EAGLE FORD PRESENTATION

CREATING **ENERGY** | CREATING **VALUE**

April 15, 2024

ADVISORY

In this presentation, we refer to certain specified financial measures which do not have any standardized meaning prescribed by International Financial Reporting Standards (“IFRS”). While these measures are commonly used in the oil and natural gas industry, our determination of these measures may not be comparable with calculations of similar measures presented by other reporting issuers. This presentation also contains oil and gas disclosures, various industry terms, and forward-looking statements, including various assumptions on which such forward-looking statements are based and related risk factors. Please see the Company’s disclosures located at the end of this presentation for further details regarding these matters.

All slides in this presentation should be read in conjunction with “Forward Looking Statements Advisory”, “Specified Financial Measures Advisory”, “Capital Management Measures Advisory” and “Advisory Regarding Oil and Gas Information”.

This presentation should be read in conjunction with the Company’s audited consolidated financial statements and Management’s Discussion and Analysis (“MD&A”) for the year ended December 31, 2023.

There is no representation by Baytex that actual results achieved will be the same in whole or in part as those referenced in the forward-looking statements. The future oriented financial information and forward-looking statements are made as of April 16, 2024 and Baytex disclaims any intent or obligation to update publicly any forward-looking statements, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.

All amounts in this presentation are stated in Canadian dollars unless otherwise specified.

AGENDA

1. **Introduction**
2. **Geology**
3. **Operations**
4. **Market Access**
5. **Closing Remarks**
6. **Q&A**

OUR TEAM

Julia Gwaltney

SVP and General Manager, Eagle Ford Operations

Over 30 years of O&G experience
Bachelor of Science in Petroleum Engineering,
Colorado School of Mines

Camilo Arias

Director, Drilling

Over 22 years of O&G experience
Bachelor of Science in Petroleum Engineering,
Universidad Industrial de Santander (Colombia)

Taylor Young

Director, Subsurface

Over 14 years of O&G experience
Bachelor of Science in Mechanical Engineering,
Colorado School of Mines

Mark Yamasaki

Director, Production

Over 25 years of O&G experience
Bachelor of Science in Petroleum Engineering,
Colorado School of Mines

Charlie Bilberry

Director, Midstream and Marketing

Over 16 years of O&G experience
Bachelor of Business Administration,
University of Houston

Charlotte Guidry

Director, Land

Over 25 years of O&G experience
Bachelor of Science in Business Administration,
University of Louisiana at Lafayette

Sean Mahaffey

Director, Health, Safety & Environmental

Over 16 years of O&G experience
Bachelor of Arts in Environmental Studies,
The Pennsylvania State University

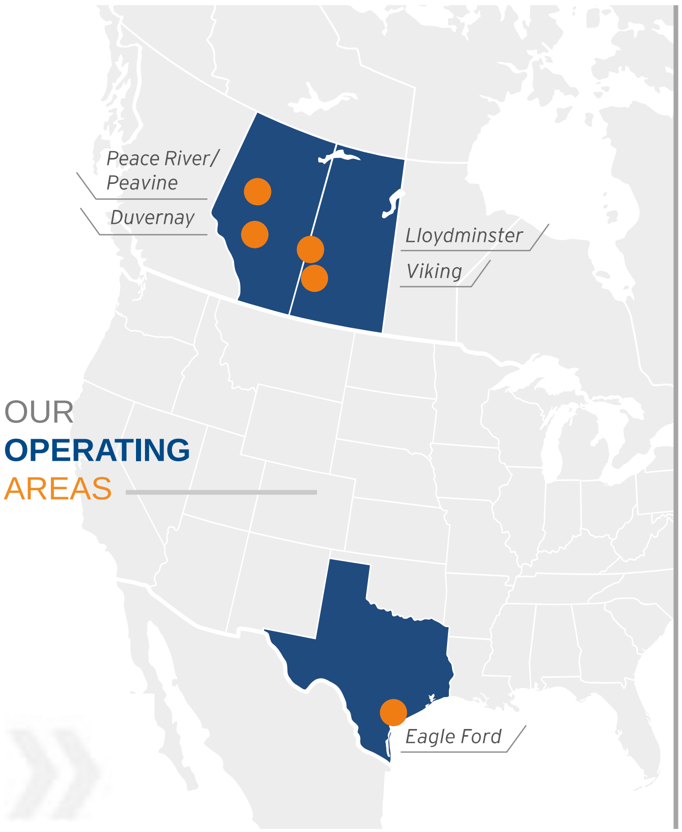
Jaime Ramirez

Director, Completions

Over 23 years of O&G experience
Bachelor of Science in Chemical Engineering,
Texas A&M University - Kingsville

A DIVERSIFIED NORTH AMERICAN E&P OPERATOR

OUR
OPERATING
AREAS



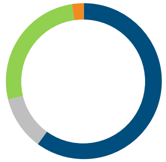
Market Summary

Ticker Symbol	TSX, NYSE | BTE
Average Daily Volume (1)	Canada: 8.6 million | US: 9.4 million
Shares Outstanding	821 million
Market Capitalization / Enterprise Value (2)	$4.3 billion / $6.8 billion
Annual Dividend per Share | Dividend Yield (3)(4)	$0.09 | 1.7%

Operating Statistics

Production (working interest) (5)	150 – 156 Mboe/d
Production Mix (5)	84% liquids
E&D Expenditures (5)	$1.2 – 1.3 billion
Reserves – 2P Gross (6)	663 MMboe
Net Acres	1.6 million

2024 Production by Business Unit



2024 Production by Commodity

(1) Average daily trading volumes for March 2024. Volumes are a composite of all exchanges.

(2) Enterprise value based on closing share price on the Toronto Stock Exchange on April 12, 2024 and net debt as at December 31, 2023. Enterprise value is calculated as market capitalization plus net debt and is used to assess the valuation of the Company. Net debt is a capital management measure. Refer to the Capital Management Measures section in this presentation for further information.

(3) Refer to the Dividend Advisory section in the presentation for further information.

(4) Dividend yield is calculated by dividing the annualized per share dividend by the market share price for the applicable period.

(5) Production, production mix, and exploration and development ("E&D") expenditures represents 2024 guidance.

(6) Baytex's year-end 2023 reserves were evaluated by McDaniel & Associates Consultants Ltd, ("McDaniel"), an independent qualified reserves evaluator in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101"). See "Advisories".

KEY TAKEAWAYS

Demonstrating the strength of our Eagle Ford Operations

Technical Expertise	Houston team has decades of direct experience in the Eagle Ford Strong sub-surface understanding and reservoir characterization Downstream marketing provides barrel differentiation
Operational Execution	Focused on maximizing efficiency of operations H&P 501 and 505 are among the most efficient rigs in the Eagle Ford Targeting an 8% improvement in operated drilling and completion costs per completed lateral foot over 2023
Asset Performance	Absolute well performance continues to increase year-over-year Normalized well performance consistent over time H2/2023 delivered top quartile performance on an absolute basis and second quartile performance on a per lateral foot basis (longer than industry average laterals on Baytex acreage)
Quality Inventory	12-15 years of sustaining development with attractive well economics Primary target Lower Eagle Ford Upper Eagle Ford / Marl, Austin Chalk and refrac opportunities

EAGLE FORD OVERVIEW

- 60% of production (1)
- 65% of asset level free cash flow (4)
- 12 to 15 years drilling inventory
- Strong drilling economics
- Upper Eagle Ford / Marl, Austin Chalk and refrac opportunities

Operational Metrics

92,000 boe/d (60% oil, 80% liquids) (1)

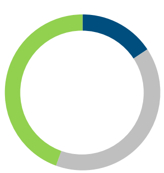
269,000 gross acres, 70% operated

418 MMboe 2P reserves (2)

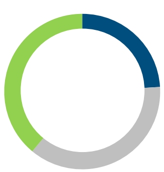
800+ net risked drilling locations (3)

~ 62 net wells to sales in 2024

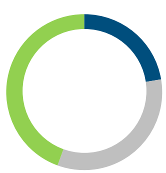
2024 Production (1)



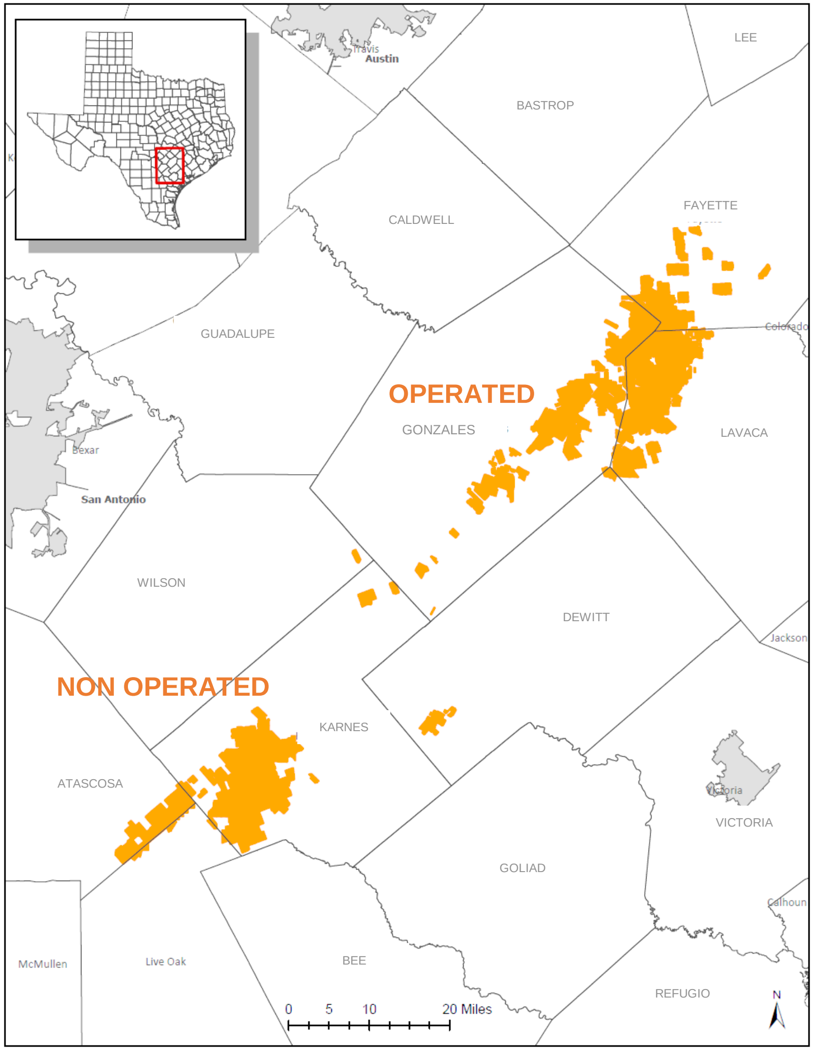
2024 2P Reserves (2)



2024 Asset Level Free Cash Flow (4)



● Eagle Ford Operated ● Eagle Ford Karnes Trough ● Canada



(1) Production and production mix represents 2024 guidance.

(2) Baytex's year-end 2023 reserves were evaluated by McDaniel & Associates Consultants Ltd, ("McDaniel"), an independent qualified reserves evaluator in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101"). See "Advisories".

(3) Net locations includes proved plus probable undeveloped reserves locations at year-end 2023 and unbooked future locations. See "Advisories".

(4) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this presentation for further information.

Geology

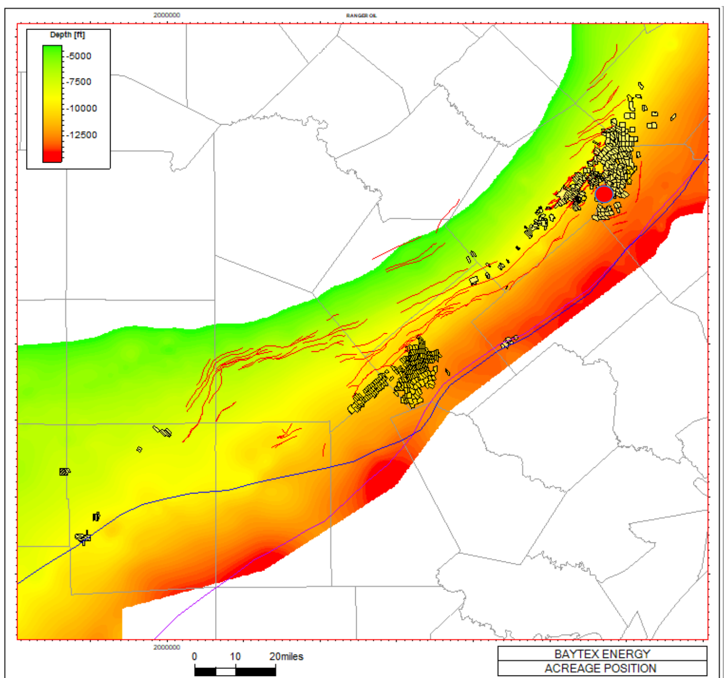
REGIONAL SUBSURFACE OVERVIEW

- Located within the black & volatile oil and condensate phase windows
- Consistent geological characteristics and reservoir continuity
- Primary Lower Eagle Ford development at varying spacing by fluid window
- Secondary stacked Upper Eagle Ford / Marl and Austin Chalk play targets

Highly consistent geology:

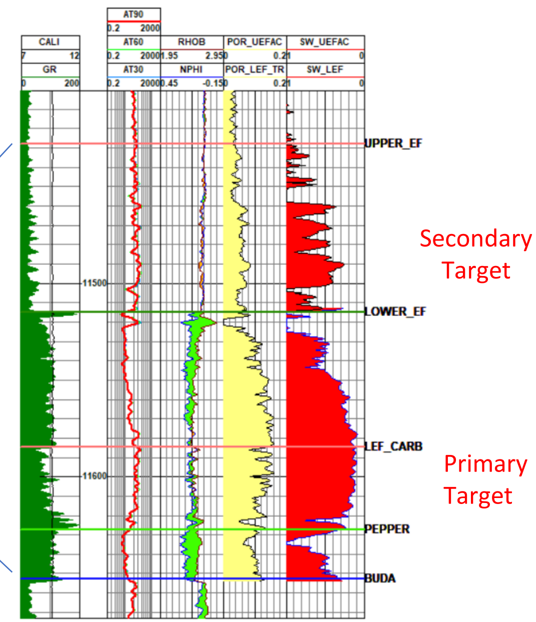
- Thickness: 90-150' Lower Eagle Ford
- Depth: 9,000' to 12,500'
- API Gravity: 38-54º (average = 45º)

