RANGE RESOURCES®

Capital One Securities
2018 Energy Conference

Forward Looking Statements

This presentation contains *certain "forward-looking statements" within the meaning of the federal securities laws, including the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 that are not limited to historical facts, but reflect Range's current beliefs, expectations or intentions regarding future events. Words such as "may," "will," "could," "should," "expect," "plan," "project," "intend," "anticipate," "believe," "outlook", "estimate," "predict," "potential," "pursue," "target," "continue," and similar expressions are intended to identify such forward-looking statements.*

All statements, except for statements of historical fact, made within regarding activities, events or developments the Company expects, believes or anticipates will or may occur in the future, such as those regarding future well costs, expected asset sales, well productivity, future liquidity and financial resilience, anticipated exports and related financial impact, NGL market supply and demand, improving commodity fundamentals and pricing, future capital efficiencies, future shareholder value, emerging plays, capital spending, anticipated drilling and completion activity, acreage prospectivity, expected pipeline utilization and future guidance information are 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. These statements are based on assumptions and estimates that management believes are reasonable based on currently available information; however, management's assumptions and Range's future performance are subject to a wide range of business risks and uncertainties and there is no assurance that these goals and projections can or will be met. Any number of factors could cause actual results to differ materially from those in the forward-looking statements. Further information on risks and uncertainties is available in Range's filings with the Securities and Exchange Commission (SEC), including its most recent Annual Report on Form 10-K. Unless required by law, Range undertakes no obligation to publicly update or revise any forward-looking statements to reflect circumstances or events after the date they are made.

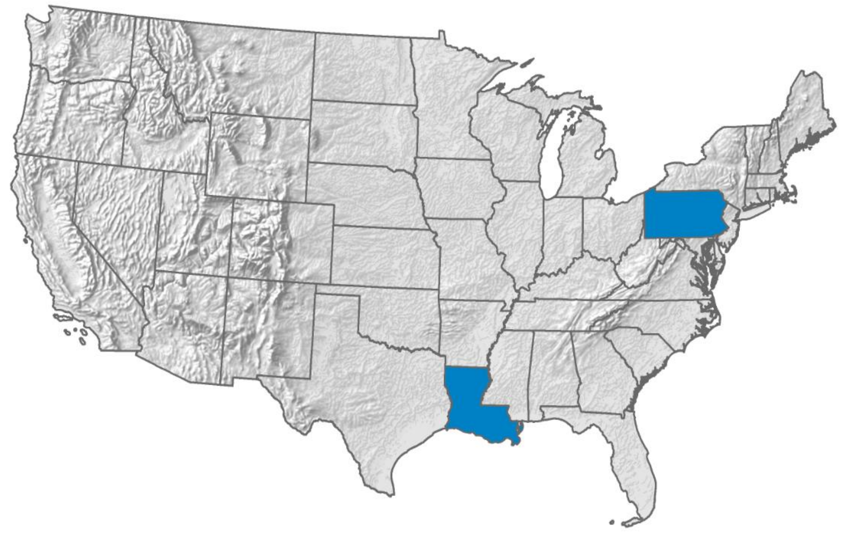
The SEC permits oil and gas companies, in filings made with the SEC, to disclose proved reserves, which are estimates that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions as well as the option to disclose probable and possible reserves. Range has elected not to disclose its probable and possible reserves in its filings with the SEC. Range uses certain broader terms such as "resource potential," "unrisked resource potential," "unproved resource potential" or "upside" or other descriptions of volumes of resources potentially recoverable through additional drilling or recovery techniques that may include probable and possible reserves as defined by the SEC's guidelines. Range has not attempted to distinguish probable and possible reserves from these broader classifications. The SEC's rules prohibit us from including in filings with the SEC these broader classifications of reserves. These estimates are by their nature more speculative than estimates of proved, probable and possible reserves and accordingly are subject to substantially greater risk of actually being realized. Unproved resource potential refers to Range's internal estimates of hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques and have not been reviewed by independent engineers. Unproved resource potential does not constitute reserves within the meaning of the Society of Petroleum Engineer's Petroleum Resource Management System and does not include proved reserves. Area wide unproven resource potential has not been fully risked by Range's management. "EUR", or estimated ultimate recovery, refers to our management's estimates of hydrocarbon quantities that may be recovered from a well completed as a producer in the area. These quantities may not necessarily constitute or represent reserves within the meaning of the Society of Petroleum Engineer's Petroleum Resource Management System or the SEC's oil and natural gas disclosure rules. Actual quantities that may be recovered from Range's interests could differ substantially. Factors affecting ultimate recovery include the scope of Range's drilling program, which will be directly affected by the availability of capital, drilling and production costs, commodity prices, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals, field spacing rules, recoveries of gas in place, length of horizontal laterals, actual drilling results, including geological and mechanical factors affecting recovery rates and other factors. Estimates of resource potential may change significantly as development of our resource plays provides additional data.

In addition, our production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases. Investors are urged to consider closely the disclosure in our most recent Annual Report on Form 10-K, available from our website at www.rangeresources.com or by written request to 100 Throckmorton Street, Suite 1200, Fort Worth, Texas 76102. You can also obtain this Form 10-K on the SEC's website at www.sec.gov or by calling the SEC at 1-800-SEC-0330.

Range Overview

Market Snapshot

NYSE Symbol:	RRC
Market Cap [(a)]:	$3.7B
Net Debt [(b)]:	$4.2B
Enterprise Value:	$7.9B
SEC Proved Reserve Value PV_{10}	$8.1B



Highlights

2018 Capital Program of $941 million

- Targeting ~11% corporate growth within cash flow
- ~85% allocated to Marcellus

2017 Year-End Proved Reserves of 15.3 Tcfe

- Reserve/Production ratio of 18.4 years [(c)]

Five-Year Outlook[(d)]

- ~$1 billion in cumulative free cash flow
- Leverage below 2X net debt to EBITDAX
- 13% debt-adjusted production per share CAGR
- FCF Yield ~36% at end of 5-year outlook

(a) As of 11/28/2018 (b) As of 09/30/2018 (c) Based off 3Q18 production annualized (d) Five-Year outlook assumes strip pricing as of 12/29/2017 and excludes any asset sales. Additional assumptions and defined terms on slide 17.

Strategic Focus

Returns-Focused Growth on a Per Share Debt-Adjusted Basis

- Growth within cash flow driven by high-return assets
- Consistent emphasis on debt-adjusted per share metrics in management incentives

Improving Corporate Returns

- Corporate returns expected to improve through expanding margins and capital efficient growth
- Cost structure improvements led by lower gathering and transportation expense per mcfe from utilizing existing infrastructure and lower interest expense

Reduce Leverage

- Target net debt/EBITDAX below 3.0x in the near-term and an Investment Grade leverage profile in the longer term
- Active asset sale processes underway to accelerate de-levering process
- 5 year outlook reduces leverage below 2.0x

Be Good Stewards of the Environment and Operate Safely

Positions Range to Return Capital to Shareholders

Five-Year Outlook Summary

Free Cash Flow

~$1 billion

Debt Reduction

<2.0x debt to EBITDAX

Growth

~13% debt adjusted per share production CAGR

FCF Yield[(a)]

