Building positive momentum

July 2019

cenovus
energy
Cenovus at a glance

$22 billion enterprise value
460 MBOE/d total production
241 Mbbls/d net refining capacity

$4.6 billion liquidity
39 year reserve life index
825 Mbbls/d regulatory approved capacity

Note: Values are approximate. Enterprise value as at June 30, 2019. Forecasted production based on the midpoint of April 23, 2019 guidance, which includes the expected impacts of mandatory curtailments. Liquidity position as at June 30, 2019. Refining capacity represents net capacity to Cenovus. Reserve life index based on 2018 proved plus probable reserves and 2018 production before royalties. Regulatory approved capacity reflects oil sands project approvals. See advisory.

Positioned to increase shareholder value

Resilience at the bottom of the cycle
- Strengthening balance sheet through free funds flow
- Managing the balance sheet to support investment grade credit ratings

Shareholder value

Realizing the value of integration
- Refining and transportation options partially mitigate wide differentials
- Bruderheim provides strategic advantage

Disciplined capital allocation
- 2019 budget reflects capital discipline
- Generating strong margins through the cycle

Leveraging a focused asset base
- Best-in-class assets and knowledge in SAGD
- Industry-leading capital efficiencies
- Regulatory approvals in place
- Streamlining the Deep Basin

Note: Bottom of the cycle commodity prices defined as US$45/bbl WTI and C$44/bbl WCS. See Advisory.
## Disciplined capital allocation priorities

### Increasing total shareholder return

<table>
<thead>
<tr>
<th>Net debt &gt;$7B</th>
<th>$7B &gt; Net debt &gt; $5B</th>
<th>Net debt &lt;$5B</th>
</tr>
</thead>
<tbody>
<tr>
<td>Safe and reliable operations</td>
<td>Safe and reliable operations</td>
<td>Safe and reliable operations</td>
</tr>
<tr>
<td>Sustaining capital</td>
<td>Base dividend</td>
<td>Sustaining capital</td>
</tr>
<tr>
<td>Debt reduction</td>
<td>Debt reduction</td>
<td>Disciplined growth</td>
</tr>
<tr>
<td>Christina Lake phase G completion</td>
<td></td>
<td>Disciplined growth</td>
</tr>
</tbody>
</table>

Note: Targeting net debt to adjusted EBITDA < 2.0x at bottom of the cycle commodity prices (US$45/bbl WTI and C$44/bbl WCS). See Advisory.

### Managing the balance sheet for the bottom of the cycle

#### Net and gross debt reduction

<table>
<thead>
<tr>
<th>$ billions</th>
</tr>
</thead>
<tbody>
<tr>
<td>$10</td>
</tr>
<tr>
<td>$8</td>
</tr>
<tr>
<td>$6</td>
</tr>
<tr>
<td>$4</td>
</tr>
<tr>
<td>$2</td>
</tr>
<tr>
<td>$0</td>
</tr>
</tbody>
</table>

- **Q4 2017**
- **Q4 2018**
- **Q1 2019**
- **Q2 2019**

#### Manageable long-term maturities

- **Principal outstanding (US$ billions)**
- **Redemption of US$800 million**
- **Repurchase of US$591 million**
- **Cash tender of US$748 million**

- **Reduced total debt by US$2.1 billion or 28% since Q3 2018**
- **Partial redemption of 2019 bond in Q4 2018**
- **Repurchased notes in Q4 2018 and H1 2019**
- **Completed cash tender of bonds in June 2019**
- **Weighted average cost of debt ~5.2%**

Note: Bottom of the cycle commodity prices defined as US$45/bbl WTI and C$44/bbl WCS. See Advisory for a definition of net debt to adjusted EBITDA.
Investing in a focused asset base

Asset base drives performance

- Largest SAGD producer with best-in-class assets
  - oil sands sustaining capital <$5/bbl
  - industry-leading capital efficiencies and regulatory approvals position for future growth
- Integration through key refining assets helps to mitigate exposure to wider light-heavy differentials
- Bruderheim Energy Terminal provides strategic advantage in crude by rail operations
- Deep Basin assets provide high-quality, short-cycle investment opportunities
  - continuing to streamline portfolio and increase competitiveness of assets
- Future development potential at Marten Hills

Note: See advisory.

Focused asset base in western Canada

Best-in-class oil sands assets

- 360 Mbbls/d production
- Producing for over 2 decades
- 100% CVE owned
- Industry leading SORs
- 6.4 billion 2P reserves
- 200 MW cogeneration

Note: Values are approximate. Forecasted production based on the midpoint of April 23, 2019 guidance, which includes the expected impacts of mandatory curtailment. Proved plus probable bitumen reserves as at December 31, 2018. Cogeneration output varies with temperature. See Advisory.
Industry leader in the oil sands

Cost leadership
- ~70% reduction in oil sands sustaining capital costs
- ~45% reduction to oil sands operating costs

Track record of execution
- Safely executed 14 major oil sands expansion phases
- Demonstrating industry-leading capital efficiencies
- CL G ahead of schedule

Largest, most efficient producer
- Largest SAGD producer
- Lowest SOR
- Most regulatory approved oil sands productive capacity

Technology innovation
- Expected to improve reservoir performance
- Anticipated to reduce GHG emissions intensity

Note: Reduction in oil sands sustaining and operating costs are relative to 2014 actual performance. See Advisory.

