Premium Combination: High Return Organic Growth

3Q 2019

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- the timing, extent and duration of changes in prices for, supplies of, and demand for, crude oil and condensate, natural gas liquids, natural gas and related commodities;
- the extent to which EOG is successful in its efforts to acquire or discover additional reserves;
- the extent to which EOG is successful in its efforts to economically develop its acreage in, produce reserves and achieve anticipated production levels from, and maximize reserve recovery from, its existing and future crude oil and natural gas exploration and development projects;
- the extent to which EOG is successful in its efforts to market its crude oil and condensate, natural gas liquids, natural gas and related commodity production;
- the availability, proximity and capacity of, and costs associated with, appropriate gathering, processing, compression, storage, transportation and refining facilities;
- the availability, cost, terms and timing of issuance or execution of, and competition for, mineral licenses and leases and governmental and other permits and rights-of-way, and EOG's ability to retain mineral licenses and leases;
- the impact of, and changes in, government policies, laws and regulations, including tax laws and regulations; climate change and other environmental, health and safety laws and regulations relating to air emissions, disposal of produced water, drilling fluids and other wastes, hydraulic fracturing and access to and use of water; laws and regulations imposing conditions or restrictions on drilling and completion operations and on the transportation of crude oil and natural gas; laws and regulations with respect to derivatives and hedging activities; and laws and regulations with respect to the import and export of crude oil, natural gas and related commodities;
- EOG's ability to effectively integrate acquired crude oil and natural gas properties into its operations, fully identify existing and potential problems with respect to such properties and accurately estimate reserves, production and costs with respect to such properties;
- the extent to which EOG's third-party-operated crude oil and natural gas properties are operated successfully and economically;
- competition in the oil and gas exploration and production industry for the acquisition of licenses, leases and properties, employees and other personnel, facilities, equipment, materials and services;
- the availability and cost of employees and other personnel, facilities, equipment, materials (such as water and tubulars) and services;
- the accuracy of reserve estimates, which by their nature involve the exercise of professional judgment and may therefore be imprecise;
- weather, including its impact on crude oil and natural gas demand, and weather-related delays in drilling and in the installation and operation (by EOG or third parties) of production, gathering, processing, refining, compression, storage and transportation facilities;
- the ability of EOG's customers and other contractual counterparties to satisfy their obligations to EOG and, related thereto, to access the credit and capital markets to obtain financing needed to satisfy their obligations to EOG;
- EOG's ability to access the commercial paper market and other credit and capital markets to obtain financing on terms it deems acceptable, if at all, and to otherwise satisfy its capital expenditure requirements;
- the extent to which EOG is successful in its completion of planned asset dispositions;
- the extent and effect of any hedging activities engaged in by EOG;
- the timing and extent of changes in foreign currency exchange rates, interest rates, inflation rates, global and domestic financial market conditions and global and domestic general economic conditions;
- geopolitical factors and political conditions and developments around the world (such as the imposition of tariffs or trade or other economic sanctions, political instability and armed conflict), including in the areas in which EOG operates;
- the use of competing energy sources and the development of alternative energy sources;
- the extent to which EOG incurs uninsured losses and liabilities or losses and liabilities in excess of its insurance coverage;
- acts of war and terrorism and responses to these acts;
- physical, electronic and cybersecurity breaches; and
- the other factors described under ITEM 1A, Risk Factors, on pages 13 through 22 of EOG's Annual Report on Form 10-K for the fiscal year ended December 31, 2018 and any updates to those factors set forth in EOG's subsequent Quarterly Reports on Form 10-Q or Current Reports on Form 8-K.

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Oil and Gas Reserves; Non-GAAP Financial Measures:
The United States Securities and Exchange Commission (SEC) permits oil and gas companies, in their filings with the SEC, to disclose not only "proved" reserves (i.e., quantities of oil and gas that are estimated to be recoverable with a high degree of confidence), but also "probable" reserves (i.e., quantities of oil and gas that are as likely as not to be recovered) as well as "possible" reserves (i.e., additional quantities of oil and gas that might be recovered, but with a lower probability than probable reserves). Statements of reserves are only estimates and may not correspond to the ultimate quantities of oil and gas recovered. Any reserve or resource estimates provided in this presentation that are not specifically designated as being estimates of proved reserves may include "potential" reserves, "resource potential" and/or other estimated reserves or estimated resources not necessarily calculated in accordance with, or contemplated by, the SEC's latest reserve reporting guidelines. Investors are urged to consider closely the disclosure in EOG's Annual Report on Form 10-K for the fiscal year ended December 31, 2018, available from EOG at P.O. Box 4362, Houston, Texas 77210-4362 (Attn: Investor Relations). You can also obtain this report from the SEC by calling 1-800-SEC-0330 or from the SEC's website at www.sec.gov. In addition, reconciliation and calculation schedules for non-GAAP financial measures can be found on the EOG website at www.eogresources.com.

Our Goal:
Be One of the Best Companies Across All Sectors in the S&P 500

Double-Digit Return &
Double-Digit Organic Growth
Through Commodity Cycles

Strong Free Cash Flow[1] Generation

Deliver Long-Term Shareholder Value

(1) *Discretionary Cash Flow less CAPEX and Dividend. See accompanying schedules for reconciliations and definitions of non-GAAP measures and other measures.*

Roadmap to Long-Term Shareholder Value

Double-Digit Return & Double-Digit Organic Growth Through Commodity Cycles

- Lower Oil Price Required for 10% ROCE[1] to < $50
- Organic Growth Through Premium Drilling

Strong Free Cash Flow[2] Generation

- Budget Annually to Generate Free Cash Flow Under Conservative Oil Price Assumptions
- Target Dividend Growth to Yield ≈2%
- Reduce Debt to Protect Dividend & Financial Strength of Company

(1) See accompanying schedules for reconciliations and definitions of non-GAAP measures and other measures.
(2) Discretionary Cash Flow less CAPEX and Dividend. See accompanying schedules for reconciliations and definitions of non-GAAP measures and other measures.

Premium Drilling Strategy is Transforming the Company

Drives Lower Costs & Higher ROCE

Premium Drilling

Minimum 30% Return[1] @ $40 Oil and $2.50 Natural Gas

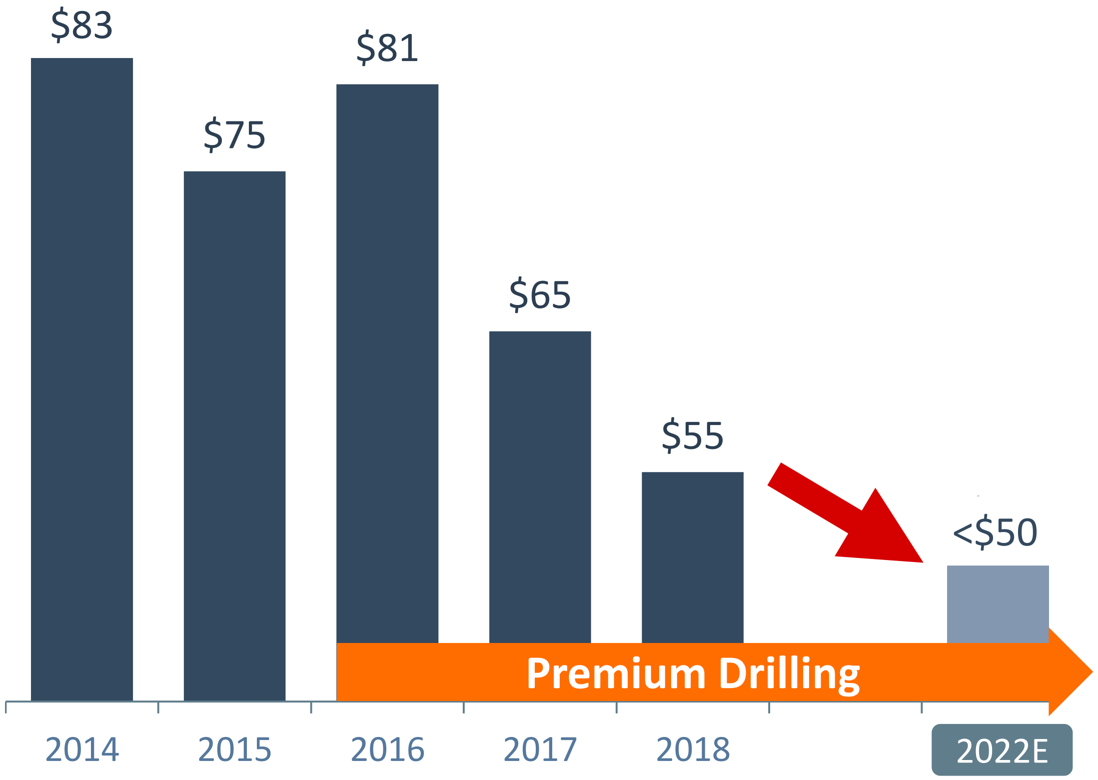
- Ensures Strong Returns Through Cycles
- Maintains Direct Finding Cost[2] < $10 Per Boe Through Cycles
- Achieves Higher Capital Efficiency

Disciplined Growth

Growth By-product of High-Return Organic Premium Drilling

- Continuous Improvement of Cost Structure and Well Productivity
- Pace of Development Not to Exceed Learning Curve
- Does Not Include Future Exploration Upside

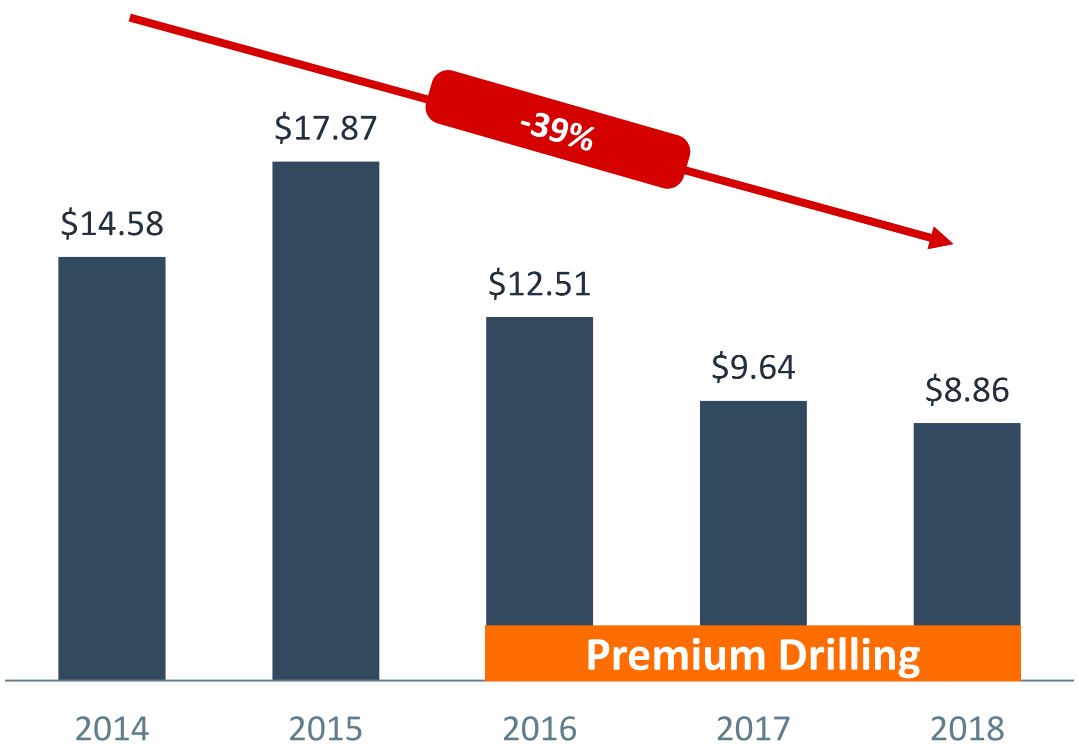
Lowering Oil Price Required for 10% ROCE[3]



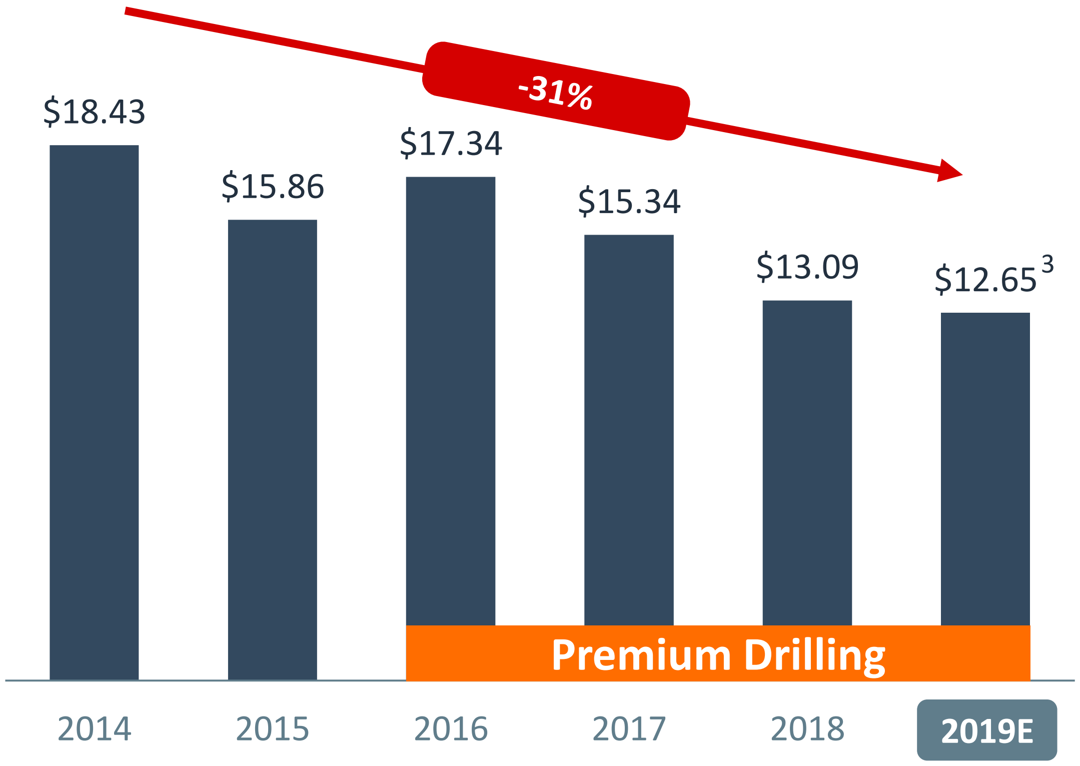
(1) Direct ATROR calculated using flat commodity prices. Direct ATROR defined in accompanying schedules.
(2) Direct Finding Cost = Well Costs / EUR. Well Costs = Drilling, Completion, Well-Site Facilities and Flowback. EUR = Estimated Ultimate Recovery.
(3) Scenario assumes double-digit oil production growth. ROCE, a non-GAAP measure, defined and reconciled in accompanying schedules.

Premium Wells Lower Finding Cost & DD&A, Increasing ROCE[1]

Finding & Development Cost[2,1]
$ per Boe



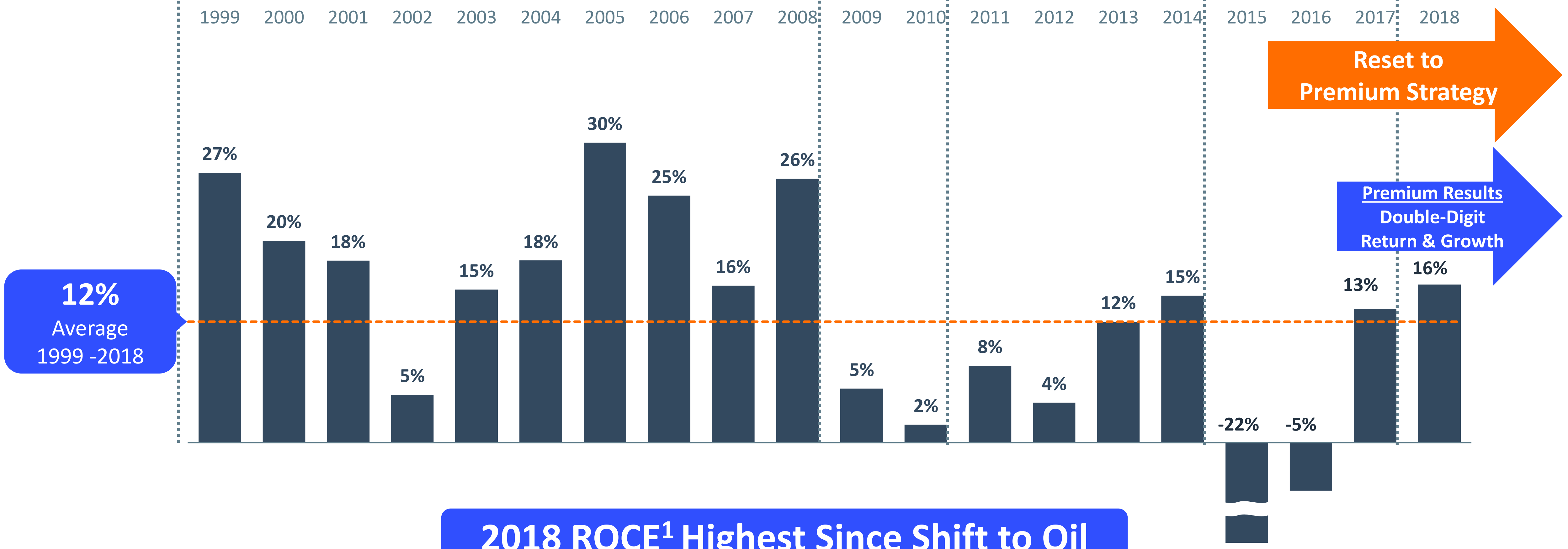
Depreciation, Depletion & Amortization
$ per Boe



(1) See accompanying schedules for reconciliations and definitions of non-GAAP measures and other measures.
(2) Total drilling costs, before revisions.
(3) Based on midpoint of 2019 guidance, as of November 6, 2019.

Long-Term Track Record of ROCE

Business Environment	High Gas Price & Growth	Shift to Oil	High Oil Price & Growth	Oil Downturn
Avg. ROCE[1]	20%	4%	10%	-4%



2018 ROCE[1] Highest Since Shift to Oil

(1) *Return on Capital Employed calculated using reported net income (GAAP). See accompanying schedules for reconciliations and definitions of non-GAAP measures and other measures.*

2019 Momentum Carrying Into 2020

Double-Digit Returns & Growth with Free Cash Flow at Lower Oil Prices

ROCE Competitive with All Sectors

- **Target Double-Digit ROCE[1,2] in 2019**
- Continue Lowering Oil Price Required for 10% ROCE
- Lower Operating Costs & Lower Finding Cost Support Higher ROCE

Disciplined Growth & Opportunistic Investment

- **Increased U.S. Oil Growth Target to 15%[3]**
  - $6.3 Bn[3] Capital Budget **- No Change**
  - ≈740 Net Planned Completions **- No Change**
- **Expect Similar Growth in 2020 with Oil in the Mid-$50s**

Innovation & Operational Execution

- Carry Strong Operational Momentum through 2019 **- Achieved**
- Improve Capital Efficiency[4] In Premium Areas[5] **- Achieved**
- Continue to Improve Well Productivity **- Achieved**
- Reduce Well Costs 5%[6] **- Achieved**

Financial Objectives Aligned with Shareholders

- **Free Cash Flow[7,2] Positive at $50 Oil**
- Generated $744 MM Free Cash Flow YTD 2019
- Raised Dividend 31%[8] for the Second Consecutive Year
- Retired $900 MM Bond in Accordance with $3 Bn Debt Reduction Target

(1) ROCE calculated using adjusted net income (non-GAAP).
(2) See accompanying schedules for reconciliations and definitions of non-GAAP measures and other measures.
(3) Based on midpoint of 2019 guidance, as of November 6, 2019.
(4) Capital efficiency = amount of capital necessary to replace base decline and add new production. Base decline calculated on a full-year average basis.
(5) Net prospective acreage disclosed in the Eagle Ford, Delaware Basin, Powder River Basin, Bakken/Three Forks, DJ Basin and Woodford Oil Window. See slide 28.
(6) Well Costs = Drilling, Completion, Well-Site Facilities and Flowback.
(7) Discretionary Cash Flow less CAPEX and Dividend.
(8) Based on indicated annual rate, as of November 6, 2019.

