Q1 2018 Operations Report

NYSE: DVN devonenergy.com

Contents

devon

Executing the 2020 Vision

Raising U.S. oil production guidance for 2018

- Q1 production at high end of guide
- Record-setting well productivity driving strong returns
- Executing multi-zone projects ahead of plan

Marketing & supply chain provides certainty of execution

- Services and supplies secured at competitive pricing
- Firm transport and basis swaps protect regional pricing

Cash flow & margins positioned to expand

- Driven by U.S. oil growth and improved WCS pricing
- G&A and interest savings to reach ~$175 MM annually

Shareholder-friendly initiatives underway

- $1 billion share-repurchase program
- Quarterly dividend raised 33%
- Divestiture program brings forward value in the Barnett

Devon's 2020 Vision

- **Maximize** cash flow
- **Focus** on capital efficiency
- **Portfolio** simplification
- **Improve** financial strength
- **Return cash** to shareholders

Key Modeling Stats

KEY METRICS	Q1 ACTUALS[1]	Q1 GUIDANCE
U.S. oil (MBbls/d)	122	117 - 122
Canada oil (MBbls/d)	129	125 - 130
NGLs (MBbls/d)	97	98 - 103
Gas (MMcf/d)	1,177	1,139 - 1,191
Total (MBoe/d)	544	530 - 554
Production expenses ($MM)	$543	$500 - $550
General & administrative expenses ($MM)	$226	$210 - $230
Financing costs, net ($MM)[2]	$119	$115 - $125
Upstream capital ($MM)	$664	$550 - $650

UPDATED GUIDANCE	Q2 2018e	FY 2018e
U.S. oil (MBbls/d)	129 - 134	***130 - 135***
Canada oil (MBbls/d)	110 - 115	125 - 130
NGLs - retained (MBbls/d)	97 - 100	***99 - 102***
Gas - retained (MMcf/d)	1,001 - 1,053	***1,011 - 1,063***
Total retained (MBoe/d)	503 - 525	***523 - 544***
Divested assets (MBoe/d)[3]	21 - 24	***13 - 16***
Total (MBoe/d)	524 - 549	***536 - 560***
Production expenses ($MM)	$530 - $580	$2,100 - $2,200
General & administrative expenses ($MM)	$180 - $200	***$775 - $825***
Financing costs, net ($MM)	$105 - $115	***$440 - $470***
Upstream capital ($MM)	$550 - $650	$2,200 - $2,400
Corporate capital ($MM)	$20 - $30	***$50 - $70***
Capitalized interest ($MM)	$15 - $20	***$50 - $80***

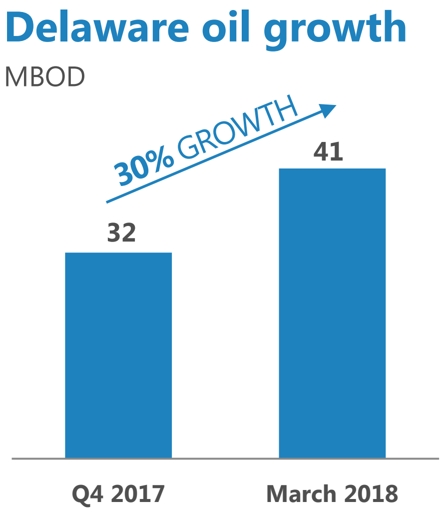
Note: Items in bold with italics have updated full-year guidance ranges.

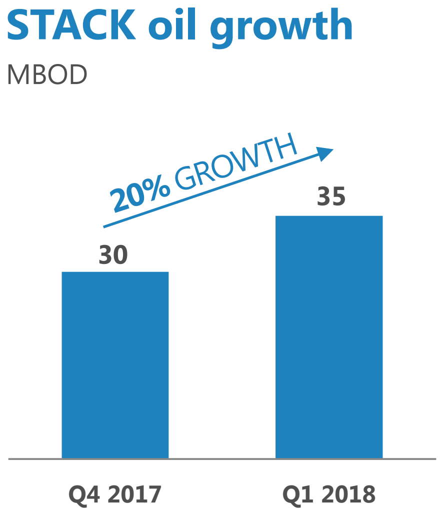
Q1 2018 - ASSET DETAIL	DELAWARE	STACK	ROCKIES	EAGLE FORD	BARNETT[1]	HEAVY OIL
PRODUCTION						
Oil (MBbl/d)	36	35	18	23	1	129
NGL (MBbl/d)	11	37	2	8	37	0
Gas (MMcf/d)	97	344	18	63	633	12
Total (MBoe/d)	64	129	23	41	143	131
ASSET MARGIN (per Boe)						
Realized price	$41.95	$29.57	$51.76	$46.68	$16.50	$27.68[4]
Lease operating expenses	($6.09)	($2.54)	($10.45)	($3.00)	($2.66)	($7.92)
Gathering, processing & transportation	($2.59)	($4.93)	($1.15)	($6.06)	($6.51)	($3.94)
Production & property taxes	($3.37)	($0.95)	($6.27)	($2.48)	($0.76)	($0.65)
Cash margin	$29.90	$21.15	$33.89	$35.14	$6.57	$15.17
CAPITAL ACTIVTY (Q1 avg.)						
Upstream capital ($MM)	$192	$230	$41	$78	$12	$71
Operated development rigs	8	9	2	n/a	0.5	
Operated frac crews	2	3.5	0.5	n/a	0.5	
Operated spuds	20	30	7	n/a	1	
Operated wells tied-in	26	20	6	n/a	2	
Average lateral length	7,800'	9,000'	9,700'	n/a	3,200'	

(1) Q1 2018 actuals include recently announced Johnson County divestiture.
(2) Excludes $312 million one-time charge for early retirement of debt.
(3) Divested assets represents production for recently announced Johnson County sale through May 2018.
(4) Cash settlements related to regional basis hedges in Canada were $97 million, or $8.23 per Boe.

Q1 2018 Results

- U.S. oil production at top end of guidance
- Delaware & STACK deliver strong growth
  - Delaware March oil production 30% higher vs. Q4 2017
  - STACK oil production increases 20% vs. Q4 2017
- Massive record-setting wells brought online
  - Two Boundary Raider wells IP24: 24 MBOED (~80% oil)
  - Coyote development: avg. IP30 ~4,400 BOED per well
- Executing multi-zone projects ahead of plan
  - Drove capital 2% above guidance in Q1
  - Showboat online ~40 days ahead of plan
  - Record drill times set at Boomslang & Seawolf





BEST WELLS IN DELAWARE BASIN HISTORY

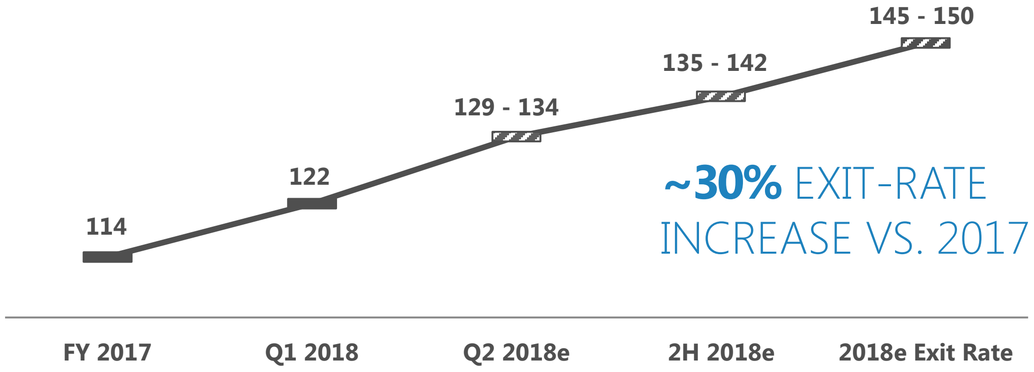
Boundary Raider 6-7 Com 212H	IP24: **12,868 BOED** (82% oil)
Boundary Raider 6-7 Com 213H	IP24: **11,149 BOED** (76% oil)

2018 Outlook

- Raising 2018 U.S. oil production guidance
  - Expect 16% growth vs. 2017 (~30% exit-rate growth)
  - Guidance increased by ~200 basis points
- Cost structure to improve throughout 2018
  - G&A and interest savings: ~$175 MM annually (~65% of 2020 Vision target)
  - Per-unit LOE to decline 5% to 10% by year end
- Positioned for significant cash flow expansion
  - Canadian WCS pricing improving
  - Eagle Ford volumes to grow from Q1 levels
  - Firm transport and basis swaps protect cash flow
- Efficiencies expected to pull forward capital activity
  - Benefits 2018 & 2019 production profile
  - Capital trending toward top half of guidance

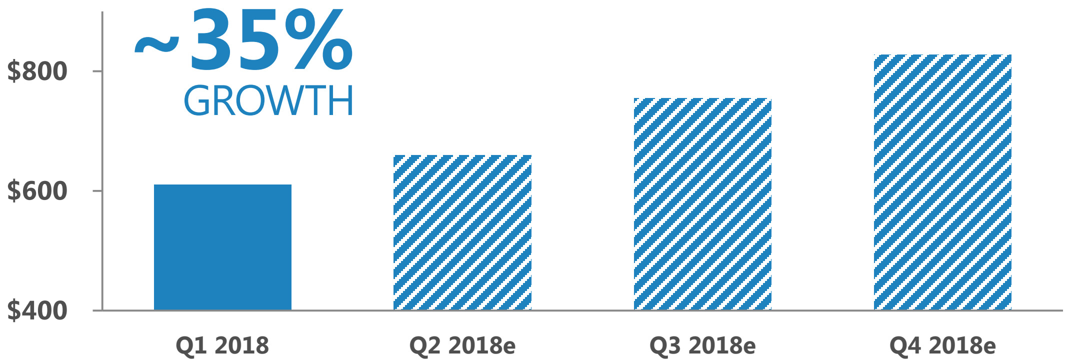
Improving 2018 oil production outlook

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



Growing upstream cash flow[1]

