play expansion
  - Majority of ~4 million net acres of land remains undeveloped

• Leader in **advancing technology**; testing new completion methods and waterflood advancement
  - New ICD waterflood system has demonstrated improved water injectivity and sweep efficiency

• **Improving efficiencies** over time as plays advance from step-out drilling to infill pad drilling

• Continually **managing risk** to maintain balance sheet strength
  - Focus on non-core dispositions to internally fund growth opportunities or reduce debt
Forward Looking Information

This presentation contains "forward-looking statements" within the meaning of applicable securities legislation, such as section 27A of the Securities Act of 1933 and section 21E of the Securities Exchange Act of 1934, including estimates of future production, cash flows and reserves, business plans for drilling and exploration, the estimated amounts and timing of capital expenditures, the assumptions upon which estimates are based and related sensitivity analyses, and other expectations, beliefs, plans, objectives, assumptions or statements about future events or performance (often, but not always, using words or phrases such as "expects" or "does not expect," "is expected," "anticipates" or "does not anticipate," "plans," "estimates," "projects," "predicts," "potential," "intends," "may," "will," "could," "would," "might" or "will be taken," "occur or be achieved.

In particular, this presentation contains forward-looking statements pertaining to the following: the Corporation’s 2017 average production guidance; ICD installation plans for the remainder of 2017; the multi-zone potential of the assets located in a new area of the Uinta Basin; the Corporation's disposition plans and expectations for the remainder of 2017; the Corporation’s thronged business strategy and its detailed 2017 priorities for each prong; the Corporation’s drilling inventory and its 2017 drilling guidance; production CAGR expectations for the Corporation’s major resource plays under its 5-year plan; plans to continue to expand the Flat Lake play and the Corporation’s Uinta Basin inventory; the expected timing for the Shaunavon play to reach the free cash flow stage; Wasatch well results assuming 1.5-mile and 2-mile completions; 2017 plans to delineate new zones in the Uinta Basin beyond the Castle Peak; the ability for refining capacity to increase in the Uinta Basin and the possibility that Uinta Basin netbacks may improve as older term contracts mature; well payout expectations for Castle Peak horizontal; the opportunity for waterflood expansion and optimization associated with the Corporation’s recent top up acquisitions in the Uinta Basin; how continued success in new Uinta Basin resource plays and investments in the western portion of the Uinta Basin in 2017 may increase horizontal drilling in the Uinta Basin and the expected impact that would have on recovery factors; the growth potential of the Uinta Basin and Flat Lake; the expectation that the Corporation will achieve additional efficiencies over time and where such efficiencies are expected to be achieved; the Corporation’s 2017 guidance; the impact of exit production, annual average production, annual decline rate, drilling capital efficiencies, funds flow from operations, total payout ratio and Q4 annualized net debt to funds flow ratio for 2017; future drilling capital efficiencies, funds flow and adjusted net debt for the Corporation’s drill projects; the Corporation’s 2017 exit production, drilling program expenditures and decline rate for the Williston Basin and SW Saskatchewan; the expectation that the Corporation’s ICD program will improve sweep efficiency; the Corporation’s optimization and infrastructure plans for SW Saskatchewan; expected capital efficiency gains from increased production rates and reduced capital costs in the Western Shaleau; how the Corporation’s hedging program is expected to reduce funds flow volatility and provide greater dividend and capital spending stability; the expectation that the Corporation’s risked inventory will change over the next five years; planned capital efficiency gains from increased production rates and relative production growth under different pricing scenarios within the Corporation’s five-year plan; the potential impact of 100 annual injection well conversions on production, incremental capex and incremental cash flow under three cases; the Corporation’s ongoing commitment to prioritizing the interests of shareholders and encourage and value ongoing feedback; the Corporation’s board renewal process through 2019; and the Corporation’s cash tax GAAP.

There are numerous uncertainties inherent in estimating crude oil, natural gas and NGL reserves and the future cash flow attributed to such reserves. The reserve and associated cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, 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 expenditures, all of which may vary materially from those estimated herein. Actual reserve values may differ materially from those estimates provided herein. 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. 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. Information relating to "resources" is deemed to be forward-looking information, as it involves the implied assessment, based on certain estimates and assumptions, that the resources described exist in the quantities predicted or estimated, and that the resources described can be profitably produced in the future. All required reserve information for the Corporation is contained in its Annual Information Form for the year ended December 31, 2016, 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.