Top Lower Eagle Ford Structure (ft TVD)



Eagle Ford Stratigrahy

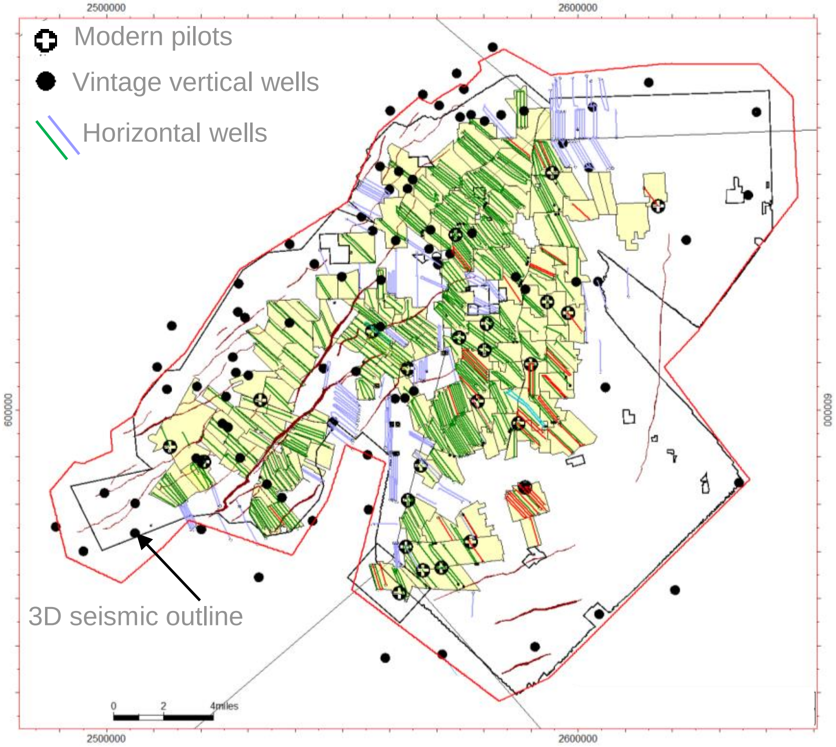
Age	Formation
TERT.	Wilcox Group
	Midway Group
UPPER CRETACEOUS	Escondido
	Olmos
	San Miguel
	Anacacho
	Austin Chalk
	Eagle Ford
	Buda
LOWER CRETACEOUS	Del Rio
	Georgetown
	Edwards/ Stuart City
	Glen Rose
	Pearsall
	Sligo



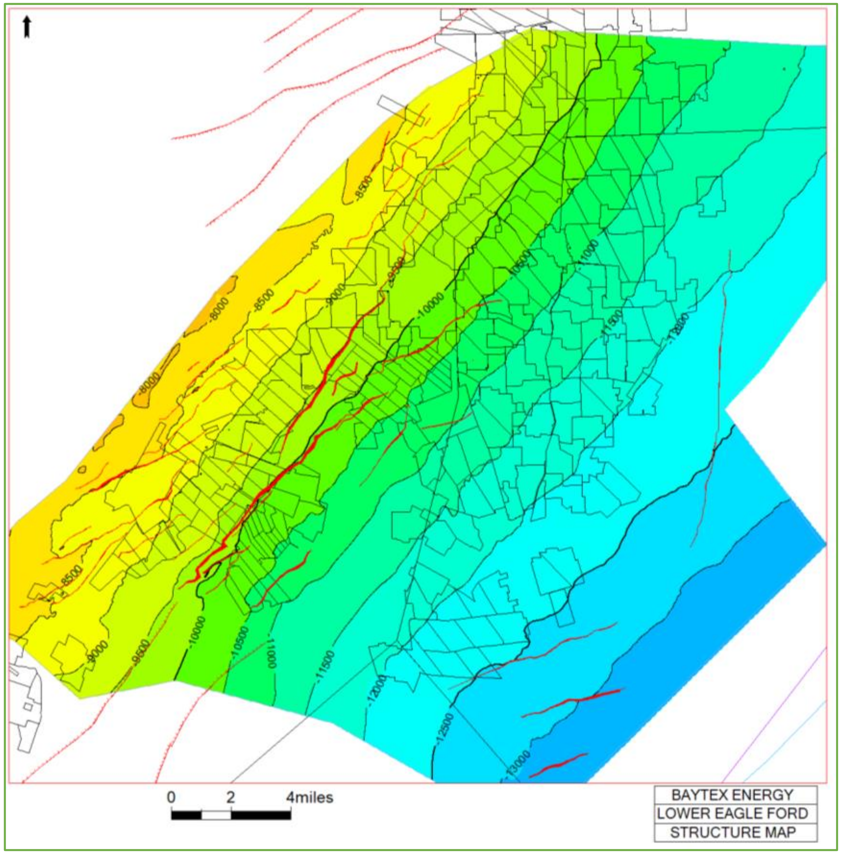
Lavaca Type Log

WELL-UNDERSTOOD SUBSURFACE

Seismic Coverage



Lower Eagle Ford Structure Map

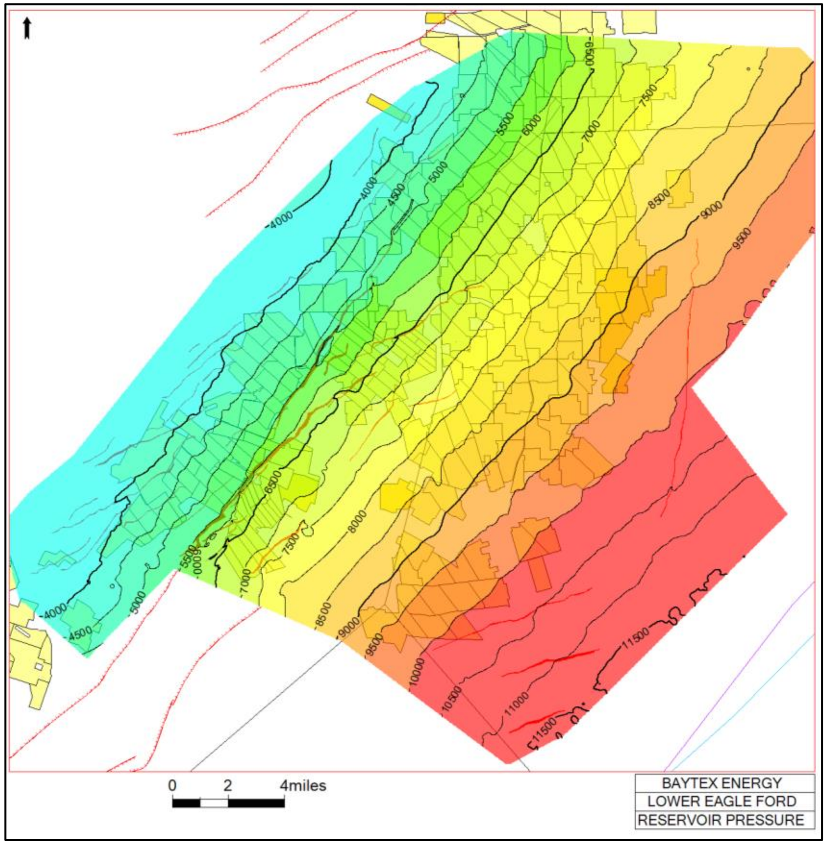


- Excellent data acquisition & sampling with over 30 Eagle Ford pilots, 90 vintage vertical wells & 9 cores
- Robust petrophysical analysis supported by 80 wells with porosity logs
- Accurate structure & fault mapping with 350 sq. miles of 3D seismic
- Integrated reservoir characterization through detailed mapping and 3D modeling

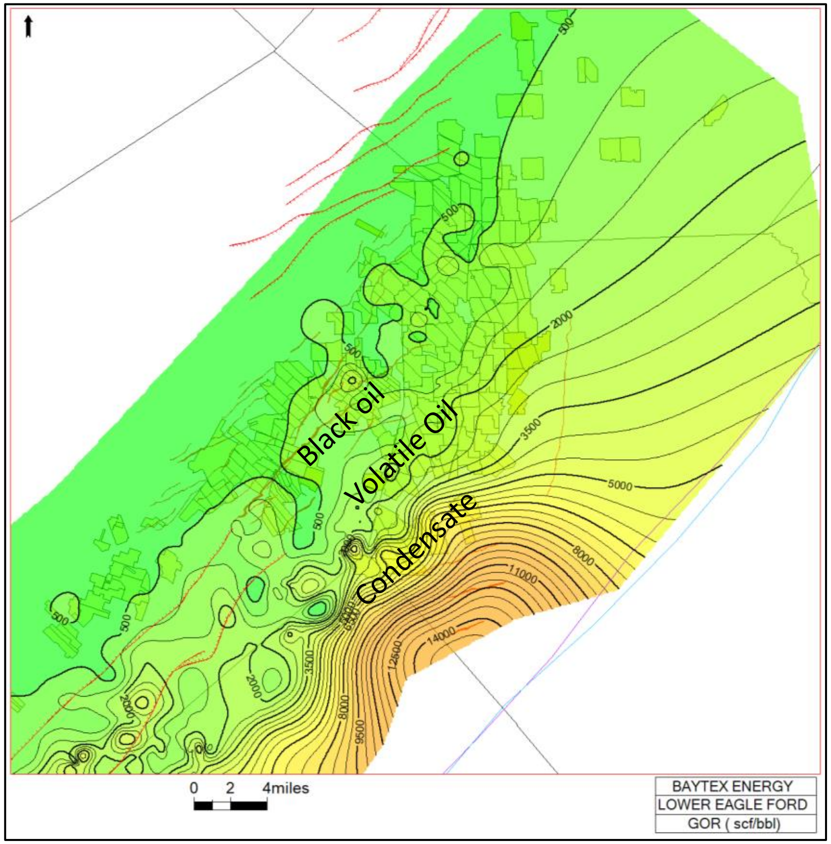
PRESSURE AND FLUID PHASE

- Pressure gradients & GOR dominantly controlled by depth
- Abnormally pressured reservoir with gradients from 4500-9500 psi (0.5-0.8 psi/ft) across acreage
- GOR ranges from 400 scf/bo in updip to ~9,000 in downdip. Sharp increase in southeast

Lower Eagle Ford Reservoir Pressure Map



Lower Eagle Ford GOR Map



Operations

WELL DESIGN EVOLUTION

Majority of online wells completed with older generation completions, which leaves abundant recoverable resource available for refrac program

Older generation wells utilize smaller, hybrid fluid designs with wider stage and cluster spacing

Modern Completions (2018+) utilize high-intensity slickwater design with tighter cluster and stage spacing

Under stimulation of wells in early years left large remaining resource in place

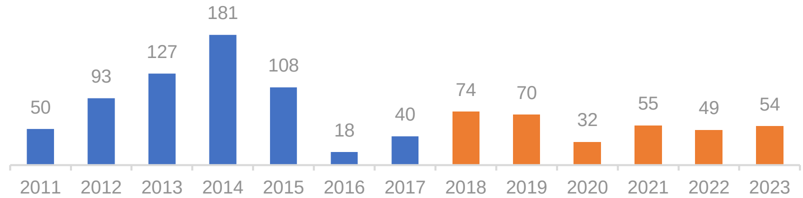
Exploited through Lower Eagle Ford redevelopment and refrac programs

Undeveloped Acreage Primary Development

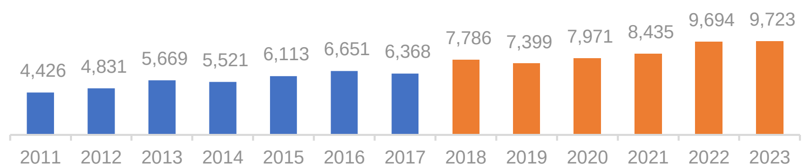
Primary Lower Eagle Ford development at varying spacing by fluid window

Secondary stacked Upper Eagle Ford play target in thickest Eagle Ford pay

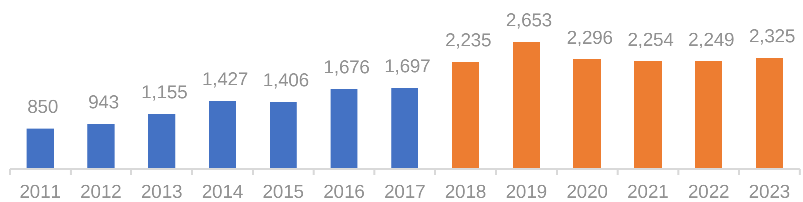
Gross Operated Wells Online



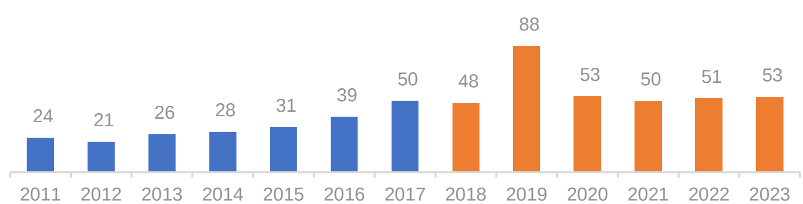
Lateral Length (ft)



Proppant Intensity (lbs/ft)



Fluid Intensity (bbl/ft)



DRILLING PERFORMANCE

H&P high spec rig fleet delivers top tier performance

Detailed engineering and offset analysis is done on every pad to minimize operational issues

H&P Rig 505 increased overall performance in 2023 by 12%, compared to 2022

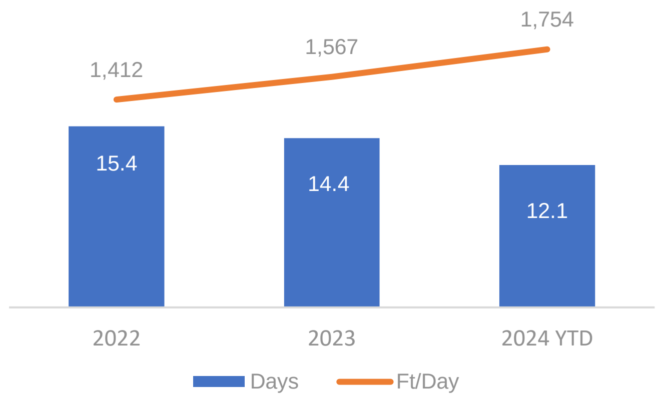
Top drilling performance in curve and lateral in LaSalle County

