Q3 2018 Operations Report

NYSE: DVN devonenergy.com

Contents

devon

Disciplined Growth Strategy

KEY STRATEGIC OBJECTIVES
1 **Fund** high-return projects
2 **Generate** free cash flow
3 **Maintain** financial strength
4 **Return** cash to shareholders

KEY ACCOMPLISHMENTS IN 2018

- ✓ U.S. oil growth ahead of plan (+200 basis point vs. budget)
- ✓ No change to capital spending outlook
- ✓ Corporate cost savings: ~$475 million/year
- ✓ Operating cash flow accelerates in Q3 (+61% YoY)
- ✓ Reduced consolidated debt by >40%
- ✓ Repurchasing ~20% of outstanding stock
- ✓ Raised quarterly dividend 33%

2018 Outlook: U.S. Growth Initiatives Ahead of Plan

KEY MESSAGES

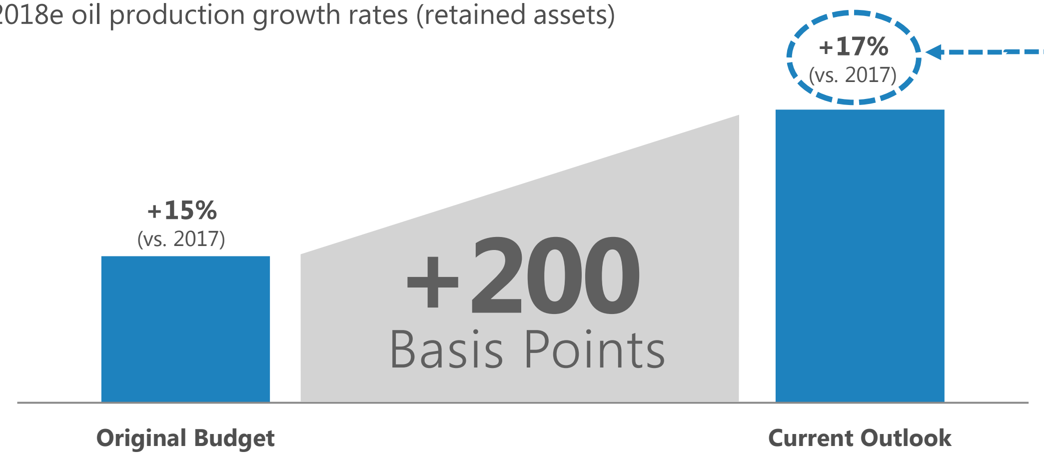
- U.S. oil growth to accelerate into 2019
- No change to activity with higher pricing
- Generating free cash flow ($249 million in Q3)

No change to capital spending plans

2018e E&P capital

U.S. growth exceeding expectations YTD

2018e oil production growth rates (retained assets)



U.S. Oil Production (MBOD)	2018e	2017	%
Delaware Basin	42	30	
STACK	32	25	
Rockies	15	10	
Eagle Ford	28	34	
Other	6	6	
Total retained assets	**123**	**105**	**+17%**
Divested assets (sold or to be sold)	9	11	
Total reported oil production	**132**	**116**	**+13%**

FOR ADDITIONAL DETAILS ON ASSET DIVESTITURES – SEE PAGE 10

2019 Preview: Keeping Our Discipline

OPTIMIZED FOR RETURNS

E&P CAPITAL PROGRAM

$2.4-$2.7 Billion

POSITIONED FOR FREE CASH FLOW

OIL GROWTH

U.S. RETAINED ASSETS

15%-19% Growth

DRIVEN BY LOW-RISK DEVELOPMENT PROGRAM

SHARE REDUCTION

OUTSTANDING SHARES

~20% Reduction

ENHANCING PER-SHARE CASH FLOW GROWTH

KEY MESSAGES

- U.S. resource plays account for ~90% of capital
- Delaware Basin top-funded asset in portfolio
- STACK & Rockies key contributors to oil growth

Executing the Multi-Year Business Plan

	2018e	Multi-Year Targets (2017-2020)
U.S. oil production (retained assets)	⬆ 17% YoY growth	+15% – 17% CAGR
Total BOE production (retained assets)	⬌ 9% YoY growth in U.S.	+5% – 7% CAGR
Per-unit cost savings (G&A, interest & LOE)	⬆ G&A/interest: ↓$475 MM	>20% by 2020
Cash flow growth	⬆ Trending above 3-year plan	>20% CAGR (on a per-share basis)
Net debt to EBITDA ratio	⬆ >40% decrease in debt	~1.0x – 1.5x
Excess cash inflow (Free cash flow + divestiture proceeds)	⬆ ~$5 billion by year end	$6 – $8 billion

Note: Assumes $65 WTI, $3 Henry Hub and current WCS strip pricing

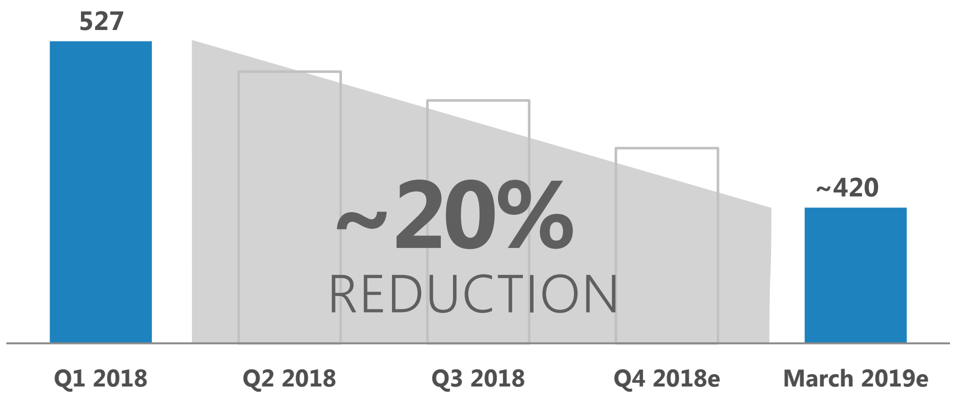
⬆ Exceeding 2018 plan
⬌ On track with 2018 plan

Strategic Deployment of Excess Cash

- $4 billion share-repurchase program underway
  - Represents ~20% of outstanding shares
  - $2.7 billion repurchased to date
- Expect program to be completed by Q1 2019
- Raised quarterly dividend by 33% in 2018
  - Target cash flow payout ratio: 5% - 10%
  - Expect to deliver sustainable dividend growth
- Retired $828 million of upstream debt year to date
  - Reduces interest expense by $66 million annually
  - EnLink sale further deleverages balance sheet
  - Plan to retire maturing debt of $257 million by early 2019

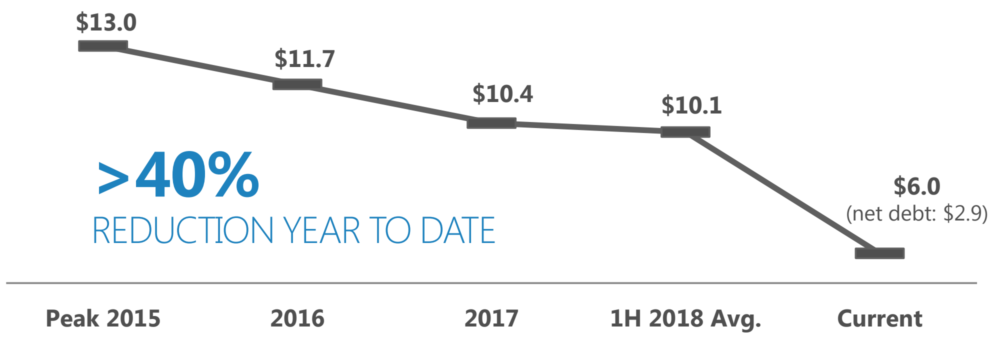
Industry leading share-repurchase program

Average outstanding shares (MM)



Aggressively deleveraging the balance sheet

Consolidated debt ($B)