Largest and most efficient SAGD producer

- Best-in-class producing assets with unmatched scale of operation
- Concentrated resources with significant reserve life
- Safely executed 14 major oil sands capacity expansions

- SOR reflects resource quality and execution
- Lower SOR contributes to lower capital and operating costs, smaller surface footprint, lower energy usage, lower emissions intensity and less water usage

Source: AER 2018 ST53 Report. Note: Portfolio-weighted SOR calculated based on project operator and is a measure of project efficiency. Peers include ATH, COP, CNOC, CNQ, DVN, HSE, IMO, MEG, PGF, and Sui. Christina Lake SOR was 1.9 in 2018 and Foster Creek SOR was 2.8 in 2018.
Sustainable reductions to oil sands cost structure

- ~70% reduction in oil sands sustaining capital costs since 2014
- Longer wells, wider spacing, optimized pad layouts
- Improvements in drilling costs and downhole technology
- Reductions in pad surface equipment
- ~45% reduction to oil sands opex since 2014
- Non-fuel costs decreasing from streamlined processes, new technology
- Improved reservoir conformance and ESP run life performance
- Capable of covering sustaining capital requirements and current dividend at bottom of the cycle commodity prices

Note: Bottom of the cycle commodity prices defined as US$45/bbl WTI and C$44/bbl WCS. See Advisory.

Industry-leading capital efficiencies drive future growth

**Phase G builds on Christina Lake success**
- Best-in-class oil sands project, industry-leading SOR
- Templated central plant facility design and manufacturing approach
- Full-cycle capital efficiency of $15,000 - $16,000/bbls/d
- Capital investment 25% below expectation
- Construction complete, available for production in Q2

**Forecasted key statistics**

<table>
<thead>
<tr>
<th>Units</th>
<th>Statistic</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project oil capacity</td>
<td>Mbbls/d</td>
</tr>
<tr>
<td>Steam-oil ratio</td>
<td>x</td>
</tr>
<tr>
<td>Capital spent to completion</td>
<td>$ millions</td>
</tr>
<tr>
<td>Construction resumed</td>
<td>date</td>
</tr>
<tr>
<td>First steam date</td>
<td>date</td>
</tr>
<tr>
<td>Go-forward capital efficiency</td>
<td>$/bbls/d</td>
</tr>
<tr>
<td>After-tax IRR</td>
<td>%</td>
</tr>
</tbody>
</table>

**Proven track record of project development**

<table>
<thead>
<tr>
<th>Capital efficiencies by project ($/mbbls/day)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CVE Christina Lake Phase G</td>
</tr>
<tr>
<td>$45</td>
</tr>
</tbody>
</table>

Note: Cenovus has flexibility on start-up and will take into consideration whether mandated curtailments have been lifted and if there is sustained improvement in market access and heavy oil benchmark prices. Go-forward capital efficiency based on forecasted remaining capital required from time of reactivation (Q1 2017) and project oil capacity. CVE and peer capital efficiencies based on the weighted average of in-service phases. Peer projects include ATN Hangingstone, ATN Lesmer, CNRL Kirby South, CNRL Primrose, CNRL Wolf Lake, HSE Sunrise, HSE Tucker Lake, IMO Cold Lake, MEG ChristinaLake, Suncor Firebag, Suncor Mackay River (Source: BMO). See Advisory.
Demonstrating cost leadership in the oil sands

- ~70% reduction in oil sands sustaining capital costs since 2014
- Design and productivity improvements are expected to be sustainable

Note: Peer projects include ATH Hangingstone, ATH Leismer, CNRL Kirby South, CNRL Primrose, CNRL Wolf Lake, HSE Sunrie, HSE Tucker Lake, IMO Cold Lake, MEG Christina Lake, Suncor Firebag, Suncor Mackay River. See advisory.
Source: Scotiabank.

Q1 2019 oil sands operating costs per barrel

- ~45% reduction to oil sands operating costs since 2014
- Non-fuel costs decreasing
- Natural gas prices and turnarounds fluctuate year-to-year

Source: Company reports. Peers include ATH, CNQ, HSE, MEG, and SU.

Track record of execution with significant running room

- Safely executed 14 major oil sands capacity expansions since 2006
- Disciplined project execution and track record of cost reductions

Note: Cenovus has flexibility on start-up of Christina Lake phase G and will take into consideration whether mandated curtailments have been lifted and if there is sustained improvement in market access and heavy oil benchmark prices. See Advisory.
Our commitment to environmental performance

Reducing environmental impact

- SAGD operating model: zero mines, zero tailings
- Voluntarily restoring caribou habitat around our operations
- Among the lowest emissions intensity in industry
- No surface water used to make steam in our oil sands operations
- Well below industry average for in situ oil sands fresh water use intensity
- Founding member of the Canadian Oil Sands Innovation Alliance and supporter of the Carbon X-Prize

Fresh water use intensity

- 0.4 bbls fresh water / BOE
- 0.3
- 0.2
- 0.1
- 0.0

2013 2014 2015 2016 2017 2018

CVE oil sands
CVE overall
In situ average (AER)

Direct GHG emissions intensity

- 0.8 Tonnes CO2e / m³Oe
- 0.6
- 0.4
- 0.2
- 0.0

2013 2014 2015 2016 2017 2018

CVE oil sands
CVE overall
Oil sands average (CAPI, 2014)

Low carbon oil sands

- 33% reduction in emissions intensity since 2004
- Premium oil sands assets with low steam to oil ratios
- Investment in GHG reduction technologies like cogeneration, solvents and energy efficiency
- Continued focus on environmental performance
- Displacing global higher emissions barrels with low carbon oil sands
- Direct emissions per barrel in line with average barrel refined in US and lower than global average