Leading performance in lateral section across all areas of operations for 2023

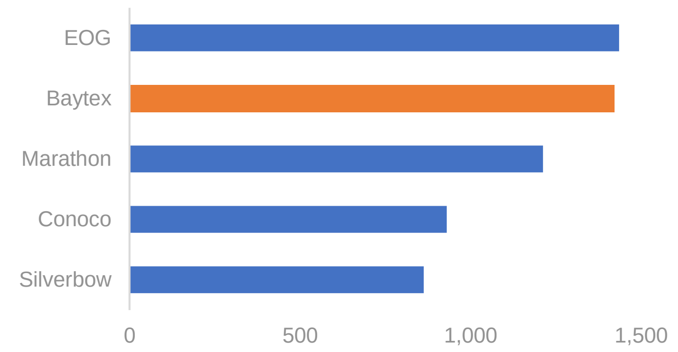
2-string designs are used in the shallower portions of the Lower Eagle Ford that require lower mud weight

3-string designs are utilized in the deeper areas of the Eagle Ford formation where pressure and mud weights require extra protection over the Wilcox formation

Drilling Performance (1)
(Spud to Rig Release)



Drilling Efficiency Cycle Time
(Spud to Rig Release, ft/day) (2)



(1) Includes both 2-string and 3-string wells.
(2) 3-string casing string design for wells drilled 2022 – Q3 2023, includes Gonzales, Lavaca and Dewitt counties. Source: TRRC and Enverus

COMPLETION PERFORMANCE

Utilizing the same Liberty frac fleet since late 2021

Q1 2024 Completion Performance:

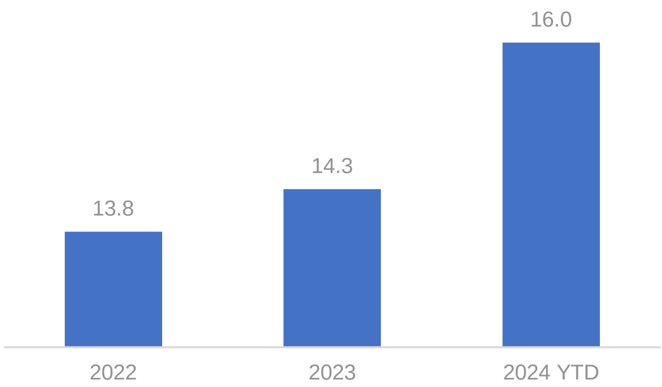
Record for total pumping hours in a 24-hour day achieved (22.3 hours)

Record for average pumping hours per day achieved (17.9 hours)

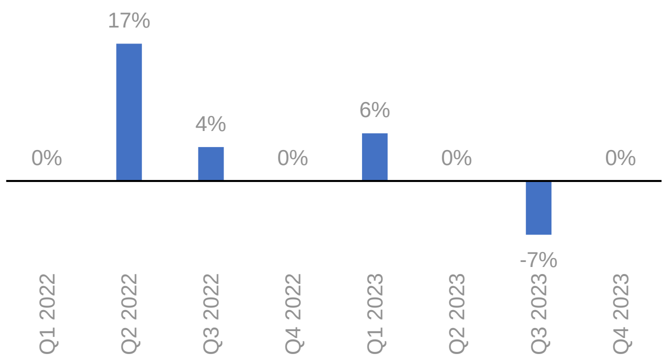
Baytex pumping hours per day performance is 11% higher than average of other Liberty fleets (6) in the Eagle Ford

- Performance metrics based on standard design of 2,250 lbs/ft proppant loading
- Consistent, modern completion designs utilized across asset base
  - High-rate injection with slickwater fluid system
  - Regional 100 mesh sand utilized
  - Limited entry perforating design

Completion Efficiency (Pumping Hours per Day)



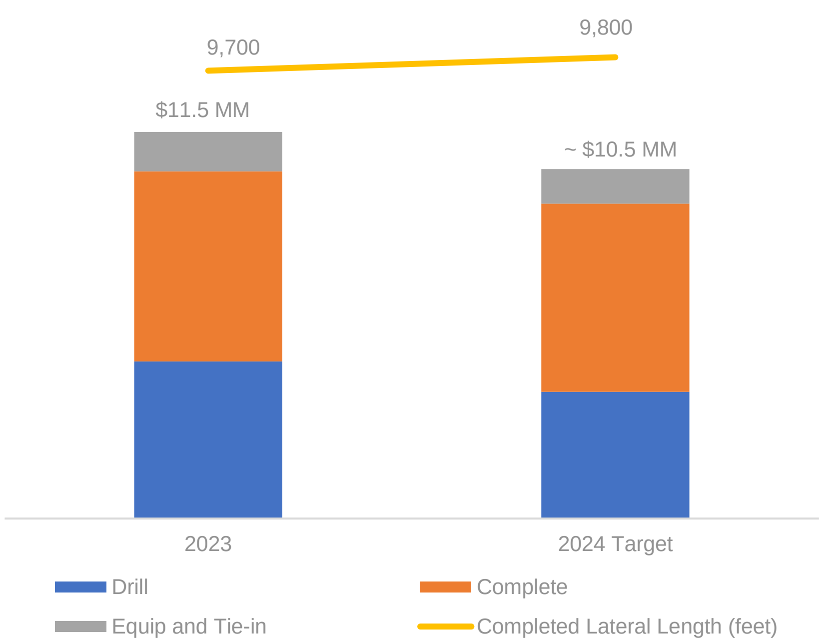
Stimulation Service Cost Trends (Quarter over Quarter Change)



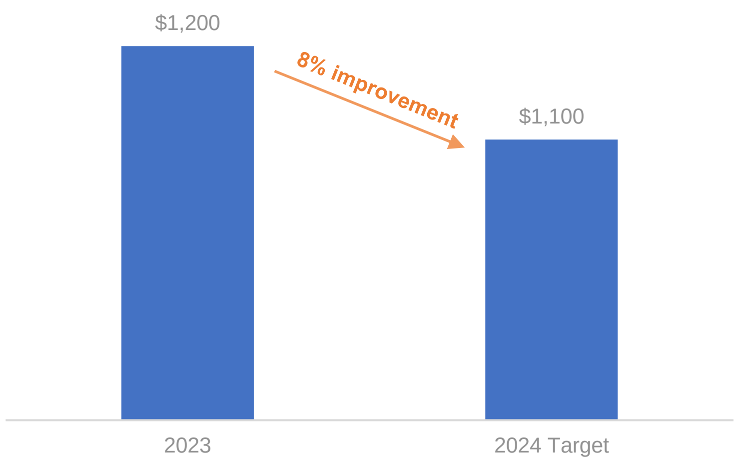
CAPITAL EFFICIENCY IMPROVEMENTS

Targeting an 8% improvement in our operated drilling and completion costs per completed lateral foot over 2023

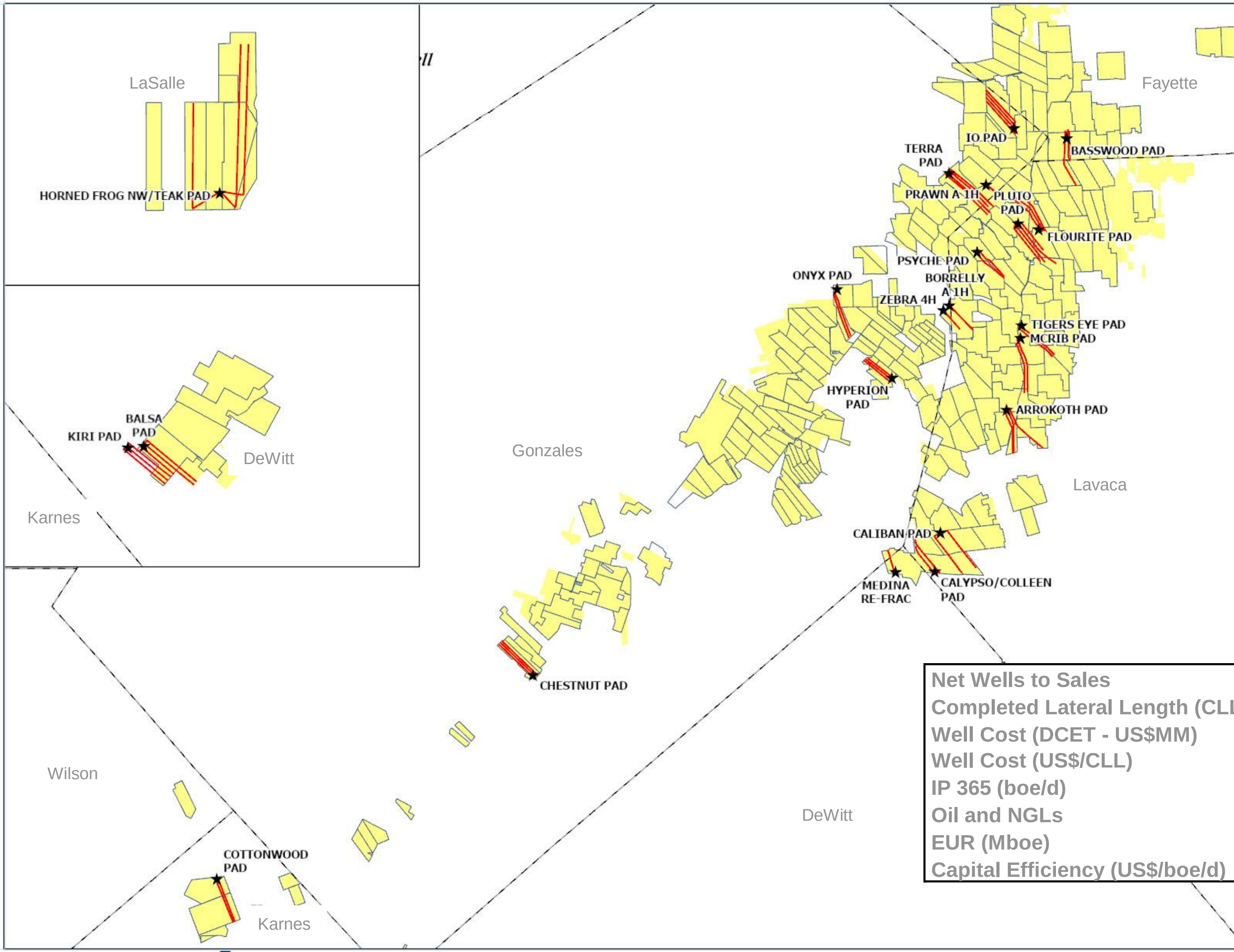
Average Well Cost (Operated) (US$ millions)



Average Well Cost (Operated) (US$ per completed lateral length)



2024 OPERATED ACTIVITY

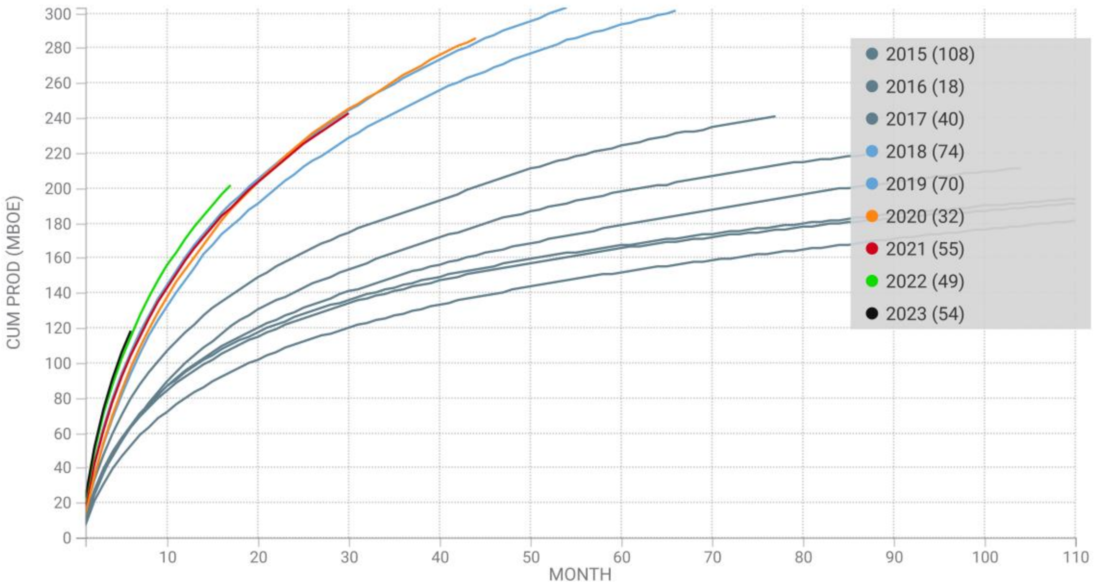


Net Wells to Sales	49
Completed Lateral Length (CLL)	9,800’
Well Cost (DCET - US$MM)	$10.5
Well Cost (US$/CLL)	$1,100
IP 365 (boe/d)	640
Oil and NGLs	85%
EUR (Mboe)	750
Capital Efficiency (US$/boe/d)	$16,000

STRONG WELL PERFORMANCE

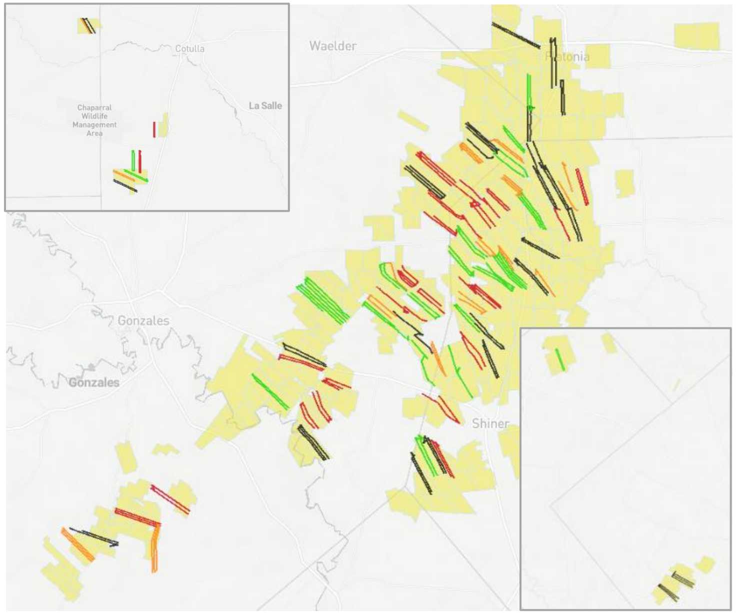
- Well performance continues to increase year-over-year
  - Identifying and executing on best locations
  - Maximizing completable lateral length
  - Deploying advanced modern completions
- Advancements in completions design evidenced by dramatic step change in performance post-2017