~36%

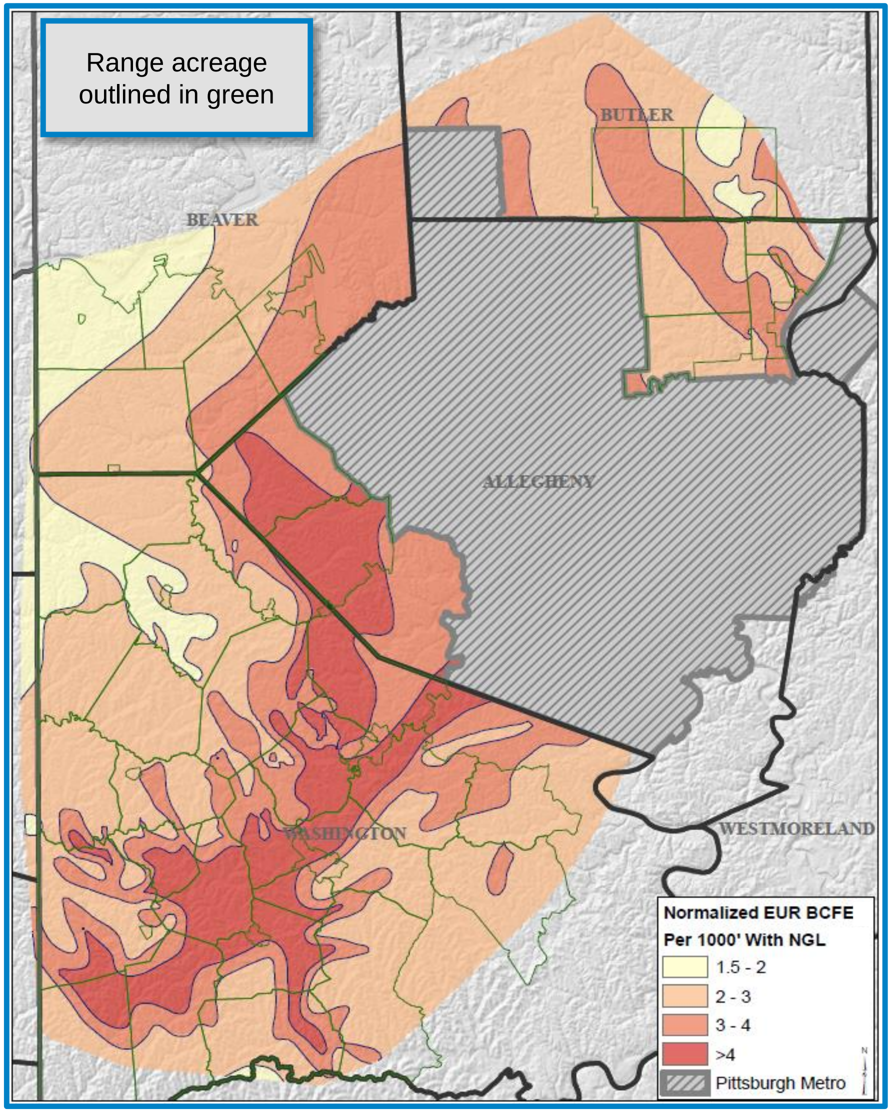
Recycle Ratio

~3.8x

Underpinned by Large, De-risked, High Quality Marcellus Inventory

Note: Five-year outlook assumes strip pricing as of 12/29/2017. Additional assumptions and defined terms on slide 17.
(a) Based on closing share price as of 11/28/2018

Large Core Marcellus Inventory



Large contiguous acreage position allows for long-lateral development

~3,800 undrilled Core Marcellus wells [(a)]

- ~300 wells with 40+ Bcfe EUR
- ~400 wells with 30-40 Bcfe EUR
- ~1,400 wells with 20-30 Bcfe EUR
- ~1,400 wells with 15-20 Bcfe EUR[(b)]
- *Based on 10,000 foot average lateral lengths*

Marcellus resource potential [(b)]

- ~ 40 Tcf of natural gas
- ~ 3 billion barrels of NGLs
- ~ 149 million barrels of condensate

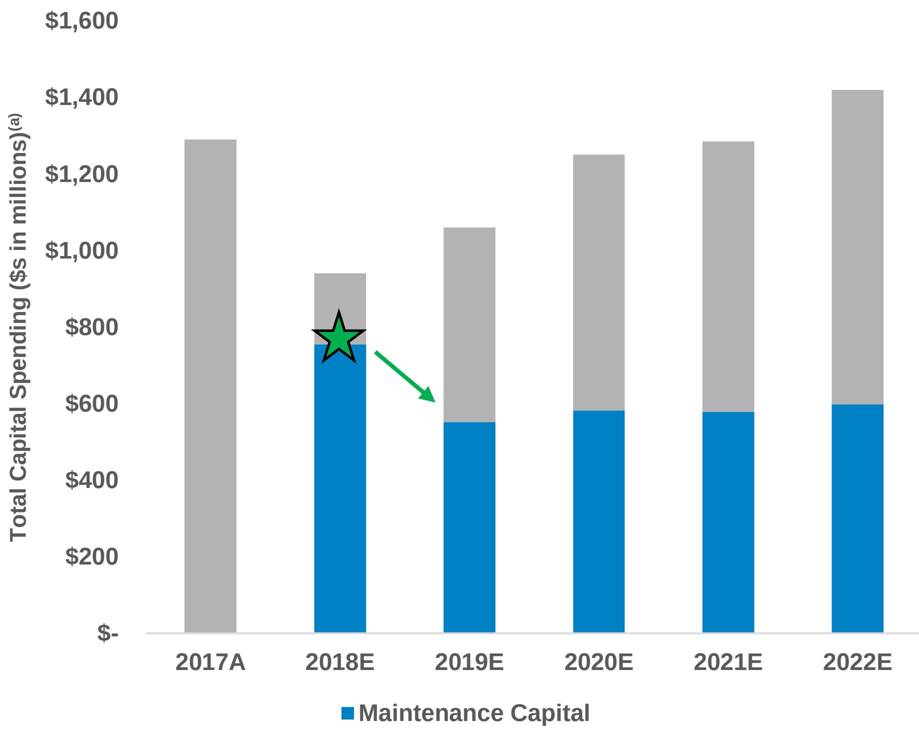
Significant inventory of highly prolific Deep Utica wells not included above

Half million acres of low-risk Upper Devonian provides additional wet/dry optionality in the future, but is not included above

(a) *Estimates as of YE2017; based on production history from thousands of wells. Includes ~300 locations not shown on map. Majority of inventory of 1.5 – 2.0 Bcfe/1000' wells are downspaced locations (not in the 5-year development plan) that incorporate expected recoveries of ~75% of 1,000' spaced wells.*

(b) *Does not include 6.5 Tcfe of proved undeveloped Marcellus resource.*

Low Maintenance Capital Drives Efficiencies



- Significant improvement in Maintenance Capital post-2018
  - Longer laterals lower base decline
  - Corporate base decline improves to <20% in 2019
  - 2019 Maintenance Capital expected to be ~$550 million
- Maintenance Capital of ~$600 million anticipated to hold production flat at 3.5 Bcfe/d (2022 exit rate)
- FCF yield ~36% at current stock price [b]
- Over 3,200 undrilled wells remaining following 5-year outlook development

Five-Year Outlook capital spending ~85% of cumulative cash flow

Note: Five-year outlook assumes strip pricing as of 12/29/2017. Additional assumptions and defined terms on slide 17. (a) Total capital includes D&C, leasehold, facilities and other spending. (b) Based on Maintenance Capital of $600 million post-2022 and market cap of $3.7B as of 11/28/18.