Our GHG emissions performance

Upstream direct emissions intensity

- kg CO2e per barrel
- 100
- 80
- 60
- 40
- 20
- 0

CVE Christina Lake
Mined dilbit paraffinic froth treatment (industry average)
Average barrel refined in the U.S.
CVE Foster Creek
Global volume weighted average barrel
SAGD (industry average)
Mined synthetic crude oil (industry average)

Low carbon oil sands

- 33% reduction in emissions intensity since 2004
- Premium oil sands assets with low steam to oil ratios
- Investment in GHG reduction technologies like cogeneration, solvents and energy efficiency
- Continued focus on environmental performance
- Displacing global higher emissions barrels with low carbon oil sands
- Direct emissions per barrel in line with average barrel refined in US and lower than global average

Source: Cenovus 2018 data, IHS Markit (2018), and Masnadi et al. (2018). Note: Data adjusted to show direct, upstream emissions only. 2018 oil sands production volumes and GHG intensities were impacted by voluntary curtailment in Q1 2018 and Q4 2018. See Advisory.
Solvents expected to create value and reduce emissions intensity

### CSAP
- Decreases SOR by ~30% - 35%
- Increases individual well production rates up to 10%
- Increases growth capital by 15% - 20%
- Decreases sustaining capital by 10% - 30%
- Reduces non-fuel operating costs by up to 20%

### SAGD

Note: Expectations of solvent are associated with conventional solvent aided process (CSAP).

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### Significant potential in the Deep Basin

- **100 MBOE/d** production
- **2.8 million** net acres
- **1.2 BCF/d** processing capacity

Note: Values are approximate. Forecasted production based on the midpoint of April 23, 2019 guidance. Capacity of 1.2 BCF/d is net natural gas processing capacity in the Deep Basin. See Advisory.
Deep Basin provides short-cycle opportunities

**Asset overview**

- Three core operating areas across approximately 2.8 million net acres
- 2019F production: 95 – 105 MBOE/d (26% liquids; 17% decline rate)
- Disciplined capital investment in 2019 of $50 – 75 million, due to commodity price environment
- Ownership and control underpins operational flexibility
- Synergies with our oil sands business

<table>
<thead>
<tr>
<th>Key statistics</th>
<th>Units</th>
<th>Statistic</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operated assets</td>
<td>#</td>
<td>14</td>
</tr>
<tr>
<td>Avg. working interest of operated facilities</td>
<td>%</td>
<td>84</td>
</tr>
<tr>
<td>Total net processing capacity</td>
<td>BCF/d</td>
<td>~1.2</td>
</tr>
</tbody>
</table>

**Key operated facilities**

<table>
<thead>
<tr>
<th>Facility</th>
<th>Units</th>
<th>Statistic</th>
</tr>
</thead>
<tbody>
<tr>
<td>Elmworth 01-08-70-11W6</td>
<td>Net MMcf/d</td>
<td>395</td>
</tr>
<tr>
<td>Noel B-059-D/093-9-08</td>
<td>Net MMcf/d</td>
<td>150</td>
</tr>
<tr>
<td>Peco 12-01-049-16W5</td>
<td>Net MMcf/d</td>
<td>69</td>
</tr>
</tbody>
</table>

Note: Forecasted production based on the midpoint of April 23, 2019 guidance. See Advisory.

Deep Basin has low decline, liquids rich production

<table>
<thead>
<tr>
<th>2019F production</th>
<th>2019F percent oil &amp; liquids</th>
<th>2020F decline rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>MBOE/d</td>
<td>%</td>
<td>%</td>
</tr>
<tr>
<td>TOU</td>
<td>VII</td>
<td>ARX</td>
</tr>
<tr>
<td>0</td>
<td>100</td>
<td>25</td>
</tr>
</tbody>
</table>

- **Essentially no drilling activity in 2019**
- Maintaining safe & reliable operations
- Focused on preserving value over production volumes
- **Oil & liquids content drive economics**
- 35-40% of liquids production is crude oil and condensate
- **17% decline rate is a competitive advantage**
- Reduces sustaining capital requirements

Additional development upside at Marten Hills

2019 activity focused on further appraisal across land base

Asset overview
- Undeveloped conventional oil opportunity located in the oil sands region
  - oil sands lease/royalties
- Q2 2019 average production: ~470 bbls/d
- Demonstrated the highest initial producing oil rate to date in Marten Hills
- Strong economics to compete for capital

Key statistics
- 208 sections of oil sands leases
- 5 producing multi-lateral wells
- 15-20°API gravity crude
- Pay thickness 10-30m

Integration across the value chain improves margin

Current ex-Alberta pipeline commitments

Crude by rail capacity

Heavy processing capacity

Realizing the value of integration

Note: Values are approximate, net to Cenovus, based on total current capacity or commitment, and are subject to market conditions that could impact refinery crude slate, pipeline utilization (apportionment), and ramp-up of crude by rail operations. See Advisory.
Benefiting from refinery location and processing capacity

Heavy oil integration through processing capacity

- Total gross refining capacity re-rated to 482 Mbbls/d effective January 2019
- Refineries have access to wide range of advantaged crudes and the flexibility to optimize crude input slates based on economics
- Minimal downstream maintenance capital of approximately $200 million annually

<table>
<thead>
<tr>
<th>Wood River Refinery</th>
<th>Borger Refinery</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crude capacity</td>
<td>333 Mbbls/d</td>
</tr>
<tr>
<td>Heavy crude capacity</td>
<td>220 Mbbls/d</td>
</tr>
<tr>
<td>Clean product yield</td>
<td>81%</td>
</tr>
<tr>
<td>Source crudes</td>
<td>Variety of heavy and light crudes, including CDB, WCS and WTI</td>
</tr>
</tbody>
</table>

Note: Capacities are gross values. Cenovus is a 50 percent partner in the Wood River and Borger refineries, operated by our partner, Phillips 66. See advisory.