Well Performance Over Time – 2 Phase (Mboe)



Source: Enverus

Development by Vintage (Years 2020+)

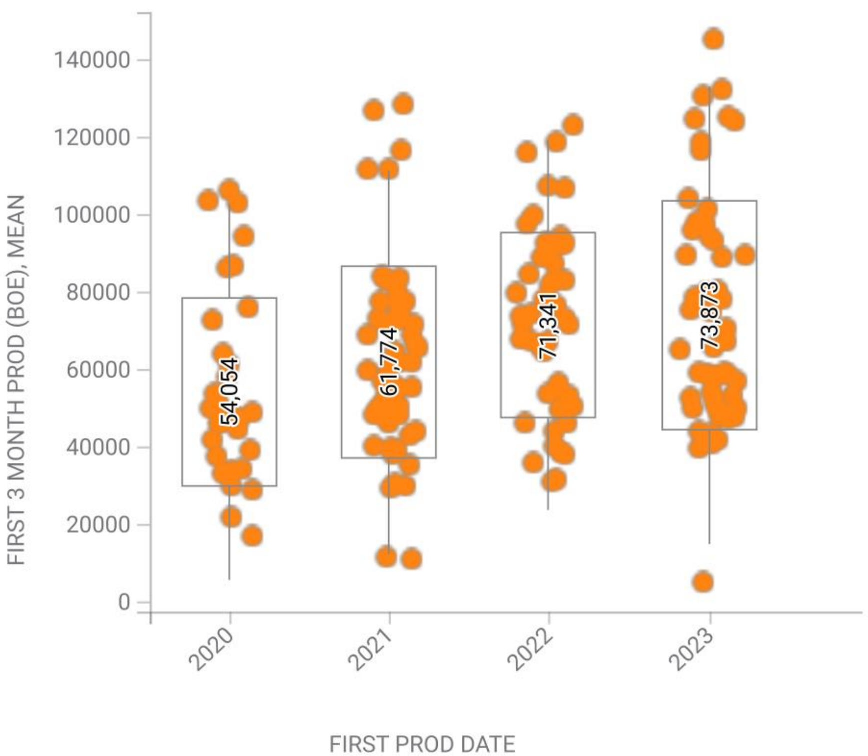


Source: Enverus

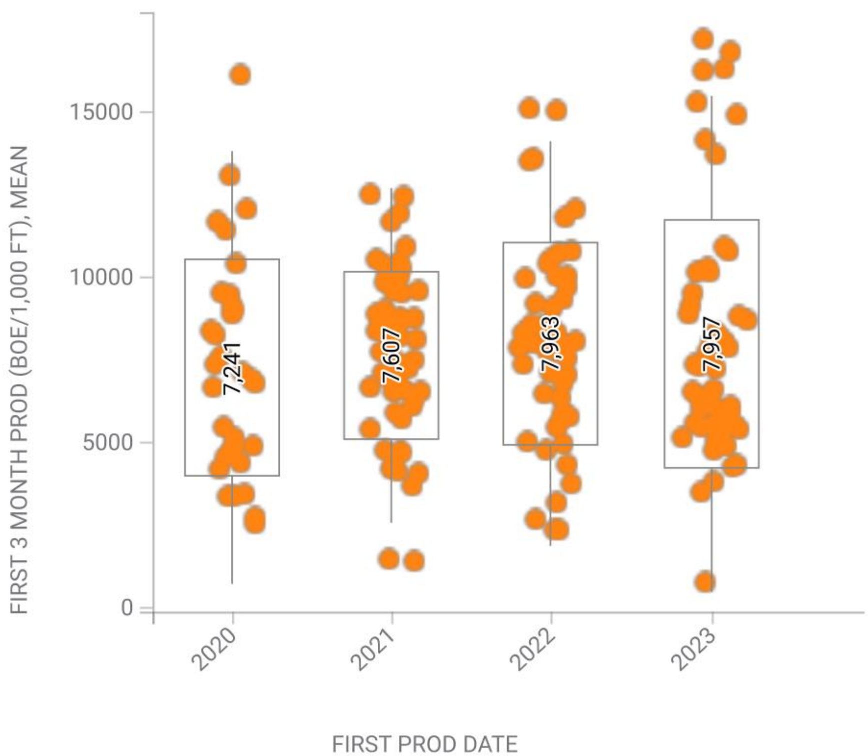
STRONG WELL PERFORMANCE

- Absolute well performance continues to increase year-over-year
- Normalized well performance consistent through time

Absolute Well Performance – 2 Phase (boe)



Normalized Well Performance – 2 Phase (boe)



Source: Enverus

TOP QUARTILE PERFORMANCE IN H2/2023

22 operated wells onstream

Strong results across thermal maturity window
black & volatile oil and condensate

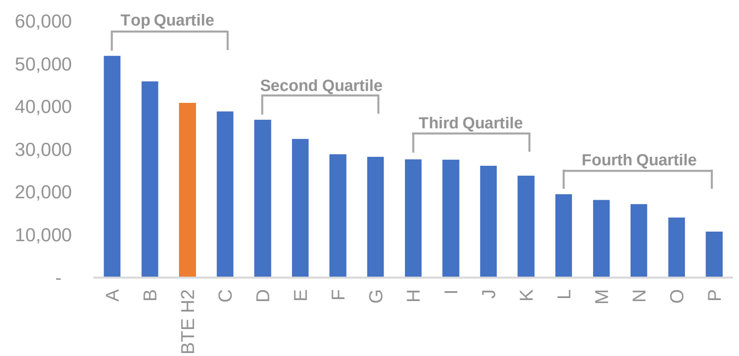
Top quartile performance
30-day peak production rate

Second quartile performance
productivity per lateral foot

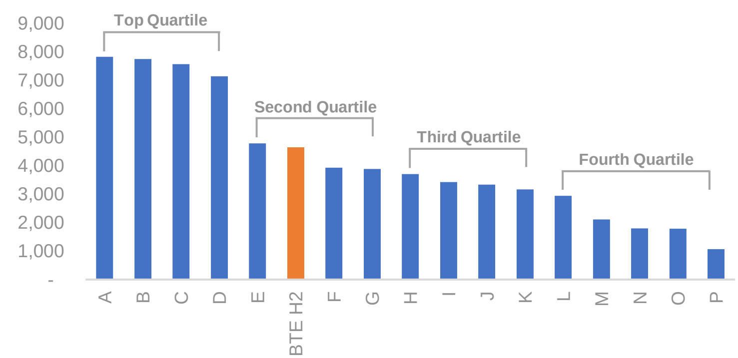
H2 2023 Wells Onstream

Well	Wells Onstream	30-day Peak Rate (boe/d)	% Crude Oil and NGLs
Q3 2023	13	1,500	78%
Q4 2023	9	1,600	80%
Average	**22**	**1,540**	**79%**

30-Day Peak Production by Eagle Ford Operator – 2023 Wells
(2 Phase boe) (1)(2)(3)



30-Day Peak Production by Eagle Ford Operator – 2023 Wells
(2-Phase boe/thousand foot) (1)(2)(3)



(1) Data set (total of 1,008 wells) includes: Arrow S, ConocoPhillips, Crescent, Devon, EOG, Exco, Exxon, Gulftex, Ineos, Magnolia, Marathon, Murphy, Silverbow, Trinity, Verdun, Wildfire.
(2) Peak production (boe and boe per thousand foot of lateral length) calculated based on the highest monthly production rate over the life of the well.
(3) Source: Enverus, Baytex internal data.

UPPER EAGLE FORD DEVELOPMENT

Upper Eagle Ford development horizon in high-graded areas
2024 program: ~4 net wells

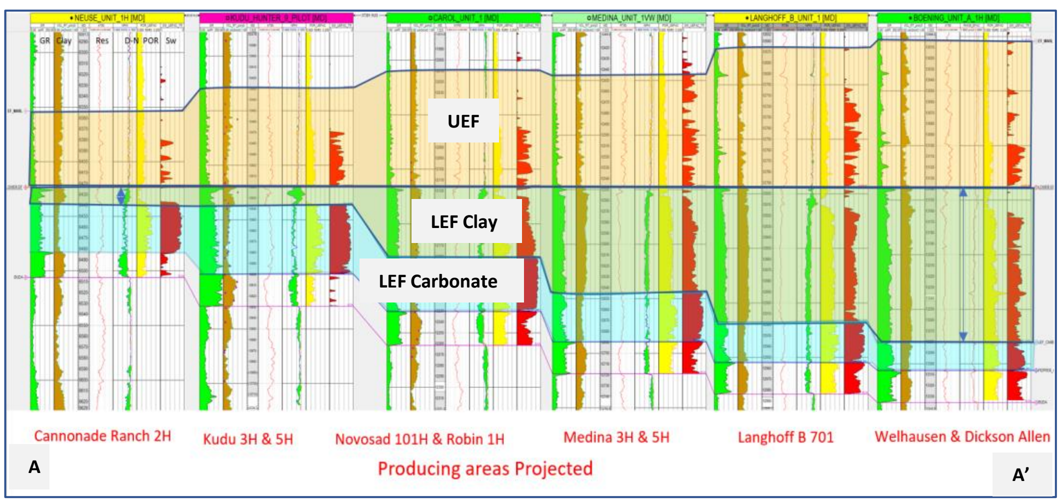
Dual Lower-Upper EF play in east due to thickness increase and clay-rich barrier in Lower EF

Thicker clay member in downdip provides baffle between LEF and UEF providing two development units

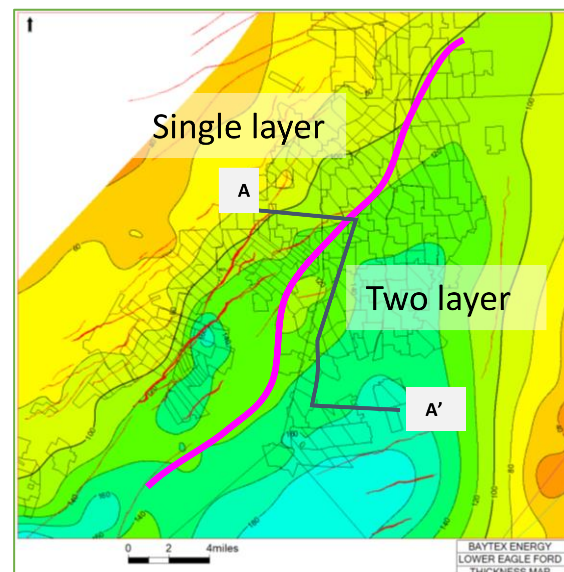
UEF play has been proven historically with over 40 operated wells utilizing hybrid completions and more recently with ~9 modern wells offsetting BTE acreage by EOG and MRO

Focused on optimizing full development spacing/stacking and well productivity

Reservoir Cross Section



Eagle Ford Thickness Map



EAGLE FORD REFRACS

Significant opportunity for refracs and improved recoveries given understimulated early development

> 300 refracs completed basin wide in the Eagle Ford to-date

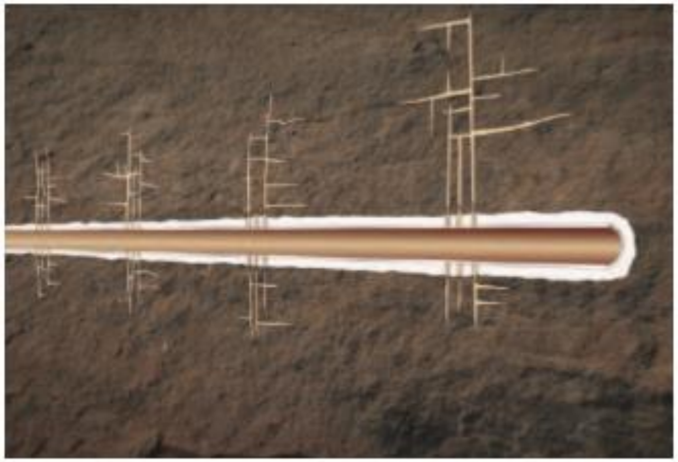
~85% in similar reservoir in Karnes, DeWitt, and Lavaca counties

Devon, Conoco and Marathon most active

Consistent improvement in production and EUR

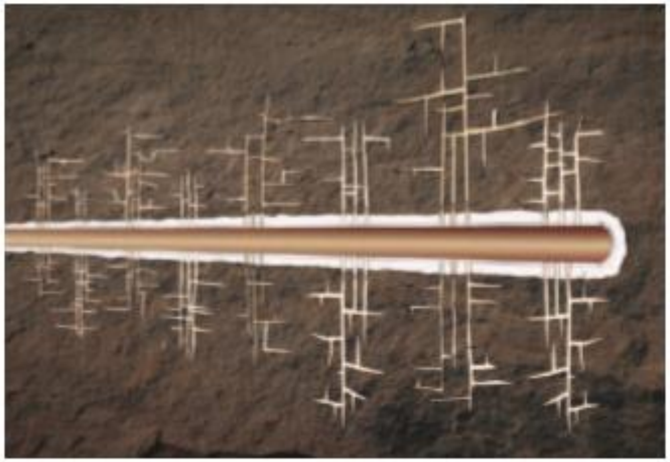
Legacy Development

- Pre-2017 drills
- Wide cluster spacing and low proppant intensity
- Lower cumulative production and resource recovery



Re-Frac Opportunity

- Utilize 5.5” casing with cemented 4” liners
- Deploy modern completion design with “new” wellbore
- Target black oil and volatile oil