Q3 2018 – Key Modeling Stats & Outlook

KEY METRICS	Q3 ACTUALS
U.S. oil – retained (MBbls/d)	125
Canada oil (MBbls/d)	102
NGLs – retained (MBbls/d)	107
Gas - retained (MMcf/d)	1,001
Total retained assets (MBoe/d)	500
U.S. divested assets (MBoe/d)	22
Total (MBoe/d)	522
LOE & GP&T ($/BOE)	$9.45
General & administrative expenses ($MM)	$147
Financing costs, net ($MM)	$75
Upstream capital ($MM)	$523

GUIDANCE	Q4 2018e
U.S. oil – retained (MBbls/d)	127 – 131
Canada oil (MBbls/d)[2]	110 – 115[1]
NGLs – retained (MBbls/d)	106 – 110
Gas – retained (MMcf/d)	955 – 1,010
Total retained assets (MBoe/d)	502 – 524
U.S. divested assets (MBoe/d)	13 – 19
Total (MBoe/d)	515 – 543
Lease operating expense & GP&T ($/BOE)	$9.50 – $9.75
Production & property taxes ($MM)	$85 – $95
General & administrative expenses ($MM)	$140 – $160
Financing costs, net ($MM)	$75 – $85
Upstream capital ($MM)	$550 – $650
Avg. basic share count outstanding (MM)	450 – 460

Q3 2018 - ASSET DETAIL	DELAWARE	STACK	ROCKIES	EAGLE FORD	BARNETT	HEAVY OIL
RETAINED PRODUCTION						
Oil (MBbl/d)	44	29	15	31	-	102
NGL (MBbl/d)	19	40	2	15	30	-
Gas (MMcf/d)	103	337	18	84	447	11
Total (MBoe/d)	79	126	19	60	105	104
ASSET MARGIN (per Boe)						
Realized price	$46.80[2]	$31.48	$55.83	$49.44	$17.78	$39.99[3]
Lease operating expenses	($4.90)	($2.16)	($6.90)	($2.34)	($2.14)	($9.61)
Gathering, processing & transportation	($2.01)	($5.05)	($1.68)	($4.92)	($7.53)	($3.93)
Production & property taxes	($3.37)	($1.71)	($6.81)	($2.72)	($1.24)	($0.83)
Cash margin	$36.52	$22.56	$40.44	$39.46	$6.87	$25.62
CAPITAL ACTIVTY (Q3 avg.)						
Upstream capital ($MM)	$198	$167	$29	$35	$15	$60
Operated development rigs	8	8	2		1	
Operated frac crews	2	2	0.5		1	
Operated spuds	25	26	6		9	
Operated wells tied-in	27	26	7		10	
Average lateral length	7,000′	9,800′	8,700′		5,200′	

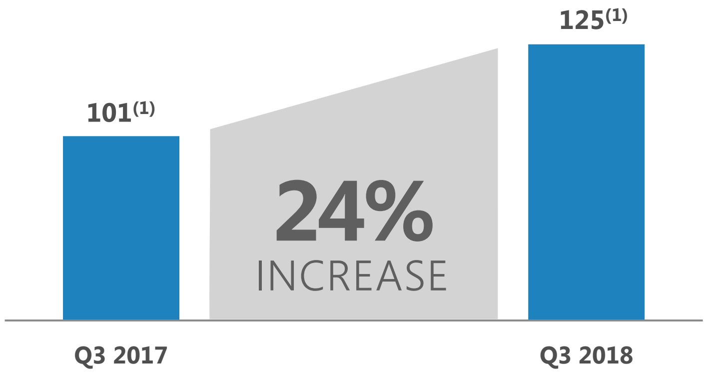
(1) Guidance assumes Jackfish complex curtailments continue throughout December.
(2) Includes benefits of regional basis swaps and firm transport in the Delaware totaling $42 million.
(3) Includes benefits of regional basis swaps in Canada totaling $84 million.

Q3 Results Headlined by Free Cash Flow Generation

- Total U.S. production exceeds guidance
  - Driven by Delaware Basin & Eagle Ford
- Firm transport and basis swaps protect pricing
  - Light-oil has access to Gulf Coast markets
  - Secured NGLs access to Mt. Belvieu (pg. 9)
  - WCS swaps protect Canadian cash flow
- Corporate cost structure continues to improve
  - G&A declines 42% vs. peak rates
  - Borrowing costs reduced 17% vs. Q3 2017
- Capital discipline accelerates free cash flow growth
  - Q3 capital 9% below midpoint guidance
  - Generated $249 million of free cash flow in Q3

Light-oil growth advances

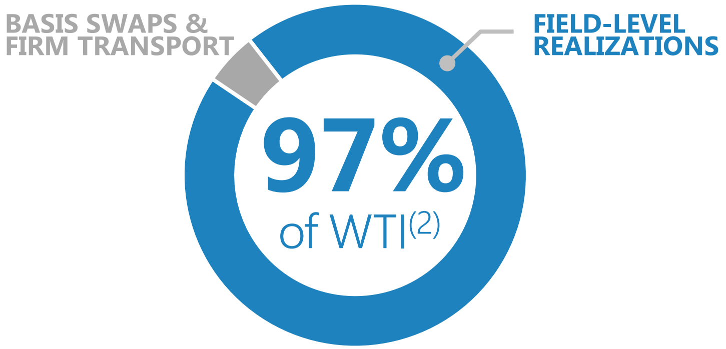
U.S. oil production – retained assets (MBOD)



(1) Excludes divesture assets (see pg. 3 for asset detail)

Strong oil realizations across U.S.

U.S. oil realizations as % of WTI



(2) Includes benefits of basis swaps & firm transport

Achieving improved capital efficiency

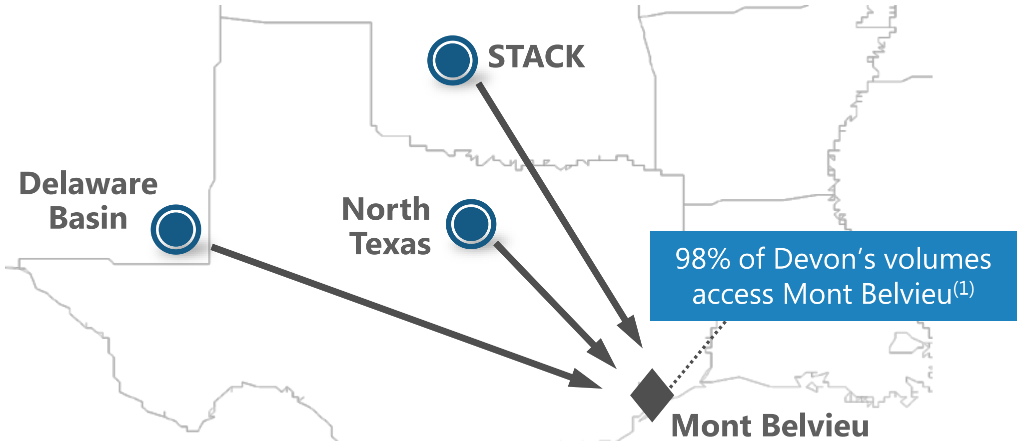
Upstream capital

Capturing the Benefit of Higher NGLs Pricing

- One of the largest NGLs producers in the U.S.
  - Q3 retained NGLs production: 107 MBbls per day
  - Represents ~20% of production mix
- 98% of NGLs have access to Mont Belvieu markets(1)
  - >30% premium to Conway pricing (see chart)
  - Margins to benefit from contractual rights to recover operated ethane production
- Legacy contracts lock in below-market fees with no exposure to rising spot rates
  - Firm sales contractually guarantee flow assurance
- Devon possesses excess capacity at Mont Belvieu
  - ~10 MBbls/day of excess fractionating capacity
  - Supports NGL growth plans through end of decade