3Q 2019

Organic Premium Inventory Expansion and Outstanding Execution

Added 1,700 Premium Locations, >2X 2019 Drilling Pace

- Announced Delaware Basin Wolfcamp M and Third Bone Spring Plays
- Added >1,000 Locations to Undrilled Premium Inventory

Beat all U.S. Production Targets - Oil, NGL, Nat Gas

- Well Performance Drives Beat of High-End for all Three U.S. Production Targets
- Increased Full Year U.S Oil Growth Target to 15%[1] with No Change to CapEx or Activity

Maintained CapEx and OpEx Momentum

- $1.5 Bn CapEx[2] Below $1.6 Bn Target Mid-Point[3]
- Drilling Efficiencies Reduce FY Rig Count vs. Prior Plan
- LOE and DD&A Per Unit Well Below Low-End of Targets
- Infrastructure Projects Lowering LOE

Strong Financial Position

- $337 MM Free Cash Flow[4,2]
- 15% Net Debt to Total Capitalization[1] Lowest Since 2008

(1) Based on midpoint of 2019 guidance, as of November 6, 2019.
(2) See accompanying schedules for reconciliations and definitions of non-GAAP measures and other measures.
(3) Based on midpoint of 2019 guidance, as of August 1, 2019.
(4) Discretionary Cash Flow less CAPEX and Dividend.

Added Two New Premium Plays in Delaware Basin
Wolfcamp M and Third Bone Spring

- ✓ **1,500 Net Premium Locations with 1.6 Billion BOE Estimated Net Resource Potential[1]**
- ✓ **Now Developing 7 Premium Delaware Basin Plays**
- ✓ **6,500 Total Net Premium Drilling Locations[2] in Delaware Basin**
  - **24 Years of Inventory at Current Drilling Pace**
- ✓ **Development Customized to Local Geology**
  - **Enables Identification of Optimal Targets and Spacing**

Wolfcamp M

- 193,000 Prospective Net Acres
- 855 Net Undrilled Premium Locations[2]
- EUR 1,175 MBoe, NAR
- Total Estimated Net Resource Potential 1.0 BnBoe[1]
- Well Cost[3] Target $7.7MM

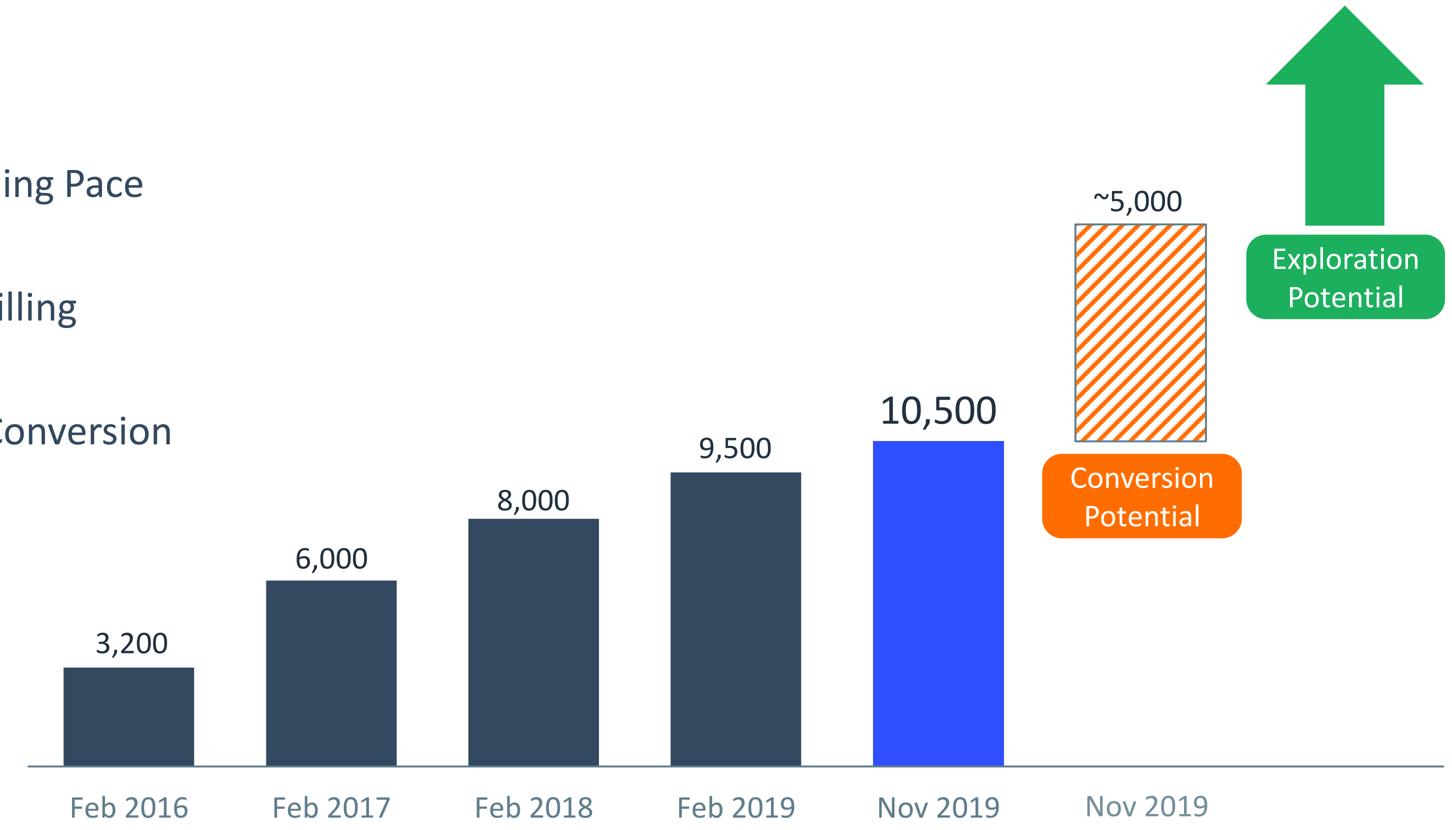
Third Bone Spring

- 200,000 Prospective Net Acres
- 615 Net Undrilled Premium Locations[2]
- EUR 950 MBoe, NAR
- Total Estimated Net Resource Potential 615 MMBoe[1]
- Well Cost[3] Target $7.6MM

(1) Estimated resource potential net to EOG, not proved reserves.
(2) Premium locations are shown on a net basis and are all undrilled. Premium return hurdle defined on slide 5.
(3) Well Cost = Drilling, Completion, Well-Site Facilities and Flowback.

Significant Premium Inventory Growth

- ✓ Premium Inventory[1] Growing in Quality & Size
- ✓ 14+ Years of Premium Inventory at Current Drilling Pace
- ✓ Replacing Premium Locations 2x Faster than Drilling
- ✓ Significant Upside Potential through Premium Conversion and Exploration



Resource Potential[2] (BnBoe)	2.0	5.1	7.3	9.2	10.2
Per Well (Mboe)	625	850	900	970	970

(1) Premium locations are shown on a net basis and are all undrilled as of date indicated. Premium return hurdle defined on slide 5.
(2) Estimated resource potential net to EOG, not proved reserves.

Significant Premium Inventory Upside Potential

Convert Non-Premium to Premium

- Plays Currently Under Development
  - Continuous Well Cost Reduction
  - Improved Target Selection
  - New Completion Technology
  - Infrastructure Additions Lower Operating Cost

Organic Exploration for New Premium Plays

- Active Exploration Program Across All Operating Areas
- Testing and Leasing in 10+ U.S. Basins
- Target High Quality Reservoirs Conducive to Horizontal Technology
- Low Drilling and Infrastructure Cost
- Goal is to Improve Inventory with Low Decline and Low Cost New Plays

Premium Capital Allocation Creates Value Through Price Cycles

Cash Flow Priorities

Disciplined, High-Return Organic Growth

- Diverse & Deep Premium Drilling Inventory
- Exploration & Low-Cost Leasing for New High-Return Plays
- **Strong Free Cash Flow[1] Generation**

Target Dividend Yield Competitive with S&P 500

- **Target Dividend Growth to Yield ≈2%**
- Ensure Dividend is Protected Through Commodity Price Cycles
- 72% Dividend Increase[2] Since 2017

Strengthen Balance Sheet

- **Target $3 Billion Total Debt[3] Reduction from 2018-2021**
- Lower Net Debt[4] Provides Flexibility through Commodity Price Cycles

Additional Cash Flow Investment Opportunities

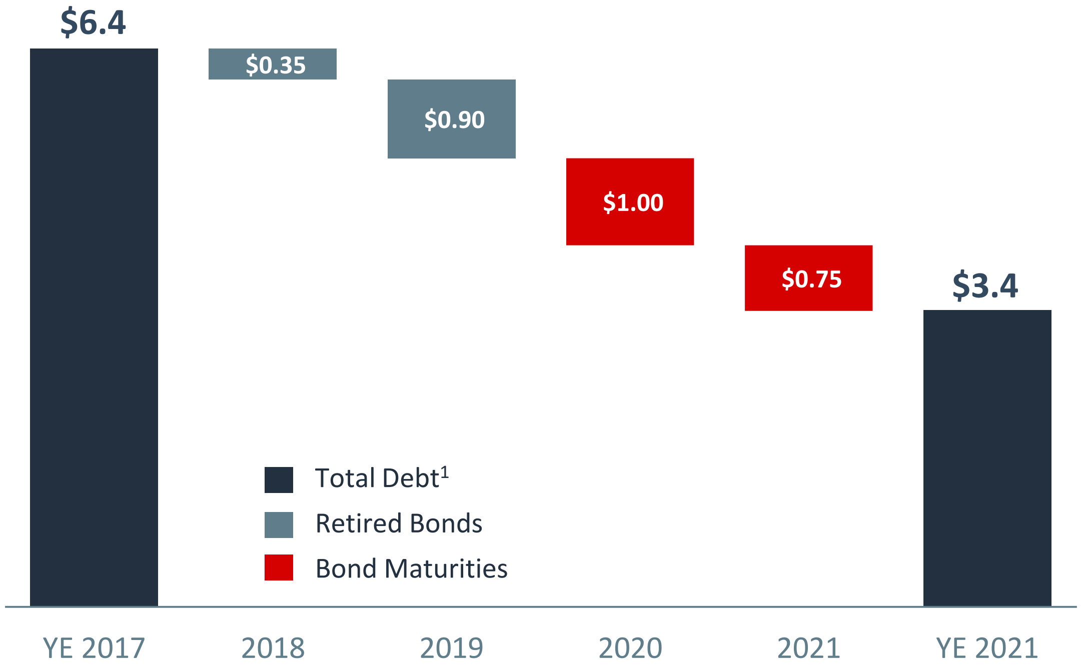
- Opportunistic Low-Cost Property Additions
  - Must Compete for Capital on Premium Drilling Return Criteria
  - **No Expensive Corporate M&A**
- Consider Value Accretive Share Repurchases

(1) Discretionary Cash Flow less CAPEX and Dividend. See accompanying schedules for reconciliations and definitions of non-GAAP measures and other measures.
(2) Based on indicated annual rate, as of November 6, 2019.
(3) Current and long-term debt.
(4) See accompanying schedules for reconciliations and definitions of non-GAAP measures and other measures..

Strong Balance Sheet & Growing Dividend Through Commodity Price Cycles

Retire Maturing Bonds From 2018 – 2021

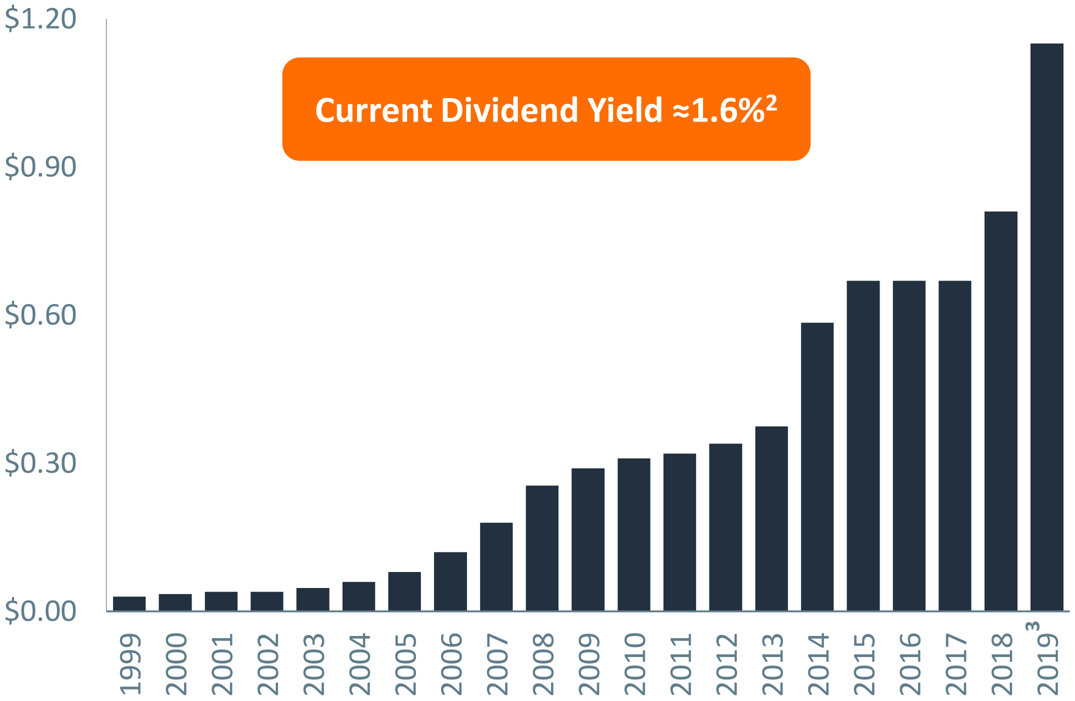
$Bn



Target $3 Billion Reduction in Total Debt[1]

Target Dividend Growth to Yield ≈2%

$ per Share



72% Increase[3] Since 2017

(1) *Current and long-term debt.*
(2) *Dividend yield calculated using indicated annual rate as of November 6, 2019 and closing stock price as of November 5, 2019.*
(3) *Based on indicated annual rate, as of November 6, 2019.*

Note: Dividends adjusted for 2-for-1 stock splits effective March 1, 2005 and March 31, 2014.

Commitment to Sustainability: Performance and Disclosure

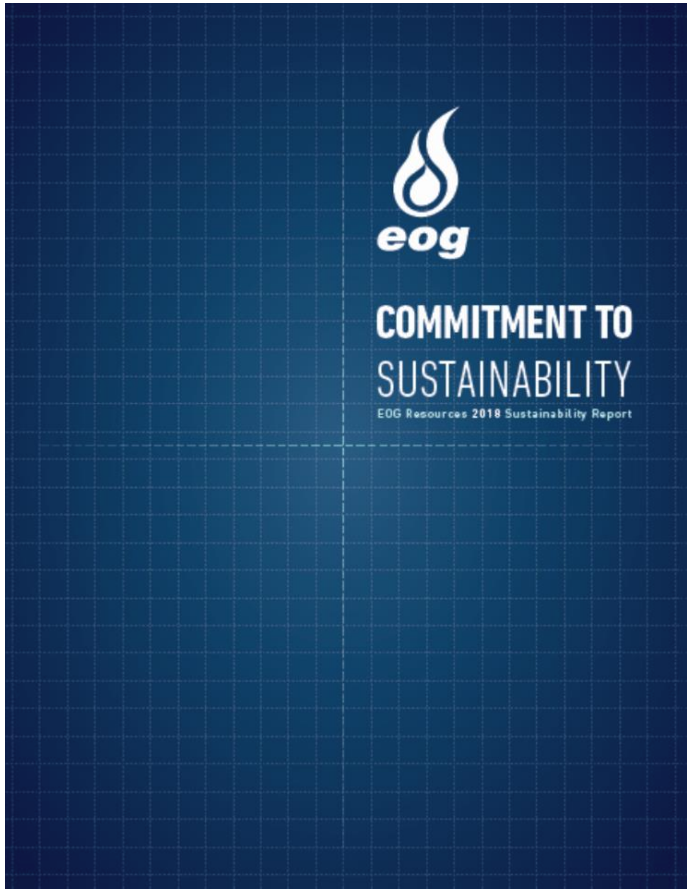
Environmental

Since 2016…

- GHG Intensity Rate[1] Down 8%
- Methane Intensity Rate[2] Down 53%
- Water Reuse Percentage More Than Tripled

Social

- Permian Strategic Partnership
- Local, Employee-Driven Community Work
- Inclusive and Diverse Workforce



Governance

- Board 88% Independent, 25% Women
- Sustainability Board Committee
- Executive Annual Bonus Plan Tied to ESG Performance
- New Position - Director of Sustainability

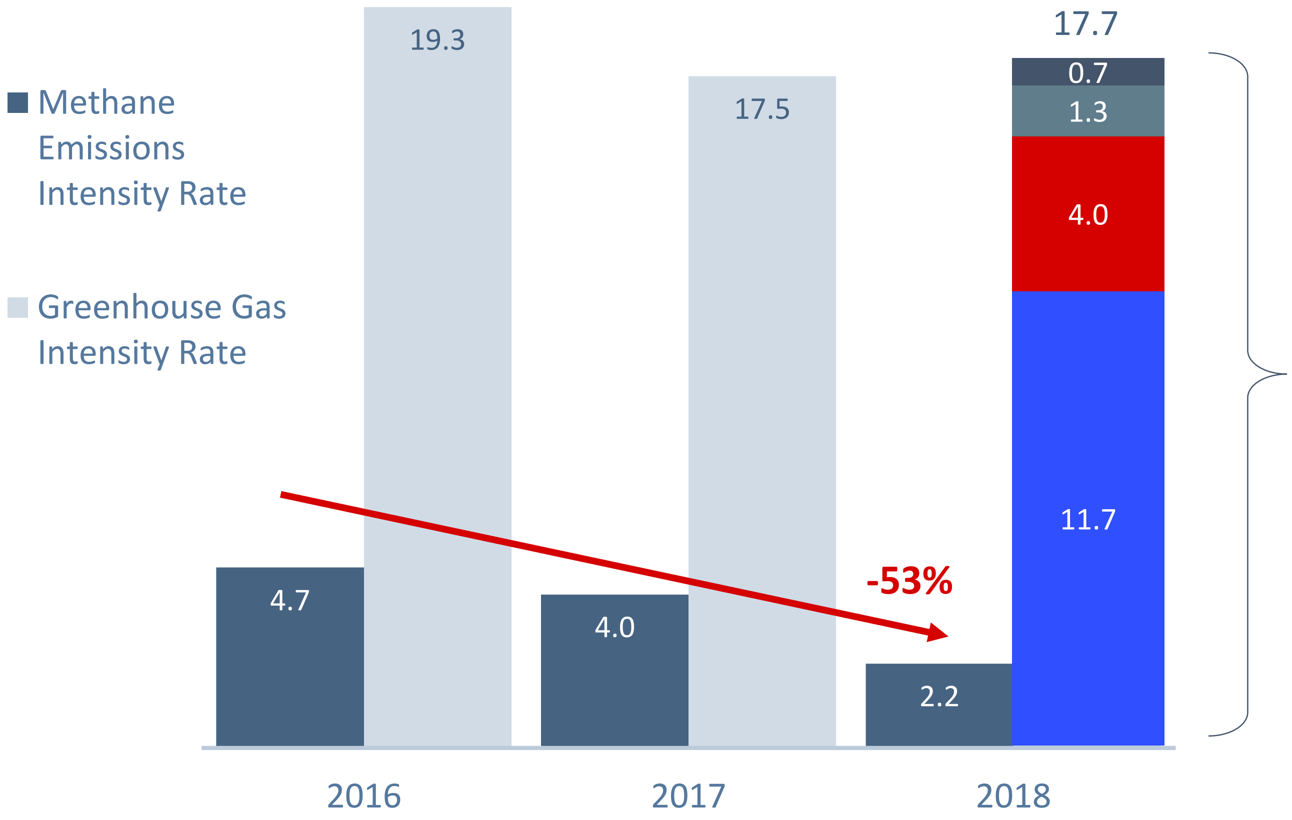
ESG Disclosure

- Integration of TCFD Recommendations
  - Scenario Analysis
- Methane Reduction Target
- Expanded Water Source Metrics – Reuse, Fresh and Non-fresh

(1) *Metric Tons of CO_2e per MBoe produced in U.S. operations.*
(2) *Metric Tons of CO_2e (related to methane emissions) per MBoe produced in U.S. operations.*

Applying Technology & Innovation to Reduce Greenhouse Gas (GHG) Intensity Rates

GHG and Methane Intensity Rates[1,2]



GHG Reduction Initiatives by Source

Other (incl. Fugitives)
- Company-wide Leak Detection and Repair (LDAR) for Both Regulated and Voluntary Inspections
- Drone-Enabled LDAR (Pilot Project)

Pneumatics
- Retrofit or Replace Methane-Emitting Controllers
- Retrofit or Replace Methane-Emitting Pumps

Flaring
- Pre-Plan and Build Natural Gas Infrastructure
- Tank Vapor Capture
- Closed Loop Gas Capture (Concept)

Combustion
- Electric-Powered Hydraulic Fracturing Fleets
- Solar-Powered Compression (Pilot Project)

(1) Metric Tons of CO_2e per MBoe produced in U.S. operations.
(2) Metric Tons of CO_2e (related to methane emissions) per MBoe produced in U.S. operations.