Source: Halliburton

MEDINA 2024 REFRAC

Baytex completed its first refrac in 2024
Medina well expected to generate > 100% IRR

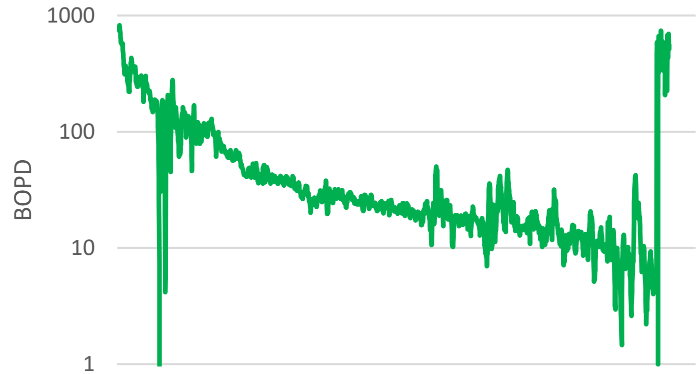
2024 Medina Refrac	2014 Original Completion
On-Line Date: February 2024	On-Line Date: November 2014
4" liner; CLL = 4,880'	5.5" casing
Slickwater: 2,250 ppf | 51 bbls fluid/ft	Cross Link 1,500 ppf | 30 bbls fluid/ft
US$4.5 million	IP90 ~ 788 boe/d
Peak IP30 ~ 671 boe/d, 78% pct oil	Cum production to-date ~ 141 Mboe

~ 300 refrac opportunities have been identified

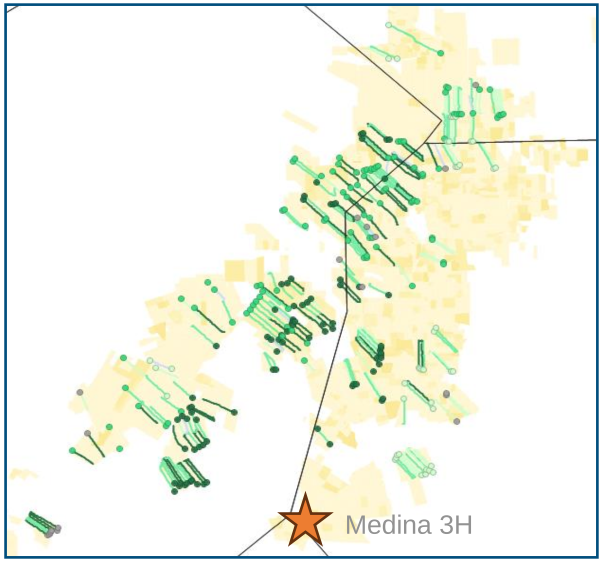
Refrac opportunities for 2024/2025 currently being identified

Potential supplement to new well completions

Medina Production Performance

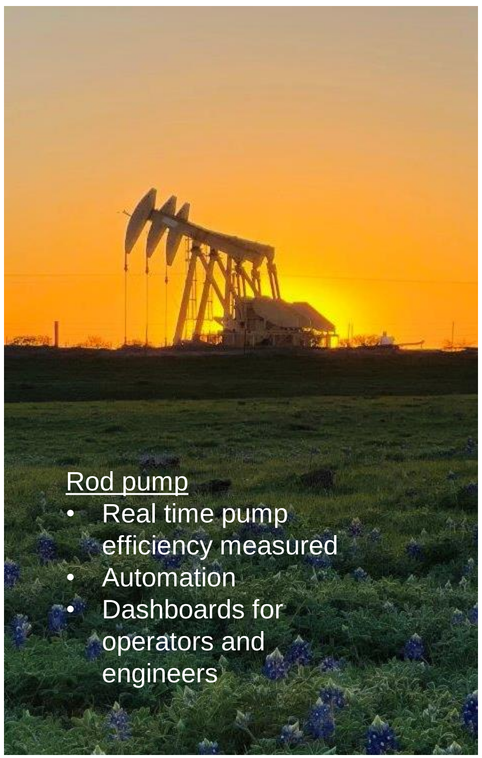


Inventory Map

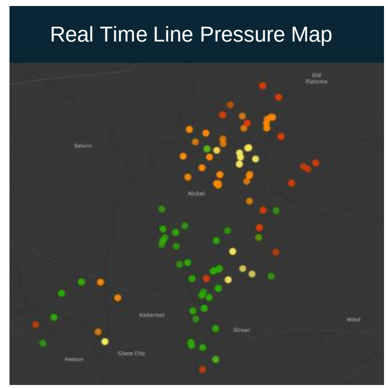


BASE PRODUCTION OPTIMIZATION – FOCUSSED ON DECLINES

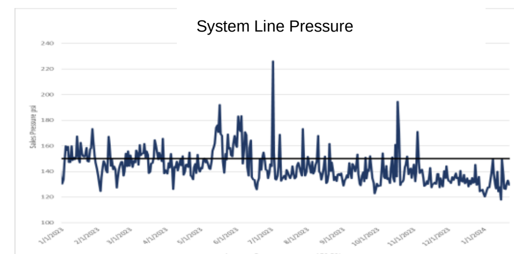
Lowering gas line pressure: adding compression, line looping, equipment runtime
Artificial lift optimization: primary lift methods are gas lift, rod pump and jet pump
Workovers: downhole repairs, lateral clean outs
Data automation: putting real time data in hands of decision makers, engineers and operators



Managing Gas Sales Pressure



Contributes to capital planning
Address isolated issues immediately



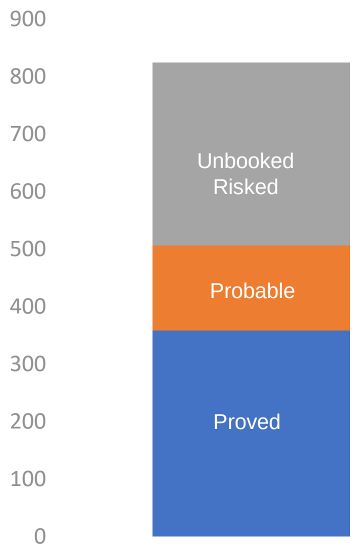
Central Compression February 2024

Lowered line pressure
Reduced expenses by releasing multiple smaller units

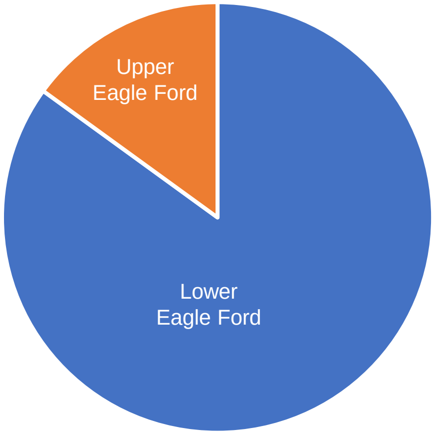
DEVELOPMENT INVENTORY AND ECONOMICS

> 800 net drilling locations and 12 to 15 years of development

Net Drilling Locations(1)



Net Drilling Locations by Zone(1)



Individual Well Economics(1)(2)

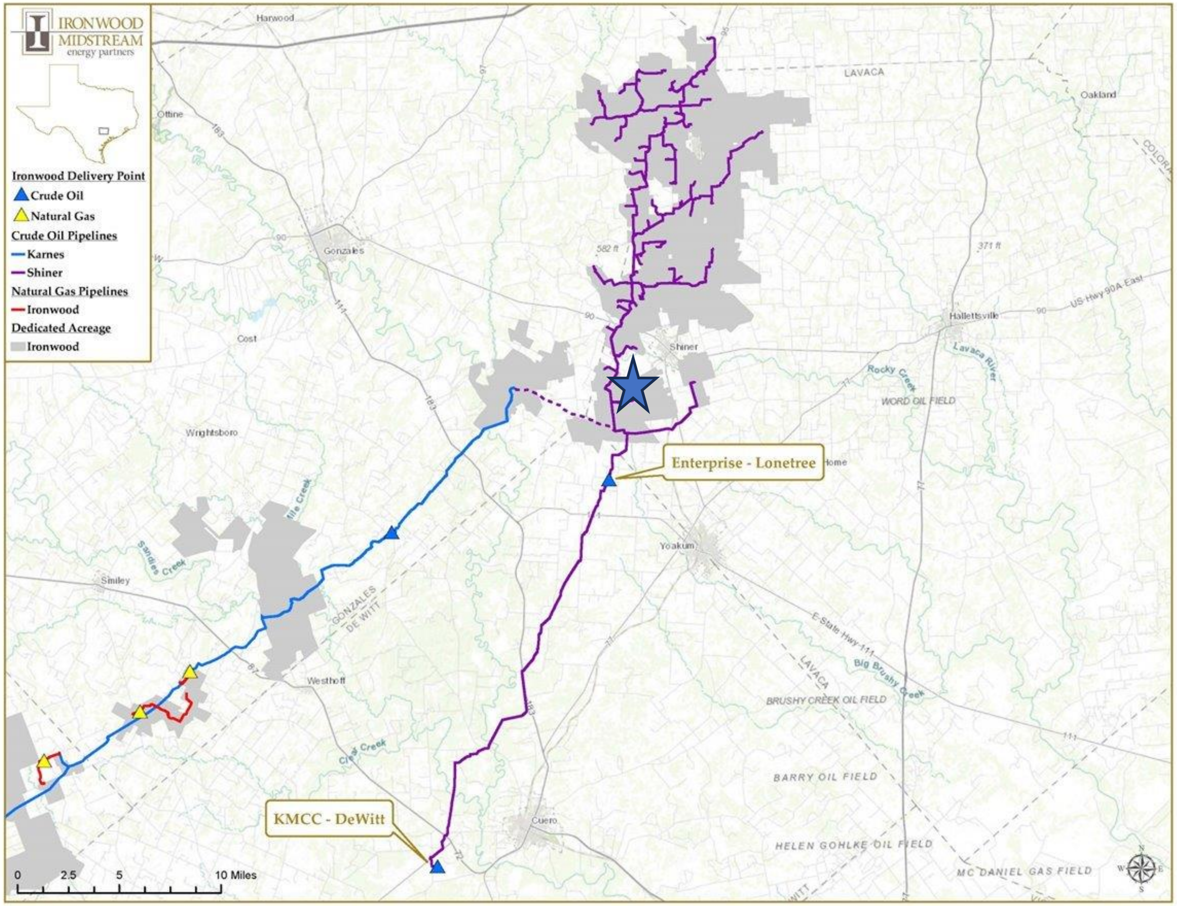
IP365	600 boe/d
EUR	680 Mboe
% Oil and NGLs	82%
Well Cost (DCET)	US$8.5 million
Average Lateral Length	~ 7,800 feet
Payout (months)	16 months
IRR (%)	74%

(1) Includes operated and non-operated acreage
(2) Individual well economics based on constant pricing and Baytex's internal assumptions using an average type curve for wells that are expected to be developed in the five-year outlook (representing 45% of our inventory of booked and un-booked risked locations). Commodity price assumptions: WTI – US$75/bbl; NYMEX gas – US$3.50 MMbtu.

Gulf Coast Market Access and Pricing

IRONWOOD SYSTEM MAP

Ironwood partnership provides strategic blending, storage, batch sales and barrel differentiation

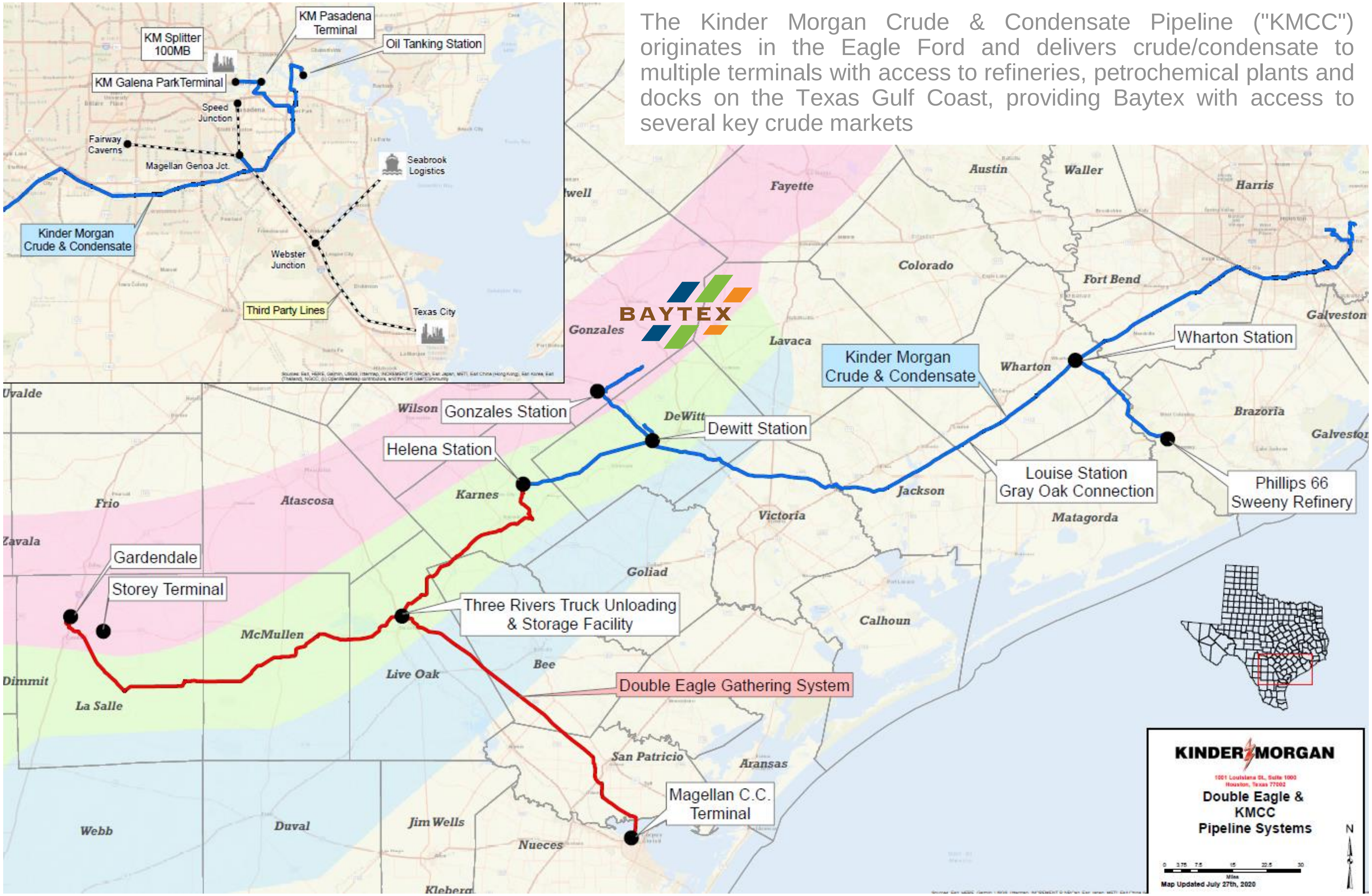


~ 67% of BTE operated barrels flow through the Ironwood facility

80% arrive via pipeline, 20% via truck

STRONG MARKET ACCESS

The Kinder Morgan Crude & Condensate Pipeline ("KMCC") originates in the Eagle Ford and delivers crude/condensate to multiple terminals with access to refineries, petrochemical plants and docks on the Texas Gulf Coast, providing Baytex with access to several key crude markets