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 described under "Critical Accounting Estimates", "Risk Factors", "Changes in Accounting Policies" and "Outlook" and are disclosed in the Management's Discussion and Analysis for the year ended December 31, 2016, under the headings "Capital Expenditures", "Liquidity and Capital Resources", "Changes in Accounting Policy" and "Outlook" and are disclosed in the Management's Discussion and Analysis for the quarter ended June 30, 2017 under "Derivatives", "Liquidity and Capital Resources", "Changes in Accounting Policy" and "Outlook". There is uncertainty that it will be commercially viable to produce any portion of the resources. Information relating to "resources" is deemed to be forward-looking information, as it involves the implied assessment, based on certain estimates and assumptions, that the resources described exist in the quantities predicted or estimated, and that the resources described can be profitably produced in the future. All required reserve information for the Corporation is contained in its Annual Information Form for the year ended December 31, 2016, 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.

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## Capital Markets Summary & 2017 Guidance

### 2017 Guidance

<table>
<thead>
<tr>
<th>Category</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Exit Production (boe/d)</td>
<td>183,000</td>
</tr>
<tr>
<td>Production</td>
<td></td>
</tr>
<tr>
<td>Oil and NGLs (bbl/d)</td>
<td>157,500</td>
</tr>
<tr>
<td>Natural Gas (mcf/d)</td>
<td>102,000</td>
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<tr>
<td><strong>Total Average Annual Production (boe/d)</strong></td>
<td>174,500</td>
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<tr>
<td>Capital Expenditures ($ millions)</td>
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</tr>
<tr>
<td>Drilling and Development</td>
<td>$1,290</td>
</tr>
<tr>
<td>Facilities and Seismic</td>
<td>$160</td>
</tr>
<tr>
<td><strong>Total Capital Expenditures</strong></td>
<td>$1,450</td>
</tr>
<tr>
<td>Annual decline rate</td>
<td>28%</td>
</tr>
<tr>
<td>Drilling Capital Efficiencies ($ per flowing boe)</td>
<td>~$21,000</td>
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### Market Summary: CPG (TSX and NYSE)

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<tr>
<th>Category</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shares Outstanding</td>
<td>549.0 million</td>
</tr>
<tr>
<td>Avg. Daily Trading Volume</td>
<td>~5.7 million</td>
</tr>
<tr>
<td>Dividend (Yield)</td>
<td>C$0.03 per month (4.3%)</td>
</tr>
</tbody>
</table>

### Capital Structure: CDN$

<table>
<thead>
<tr>
<th>Category</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market Capitalization</td>
<td>$4.6 billion</td>
</tr>
<tr>
<td>Net Debt</td>
<td>$4.0 billion</td>
</tr>
<tr>
<td>Enterprise Value</td>
<td>$8.6 billion</td>
</tr>
<tr>
<td>Unutilized Credit Capacity</td>
<td>$1.5 billion</td>
</tr>
</tbody>
</table>

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2017 production, capital expenditures, expected decline rate are based on guidance as of July 2017
Net debt and unutilized credit capacity as of June 30, 2017
Market capitalization and dividend yield based on share price as of market close on August 25, 2017 and 549.0 million fully diluted shares outstanding as of June 30, 2017
Average daily trading volume based on Canadian and US volumes from January 1 to August 25, 2017
Williston Basin includes: Viewfield, Flat Lake, North Dakota and SE SK

**Bakken**
- Largest and longest producing resource play within the company
- Generates significant cash flow in excess of its capital expenditures
- Focused on infill development, secondary waterflood recovery and the potential expansion of the play’s economic boundary

**Three Forks**
- ND Three Forks resource play continues to extend into Canada in multiple directions
- Step-out program enhanced by new completion fluids
- Focused on efficiency gains through optimization, sharing of infrastructure and pad drilling