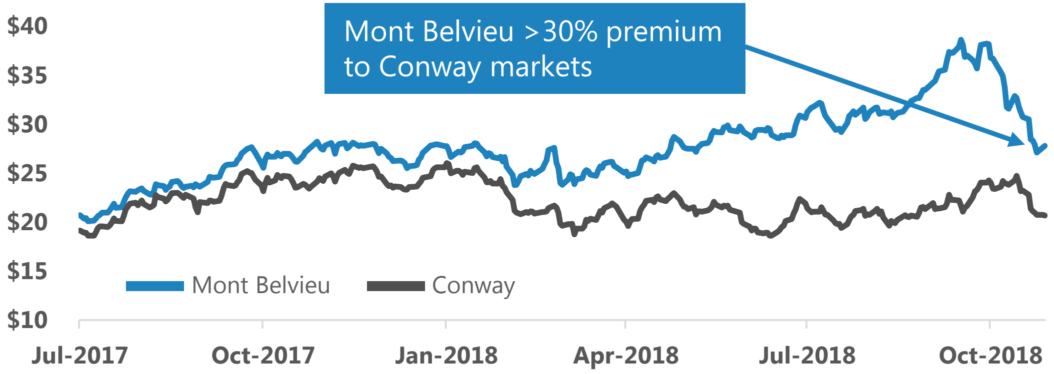
(1) Represents percentage of operated production

Flow Assurance to Premium NGLs Markets



Advantaged Pricing at Mont Belvieu

$/Barrel (Mont Belvieu vs. Conway Pricing)



Divestiture Program Accelerates Value Creation

- Resource quality & depth allows for high-grading of portfolio
- Announced $4.7 billion of divestitures to date
  - Closed EnLink transaction in July ($3.125 billion)
  - Upstream asset sales: $1.6 billion
  - No incremental cash taxes from transactions
- Expect to exceed $5 billion divestiture target around year end
  - Rockies CO_2 projects (bids by year end)
  - Central Basin Platform assets (bids by year end)
- Continuously evaluating options to further high-grade upstream portfolio

TRANSACTION DETAILS

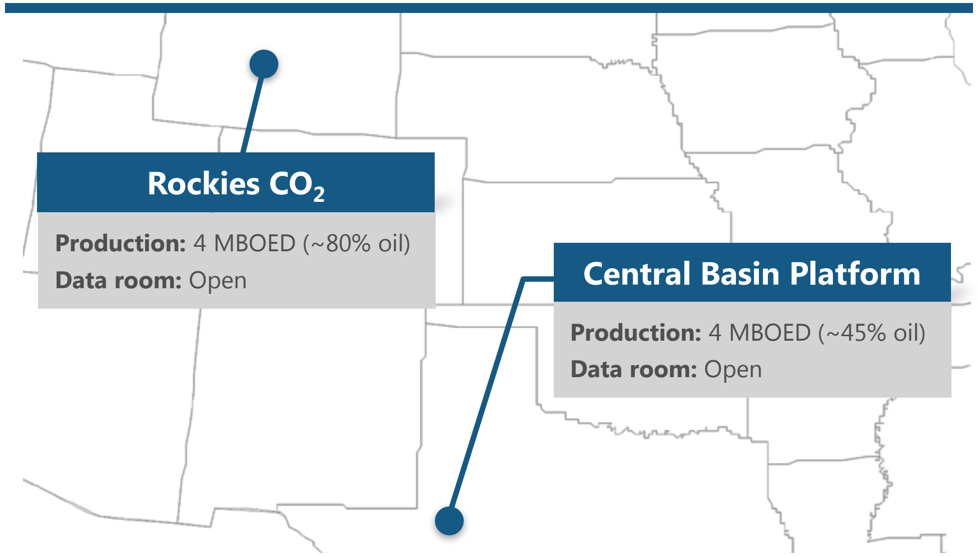
ENLINK MIDSTREAM

CLOSED

SALES PRICE: **$3.125** Billion

ACCRETIVE MULTIPLE: **12x** Cash Flow

Next Steps in High-Grading Portfolio

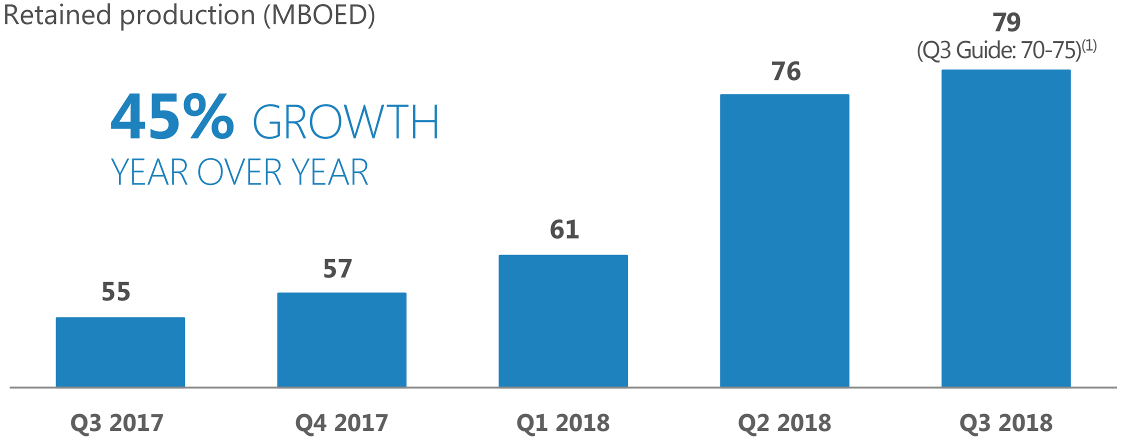


Delaware Basin – Q3 2018 Results

- Production increased 45% year over year[1]
  - 4,000 BOE per day above top end of guidance
  - Oil and liquids reach 78% of product mix
- "Step-change" improvement in 2018 well results
  - >70% improvement in productivity vs. 3-year avg.
  - Driven by focused program in state-line area
- Q3 performance driven by strong well productivity
  - Top 10 wells achieved IP30: ~3,400 BOED (60% oil)
  - Driven by prolific Wolfcamp results (see pg. 12)
- Effectively mitigating inflation pressures
  - Per-unit LOE declined 8% vs. Q2 2018
  - Capital in line with budget expectations YTD

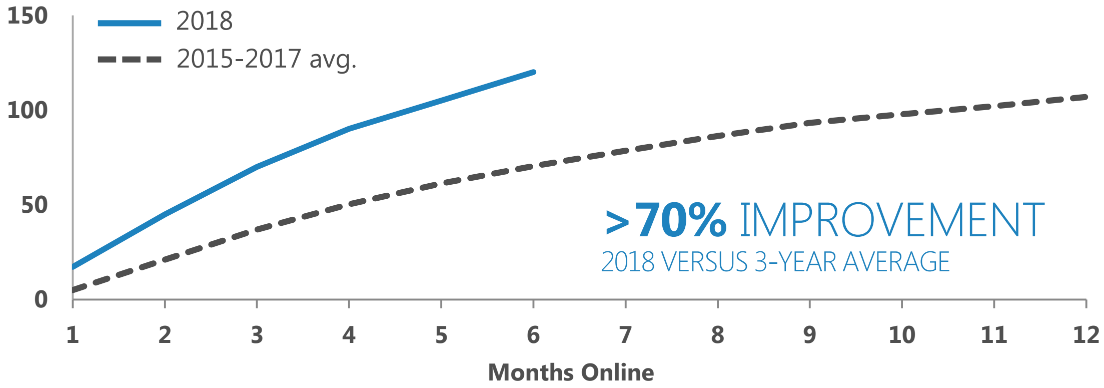
Q3 Production Outperforms Guidance[1]

Retained production (MBOED)



Delaware Well Productivity Reaching Record Highs

Average Cumulative Oil Production Per Well (MBOD)

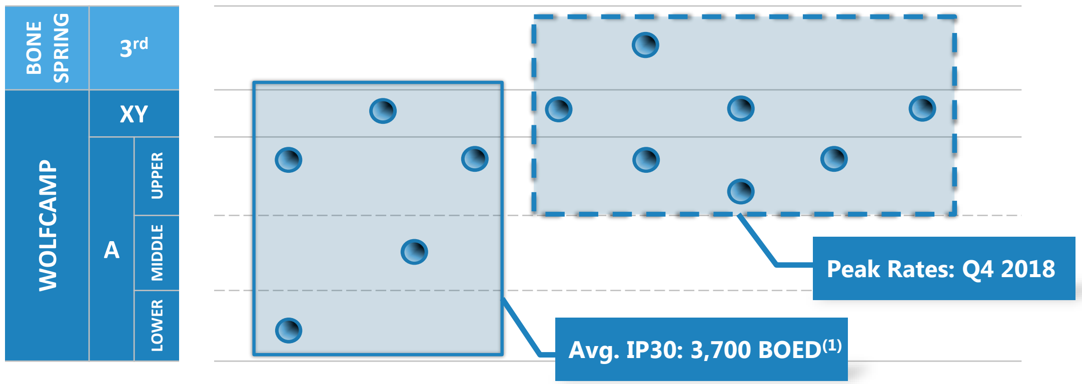


(1) Production and guidance range adjusted for "Mi Vida" and other non-core asset divestitures (~3 MBOED impact).

