3Q20 Results Conference Call

Ovintiv™

NEW E&P MODEL DELIVERING

3Q20 Ahead of Plan

Net Debt[Ŧ] Reduction
$217 MM reduction
QoQ

Cash Flow [Ŧ]
$398 MM
$1.53/ share

Adj. EBITDA [Ŧ]
$487 MM

Liquidity
$3.1B
Available to 2024

Beat 3Q20 Guidance
186 Mbbls/d oil & condy
180 Mbbls/d guidance

Free Cash Flow[Ŧ]
$47 MM
@ ~$41/bbl WTI

'20
>$200 MM Savings
Delivering the plan
$300 MM '21 savings

(1) Ŧ Non-GAAP measures defined in advisories. For additional information regarding non-GAAP measures see the Company's website and disclosure in the appendix of this document

2020 – Third Consecutive Year of Free Cash Flow

Delivering free cash flow[Ŧ] in a volatile year

$217 MM 3Q20 Net Debt Reduction	Similar debt reduction expected in 4Q20
<$1.8B FY20 Capex	<$400 MM capex in 4Q20; FY20 capex down $900MM vs. original Budget
200 Mbbls/d 4Q20 crude & condensate	4Q20 & '21 crude & condensate volumes achieved in October
~$11.70 / BOE 4Q20 Total Costs[Ŧ]	>$200 MM '20 cash cost reductions create leading cost structure
~30 Normalized YE20 DUCs	Resumed completions in 3Q20; exit '20 with normalized DUC levels
~90% Hedged 4Q20 crude & condensate	Protects cash flow; 4Q20 crude & condy hedge gain of ~$200 MM at $40

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Track Record of Enhancing Efficiency

Ovintiv™

Achieved 20% D&C efficiencies in 3Q20

- Achieved efficiencies ahead of schedule
- Innovation continues to drive lower costs

UPDATED

2021 Well Cost Estimates ($ MM)

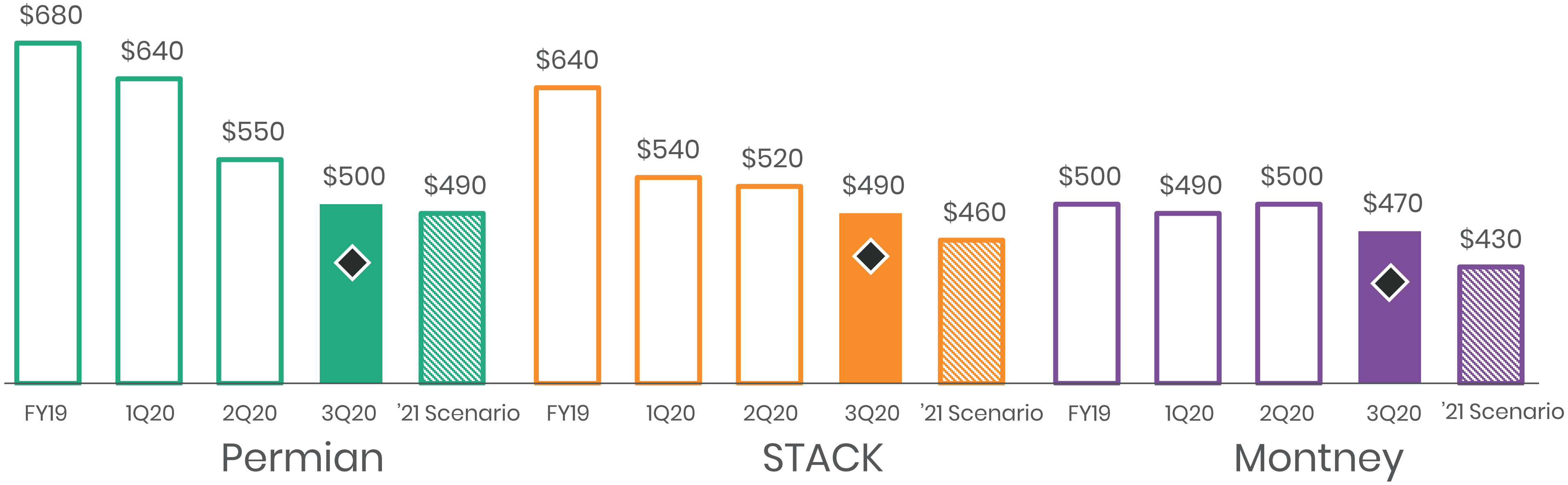
Play	Previous (2Q20) D&C	Previous (2Q20) DC&E[1]	NEW (3Q20) D&C	NEW (3Q20) DC&E[1]
Permian	$5.3	$5.8	$4.9	$5.4
STACK	$5.0	$5.4	$4.6	$4.9
Montney	$3.4	$3.5	$3.2	$3.4