**Multi-zone**
- Additional growth targeted through Midale, Ratcliffe and other conventional formations

<table>
<thead>
<tr>
<th>Williston Basin</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>2017 Exit Production (boe/d)</td>
<td>~108,000 (↑5%)</td>
</tr>
<tr>
<td>Net Acres</td>
<td>~2.3 million</td>
</tr>
<tr>
<td>OOIP (barrels)</td>
<td>&gt;8.5 billion</td>
</tr>
<tr>
<td>Recovery to Date</td>
<td>3.3%</td>
</tr>
<tr>
<td>Risked Inventory (Booked + Unbooked)</td>
<td>3,470</td>
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<tr>
<td>2017 Net Drill Program</td>
<td>~350</td>
</tr>
<tr>
<td>% of 2017 Capital Expenditures Budget</td>
<td>51%</td>
</tr>
<tr>
<td>2017 Decline Rate</td>
<td>~29%</td>
</tr>
</tbody>
</table>
ICD: Newest Waterflood Technology to Improve Sweep Efficiency

Well Response from 132 Direct Offsets

Normalized to Injection Date (Months)

Average Offset Response from First ICD Install

Normalized to ICD (Months)
Viewfield Bakken Primary Infill Economics Hold Strong

Bakken Drills (Rate vs. Time)

Bakken Drills (Count vs. Time)

<table>
<thead>
<tr>
<th>Economic Indicators – $50 WTI</th>
<th>Economic Indicators – $55 WTI</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Type Well Economics</strong></td>
<td><strong>IP</strong> (bbl/d)</td>
</tr>
<tr>
<td>50 mbbl</td>
<td>105</td>
</tr>
<tr>
<td>75 Infill mbbl</td>
<td>100</td>
</tr>
<tr>
<td>100 Infill mbbl</td>
<td>125</td>
</tr>
<tr>
<td>125 mbbl</td>
<td>135</td>
</tr>
<tr>
<td>150 mbbl</td>
<td>135</td>
</tr>
<tr>
<td>350 mbbl – waterflood</td>
<td>125</td>
</tr>
</tbody>
</table>

Well reserves shown represent oil liquids only
$1.3 M D/C/E/T capital, 100% WI, varying CR/FH at 18% split
SW Saskatchewan includes: Shaunavon, Battrum/Cantaur and Viking

Shaunavon
- Company’s second largest producing resource play
- Approaching free cash flow stage of its life-cycle
- Benefits from the transfer of knowledge from Viewfield Bakken (i.e. cemented liner, closeable sliding sleeves, waterflood, completion fluid systems)
- Continuing to optimize the stage/tonnage during completions process
- Adding new infrastructure in 2017 to accommodate future growth plans

Viking
- Increased well density in drilling program from 16 to 22 wells per section
- Testing extended reach horizontal wells to further improve the economic development
- Implementing closeable sliding sleeves to reduce well cleanout costs (similar to results observed in Viewfield and Shaunavon resource plays)

### SW Saskatchewan

<table>
<thead>
<tr>
<th>Metric</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017 Exit Production (boe/d)</td>
<td>~43,000 (↑10%)</td>
</tr>
<tr>
<td>Net Acres</td>
<td>~960,000</td>
</tr>
<tr>
<td>OOIP (barrels)</td>
<td>&gt;7.8 billion</td>
</tr>
<tr>
<td>Recovery to Date</td>
<td>2.5%</td>
</tr>
<tr>
<td>Risked Inventory (Booked + Unbooked)</td>
<td>3,375</td>
</tr>
<tr>
<td>2017 Net Drill Program</td>
<td>~270</td>
</tr>
<tr>
<td>% of 2017 Capital Expenditures Budget</td>
<td>25%</td>
</tr>
<tr>
<td>2017 Decline Rate</td>
<td>~26%</td>
</tr>
</tbody>
</table>
Lower Shaunavon: Strong Primary and Secondary Results

- Improving capital efficiencies resulting from increasing production rates and reduced capital costs

- Waterflood response observed on direct offsets
- Average peak incremental oil rate of 40 bbl/d versus primary forecast
Commodity Hedging Strategy

- Added approximately 736,000 bbl during Q2/17 to hedging program

- Active hedging program reduces funds flow from operations (“funds flow”) volatility and provides greater stability to dividends and capital spending

As of August 28, 2017. Floor hedge price is calculated using the forward strip for the 3-way collar hedges. Floor hedge price of 3-way collar hedges are subject to change based on forward market prices. 2017 percentage hedged figures based on 2017 annual average oil production guidance. 2018 percentage hedged figures based on 2017 exit guidance.
Balance Sheet Strength