Two Years Ahead of Schedule on Leverage Target

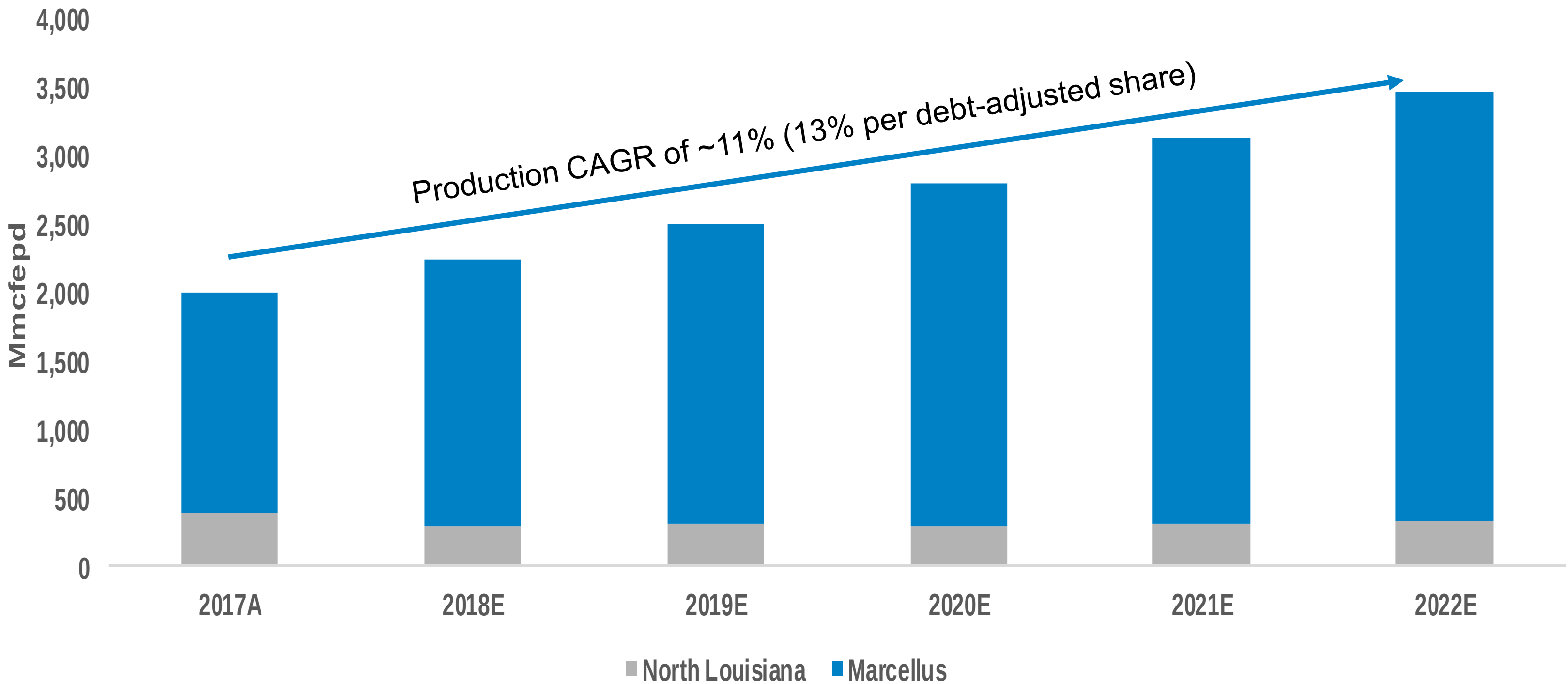
Asset Sales and NGL Pricing Strength Have Accelerated Leverage Reduction. Range Now Expects <3.0x Net Debt to EBITDAX at YE18.

Five-Year Outlook *Announced January 2018*	Current Expectation
Leverage Under 3.0x by 2020	Leverage Under 3.0x by YE18

As Leverage Gets Below 2.5x, Share Repurchases and Dividend Increases Will Be Evaluated as Range Seeks to Maximize Long-Term Shareholder Value. Additional Asset Sales Will Be Pursued to Accelerate This Process.

Note: Five-year outlook assumes strip pricing as of 12/29/2017. Additional assumptions and defined terms on slide 17.
Updated outlook assumes year-to-date performance and strip pricing as of 10/10/18. No other assumptions have been updated or changed.

Production Growth Within Cash Flow

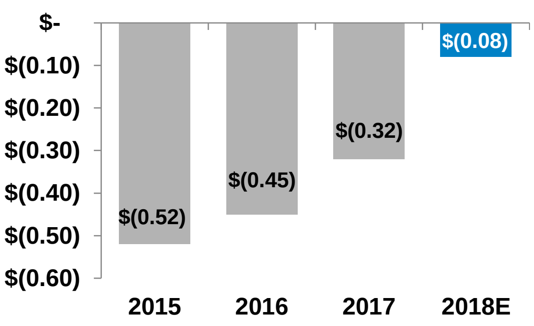


Growing production at ~11% and **spending within cash flow** at strip pricing provides a steady path to improved leverage, while simultaneously driving efficiencies through increased scale and consistent operations.

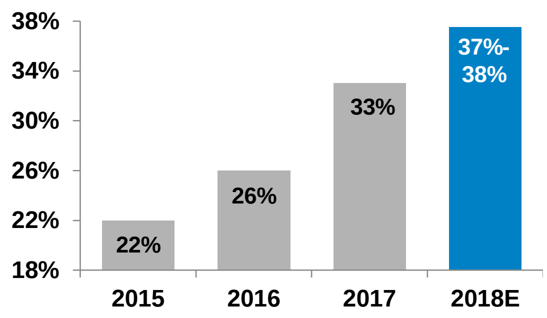
Note: Five year-outlook assumes strip pricing as of 12/29/2017. Additional assumptions and defined terms on slide 17.

Differential Improvements Driving Margin Expansion

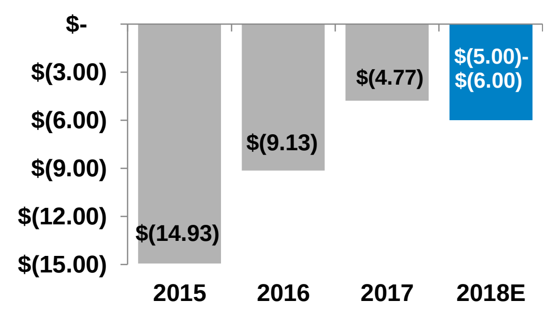
Natural Gas Differential (a)



NGL as a % of WTI (b)



Condensate Differential



Natural Gas

- 2018 NG differential expected to improve further as transportation projects are complete
- Upon completion of transportation projects, TGC&P expense expected to peak in 4Q 2018 before trending downward

Natural Gas Liquids

- Range has sent 40,000 barrels per day of ethane and propane combined to Marcus Hook export facilities since early 2016
- North Louisiana NGL's sold FOB processing plant and receive Mont Belvieu related pricing
- Continued ethane and propane demand growth anticipated in 2018 from petrochemical sector and exports

Condensate (Oil)

- Constructive oil macro driving highest condensate realizations since 2014

(a) NG estimate includes basis hedges and is based on strip pricing at 10/10/2018 (b) 2018E based on NGL strip pricing at 10/10/2018. 2018E represents recent accounting change