Refining capacity mitigates heavy oil differentials

Refinery complexity drives margins

- Refining assets help to mitigate exposure to wider light-heavy differentials
- Approximately 25% of total blended heavy oil volumes are mitigated with processing capacity
  - Wood River capable of processing 220,000 gross bbls/d of heavy
  - Borger capable of processing 35,000 gross bbls/d of heavy
- Downstream operations have generated over $4 billion in free funds flow since 2009

Note: Cumulative free funds flow since 2009 as at June 30, 2019. See Advisory for definition of operating margin and free funds flow.
Shifting destination sales away from Canadian pricing

**Expanding our marketing network**
- Currently marketing in excess of 550 Mbbls/d blended heavy oil
- Refining capacity, pipeline and rail transportation options mitigate 60-65% of our current exposure to wide differentials
- Incremental rail and pipeline commitments shift our destination sales out of Alberta and increase exposure to the USGC
- Crude by rail from two market hubs in Alberta using CP and CN mitigates logistical risks
- Salt cavern storage capacity at Foster Creek and Bruderheim supports marketing optimization efforts

**Mitigating our exposure to wider heavy differentials**

<table>
<thead>
<tr>
<th>Volumes (Mbbls/d)</th>
<th>Current Mitigation</th>
<th>Future Mitigation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dry bitumen production capacity</td>
<td>CL-G</td>
<td>&gt;95%</td>
</tr>
<tr>
<td>Blended heavy oil</td>
<td>KXL</td>
<td>Rail</td>
</tr>
<tr>
<td></td>
<td>TMX</td>
<td>Refining</td>
</tr>
</tbody>
</table>

Note: Options are based on total capacity or commitment, net to Cenovus, and are subject to market conditions that could impact refinery crude slate, pipeline utilization (apportionment), and ramp-up of crude by rail operations. Future pipeline capacity reflects commitment of 150,000 bb/d on the proposed Keystone XL pipeline project and 125,000 bb/d on the proposed Trans Mountain Expansion Project. Current mitigation options percentages based on existing capacity. Future mitigation options percentages include CL phase G capacity. See Advisory.

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Crude by rail provides structural support and optionality

**Total U.S. destination crude by rail sales**

<table>
<thead>
<tr>
<th>Total US crude by rail sales (Mbbls/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan</td>
</tr>
<tr>
<td>0</td>
</tr>
</tbody>
</table>

**Ramp-up drives margin improvement**
- Crude by rail is a structural part of our portfolio approach to market access
- Signed rail agreements with CN and CP to move crude to the US Gulf Coast
- Received ~1/3 of railcars so far and we are on track to reach 100 Mmbbls/d of crude by rail by the end of 2019
  - ramp-up through 2019 starting at Bruderheim in Q4 2018, Hardisty in Q2 2019
- Increased price exposure to the USGC mitigates heavy oil differentials in Alberta

Note: Total U.S. destination crude by rail sales includes third-party volumes.
Pipelines are core to market access strategy

Optimizing takeaway capacity to provide flexibility

- Taking a portfolio approach to maximize the value of every barrel
- Secured pipeline access to key markets outside of Alberta
- Multiple pipelines provide diversification of markets and mitigate exposure to wide differentials

Ex-Alberta pipeline commitments

<table>
<thead>
<tr>
<th>Current pipeline access</th>
<th>Volumes</th>
</tr>
</thead>
<tbody>
<tr>
<td>PADD III: Enbridge US Gulf Coast pipelines</td>
<td>82,500 bbls/d</td>
</tr>
<tr>
<td>PADD II: Express – Platte pipelines</td>
<td>24,000 bbls/d</td>
</tr>
<tr>
<td>West Coast: Trans Mountain Pipeline</td>
<td>11,500 bbls/d</td>
</tr>
<tr>
<td>Committed capacity on proposed pipelines</td>
<td>Volumes</td>
</tr>
<tr>
<td>PADD III: Keystone XL</td>
<td>150,000 bbls/d</td>
</tr>
<tr>
<td>West Coast: Trans Mountain Expansion</td>
<td>125,000 bbls/d</td>
</tr>
</tbody>
</table>

Sufficient near term takeaway capacity

Note: Values are based on total commitment and are subject to market conditions that could impact pipeline utilization due to upstream pipeline apportionment. See Advisory.