EOG Culture is Our Competitive Advantage

Culture

- ✓ Rate-of-Return Driven
- ✓ Decentralized / Non-Bureaucratic
- ✓ Multi-Disciplinary Teamwork
- ✓ Innovative / Entrepreneurial
- ✓ Every Employee is a Business Person First
- ✓ Safety, Environment, & Community

Exploration

- Internal Prospect Generation
- Early Mover Advantage
- Best Rock / Best Plays
- Low-Cost Acreage
- Most Prolific U.S. Horizontal Wells

Operations

- Low Cost Operator
- Industry Leading Drilling & Completion Technology
- Self-Sourcing Materials / Services
- Proven Track Record of Execution

Information Technology

- Real-Time Data Capture
- Large Proprietary Integrated Data Warehouses
- Predictive Analytics
- 100+ In-House Desktop / Mobile Apps
- Fast / Continuous Tech Advancement

Sustainability

- Commitment to Reduce Environmental Footprint
- Commitment to Safety and our Communities
- Commitment to Ethical Conduct
- Inclusive and Diverse Workforce
- Compensation Tied to Performance

High-Return Organic Growth

EOG Resources
High Return Organic Growth Company

ROCE Leader Through Commodity Price Cycles

Disciplined Growth with Free Cash Flow

Low-Cost Producer Competitive in Global Energy Market

Commitment to Sustainability

Appendix

Diverse and Flexible Portfolio of Inventory and Acreage

EOG's Non-Federal vs. Federal Position

Premium Locations[1]

7+ Years of Non-Federal Premium Inventory

11+ Years Permian Basin Non-Federal Premium Inventory

4 Years of Federal Permits in Process

U.S Acreage[2]

Currently Drilling in 6 Basins

Active Exploration Program Across 10+ Basins

80% Total Federal Acreage HBP[3]

90% Permian Basin Federal Acreage HBP[3]

(1) 46% of Permian and 5% of Powder River Basin premium locations are on Non-Federal land.
(2) 50% of Permian and 33% of Powder River Basin acreage is on Non-Federal land.
(3) Held By Production.

Oil and Gas Regulatory Process Promotes Balanced Regulatory Framework

Checks and Balances

Executive Order

- Subject to Judicial Review
- Requires Constitutional Authority

Process for Regulatory Changes Governed by Federal Law

- New Regulations must be Consistent with Existing Laws
- Subject to Public Review

Stakeholder Interests Are Aligned

Revenues from Federal Lands Shared with the States

Oil and Gas Revenues Provide Significant Budget Support

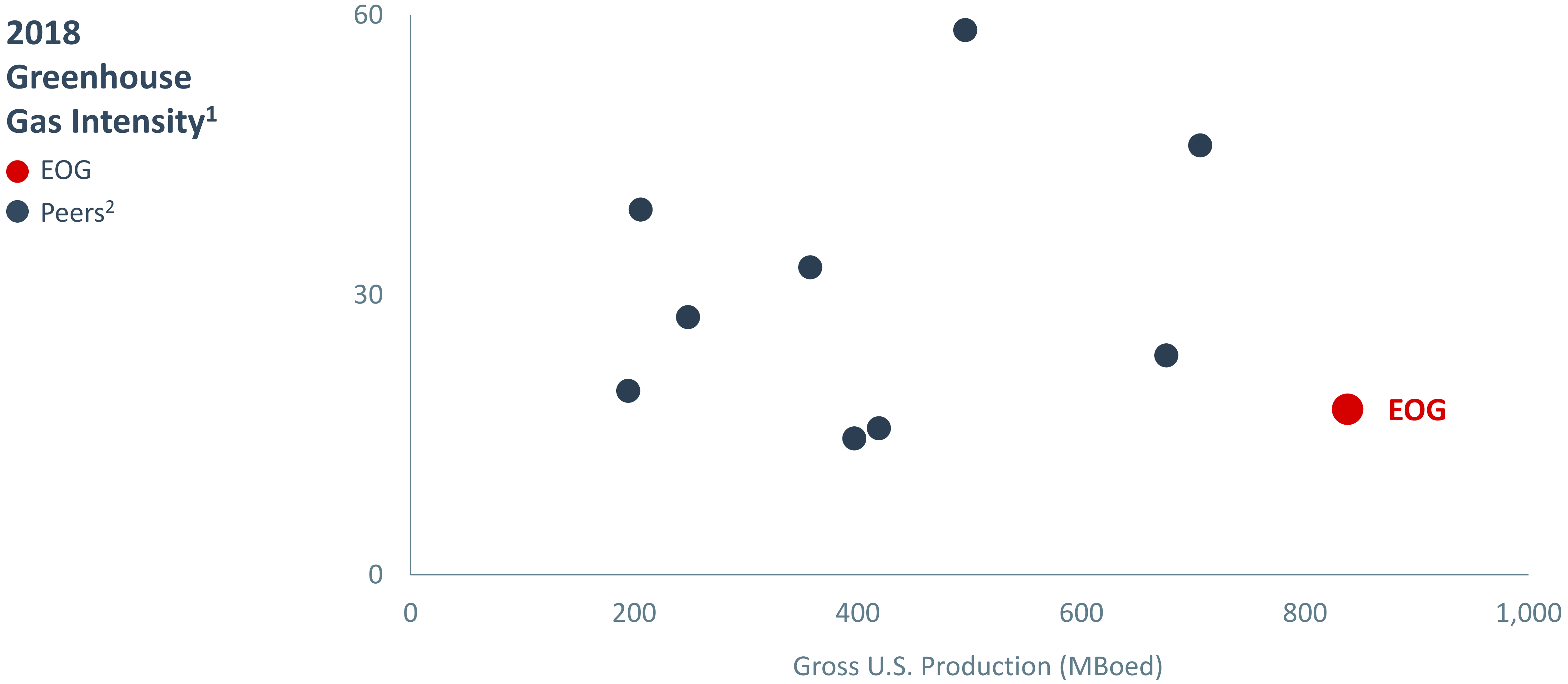
- Public Education, Health Care, Infrastructure Projects

Industry Activity Provides Jobs and Economic Benefits to Local Communities

U.S. Energy Production Driver of U.S. Economic Growth and Energy Independence

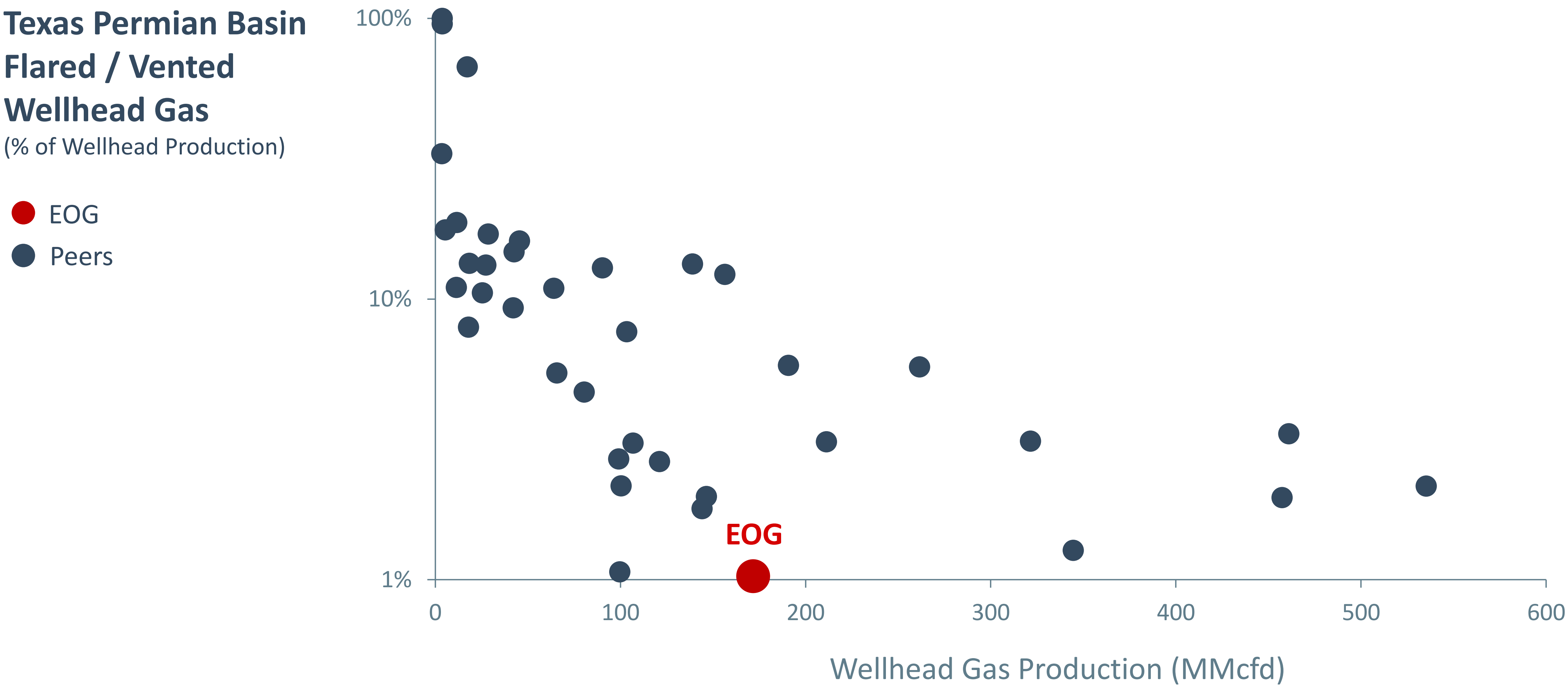
Committed to Minimizing Emissions

2018 Greenhouse Gas Intensity[1]



(1) Metric tons of 2018 CO_2e emissions per MBoe of 2018 gross U.S. production.
(2) Peers include APA, APC, COP, DVN, HES, MRO, NBL, OXY and PXD.
Sources: EPA website for company emissions data and IHS for company gross production data.

EOG Industry Leader in Capturing Produced Gas

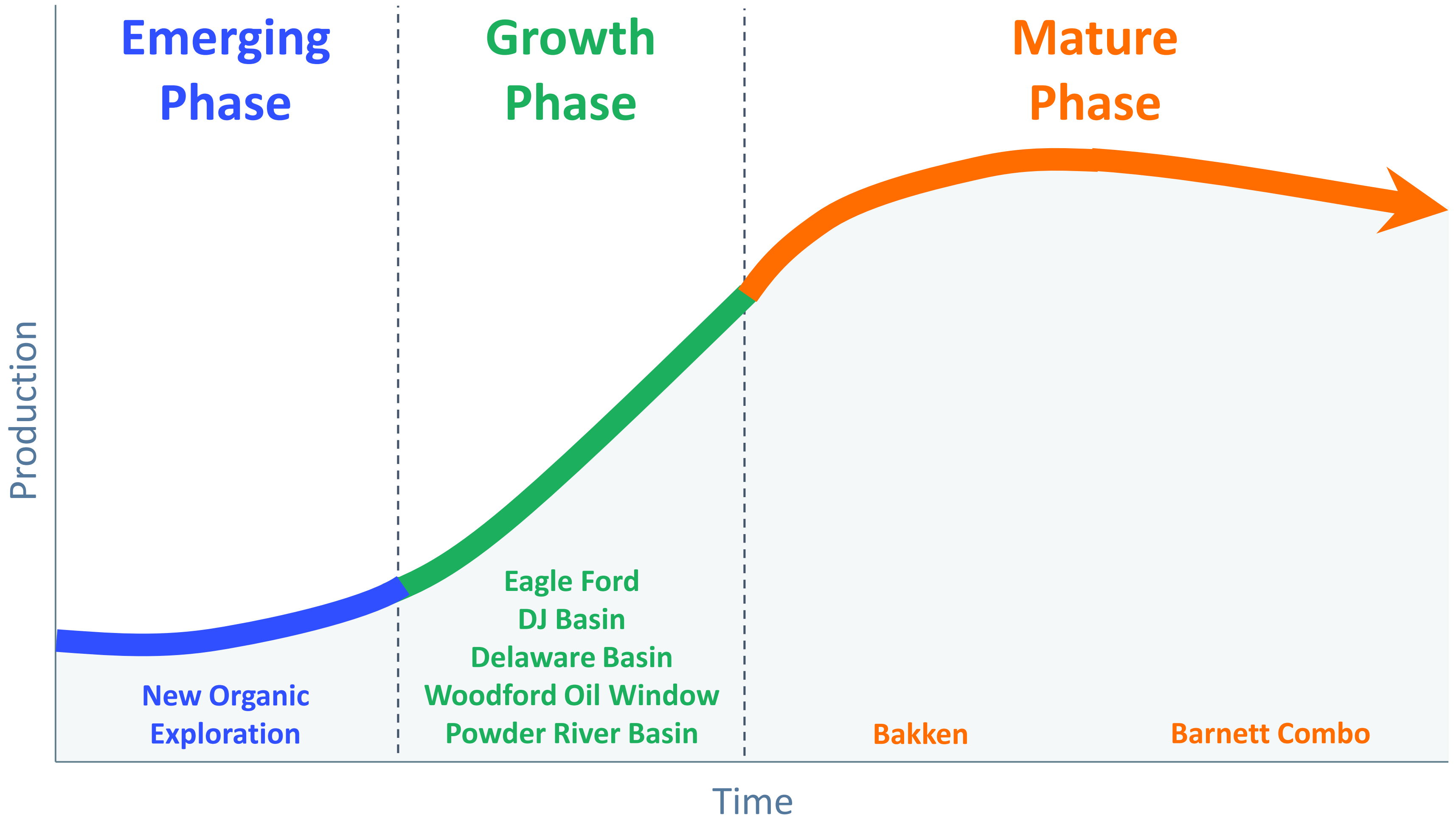


Source: Bernstein analysis of Texas Permian Basin July 2018 production and flaring / venting data from the Texas Railroad Commission.

Organic Exploration Fuels High Return Growth

EOG Operates Plays in Each Phase

Life Cycle of a Typical Oil & Gas Asset



EOG's Diversified Marketing Options Provide Pricing Advantage & Flow Assurance

EOG Marketing Strategy

Control

EOG Firm Capacity Provides Flow Assurance

Flexibility

Multiple Transportation Options in Each Basin

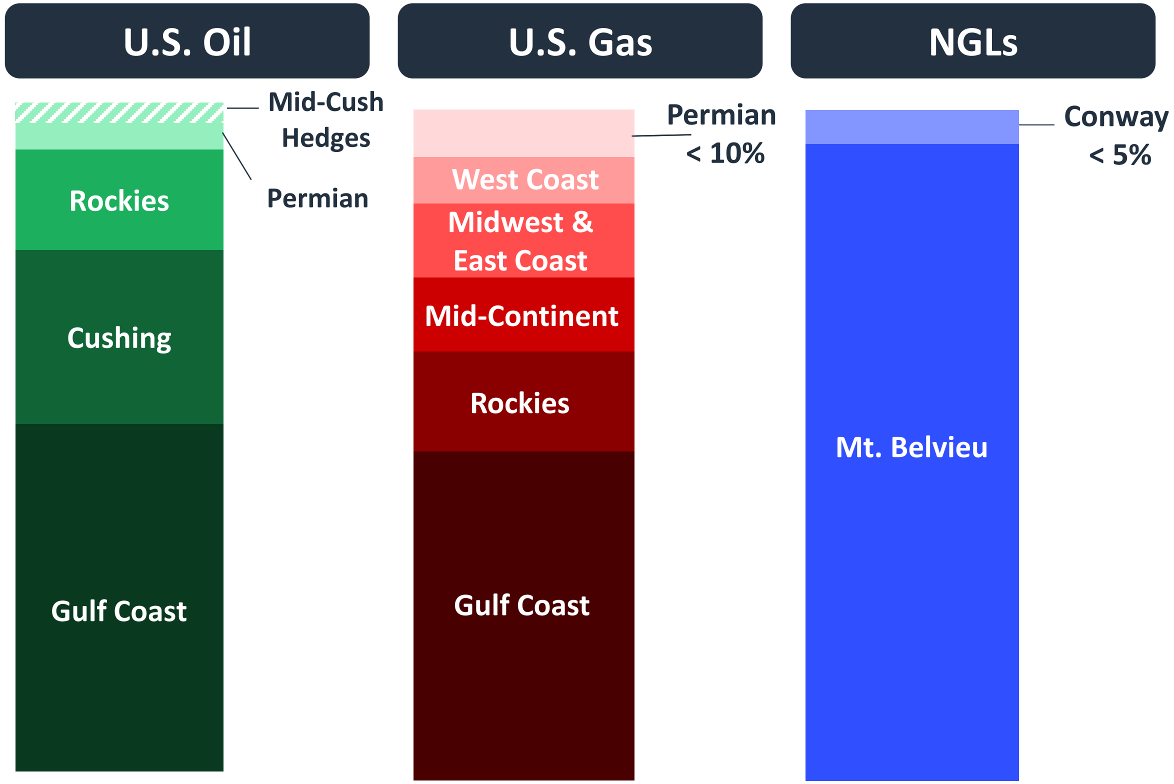
Diversification

Access to Multiple Markets to Maximize Margins

Duration

Avoid Long-Term, High-Cost Commitments

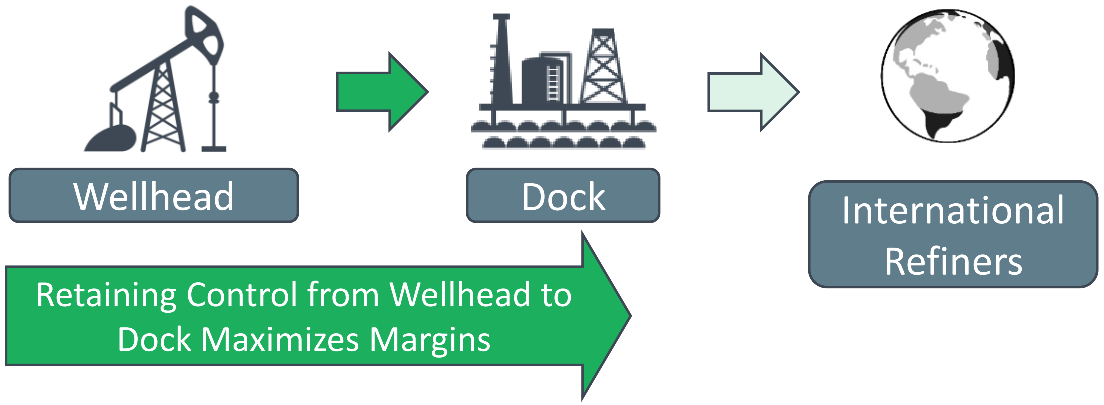
2019 EOG Estimated Sales Markets



Oil & Natural Gas Export Capacity Adds Access to New International Markets

EOG Uniquely Positioned in the U.S. Oil Market

- High Quality Crude Oil
  - 45° API Average
  - Reliable & Consistent Delivery
- Low-Cost Pipeline Transportation and Tank Storage Capacity in Key Marketing Segments
- Export Capacity Increases from 100 MBopd in 2020 to 250 MBopd in 2022
- Maintain Diversified Sales to Domestic Refiners