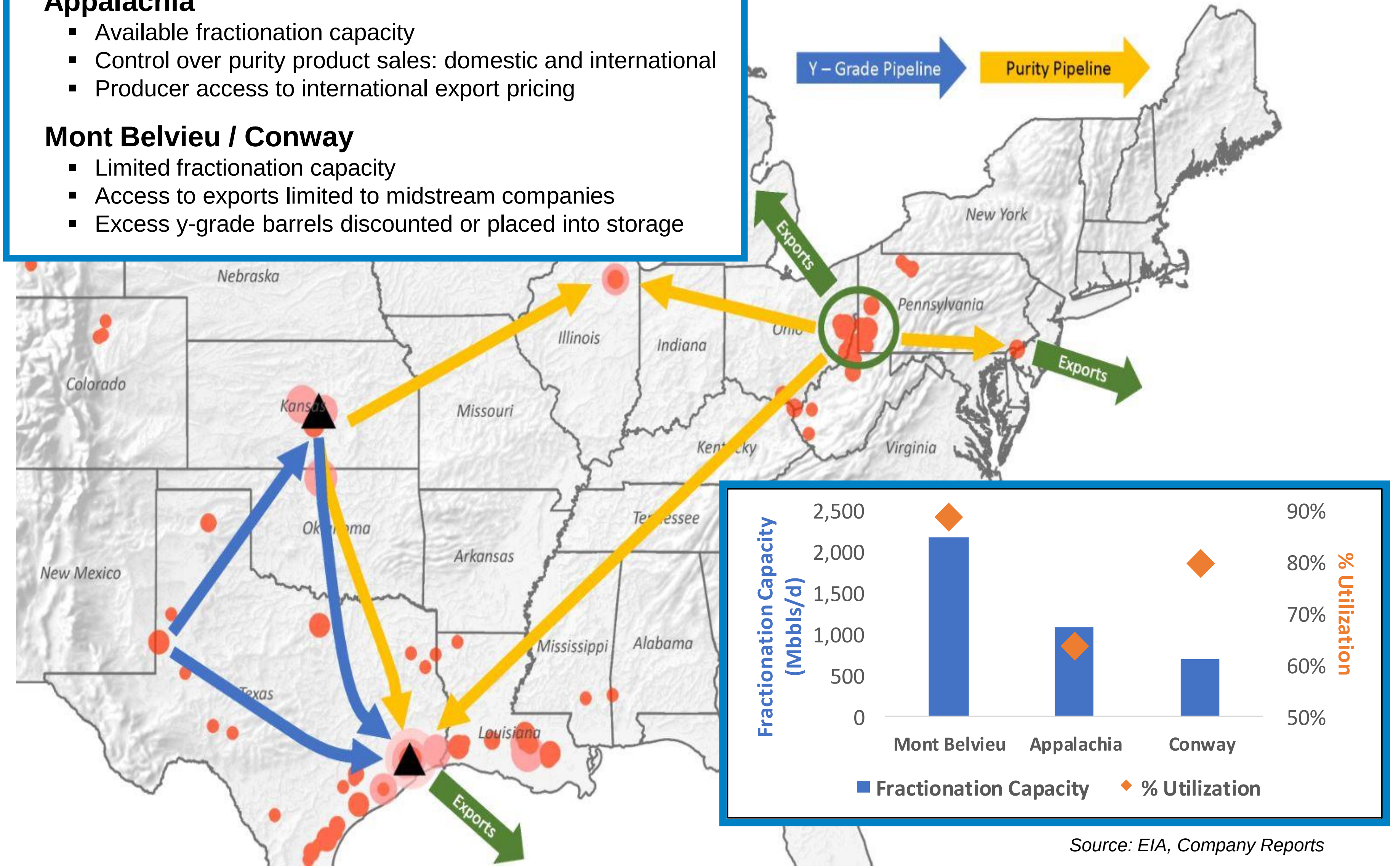
Appalachian In-Basin Fractionation Advantage

Appalachia

- Available fractionation capacity
- Control over purity product sales: domestic and international
- Producer access to international export pricing

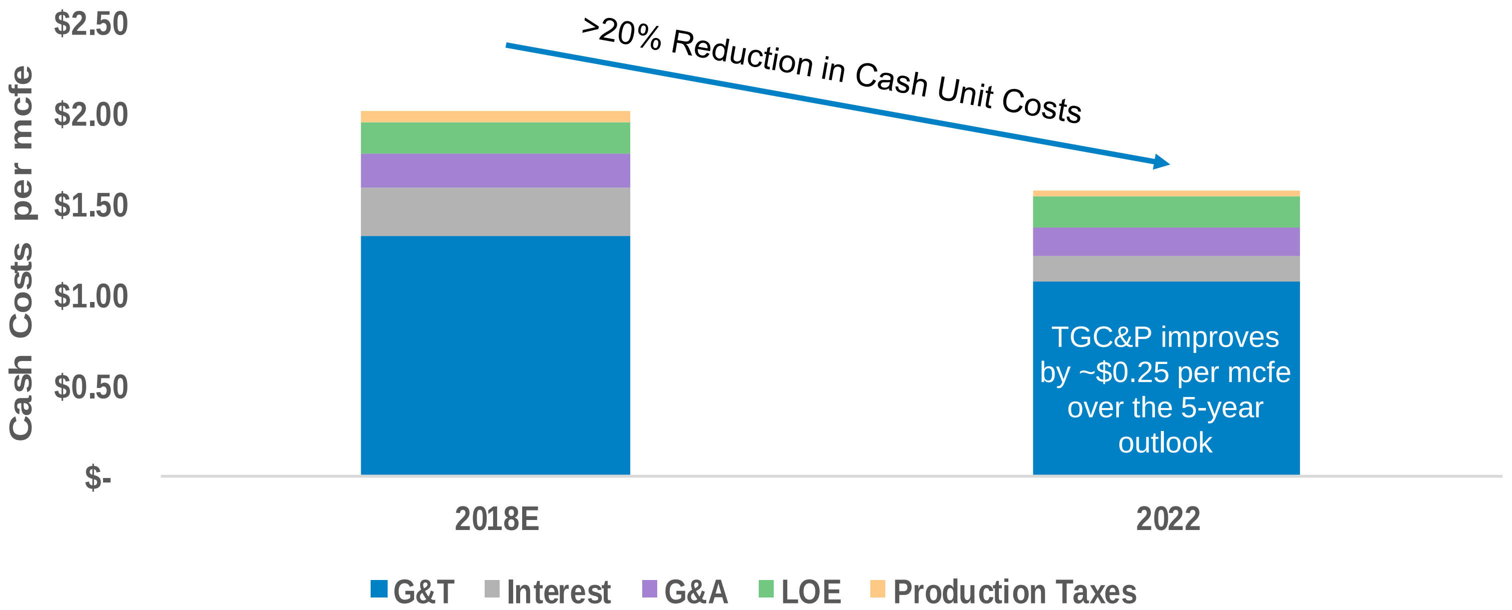
Mont Belvieu / Conway

- Limited fractionation capacity
- Access to exports limited to midstream companies
- Excess y-grade barrels discounted or placed into storage



Source: EIA, Company Reports

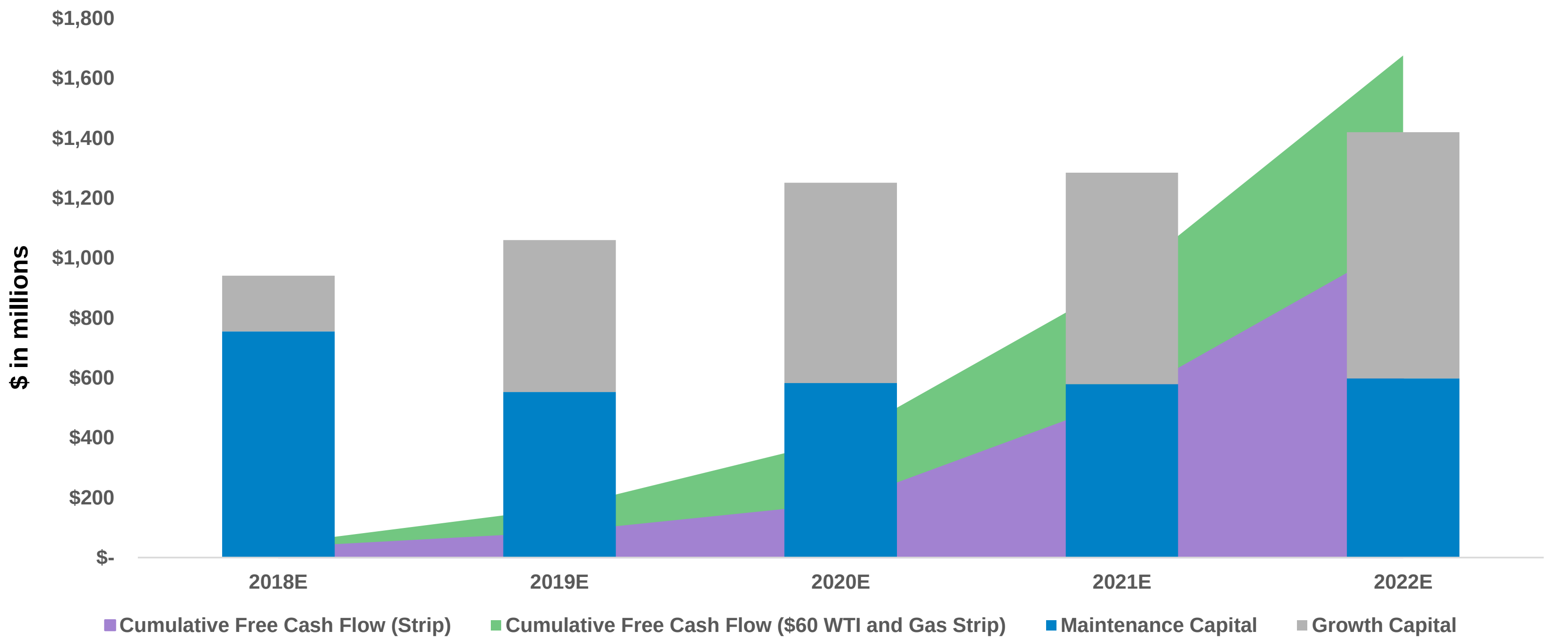
Improving Cost Structure Drives Cash Flow & Margin Growth