UPDATED

3Q20 – Record costs in all basins

D&C ($ M) / 1k ft[2]

◆ Pacesetter



Note 1, 2: Refer to Slide Notes

Proving World Class Operatorship

Permian

- Simul-Frac results leading to increased completion rates and $350k → $400k savings per well

Anadarko

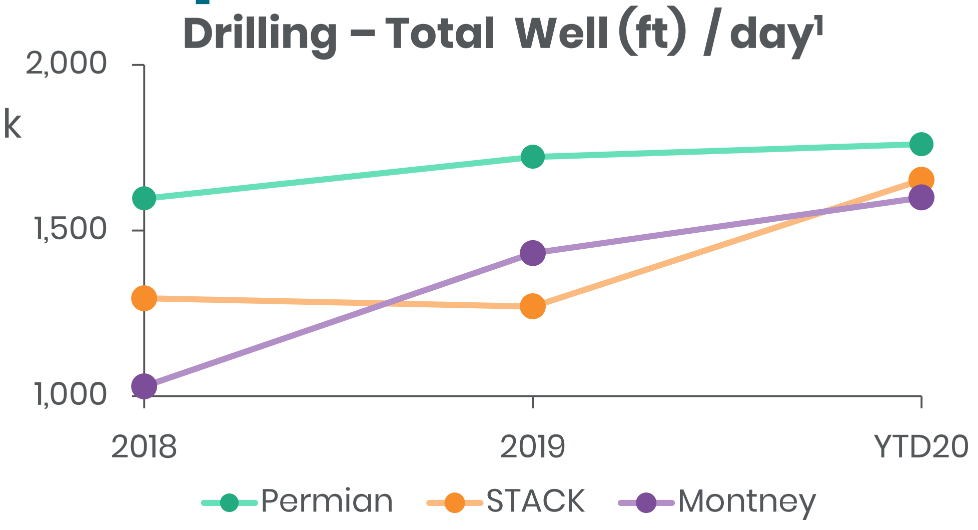
- $4.6 MM go-forward D&C ($3.3 MM savings vs Newfield)
- Implementing Simul-Frac operations to further reduce costs

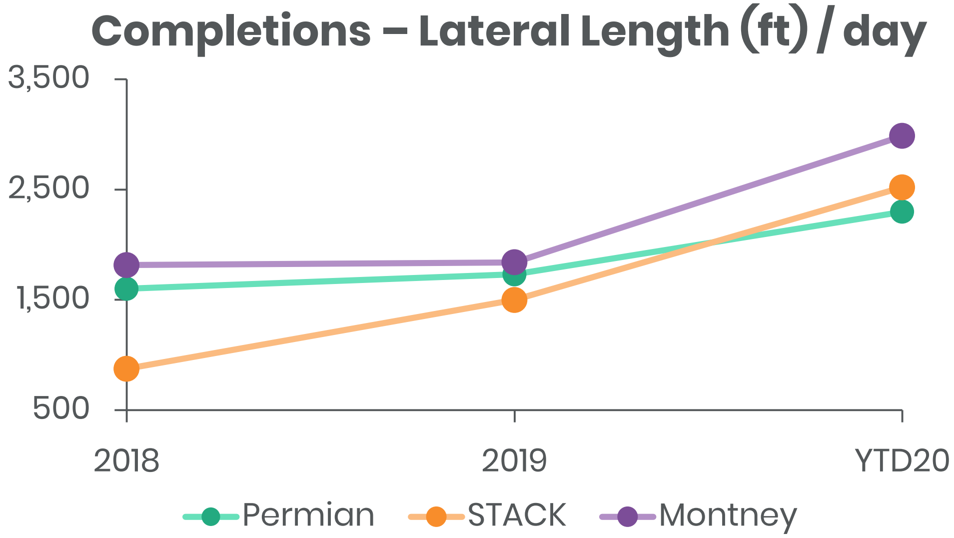
Montney

- Record pacesetter well <$1.0 MM drilling costs
- New Pipestone processing plant online 5 mos. ahead of schedule

