ENERCOM – OIL & GAS CONFERENCE

August 2021

TSX & NYSE: **ERF**

Forward looking information and statements

This presentation contains certain forward-looking information and statements ("forward-looking information") within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", “guidance”, "ongoing", "may", "will", "project", "plans", “budget”, "strategy" and similar expressions are intended to identify forward-looking information. In particular, but without limiting the foregoing, this presentation contains forward-looking information pertaining to the following: anticipated completion of the Acquisition, including expected purchase price, terms, timing and completion thereof; expected benefits of the Acquisition; expected impacted of the Acquisition on Enerplus' operations and financial results, including inventory of drilling locations, expected accretion to Enerplus' metrics (including expected free cash flow in 2021 and beyond and year-end net debt to adjusted funds flow ratio); Enerplus' expected 2021 average production volumes and expected capital levels to support such production; anticipated production mix and Enerplus’ expected source of funding thereof; expected operating plans; oil and natural gas prices and differentials; anticipated impact of the Acquisition on Enerplus' future costs and expenses; expected increase in the size of Enerplus’ credit facility; Enerplus' five year outlook, including expected capital spending levels and resulting production, production growth and free cash flow, and plans for excess cash flow, including potential share repurchases.

The forward-looking information contained in this presentation reflects several material factors, expectations and assumptions including, without limitation: that we will conduct our operations and achieve results of operations as anticipated, including considering the Hess asset and Bruin acquisitions; that our development plans will achieve the expected results; that lack of adequate infrastructure and/or low commodity price environment will not result in curtailment of production and/or reduced realized prices beyond our current expectations ; current and estimated commodity price, differentials and cost assumptions; the general continuance of current or, where applicable, assumed industry conditions, including expectations regarding the duration and overall impact of COVID-19; the continued ability to operate DAPL and lack of court order restricting its operation; that our development plans will achieve the expected results; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and contingent resource volumes; the continued availability of adequate debt and/or equity financing and adjusted funds flow to fund our capital, operating and working capital requirements, and dividend payments as needed; the continued availability and sufficiency of our adjusted funds flow and availability under our bank credit facility to fund our working capital deficiency; our ability to comply with our debt covenants; the availability of third party services; the extent of our liabilities; the rates used to calculate the amount of our future abandonment and reclamation costs and asset retirement obligations; the availability of technology and processes to achieve environmental targets. In addition, Enerplus’ 2021 outlook contained in this presentation is based on the following rest of year prices: US$69/bbl WTI, US$3.92/Mcf NYMEX, and a USD/CDN exchange rate of 1.26. Enerplus’ five-year outlook contained in this presentation is based on the following prices for 2022-2025: US$50/bbl and US$55/bbl WTI, US$2.75/Mcf NYMEX, and a USD/CDN exchange rate of 1.27. Enerplus believes the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations, and assumptions will prove to be correct.

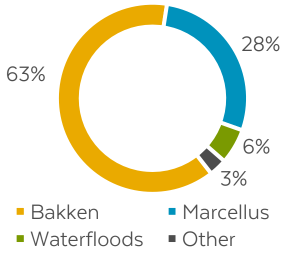
The forward-looking information included in this presentation is not a guarantee of future performance and should not be unduly relied upon. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information including, without limitation: continued instability, or further deterioration, in global economic and market environment, including from COVID-19; continued low commodity prices environment or further volatility in commodity prices; changes in realized prices of Enerplus’ products; changes in the demand for or supply of our products; failure to realize the anticipated benefits of the Hess assets or Bruin acquisitions; unanticipated operating results, results from our capital spending activities or production declines; the legal proceedings in connection with DAPL; curtailment of our production due to low realized prices or lack of adequate infrastructure; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties; increased debt levels or debt service requirements; inability to comply with debt covenants under our bank credit facility and outstanding senior notes; inaccurate estimation of our oil and gas reserve and contingent resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; changes in law or government programs or policies in Canada or the United States; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks and contingencies described under "Risk Factors and Risk Management" in Enerplus’ 2020 MD&A and in our other public filings).

The purpose of our estimated free cash flow disclosure, is to assist readers in understanding our expected and targeted financial results, and this information may not be appropriate for other purposes. Information in this presentation is provided as of the date hereof and Enerplus assumes no obligation to update any forward-looking statements, unless otherwise required by law.