Debt Composition ($CAD) as of June 30, 2017

- $2.1B Drawn on Bank Credit Facilities (~58% utilized)
- $1.7B Senior Guaranteed Notes*
- $1.5B Unutilized Credit Capacity

Significant amount of liquidity and financial flexibility

Includes underlying currency swaps

Net Debt to Funds Flow From Operations

• No material near-term debt maturities, significant unutilized credit capacity of ~$1.5 billion
• Bank credit facilities and senior guaranteed notes rank equal and are unsecured and covenant-based. Bank credit facilities have a June 2020 renewal date
• US$ denominated senior guaranteed notes fully hedged with cross currency swaps

Senior Guaranteed Notes Maturity Schedule

<table>
<thead>
<tr>
<th>Year</th>
<th>Amount ($Million)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2018</td>
<td>50</td>
</tr>
<tr>
<td>2019</td>
<td>74</td>
</tr>
<tr>
<td>2020</td>
<td>158</td>
</tr>
<tr>
<td>2021</td>
<td>185</td>
</tr>
</tbody>
</table>
Diversified Shareholder Base

- Listed on the NYSE in Jan 2014 to increase exposure to U.S. and international investor base
- U.S. ownership (institutional and retail) has increased to ~25% since listing

Source: Computershare
## Economics by Play

<table>
<thead>
<tr>
<th>Region</th>
<th>Type Well (EUR) (mbbl)</th>
<th>Cost per well ($M)</th>
<th>NPV @ 10% ($M)</th>
<th>IRR (%)</th>
<th>Payout (months)</th>
<th>NPV @ 10% ($M)</th>
<th>IRR (%)</th>
<th>Payout (months)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Williston Basin</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Viewfield Bakken</td>
<td>75 – 125</td>
<td>$1.3</td>
<td>$1.1 to $2.9</td>
<td>68 to 216</td>
<td>9 to 16</td>
<td>$1.4 to $3.4</td>
<td>86 to 268</td>
<td>8 to 14</td>
</tr>
<tr>
<td>Flat Lake – Torquay</td>
<td>125 – 225</td>
<td>$2.3</td>
<td>$1.2 to $4.4</td>
<td>39 to 155</td>
<td>11 to 25</td>
<td>$1.6 to $5.1</td>
<td>48 to 193</td>
<td>10 to 22</td>
</tr>
<tr>
<td>Flat Lake – Midale</td>
<td>100 – 150</td>
<td>$1.7</td>
<td>$0.6 to $1.0</td>
<td>38 to 65</td>
<td>15 to 21</td>
<td>$0.8 to $1.3</td>
<td>53 to 89</td>
<td>12 to 17</td>
</tr>
<tr>
<td>Flat Lake – Conventional Ratcliffe</td>
<td>75 – 100</td>
<td>$1.1</td>
<td>$1.0 to $1.7</td>
<td>82 to 144</td>
<td>10 to 14</td>
<td>$1.3 to $2.0</td>
<td>108 to 187</td>
<td>9 to 12</td>
</tr>
<tr>
<td>North Dakota ($US)</td>
<td>430 – 700</td>
<td>$4.2 to $5.3</td>
<td>$0.5 to $2.5</td>
<td>14 to 28</td>
<td>34 to 61</td>
<td>$1.0 to $3.8</td>
<td>20 to 40</td>
<td>25 to 44</td>
</tr>
<tr>
<td>SE Saskatchewan Conventional</td>
<td>60</td>
<td>$1.0</td>
<td>$0.7</td>
<td>47</td>
<td>23</td>
<td>$0.9</td>
<td>60</td>
<td>19</td>
</tr>
<tr>
<td><strong>SW Saskatchewan Resource Play</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Shaunavon</td>
<td>84 – 150</td>
<td>$1.4</td>
<td>$0.4 to $1.3</td>
<td>21 to 68</td>
<td>16 to 41</td>
<td>$0.6 to $1.7</td>
<td>29 to 92</td>
<td>13 to 32</td>
</tr>
<tr>
<td>Viking</td>
<td>41 – 51</td>
<td>$0.6</td>
<td>$0.6 to $0.8</td>
<td>66 to 92</td>
<td>14 to 17</td>
<td>$0.8 to $1.0</td>
<td>88 to 121</td>
<td>12 to 14</td>
</tr>
<tr>
<td><strong>Uinta Basin</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Castle Peak Horizontals ($US)</td>
<td>380</td>
<td>$5.0</td>
<td>$2.2</td>
<td>58</td>
<td>13</td>
<td>$3.1</td>
<td>83</td>
<td>11</td>
</tr>
</tbody>
</table>