Bruderheim provides strategic advantage

Long-term and low-cost optionality

- 100 Mbbls/d of gross loading capacity plus storage
  - loaded an average of 54,000 bbls/d in Q2 2019
- Ability to move wider variety of crude
- Salt cavern storage to provide additional flexibility in 2019
- Continuing to support shipment of additional third-party volumes
- Progressing low-cost projects to increase gross loading capacity to 120 Mbbls/d – or two unit trains per day – in late 2019
- Development optionality has potential to generate additional value

Leveraging a strategic location

Note: Total crude by rail shipments at Bruderheim include third-party volumes. Salt cavern storage expected to be operational in 2019.
## Creating value through corporate responsibility

### Committed to good governance
- SERR Committee of the Board provides oversight of environment and sustainability performance
- Enterprise Risk Management program, practices, and policy help ensure active and effective risk mitigation
- Transparent disclosure and reporting through annual Environmental, Social & Governance (ESG) Report

### Recognized for corporate sustainability
- Dow Jones Sustainability Index
- Euronext Vigeo World 120 Index for Responsible Performance
- MSCI Global Sustainability Index
- FTSE4Good Index

### Building long-term support in our communities
- Partnering with Aboriginal communities through employment, education, and business development
  - more than $2.7 billion spent since 2009 on goods and services supplied by Aboriginal businesses
- Community investment program helps build meaningful relationships with our local communities that reflect the long-term nature of our business
  - more than $112 million invested since 2009 in communities around our operations through financial, in-kind and employee contribution matching

### Supplemental
Foster Creek overview

Key facts and reservoir characteristics
- Current productive capacity phases A-G (bbls/d) 180,000
- Regulatory approved capacity (bbls/d) 295,000
- Reservoir depth ~450 meters
- Net pay 25 – 30 meters
- High permeability 5 – 10 darcies
- High oil saturation ~80%
- API bitumen 9° – 11°
- Cogeneration capacity (MW) 98
- CSOR 2.5
- 2018 average production per well (bbls/d) 560
- 2P reserves (MMbbls) 2,656
- 2019F production (bbls/d) ~162,000

Successfully executed 7 SAGD expansions

Note: Production is shown before royalties on a gross basis. CSOR and average production per well were impacted by voluntary curtailment in 2018. 2019F production based on the midpoint of April 23, 2019 guidance which includes the impacts of mandatory curtailments. CSOR and 2P reserves as of December 31, 2018. See Advisory.

Christina Lake overview

Key facts and reservoir characteristics
- Current productive capacity phases A-F (bbls/d) 210,000
- Regulatory approved capacity (bbls/d) 310,000
- Reservoir depth ~375 meters
- Net pay 375 – 40 meters
- High permeability 5 – 10 darcies
- High oil saturation 80%
- API bitumen 7.5° – 9.5°
- Cogeneration capacity (MW) 100
- CSOR 1.9
- 2018 average production per well (bbls/d) 900
- 2P reserves (MMbbls) 2,728
- 2019F production (bbls/d) ~198,000

Successfully executed 7 SAGD expansions and optimizations

Note: Production is shown before royalties on a gross basis. CSOR and 2018 average production per well were impacted by voluntary curtailment in 2018. 2019F production based on the midpoint of April 23, 2019 guidance which includes the impacts of mandatory production curtailments. Phase G achieved first steam in January 2019 but full utilization of incremental production capacity is impacted by mandatory curtailment. CSOR and 2P reserves as of December 31, 2018. See Advisory.
New design improves well conformance

Major improvements
• Superior start-up and steam circulation methods
• Advanced sub-surface equipment and design
• High pressure ramp up

Potential for
• Better conformance along the full horizontal well length
• Lower SOR
• Higher oil rates per well pair

Old well design: ~75% conformance

New well design: ~90-95% conformance

4D, or time-lapse seismic, can be acquired to determine changes in reservoir over an extended period. Lower conformance (left) can be identified for opportunities to improve well productivity. Consistent and continuous conformance (right) is ideal for best well productivity.

Improved start-up procedures on new pads

Technology driven field improvements
• Longer reach horizontal well pairs
• Drilling improvements
• Inflow/outflow control devices
• Improved start-up techniques

Potential for
• Quicker start-up
• Better conformance and faster recovery
• Fewer Wedge Wells™ required

Foster Creek well performance improving
Improved conformance allows longer horizontal wells

- Improved conformance allows us to drill longer wells and capture a larger drainage area
  - fewer wells and surface facilities (~25% reduction)
  - reduces environmental footprint

Well results from 1,400m wells

Note: Well results show average of two 1,400m wells compared to two 965m wells.

Redesigned well pads drive cost improvements

- Improved modular and scalable design for well pairs and pads
- Materially reduces costs while maintaining safety, compliance, and production
- Scope reduction drives 35% – 50% cost savings
  - 40% – 60% material reduction
  - 15% – 20% well pad surface footprint reduction
- Reduces engineering and construction time
  - 30% reduction in field construction time
  - 70% reduction in field executed scope
  - 65% reduction in man hours
Foster Creek estimated capital savings of $500 million

Before:
- 18 pads
- 120 wells
- ~$1.1 billion
- 200 MMbbls recoverable

After:
- 8 pads
- 66 wells
- ~$600 million
- 220 MMbbls recoverable

Improved conformance, longer horizontal wells, and redesigned well pads result in substantial cost savings

Christina Lake estimated capital savings of $800 million

Before:
- 19 pads
- 213 wells
- ~$1.6 billion
- 310 MMbbls recoverable

After:
- 13 pads
- 105 wells
- ~$800 million
- 310 MMbbls recoverable

Improved conformance, longer horizontal wells, and redesigned well pads result in substantial cost savings
Oil sands royalties

- Foster Creek and Christina Lake are post-payout projects
- Royalty calculation is annualized using the greater of gross revenues or net profits multiplied by applicable royalty rates
- Gross revenues are a function of sales revenues less diluent costs and transportation costs
- Net profits are a function of sales revenues less diluent costs, transportation costs, and allowed operating and capital costs.

Note: See Advisory.