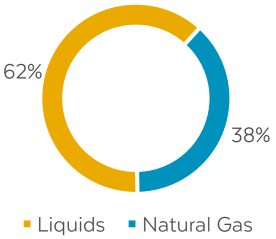
Enerplus overview

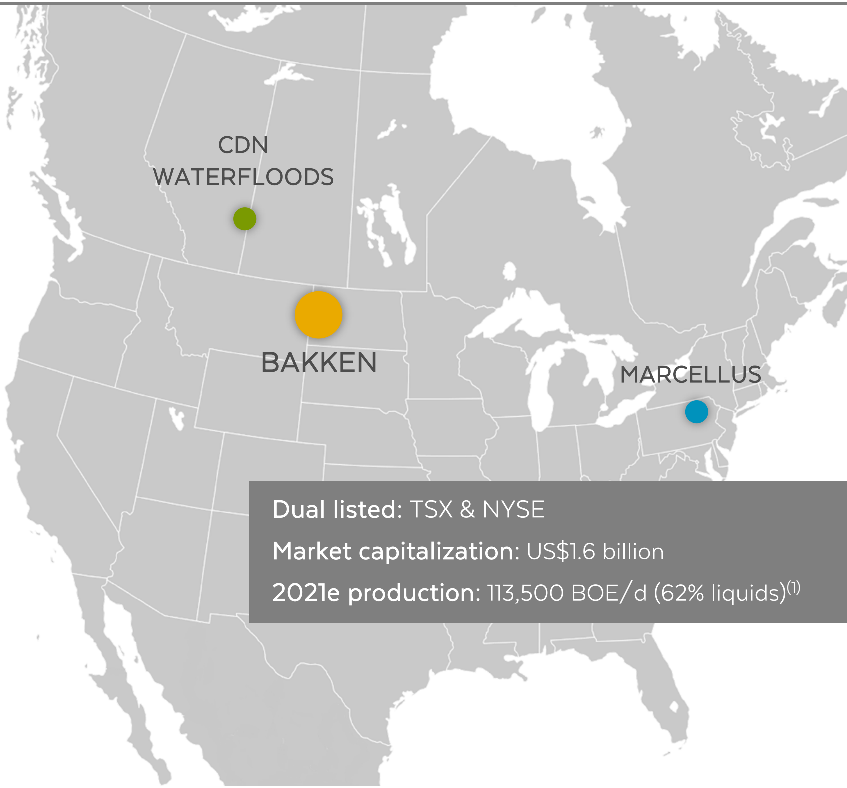
- Concentrated acreage position in the Bakken core
- Strong balance sheet and liquidity position
- Robust free cash flow outlook
- Disciplined returns-based capital allocation
- Committed to strong ESG performance

2021e production by area[1]



2021e production by product[1]





Dual listed: TSX & NYSE

Market capitalization: US$1.6 billion

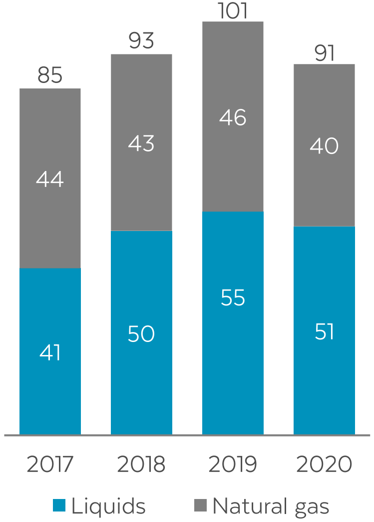
2021e production: 113,500 BOE/d (62% liquids)[1]

1) *Production is based on the guidance mid-point.*

High return growth, free cash flow and low leverage

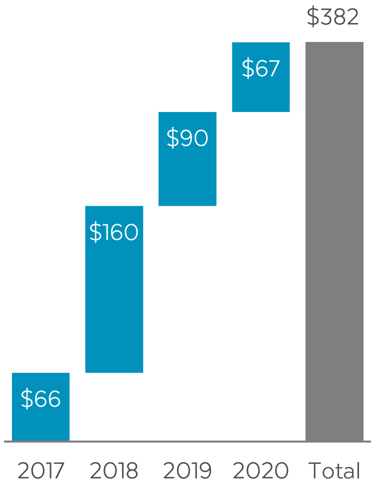
High return oil growth
Production, MBOE/d

8%
3-year liquids production CAGR since 2017



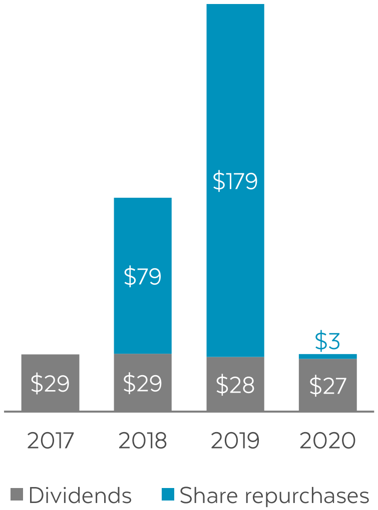
Focus on free cash flow
Free cash flow[1], C$ millions

>$380MM
Cumulative free cash flow since 2017



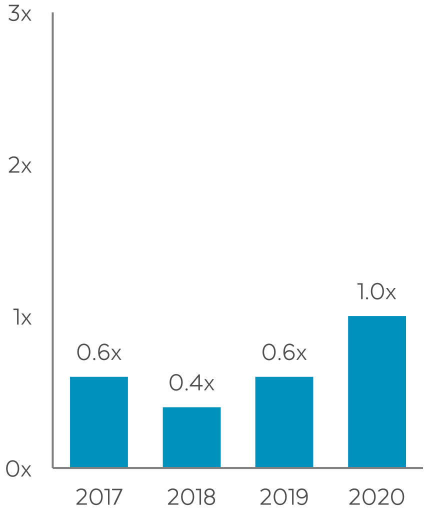
Return of capital
C$ millions

>$370MM
Returned to shareholders since 2017



Low financial leverage
Net debt to adjusted funds flow ratio[1]