All figures are approximate and in CAD unless otherwise noted.
The capital costs per well include drilling, completion, equipment and tie-in expenditures.
Economics by play represent type wells expected to be drilled in 2017 program.
North Dakota type wells include locations acquired in Williams County in Q1/17.
Portfolio Summary – Increasing Free Cash Flow and Reserves

**Growth Phase**  
(50% of 2017 Budget)  
- Exploit early stage, large OOIP pools  
- Step-out drilling to expand resource  
- Utilize transfer of knowledge from existing properties  
- Optimize completions  
- Build-out infrastructure  

**Transitional Phase**  
(25% of 2017 Budget)  
- Delineation and infill drilling  
- Improve efficiencies (new technology)  
- Continue to add infrastructure and expand resources  
- Implement initial phases of potential waterflood  

**Free Cashflow Phase**  
(25% of 2017 Budget)  
- Focus on free cashflow sustainability and lowering costs  
- Lower declines and increase recoveries (infill drilling and waterflood)  
- Continue to implement new technology to expand resource and improve efficiencies  
- Use excess cashflow to fund growth, reduce debt and/or return cash to shareholders through dividend  

- Williston Basin  
  (Battrum)  
- SW Sask. (Viking)  
- Williston Basin  
  (Viewfield + Conventional)  
- SW Sask. (Shaunavon)  
- Swan Hills  
- Uinta Basin  
  (Flat Lake + North Dakota)  
- Cash Flow Neutral
Acquisition History: Significant Reserves Growth

<table>
<thead>
<tr>
<th>Property</th>
<th>Acquired TPP Reserves (Mboe)</th>
<th>Estimated Production to Date (Mboe)</th>
<th>Current TPP Reserves (Mboe)</th>
<th>Total TPP Ult. Recovery (Mboe)</th>
<th>Increase In TPP Reserves (Mboe)</th>
<th>Increase in Reserves (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Williston Basin</td>
<td>184,154</td>
<td>177,754</td>
<td>429,594</td>
<td>607,348</td>
<td>423,194</td>
<td>230%</td>
</tr>
<tr>
<td>SW Saskatchewan</td>
<td>150,772</td>
<td>76,077</td>
<td>216,117</td>
<td>292,194</td>
<td>141,422</td>
<td>94%</td>
</tr>
<tr>
<td>Uinta Basin</td>
<td>63,322</td>
<td>19,301</td>
<td>95,616</td>
<td>114,917</td>
<td>51,595</td>
<td>82%</td>
</tr>
<tr>
<td>Other</td>
<td>25,071</td>
<td>10,474</td>
<td>39,534</td>
<td>50,007</td>
<td>24,936</td>
<td>99%</td>
</tr>
<tr>
<td>Corporate Total</td>
<td>423,319</td>
<td>283,606</td>
<td>780,861</td>
<td>1,064,466</td>
<td>641,147</td>
<td>152%</td>
</tr>
</tbody>
</table>

As of December 31, 2016 as evaluated by GLJ Petroleum Consultants Ltd. and Sproule Associates Limited. Total 2P reserves = estimated production plus current 2P reserves.

- Increased 2P reserves by >600 million boe (152%)
- Large oil-in-place pools have outperformed initially estimated recoveries over time

Williston Basin acquisition history includes: Viewfield Bakken, Flat Lake Resource, North Dakota, Manor, Tatagwa Unit
SW Saskatchewan acquisition history includes: Shaunavon, Battrum/Cantuar, Saskatchewan Viking, Sounding Lake
Other acquisitions includes: Alberta
Amounts may not add due to rounding
Risked and Unrisked Inventory Summary

- Majority of Crescent Point’s ~4 million net acres is currently undeveloped
- CPG technical staff are focused on continually expanding the corporate inventory. Both the Company’s risked inventory (historically referenced) and unrisked inventory will change over time