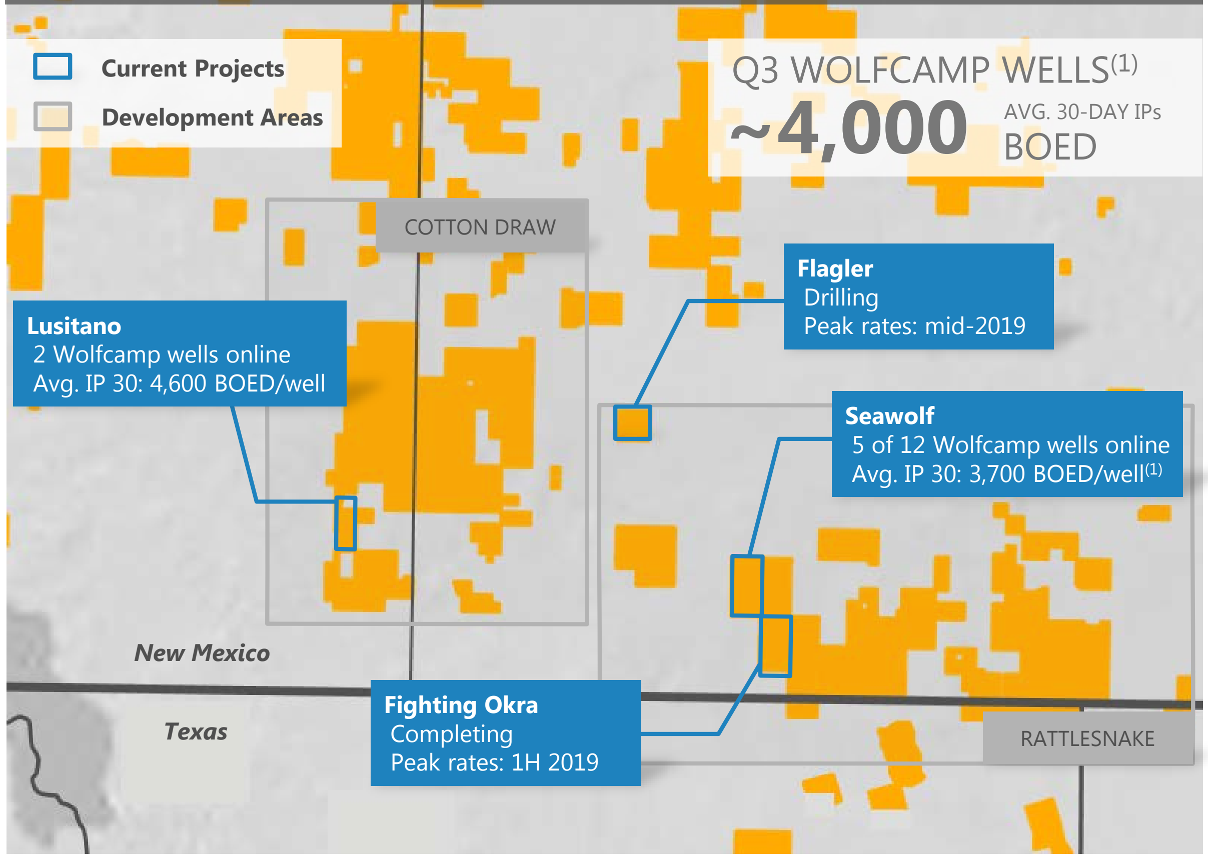
Delaware – Wolfcamp Program Delivers Prolific Results

- Well productivity at Seawolf trending above plan
  - Wolfcamp sweet spot in southern Lea County
  - Avg. IP30: 3,700 BOED[1] (represents 5 of 12 wells)
  - Peak rates for remaining 7 wells expected in Q4
- Lusitano derisks Cotton Draw Wolfcamp potential
  - 6-well project testing Leonard and Wolfcamp
  - Wolfcamp wells avg. IP30: 4,600 BOED (50% oil)

Seawolf Development - Rattlesnake Area



WOLFCAMP DEVELOPMENT PROGRAM BUILDING MOMENTUM



(1) Includes two appraisal wells (avg. lateral 5,700') that were normalized for 10,000' at a 1.75 multiplier.

Delaware – Infrastructure Supports Profitable Growth

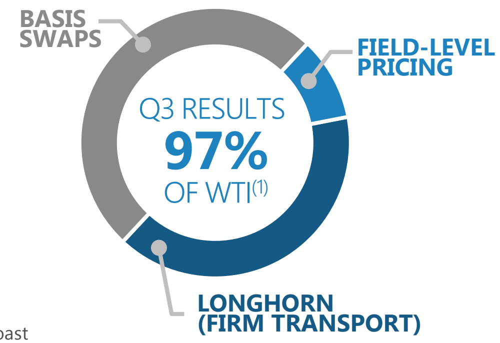
- Premium oil pricing and flow assurance
  - Q3 oil realizations: 97% of WTI(1)
  - Swaps & firm transport protect ~75% of 2019 oil
  - Firm oil sales contracts guarantee in basin flow assurance (100 MBOD of contractual capacity in basin)
- NGLs have firm transport to Mont Belvieu (see pg. 9)
  - Revenue improves ~30% vs. Q2 2018
- Swaps protect gas production through 2019
- Infrastructure drives sustainable cost savings
  - Operating costs improved ~60% vs. peak rates
  - Oil and produced water gathered on pipe (avoids trucking)
  - Operate ~50 disposal wells and 8 water reuse facilities
  - 80% of water used in operations is recycled

Positioned for flow assurance & premium pricing

FLOW ASSURANCE PLAN

- ❑ Firm transport: ~20 MBOD on Longhorn
- ❑ Firm sales(2): 100 MBOD in basin
- ❑ Established local refinery relationships
- ❑ ~85% of oil gathered on pipe
- ❑ >90% of produced water on pipe

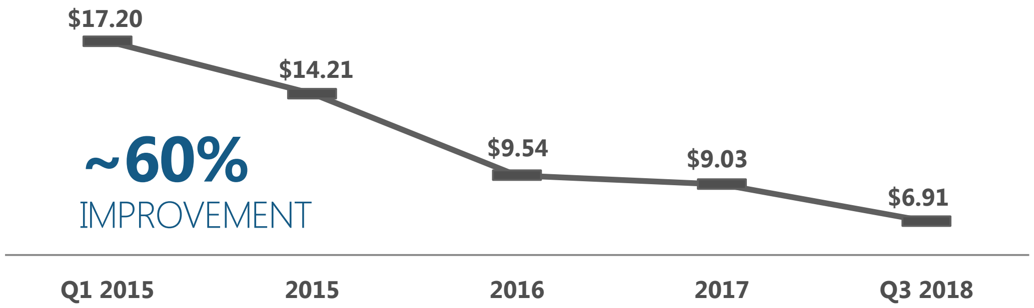
STRONG PRICE REALIZATIONS



(1) Includes benefits of basis swaps and firm transport to Gulf Coast
(2) Long-term guaranteed contractual capacity with firm transport partners