Gas Supply Agreements (GSA) for LNG Exports

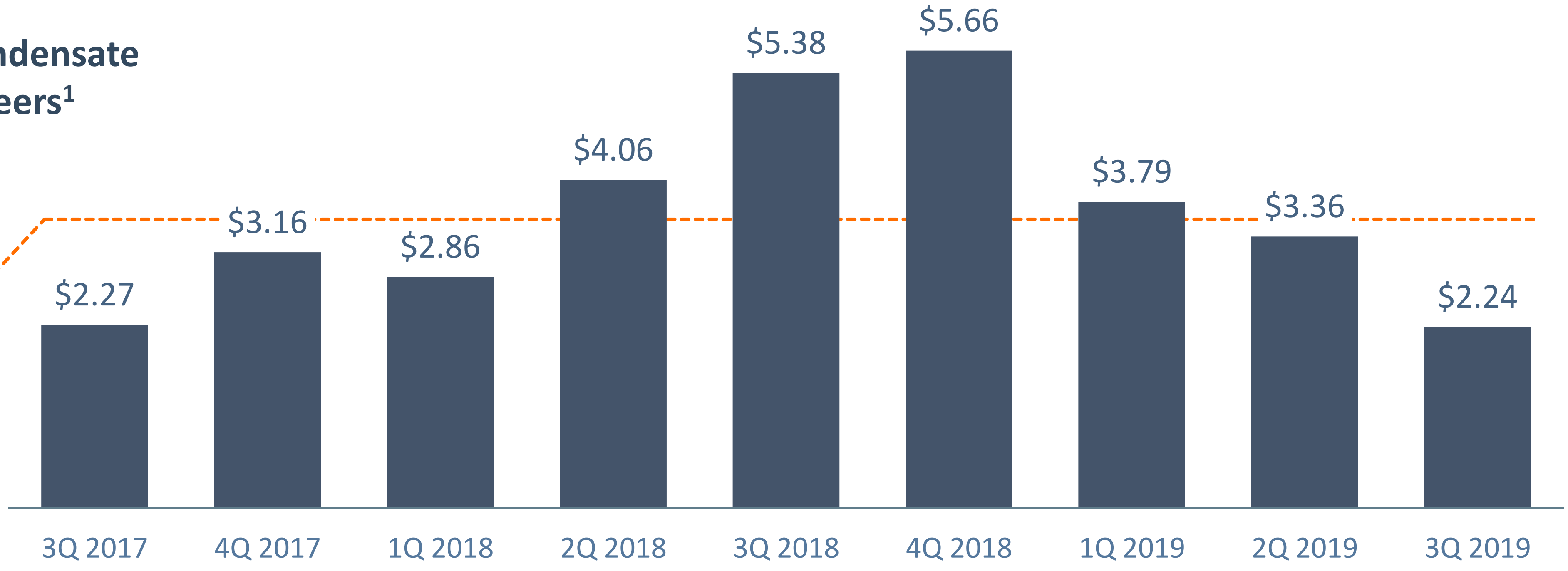
- Expands EOG's Reach into Growing Global Market for Natural Gas
- 15-Year GSA for 140,000 MMBtu per day Starts in 2020 and Grows to 440,000 MMBtu per day
- Linked to LNG Price (Japan Korea Marker) and Henry Hub

EOG Realizes Higher Oil Prices than Peers

U.S. Crude Oil and Condensate Price Realization vs. Peers[1]

($ per Bbl)

$3.64 per Bbl
EOG Average Advantage



	3Q 2017	4Q 2017	1Q 2018	2Q 2018	3Q 2018	4Q 2018	1Q 2019	2Q 2019	3Q 2019
EOG	$48.06	$56.95	$64.24	$67.91	$69.53	$59.37	$56.11	$61.01	$56.67
Peers[1]	$45.79	$53.79	$61.38	$63.85	$64.15	$53.71	$52.32	$57.65	$54.43[2]

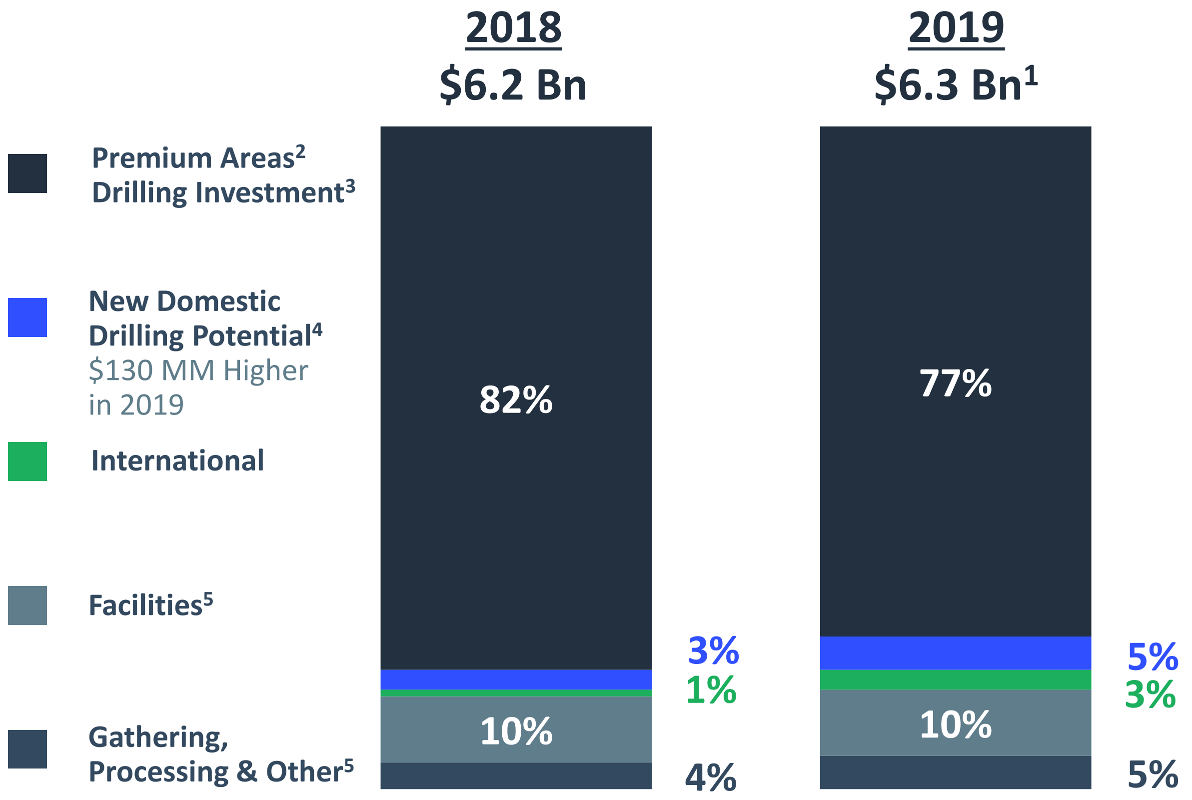
(1) Difference in U.S. crude oil and condensate price realization between EOG and peer average. Peers include APA, COP, CXO, DVN, HES, MRO, NBL, OXY, PXD. CXO replaced APC beginning 3Q 2019. Source: Company filings.

(2) 3Q 2019 peer average excludes peers that have not reported 3Q 2019 results prior to November 6, 2019.

Improving Capital Efficiency in 2019

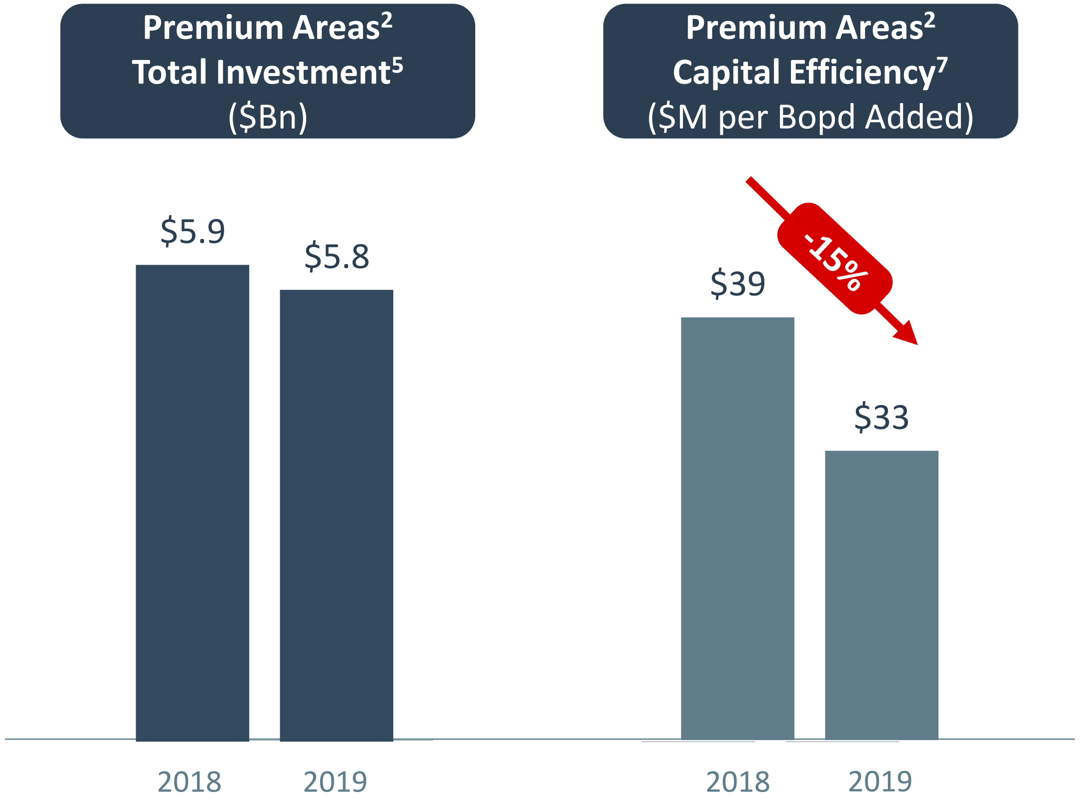
2019 Plan Does Not Change with Higher Oil Price

Delivers 15%[1] U.S. Oil Growth Plus Higher Investment in Premium Exploration



Improving Capital Efficiency in Premium Areas

Assumes 31% Base Decline[6]



(1) *Based on midpoint of 2019 guidance, as of November 6, 2019.*

(2) *Premium areas include net prospective acreage disclosed in the Eagle Ford, Delaware Basin, Powder River Basin, Bakken/Three Forks, DJ Basin and Woodford Oil Window.*

(3) *Drilling investment includes leasing, exploration and development expenditures.*

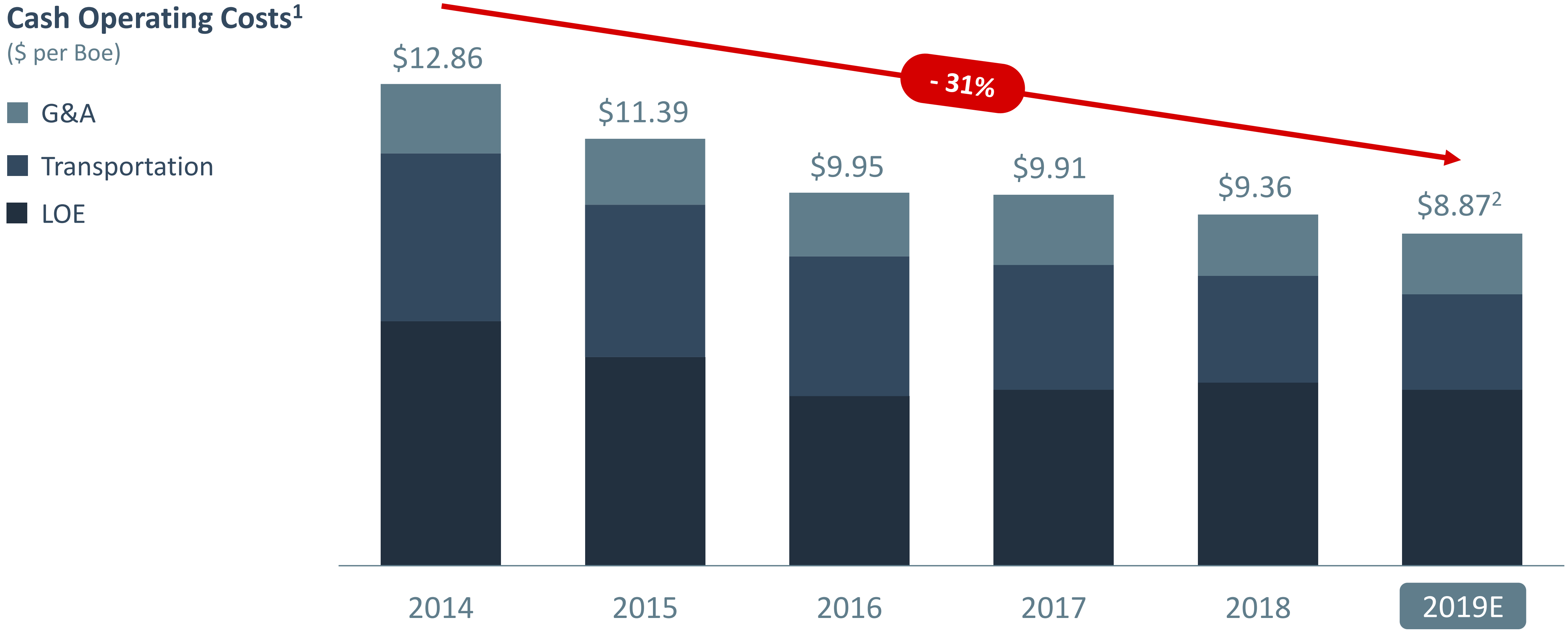
(4) *Capital spend for new domestic drilling potential includes leasing, exploration and development expenditures outside of Premium Areas.*

(5) *Total Investment includes drilling investment plus facilities and gathering, processing & other expenditures.*

(6) *Reflects 31% base decline rate for full year 2018 oil production. Base decline rate for full year 2018 total production is 25%.*

(7) *Capital Efficiency = amount of capital necessary to replace base decline and add new production. Base decline calculated on a full-year average basis.*

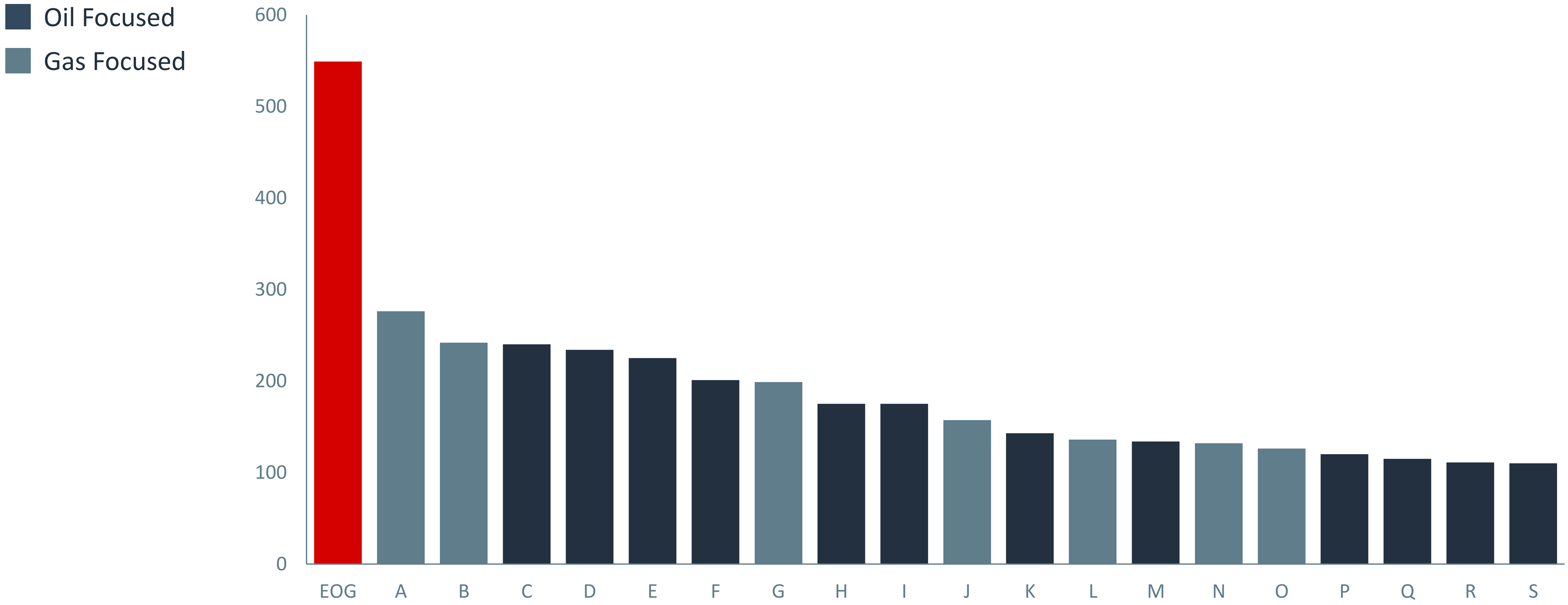
EOG Continues Reducing Operating Costs



(1) Excludes certain non-recurring expenses as applicable. See accompanying schedules for reconciliations and definitions of non-GAAP measures and other measures.
(2) Based on midpoint of guidance, as of November 6, 2019.