Based on pricing assumption of US $55 WTI
Relative Production Growth (2021 Exit / 2016 Exit)

$50 WTI Case

- Williston: 22%
- SW Sk: 19%
- Utah: 69%
- Other: 28%

$55 WTI Case

- Williston: 29%
- SW Sk: 44%
- Utah: 152%
- Other: 37%

$60 WTI Case

- Williston: 22%
- SW Sk: 52%
- Utah: 184%
- Other: 45%

$65 WTI Case

- Williston: 53%
- SW Sk: 66%
- Utah: 188%
- Other: 48%
Financial Impact: 100 Annual Injection Well Conversions

<table>
<thead>
<tr>
<th>Case #1 Historical Response</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
</tr>
</thead>
<tbody>
<tr>
<td>Injectors (net)</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>Production (boe/d)</td>
<td>(491)</td>
<td>(1,109)</td>
<td>(134)</td>
<td>1,462</td>
<td>3,234</td>
</tr>
<tr>
<td>Incremental Capex ($M)</td>
<td>$40.0</td>
<td>$40.0</td>
<td>$40.0</td>
<td>$40.0</td>
<td>$40.0</td>
</tr>
<tr>
<td>Incremental Cash Flow ($M)</td>
<td>($11.6)</td>
<td>($30.4)</td>
<td>($16.3)</td>
<td>$10.7</td>
<td>$40.7</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Case #2: Potential ICD Technology</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
</tr>
</thead>
<tbody>
<tr>
<td>Injectors (net)</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>Production (boe/d)</td>
<td>(481)</td>
<td>(954)</td>
<td>912</td>
<td>3,590</td>
<td>6,186</td>
</tr>
<tr>
<td>Incremental Capex ($M)</td>
<td>$40.0</td>
<td>$40.0</td>
<td>$40.0</td>
<td>$40.0</td>
<td>$40.0</td>
</tr>
<tr>
<td>Incremental Cash Flow ($M)</td>
<td>($11.4)</td>
<td>($27.3)</td>
<td>$5.1</td>
<td>$54.7</td>
<td>$103.6</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Case #3: Simulation Scenario</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
</tr>
</thead>
<tbody>
<tr>
<td>Injectors (net)</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>Production (boe/d)</td>
<td>(474)</td>
<td>(829)</td>
<td>1,955</td>
<td>6,058</td>
<td>10,246</td>
</tr>
<tr>
<td>Incremental Capex ($M)</td>
<td>$40.0</td>
<td>$40.0</td>
<td>$40.0</td>
<td>$40.0</td>
<td>$40.0</td>
</tr>
<tr>
<td>Incremental Cash Flow ($M)</td>
<td>($11.2)</td>
<td>($24.8)</td>
<td>$26.3</td>
<td>$105.5</td>
<td>$189.6</td>
</tr>
</tbody>
</table>

- 100 annual injector conversions equates to $40 million of annual capital expenditures
- Higher number of annual conversions provides greater impact to decline rate and ultimate recoveries
- Decline rates and incremental cash flow improve substantially long-term

Based on $55 WTI pricing and 0.76 CAD/USD fx
High Employee Engagement Contributes to Strong Corporate Governance

- 10th annual employee survey delivered to all field and office staff (82% or 823 responded in 2016) measures perception of management integrity, ethics and values; trends are consistently high

- 2016 survey responses demonstrate a highly engaged workforce with an entrepreneurial focus:
  - Leads to enhanced organizational productivity and efficiency
  - Lower rates of staff turnover builds team commitment and a foundation for innovation

96% “Employees are inclined to do the right thing”
91% “I have confidence in the executive team”
94% “I am proud to tell people I work for Crescent Point”
94% “I am inspired to give my very best”
90% “Executives demonstrate integrity and ethical behaviour”
93% “I would recommend Crescent Point as a great place to work”
95% “I am driven to make a difference at Crescent Point”

We respond to survey results and make positive changes
Committed and Ongoing Shareholder Engagement

Following AGM Say-On-Pay voting results, we solicited shareholders and proxy advisory firms’ input

- Invited our 25 largest shareholders (holding ~30% of shares outstanding) to engage in 2016

- Chair of Compensation Committee spoke directly with shareholders representing ~15% of shares outstanding