Deep Basin takeaway capacity and marketing

- Current firm receipt capacity exceeds forecast production levels
  - sufficient transportation via committed capacity and system efficiencies
  - reviewing risked scenarios to help ensure adequate needs in the future
- Demand opportunities
  - access to multiple natural gas export routes
  - coal fired power plant conversions and retirements
  - oil sands expansion
  - Synergies with our oil sands business
    - natural gas liquids use and solvent aided process

Note: 2019F forecasted production based on the midpoint of April 23, 2019 guidance. See Advisory.
Typical crude slate and product yield

![Diagram showing crude slate and product yield distribution]

Note: Our realized crack spreads are affected by many other factors such as the variety of crude oil feedstock, refinery configuration, and product output, the time lag between the purchase and delivery of crude oil feedstock, and the cost of feedstock which is valued on a first in, first out ("FIFO") accounting basis.

Refining operating margin sensitivities

![Diagram showing refining operating margin sensitivities]

Note: Operating margin sensitivities calculated on a full year basis using pricing as per April 23, 2019 guidance document and assumes no unplanned downtime or external disruptions. RINs assumed at US$0.32 cpg.
Hedging summary

<table>
<thead>
<tr>
<th>Hedges at June 30, 2019</th>
<th>Terms</th>
<th>Volumes</th>
<th>Average price</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crude – WTI Collars</td>
<td>January – December 2019</td>
<td>19,000 bbls/d</td>
<td>US$50.00 – US$62.08/bbl</td>
</tr>
</tbody>
</table>
Oil and Gas Information

The estimates of reserves and related information were prepared effective December 31, 2018 by independent qualified reserves evaluators ("IQREs"), based on the Canadian Oil and Gas Evaluation Handbook and in compliance with the requirements of National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities.

Barrels of Oil Equivalent

Natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of six Mcf to one barrel (bbl). BOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalence at the wellhead. Given that the value ratio based on the current price of crude oil compared with natural gas is significantly different from the energy equivalency conversion ratio of 6:1, utilizing a conversion on a 6:1 basis is not an accurate reflection of value.

Definitions and Industry Terminology

Decline Rate is defined as the rate at which production declines year-over-year. IRR is defined as the interest rate at which the net present value of all future cash flows from a well equal zero. IRR does not have any standard meaning prescribed by IFRS or the COGE Handbook and therefore may not be comparable with similar measures for other entities. We believe that the presentation of IRR is relevant and useful to investors because it shows illustrative well-level economics in respect of wells that may be comparable to those we anticipate drilling in respect of the Deep Basin Assets.

Non-GAAP Measures and Additional Subtotal

The following measures do not have a standardized meaning as prescribed by IFRS and therefore are considered non-GAAP measures. You should not consider these measures in isolation or as a substitute for analysis of our results as reported under IFRS. These measures are defined differently by different companies in our industry. These measures may not be comparable to similar measures presented by other companies.

Adjusted Funds Flow is used in the oil and gas industry to assist in measuring a company’s ability to finance its capital programs and meet its financial obligations. Adjusted Funds Flow is defined as Cash From Operating Activities excluding net change in other assets and liabilities and net change in non-cash working capital. Net change in other assets and liabilities is composed of site restoration costs and pension funding. Non-cash working capital is composed of current assets and current liabilities, excluding cash and cash equivalents, risk management, the contingent payment, assets held for sale and liabilities related to assets held for sale.

Free Funds Flow is defined as Adjusted Funds Flow less capital investment.

Debt to adjusted EBITDA and net debt to adjusted EBITDA are ratios that management uses to steward the company’s overall debt position as measures of the company’s overall financial strength. Debt is defined as short-term borrowings and long-term debt, including the current portion. Net debt is defined as debt net of cash and cash equivalents. Capitalization is defined as net debt plus shareholders’ equity. Net debt to capitalization is defined as net debt divided by net debt plus shareholders’ equity. Adjusted EBITDA - earnings before finance costs, interest income, income tax expense, DDA, goodwill impairments, asset impairments and reversals, unrealized gains (losses) on risk management, foreign exchange gains (losses), revaluation gain, re-measurement of contingent payment, gains (losses) on divestiture of assets and other income (loss), net, calculated on a trailing 12-month basis.

Operating Margin is an additional subtotal found in Note 1 and 7 of the Consolidated Financial Statements and is used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between periods. Operating Margin is defined as revenues less purchased product, transportation and blending, operating expenses, production and mineral taxes plus realized gains less realized losses on risk management activities. Items within the Corporate and Eliminations segment are excluded from the calculation of Operating Margin.

Production Presentation Basis

Cenovus presents production volumes on a net to Cenovus before royalties basis, unless otherwise stated.

Forward-looking Information

This presentation contains certain forward-looking statements and forward-looking information (collectively referred to as “forward-looking information”) within the meaning of applicable securities legislation, including the United States Private Securities Litigation Reform Act of 1995, about our current expectations, estimates and projections about the future, based on certain assumptions made by us in light of our experience and perception of historical trends. Although we believe that the expectations represented by such forward-looking information are reasonable, there can be no assurance that such expectations will prove to be correct.