Largest improvement to cash unit costs is expected in gathering & transportation expenses, driven primarily by improved utilization of existing infrastructure and midstream commitments.

Note: Five-year outlook assumes strip pricing as of 12/29/2017. Additional assumptions and defined terms on slide 17.

Free Cash Flow Profile



Cumulative FCF of ~$1 billion over the next five years assuming strip pricing. Cumulative FCF increases ~70% to ~$1.7 billion assuming an increase in oil price to $60 per bbl (gas pricing at strip).

Note: Five-year outlook assumes strip pricing as of 12/29/2017. Additional assumptions and defined terms on slide 17.

Current Enterprise Value a Discount to YE17 PV-10

YE17 PV-10 at Strip Pricing[a]	$9.5 billion
Enterprise Value[b]	$7.9 billion

YE17 PV_{10} > Enterprise Value. Assumes no value for ~58 Tcfe of Marcellus resource potential[c].

YE17 Proved Reserves	15.3 Tcfe
Enterprise Value[b]/Proved Reserves	~$0.56 per mcfe

Trading at ~$0.56 per Proved Mcfe which excludes ~58 Tcfe of Marcellus resource potential[c].

(a) Strip pricing as of 12/29/2017 (b) Enterprise Value as of 11/28/2018 (c) Marcellus resource potential of 58 Tcfe excludes ~500k net acres prospective for the Upper Devonian and ~400k net acres prospective for the Utica

Beyond the 5-Year Outlook

Snapshot December 2022E		
	Production	3.5 Bcfe per day
	Annual CF @ Strip	$1.95 billion
	Maintenance Capital	~$600 million
	Remaining Core Marcellus Inventory	3,200 Wells
	YE2022 Debt to EBITDAX	<2.0x

Range can hold 3.5 Bcfe per day flat for approximately $600 million per year of maintenance capital. This would generate approximately **$1.3 billion [a] in Annual Free Cash Flow** at strip pricing, giving Range the ability to return capital to shareholders.

With **3,200 Core Marcellus** wells remaining post-2022, this would represent over 30 years of inventory holding production at 3.5 Bcfe per day.

The size and quality of Range's remaining inventory, combined with improved access out of southwest Appalachia will also provide Range with a **growth option.** As an example, Range could generate average annual growth of >20% from 2023-2025 and still generate over $1 billion of additional free cash flow over that time frame.

Lower Cotton Valley, Deep Utica and Upper Devonian extend the runway for FCF generation and growth.

Note: Five-year outlook assumes strip pricing as of 12/29/2017. Additional assumptions and defined terms on slide 17.
(a) $1.3 billion represents 2022E cash flow of ~$1.9 billion less $600 million of maintenance capital.

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Appendix

Five-Year Outlook Assumptions and Definitions

Assumptions:

- Production growth is driven by de-risked Marcellus inventory.
- North Louisiana production held relatively flat from YE18 through remainder of outlook.
- Strip pricing as of 12/29/2017:
  - Henry Hub - $2.83 (2018), $2.84 (2019-2022 average)
  - SWPA - $2.37 (2018), $2.44 (2019-2022 average)
  - WTI - $59.37 (2018), $53.48 (2019-2022 average)
  - NGL - 39% of WTI (2018), 42% (2019-2022 average)
- Range is pursuing multiple asset sales, but no asset sales have been included in five-year outlook. Any additional asset sale proceeds would be used to reduce debt.
- Free cash flow is used to pay down debt balance.
- Deep Utica and Upper Devonian not considered in 5-year development outlook, though they provide thousands of additional drilling locations to Range inventory.
- Lateral lengths kept at 10,000 feet through 2022, similar to 2018 expected laterals.
- Capital savings from operational efficiencies held to approximately $50 million per year starting in 2020, or ~$300k per well to be conservative. These savings approximate what would be expected on a go-forward basis from known operational efficiencies off existing pad development and recycled water savings. Range's estimated water costs are $1.4 million per well as Range now recycles ~100% of its produced water.
- Additional efficiency gains from drilling and completion improvement and optimization are not included, though historical trends realized by the company would suggest this is possible.

Definitions:

Recycle ratio - ***Cash margin per mcfe / PUD development costs per mcfe. Example in Appendix***

Non-GAAP cash flow - ***Net cash from operations before changes in working capital***

Free cash flow - ***Non-GAAP cash flow minus total capital spending***

Free cash flow yield - ***(Non-GAAP cash flow minus <u>Maintenance capital</u>) / Market Cap. (Examples shown are post-2022)***

Maintenance capital - ***Estimated total capital required to hold production flat from the previous year's exit rate***

Revenue Recognition Accounting Standard Adopted in 2018

Range adopted the new revenue recognition accounting standards in 1Q18 which changes our financial statement presentation related to revenue from certain gas processing contracts. As shown below, this is solely an accounting change and has no effect on earnings or cash flow.

($ in thousands, except for per bbl and per mcfe metrics)

	3Q18 As Reported	3Q18 Old Method	Difference:	4Q17 As Reported	4Q17 New Method	Difference:
Realized Price- Pre-hedge (per bbl)						
Natural Gas Liquids:	$ 27.16	$ 22.51		$ 19.70	$ 24.19	
Total NGL Volumes (bbls)	10,255	10,255		9,755	9,755	
Total NGL Revenue	$ 278,563	$ 230,816	$ 47,747	$ 192,232	$ 235,974	$ 43,742
TGC&P per Mcfe	$ 1.46	$ 1.23		$ 1.00	$ 1.22	
Total Corporate Volumes (mcfe)	208,534	208,534		199,681	199,681	
Total TGC&P Expense	$ 304,562	$ 256,815	$ 47,747	$ 200,300	$ 244,042	$ 43,742

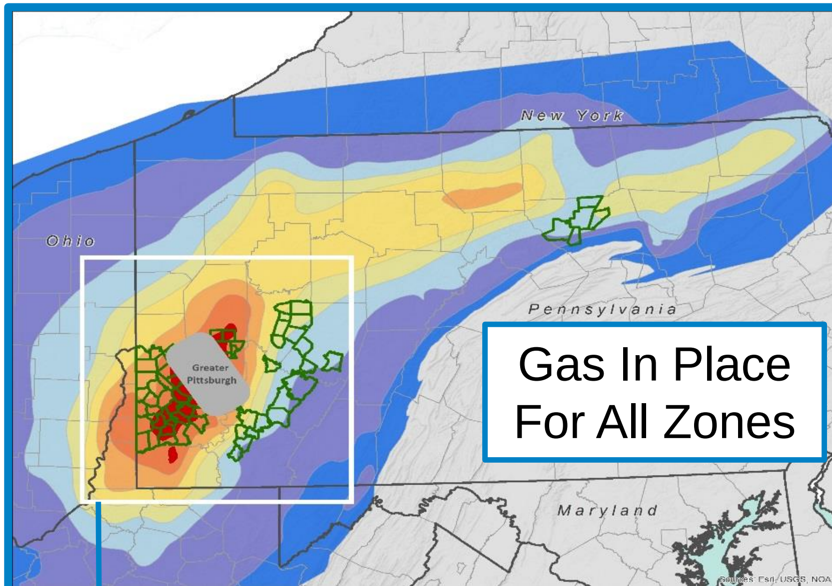
Identical increase in NGL revenue and TGC&P expense