Total Company

- Now achieved 20% lower well costs vs. 2019
- Op. costs down 19% from 1Q20: $3.34 → $2.69 / BOE (excl LTI)





Note 1, Refer to Slide Notes

OVV is the "New E&P"

Premier Multi-Basin Portfolio

3Q20 Production

1.4	186	84
Natural Gas (Bcf/d)	Crude & Condensate (Mbbls/d)	Other NGLs (MBOE/d)

Multi-Basin scale and commodity exposure

Our Priorities

Reduce Debt (1)

'20 will be 3rd consecutive year of FCF
$217 MM 3Q20 reduction & similar expected in 4Q20

Maintain Scale

200 Mbbls/d crude and condensate
Significant exposure to natural gas and NGLs

Drive Efficiencies

20% cost reduction achieved ahead of schedule
Culture of innovation

Return of Cash to Shareholders

Sustainable dividend untouched through downturn
>$1.7B in dividends & buybacks since '18

Note 1, Refer to Slide Notes

Additional Framework on "New E&P" Model

1 **Reduce Debt**

- ✓ **>$1B** debt reduction 2H20 – YE21 (1)
- <1.5x leverageŦ

2 **Capital Allocation**

- ✓ <75% Reinvestment Rate

Reduce debt, drive efficiencies, maintain scale

Note 1, Refer to Slide Notes
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Industry Leader in ESG

Industry leading reporting and performance

- Alignment to Task Force on Climate-related Financial Disclosure (TCFD)
- Utilizing Sustainability Accounting Standards Board (SASB) guidance
- Publishing annual sustainability reports since 2005
- Additional 2019 ESG metrics will be disclosed online

On track to link ESG performance to compensation in '21

- Effective in 2021 compensation year for entire organization
- Tied to key emissions-related performance metrics

Sustainability Report Preview

Methane Intensity	Flared Gas Production
0.15	**~0.60%**
2019 Tons CH_4 / MBOE	3Q20 (% of sales gas)

Performance & Reporting

15yrs
Sustainability reporting

7th
Consecutive "Safest Year Ever" 2020 YTD

Leading Industry Initiatives

API American Petroleum Institute

AXPC

CAPP

We are the “New E&P”

We have a history of leading the industry towards the era of the “New E&P”
Focus on execution efficiency, disciplined capital allocation, and generating free cash flow – Doug Suttles, October 2017

Key Ingredients	Track Record	Path Forward
Strong Capital Discipline	’20 will be 3rd consecutive year of FCF[Ŧ]	Clear focus on FCF and debt reduction
Return of Cash to Shareholders	>$1.7B returned through dividends & buybacks since ’18	Maintain sustainable dividend Reinvestment rate <75%
Top Tier ESG Performance	15th year of leading sustainability reporting; ~0.60% 3Q20 sales gas flared	’21 compensation has key emissions-related performance metrics
Industry Leading Efficiencies	Achieved record well costs in 3Q20; Industry leading break-evens	+20% capital efficiency in ’21 vs. ’19
Stability through Size & Scale	Quality multi-basin portfolio of scale; ~1.5 Bcf/d of legacy gas production	Maintain 200 Mbbls/d crude and condensate

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Future Oriented Information

This presentation contains forward-looking statements or information (collectively, "FLS") within the meaning of applicable securities legislation, including Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. FLS include:

- anticipated operating costs, legacy costs, capital efficiencies, margins, cost savings and sustainability thereof
- financial flexibility and ability to maintain balance sheet strength
- outcomes of risk management program, including exposure to commodity prices, market access, market diversification strategy and physical sales locations
- capital investment scenarios and associated production
- focus of development and allocation of capital, level of capital productivity and expected return
- anticipated production, cash flow, free cash flow, payout, net present value, rates of return, including expected timeframes and potential upside
- expected drilling and completions activity and the timing thereof
- ability to meet targets, including with respect to capital allocation, debt reduction, cash flow reinvestment and emissions-related performance, and the timing thereof
- number of rigs, drilling locations, well performance, spacing, wells per pad, rig release metrics, cycle times, well costs, commodity composition and performance against type curves and versus peers
- pacesetting metrics being indicative of future well performance and costs
- statements regarding the Company's intention to limit production volumes until targeted leverage ratio has been met
- commodity price outlook
- anticipated success of and benefits from technology and innovation
- expected transportation and processing capacity, commitments, curtailments and restrictions, including flexibility of commercial arrangements
- management of balance sheet, including target leverage, available free cash flow, debt reduction and expected net debt
- planned dividend and the declaration and payment of future dividends, if any
- statements regarding the Company's application of free cash flow to reduce debt
- statements regarding the benefits of the Company's multi-basin portfolio
- expectation that the Company will meet or exceed safety targets
- ESG approach, performance and results, and sustainability thereof

FLS involve assumptions, risks and uncertainties that may cause such statements not to occur or results to differ materially. These assumptions include: future commodity prices and differentials; assumptions as specified herein; data contained in key modeling statistics; availability of attractive hedges and enforceability of risk management program; assumed tax, royalty and regulatory regimes; and expectations and projections made in light of the Company's historical experience. Risks and uncertainties include: suspension of or changes to guidance, and associated impact to production; ability to generate sufficient cash flow to meet obligations; commodity price volatility and impact to the Company's stock price and cash flows; ability to secure adequate transportation and potential curtailments of refinery operations, including resulting storage constraints or widening price differentials; discretion to declare and pay dividends, if any; business interruption, property and casualty losses or unexpected technical difficulties; impact of COVID-19 to the Company's operations, including maintaining ordinary staffing levels, securing operational inputs, executing on portions of its business and cyber-security risks associated with remote work; counterparty and credit risk; impact of changes in credit rating and access to liquidity, including costs thereof; risks in marketing operations; risks associated with technology; risks associated with lawsuits and regulatory actions, including disputes with partners; risks associated with decommissioning activities, including timing and costs thereof; ability to acquire or find additional reserves; imprecision of reserves estimates and estimates of recoverable quantities; and other risks and uncertainties, as described in the Company's most recent Annual Report on Form 10-K, Quarterly Report on Form 10-Q and as described from time to time in its other periodic filings as filed on EDGAR and SEDAR. Although the Company believes such FLS are reasonable, there can be no assurance they will prove to be correct. The above assumptions, risks and uncertainties are not exhaustive. FLS are made as of the date hereof and, except as required by law, the Company undertakes no obligation to update or revise any FLS.

Certain future oriented financial information or financial outlook information is included in this presentation to communicate current expectations as to Ovintiv's performance. Readers are cautioned that it may not be appropriate for other purposes. Rates of return for a particular asset or well are on a before-tax basis and are based on specified commodity prices with local pricing offsets, capital costs associated with drilling, completing and equipping a well, field operating expenses and certain type curve assumptions. Pacesetter well costs for a particular asset are a composite of the best drilling performance and best completions performance wells in the current quarter in such asset and are presented for comparison purposes. Drilling and completions costs have been normalized as specified in this presentation based on certain lateral lengths for a particular asset. For convenience, references in this presentation to "Ovintiv", the "Company", "we", "us" and "our" may, where applicable, refer only to or include any relevant direct and indirect subsidiary corporations and partnerships ("Subsidiaries") of Ovintiv Inc., and the assets, activities and initiatives of such Subsidiaries.

Advisory Regarding Oil & Gas Information

All reserves estimates referenced in this presentation are effective as of December 31, 2019, prepared by qualified reserves evaluators in accordance with procedures and standards contained in the Canadian Oil and Gas Evaluation ("COGE") Handbook, National Instrument 51-101 (NI 51-101) and SEC regulations, as applicable. Detailed Canadian and U.S. protocol disclosure will be contained in the Form 51-101F1 and Annual Report on Form 10-K, respectively. Information on the forecast prices and costs used in preparing the Canadian protocol estimates are contained in the Form 51-101F1. For additional information relating to risks associated with the estimates of reserves, see "Item 1A. Risk Factors" of the Annual Report on Form 10-K.