EOG Continued Leading the "Thousand Club" in 2018

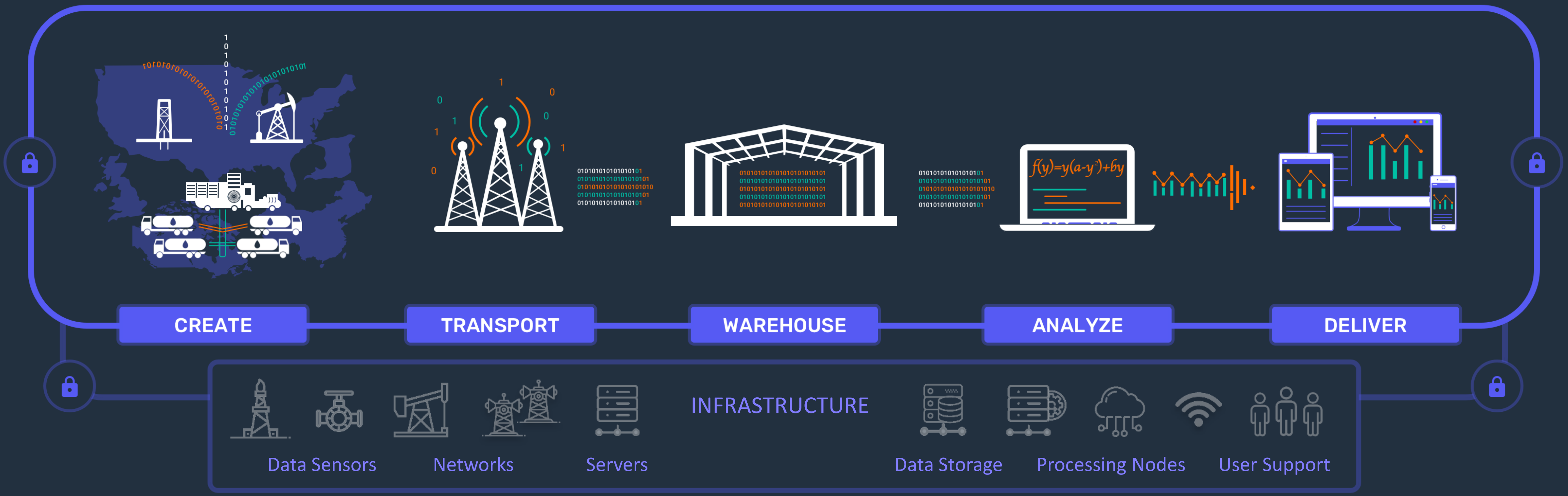
Number of Wells with 30-Day Peak Rate > 1,000 Boed



Source: Sanford C. Bernstein & Co. Thousand Club includes wells with peak 30-day production over 1,000 Boed.
Represents 7,245 out of 29,692 wells with initial production in 2018.
Companies: AR, CHK, CLR, COP, CVX, CXO, DVN, ECA, EQT, FANG, MRO, NBL, OXY, PXD, RRC, SWN, VII, WPX and XOM.

Owning Data from Creation to Delivery℠ via 100+ Apps

EOG Data Supply Chain



Enabling EOG's Culture of Real-Time, Returns-Focused Decision Making

Lower Costs Drive Higher Margins

	2014	2015	2016	2017	2018	2019		
						1Q	2Q	3Q
Composite Average Wellhead Revenue per Boe	$58.01	$30.66	$26.82	$35.58	$45.51	$39.56	$40.36	$37.18
Operating Costs per Boe								
Lease & Well	$6.53	$5.66	$4.53	$4.70	$4.89	$4.83	$4.70	$4.55
Transportation	4.48	4.07	3.73	3.33	2.85	2.54	2.35	2.60
Gathering & Processing[1]	0.67	0.70	0.60	0.67	1.66	1.60	1.52	1.66
G&A[2]	1.85	1.66	1.70	1.87	1.63	1.53	1.65	1.77
Taxes Other than Income	3.49	2.02	1.71	2.45	2.94	2.77	2.76	2.65
Interest Expense, Net	0.93	1.14	1.37	1.23	0.93	0.79	0.67	0.52
Total Cash Cost per Boe (Excluding DD&A and Total Exploration Costs)	$17.95	$15.25	$13.64	$14.25	$14.90	$14.06	$13.65	$13.75
Composite Average Margin per Boe (Excluding DD&A and Total Exploration Costs)	$40.06	$15.41	$13.18	$21.33	$30.61	$25.50	$26.71	$23.43
DD&A per Boe	$18.43	$15.86	$17.34	$15.34	$13.09	$12.63	$12.94	$12.43
Total Cost per Boe (Excluding Total Exploration Costs)	$36.38	$31.11	$30.98	$29.59	$27.99	$26.69	$26.59	$26.18
Composite Average Margin per Boe (Excluding Total Exploration Costs)	$21.63	($0.45)	($4.16)	$5.99	$17.52	$12.87	$13.77	$11.00
Total Exploration Costs[3] per Boe	$0.70	$2.25	$2.12	$1.65	$1.33	$1.22	$1.13	$1.79
Total Cost per Boe (Including DD&A and Total Exploration Costs)	$37.08	$33.36	$33.10	$31.24	$29.32	$27.91	$27.72	$27.97
Composite Average Margin per Boe (Including DD&A and Total Exploration Costs)	$20.93	($2.70)	($6.28)	$4.34	$16.19	$11.65	$12.64	$9.21

(1) Increase in Gathering and Processing expenses from 2017 to 2018 is primarily due to the adoption of Accounting Standards Update 2014-09, which required EOG to present certain processing fees as Gathering and Processing costs instead of as a deduction to natural gas revenues. See Note 1 to financial statements in EOG's 2018 Form 10-K.
(2) See accompanying schedules for reconciliations and definitions of non-GAAP measures and other measures.
(3) Total Exploration Costs includes Exploration, Dry Hole and Impairment Costs. See accompanying schedules for reconciliations and definitions of non-GAAP measures and other measures..

4Q & FY 2019 Guidance

	Estimated Ranges (Unaudited) 4Q 2019	Full Year 2019
Daily Sales Volumes		
Crude Oil and Condensate Volumes (MBbld)		
United States	459.5 - 469.5	453.3 - 455.8
Trinidad	0.4 - 0.6	0.6 - 0.7
Other International	0.0 - 0.2	0.1 - 0.1
Total	459.9 - 470.3	454.0 - 456.6
Natural Gas Liquids Volumes (MBbld)		
Total	135.0 - 145.0	131.8 - 134.4
Natural Gas Volumes (MMcfd)		
United States	1,085 - 1,145	1,054 - 1,069
Trinidad	225 - 255	256 - 264
Other International	34 - 38	36 - 37
Total	1,344 - 1,438	1,346 - 1,370
Crude Oil Equivalent Volumes (MBoed)		
United States	775.3 - 805.3	760.7 - 768.3
Trinidad	37.9 - 43.1	43.3 - 44.6
Other International	5.7 - 6.5	6.1 - 6.3
Total	818.9 - 854.9	810.1 - 819.2
Capital Expenditures[1] ($MM)	$ 1,400 - $ 1,600	$ 6,200 - $ 6,400
Operating Costs		
Unit Costs ($/Boe)		
Lease and Well	$ 4.50 - $ 4.80	$ 4.65 - $ 4.75
Transportation Costs	$ 2.55 - $ 3.05	$ 2.50 - $ 2.60
Depreciation, Depletion and Amortization	$ 12.45 - $ 12.85	$ 12.60 - $ 12.70

	Estimated Ranges (Unaudited) 4Q 2019	Full Year 2019
Expenses ($MM)		
Exploration and Dry Hole	$ 35 - $ 45	$ 165 - $ 175
Impairment	$ 95 - $ 105	$ 270 - $ 280
General and Administrative	$ 110 - $ 120	$ 470 - $ 490
Gathering and Processing	$ 130 - $ 140	$ 480 - $ 490
Capitalized Interest	$ 9 - $ 11	$ 37 - $ 39
Net Interest	$ 39 - $ 41	$ 183 - $ 185
Taxes Other Than Income (% of Wellhead Revenue)	6.9% - 7.3%	6.8% - 7.2%
Income Taxes		
Effective Rate	21% - 26%	21% - 26%
Current Tax (Benefit) / Expense ($MM)	$ (40) - $ 0	$ (110) - $ (70)
Pricing[2]		
Crude Oil and Condensate ($/Bbl)		
Differentials		
United States - above (below) WTI	$ (1.85) - $ 0.15	$ 0.15 - $ 0.65
Trinidad - above (below) WTI	$ (11.00) - $ (9.00)	$ (10.00) - $ (9.00)
Other International - above (below) WTI	$ (1.00) - $ 3.00	$ 0.69 - $ 2.00
Natural Gas Liquids		
Realizations as % of WTI	20% - 28%	26% - 28%
Natural Gas ($/Mcf)		
Differentials		
United States - above (below) NYMEX Henry Hub	$ (0.70) - $ (0.30)	$ (0.50) - $ (0.40)
Realizations		
Trinidad	$ 2.50 - $ 2.90	$ 2.65 - $ 2.75
Other International	$ 3.80 - $ 4.20	$ 4.10 - $ 4.30

(1) *The capital expenditures forecast includes expenditures for Exploration and Development Drilling, Facilities, Leasehold Acquisitions, Capitalized Interest, Exploration Costs, Dry Hole Costs and Other Property, Plant and Equipment. The forecast excludes Property Acquisitions, Asset Retirement Costs and any Non-Cash Exchanges.*

(2) *EOG bases United States and Trinidad crude oil and condensate price differentials upon the West Texas Intermediate crude oil price at Cushing, Oklahoma, using the simple average of the NYMEX settlement prices for each trading day within the applicable calendar month. EOG bases United States natural gas price differentials upon the natural gas price at Henry Hub, Louisiana, using the simple average of the NYMEX settlement prices for the last three trading days of the applicable month.*

Play Details

Premium Drilling in All Major U.S. Oil Basins

Rocky Mountain Area
62 MBopd in 2018

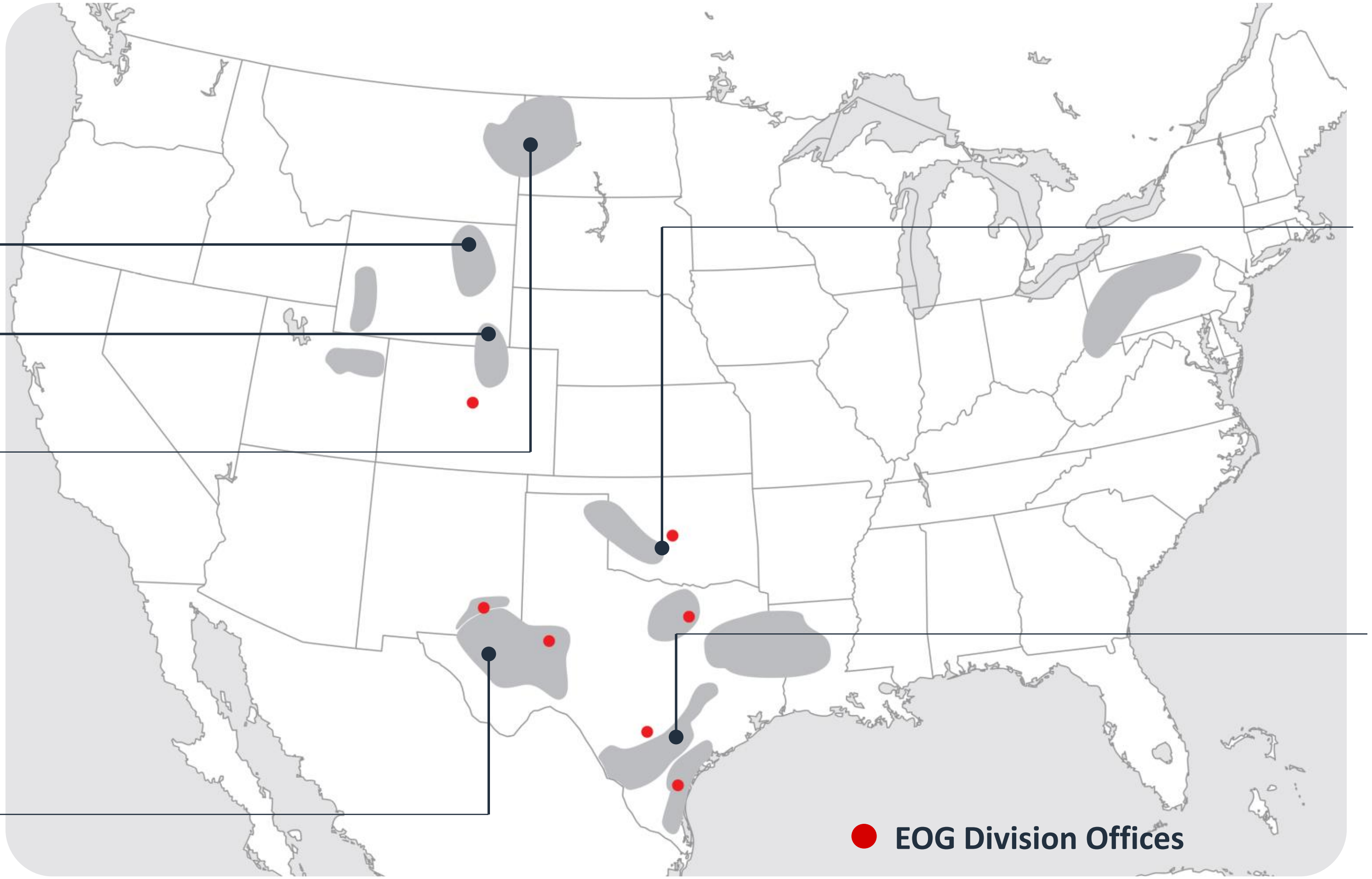
Powder River Basin
≈40 Net Completions in 2019

Wyoming DJ Basin
≈35 Net Completions in 2019

Bakken
≈20 Net Completions in 2019

Permian Basin
132 MBopd in 2018

Delaware Basin
≈270 Net Completions in 2019



Mid-Continent
6 MBopd in 2018

Woodford Oil Window
≈30 Net Completions in 2019

Eagle Ford
171 MBopd in 2018

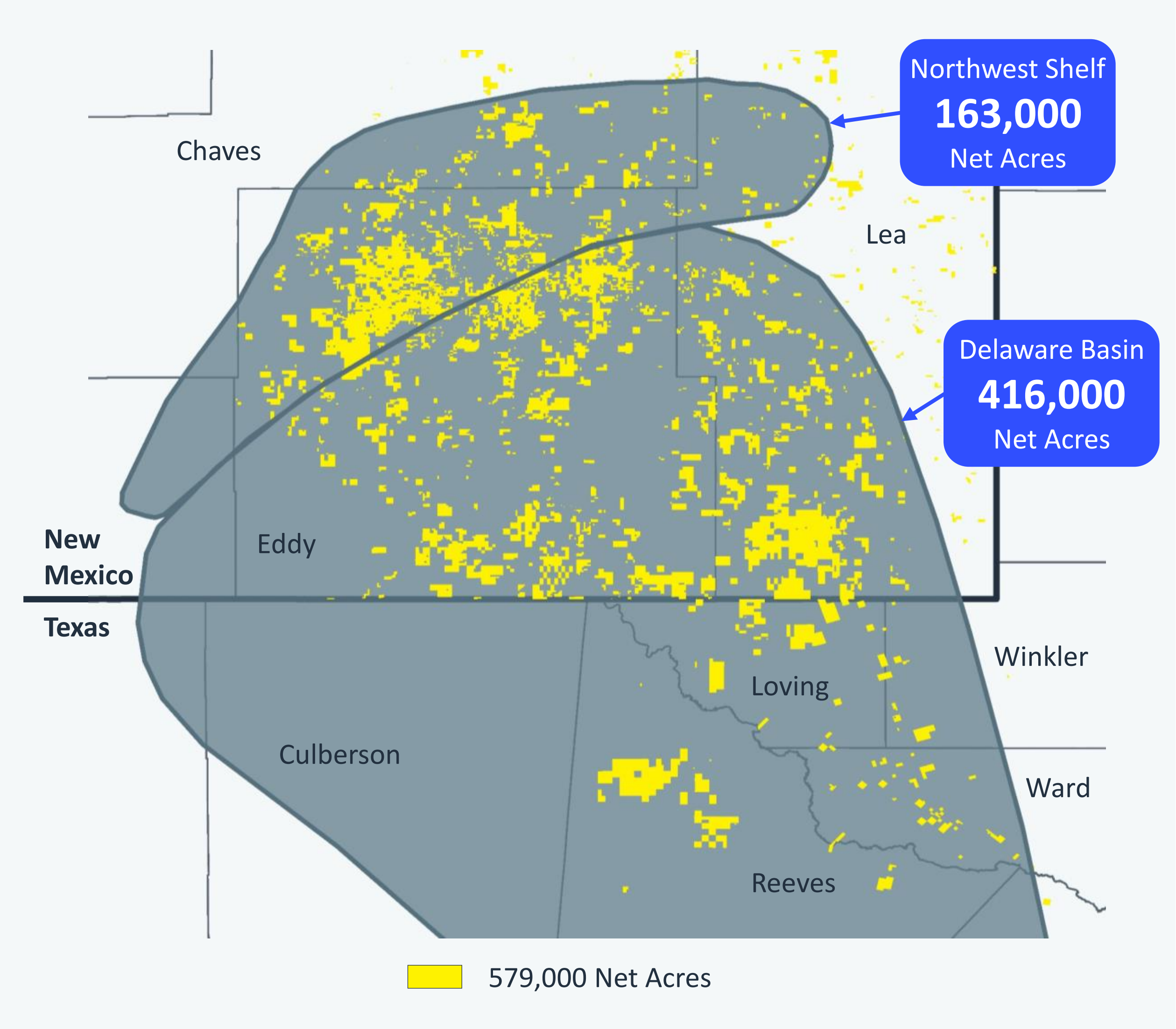
≈300 Net Completions in 2019

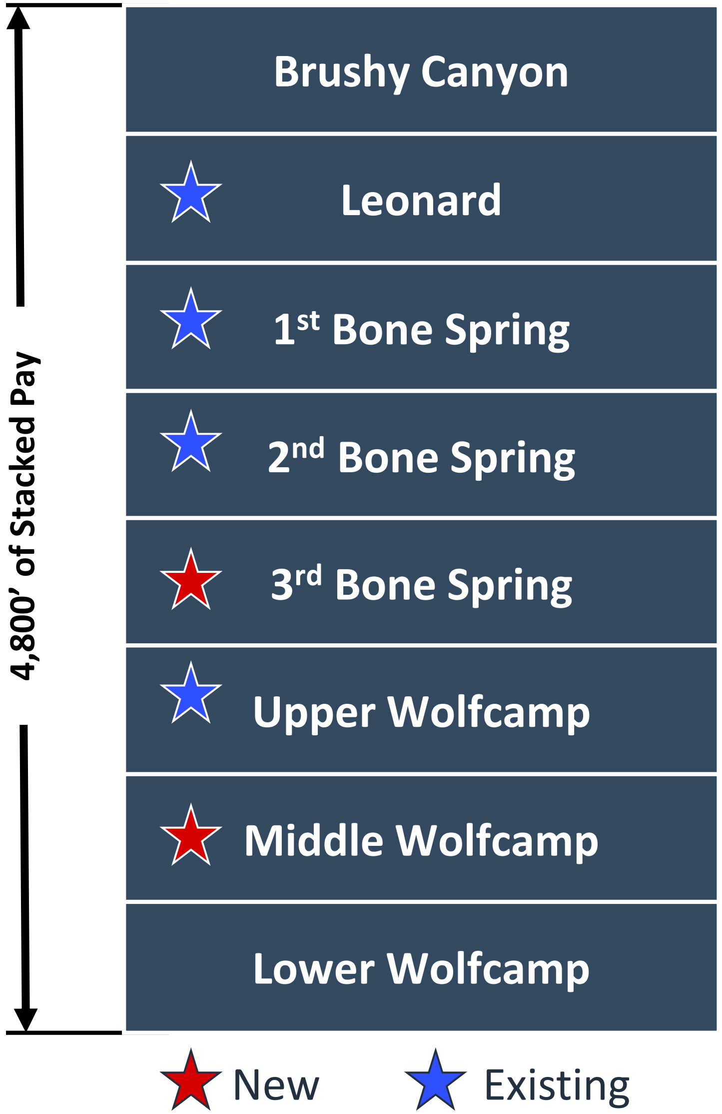
Deep Inventory of Crude Oil Assets

Play	Net Undrilled Premium Locations[1]	2019 Average Drilling Rigs	2019 Average Completion Spreads	2019 Net Planned Completions
Eagle Ford	**1,900**	**9**	**6**	**300**
Delaware Basin	**6,500**	**18**	**6**	**270**
Wolfcamp U Oil	1,135			208
Wolfcamp U Combo	555			
Wolfcamp M	855			2
First Bone Spring	575			15
Second Bone Spring	1,360			25
Third Bone Spring	615			10
Leonard	1,405			10
Powder River Basin	**1,655**	**2**	**<1**	**40**
Mowry	875			
Niobrara	555			
Turner/Parkman	225			
Bakken/Three Forks	**270**	**1**	**<1**	**20**
Wyoming DJ Basin	**150**	**2**	**<1**	**35**
Woodford Oil Window	**75**	**2**	**1**	**30**
Other Plays	**—**	**2**	**<1**	**45**
Total	**~10,500**	**36**	**15**	**740**

(1) Premium locations are shown on a net basis and are all undrilled as of date hereof. Premium return hurdle defined on slide 5. Totals are rounded.