PREMIUM PRICE REALIZATIONS

Light oil and condensate
~ 60% of production

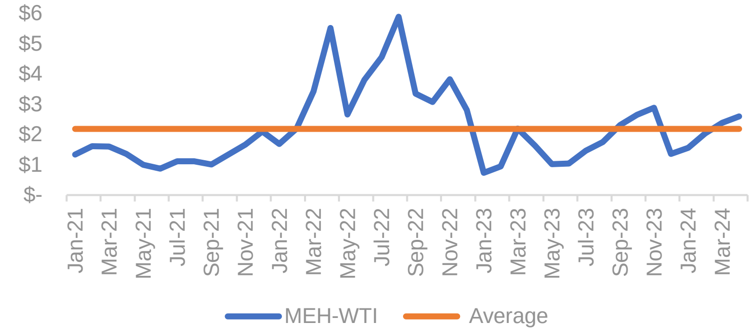
Baytex crude quality ~ 45° API (range 38 to 54°)

Light oil steam priced in reference to the Magellan East (“MEH”) benchmark at Houston, Texas

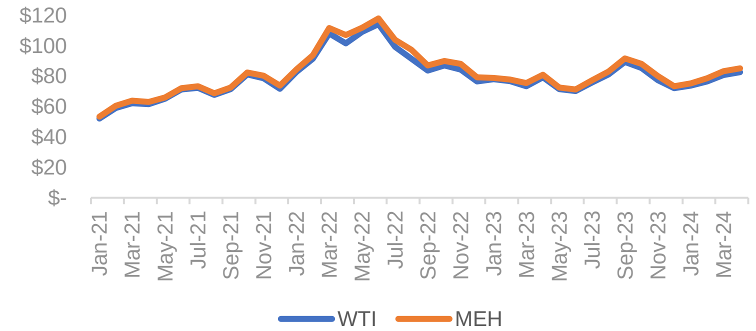
MEH typically trades greater than US$2/bbl premium to WTI

Baytex price realization MEH less ~US$3/bbl

MEH – WTI Differential (US$/bbl)



Historical MEH and WTI Benchmark Prices (US$/bbl)



Wrap-Up

FIVE-YEAR OUTLOOK (2024 – 2028) at US$70/bbl WTI

Sustainable plan(1) delivers significant value

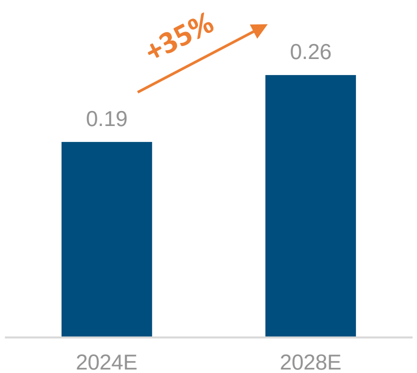
1-4% annual production growth
Underpinned by strong drilling economics and > 10 years drilling inventory

~ 60% annual reinvestment rate(3)
Annual E&D expenditures of $1.2 to $1.4 billion drives meaningful free cash flow(4)

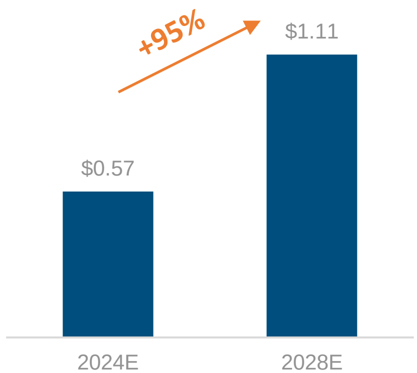
Balance sheet strength
Total debt(2) declines 55% to ~ $1 billion

Enhancing shareholder returns
Share buybacks and dividend

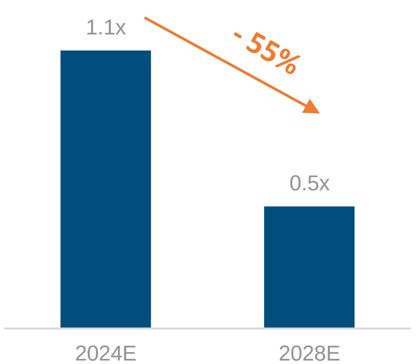
Production (boe/d per thousand shares)



Free Cash Flow per Share(4)



Total debt to EBITDA(2)



(1) Five-year outlook based on US$70/bbl WTI and the following pricing assumptions: WCS differential – US$15/bbl in 2024, US$12/bbl in 2025-2028; NYMEX gas – US$3.50/MMbtu in 2024, US$3.75/MMbtu in 2025-2028; 1.35 exchange rate (CAD/USD).
(2) Total debt and EBITDA are calculated in accordance with the amended credit facilities agreement which is available on the SEDAR+ website at www.sedarplus.com
(3) Reinvestment rate is a supplementary financial measure calculated as exploration and development expenditures expressed as a percentage of EBITDA for the applicable period.
(4) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this presentation for further information.

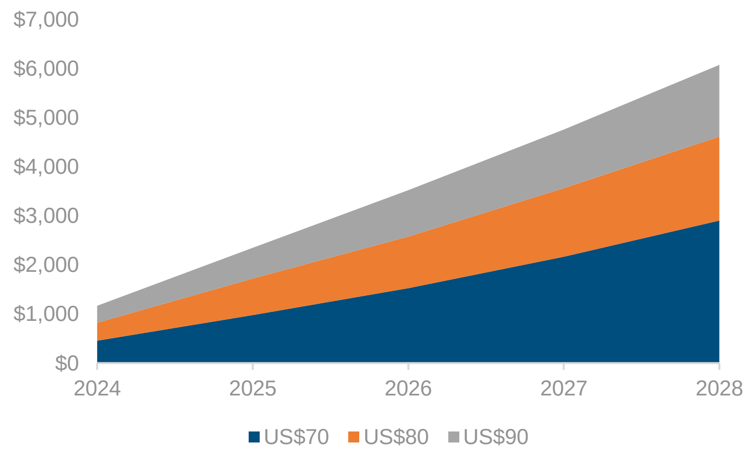
FIVE-YEAR OUTLOOK: 2024 - 2028

Shareholder Returns(1)

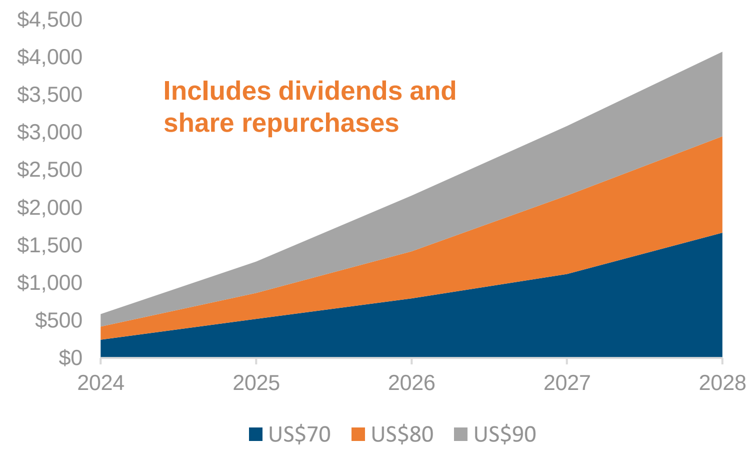
Compelling Returns Profile

Underpinned by disciplined reinvestment and capital allocation

Free Cash Flow(1)(2) over Five-Year Outlook ($ millions)



Return of Capital(2) over Five-Year Outlook(1) ($ millions)



(1) Five-year outlook at each WTI assumption (US$/bbl) and the following pricing assumptions: WCS differential – US$15/bbl in 2024, US$12/bbl in 2025-2028; NYMEX gas – US$3.50/MMbtu in 2024, US$3.75/MMbtu in 2025-2028; and 1.35 exchange rate (CAD/USD).

(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this presentation for further information.

Focus on Operational Excellence to Deliver Long-Term Value and Enhanced Shareholder Returns

Disciplined Reinvestment and Capital Allocation	High-quality and diversified oil portfolio with more than 10 years of drilling inventory Track record of new discoveries Targeting modest single-digit organic growth with ~ 60% reinvestment rate(1)
Strong Free Cash Flow Generation	50% of free cash flow(2) to direct shareholder returns through share buybacks and a quarterly dividend 50% of free cash flow to further strengthen balance sheet
Maintain Financial Strength	Commitment to a strong balance sheet Total debt(3) target of $1.5 billion Disciplined hedging program to help mitigate revenue volatility due to commodity prices

(1) Reinvestment rate is a supplementary financial measure calculated as exploration and development expenditures expressed as a percentage of EBITDA for the applicable period.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this presentation for further information..
(3) Total debt and EBITDA are calculated in accordance with the amended credit facilities agreement which is available on the SEDAR+ website at www.sedarplus.com

Appendix

COMMITTED TO SAFETY AND ESG LEADERSHIP

Operational Best Practices

Leading indicators

Focused on being proactive

- Daily Job Site Analysis (JSAs)
- Hazard identification and tracking
- Vendor safety compliance audits

Continual Improvement

- Incident investigation and communication
- Training for the job and to equip our employees to be a part of the safety team.

Minimizing Flaring and Emissions

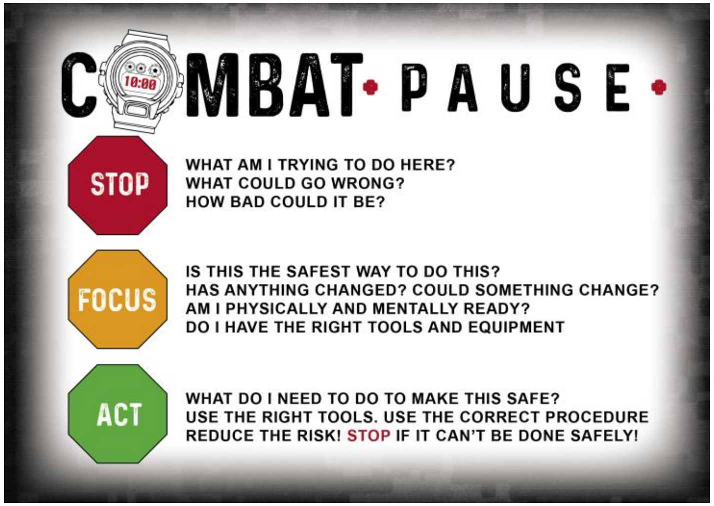
- Reduce flaring by connecting wells to pipelines prior to production
- Transport majority of oil via pipeline, reducing vehicle emissions and risk of spills