Reserves are the estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: analysis of drilling, geological, geophysical and engineering data, the use of established technology, and specified economic conditions, which are generally accepted as being reasonable. Proved reserves are those reserves which can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

Ovintiv uses the terms play and resource play. Play encompasses resource plays, geological formations and conventional plays. Resource play describes an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section, which when compared to a conventional play, typically has a lower geological and/or commercial development risk and lower average decline rate. Certain information contained within this presentation may constitute "analogous information" as defined in NI 51-101. Analogous information is presented on a basin, sub-basin or area basis utilizing data derived from Ovintiv's internal sources, as well as from a variety of publicly available information sources which are predominantly independent in nature. Production type curves are based on a methodology of analog, empirical and theoretical assessments and workflow with consideration of the specific asset, but are not necessarily indicative of ultimate recovery. Some of this data may not have been prepared by qualified reserves evaluators, may have been prepared based on internal estimates, and the preparation of any estimates may not be in strict accordance with COGEH. Estimates by engineering and geo-technical practitioners may vary and the differences may be significant. Estimates of Ovintiv's potential gross inventory locations, including premium return well inventory, include proved undeveloped reserves, probable undeveloped reserves, un-risked 2C contingent resources and unbooked inventory locations. As of December 31, 2019, on a proforma basis, 2,184 proved undeveloped locations, 2,671 probable undeveloped locations and 4,292 un-risked 2C contingent resource locations (in the development pending, development on-hold or development unclarified project maturity sub-classes) have been categorized as either reserves or contingent resources. Unbooked locations have not been classified as either reserves or resources and are internal estimates that have been identified by management as an estimation of Ovintiv's multi-year potential drilling activities based on evaluation of applicable geologic, seismic, engineering, production, resource and acreage information. There is no certainty that Ovintiv will drill all unbooked locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The locations on which Ovintiv will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of capital, regulatory and partner approvals, seasonal restrictions, equipment and personnel, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained, production rate recovery, transportation constraints and other factors. While certain of the unbooked locations may have been de-risked by drilling existing wells in relative close proximity to such locations, many other unbooked locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional proved or probable reserves, resources or production.

30-day IP and other short-term rates are not necessarily indicative of long-term performance or of ultimate recovery. The conversion of natural gas volumes to barrels of oil equivalent ("BOE") is on the basis of six thousand cubic feet to one barrel. BOE is based on a generic energy equivalency conversion method primarily applicable at the burner tip and does not represent economic value equivalency at the wellhead. Readers are cautioned that BOE may be misleading, particularly if used in isolation.

Non-GAAP Measures

Certain measures in this presentation do not have any standardized meaning as prescribed by U.S. GAAP and, therefore, are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other companies. These measures have been provided for meaningful comparisons between current results and other periods and should not be viewed as a substitute for measures reported under U.S. GAAP. For additional information regarding non-GAAP measures, including reconciliations, see the Company's website and Ovintiv's most recent Annual Report as filed on SEDAR and EDGAR. This presentation contains references to non-GAAP measures as follows:

- **Non-GAAP Cash Flow and Non-GAAP Free Cash Flow** – Non-GAAP Cash Flow (or Cash Flow) is defined as cash from (used in) operating activities excluding net change in other assets and liabilities, net change in non-cash working capital and current tax on sale of assets. Non-GAAP Free Cash Flow (or Free Cash Flow) is Non-GAAP Cash Flow in excess of capital expenditures, excluding net acquisitions and divestitures. Management believes these measures are useful to the company and its investors as a measure of operating and financial performance across periods and against other companies in the industry, and are an indication of the company's ability to generate cash to finance capital programs, to service debt and to meet other financial obligations. These measures may be used, along with other measures, in the calculation of certain performance targets for the company's management and employees.

- **Total Costs** is non-GAAP measure which includes the summation of production, mineral and other taxes, upstream transportation and processing expense, upstream operating expense and administrative expense, excluding the impact of long-term incentive costs, restructuring costs and current expected credit losses. It is calculated as total operating expenses excluding non-upstream operating costs and non-cash items which include operating expenses from the Market Optimization and Corporate and Other segments, depreciation, depletion and amortization, impairments, accretion of asset retirement obligation, long-term incentive costs, restructuring costs and current expected credit losses. When presented on a per BOE basis, Total Costs is divided by production volumes. Management believes this measure is useful to the company and its investors as a measure of operational efficiency across periods.