Actively engaged with investment community throughout 2016

- Held earnings conference calls for investor community members and media

- Attended 18 investor conferences and met with over 320 institutional investors

- Held over 20 retail investor meetings and more than 30 analyst meetings

- Implementing regularly scheduled “technical days” presentations for analysts and shareholders

Continuing governance engagement in 2017

- Completed 360 degree feedback loop with current stakeholders on changes made during 2016

- Remain committed to prioritizing the interests of our shareholders and encourage and value ongoing feedback
Board Renewal Process Supported by Robust Orientation

Ongoing and Deliberate Board Renewal Process
- Board renewal process initiated in 2014
- 6 new members added since process began
- New directors in 2017-2019 will continue to replace and build on skillsets of retiring members

Strong Director Orientation and Training
- Director orientation includes comprehensive handbook of responsibilities and corporate information as well as one-on-one meetings with key executives on our business, financial model, operations, compensation and culture
- All directors provided with membership to the Institute of Corporate Directors
- Learning opportunities provided regularly through quarterly management presentations, field tours, mentoring (on request), various in-house courses provided by technical experts and access to weekly executive meetings to maintain ongoing insight into daily operations

Impact of board renewal process on tenure
Entrepreneurial Culture Drives Low G&A

- Target $1.50/boe cash G&A
  - G&A averaging $1.49/boe over past 10 years supported by entrepreneurial culture
- Focus on responsible cost structure has ensured cash G&A has never exceeded $1.65/boe:
  - Knowledgeable staff that is tasked with multiple responsibilities
  - Concentrated asset base allowing for a lean and efficient structure
  - Investment in data capture and reporting technology enables focus on high-value work
Disclosure Committee

NOTE TO READER REGARDING DISCLOSURE

In addition to obtaining all necessary Board approvals, the Company’s long-established Disclosure Committee’s mandate is to review and confirm the accuracy of the data and information contained in the documents, including this presentation, Crescent Point uses to communicate to the public. This review and confirmation process is formally completed prior to any such disclosure being released. This Committee is comprised of senior representatives (including officers) from each of the following departments: accounting and finance; engineering and operations (including drilling and completions, environment, health and safety and regulatory); exploration and geosciences; investor relations; land; legal; marketing and reserves.

This presentation contains “forward-looking statements” within the meaning of applicable securities legislation, such as section 27A of the Securities Act of 1933 and section 21E of the Securities Exchange Act of 1934, including estimates of future production, cash flows and reserves, business plans for drilling and exploration, the estimated amounts and timing of capital expenditures, the assumptions upon which estimates are based and related sensitivity analyses, and other expectations, beliefs, plans, objectives, assumptions or statements about future events or performance. Please see the “Forward-Looking Statements” and “Endnotes” sections of this presentation for additional details regarding such statements.
Definitions / Non-GAAP Financial Measures

Drilling Locations

This presentation discloses drilling locations in three categories: (i) booked locations; (ii) unbooked locations; and (iii) an aggregate total of (i) and (ii), hereafter referred to as “total location inventory”. In addition, unbooked locations are subdivided into (a) risked locations; (b) unrisked locations; and an aggregate total of (a) and (b), hereafter referred to as “total unbooked location inventory”. The booked locations are derived from the Corporation’s most recent independent reserves evaluation as prepared by GLJ Petroleum Consultants Ltd. and Sproule Associates Limited, both as at December 31, 2016, and were aggregated by GLJ and account for drilling locations that have associated proved and/or probable reserves, as applicable, unless otherwise stated.

Of the ~8,085 risked total net corporate undrilled locations and the 14,856 net total location inventory disclosed in this presentation, 3,680 are booked. The remaining net locations are internally identified and are unbooked.

Of the approximately 200 risked net Uinta horizontal locations disclosed in this presentation, 23 are booked. The remaining net locations are internally identified and are unbooked.

Of the 3,470 risked net undrilled locations in the Williston Basin disclosed in this presentation, 1,801 are booked. The remaining net locations are internally identified and are unbooked.

Of the 3,375 risked net undrilled locations in SW Saskatchewan disclosed in this presentation, 1,276 are booked. The remaining net locations are internally identified and are unbooked.

Unbooked locations are internal estimates based on the Corporation’s prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources (including contingent and prospective). Unbooked locations have been identified by management as an estimation of the Corporation’s multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Corporation will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Corporation will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors.