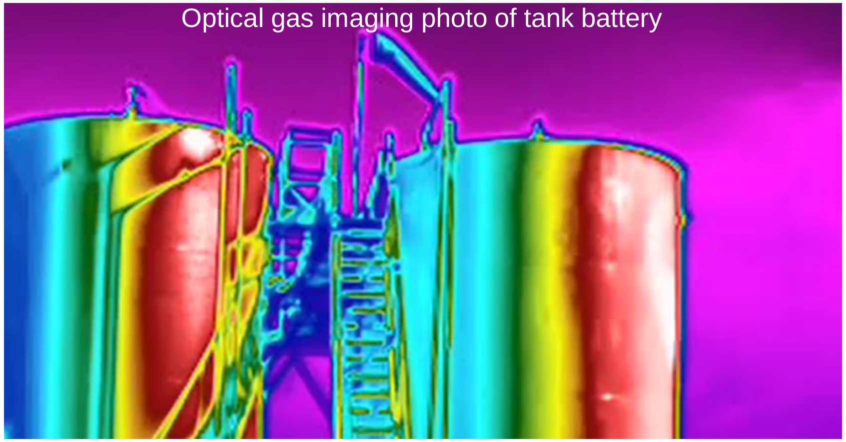
Development Techniques and Well Design

- Multi-well pads and longer laterals reduce environmental footprint

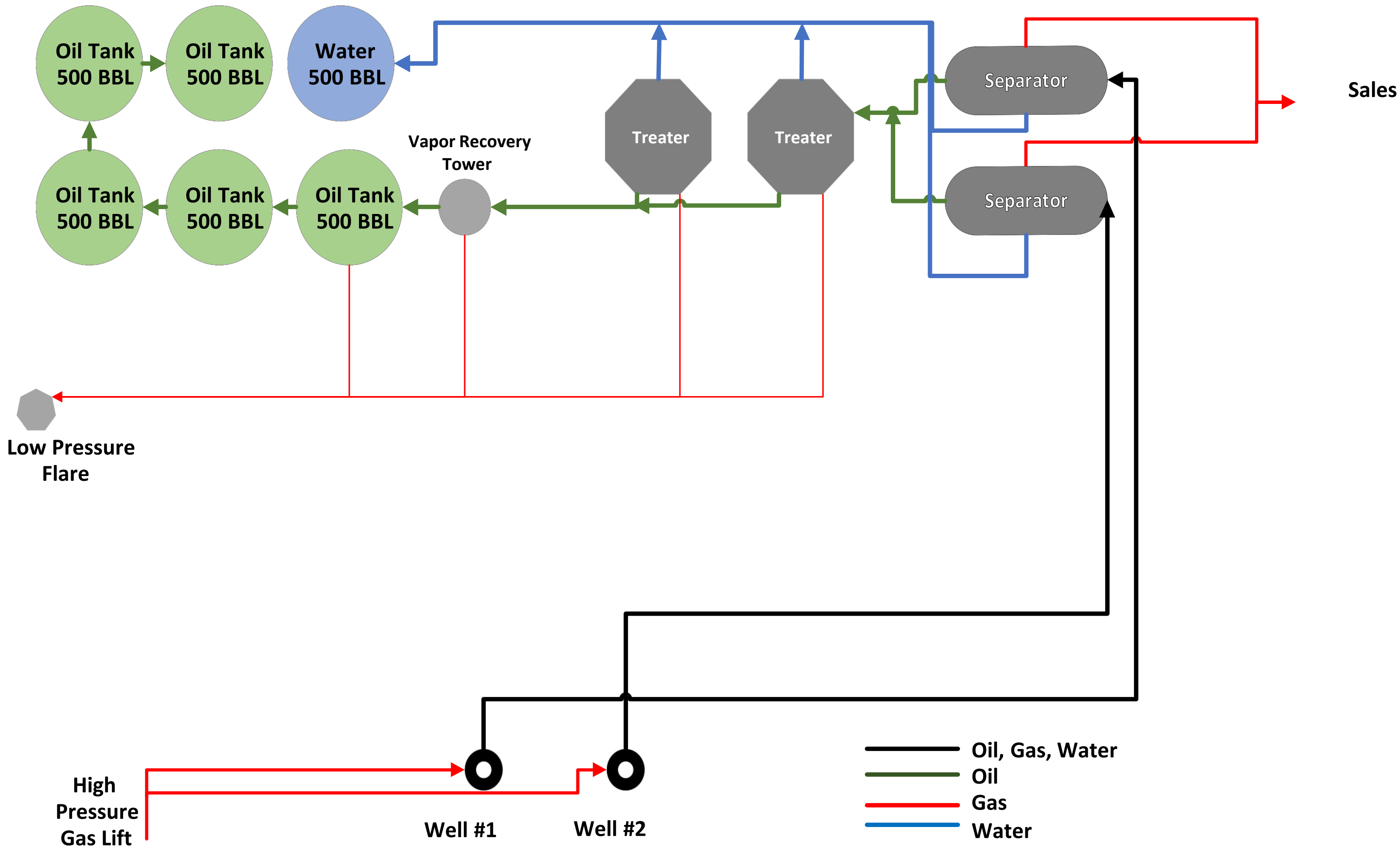
Leak Detection and Prevention

- Daily visual inspections of well pads.
- Optical gas imaging cameras scan production facilities to detect fugitive emissions





STANDARD GAS LIFT PRODUCTION PAD FACILITY



HISTORY AND TRANSFORMATION OF ASSET BASE

Corporate Highlights

September 2016
Company exits bankruptcy

2019 – 2020
New Corporate Officers Appointed

January 2021
Juniper Capital provides investment and becomes majority owner

October 2021
Rebranded to Ranger Oil

June 2023
Baytex acquires Ranger Oil through merger

Asset Base Transformation

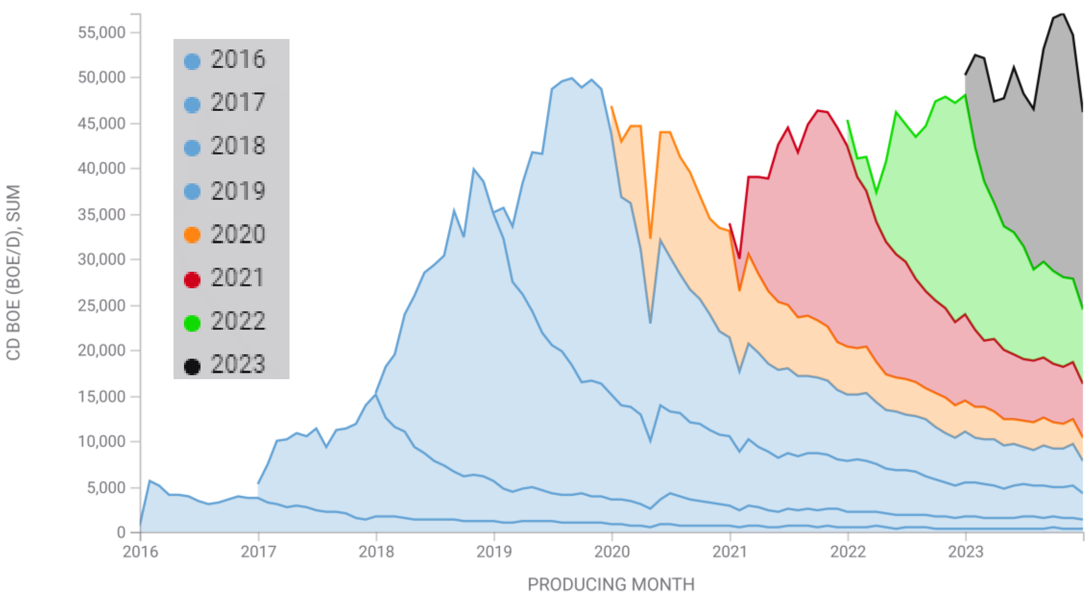
2017-2018
Acquisitions add ~ 29,300 net acres

January 2021
Acquisition adds ~ 4,000 net acres

October 2021
Lonestar Resources merger adds ~ 53,000 net

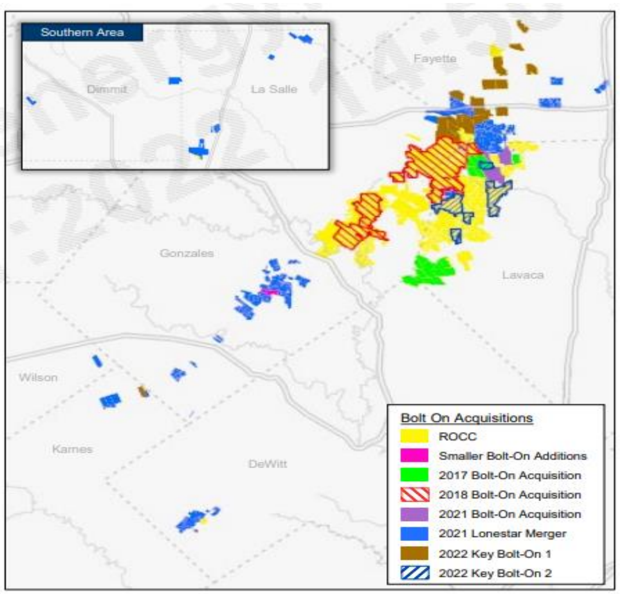
2022 - 2023
Various bolt on acquisitions total ~ 20,000 net acres

Production Profile – 2 Phase (boe)

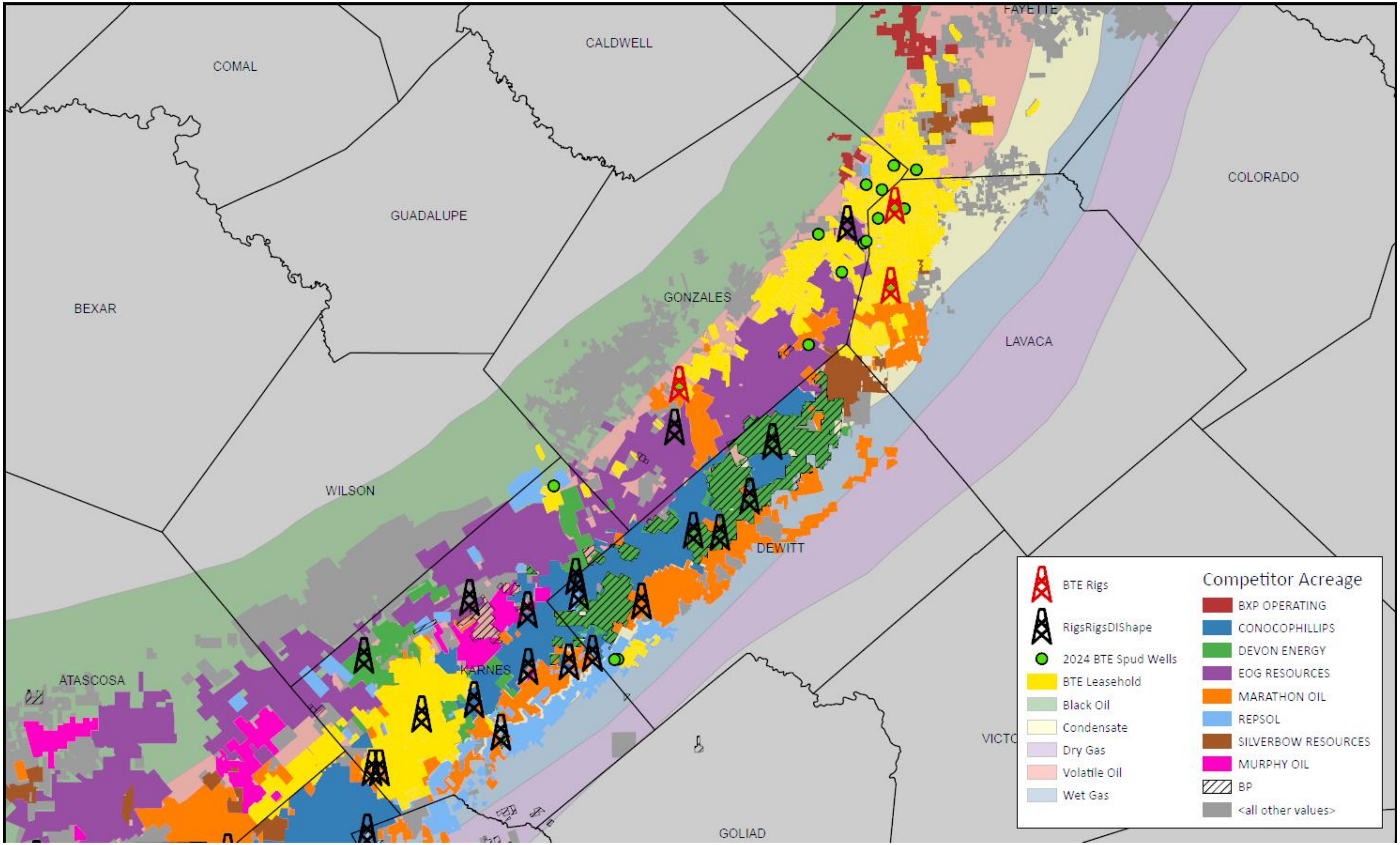


Source: Enverus

Land Acquisitions



REGIONAL ACTIVITY BY TOP OPERATORS



U.S. BUSINESS UNIT – OPERATING AND FINANCIAL RESULTS

	Q1 2023	Q2 2023	Q3 2023	Q4 2023	2023
Benchmark Prices					
WTI crude oil (US$/bbl)	$76.13	$73.78	$82.26	$78.32	**$77.62**
NYMEX natural gas (US$/MMbtu)	$3.42	$2.10	$2.55	$2.88	**$2.74**
Production					
Light oil and condensate (bbl/d)	15,280	20,710	58,122	55,981	**37,691**
Natural gas liquids (bbl/d)	5,338	7,186	15,902	20,223	**12,214**
Natural gas (Mcf/d)	32,946	35,946	79,722	116,548	**66,556**
Oil equivalent (boe/d) (1)	26,109	33,887	87,311	95,629	**60,997**
% Liquids	79%	82%	85%	80%	**82%**
Average Realized Sales Prices					
Light oil and condensate ($/bbl)	$103.27	$97.55	$109.09	$105.83	**$105.71**
Natural gas liquids ($/bbl)	$32.83	$25.07	$28.04	$26.68	**$27.55**
Natural gas ($/Mcf)	$4.02	$2.52	$3.20	$3.07	**$3.15**
Operating Netback ($/boe)					
Total sales, net of blending and other expenses (2)	$72.22	$67.60	$80.64	$71.34	**$74.27**
Royalties (3)	(21.02)	(19.66)	(21.89)	(19.42)	**(20.51)**
Operating expense (3)	(9.03)	(9.11)	(10.09)	(8.17)	**(9.08)**
Transportation expense (3)	(0.00)	(0.43)	(1.48)	(1.33)	**(1.12)**
Operating Netback (2)	$42.17	$38.40	$47.18	$42.42	**$43.56**

(1) Barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. The use of boe amounts may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this presentation for further information.

(3) Supplementary financial measure calculated as royalties, operating or transportation expenses divided by barrels of oil equivalent production volume for the applicable period.

Advisories

FORWARD LOOKING STATEMENTS ADVISORY

In the interest of providing the shareholders of Baytex and potential investors with information regarding Baytex, including management's assessment of future plans and operations, certain statements in this presentation are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). In some cases, forward-looking statements can be identified by terminology such as "anticipate", "believe", "continue", "could", "estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this presentation peak only as of the date hereof and are expressly qualified by this cautionary statement.

Specifically, this presentation contains forward-looking statements relating to but not limited to: expectations for 2024 as to Baytex's production on a boe/d basis, percentage of production that will be liquids, exploration and development expenditures and our expected production by area and commodity; that we have more than 10 years of drilling inventory; our target of modest single digit organic production growth and expected reinvestment rate; the allocation of free cash flow, including with respect to debt repayment, share buybacks and dividends; our total debt target; that the Ranger assets have 12-15 years of sustaining development with attractive well economics; for 2024 our expected: production, percentage of production that will be liquids, the number of net wells onstream, exploration and development expenditures, 2024 priorities, capital efficiency, production growth and number of stratigraphic test wells; expectations regarding the quarterly dividend and our expected free cash flow at specified prices for WTI; with respect to our five-year outlook, the expected: production growth, decrease in total debt, reinvestment rate, increase in production per share and free cash flow per share, decrease in total debt to EBITDA, free cash flow at specified prices for WTI, share buybacks and dividends at specified prices for WTI; the expected individual well CROCI, payout and IRR for expected type wells in the Eagle Ford, Duvernay, Viking, Clearwater and Heavy Oil assets; our hedging plans, including our target to hedge 40% of net crude volumes, that we intend to utilize wide 2-way collars to ensure a modest return on our highest breakeven assets and the percentage of our expected production that is hedged until the end of 2024; that we are committed to a strong balance sheet and that $1.5 billion total debt represents ~0.7x total debt to EBITDA at US$70 WTI; the sensitivity of our annual adjusted funds flow to changes in WTI prices, WCS, NYMEX natural gas prices and the Canada-United States foreign exchange rate; for 2024 the expected production rate, percentage of production that will be liquids and percentage contribution to asset level free cash flow for our business units; the expected number of net wells to sales for our assets in 2024; that we have 90 section prospective for Clearwater development at Peavine and ~100 sections prospective for Mannville development in NE Alberta; our values, visions and approach to ESG; that we are committed to corporate sustainability; the components of our GHG emissions reduction strategy; and our ESG targets: reducing our GHG emissions intensity by 65% by 2025 from our 2018 baseline, reducing our 2020 end of life well inventory of 4,500 wells to zero by 2040; our free cash flow allocation policy; and our 2024 guidance, including: our expected exploration and development expenditures, production, average royalty rate, expenses (operating, transportation, general and administrative, interest costs and current income taxes), leasing expenditures and asset retirement obligations. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that they can be profitably produced in the future.