1.0x
Leverage ratio at Dec 31, 2020



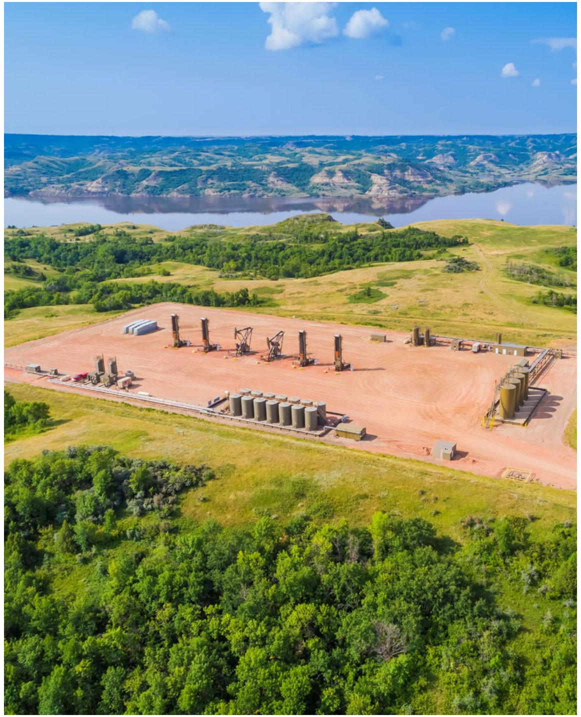
1) *Non-GAAP measure*

Material focus areas

TARGETS[1]	2020 PERFORMANCE[1]
GHG emissions intensity reduction targets[2] ▪ 2022 target: **20%** reduction in methane emissions ▪ 2030 target: **50%** reduction	**24%** Emissions intensity reduction in 2020
Freshwater use reduction targets ▪ 2021 target: **25%** reduction/well comp. in FBIR ▪ 2025 target: **50%** reduction/well comp. corporately	**23%** Freshwater use reduction per completion in 2020
Health & Safety target ▪ Reduce LTIF[3] by **25%** on average, between 2020-2023	**67%** LTIF[3] reduction in 2020

1) *Targets and 2020 performance are relative to a 2019 baseline.*
2) *Enerplus' GHG emissions reduction targets address scope 1 and 2 emissions. Scope 1 emissions are direct emissions from owned and operated facilities. Scope 2 emissions are indirect emissions from the generation of purchased energy for the Company's owned and operated facilities. Targets are relative to a 2019 baseline.*
3) *Lost Time Injury Frequency.*

Q2 2021 update

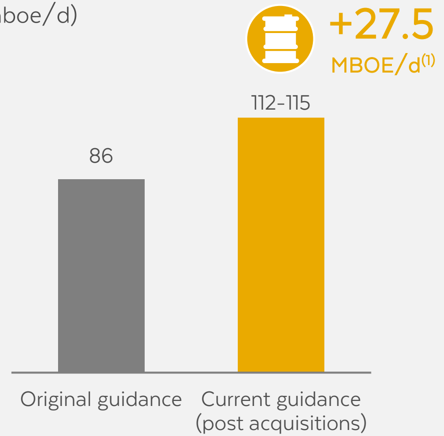


STRATEGIC ACQUISITIONS	▪ Completed the integration of the Q1 Bruin acquisition ▪ Announced and closed the acquisition of assets from Hess
STRONG PRODUCTION	▪ Company record production of 115,350 BOE/d in Q2, up 26% q-o-q ▪ 2021 annual average guidance now 112,000 to 115,000 BOE/d
FREE CASH FLOW GENERATION	▪ Generated ~$55MM in free cash flow in Q2 ▪ Estimate >$450MM in free cash flow in 2021[1]
FINANCIAL FLEXIBILITY	▪ Allocating ~90% of FCF, after dividends, to debt reduction in near term ▪ Estimated year end 2021 ND/Adj FF ratio at or below 1.0x[1][2]
INCREASING RETURN OF CAPITAL	▪ Dividend increased 15%, share buyback program reinitiated ▪ Expectation of further increasing capital returns to shareholders once debt target achieved[3]
SOLID EXECUTION	▪ Averaging >30% improvement in ND completions efficiency YTD vs 2020 ▪ Tracking 25% improvement in total ND well costs in 2021 vs 2019

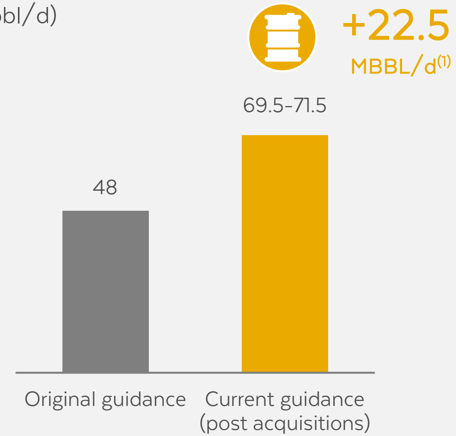
1) Non-GAAP measure, see "Advisories". Based on forward strip commodity prices at July 21, 2021 .
2) 2021e net debt to adjusted funds flow ratio assumes annualized adjusted funds flow from the 2021 acquisitions.
3) Debt reduction target of $400MM from Q2 2021 expected to be achieved by mid-2022 based on current commodity price environment. Increasing capital returns assumes commodity price environment remains constructive.

2021 operating outlook

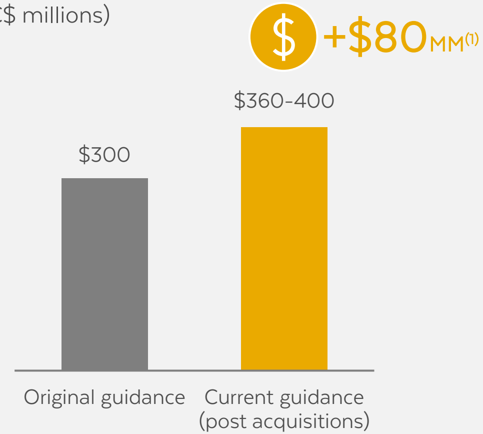
2021e total production
(mboe/d)



2021e liquids production
(mbbl/d)



E&D capital spending
(C$ millions)



1) Based on guidance mid-points.