Improved infrastructure driving lower costs

LOE & Transportation Expense ($/BOE)



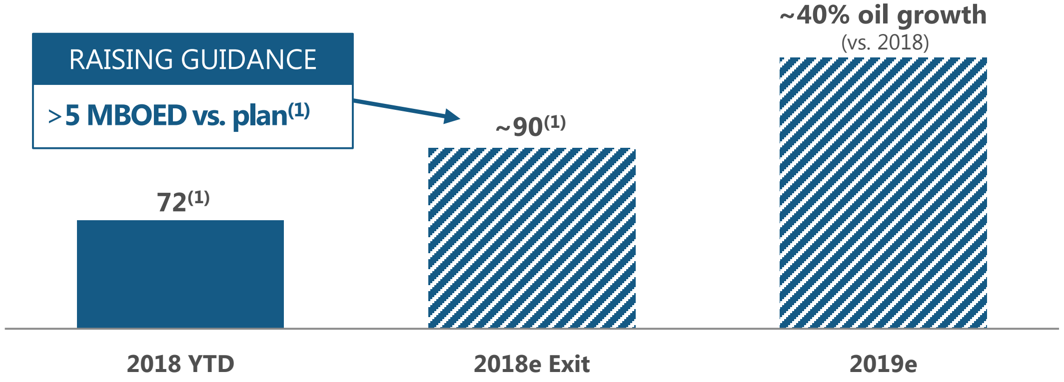
Note: 2015-2017 costs are pro forma for revenue recognition accounting rules recently implemented.

Delaware Basin – Raising Growth Outlook

- Raising 2018 production growth estimates
  - Increasing 2018 exit rate growth: ~90 MBOED(1)
  - Non-core divestitures: 3 MBOED impact to Q4
  - Activity to reach 10 operated rigs around year end
- Ramping-up capital investment in 2019
  - Delaware is top-funded asset by a wide margin
  - Capital investment: up to $1.0 billion
  - Oil production growth: ~40% vs. 2018
  - Per-unit LOE to decline 10% to 15%
- Accelerating Todd 2nd Bone Spring program
  - Two Boundary Raider wells delivered highest rates in Delaware history (IP24: 24 MBOED)
  - Drill >20 wells in focus area over next year (see map)

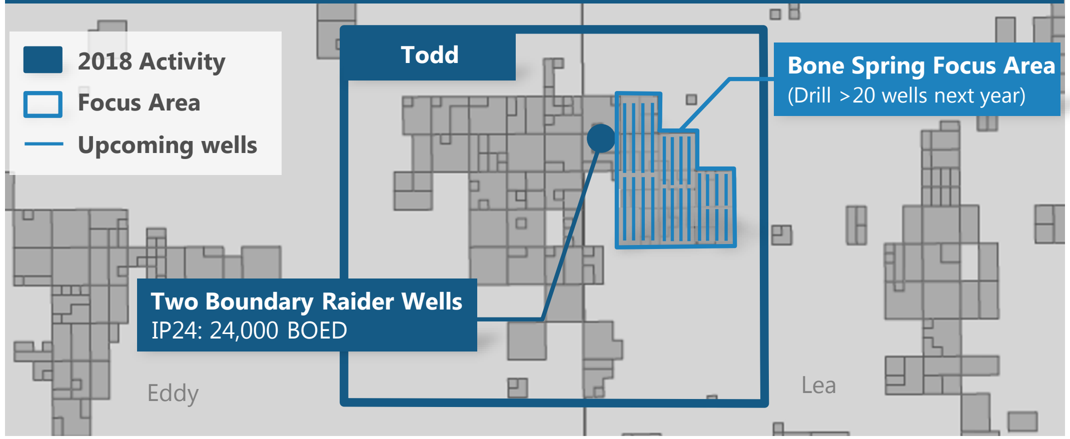
High-return oil growth positioned to accelerate

Retained production (MBOED)



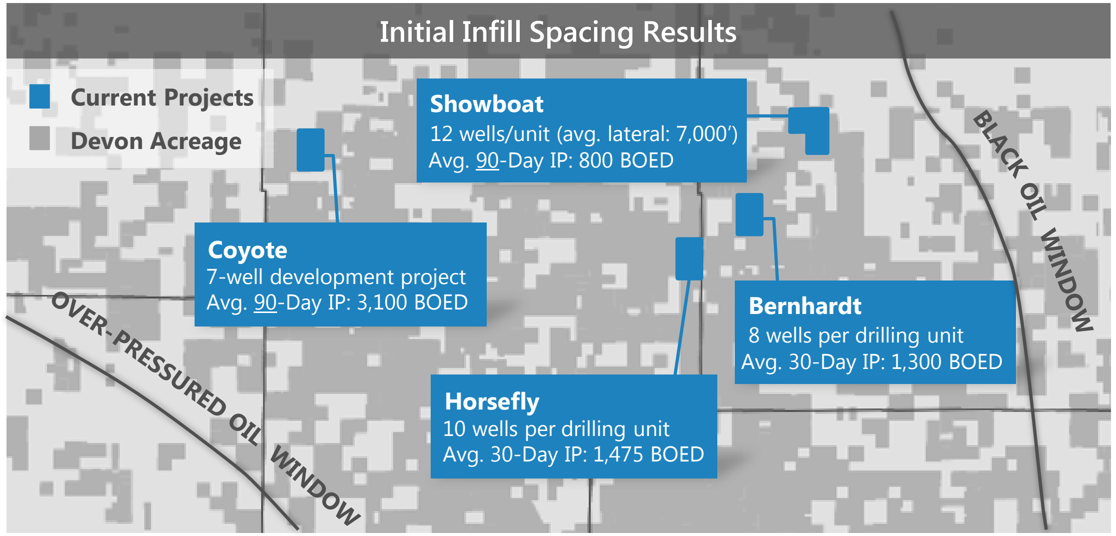
(1) Production and guidance range adjusted for "Mi Vida" and other minor non-core asset divestitures (~3 MBOED impact).

2019 PREVIEW: ACCELERATING TODD 2ND BONE SPRING PROGRAM



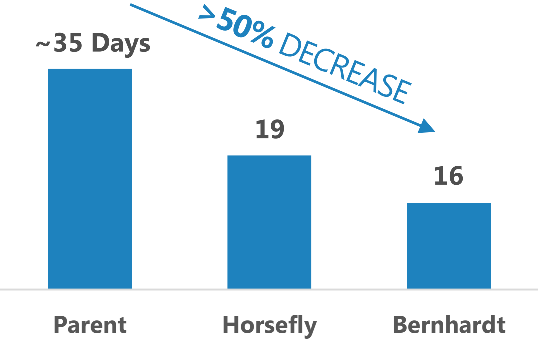
STACK – Initial Infill Spacing Results

- Q3 net production up 16% year over year
  - — Dewey County assets sold in Q3 (~7 MBOED)
  - — NGLs up ~30% with benefits of Mont Belvieu pricing
  - — Total volume growth limited by infill pilot performance
  - — Capital efficiency improves (spending 31%↓ vs. 1H 2018 avg.)
- Infill activity accelerates D&C capital efficiencies
  - — Horsefly costs reduced to ~$7.5 million per well
  - — Bernhardt achieves >30% savings vs. parent (~$7MM/well)
- Pilots testing higher-density spacing not optimized
  - — Showboat upside test underperforms vs. plan (12 wells/unit)
  - — Horsefly delivered improved results (10 wells/unit)
  - — Bernhardt rates limited by flowback strategy (8 wells/unit)
  - — Lighter-spaced Coyote project delivers best results