Forward-looking information in this presentation is identified by words such as “anticipate”, “believe”, “expect”, “estimate”, “plan”, “forecast”, “future”, “target”, “position”, “project”, “committed”, “capacity”, “focus”, “on track”, “outlook”, “potential”, “priority”, “may”, “strategy”, “go-forward”, “will”, “upside”, “implication”, “intend”, or similar expressions and includes suggestions of future outcomes, including statements about: our strategy and related milestones and schedules; projections for 2019 and future years and plans to realize such projections; our priorities and other statements relating to forecast capital spending, cost reductions, production guidance, debt reduction, future development potential, including through free funds flow and asset sales; targeted net debt and net debt to adjusted EBITDA ratio; expected crude oil and crude bitumen production; expected impacts of our rail commitments and our timeline and ability to ramp up our oil-by-rail; expectations regarding price differentials for Western Canadian oil, including the impact of mandated and voluntary production curtailments; planned ramp-up of Canadian oil-by-rail activity and the anticipated start-up in the second half of 2020 of Enbridge’s Line 3 Replacement project; our ability to potentially mitigate wide WTI/WCS price differentials through refining and transportation options; generating significant free funds flow as market conditions improve and price differentials return to more historic levels; our pipeline capacity commitments; expected outcomes of the company’s hedge positions, including relative to forecast oil production and expected impacts with respect to the company’s light-heavy crude oil differential exposure; expected value creation and emissions intensity reductions from the use of solvents; expected impacts of the company’s capacity for storage in its oil sands reservoirs; full-year production volume and steam to oil ratio forecasts; Christina Lake phase G expansion progress, including relative to budget and schedule, expected production capacity and expected capital costs, including relative to previous estimates; estimates of finding and development costs, and all statements related to the company’s 2019 guidance.
Developing forward-looking information involves reliance on a number of assumptions and consideration of certain risks and uncertainties, some of which are specific to Cenovus and others that apply to the industry generally. The factors or assumptions on which the forward-looking information is based include: forecast oil and natural gas prices and other assumptions inherent in Cenovus’s 2019 guidance, available at cenovus.com; projected capital investment levels, the flexibility of capital spending plans and associated sources of funding; achievement of further cost reductions and sustainability thereof; future improvements in availability of product transportation capacity, including shipping oil by rail and pipeline construction; the impact of mandated and voluntary production curtailments, as well as available storage capacity; bottom of the cycle commodity prices of US$45/bbl WTI and C$44/bbl WCS; start-up of Enbridge’s Line 3 Replacement project in late 2020 as announced; future narrowing of crude oil differentials; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; accounting estimates and judgments; future use and development of technology and associated expected future results; ability to obtain necessary regulatory and partner approvals; the successful and timely implementation of capital projects or stages thereof; and ability to access and implement all technology necessary to achieve expected future results.

The risk factors and uncertainties that could cause our actual results to differ materially, include: possible failure to access or implement some or all of the technology necessary to efficiently and effectively operate our assets and achieve and sustain future cost reductions; volatility of and other assumptions regarding commodity prices; the effectiveness of our risk management program, including the impact of derivative financial instruments, the success of our hedging strategies and the sufficiency of our liquidity position; the accuracy of cost estimates; commodity prices, currency and interest rates; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; exposure to counterparties and partners, including ability and willingness of such parties to satisfy contractual obligations in a timely manner; risks inherent in the operation of our crude-by-rail terminal, including health, safety and environmental risks; abnormal turnaround activity at North American refineries; maintaining desirable debt ratios; ability to access various sources of debt and equity capital, generally, and on terms acceptable to Cenovus; ability to finance growth and sustaining capital expenditures; changes in credit ratings applicable to Cenovus or any of its securities; changes to dividend plans or strategy, including the dividend reinvestment plan; accuracy of reserves, resources, future production and future net revenue estimates; ability to replace and expand oil and gas reserves; ability to maintain relationships with Cenovus’s partners and to successfully manage and operate its integrated business; reliability of assets including in order to meet production targets; refining and marketing margins; inflationary pressures on operating costs, including labour, natural gas and other energy sources used in oil sands processes; potential failure of projects to achieve or maintain acceptance in the market; risks associated with fossil fuel industry reputation; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in producing, transporting or refining of crude oil into petroleum and chemical products; risks associated with technology and its application to our business; risks associated with climate change; the timing and the costs of well and pipeline construction; ability to secure adequate and cost-effective product transportation including sufficient pipeline, crude-by-rail, marine or alternate transportation, including to address any gaps caused by constraints in the pipeline system; availability of, and our ability to attract and retain, critical talent; changes in the regulatory framework in any of the locations in which we operate, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon, climate change and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on our business, its financial results and its consolidated financial statements; changes in general economic, market and business conditions; the political and economic conditions in the countries in which we operate or supply; occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits and regulatory actions against Cenovus.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. Events or circumstances could cause our actual results to differ materially from those estimated or projected and expressed in, or implied by, the forward-looking information. For a full discussion of Cenovus’s material risk factors, see “Risk Management and Risk Factors” in our annual Management’s Discussion and Analysis (MD&A) or Form 40-F for the period ended December 31, 2018 and the updates under “Risk Management and Risk Factors” in the company’s most recently filed Management’s Discussion and Analysis available on SEDAR at sedar.com, on EDGAR at sec.gov and on Cenovus’s website at cenovus.com.