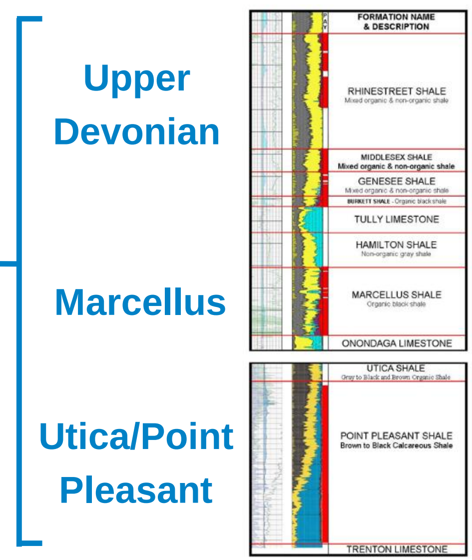
No change to cash margin, production or cash flow. The accounting change effectively increased NGL revenue and TGC&P by the same amount.

Appalachia Assets – Stacked Pay

- ~1.5 million net effective acres [(a)] in SW PA leads to decades of drilling inventory
- Gas In Place (GIP) analysis shows the greatest potential is in Southwest Pennsylvania
- Hundreds of producing wells demonstrate high quality, consistent results across Range's position
- Range's Utica results continue to produce strongly; Range's most recent well continues to be one of the best in the play
- Near-term activity led by Core Marcellus development in Southwest PA

Stacked Pay and Existing Pads Allow for Multiple Development Opportunities



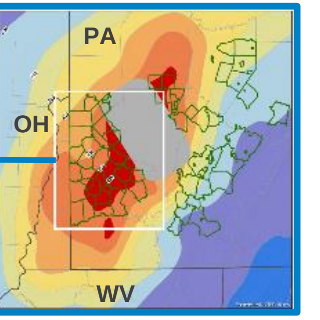


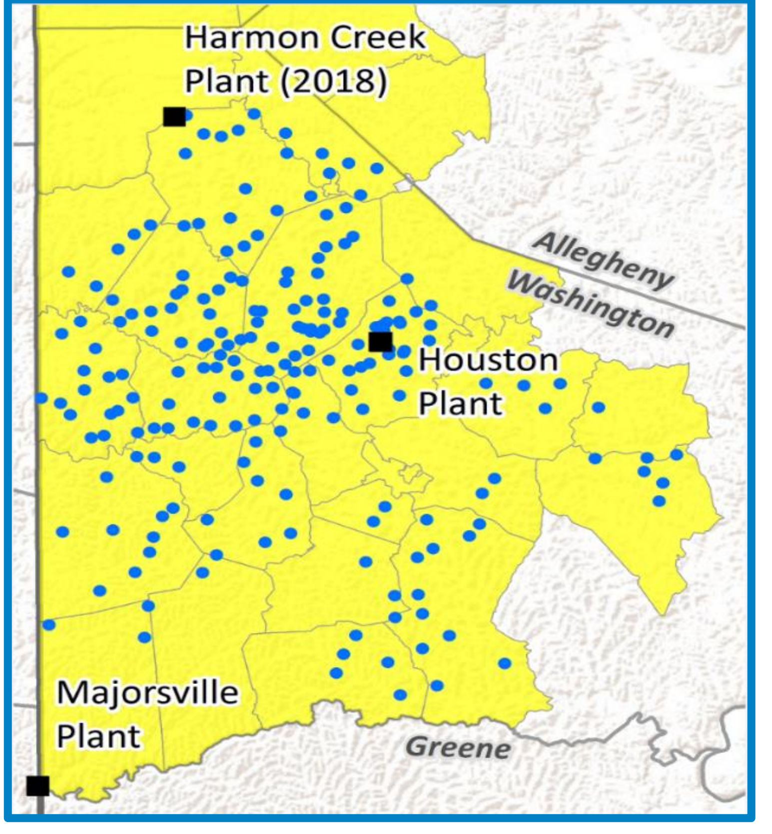
** Map acreage as of January 2018; outlined townships hold 2,000 or more acres (a) Assumes stacked pay opportunities in Deep Utica and Upper Devonian*

Southwest Appalachia Acreage Position

- Longer laterals and existing pads in 2018 provide low-risk efficiency gains
- Increased optionality due to quality of acreage position, gathering system, available locations and existing pads
- Majority of existing pads are in the liquids-rich areas (map to the right)

Note: Grey area is greater Pittsburgh area. Range acreage outlined in green.





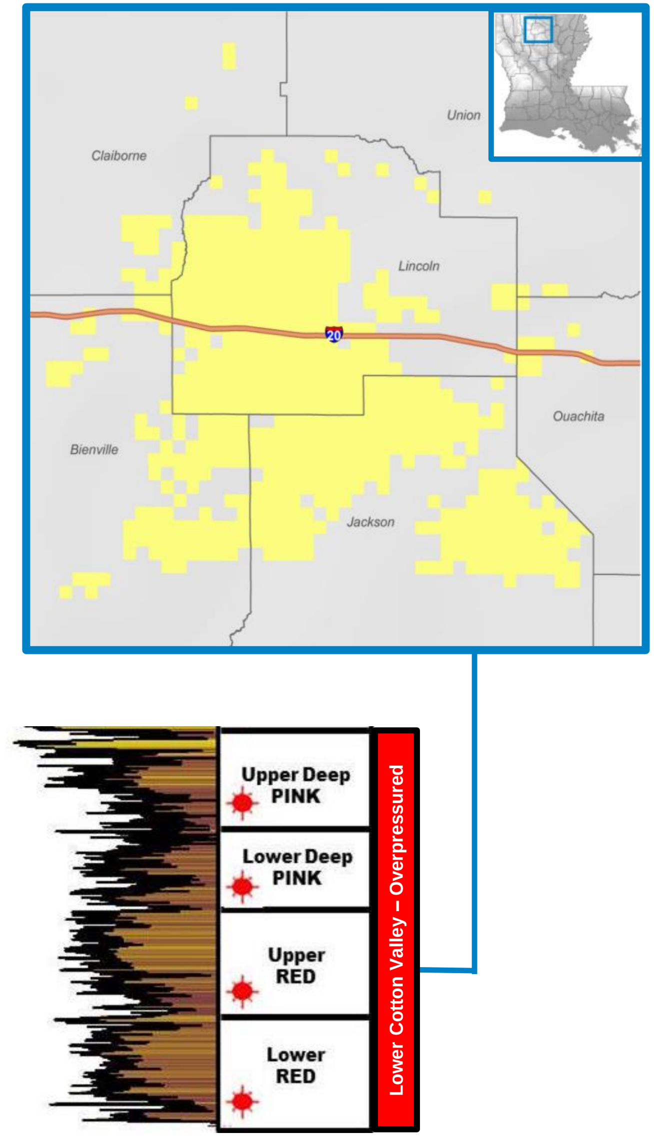
Southwest Marcellus Economics

	Dry	Wet	Super-Rich
EUR	24.8 Bcf	28.3 Bcfe	30.1 Bcfe
EUR/1,000 ft. lateral	2.5 Bcf	3.0 Bcfe	2.6 Bcfe
Well Cost	$6.5 MM	$7.3 MM	$9.2 MM
Cost/1,000 ft. lateral	$656 K	$768 K	$793 K
Lateral Length	9,830 ft.	9,550 ft.	11,550 ft.
IRR* - $3.00	70%	64%	72%
IRR* at Strip as of 12/29/2017	58%	55%	62%