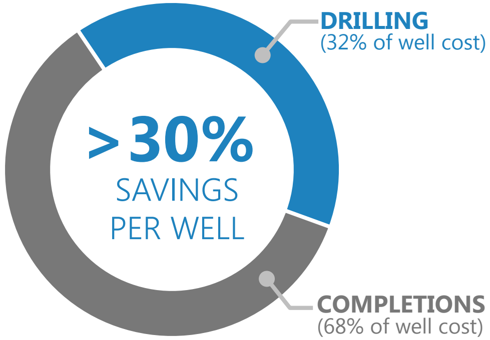
Drilling Days Reduced

Extended reach laterals



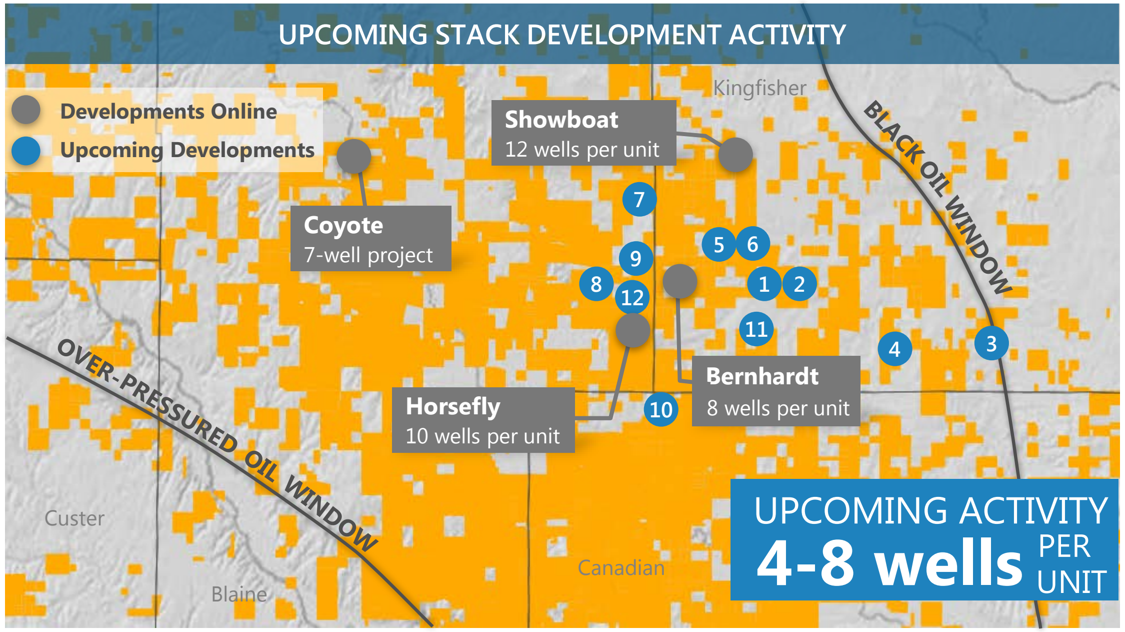
Significant Capital Savings

Bernhardt D&C costs vs. parent well



STACK – Next Steps to Optimize Development Returns

- Learnings from high-density infill tests
  - Initial results indicate spacing was too tight
  - Flowback approach key for oil recoveries
  - Upper Meramec delivered best well results
  - Vertical communication observed
  - Substantial D&C savings achieved (pg. 15)
- Reverting to "base case" spacing to optimize returns
  - Upcoming activity targeting 4-8 wells per unit
  - Well placement focused in Upper Meramec
  - Flowback adjusted to improve performance
- Project IRRs to benefit from less capital intensity
  - Utilizing tailored, more capital efficient completions
  - Projects to benefit from less infrastructure capital on centralized facilities



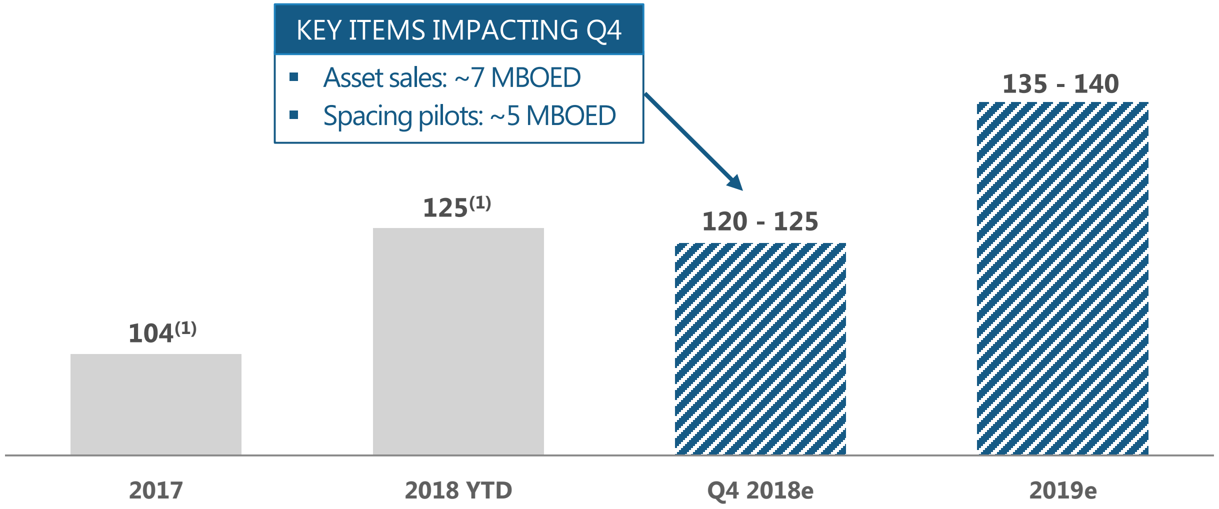
1 **Geis** 7 wells per unit Flowing Back	2 **Safari** 4 wells per unit Online Q4 2018	3 **Whiskey Jack** 5 wells per unit Online Q4 2018	4 **Shangri-La** 5 wells per unit Online Q4 2018
5 **Pony Express** 4 wells per unit Online Q4 2018	6 **Northwoods** 4 wells per unit 2019 project	7 **Scott** 6 wells per unit 2019 project	8 **Doppelganger/Kraken** 8 & 7 wells per unit 2019 project
9 **Morning Thunder** 4 wells per unit 2019 project	10 **ML Block** 8 wells per unit 2019 project	11 **Brachiosaurus** 4 wells per unit 2019 project	12 **Minnie Ha Ha** 6 wells per unit 2019 project

STACK – Outlook

- Upcoming activity highly accretive to corporate return targets
  - Q4 activity: 20 to 25 new wells online
  - Re-establishes growth trajectory by year end
- Positioned for production growth in 2019
  - 2nd highest funded asset in portfolio
  - Capital investment: $500-$700 million
  - Expect to bring online 70-90 wells
  - Targeting 4-8 wells per drilling unit
- Significant growth inventory remaining
  - 130,000 net acres in over-pressured oil window
  - Acreage position >90% undeveloped
  - Meramec inventory risked at 6 wells per unit
  - High-quality Woodford optionality

PRODUCTION GROWTH TO RESUME IN 2019

Retained production (MBOED)



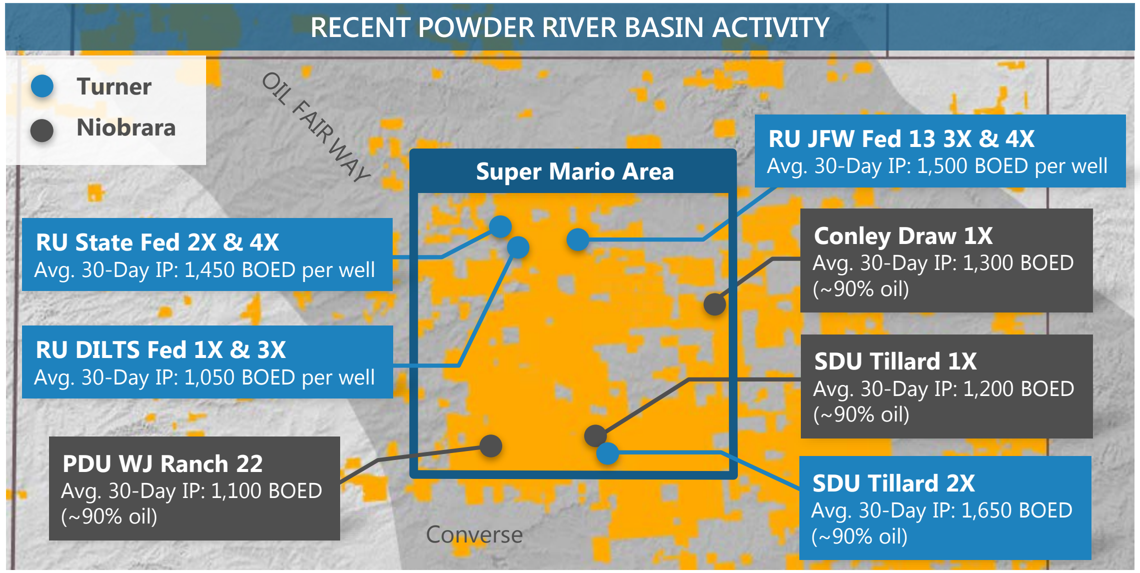
(1) Production adjusted for recent Dewey County asset sale.