FORWARD LOOKING STATEMENTS ADVISORY (CONT.)

These forward-looking statements are based on certain key assumptions regarding, among other things: petroleum and natural gas prices and differentials between light, medium and heavy oil prices; well production rates and reserve volumes; success obtained in drilling new wells; our ability to add production and reserves through our exploration and development activities; that our core assets have more than 10 years development inventory at the current pace of development; capital expenditure levels; operating costs; our ability to borrow under our credit agreements; the receipt, in a timely manner, of regulatory and other required approvals for our operating activities; the availability and cost of labour and other industry services, including operating and transportation costs; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our hedging program; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; timing and amount of capital expenditures; our future costs of operations are as anticipated; the timing of drilling and completion of wells is as anticipated; that we will have sufficient cash flow, debt or equity sources or other financial resources required to fund our capital and operating expenditures and requirements as needed; that our conduct and results of operations will be consistent with our expectations; that we will have sufficient financial resources in the future to allocate to shareholder returns; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the risk of an extended period of low oil and natural gas prices; risks associated with our ability to develop our properties and add reserves; that we may not achieve the expected benefits of acquisitions and we may sell assets below their carrying value; the availability and cost of capital or borrowing; restrictions or costs imposed by climate change initiatives and the physical risks of climate change; the impact of an energy transition on demand for petroleum productions; availability and cost of gathering, processing and pipeline systems; retaining or replacing our leadership and key personnel; changes in income tax or other laws or government incentive programs; risks associated with large projects; risks associated with higher a higher concentration of activity and tighter drilling spacing; costs to develop and operate our properties; risks associated with achieving our total debt target, production guidance, exploration and development expenditures guidance; the amount of free cash flow we expect to generate; risk that the board of directors determines to allocate capital other than as set forth herein; current or future controls, legislation or regulations; restrictions on or access to water or other fluids; public perception and its influence on the regulatory regime; new regulations on hydraulic fracturing; regulations regarding the disposal of fluids; risks associated with our hedging activities; variations in interest rates and foreign exchange rates; uncertainties associated with estimating oil and natural gas reserves; our inability to fully insure against all risks; risks associated with a third-party operating our Eagle Ford properties; additional risks associated with our thermal heavy crude oil projects; our ability to compete with other organizations in the oil and gas industry; risk that we do not achieve our GHG emissions intensity reduction target; risks associated with our use of information technology systems; adverse results of litigation; that our Credit Facilities may not provide sufficient liquidity or may not be renewed; failure to comply with the covenants in our debt agreements; risks associated with expansion into new activities; the impact of Indigenous claims; risks of counterparty default; impact of geopolitical risk and conflicts; loss of foreign private issuer status; conflicts of interest between the Corporation and its directors and officers; variability of share buybacks and dividends; risks associated with the ownership of our securities, including changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond our control. Readers are cautioned that the foregoing list of risk factors is not exhaustive. New risk factors emerge from time to time, and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements. .

These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2023, filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission and in our other public filings. The above summary of assumptions and risks related to forward-looking statements has been provided in order to provide shareholders and potential investors with a more complete perspective on Baytex's current and future operations and such information may not be appropriate for other purposes.

There is no representation by Baytex that actual results achieved will be the same in whole or in part as those referenced in the forward-looking statements and Baytex does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law.

FORWARD LOOKING STATEMENTS ADVISORY (CONT.)

Financial Outlook Advisory

This presentation contains information that may be considered a financial outlook under applicable securities laws about Baytex's potential financial position, including, but not limited to, estimated EBITDA, exploration and development expenditures, allocation of free cash flow to shareholder returns, total debt to adjusted EBITDA, free cash flow and adjusted funds flow, and the dividend payable by Baytex, all of which are subject to numerous assumptions, risk factors, limitations and qualifications, including those set forth herein. The actual results of operations of Baytex will vary from the amounts set forth in this presentation and such variations may be material. This information has been provided for illustration only and with respect to future periods are based on budgets and forecasts that are speculative and are subject to a variety of contingencies and may not be appropriate for other purposes. Accordingly, these estimates are not to be relied upon as indicative of future results. Except as required by applicable securities laws, Baytex undertakes no obligation to update such financial outlook. The financial outlook contained in this press release was made as of the date of this press release and was provided for the purpose of providing further information about Baytex's potential future business operations. Readers are cautioned that the financial outlook contained in this presentation is not conclusive and is subject to change.

Share Buyback Advisory

The future acquisition by Baytex of its shares pursuant to a share buyback program, if any, and the level thereof is uncertain. Any decision to acquire shares of Baytex will be subject to the discretion of the Baytex Board of Directors and may depend on a variety of factors, including, without limitation, Baytex's business performance, financial condition, financial requirements, growth plans, expected capital requirements and other conditions existing at such future time including, without limitation, contractual restrictions, satisfaction of the solvency tests imposed on Baytex under applicable corporate law and receipt of regulatory approvals. There can be no assurance that Baytex will buyback any shares of Baytex in the future.

Dividend Advisory

Future dividends, if any, and the level thereof is uncertain. Any decision to pay dividends on the common shares (including the actual amount, the declaration date, the record date and the payment date) will be subject to the discretion of the Board of Directors of Baytex and may depend on a variety of factors, including, without limitation, Baytex’s business performance, financial condition, financial requirements, growth plans, expected capital requirements and other conditions existing at such future time including, without limitation, contractual restrictions and satisfaction of the solvency tests imposed on Baytex under applicable corporate law.

SPECIFIED FINANCIAL MEASURES ADVISORY

In this presentation, we refer to certain specified financial measures which do not have any standardized meaning prescribed by International Financial Reporting Standards ("IFRS"). While these measures are commonly used in the oil and natural gas industry, our determination of these measures may not be comparable with calculations of similar measures presented by other reporting issuers. There are no significant differences in the calculations between historical and forward-looking specified financial measures.

Non-GAAP Financial Measures

Free cash flow

Free cash flow in this presentation may refer to a forward-looking non-GAAP measure that is calculated consistently with the measures disclosed in the Company's MD&A. The most directly comparable financial measure for free cash flow disclosed in the Company's primary financial statements is cash flow from operating activities. For the year-ended December 31, 2023, cash flow from operating activities was $1.3 billion and free cash flow was $543.6 million. For information on the composition of free cash flow and how the Company uses this measure, refer to the "Specified Financial Measures" section of the MD&A for the period ended December 31, 2023, which section is incorporated herein by reference, and available on the SEDAR+ website at www.sedarplus.com.

Asset level free cash flow

Asset level free cash flow represents the free cash flow for a set of assets and is used to assess the operating performance of a specific business unit. Asset level free cash flow is calculated the same as free cash flow, with the exclusion of corporate costs. This measure is comprised of petroleum and natural gas sales, adjusted for blending expense, royalties, operating expense, transportation expense, additions to exploration and evaluation assets, additions to oil and gas properties and asset retirement obligations settled.

Operating netback

The most directly comparable financial measure for operating netback disclosed in the Company's primary financial statements is petroleum and natural gas sales. For the year ended December 31, 2023, petroleum and natural gas sales were $3.4 billion and operating netback was $1.9 billion. For information on the composition of operating netback and how the Company uses this measure, refer to the "Specified Financial Measures" section of the MD&A for the period ended December 31 2023, which section is incorporated herein by reference, and available on the SEDAR+ website at www.sedarplus.com.

Total sales, net of blending and other expense

Total sales, net of blending and other expense may refer to a forward-looking non-GAAP measure that is calculated consistently with the measures disclosed in the Company's MD&A. The most directly comparable financial measure for total sales, net of blending and other expense disclosed in the Company's primary financial statements is petroleum and natural gas sales. . For the year ended December 31, 2023, petroleum and natural gas sales were $3.4 billion and total sales, net of blending and other expense were $3.2 billion. For information on the composition of total sales, net of blending and other expense and average royalty rate and how the Company uses these measures, refer to the "Specified Financial Measures" section of the MD&A for the period ended December 31, 2023, which section is incorporated herein by reference, and available on the SEDAR+ website at www.sedarplus.com.

Return of capital

Return of capital is comprised of dividends declared and repurchase of common shares and is used to measure the amount of capital returned to shareholders during a given period. Return of capital in this presentation may refer to a forward-looking non-GAAP measure and is calculated consistently with the historical return of capital. Historical return of capital for year ended December 31, 2023 is calculated below.

	Year Ended December 31	
	2023	2022
Dividends declared	$ 37,519	$ —
Repurchase of common shares	325,039	245,430
Return of capital	$ 362,558	$ 245,430

Non-GAAP Financial Ratios

Free cash flow per unit

Free cash flow per share is calculated as free cash flow at an assumed WTI price divided by the number of shares outstanding during the applicable period. This measure is used by management to compare against earnings per share metrics. There are no significant differences in calculations between historical and forward-looking specific financial measures.

Average royalty rate

Average royalty rate is used calculated as royalties divided by total sales, net of blending and other expense which is a non-GAAP measure.

CAPITAL MANAGEMENT MEASURES ADVISORY

This presentation contains the terms "adjusted funds flow" and "net debt", which are capital management measures. We believe that the inclusion of these capital management measures provides useful information to financial statement users when evaluating the financial results of Baytex. Net debt and adjusted funds flow are calculated consistently with the measures disclosed in the Company's MD&A. The most directly comparable financial measures for net debt and adjusted funds flow disclosed in the Company's primary financial statements are credit facilities and cash flow from operating activities, respectively. For the year ended December 31, 2023, credit facilities and cash flow from operating activities were $848.7 million and $1.3 billion respectively For the year ended December 31, 2023, net debt and adjusted funds flow were $2.5 billion and $1.6 billion, respectively. For information on the composition of these measures and how the Company uses them, refer to the "Specified Financial Measures" section of the MD&A for the period ended December 31, 2023, which section is incorporated herein by reference, and available on the SEDAR+ website at www.sedarplus.com.

ADVISORY REGARDING OIL AND GAS INFORMATION

The reserves information contained in this presentation has been prepared in accordance with National Instrument 51-101 -Standards of Disclosure for Oil and Gas Activities of the Canadian Securities Administrators ("NI 51-101"). The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved and probable reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery. The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts, including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods, is required to properly use and apply reserves definitions.

The recovery and reserves estimates described herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves and future production from such reserves may be greater or less than the estimates provided herein. The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation. Complete NI 51-101 reserves disclosure for year-end 2023 is included in our Annual Information Form for the year ended December 31, 2023 which has been filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.

This presentation discloses drilling inventory and potential drilling locations. Drilling inventory and drilling locations refers to Baytex's total proved, probable and unbooked locations. Proved locations and probable locations account for drilling locations in our inventory that have associated proved and/or probable reserves. Unbooked locations are internal estimates based on our prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves. Unbooked locations are farther away from existing wells and, therefore, there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty whether such wells will result in additional oil and gas reserves, resources or production. In the Eagle Ford, Baytex's net drilling locations include 358 proved and 148 probable locations as at December 31, 2023 and 318 unbooked locations. In the Viking, Baytex's net drilling locations include 586 proved and 173 probable locations as at December 31, 2023 and 238 unbooked locations. In Peace River (including Clearwater), Baytex's net drilling locations include 64 proved and 52 probable locations as at December 31, 2023 and 331 unbooked locations. In Lloydminster, Baytex's net drilling locations include 73 proved and 69 probable locations as at December 31, 2023 and 263 unbooked locations. In the Duvernay, Baytex's net drilling locations include 23 proved and 24 probable locations as at December 31, 2023 and 174 unbooked locations.

References herein to average 30-day initial production rates and other short-term production rates are useful in confirming the presence of hydrocarbons, however, such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long term performance or of ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating aggregate production for us or the assets for which such rates are provided. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, we caution that the test results should be considered to be preliminary.

Where applicable, oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Notice to United States Readers

The petroleum and natural gas reserves contained in this presentation have generally been prepared in accordance with Canadian disclosure standards, which are not comparable in all respects to United States or other foreign disclosure standards. For example, the United States Securities and Exchange Commission (the "SEC") requires oil and gas issuers, in their filings with the SEC, to disclose only "proved reserves", but permits the optional disclosure of "probable reserves" (each as defined in SEC rules). Canadian securities laws require oil and gas issuers disclose their reserves in accordance with NI 51-101, which requires disclosure of not only "proved reserves" but also "probable reserves". Additionally, NI51-101 defines "proved reserves" and "probable reserves" differently from the SEC rules. Accordingly, proved and probable reserves disclosed in this presentation may not be comparable to United States standards. Probable reserves are higher risk and are generally believed to be less likely to be accurately estimated or recovered than proved reserves.

In addition, under Canadian disclosure requirements and industry practice, reserves and production are reported using gross volumes, which are volumes prior to deduction of royalty and similar payments. The SEC rules require reserves and production to be presented using net volumes, after deduction of applicable royalties and similar payments.

Moreover, Baytex has determined and disclosed estimated future net revenue from its reserves using forecast prices and costs, whereas the SEC rules require that reserves be estimated using a 12-month average price, calculated as the arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. As a consequence of the foregoing, Baytex's reserve estimates and production volumes in this presentation may not be comparable to those made by companies utilizing United States reporting and disclosure standards.