- **Net Debt, Adjusted EBITDA and Net Debt to Adjusted EBITDA and Annualized Leverage** – Net Debt is defined as long-term debt, including the current portion, less cash and cash equivalents. Management uses this measure as a substitute for total long-term debt in certain internal debt metrics as a measure of the company's ability to service debt obligations and as an indicator of the company's overall financial strength. Adjusted EBITDA is defined as trailing 12-month net earnings (loss) before income taxes, DD&A, impairments, accretion of asset retirement obligation, interest, unrealized gains/losses on risk management, foreign exchange gains/losses, gains/losses on divestitures and other gains/losses. Net Debt to Adjusted EBITDA is monitored by management as an indicator of the company's overall financial strength. Annualized leverage is defined as net debt to adjusted EBITDA based on Adjusted EBITDA generated in the period(s) on an annualized basis.

Appendix

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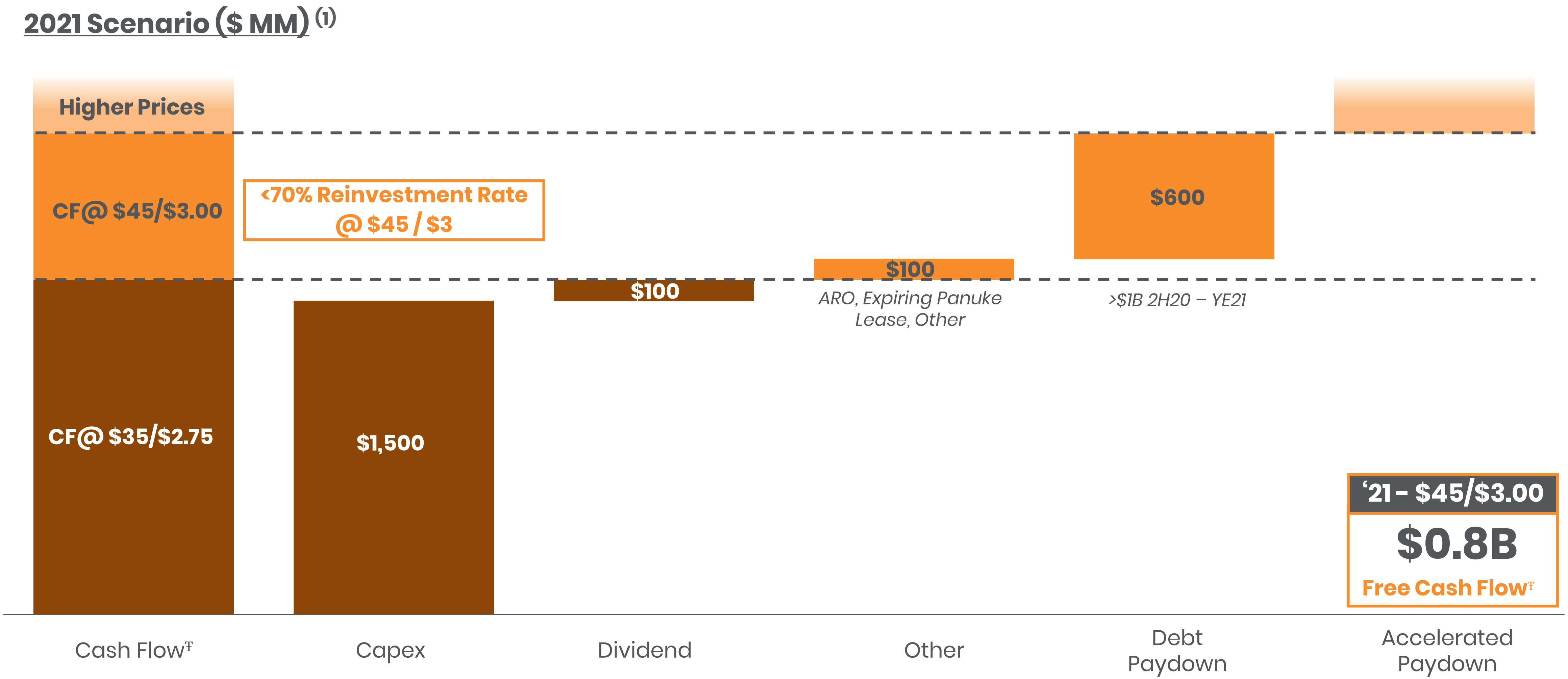
‘21 Scenario – Our Path to Debt Reduction