($MM)

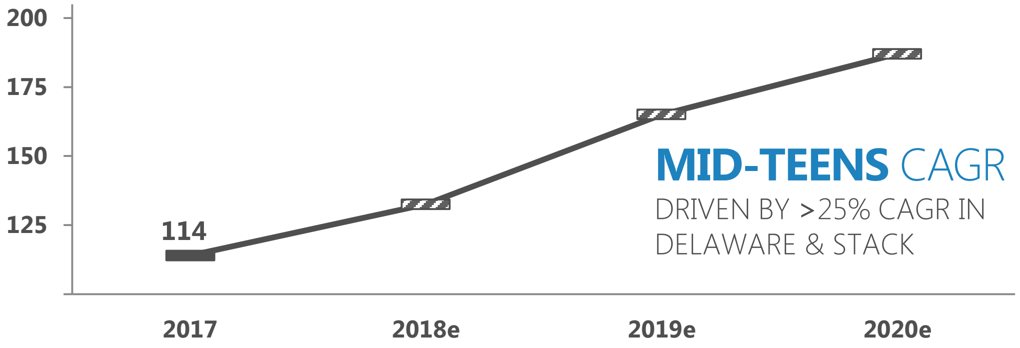


(1) Represents Devon upstream cash flow. Assumes $65 WTI & $2.75 Henry Hub for Q2 – Q4 2018.

2020 Vision: Driving Significant Cash Flow Growth

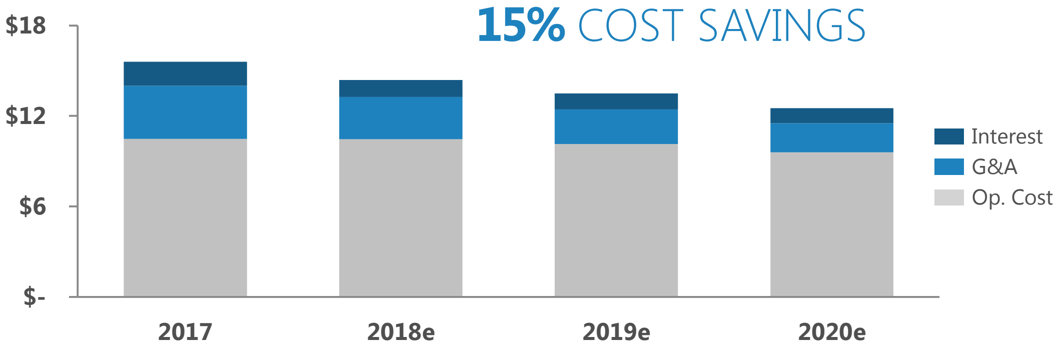
Growing higher-value production

U.S. Oil Production (MBOD)



Cost savings to expand margins

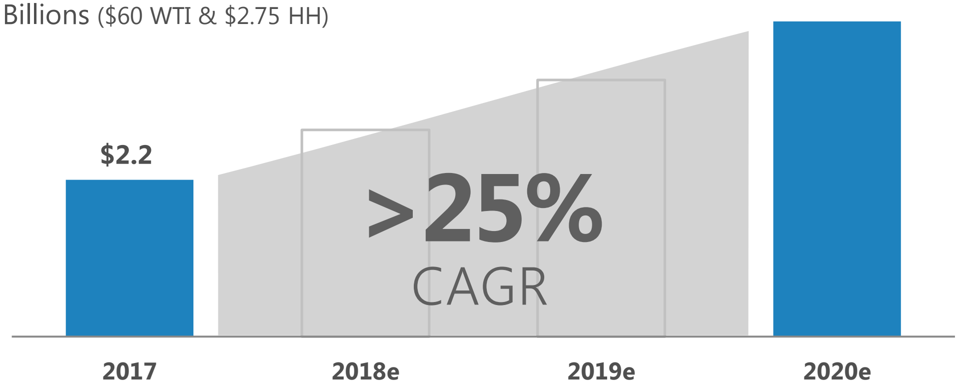
Upstream Per-Unit Cash Cost ($/BOE)



Note: 2017 operating costs been restated under the current accounting methodology.

Driving upstream cash flow expansion

$ Billions ($60 WTI & $2.75 HH)



Significant free cash flow generation

Through 2020 ($60 WTI & $2.75 HH)

$2.5 Billion

CUMULATIVE FREE CASH FLOW

Shareholder-Friendly Initiatives

- $1 billion share-repurchase program underway
  - $204 million repurchased to date (6.2 million shares)
  - Average price: $33 per share
  - Expect to be completed by year end
- Raised quarterly dividend by 33%
  - New quarterly rate: $0.08 per share (effective Q2 2018)
  - Target cash flow payout ratio: 5% - 10%
  - Positioned for sustainable annual dividend growth
- Successfully tendered $807 million of debt in Q1
  - Reduces interest by $64 million annually
  - Plan to retire $277 million of maturing upstream debt (next 9 months)

KEY INITIATIVES UNDERWAY

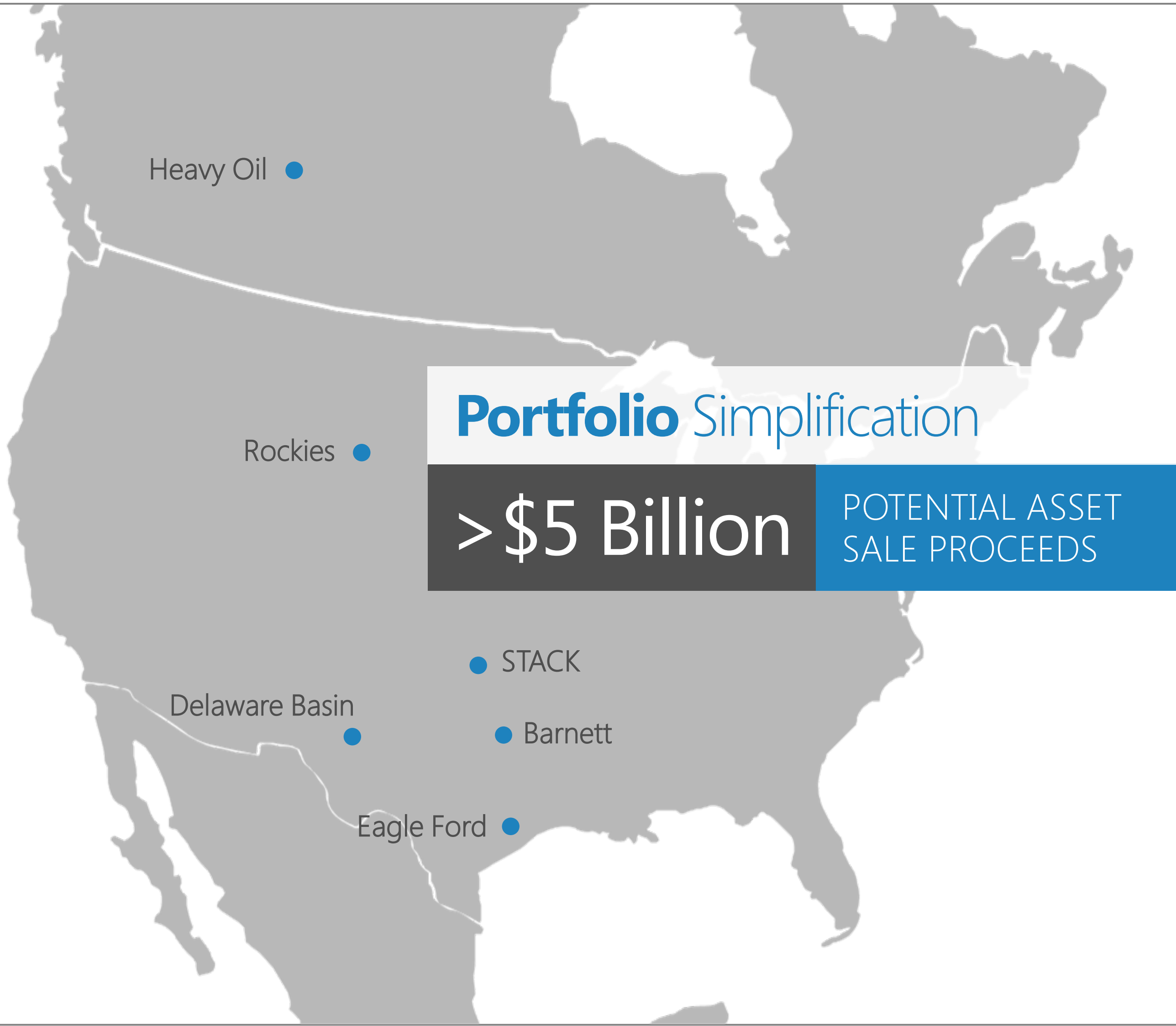
$1 Billion
share repurchase program initiated

33% Increase
in quarterly cash dividend

$1 Billion
debt reduction plan

Portfolio Simplification Strategy

- Resource quality & depth allows for high-grading of portfolio
- Potential for >$5 billion of asset disposals
  - — Divest proceeds to date: $1.1 billion
  - — Committed to bringing forward appropriate value as market conditions allow
  - — Optionality to monetize oil or gas
- Multiple initiatives underway to further focus portfolio footprint
  - — Actively pursuing larger asset transactions
  - — Concurrently marketing ~$1 billion of non-core asset packages across U.S. (high-multiple properties)