Capital allocation principles and framework

Principles	Framework
MAINTAIN LOW LEVERAGE	Long term ND/AFF ratio target: 1.0x or less assuming US$50 WTI price environment
GENERATE FREE CASH FLOW	Long term capital spending reinvestment rate of less than 75% of adjusted funds flow
RETURN CAPITAL TO SHAREHOLDERS	Sustainably grow base dividend supported by an increasing cash flow base. Consider share repurchases to further enhance the return of capital to shareholders

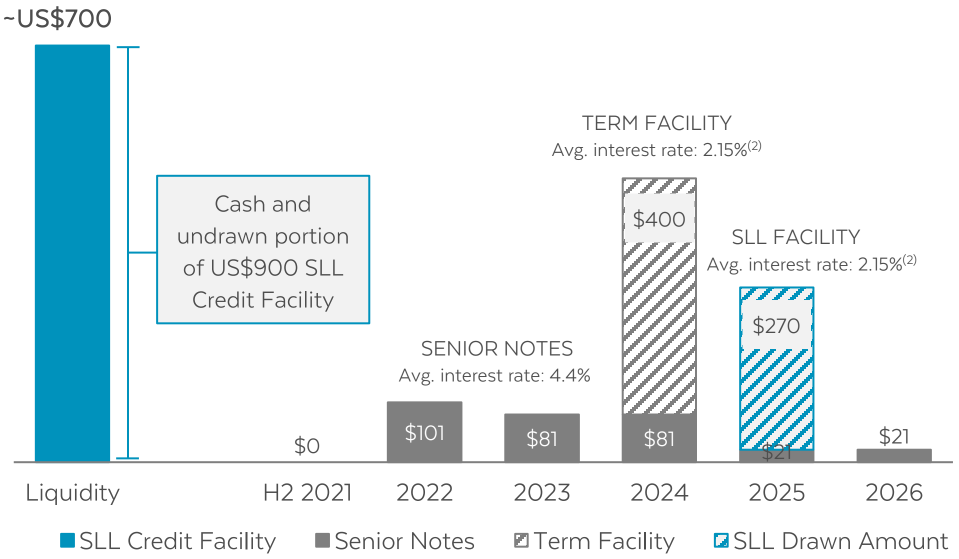
The key principles above and the macro environment will drive Enerplus' disciplined approach to growth, maximizing free cash flow and shareholder returns

Strong liquidity position and line of sight to leverage target

Significant liquidity

Estimated liquidity position at June 30, 2021 (US$ millions)

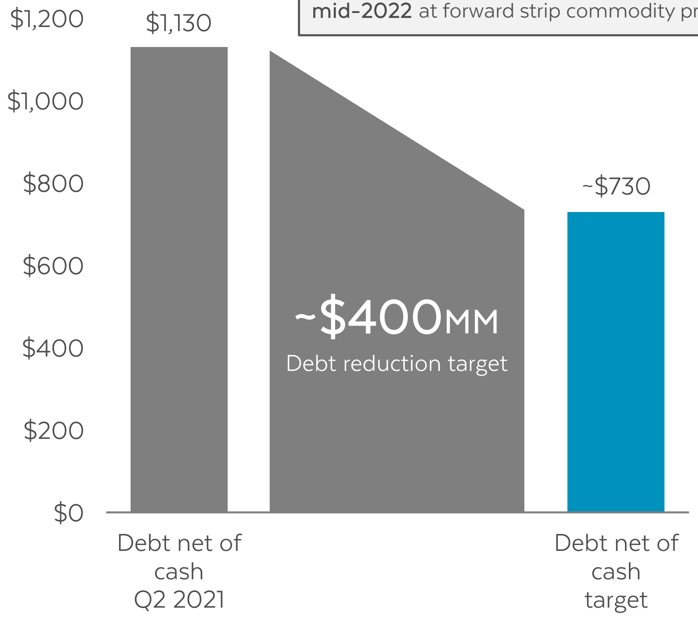
ESG — Enerplus was the first North American E&P to transition its principal credit facility to a Sustainability Linked Credit Facility, incorporating ESG performance targets



Debt reduction target

From Q2 2021 (C$ millions)

Debt target estimated to be **achieved by mid-2022** at forward strip commodity prices[1]

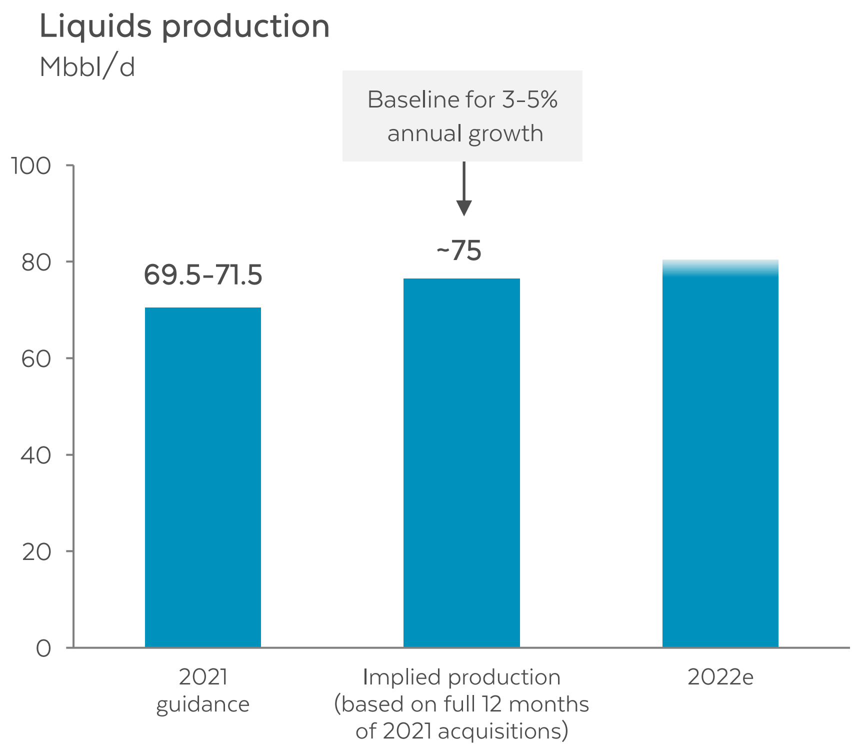


1) *Based on forward strip commodity prices at July 21, 2021.*
2) *Drawn fees are expected to be approximately 2.15% based on an underlying 3-month LIBOR rate of 0.1%*