KEY MESSAGES

- Growth trajectory re-established by year end
- Upcoming infill projects recalibrated to optimize IRRs
- D&C costs expected to further decline in 2019

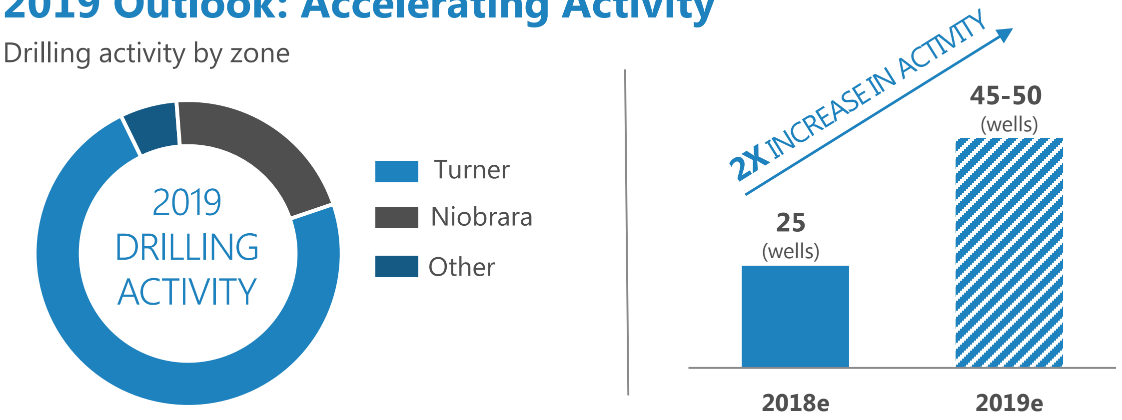
Rockies – An Emerging Growth Opportunity

- Net production increased 17% vs. Q2 2018
  - Oil production ~75% of product mix
  - Powder River barrels receive WTI pricing
- Accelerating capital activity in 2019
  - Expect to operate 4 rigs by early next year
  - Represents 2x increase in activity from 2018
  - No permitting or infrastructure constraints
- Shifting Super Mario area into development
  - ~35 Turner wells planned to spud in 2019
  - Multi-year Turner inventory (~200 wells)
- Niobrara provides significant upside potential
  - Initial 3 wells successful (product mix: ~90% oil)
  - >10 additional tests scheduled in 2019
  - Net acres: ~200,000 in oil fairway