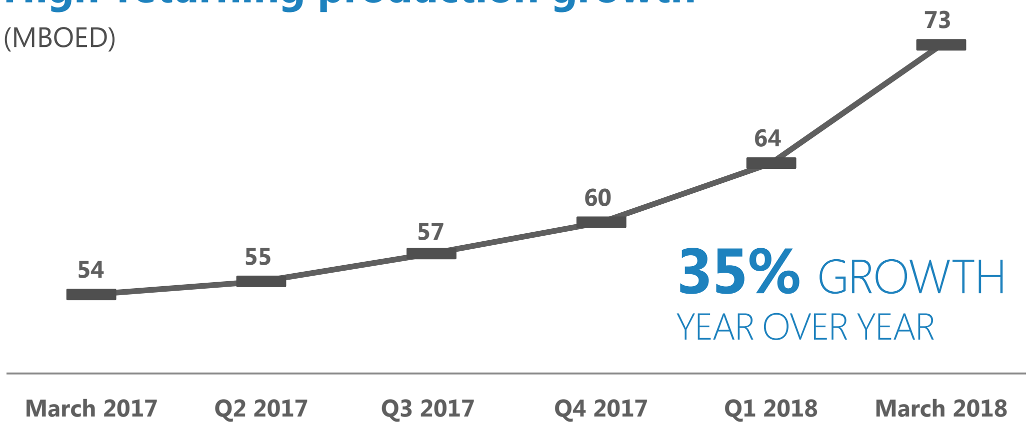


Delaware Basin – Q1 2018 Results

- March production averages 73 MBOED
  - Oil volumes 30% higher vs. Q4 2017
  - Driven by focused development program
  - Generating best returns in portfolio
- Two Boundary Raider wells achieve highest flow rates in Delaware Basin history
  - B. Raider 212H - IP24: 12,868 BOED (82% oil)
  - B. Raider 213H - IP24: 11,149 BOED (76% oil)
  - Landed in 2nd Bone Spring interval (Todd area)
  - 25 wells planned in sweet spot over next 18 months
- Cash margin expands 27% YoY ($30 per BOE)
  - Oil increases to 56% of mix (54% in prior qtr.)
  - Per-unit operating costs to decline by >10% in 2018

High-returning production growth

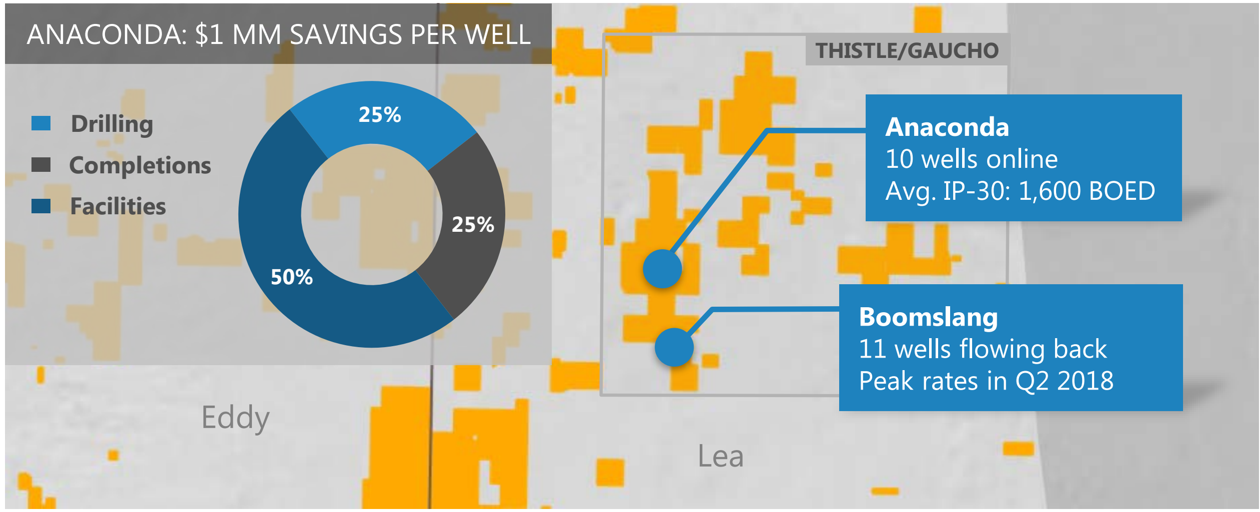
(MBOED)



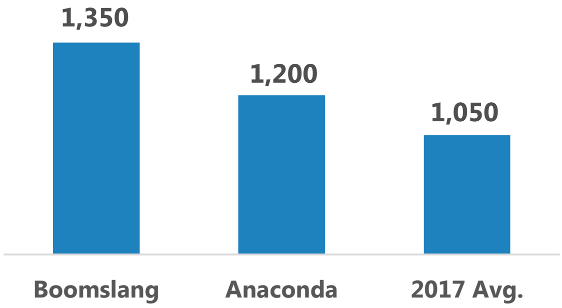
DELAWARE BASIN	Q1 18	Q4 17
Net production (MBOED)	64	60
Upstream capital ($MM)	$192	$153
Operated rigs / Frac crews (average)	8/2	8/2
Operated spuds / Wells tied-in	20/26	22/20
Average lateral length	7,800′	9,000′

Initial Multi-Zone Projects Delivering Strong Results

- Frac efficiencies reaching up to 15 stages/day
- Anaconda project savings: $1 MM per well
  - Average well cost declined to ~$5.5 million
  - Project EUR trending toward 8 MMBOE
- Boomslang project attains 1st production
  - 11 wells across 3 intervals (Leonard & Bone Spring)
  - Avg. IP30: ~1,400 BOED (represents 7 of 11 wells)
  - Record drill time: 1,350 ft/day
  - Project cycle time: ~6 months
- New play type derisked at Boomslang/Thistle area
  - Two 2nd Bone Siltstone wells (Avg. IP24: ~1,700 BOED)
  - Potential across state-line area

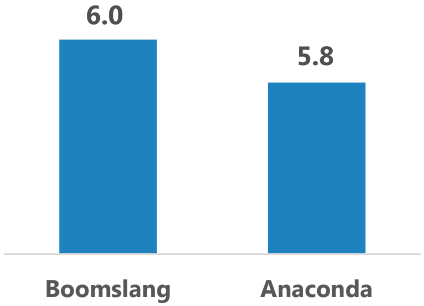


Feet Drilled Per Day



Short Cycle Times

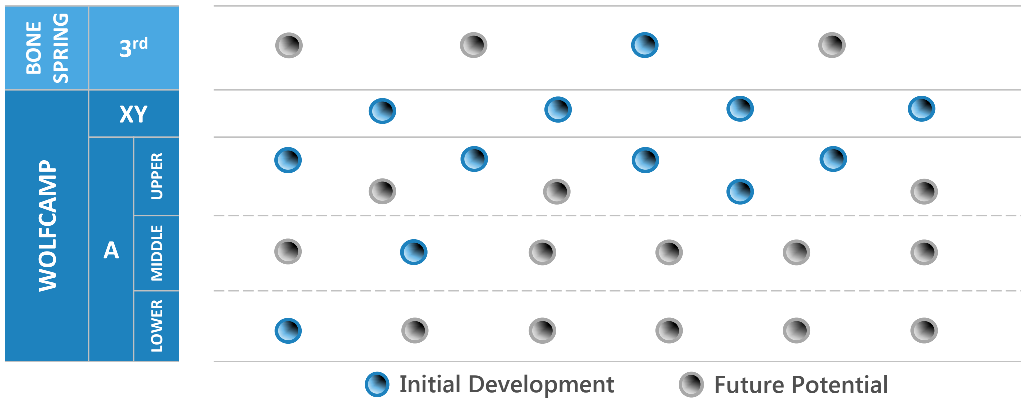
Spud to first production (months)