Five year outlook focused on free cash flow growth

HIGHLIGHTS OF THE FIVE YEAR OUTLOOK
(assumes constructive oil price: ~US$50-55+/bbl WTI)

ANNUAL CAPITAL SPENDING	~$500 MM (2022-2025)
CUMULATIVE FREE CASH FLOW[1]	~$1.5 to $2.0 Bn (2021-2025)
AVERAGE REINVESTMENT RATE[1]	~55% to 60% (2021-2025)
ANNUAL LIQUIDS PRODUCTION GROWTH RATE	~3% to 5% (2022-2025)



1) *Non-GAAP measure, see "Advisories". 2021 is based on year to date commodity prices and forward strip for the remainder of the year. Years 2022-2025 are based on WTI oil prices of US$50-$55/bbl and NYMEX natural gas prices of US$2.75/Mcf.*

enerPLUS

Strategic acquisitions improve Bakken scale

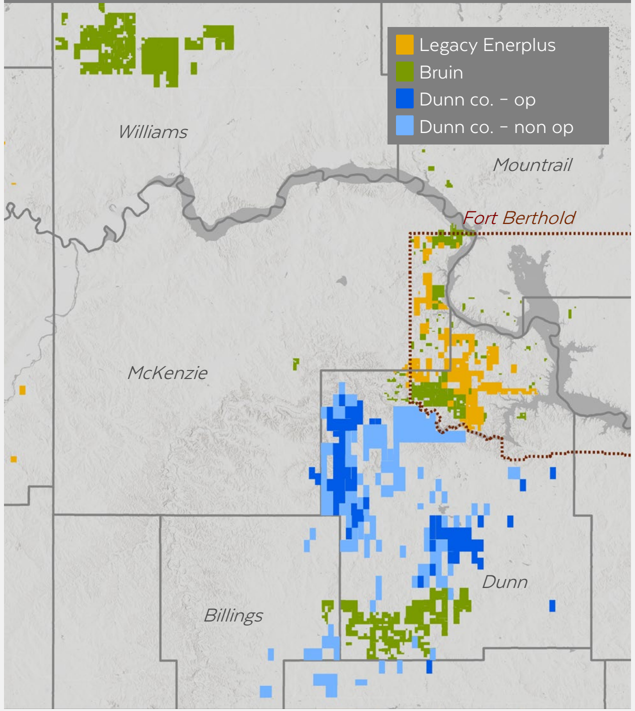
HIGHLIGHTS OF ACQUISITIONS

- 4x increase in acreage position; now 296,000 net acres
- 340 net identified economic drilling locations[1] added
- ~30,000 BOE/d current production added

Bruin acquisition
CLOSED March 10, 2021

Dunn county acquisition
CLOSED April 30, 2021

ENERPLUS NORTH DAKOTA POSITION

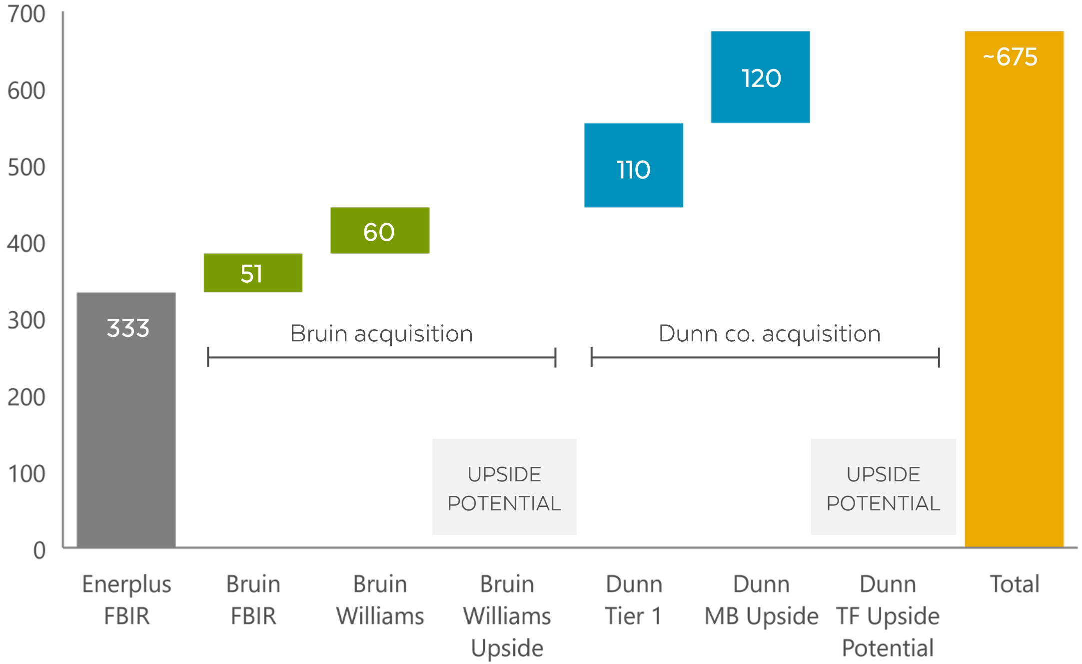


1) See "Advisories – Drilling Inventory" for a reconciliation of undrilled locations between those associated with reserves and those not associated with any reserves.