The total unbooked location inventory contains risked future drilling locations that have a greater certainty of success due to these risked locations relative close proximity to current existing wells. The remainder of the unbooked drilling locations considered unrisked as they 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 oil and gas reserves, resources or production.

Well Economics

This presentation discloses well economic scenarios based on US $50 WTI and US $55 WTI constant pricing / 0.75 USD/CAD fx. Net present value (“NPV”) calculations are before tax.

Hypothetical field based on 500 injection candidates (waterflood) assumes US $55 WTI escalated pricing of 1% per annum.

Hedging

Hedges extend into end of Q1 2019
Oil and Gas Definitions

1. Barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf : 1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. 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 oil, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

2. Original Oil-In-Place (OOIP) means Discovered Petroleum Initially-In-Place (DPIIP) as at December 31, 2016. DPIIP, as defined in the Canadian Oil and Gas Evaluations Handbook (COGEH), is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of DPIIP includes production, reserves and contingent resources; the remainder is unrecoverable. OOIP/DPIIP estimates and recovery rates are as at December 31, 2016, and are based on current accepted technology and have been prepared by Crescent Point’s qualified reservoir engineers. There is significant uncertainty regarding the ultimate recoverable OOIP/DPIIP. For further information see Crescent Point’s Annual Information Form for the year-ended December 31, 2016.

3. There is significant uncertainty regarding the ultimate recoverable OOIP/DPIIP. For further information see Crescent Point’s Annual Information Form for the year-ended December 31, 2016.

4. Net present values disclosed in this presentation are calculated before tax.

5. Enhanced Ultimate Recovery (or EUR) relates to the extraction of additional crude oil, natural gas, and related substances from reservoirs through a production process other than natural depletion, which includes both secondary and tertiary recovery processes such as pressure maintenance, cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids.

6. Type wells are internally generated based on actual well results and data that is interpreted by internal qualified reserves evaluators.

7. Cash flow equates to funds flow from operations. Cash flow from operations equals funds flow from operations per share.
Definitions / Non-GAAP Financial Measures

Non-GAAP Measures

Throughout this presentation the Company uses the terms “funds flow from operations”, “funds flow from operations netback”, “total payout ratio”, “market capitalization”, “net debt”, “enterprise value” and “net debt to funds flow from operations”. 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 netback is calculated on a per boe basis as funds flow from operations divided by total production. 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.

Total payout ratio is calculated on a percentage basis as capital expenditures and dividends 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.

Market capitalization is an indication of enterprise value and is calculated by applying a recent share trading price to the number of diluted shares outstanding. Market capitalization is an indication of enterprise value.

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

Enterprise value is calculated as market capitalization plus net debt. Management uses enterprise value to assess the valuation of the Company.

Net debt to funds flow from operations is calculated as the net debt divided by 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.

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. This information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. For definitions of the non-GAAP measures listed above along with reconciliations from the non-GAAP measure to the most directly comparable GAAP measure, each of which is incorporated by reference please see the Company’s most recent annual Management’s Discussion & Analysis (“MD&A”) available on SEDAR at sedar.com, or EDGAR as www.sec.gov and on our website as www.crescentpointenergy.com.
## Company Information

<table>
<thead>
<tr>
<th>Role</th>
<th>Information</th>
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<tbody>
<tr>
<td>BANKER</td>
<td>Bank of Nova Scotia</td>
</tr>
<tr>
<td>AUDITOR</td>
<td>PricewaterhouseCoopers LLP</td>
</tr>
<tr>
<td>LEGAL COUNSEL</td>
<td>Norton Rose Fulbright Canada LLP</td>
</tr>
<tr>
<td>EVALUATION ENGINEERS</td>
<td>GLJ Petroleum Consultants Ltd Sproule Associates Ltd</td>
</tr>
<tr>
<td>REGISTRAR &amp; TRANSFER AGENT</td>
<td>Computershare Trust Company</td>
</tr>
<tr>
<td>INVESTOR CONTACTS</td>
<td>403.767.6930 1.855.767.6923 (Toll Free)</td>
</tr>
<tr>
<td></td>
<td><a href="mailto:investor@crescentpointenergy.com">investor@crescentpointenergy.com</a></td>
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</tbody>
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