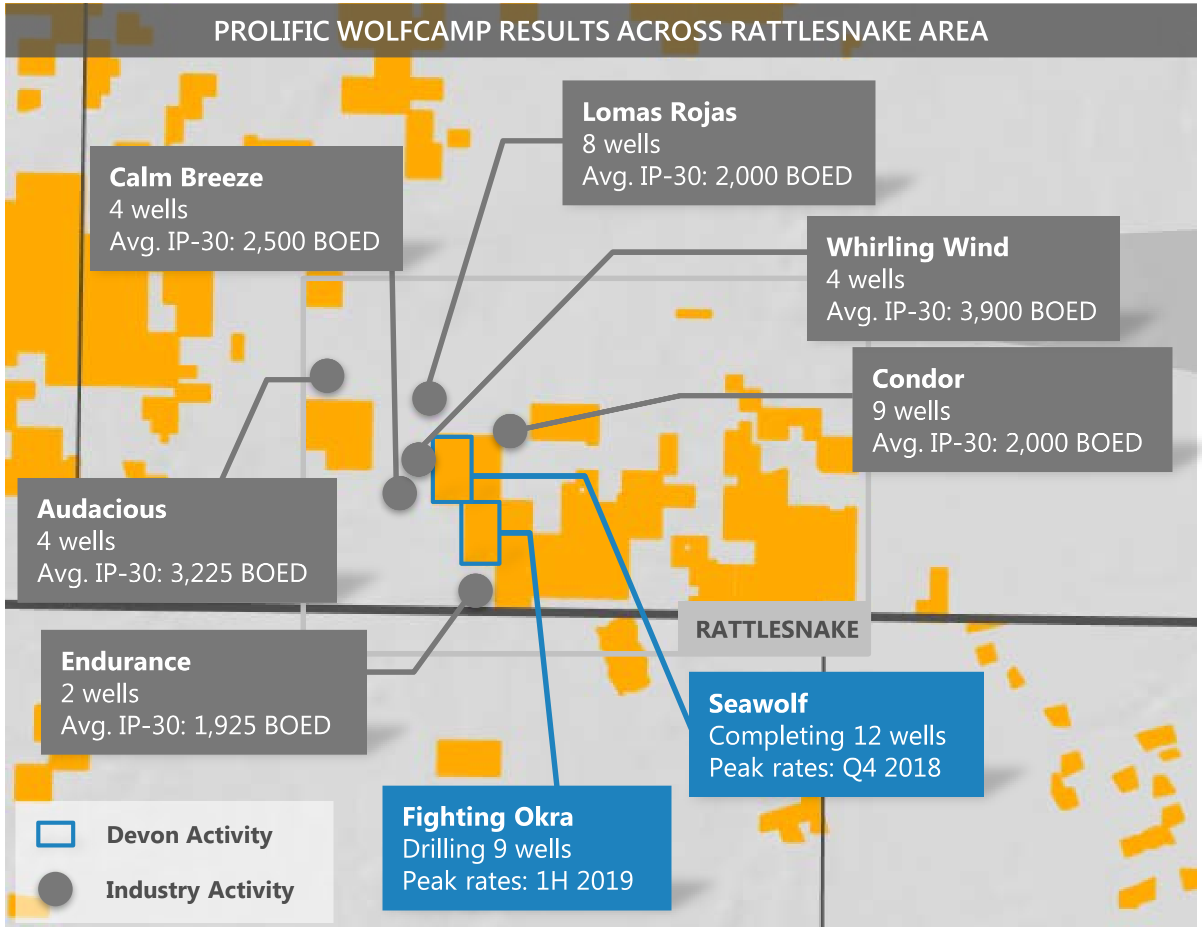


World-Class Rattlesnake Developments Advancing

- Completion work underway at Seawolf project
  - 12 wells targeting multiple Wolfcamp intervals
  - Drilling efficiency improved 67% vs. prior activity
  - Avg. drilling savings: ~$800,000 per well
- Fighting Okra infill drilling program progressing
  - Developing 9 Wolfcamp wells
  - Key contributor to production growth in 1H 2019

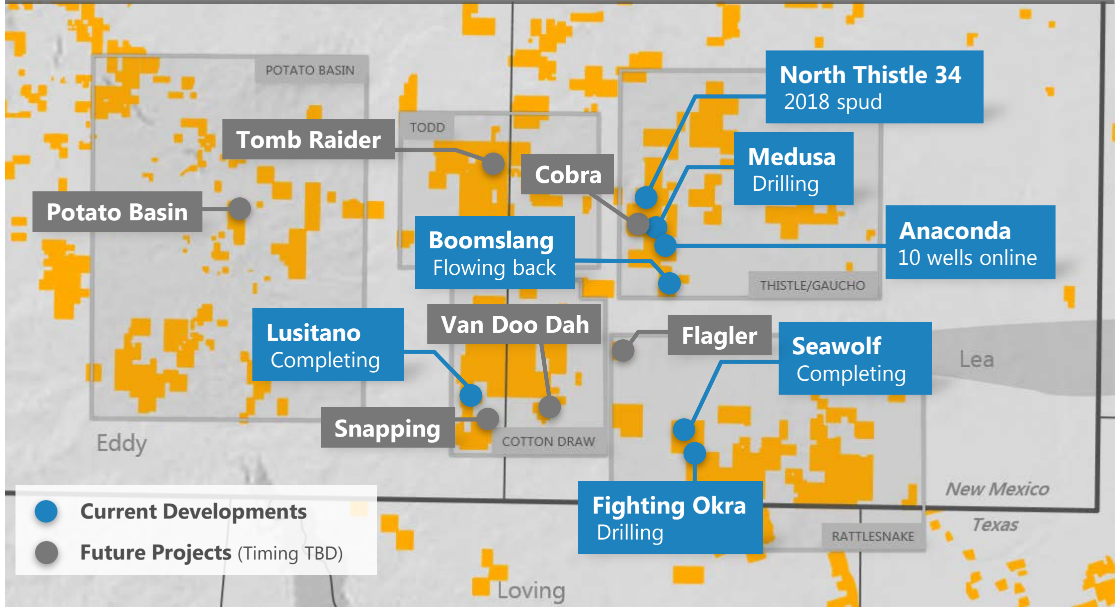
Seawolf Development - Rattlesnake Area





Delaware Development Projects Advancing on Plan

DELAWARE BASIN DEVELOPMENT ACTIVITY



Q1-2018a | Q2-2018e | Q3-2018e | Q4-2018e

Boomslang — Completion, Production
(11 well pattern across 3 intervals in the Leonard and Bone Spring)

Seawolf — Drilling, Completion, Production
(12 well pattern across 4 Wolfcamp intervals)

Lusitano — Drilling, Completion, Production
(6 well pattern across multiple intervals in the Leonard, Bone Spring and Wolfcamp)

Medusa — Drilling, Completion, Production
(12 well pattern across 3 intervals in the Leonard Shale and Bone Spring)

Fighting Okra — Drilling, Completion, Production
(9 well pattern across 3 intervals in the Wolfcamp)

North Thistle 34 — Drilling, Completion
(7 well pattern across 1 interval of the Leonard Shale)

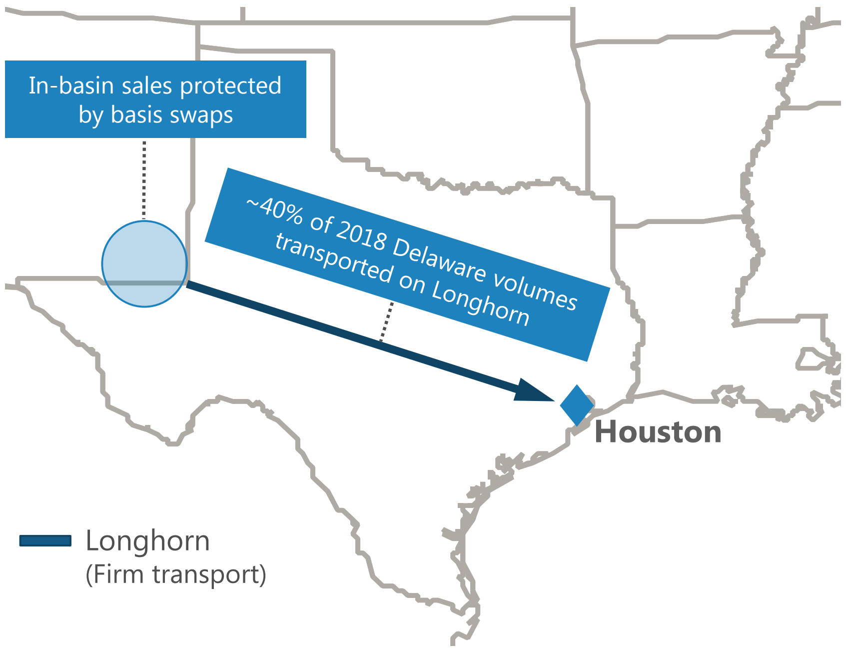
DEVELOPMENT STRATEGY BUILDING MOMENTUM

- 70% of 2018 capital activity associated with multi-zone developments
- 6 multi-zone projects expected to contribute to 1st production by YE 2018

Delaware Basin – Certainty of Execution

- Firm transport and basis swaps protect price realizations
  - Midland basis swaps protect ~50% of oil production
  - ~40% of oil delivered on firm transport to Gulf Coast
  - Term gas sales in place to flow to West Coast (avoids WAHA hub)
  - Gas basis swaps protect ~40% of production
- Field-level infrastructure in place to support growth plans
  - >90% of produced water piped to disposal wells or recycling facilities
  - ~80% of total water used in operations is recycled (DVN: 8 facilities)
  - >80% of oil gathering on pipe by 2H 2018
  - Excess gas processing capacity projected through 2022
- Services and supplies requirements secured through 2019
  - Rig requirements secured to complete current program (~8 rigs)
  - Dedicated frac crews secured to execute capital plans (~2.5 crews)
  - 30% savings on self-sourced regional sand

Protecting Price & Flow Assurance



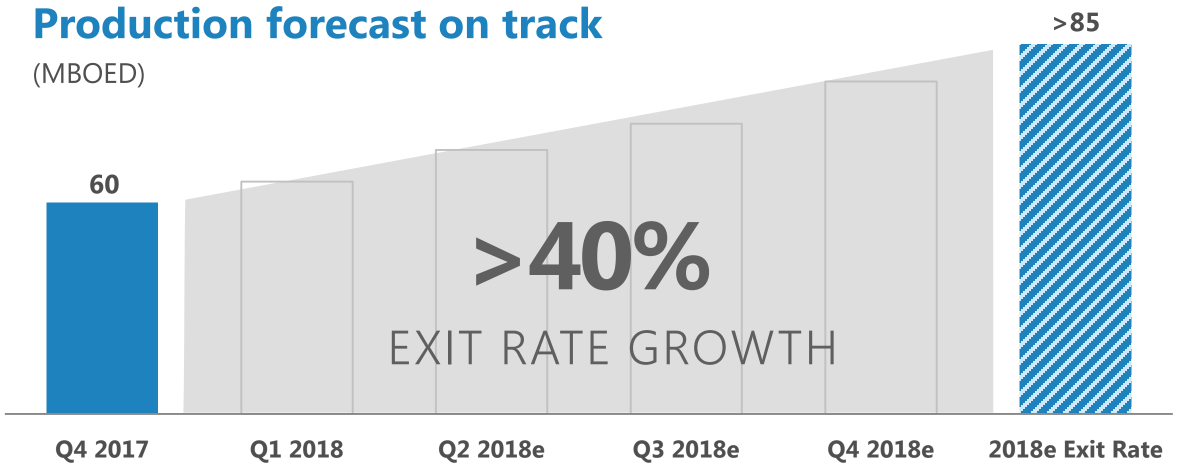
OIL BASIS SWAPS PROTECT PRICE	2018	2019
Midland oil swaps (MBbls/d)	23	28
Avg. differential to WTI ($/Bbl)	($1.02)	($0.46)