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## 2019 Corporate Guidance - C$, before royalties

### April 23, 2019

#### UPSTREAM

<table>
<thead>
<tr>
<th>Production (Mbbls/d)</th>
<th>Capital expenditures ($ millions)</th>
<th>Operating costs ($/bbl)</th>
<th>Effective royalty rates (%)</th>
<th>Steam to oil ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>OIL SANDS</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Foster Creek</td>
<td>158 - 166</td>
<td>250 - 300</td>
<td>Fuel: 1.75 - 2.25</td>
<td>18 - 23</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Non-fuel: 6.50 - 7.50</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Total: 8.25 - 9.75</td>
<td></td>
</tr>
<tr>
<td>Christina Lake</td>
<td>192 - 204</td>
<td>425 - 475</td>
<td>Fuel: 1.75 - 2.25</td>
<td>18 - 23</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Non-fuel: 4.50 - 5.50</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Total: 6.25 - 7.75</td>
<td></td>
</tr>
<tr>
<td>Narrows Lake</td>
<td>-</td>
<td>5 - 15</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Technology &amp; other</td>
<td>(1)</td>
<td>55 - 65</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Oil Sands total</strong></td>
<td>350 - 370</td>
<td>735 - 855</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Production (Mbbls/d)</th>
<th>Capital expenditures ($/bbl)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>DEEP BASIN</strong></td>
<td></td>
</tr>
<tr>
<td>Light/Medium oil</td>
<td>4 - 6</td>
</tr>
<tr>
<td>NGLs</td>
<td>19 - 22</td>
</tr>
<tr>
<td>Natural gas</td>
<td>430 - 460</td>
</tr>
<tr>
<td><strong>Deep Basin total</strong></td>
<td>95 - 105</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Production (Mbbls/d, MMcf/d, MBOE/d)</th>
<th>Capital expenditures ($ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>TOTAL</strong></td>
<td></td>
</tr>
<tr>
<td>Total liquids</td>
<td>373 - 398</td>
</tr>
<tr>
<td>Total natural gas</td>
<td>430 - 460</td>
</tr>
<tr>
<td>Total upstream</td>
<td>445 - 475</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Capital expenditures ($ millions)</th>
<th>Operating costs ($/bbl)</th>
<th>Effective royalty rates (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>REFINING &amp; MARKETING</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Refining (2)</td>
<td>225 - 250</td>
<td>9.50 - 10.50</td>
</tr>
<tr>
<td>Marketing &amp; transportation</td>
<td>15 - 25</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Corporate &amp; other expenditures ($ millions)</th>
<th>Upstream DD&amp;A ($ billions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>General &amp; administrative expenses (3)</td>
<td>150 - 175</td>
</tr>
<tr>
<td>Total capital expenditures ($ billions)</td>
<td>1.2 - 1.4</td>
</tr>
<tr>
<td>Cash tax (recovery) ($ millions)</td>
<td>270 - 295</td>
</tr>
<tr>
<td>Effective tax rate (%) (3)</td>
<td>1.8 - 2.0</td>
</tr>
<tr>
<td>Increase (m) (4)</td>
<td>Decrease (m)</td>
</tr>
</tbody>
</table>

## PRICE ASSUMPTIONS & ADJUSTED FUNDS FLOW SENSITIVITIES (4)

1. Technology & other includes Telephone Lake, and other emerging plays.
2. Refining capital and operating costs are reported in C$, but incurred in US$ and as such will be impacted by FX.
3. Forecasted G&A includes stock based compensation.
4. Includes DD&A related to Refining and Corporate and Eliminations.
5. Statutory rates of 27% in Canada and 25% in the US are applied separately to pre-tax operating earnings streams for each country. Excludes the effect of divestiture and mark-to-market gains and losses.
6. Sensitivities include current hedge positions applicable for the remainder of 2019. Refining results embedded in the sensitivities are based on unlagged margin changes and do not include the effect of changes in inventory valuation for first-in, first-out/lower of cost or net realizable value.
Forward-looking Information

This guidance document contains certain forward-looking statements and future-oriented financial information (collectively referred to as “forward-looking information”) within the meaning of applicable securities legislation, including the United States Private Securities Litigation Reform Act of 1995, about our current estimates and projections about the future. This forward-looking information is current only as of the date indicated above and is prepared solely for the purpose of providing our reasonable estimates and expectations for the time period indicated, based on certain assumptions made by us in light of our experience and perception of historical trends. This forward-looking information may not be appropriate for other purposes. Although Cenovus believes this forward-looking information is reasonable based on the assumptions contained in this document, there can be no assurance that it will prove to be correct and it may not be appropriate for other purposes. Readers are cautioned not to place undue reliance on forward-looking information as actual results may differ materially from those expressed or implied. Cenovus undertakes no obligation to update or revise any forward-looking information except as required by law.

In addition to the price assumptions disclosed above, the factors or assumptions on which the forward-looking information in this document is based include: projected capital investment levels, the flexibility of capital spending plans and associated sources of funding; achievement of further operating efficiencies, cost reductions and sustainability thereof; lower production as a result of the government-mandated production curtailment contributing to improvement in WCS prices, narrowing of the price differential between WTI and WCS; future improvements in availability of product transportation capacity, including Canadian oil-by-rail activity ramping up as planned; realization of expected impacts of the company’s storage capacity within its oil sands reservoirs; the ability of our refining capacity, existing pipeline commitments and plans to ramp up crude-by-rail loading capacity to mitigate a portion of heavy oil volumes against wider differentials; continued improved Canadian commodity prices; low-cycle commodity prices of US$45/bbl WTI and C$43/bbl WCS; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; accounting estimates and judgments; future use and development of technology and associated expected future results; ability to obtain necessary regulatory and partner approvals; the successful and timely implementation of capital projects or stages thereof; ability to complete asset sales, including with desired transaction metrics and expected timelines; and ability to access and implement all technology necessary to achieve expected future results.

The information in this Guidance document is also subject to risks disclosed in our annual Management’s Discussion and Analysis (“MD&A”) for the period ended December 31, 2018, supplemented by updates in our most recent quarterly MD&A, available on SEDAR at sedar.com, on EDGAR at sec.gov and at cenovus.com.
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