** Returns as of 12/29/17. For flat pricing case, gas price assumed to be $3.00/mcf and oil price assumed to be $60/bbl to life. Not updated for 1% ORRI sale, though impact is minimal.*

North Louisiana Acreage Position

- ~140,000[(a)] net acres of stacked pay potential in North Louisiana
- Acreage favorably located near growing Gulf Coast demand center provides improved price realizations and minimal transportation cost
- Currently focused on Terryville development while continuing to methodically test extension areas



N. Louisiana Economics

	Combined Lower Cotton Valley
EUR	12.1 Bcfe
EUR/1,000 ft. lateral	1.61Bcfe
Well Cost	$8.4 MM
Cost/1,000 ft. lateral	$1,120 K
Lateral Length	7,500 ft.
IRR* - $3.00	33%
IRR at Strip as of 12/29/17	27%

For flat pricing case, gas price assumed to be $3.00/mcf and oil price assumed to be $60/bbl to life
(a) Estimated YE18 acreage

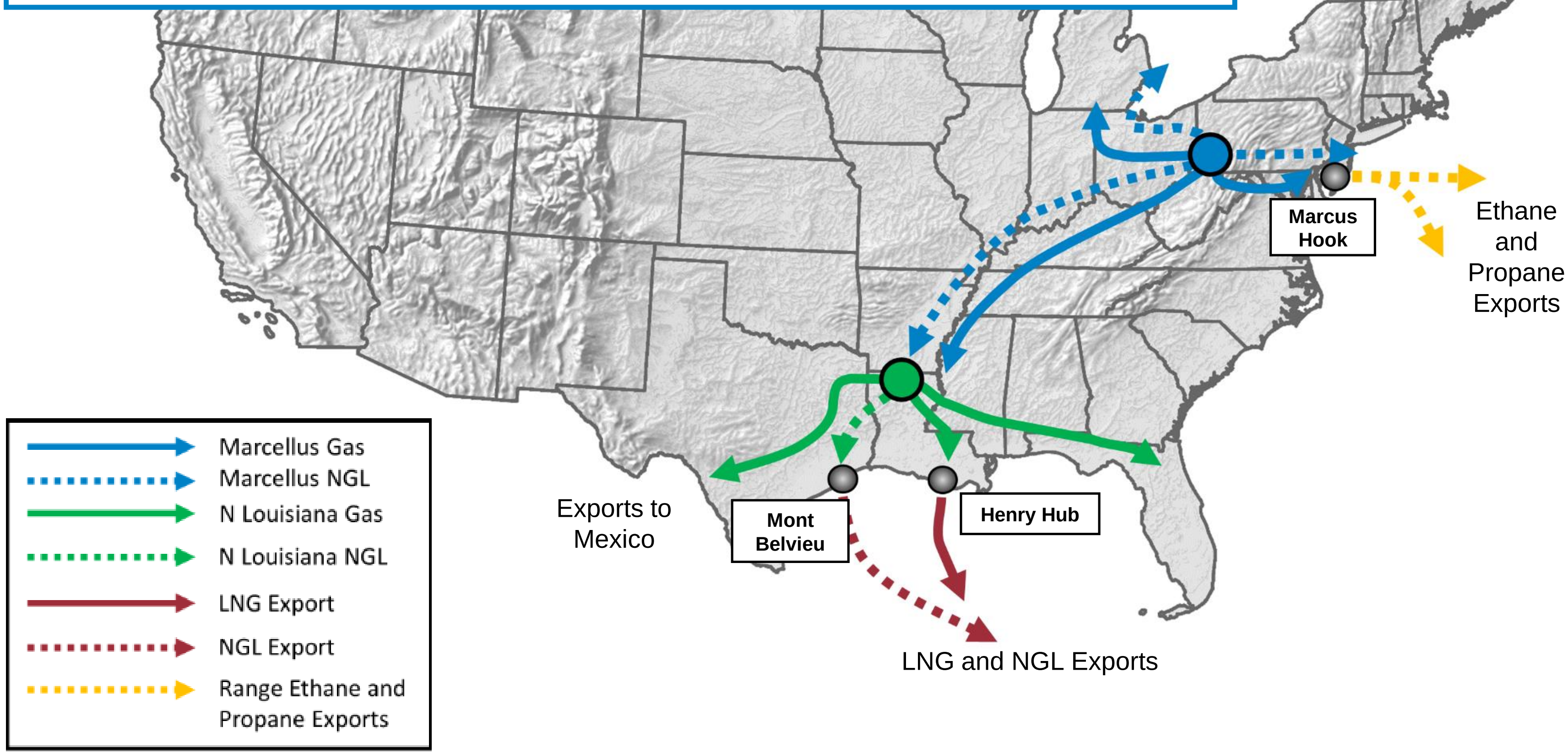
Diversified Marketing Strategy

Appalachian Production Has Ability to Reach Multiple Markets

- Currently selling natural gas in the Gulf Coast, Midwest, Southeast and Northeast markets
- Exporting ethane and propane internationally with optionality of in-basin and Gulf Coast sales

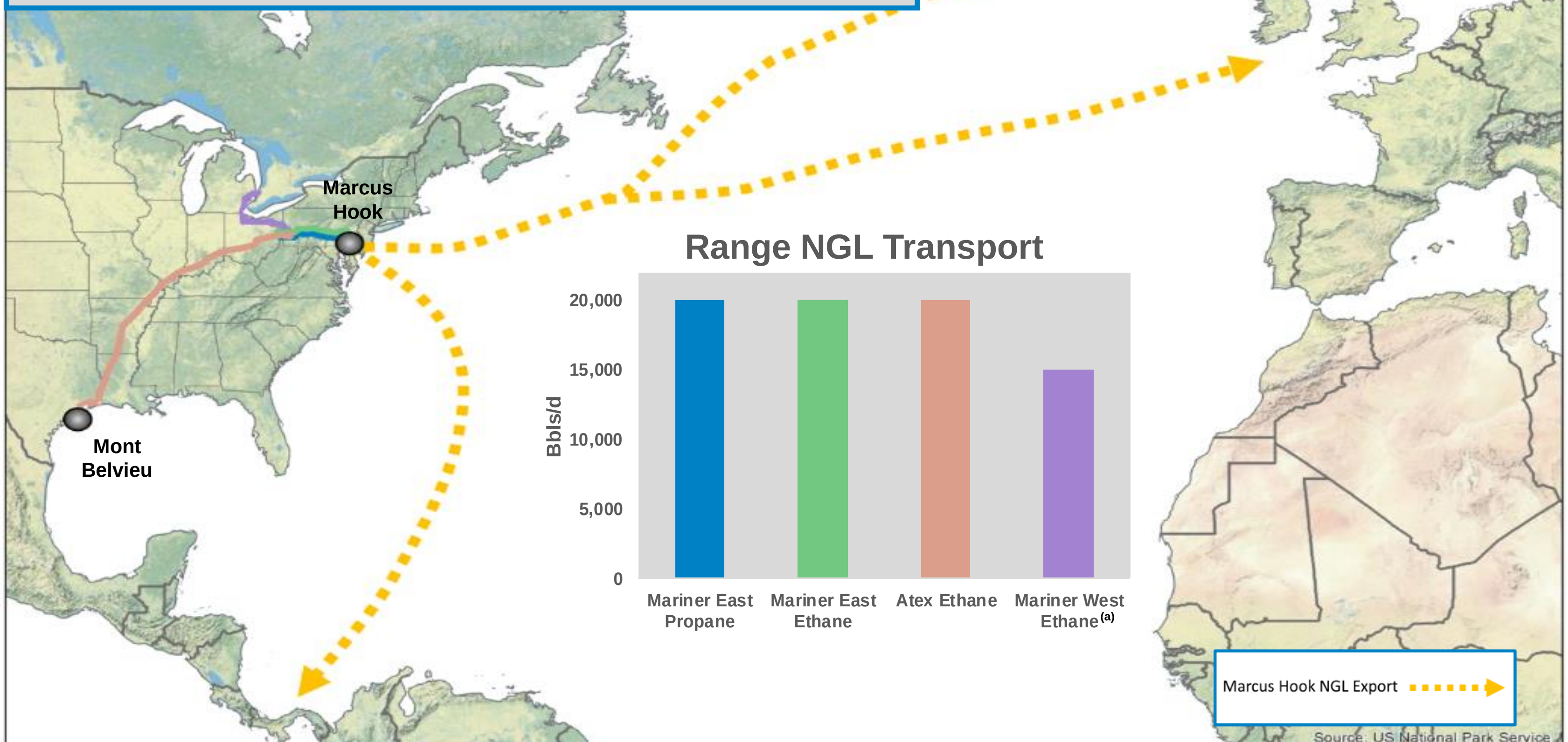
North Louisiana Production is Close to Growing Demand Centers