Delaware Basin – Outlook

- >15% sequential quarter production growth expected in Q2
  - Capital spending on track with 2018 budget (~$725 million)
  - Production exit-rate growth: >40% by year end
- Franchise asset provides multi-decade oil growth opportunity
  - ~300k net surface acres (>15 different development targets)
  - >1.3 million net effective acres

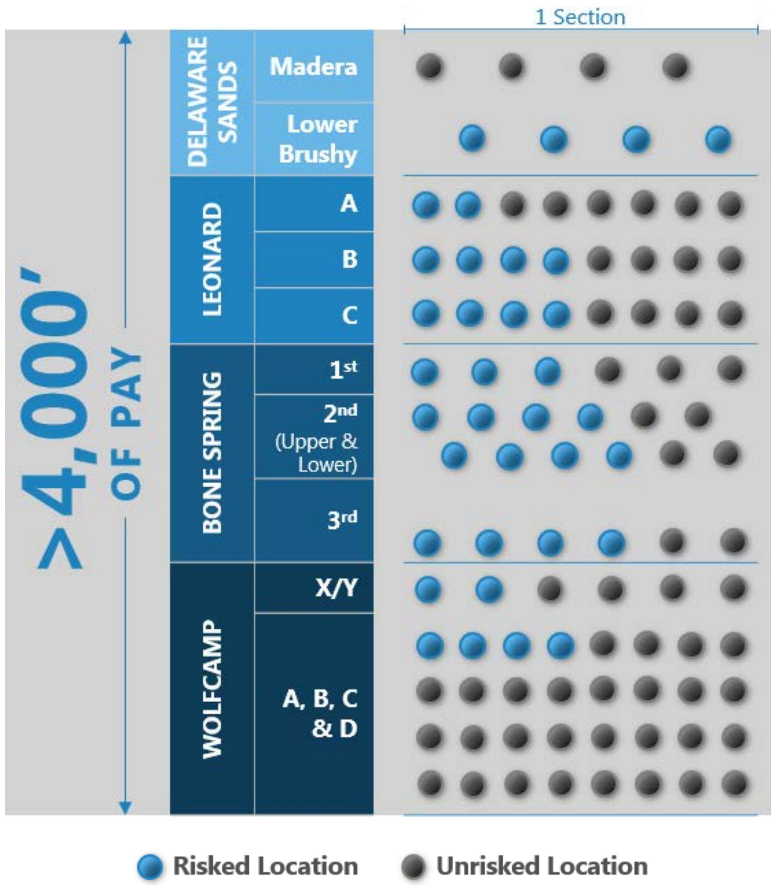
Production forecast on track

(MBOED)



Significant resource opportunity

(~300,000 net surface acres with >15 development targets)



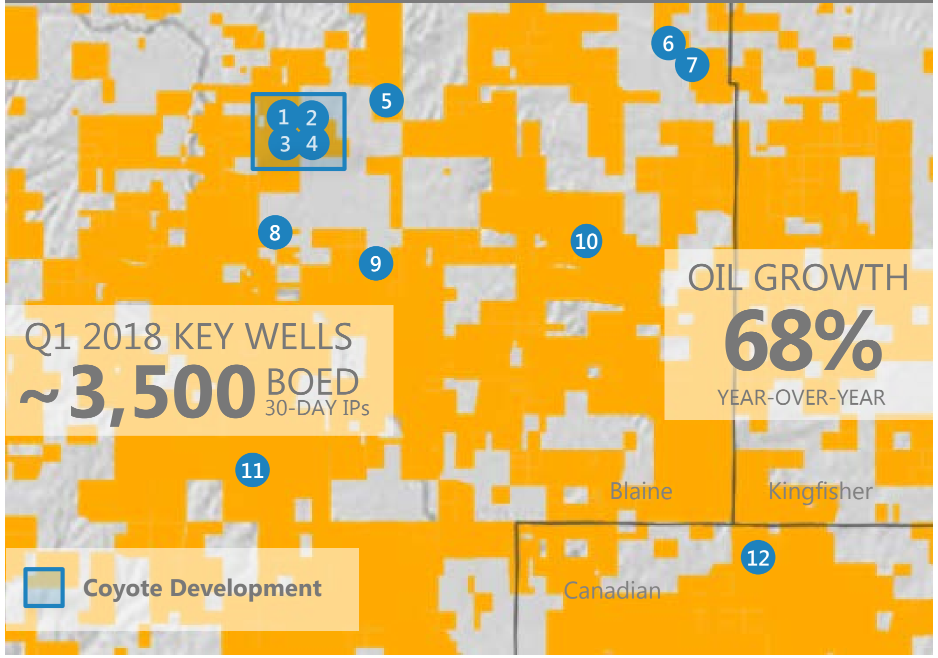
Note: Graphic for illustrative purposes only and not necessarily representative across Devon's entire acreage position.

STACK – Q1 2018 Results

- Oil production increases 68% from Q1 17
  - Coyote development delivering record flow rates
  - Top wells average IP30 of ~3,500 BOED
- Field-level cash flow expands 60% year over year
  - Liquids volumes account for ~80% of revenue
  - Per-unit operating costs to decline >10% by Q4 2018
- Showboat project online ~40 days ahead of plan
  - Efficiencies accelerated capital spend in Q1 (33% of budget)

KEY STATS	Q1 18	Q4 17
Net production (MBOED)	129	117
Upstream capital ($MM)	$230	$230
Operated rigs / Frac crews (average)	9/3.5	10/3.5
Operated spuds / Wells tied-in	30/20	32/24
Average lateral length	9,000′	8,600′

RECORD-SETTING STACK WELL PRODUCTIVITY

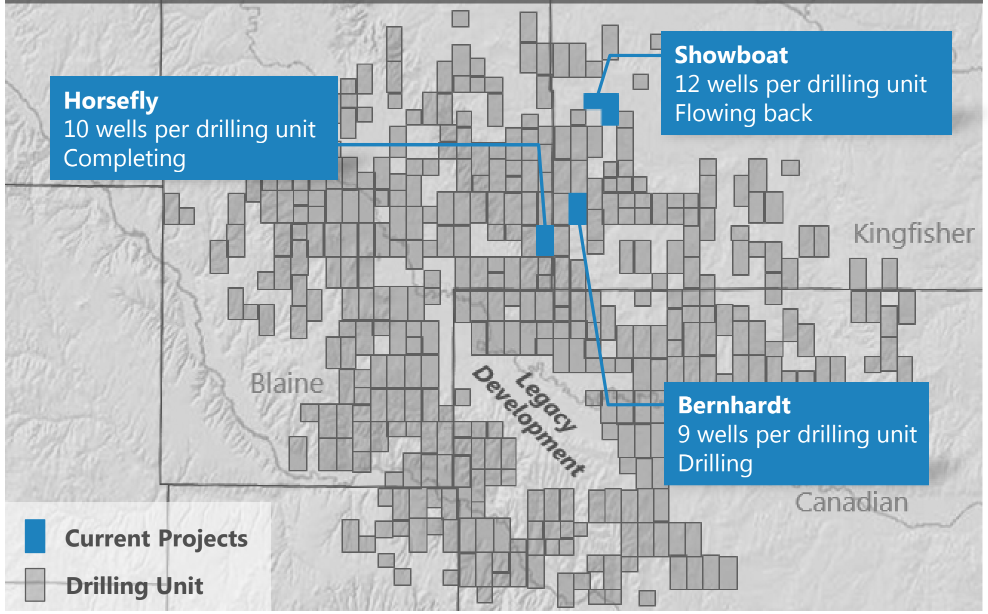


1. **Chipmunk** IP 30: 5,900 BOED
2. **Coyote 2HX** IP 30: 3,400 BOED
3. **Coyote 3HX** IP 30: 4,400 BOED
4. **Coyote 1X** IP 30: 3,800 BOED
5. **Cottontail** IP 30: 4,400 BOED
6. **Sonoyta 2HX** IP 30: 3,500 BOED
7. **Sonoyta 3HX** IP 30: 3,500 BOED
8. **Otter** IP 30: 3,400 BOED
9. **Grizzly** IP 30: 2,000 BOED
10. **Hydra** IP 30: 2,150 BOED
11. **Bonsai** IP 30: 3,900 BOED
12. **Rhino** IP 30: 2,100 BOED