Note 1, Refer to Slide Notes

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Key Modeling Assumptions

Assumptions

’21 Price Sensitivities

$ rounded	Hedged	Unhedged
Oil: +/- $5	$275 MM	$375 MM
Gas: +/- $0.25	$100 MM	$140 MM

’21 Rig Scenario

	Avg Rigs
Permian	3 – 4
Montney	3 – 4
Anadarko	2 – 3
Base Assets	0 – 1

Hedge Positions (Oct 16, 2020)

Oil and Condensate[1]		4Q20	2021
WTI Swaps	Volume Mbbls/d	89	26
	Price $/bbl	$52.95	$43.55
WTI Costless Collars	Volume Mbbls/d	15	15
	Call Strike $/bbl	$68.71	$45.84
	Put Strike $/bbl	$50.00	$35.00
WTI 3-Way Options	Volume Mbbls/d	76	37
	Call Strike $/bbl	$61.46	$50.27
	Put Strike $/bbl	$53.36	$39.61
	Put (Sold) Strike $/bbl	$43.36	$29.39

Natural Gas[1,2]		4Q20	2021
NYMEX Swaps	Volume MMcf/d	793	165
	Price $/mcf	$2.65	$2.51
NYMEX Costless Collars	Volume MMcf/d	55	–
	Call Strike $/mcf	$2.88	
	Put Strike $/mcf	$2.50	
NYMEX 3-Way Options	Volume MMcf/d	330	842
	Call Strike $/mcf	$2.72	$3.42
	Put Strike $/mcf	$2.60	$2.87
	Put (Sold) Strike $/mcf	$2.25	$2.49

Hedge Gain/loss ($ MM)[1]

WTI $/bbl	4Q20	2021
$20	381	451
$30	285	269
$40	190	55
$50	48	(87)

Gas $/MMBtu	4Q20	2021
$2.00	63	147
$2.50	16	115
$3.00	(32)	(30)
$3.50	(92)	(100)

Hedges protected ‘20 cash flows

- +$8/bbl YTD vs. WTI of $38.32
- +$0.38/mcf YTD (+20%) vs NYMEX of $1.88/MMBtu

Note 1, 2: Refer to Slide Notes
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Notes

Slide 4
1) DC&E includes: drill, complete, facilities and on lease tie in costs. STACK and Permian well lengths normalized to 10,000 ft. Montney normalized to 7,500 ft. Montney costs displayed in USD. 0.72 FX rate
2) Montney D&C / 1,000 ft 2Q20 cost performance reflects only Pipestone turned-in-lines. All other time frames reflect an approximately even split between Pipestone and Dawson

Slide 5
Well lengths normalized to 10,000 ft
1) Total well (ft) / day is calculated by: Total well measured depth / spud to rig release in days (Spud to rig release time excludes surface casing rig drill time for Permian and STACK)

Slides 6,7, 15
1) Assumptions for the 2021 Scenario debt and cash flow projections are noted on slide 16, Key Modeling Assumptions.

Chart illustration on slide 15 is non-GAAP cash flow less expected capital expenditures and other outlays. The closest GAAP measure Cash from operating activities is expected to be $30 MM lower due to expected changes in net change in other assets and liabilities and net change in non cash working capital. This use of cash is included in the $100 MM use of cash labeled as additional '21E Cash costs.

Non-GAAP measures defined in advisories. For additional information regarding non-GAAP measures see the Company's website

Slide 16
1) Hedges as of October 16, 2020 For more information on Ovintiv's Financial Instruments and Risk Management please refer to Note 22 of the interim financial statements. 2021 Oil positions exclude WTI swaptions of 10 Mbbls/d @$58.00
2) Excludes 230 BBtu/day of NYMEX call options sold