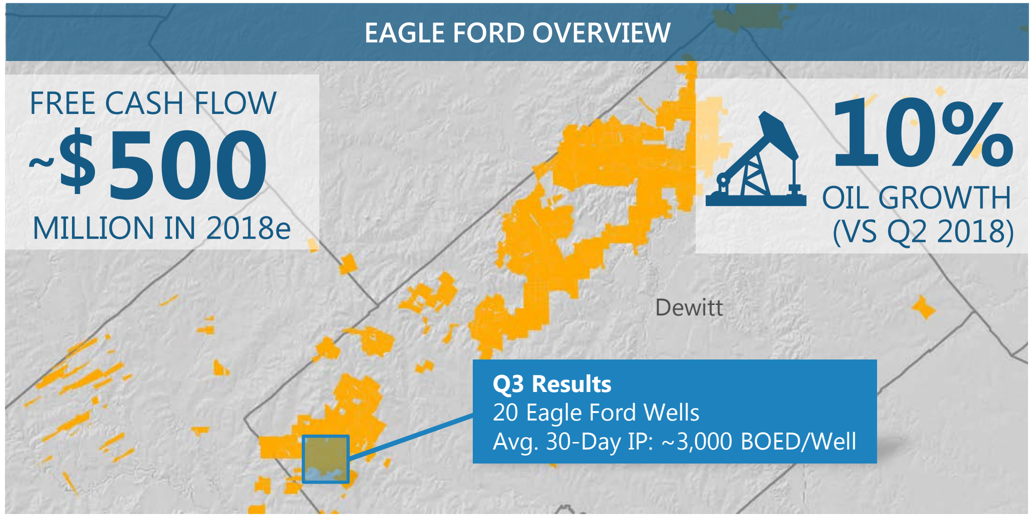


2019 Outlook: Accelerating Activity

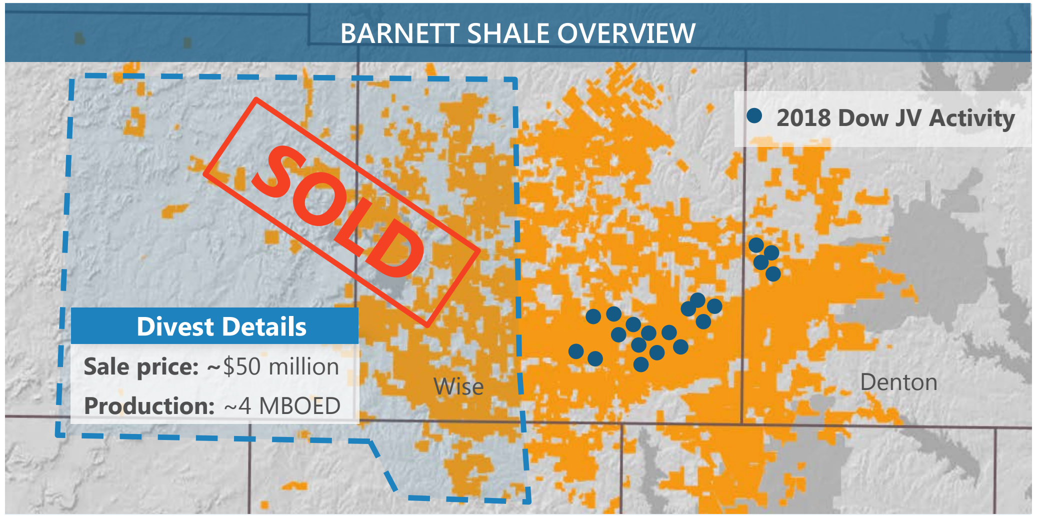
Drilling activity by zone



Eagle Ford and Barnett Shale



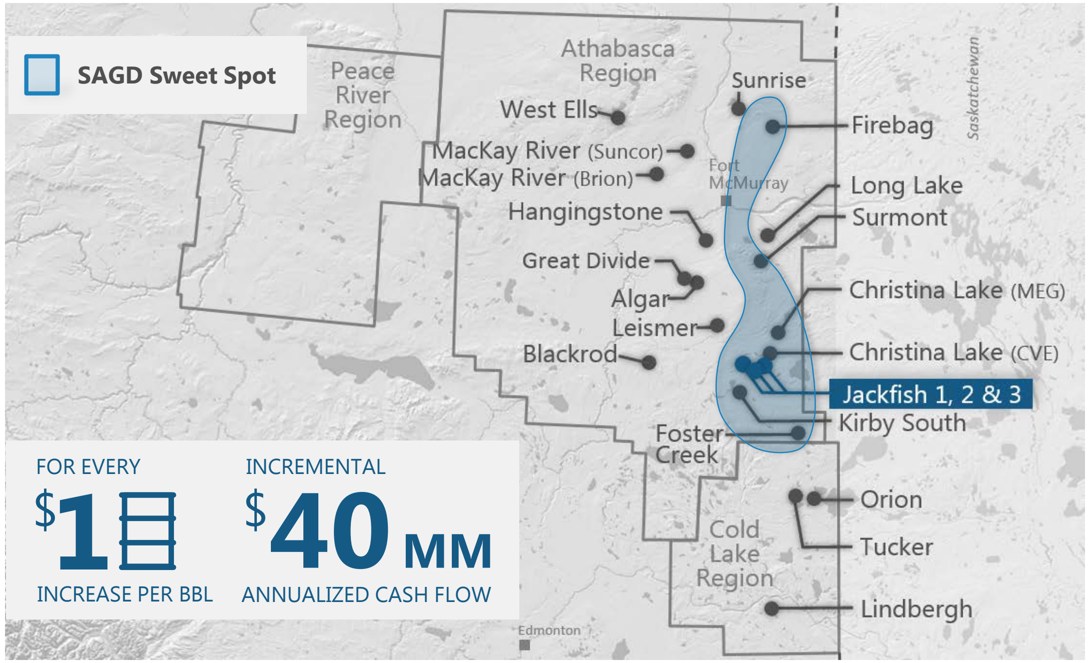
- Q3 production averaged 60 MBOED (51% oil)
- Strong well results drive 10% growth vs. Q2
  - 20 new wells : IP30 ~3,000 BOED (50% oil)
  - Completion design contributes to performance
- Free cash flow accelerates (~$500 million in 2018e)
- Q4 outlook: ~60 MBOED (15 new wells online)



- Q3 production averaged 105 MBOED (~30% NGLs)
- Dow JV and refrac activity stabilizing production
- NGL pricing drives margin expansion
- GP&T expense to decline by ~$90 million in 2019
- Wise County package sold for ~$50 million (Q4 close)

Heavy Oil – Overview & Outlook

- Q3 net production: 104,000 Boe per day
  - Jackfish 1 maintenance impact: ~15 MBOD
  - Jackfish 2&3 produced at nameplate capacity
  - LOE per Boe declined 16% vs. Q2 2018
- Full-scale operations restored at Jackfish complex
  - Rates reach ~110% of nameplate capacity in October
- Adjusted November production rates at Jackfish due to market conditions (~8 MBOD impact to Q4)
  - Previously incorporated in Q4 oil production outlook (press release issued 10/16/18)
- Potential to continue curtailing barrels in December
  - Decision based on real-time pricing
- WCS basis swaps protect Q4 cash flow (~$150 MM benefit)



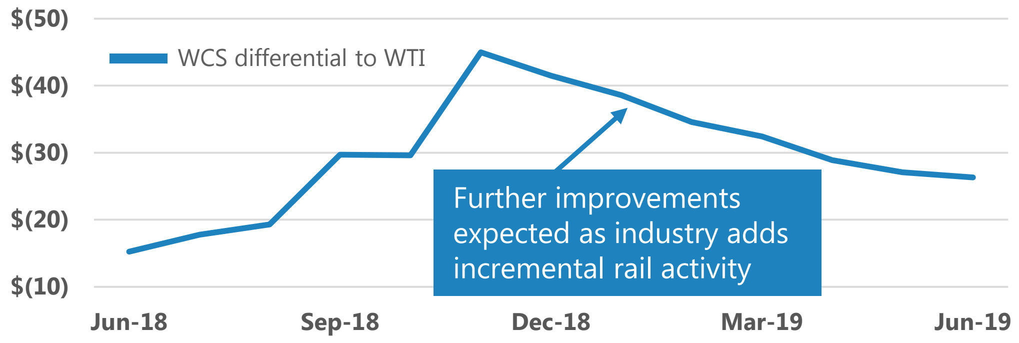
Q3 PRODUCTION	GROSS	NET
Jackfish 1 (MBOD)	20.4	19.4
Jackfish 2 (MBOD)	34.9	33.1
Jackfish 3 (MBOD)	34.8	33.0
Lloydminster (MBOED)	20.7	18.3
Total Heavy Oil (MBOED)	110.8	103.8

Heavy Oil – Mitigating Pricing Pressures in 2019

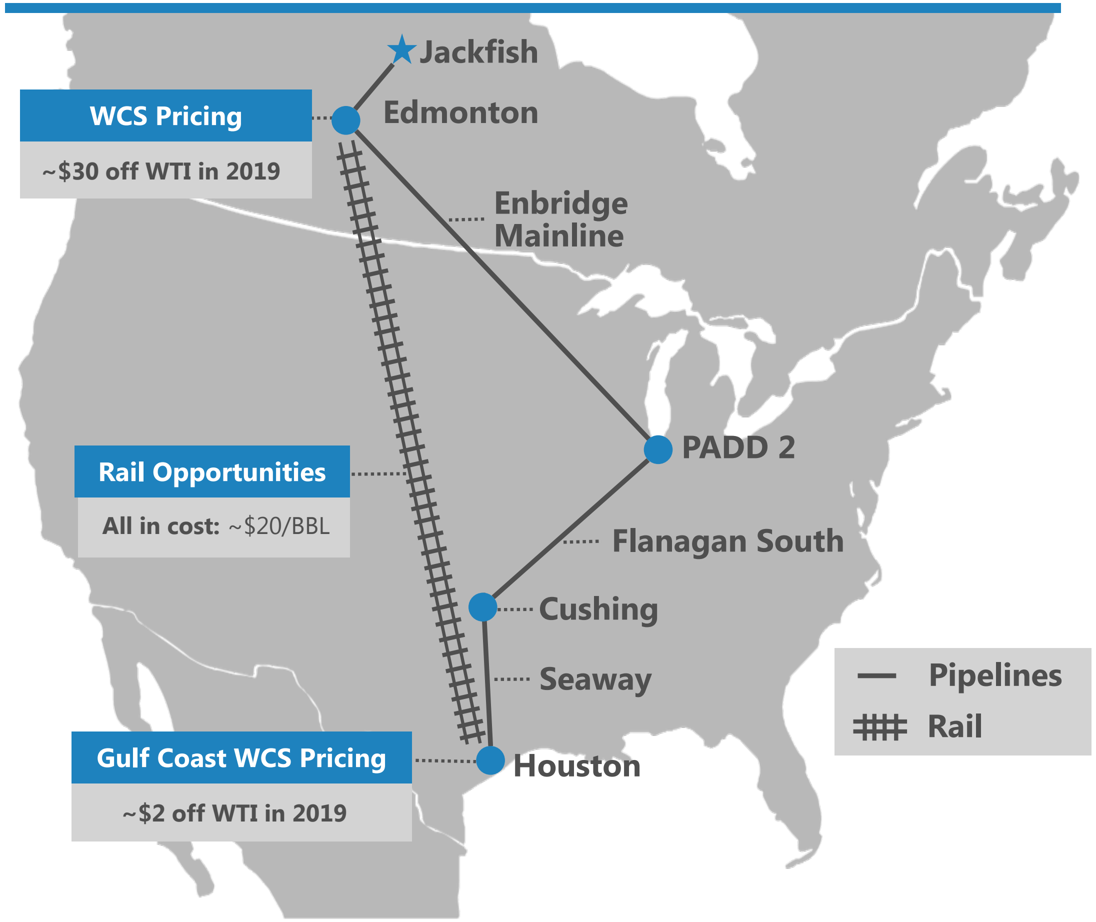
- Actively adding WCS financial swaps in 2019 (21 MBOD at ~$23 off WTI in 1H 2019)
- Secured firm transport to Gulf Coast (Agreements cover ~10% of production)
- Seeking accretive rail contracts (Targeting up to 20% of production)
- Directly connected to Northwest upgrader (Limits impact of future apportionments)
- Line 3 expansion in Q4 2019 (+370 MBOD capacity)

Differentials Narrowing into 2019

$/Barrel Differential (WCS vs. WTI)



Canadian Heavy Oil Marketing Opportunities



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