STACK – Infill Development Strategy

- Next 3 projects designed to inform future infill decisions
  - Testing 9, 10 & 12 Meramec wells per drilling unit
- Program to deliver attractive returns (Showboat/Horsefly/Bernhardt)
  - Burdened wellhead IRRs projected at ~40%(1) (at strip pricing)
  - Low-risk appraisal objectives (testing spacing & secondary targets)
  - Conservatively risked performance within our 2018 outlook
- Infill projects to deliver improved capital efficiency
  - Projected IRRs superior to historical appraisal drilling results
  - Driven by optimized subsurface planning, significantly lower capital costs and improved LOE costs per well
- Positioned for significant resource & inventory upside
  - 130k surface acres in over-pressured oil window
  - Economic core of play with up to 5 different landing zones
  - Infill spacing to de-risk upside (currently risked at 6 wells/section)

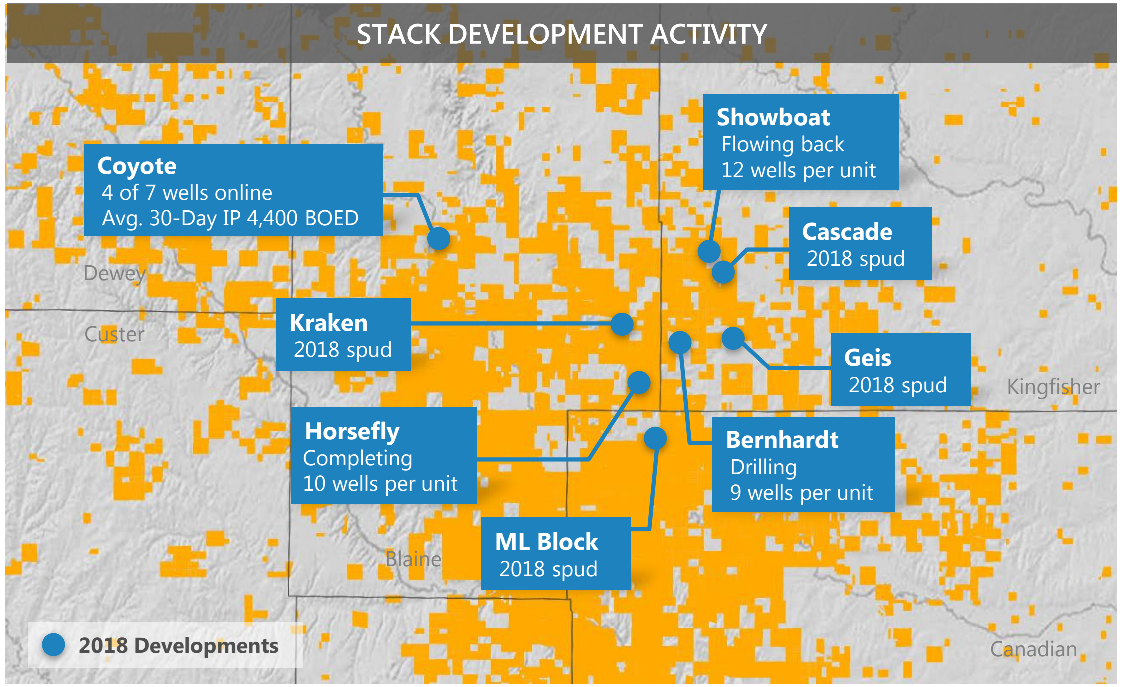
Current Projects to Inform Future Infill Decisions



MERAMEC RESOURCE	
Over-pressured oil acreage	130,000 net surface acres
Stacked-pay opportunity	5 Meramec landing zones
Risked inventory	6 wells per surface section
Infill spacing tests	9 to 12 wells per surface section

(1) Returns are burdened for corporate overhead costs

STACK Development Activity Progressing



Q1-2018a | Q2-2018e | Q3-2018e | Q4-2018e

Coyote — Completion, Production
(7 well development in the Meramec)

Showboat — Completion, Production
(Testing 12 wells per drilling unit across 3 intervals in the Meramec and 1 Woodford zone)

Horsefly — Drilling, Completion, Production
(Testing 10 wells per drilling unit across 3 Meramec intervals)

Bernhardt — Drilling, Completion, Production
(Testing 9 wells per drilling unit across 3 Meramec intervals)

Geis — Drilling, Completion
(7 wells per drilling unit across 2 intervals in the Meramec)

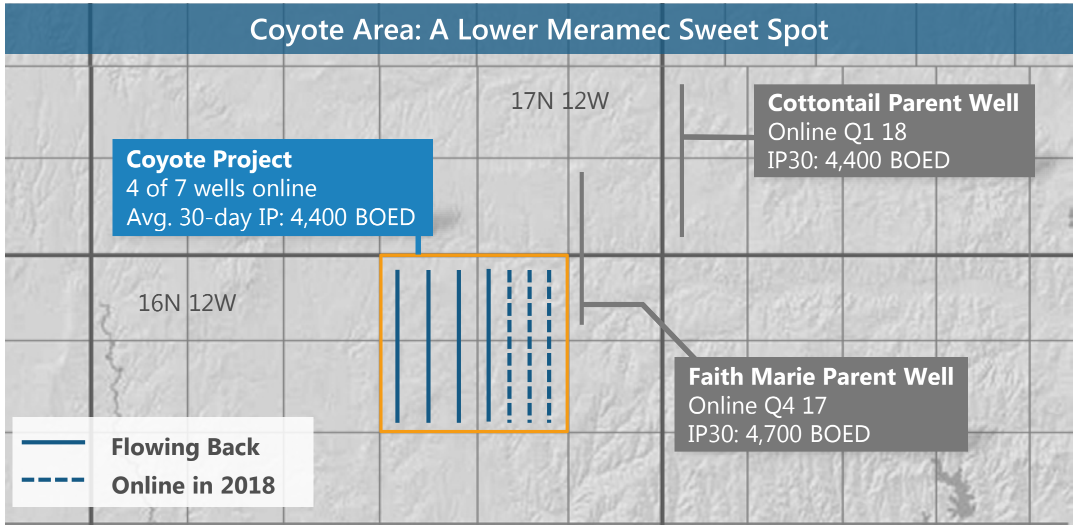
Kraken — Drilling, Completion
(7 wells per drilling unit across 3 intervals in the Meramec and 1 Woodford zone)

DEVELOPMENT STRATEGY BUILDING MOMENTUM

- 60% of capital activity in 2018 associated with multi-zone developments
- 4 multi-zone projects expected to contribute to 1st production by YE 2018

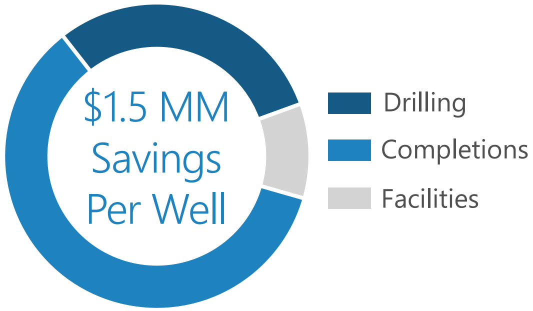
STACK Infill Projects Delivering Efficiencies

- Record flow rates achieved at Coyote project
  - Project developing Lower Meramec sweet spot
  - Average IP30: 4,400 BOED (4 of 7 wells online)
  - Drilling time improved by up to 25% vs. offsetting Faith Marie well ($1 MM savings per well)
  - Completion costs reduced by ~10% vs. previous activity

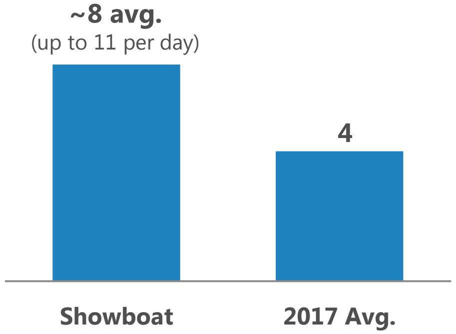


- Showboat cost savings: ~$1.5 million per well
  - 30% drilling efficiencies ($500k savings per well)
  - 2x improvement in frac stages per day
  - 1st production achieved in April (~40 days ahead of plan)
  - Well tie-ins staggered over next two months
  - Peak project rates expected by mid-year
  - Spud-to-1st production cycle time: ~7 months

Cost Savings By Area



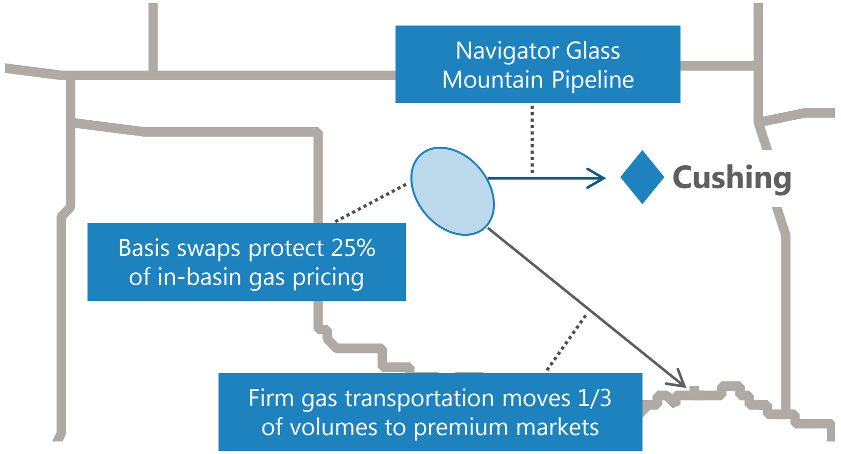
Frac Stages Per Day



STACK – Certainty of Execution

- Improved oil takeaway infrastructure boosts pricing (~$1/Bbl uplift)
  - Majority of oil planned to be connected to gathering systems (Black Coyote online in April)
  - Reliable and cost-effective pipeline access to Cushing (see map)
- Gas flow assurance: Devon holds firm transportation
  - Covers vast majority of estimated STACK gas production
  - Access to premium pricing outside of Mid-Con (covers 1/3 of volumes)
  - Basis swaps protect ~25% of gas production (~$0.45 off HH)
- Sufficient gas processing capacity to support growth plans
  - Thunderbird plant increases EnLink capacity to 1.2 BCFD
- Services and supplies requirements secured through 2019
  - Rig requirements secured to complete current program (~8 rigs)
  - Dedicated frac crews secured to execute capital plans (~3 crews)
  - 30% savings on self-sourced regional sand