Delaware Basin

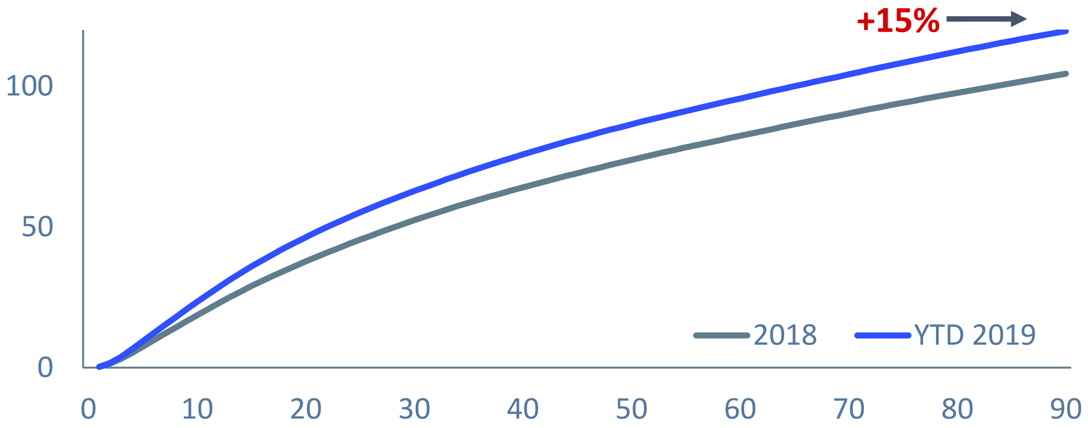




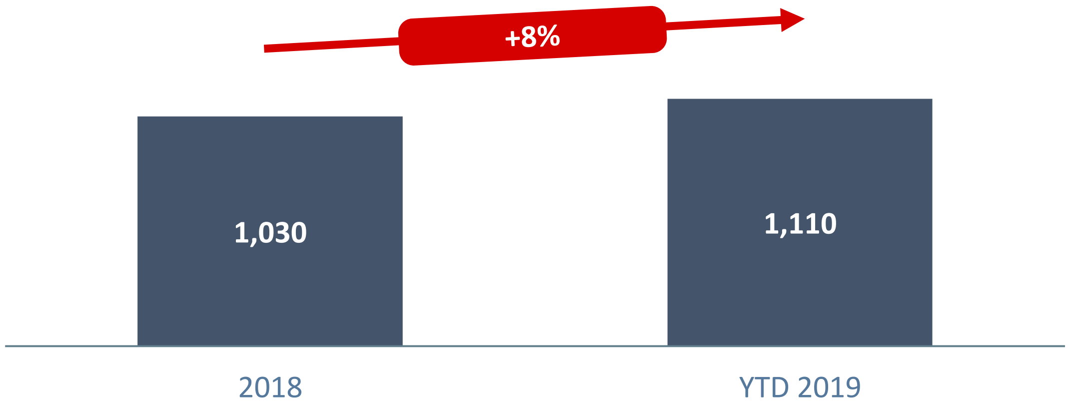
Operating Results Continue to Improve in 2019

Wolfcamp U Oil Well Productivity and Operating Efficiencies

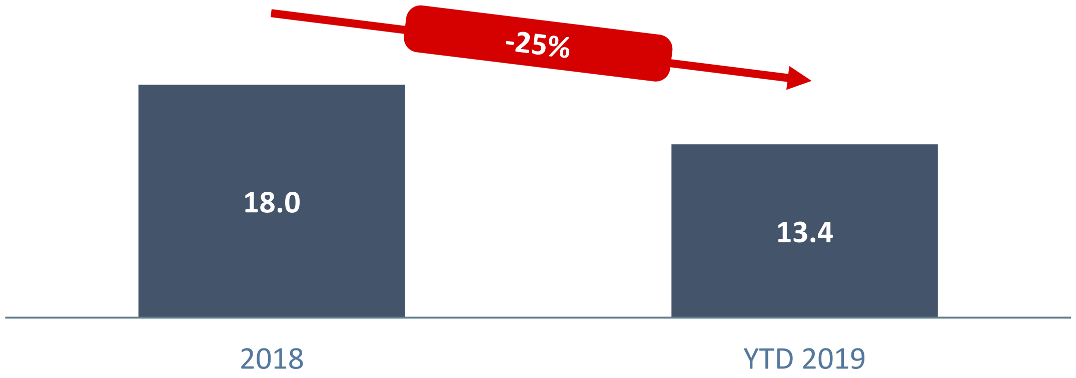
90 Day Cumulative Crude Oil Production (MBo)[1]



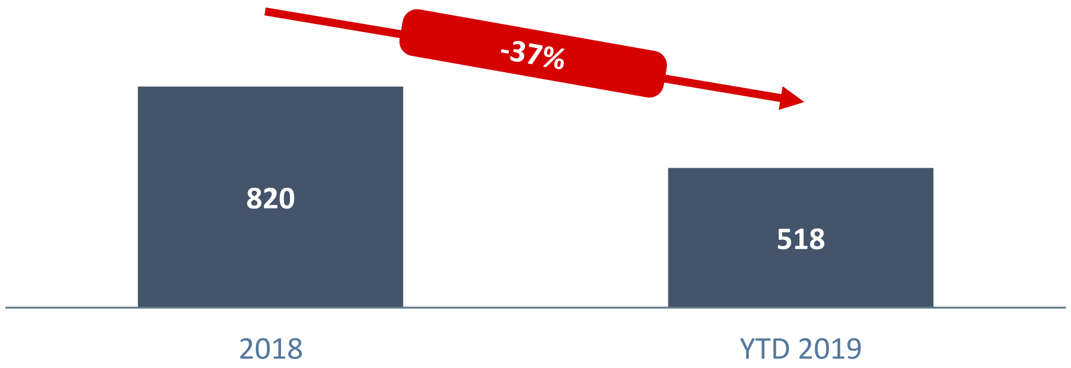
Completed Lateral Feet per Day



Days to Drill[2]



Sand Cost per Well ($M)

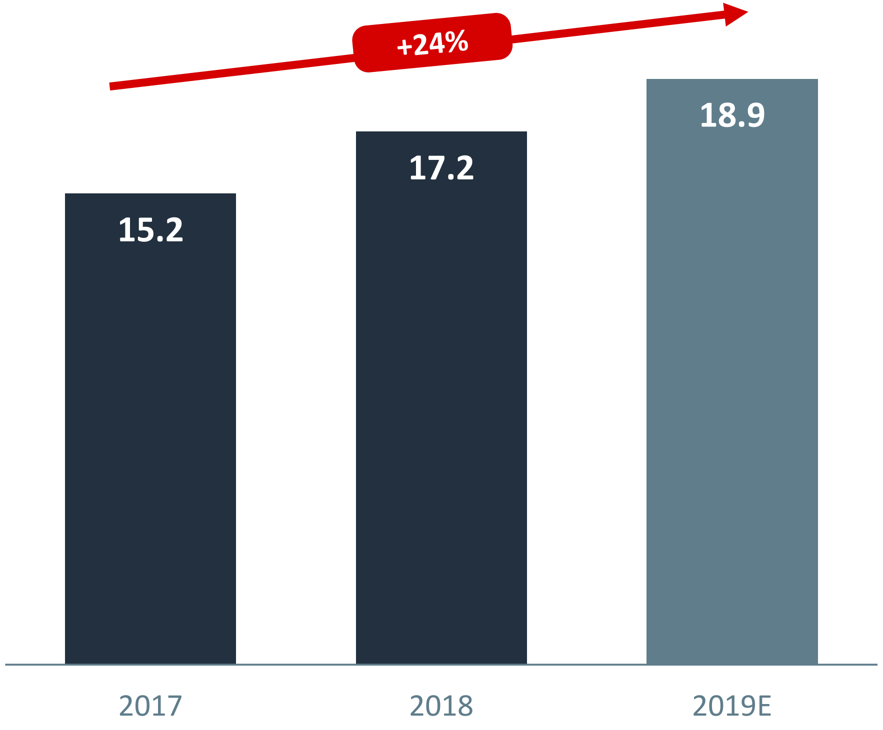


(1) Normalized to 7,000' lateral
(2) Spud to target depth.

Relentless Focus on Efficiencies Continues

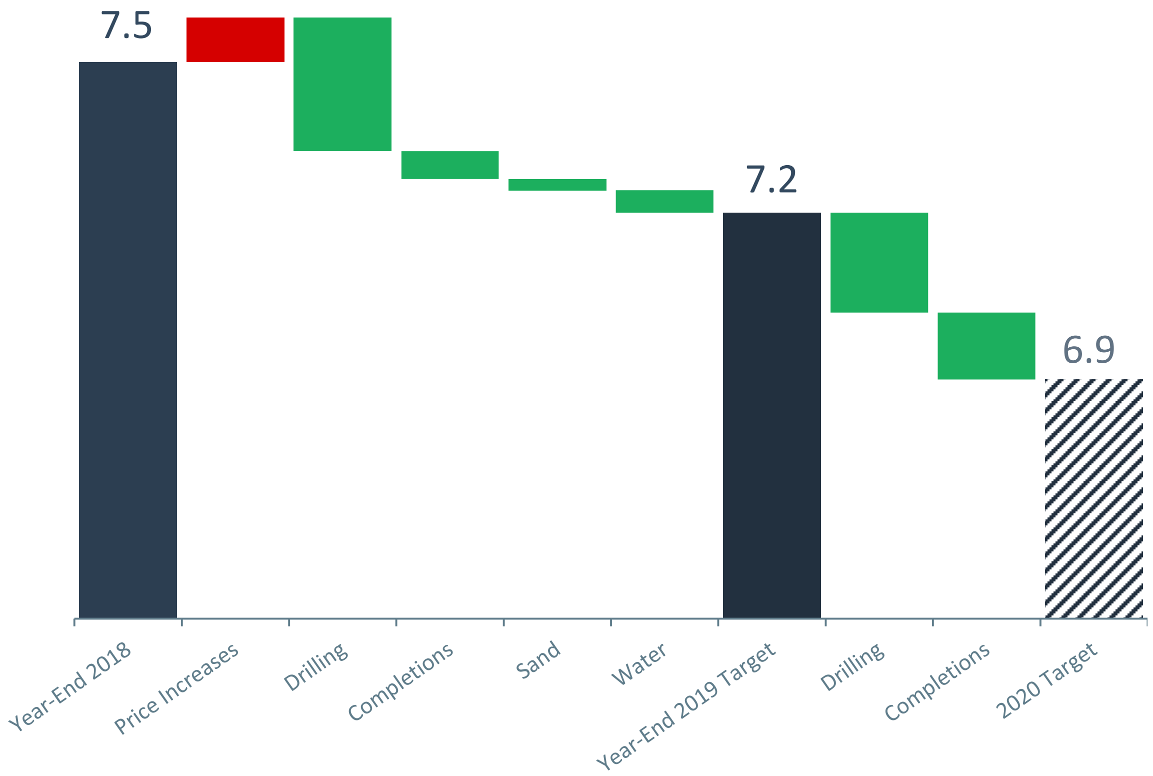
Delaware Basin

(Gross Wells/Rig/Year[1])



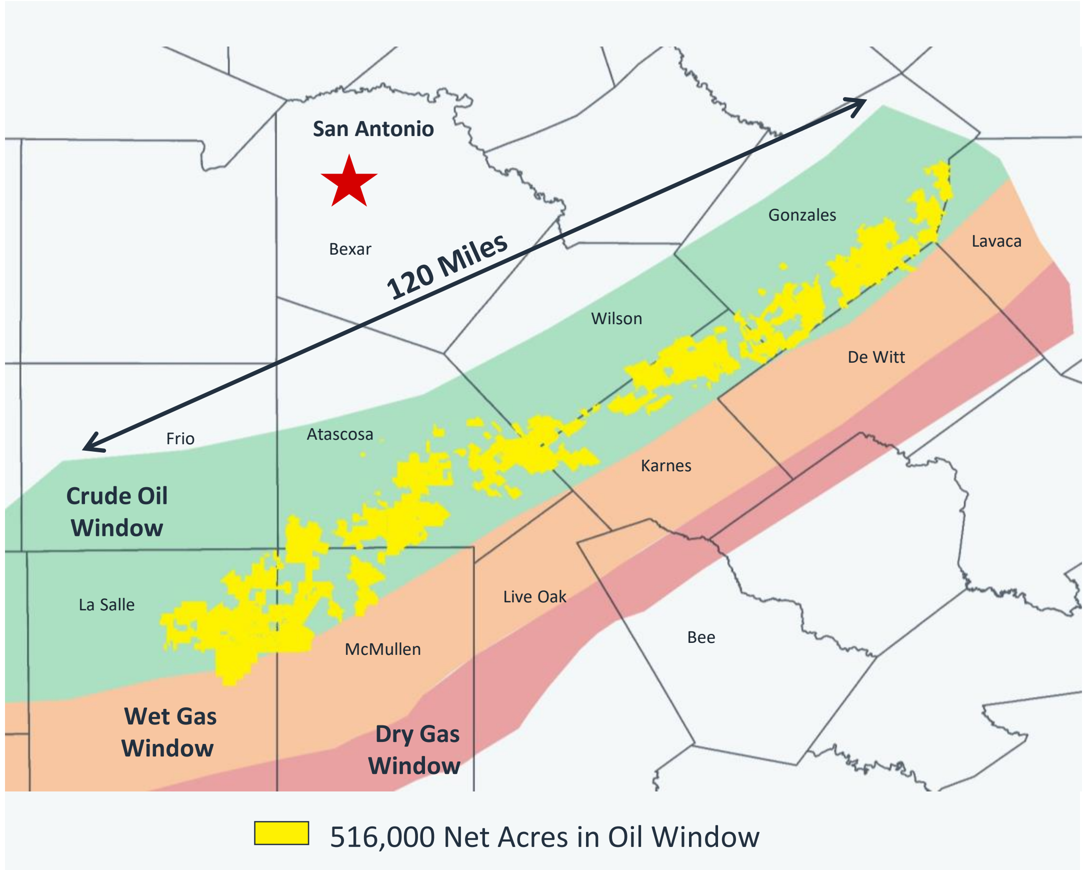
Wolfcamp U Oil Well Cost[2]

($MM)



(1) Average measured depths of 17,952, 18,430 and 19,245 feet for 2017, 2018, and 2019E, respectively.
(2) Well Cost = Drilling, Completion, Well-Site Facilities and Flowback. Normalized to 7,000' lateral.

South Texas Eagle Ford Oil



2019 Highlights

- Record Well Drilled in 2.4 Days to 17,288’
- Exceeded 5% Well Cost Reduction by 3Q19

Bellwether Asset for EOG

- EOG Largest Oil Producer & Acreage Holder
- Organically Leased Position for ≈$450 per Acre
- Capable of Growth for 10+ Years

Concurrent Austin Chalk Development

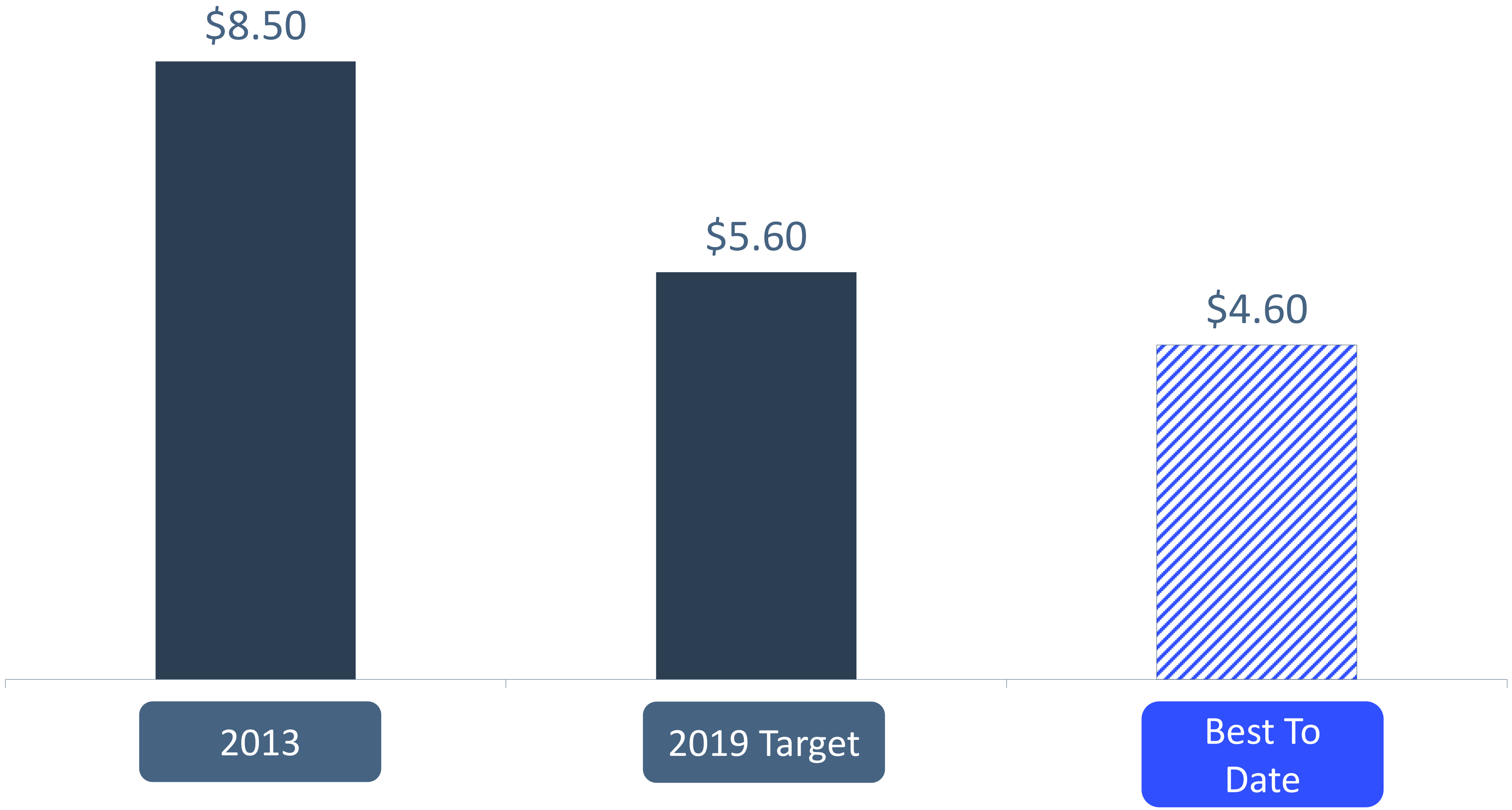
- Focused on Matrix Flow
- Complex Play with “Sweet Spots”