Acquisitions have extended high quality inventory

Drilling inventory expansion[1]

Net locations

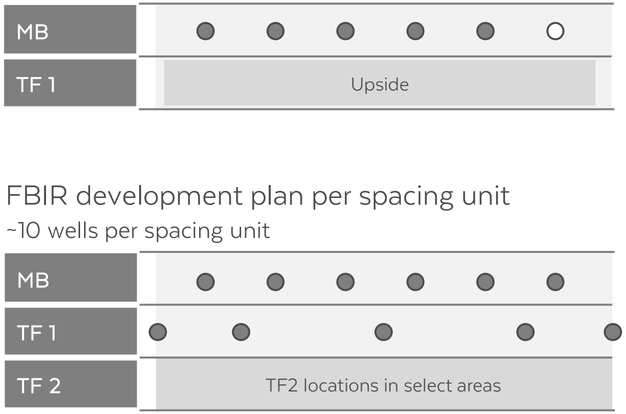


Non-FBIR development plan

5-6 wells per spacing unit

FBIR development plan per spacing unit

~10 wells per spacing unit

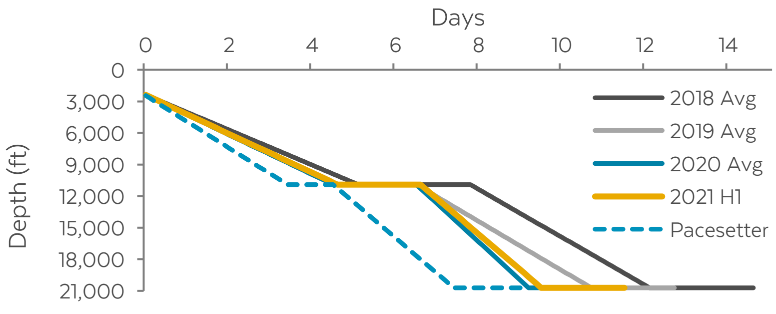


1) *See "Advisories – Drilling Inventory" for a reconciliation of undrilled locations between those associated with reserves and those not associated with any reserves. As at 1 Jan 2021. Includes drilled uncompleted wells.*

Solid execution delivering capital efficiency gains

Drilling efficiency gains

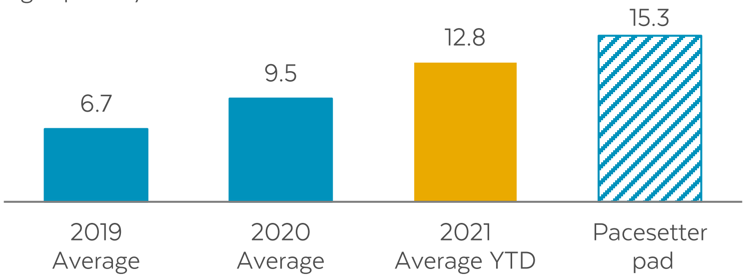
Drilling days vs. depth (spud to rig release)[1]



>20% IMPROVEMENT SINCE 2018

Completion efficiency gains

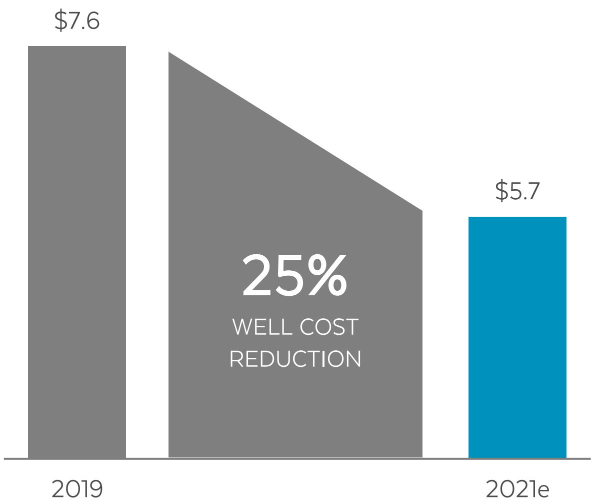
Stages per day



>90% IMPROVEMENT SINCE 2019

Total well costs

(US$MM)[1][2]