Protecting Price and Flow Assurance



BASIS SWAPS PROTECT PRICE REALIZATIONS

	2018
MidCon basis swaps (MMBtu/d)	94,370
Avg. differential to Henry Hub ($/MMBtu)	($0.45)

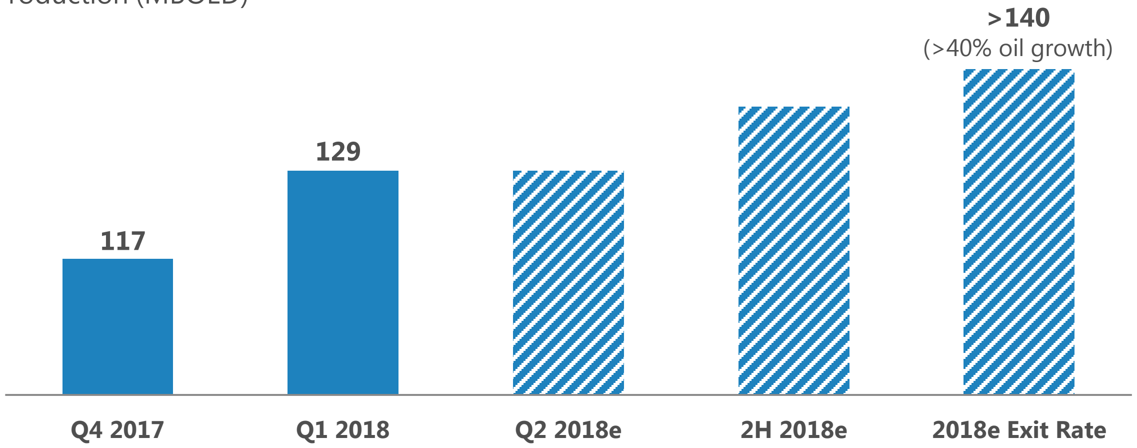
STACK – Outlook

Activity shifting to economic core

- Activity concentrated in over-pressured oil window (best returns in play)
  - >100 new operated wells online in 2018
  - Targeting higher-return Meramec formation
  - Accelerated capital spend in Q1 due to completion efficiencies (32% of budget)

High-returning production growth

Production (MBOED)

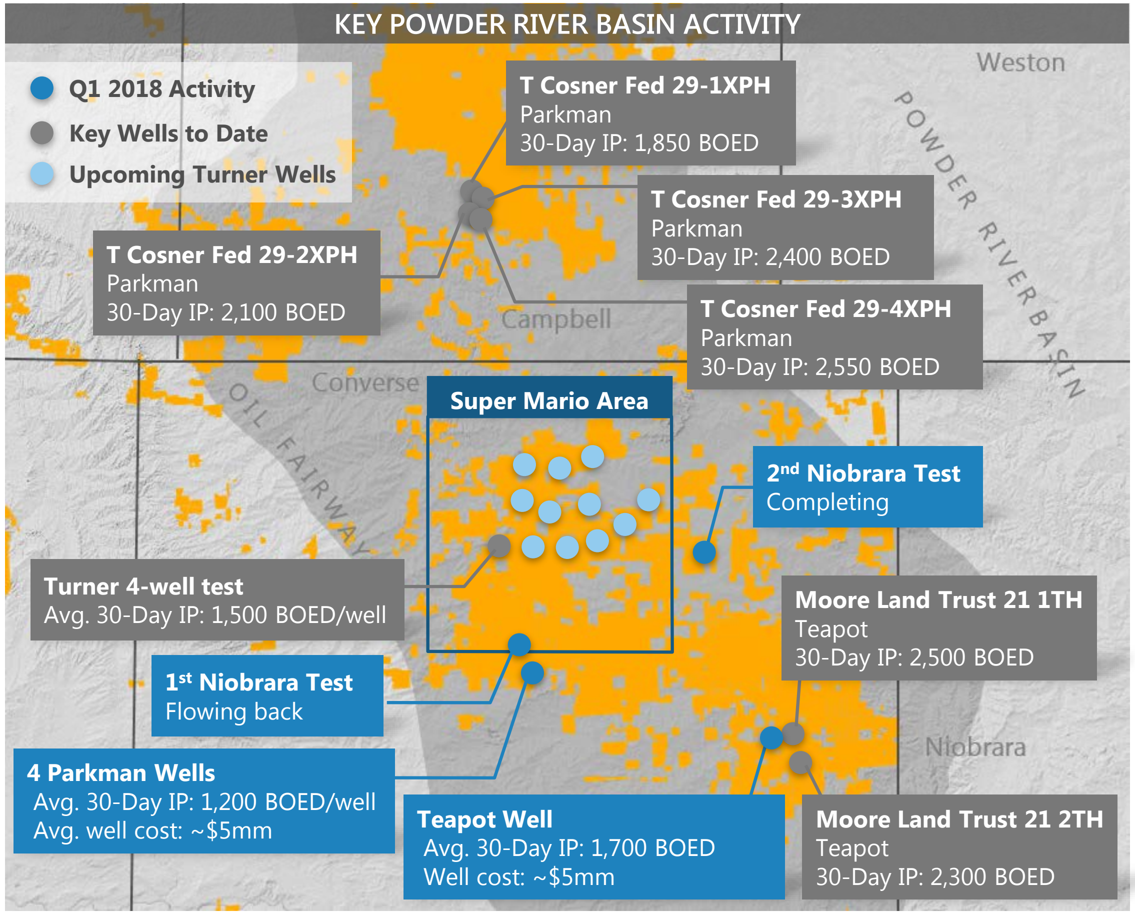


- 2018 production plan on track
  - Q2 oil volumes flat due to timing of development projects
  - Multi-zone projects to accelerate production growth in 2H 2018
  - Year-end 2018 exit rates: >40% oil growth

Rockies

- Oil production increased 17% vs. Q4 2017
  - Parkman/Teapot activity drives growth
  - Low costs drive strong returns (~$5 MM per well)
- Testing Niobrara potential (~400k prospective acres)
  - Initial well flowing back
  - Completion work underway at 2nd appraisal well
- "Super Mario" Turner activity accelerating
  - ~10 wells scheduled for remainder of 2018

KEY STATS	Q1 18	Q4 17
Net production (MBOED)	23	19
Upstream capital ($MM)	$41	$66
Operated rigs / Frac crews (average)	2/0.5	3/0.5
Operated spuds / Wells tied in	7/6	7/11
Average lateral length	9,700′	8,000′