Enhanced Oil Recovery Program

- Converted 54 Wells in 2018
- Strong Results from ≈150 EOR Wells Converted Since Start of Program
- Continue to Refine Technique for Future Growth

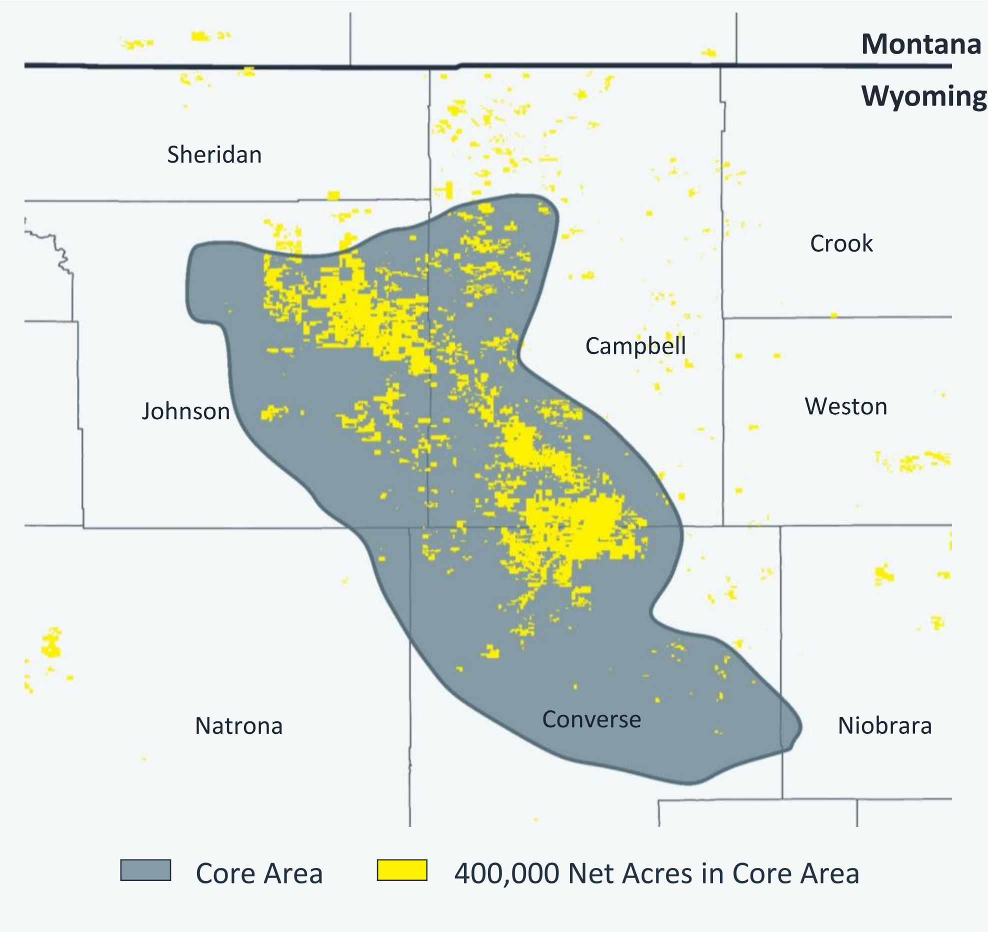
Relentless Focus on Well Cost Reductions

Eagle Ford Well Costs[1]
($MM)



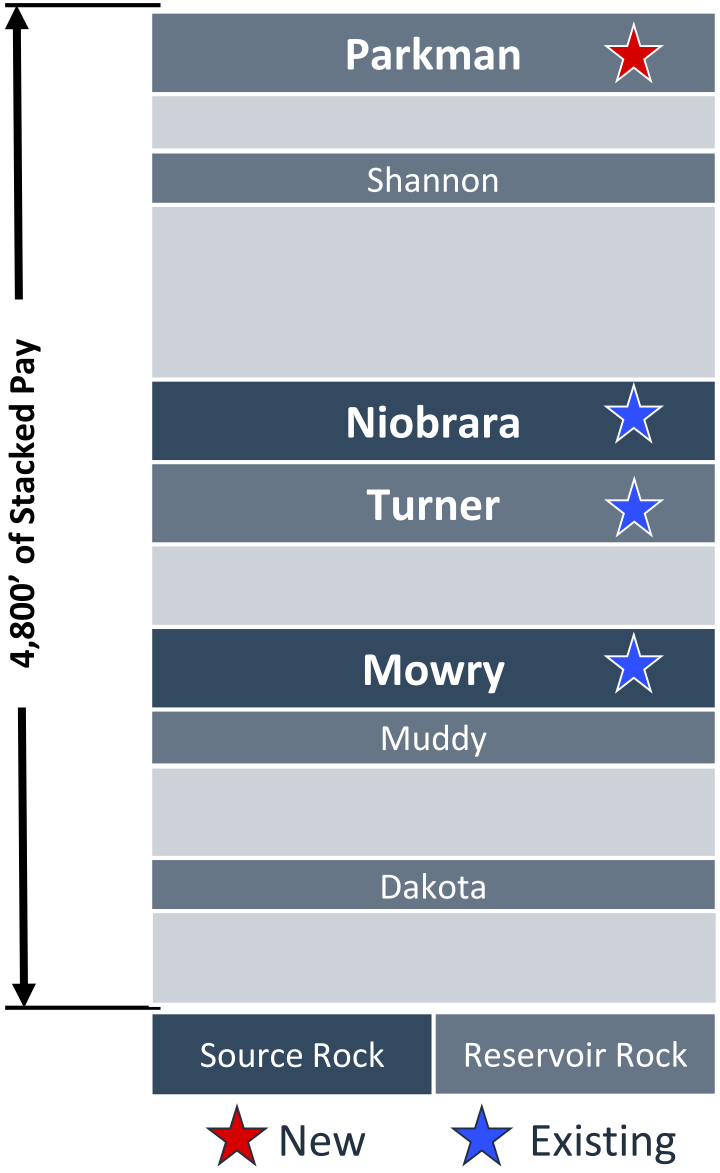
(1) *Well Cost = Drilling, Completion, Well-Site Facilities and Flowback. Normalized to 8,400' lateral.*

Powder River Basin



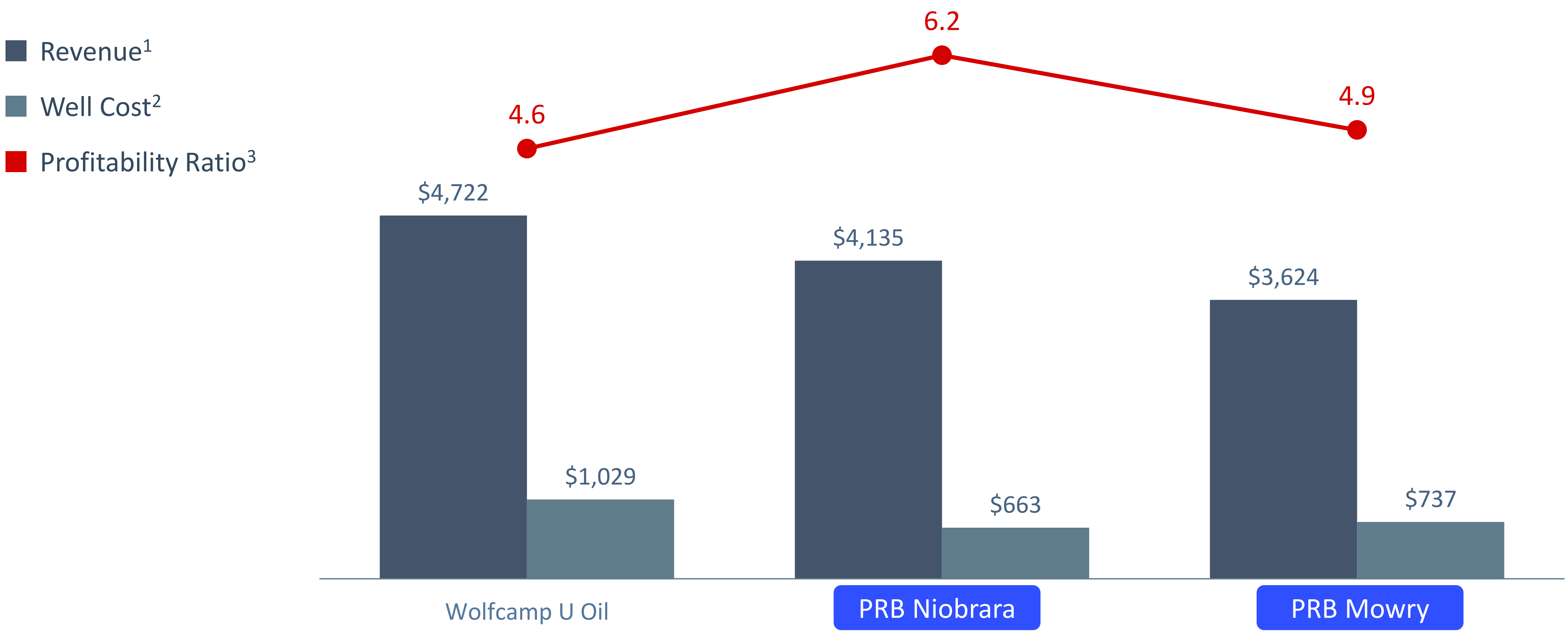
3Q 2019 Highlight-Well: Niobrara Arbalest 473

- Record Well - IP30 1,250 Bopd, 250 Bpd NGLs, 4 MMcfd Gas



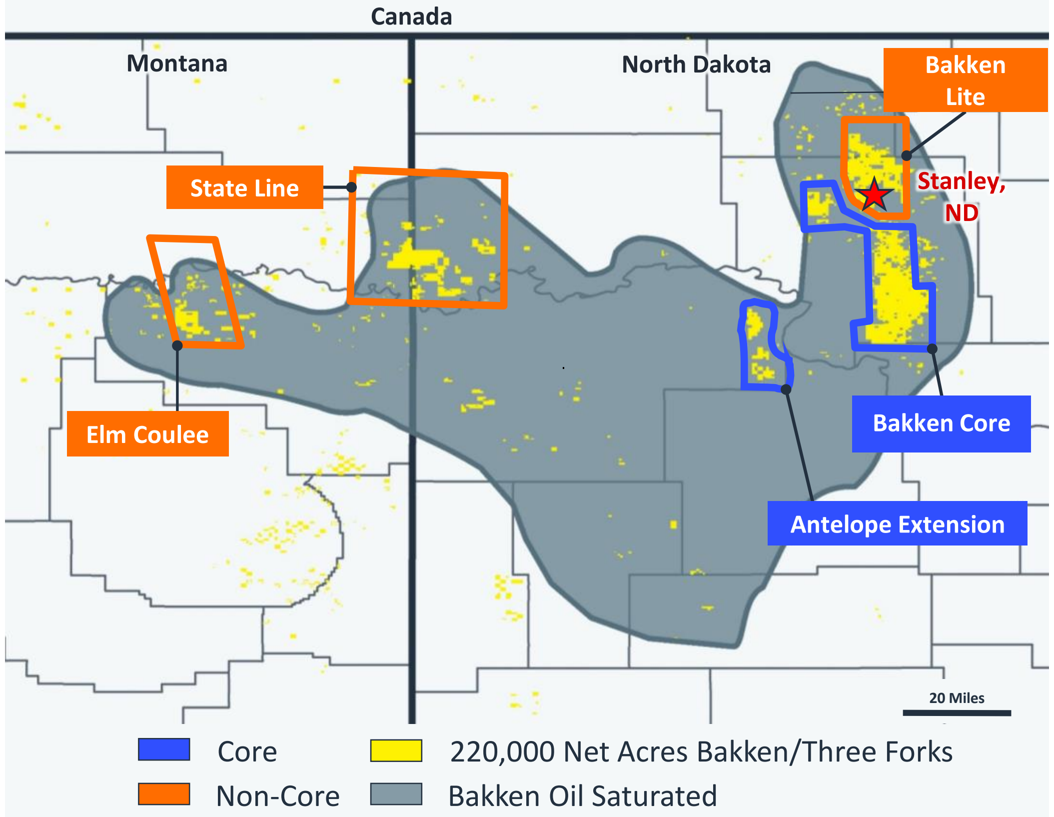
Powder River Basin Plays Competitive in Premium Portfolio

($ per lateral foot)



(1) Revenue per lateral foot calculated using $40 WTI, $2.50 NYMEX and $15 NGL fixed for life of well.
(2) Well Cost = Drilling, Completion, Well-Site Facilities and Flowback per lateral foot.
(3) Profitability Ratio = Revenue / Well Cost.

Bakken/Three Forks



High-Return Drilling Activity Since 2006

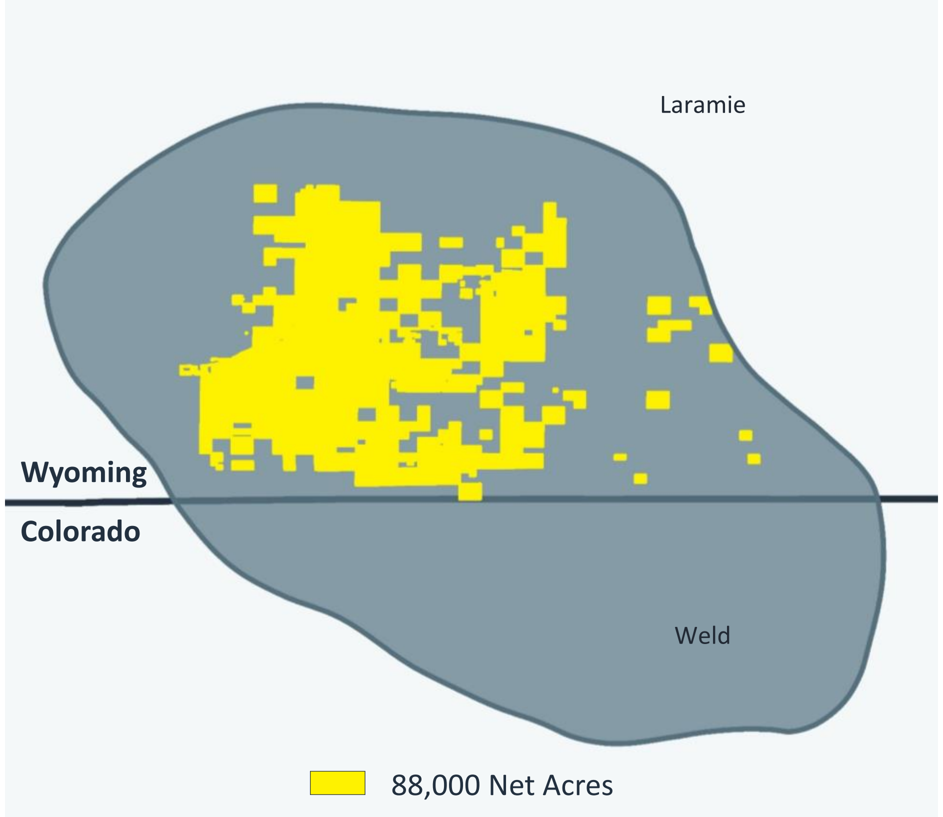
Seasonal Development

- Complete Wells and Build Facilities During Warmer Months
- Developing Antelope Extension in 2019

3Q 2019 Highlight-Well: Clarks Creek 18 IP30 of 3,800 Bopd, 4,800 Boepd

- 15-Well Average IP30 of 2,150 Bopd, 300 Bpd NGLs, 2 MMcfd Gas

Wyoming DJ Basin



Codell and Niobrara Identified as Premium Plays

EOG Development Entirely in Wyoming

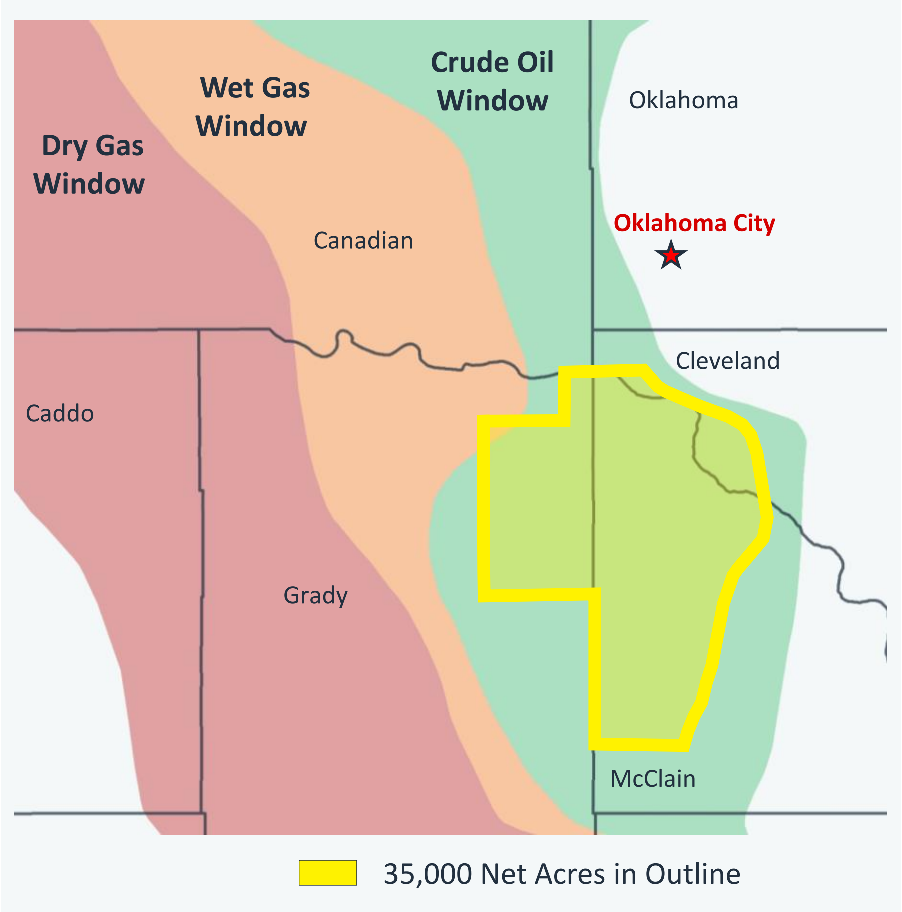
3Q 2019 5-Well Average IP30 800 Bopd, 900 Boepd

Eastern Anadarko Basin Woodford Oil Window

High-Return, Low-Decline Premium Play in Crude Oil Window

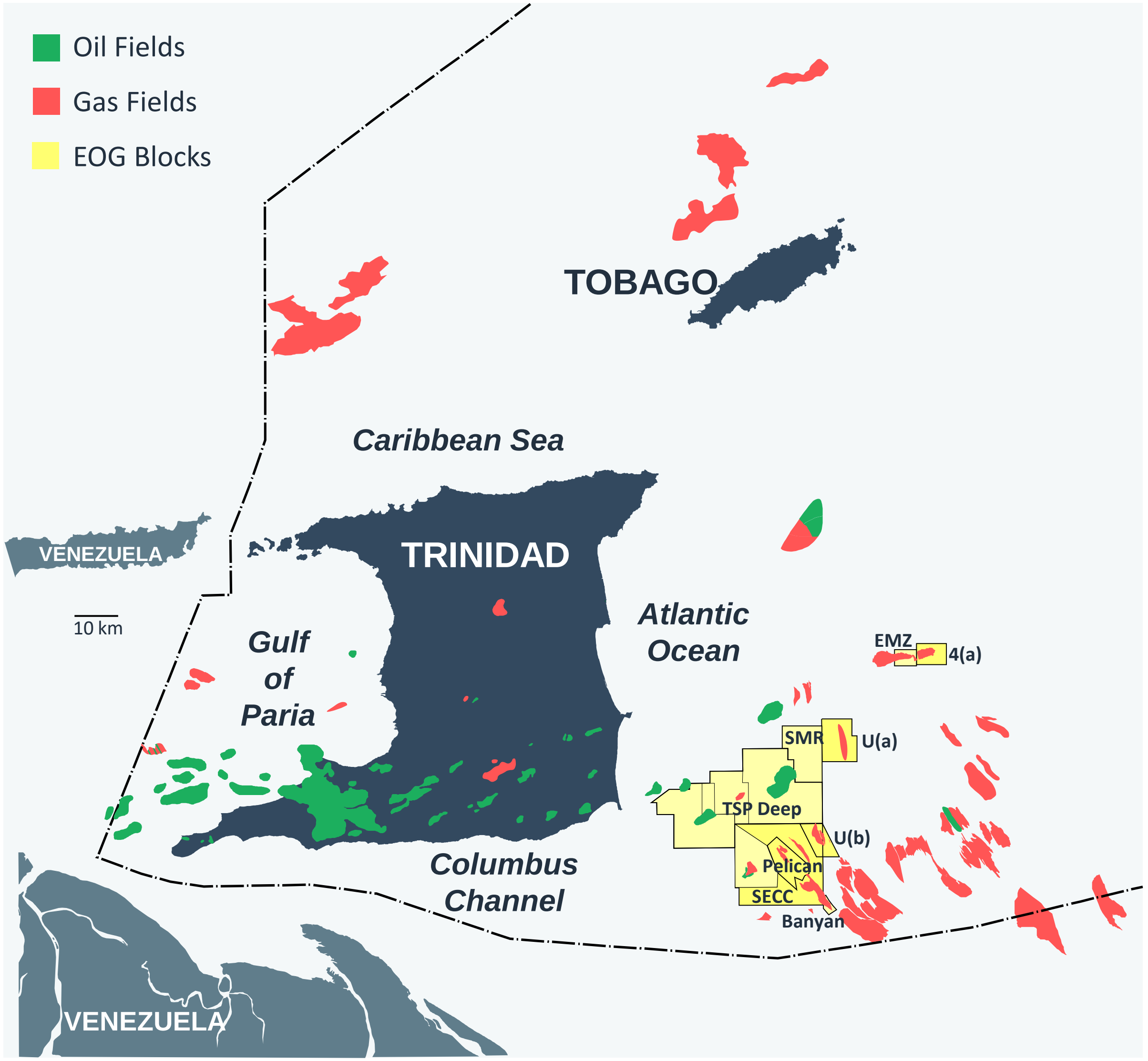
Lowered Well Cost[1] Target from $6.5MM to $6.1MM

Anticipate Sourcing >50% of Water Needs with Recycled Water in 2019



(1) Well Costs = Drilling, Completion, Well-Site Facilities and Flowback. Normalized to 9,500' lateral.