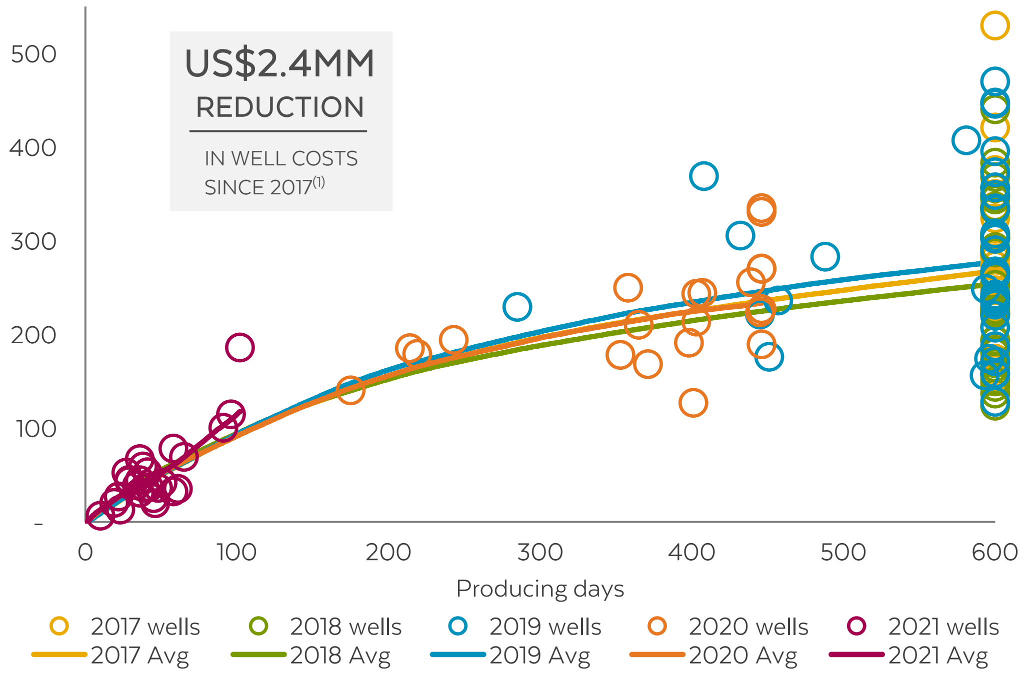


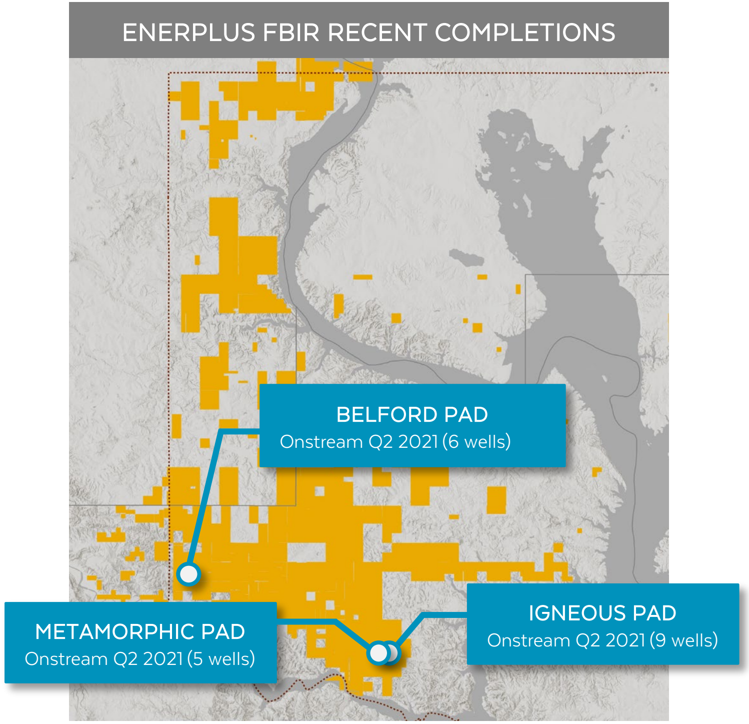
1) *Based on two-mile lateral wells.*
2) *Total well cost includes drilling, completion and facilities costs.*

Maintaining strong well performance at lower cost

Enerplus Fort Berthold well performance

Cumulative oil production per well (Mbbl)

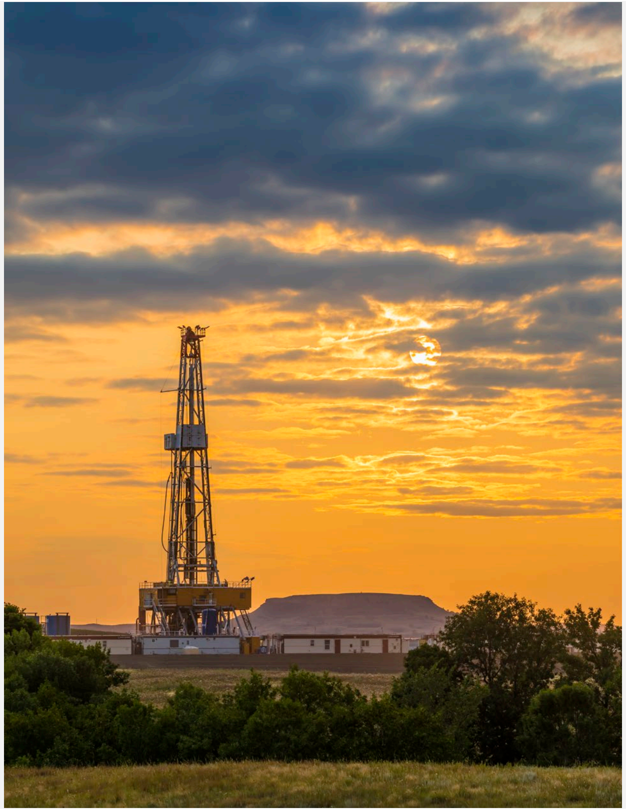




1) *Well costs in 2017 averaged US$8.1mm compared to US$5.7mm expected in 2021.*

Key messages

- Concentrated acreage position in the Bakken core
- Strong balance sheet and liquidity position
- Robust free cash flow outlook
- Disciplined returns-based capital allocation
- Returning capital to shareholders
- Committed to strong ESG performance



APPENDIX

2021 guidance, operating statistics and well economics

2021 GUIDANCE	
E&D capital spending (C$MM)[1]	$360-400
Total production (Mboe/d)	112-115
Liquids production (Mbbl/d)	69.5-71.5
Avg. royalty & production tax rate	26%
Operating expense ($/boe)	$8.25
Transportation expense ($/boe)	$3.85
Cash G&A expense ($/boe)	$1.25
Current income tax expense (US$MM)	$5-7
Bakken oil price differential compared to WTI (US$/bbl)	$(2.35)
Marcellus natural gas price differential compared to NYMEX (US$/Mcf)	$(0.65)

2021 ASSET DETAILS[2]	BAKKEN	MARCELLUS	CANADA	DJ BASIN
Capital allocation (approx.)[1]	76%	12%	6%	6%
Wells drilled (gross)	19-23 (~99% WI)	54-66 (~5% WI)	2 (~15% WI)	-
Wells online (gross)	42-50 (~80% WI)	64-72 (~7% WI)	2 (~15% WI)	3 (~87% WI)

1) Capital spending includes capitalized G&A.
2) Wells drilled and completed are based on operated activity only except for the Marcellus and Canada which include non-operated activity.