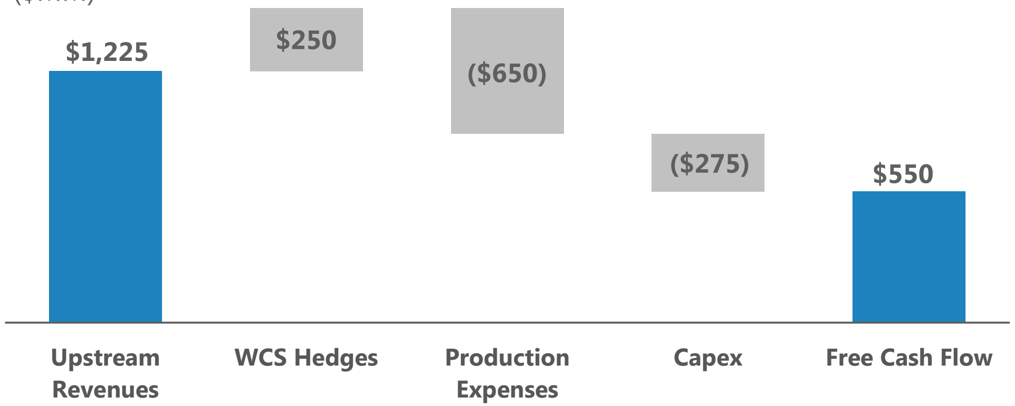


Heavy Oil

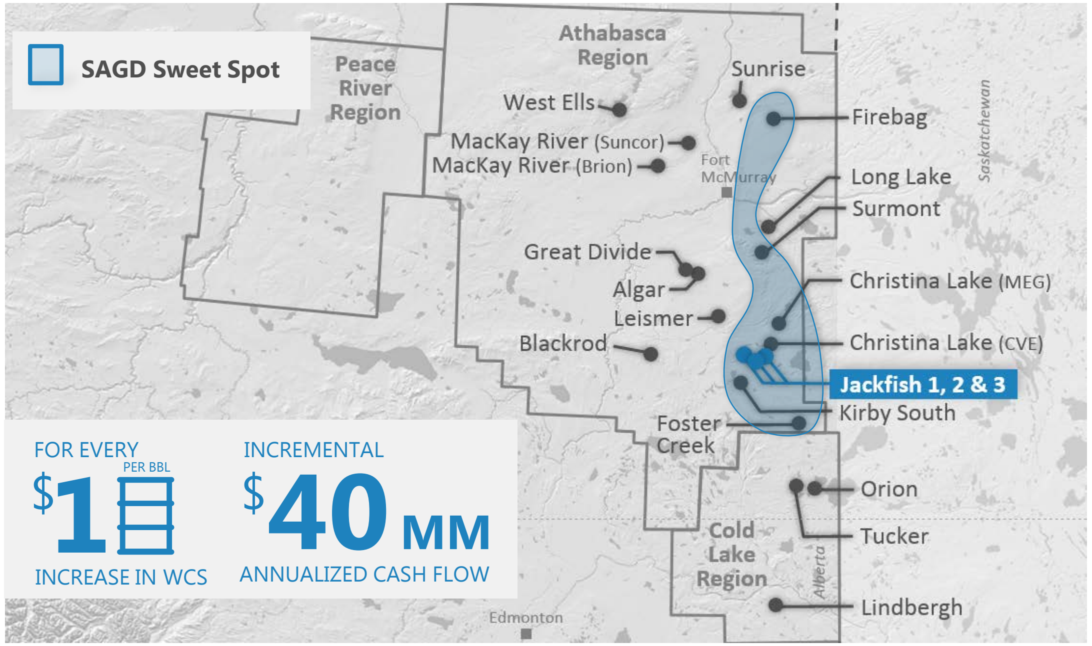
- Oil production at high end of guidance in Q1
- Q2 volumes impacted by turnaround and royalties
  - Jackfish turnaround impact: ~15 MBOD
  - Higher royalties: ~3 MBOD
- WCS hedges protecting cash flow in 2018
  - ~50% hedged at $15 off WTI
  - Free cash flow in 2018: $550 million(1)

Heavy Oil 2018e Free Cash Flow

($MM)



(1) Assumes $65 WTI & $25 differential for remainder of 2018.

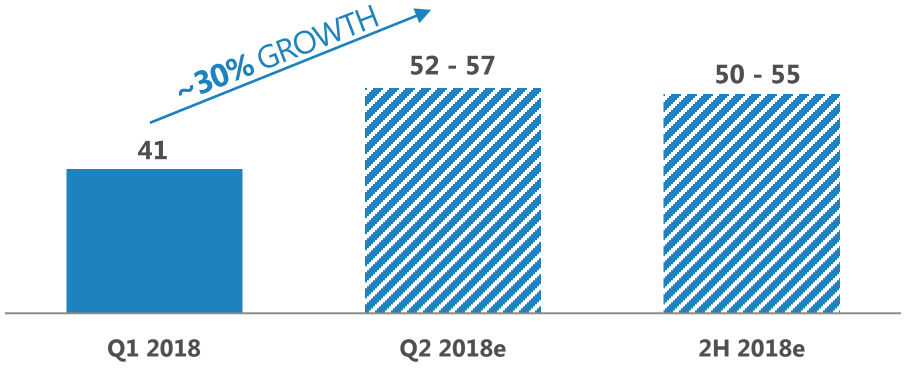


Q1 PRODUCTION	GROSS	NET
Jackfish 1 (MBOD)	35.0	31.8
Jackfish 2 (MBOD)	41.7	40.3
Jackfish 3 (MBOD)	40.0	38.7
Lloydminster (MBOED)	21.8	20.3
Total Heavy Oil (MBOED)	138.5	131.1

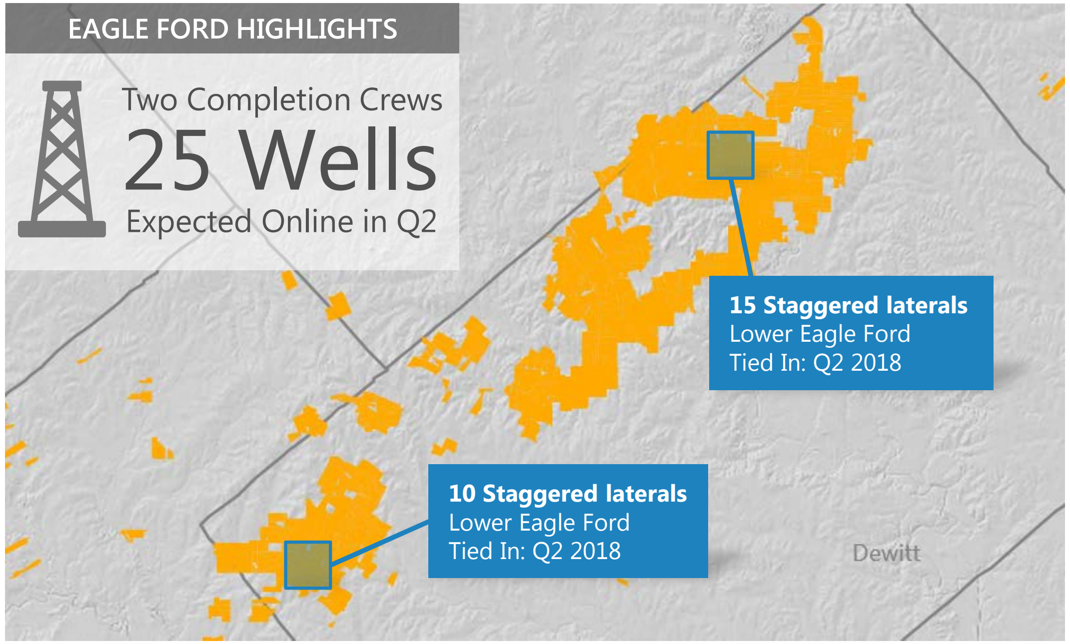
Eagle Ford

- Strong production growth in Q2 (chart below)
  - Two frac crews currently on site
  - 25 wells to be tied-in
- Plan in place to stabilize production
  - 35 to 40 new wells online in 2H 2018
- Free cash flow in 2018: >$400 million[1]

Stabilizing High-Margin Production
(MBOED)



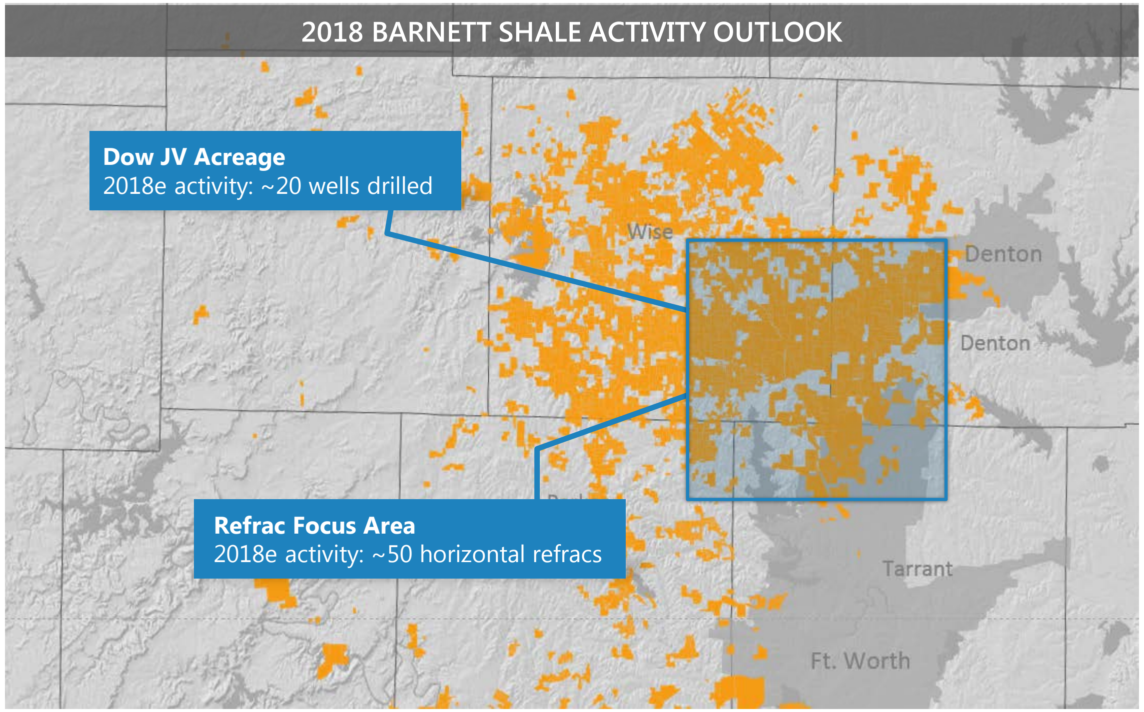
(1) Assumes $65 WTI & $2.75 Henry Hub for remainder of 2018.



KEY STATS	Q1 18	Q4 17
Net production (MBOED)	41	55
Upstream capital ($MM)	$78	$41

Barnett Shale

- Johnson County divestiture announced
  - Proceeds: $553 million (closing late May)
  - Q1 production: 33 MBOED (18% liquids)
- Partnership formed with DowDupont
  - Selling ½ working interest in 116 locations
  - Devon to receive ~$75 million over 5 yrs
  - Drilling commitment of up to 24 wells/year
  - No restrictions on exiting Barnett
- ~50 horizontal refracs planned in 2018
- Capital program to stabilize production for retained Barnett assets (table right)



PRODUCTION (MBOED)	Q1 18	Q2 18e	2H 18e
Retained Barnett assets	110	105 - 115	110- 115
Johnson County divestiture	33	22	0
Total Barnett production	143	127 - 137	110 - 115

Investor Contacts & Notices

Investor Relations Contacts

Scott Coody
VP, Investor Relations
405-552-4735

Chris Carr
Supervisor, Investor Relations
405-228-2496

Email: investor.relations@dvn.com

Investor Notices

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