Trinidad



Drilling Program Resumed in 2019

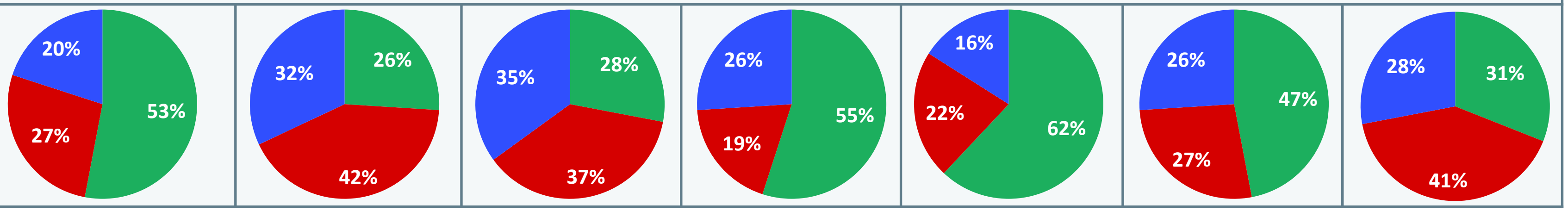
- Exploration Benefitting from 2017-2018 Seismic Program
- Initiated 5-Well Drilling Campaign

Entered Into New Gas Supply Contract

- Enables Additional Development
- Sold into Trinidad Domestic Gas Market

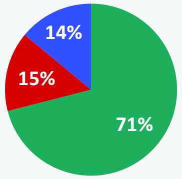
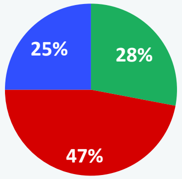
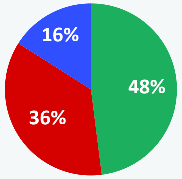
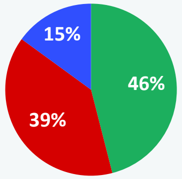
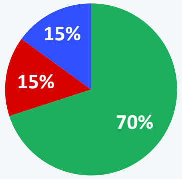
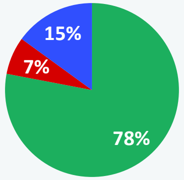
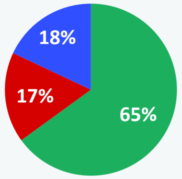
EOG Premium Play Details – Delaware Basin

		Wolfcamp U Oil	Wolfcamp U Combo	Wolfcamp M	First Bone Spring	Second Bone Spring	Third Bone Spring	Leonard
Total	Net Prospective Acres	226,000	120,000	193,000	100,000	289,000	200,000	160,000
	Estimated Total Resource Potential[1]	2.9 BnBoe		1.0 BnBoe	540MMBoe	1.4 BnBoe	615 MMBoe	1.7 BnBoe
Premium	Estimated Remaining Resource Potential[2]	1.33 BnBoe	670 MMBoe	1.0 BnBoe	520 MMBoe	1.0 BnBoe	585 MMBoe	1.4 BnBoe
	Net Undrilled Locations[3]	1,135	555	855	575	1,360	615	1,405
	EUR, Gross / Net After Royalty (Mboe/Well)	1,405/1,170	1,475/1,200	1,455/1,175	1,100/910	900/745	1,170/950	1,205/990
	Well Cost[4] Target ($MM)	$7.2	$7.5	$7.7	$7.3	$7.3	$7.6	$6.3
	Lateral Length	7,000’	8,300’	7,300’	7,000’	7,000’	8,400’	6,800’
	Spacing	660’	880’	1,050’	1000’	850’	880’	660’
	Working Interest / NRI %	77% / 63%						
	Royalty %	18%						
	Average API Gravity	46°						
	Typical EOG Well EUR: Oil, Gas, NGLs							



(1) Estimated resource potential net to EOG, not proved reserves. Includes (i) 601 MMBoe of proved reserves in the Wolfcamp, 75 MMBoe of proved reserves in the First Bone Spring, 85 MMBoe of proved reserves in the Second Bone Spring, and 128 MMBoe of proved reserves in the Leonard, in each case booked at December 31, 2018, and (ii) prior production from existing wells. EOG has 905 MMBoe of total proved reserves in the Delaware Basin booked at December 31, 2018.
(2) Estimated remaining resource potential net to EOG, not proved reserves. Based on number of net undrilled locations in such play and the per-well estimated ultimate recovery (NAR) from such locations.
(3) Premium locations are shown on a net basis and are all undrilled as of date hereof. Premium return hurdle defined on slide 5.
(4) Well Cost = Drilling, Completion, Well-Site Facilities and Flowback. Normalized to the stated lateral length for each play.

EOG Premium Play Details

		Eagle Ford	Powder River Basin			Bakken / Three Forks	Wyoming DJ Basin Codell/Niobrara	Woodford Oil Window
			Mowry Shale	Niobrara Shale	Turner Sand/Parkman			
Total	Net Prospective Acres	516,000	141,000	89,000	154,000	220,000	88,000	35,000
Total	Estimated Total Resource Potential[1]	3.2 BnBoe	1.37 BnBoe	805 MMBoe	300 MMBoe	1.0 BnBoe	210 MMBoe	85 MMBoe
Premium	Estimated Remaining Resource Potential[2]	950 MMBoe	1.37 BnBoe	805 MMBoe	185 MMBoe	240 MMBoe	65 MMBoe	50 MMBoe
Premium	Net Undrilled Locations[3]	1,900	875	555	225	270	150	75
Premium	EUR, Gross / Net After Royalty (Mboe/Well)	645/500	1,885/1,565	1,750/1,455	980/820	1,090/895	520/420	840/670
Premium	Well Cost[4] Target ($MM)	$5.6	$7.0	$6.3	$5.7	$6.5	$4.0	$6.1
Premium	Lateral Length	8,400’	9,500’	9,500’	9,500’	10,800’	9,900’	9,500’
Premium	Spacing	330’	660’	660’	1,700’	650’	1,300’	660’
Premium	Working Interest / NRI	97% / 75%	70% / 58%			70% / 59%	63% / 51%	69%/55%
Premium	Royalty	22%	17%			18%	19%	20%
Premium	Average API Gravity	44°	49°			40°	36°	42°
Premium	Typical EOG Well EUR: Oil, Gas, NGLs	 14%, 15%, 71%	 25%, 28%, 47%	 16%, 48%, 36%	 15%, 46%, 39%	 15%, 15%, 70%	 15%, 7%, 78%	 18%, 17%, 65%

(1) Estimated resource potential net to EOG, not proved reserves. Includes (i) 1,163 MMBoe of proved reserves in the Eagle Ford, 6 MMBoe of proved reserves in the Mowry, 6 MMBoe of proved reserves in the Niobrara, 78 MMBoe of proved reserves in the Turner, 228 MMBoe of proved reserves in the Bakken / Three Forks, 48 MMBoe of proved reserves in the DJ Basin and 73 MMBoe of proved reserves in the Woodford, in each case booked at December 31, 2018, and (ii) prior production from existing wells. EOG has 107 MMBoe of total proved reserves in the Powder River Basin booked at December 31, 2018.

(2) Estimated remaining resource potential net to EOG, not proved reserves. Based on number of net undrilled locations in such play and the per-well estimated ultimate recovery (NAR) from such locations.

(3) Premium locations are shown on a net basis and are all undrilled as of date hereof. Premium return hurdle defined on slide 5.

(4) Well Cost = Drilling, Completion, Well-Site Facilities and Flowback. Normalized to the stated lateral length for each play.

Initial 30-Day Average Production Rates[1]

		Gross Wells	Net Wells	Gross Bopd	Gross Boed	Lateral
Delaware Basin Wolfcamp	3Q 2019	51	48	1,950	3,150	7,300
	2Q 2019	63	57	1,950	2,900	6,500'
	1Q 2019	61	53	1,950	2,950	7,800'
	4Q 2018	42	37	1,950	3,150	7,000'
	3Q 2018	61	58	1,655	2,640	7,100'
Delaware Basin Bone Spring	3Q 2019	24	21	1,600	2,300	5,900
	2Q 2019	5	5	1,300	1,850	5,200'
	1Q 2019	12	10	1,500	2,100	5,500'
	4Q 2018	13	11	1,550	2,150	5,300'
	3Q 2018	4	4	1,135	1,675	5,200'
Delaware Basin Leonard	3Q 2019	2	1	2,000	3,100	9,700
	2Q 2019	3	3	1,200	2,300	4,700'
	1Q 2019	5	5	1,650	3,000	7,600'
	4Q 2018	2	1	1,200	2,350	4,600'
	3Q 2018	6	5	995	1,645	4,500'
Powder River Basin Turner / Parkman	3Q 2019	7	6	800	1,550	9,800
	2Q 2019	6	5	700	1,300	8,400'
	1Q 2019	5	4	650	1,450	9,800'
	4Q 2018	4	3	800	1,400	9,700'
	3Q 2018	13	11	795	1,730	7,500'
Powder River Basin Mowry	2Q 2019	2	1	700	1,950	9,500'
	4Q 2018	2	2	700	2,050	9,200'
	2Q 2018	2	2	760	2,190	9,100'

		Gross Wells	Net Wells	Gross Bopd	Gross Boed	Lateral
Powder River Basin Niobrara	3Q 2019	1	1	1,250	2,200	10,200
	2Q 2019	5	3	1,000	1,450	9,800'
South Texas Eagle Ford	3Q 2019	81	74	1,150	1,350	7,900
	2Q 2019	86	78	1,100	1,350	7,300'
	1Q 2019	93	89	1,350	1,650	8,300'
	4Q 2018	82	78	1,300	1,600	7,300'
	3Q 2018	90	83	1,235	1,540	7,300'
South Texas Austin Chalk	3Q 2019	4	2	1,850	2,500	4,600
	2Q 2019	6	4	1,450	1,850	4,300'
	4Q 2018	6	5	2,650	3,650	5,500'
	3Q 2018	14	10	1,815	2,485	5,000'
DJ Basin Codell / Niobrara	3Q 2019	5	4	800	900	9,700
	2Q 2019	18	12	800	900	11,400'
	1Q 2019	25	13	600	700	9,600'
	4Q 2018	20	10	700	800	9,600'
	3Q 2018	25	19	915	1,090	10,100'
Williston Basin Bakken / Three Forks	3Q 2019	15	13	2,150	2,800	10,600
	4Q 2018	7	5	550	600	10,100'
	3Q 2018	19	12	1,135	1,370	9,400'
Woodford Oil Window	3Q 2019	16	14	950	1,150	9,900
	2Q 2019	11	9	650	800	9,500'
	1Q 2019	4	3	900	1,100	9,700'
	4Q 2018	5	4	600	750	9,200'
	3Q 2018	11	9	720	915	8,500'

(1) *Note: Wells with longer laterals exhibit shallower decline profiles and earn higher returns than comparable wells with shorter laterals.*

Cautionary Notice Regarding Forward-Looking Statements:
This presentation includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, including, among others, statements and projections regarding EOG's future financial position, operations, performance, business strategy, returns, budgets, reserves, levels of production, capital expenditures, costs and asset sales, statements regarding future commodity prices and statements regarding the plans and objectives of EOG's management for future operations, are forward-looking statements. EOG typically uses words such as "expect," "anticipate," "estimate," "project," "strategy," "intend," "plan," "target," "aims," "goal," "may," "will," "should" and "believe" or the negative of those terms or other variations or comparable terminology to identify its forward-looking statements. In particular, statements, express or implied, concerning EOG's future operating results and returns or EOG's ability to replace or increase reserves, increase production, generate returns, replace or increase drilling locations, reduce or otherwise control operating costs and capital expenditures, generate cash flows, pay down or refinance indebtedness or pay and/or increase dividends are forward-looking statements. Forward-looking statements are not guarantees of performance. Although EOG believes the expectations reflected in its forward-looking statements are reasonable and are based on reasonable assumptions, no assurance can be given that these assumptions are accurate or that any of these expectations will be achieved (in full or at all) or will prove to have been correct. Moreover, EOG's forward-looking statements may be affected by known, unknown or currently unforeseen risks, events or circumstances that may be outside EOG's control. Furthermore, this presentation and any accompanying disclosures may include or reference certain forward-looking, non-GAAP financial measures, such as free cash flow or discretionary cash flow, and certain related estimates regarding future performance, results and financial position. Any such forward-looking measures and estimates are intended to be illustrative only and are not intended to reflect the results that EOG will necessarily achieve for the period(s) presented; EOG's actual results may differ materially from such measures and estimates. Important factors that could cause EOG's actual results to differ materially from the expectations reflected in EOG's forward-looking statements include, among others:

- the timing, extent and duration of changes in prices for, supplies of, and demand for, crude oil and condensate, natural gas liquids, natural gas and related commodities;
- the extent to which EOG is successful in its efforts to acquire or discover additional reserves;
- the extent to which EOG is successful in its efforts to economically develop its acreage in, produce reserves and achieve anticipated production levels from, and maximize reserve recovery from, its existing and future crude oil and natural gas exploration and development projects;
- the extent to which EOG is successful in its efforts to market its crude oil and condensate, natural gas liquids, natural gas and related commodity production;
- the availability, proximity and capacity of, and costs associated with, appropriate gathering, processing, compression, storage, transportation and refining facilities;
- the availability, cost, terms and timing of issuance or execution of, and competition for, mineral licenses and leases and governmental and other permits and rights-of-way, and EOG's ability to retain mineral licenses and leases;
- the impact of, and changes in, government policies, laws and regulations, including tax laws and regulations; climate change and other environmental, health and safety laws and regulations relating to air emissions, disposal of produced water, drilling fluids and other wastes, hydraulic fracturing and access to and use of water; laws and regulations imposing conditions or restrictions on drilling and completion operations and on the transportation of crude oil and natural gas; laws and regulations with respect to derivatives and hedging activities; and laws and regulations with respect to the import and export of crude oil, natural gas and related commodities;
- EOG's ability to effectively integrate acquired crude oil and natural gas properties into its operations, fully identify existing and potential problems with respect to such properties and accurately estimate reserves, production and costs with respect to such properties;
- the extent to which EOG's third-party-operated crude oil and natural gas properties are operated successfully and economically;
- competition in the oil and gas exploration and production industry for the acquisition of licenses, leases and properties, employees and other personnel, facilities, equipment, materials and services;
- the availability and cost of employees and other personnel, facilities, equipment, materials (such as water and tubulars) and services;
- the accuracy of reserve estimates, which by their nature involve the exercise of professional judgment and may therefore be imprecise;
- weather, including its impact on crude oil and natural gas demand, and weather-related delays in drilling and in the installation and operation (by EOG or third parties) of production, gathering, processing, refining, compression, storage and transportation facilities;
- the ability of EOG's customers and other contractual counterparties to satisfy their obligations to EOG and, related thereto, to access the credit and capital markets to obtain financing needed to satisfy their obligations to EOG;
- EOG's ability to access the commercial paper market and other credit and capital markets to obtain financing on terms it deems acceptable, if at all, and to otherwise satisfy its capital expenditure requirements;
- the extent to which EOG is successful in its completion of planned asset dispositions;
- the extent and effect of any hedging activities engaged in by EOG;
- the timing and extent of changes in foreign currency exchange rates, interest rates, inflation rates, global and domestic financial market conditions and global and domestic general economic conditions;
- geopolitical factors and political conditions and developments around the world (such as the imposition of tariffs or trade or other economic sanctions, political instability and armed conflict), including in the areas in which EOG operates;
- the use of competing energy sources and the development of alternative energy sources;
- the extent to which EOG incurs uninsured losses and liabilities or losses and liabilities in excess of its insurance coverage;
- acts of war and terrorism and responses to these acts;
- physical, electronic and cybersecurity breaches; and
- the other factors described under ITEM 1A, Risk Factors, on pages 13 through 22 of EOG's Annual Report on Form 10-K for the fiscal year ended December 31, 2018 and any updates to those factors set forth in EOG's subsequent Quarterly Reports on Form 10-Q or Current Reports on Form 8-K.

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The United States Securities and Exchange Commission (SEC) permits oil and gas companies, in their filings with the SEC, to disclose not only "proved" reserves (i.e., quantities of oil and gas that are estimated to be recoverable with a high degree of confidence), but also "probable" reserves (i.e., quantities of oil and gas that are as likely as not to be recovered) as well as "possible" reserves (i.e., additional quantities of oil and gas that might be recovered, but with a lower probability than probable reserves). Statements of reserves are only estimates and may not correspond to the ultimate quantities of oil and gas recovered. Any reserve or resource estimates provided in this presentation that are not specifically designated as being estimates of proved reserves may include "potential" reserves, "resource potential" and/or other estimated reserves or estimated resources not necessarily calculated in accordance with, or contemplated by, the SEC's latest reserve reporting guidelines. Investors are urged to consider closely the disclosure in EOG's Annual Report on Form 10-K for the fiscal year ended December 31, 2018, available from EOG at P.O. Box 4362, Houston, Texas 77210-4362 (Attn: Investor Relations). You can also obtain this report from the SEC by calling 1-800-SEC-0330 or from the SEC's website at www.sec.gov. In addition, reconciliation and calculation schedules for non-GAAP financial measures can be found on the EOG website at www.eogresources.com.