WELL ECONOMICS		
BAKKEN - FORT BERTHOLD[1]		
WTI oil price	US$50/bbl	US$60/bbl
Payout	1.5 years	0.9 years
IRR:	60%	100%+
Breakeven (10% IRR)	US$38/bbl WTI	
MARCELLUS[2]		
NYMEX natural gas price	US$3.00/Mcf	US$3.50/Mcf
Payout	2.0 years	1.4 years
IRR	50%	90%
Breakeven (10% IRR)	US$2.30/Mcf NYMEX	

1) Fort Berthold well economics are based on the average 2P reserves booked per undeveloped location for a 2-mile lateral (~730 mboe) and a total well cost of US$5.7MM.
2) Marcellus well economics are based on the average 2P reserves booked per undeveloped location (~18 Bcf/well, 7,400 ft lateral) and a total well cost of US$6.3MM.

Advisories

Investor Relations Contacts

Drew Mair
Manager, Investor Relations & Corporate Planning
403-298-1707

Krista Norlin
Sr. Investor Relations Analyst
403-298-4304

Email:
investorrelations@enerplus.com

Assumptions

All amounts in this presentation are stated in Canadian dollars unless otherwise specified. All financial information in this presentation has been prepared and presented in accordance with U.S. GAAP, except as noted below under "Non-GAAP Measures".

Barrels of Oil Equivalent and Cubic Feet of Gas Equivalent

This presentation also contains references to "BOE" (barrels of oil equivalent), "MBOE" (one thousand barrels of oil equivalent), and "MMBOE" (one million barrels of oil equivalent). Enerplus has adopted the standard of six thousand cubic feet of gas to one barrel of oil (6 Mcf: 1 bbl) when converting natural gas to BOEs. BOE, MBOE and MMBOE may be misleading, particularly if used in isolation. The foregoing conversion ratios are based on an energy equivalency conversion method primarily applicable at the burner tip and do not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalent of 6:1, utilizing a conversion on a 6:1 basis may be misleading.

Non-GAAP Measures

In this presentation, Enerplus uses the terms "adjusted funds flow", "free cash flow" (including per share measures), "net debt to adjusted funds flow ratio", and "reinvestment rate" as measures to analyze operating and financial performance. "Adjusted funds flow" is calculated as net cash generated from operating activities but before changes in non-cash operating working capital and asset retirement obligation expenditures. "Free cash flow" is defined as "Adjusted funds flow less exploration and development capital spending". "Net debt to adjusted funds flow ratio" is calculated as total debt net of cash divided by a trailing twelve months of adjusted funds flow. "Reinvestment rate" is calculated as exploration and development capital spending divided by adjusted funds flow..

Enerplus believes that, in addition to net earnings and other measures prescribed by U.S. GAAP, the terms "adjusted funds flow", "free cash flow" (including per share measures), "net debt to adjusted funds flow ratio", and "reinvestment rate" are useful supplemental measures as such provide an indication of the results generated by Enerplus' principal business activities. However, these measures are not recognized by U.S. GAAP and do not have a standardized meaning prescribed by U.S. GAAP. Therefore, these measures, as defined by Enerplus, may not be comparable to similar measures presented by other issuers.

Presentation of Production and Reserves Information

All production volumes and revenues presented herein are reported on a "company interest" basis, before deduction of Crown and other royalties, plus Enerplus' royalty interest with the exception of production utilized to calculate reserves replacement ratios which are on a working interest basis. Unless otherwise specified, all reserves volumes in this presentation (and all information derived therefrom) are based on "gross reserves" using forecast prices and costs. "Gross reserves" (as defined in NI 51-101), are Enerplus' working interest before deduction of any royalties. Enerplus' oil and gas reserves statement for the year ended December 31, 2020, which will include complete disclosure of our oil and gas reserves and other oil and gas information in accordance with NI 51-101, is contained within our Annual Information Form (AIF) for the year ended December 31, 2020 which is available on our website at www.enerplus.com and under our SEDAR profile at www.sedar.com. Additionally, our AIF forms part of our Form 40-F that is filed with the U.S. Securities and Exchange Commission and is available on EDGAR at www.sec.gov. Readers are also urged to review the Management's Discussion & Analysis and financial statements filed on SEDAR and as part of our Form 40-F on EDGAR concurrently with this presentation for more complete disclosure on our operations. All references to "liquids" in this presentation include light and medium crude oil, heavy oil and tight oil (all together referred to as "crude oil") and natural gas liquids on a combined basis.

Drilling Inventory

Drilling locations associated with proved plus probable undeveloped reserves have been evaluated or reviewed by Enerplus' independent qualified reserves evaluators in accordance with the COGE Handbook. Drilling locations associated with unrisked "best estimate" economic contingent resources in "development pending" project maturity sub-class pertaining to North Dakota have been evaluated by internal qualified reserves evaluators and audited by Enerplus' independent qualified reserves evaluators, McDaniel & Associates Ltd, in accordance with the COGE Handbook. Unbooked future drilling locations are not associated with any reserves or contingent resources of Enerplus and have been identified by internal qualified reserves evaluators and have not been audited by Enerplus' independent qualified reserves evaluators. Existing Enerplus net locations are as at 1 Jan 2021 and comprise 287 2P undeveloped reserves locations (includes drilled uncompleted wells), 136 best estimate contingent resources locations and 251 unbooked future locations.