- Location near benchmark pricing hubs improves price realizations and minimizes transport costs
- Close proximity to New LNG export facilities, industrial demand and exports to Mexico



Innovative NGL Marketing Agreements Enhance Pricing

- First-mover on Appalachian NGL exports to Europe via ethane sales to INEOS using Mariner East capacity
- Range's propane has been sold internationally since 2016 through Marcus Hook, with option to sell into premium NE winter markets
- Mariner West ethane sent to Nova Chemical (Canada)
- ATEX moves Appalachia ethane to the Gulf Coast (Mont Belvieu)



(a) FOB Houston Plant

Mariner East: Exporting Ethane and Propane

- Only producer with current capacity on Mariner East 1
- Historic first shipments of ethane from U.S. to Europe
- Optionality of selling propane internationally or in local markets
- Improved ethane and propane netbacks

First VLGC Loading of Range Propane for Export

SW PA Wet Area Marcellus 2018 Well Economics

- Southwestern PA – (Wet Gas case)
- ~225,000 Net Acres
- EUR / 1,000 ft. – 2.95 Bcfe
- EUR – 28.3 Bcfe
  (77 Mbbls condensate, 2,330 Mbbls NGLs & 13.8 Bcf gas)
- Drill and Complete Capital $7.3 MM
  ($768 K per 1,000 ft.)
- Average Lateral Length – 9,550 ft.
- F&D - $0.31/mcf

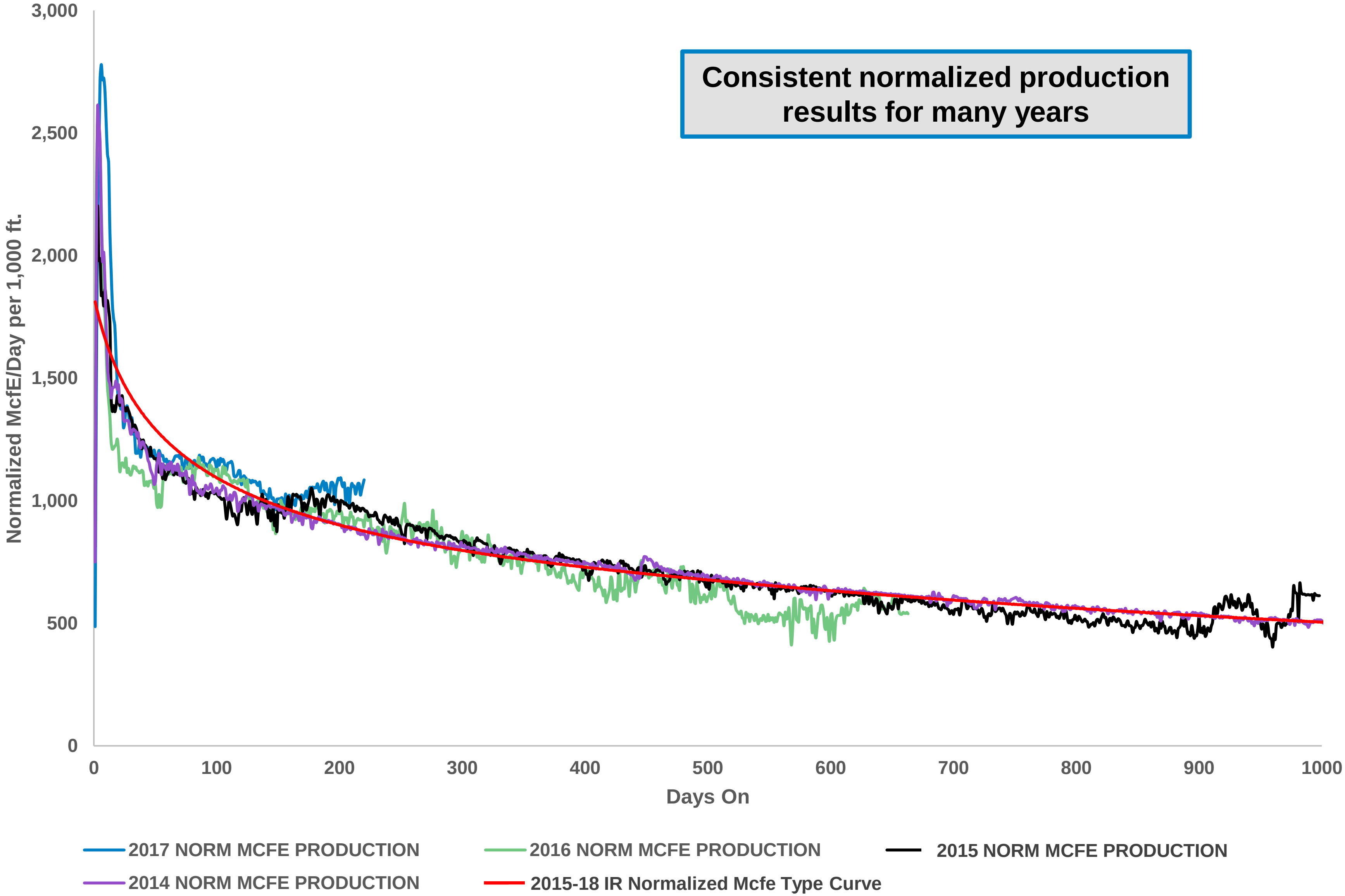
NYMEX Gas Price	Rate of Return
Strip -	55%
$3.00 -	64%

Estimated Cumulative Recovery for 2018 Production Forecast

	Condensate (Mbbls)	Residue (Mmcf)	NGL w/ Ethane (Mbbls)
1 Year	27	1,659	279
2 Years	41	2,759	465
3 Years	50	3,651	615
5 Years	60	5,062	852
10 Years	70	7,495	1,262
20 Years	75	10,488	1,766
EUR	77	13,839	2,330

- Includes current and expected differentials less gathering and transportation costs
- For flat pricing case, gas price assumed to be $3.00/mcf and oil price assumed to be $60/bbl
- Strip dated 12/29/17 with 10-year average $53.45/bbl and $2.94/mcf
- Not updated for 1% ORRI sale (announced October 2018), though impact is minimal

SW PA - Wet Area 2018 Production Forecast



SW PA Super-Rich Area Marcellus 2018 Well Economics

- Southwestern PA – (Wet Gas case)
- ~110,000 Net Acres
- EUR / 1,000 ft. – 2.60 Bcfe
- EUR – 30.1 Bcfe
  (416 Mbbls condensate, 2,309 Mbbls NGLs & 13.7 Bcf gas)
- Drill and Complete Capital $9.2 MM
  ($793 K per 1,000 ft.)
- Average Lateral Length – 11,550 ft.
- F&D - $0.37/mcf

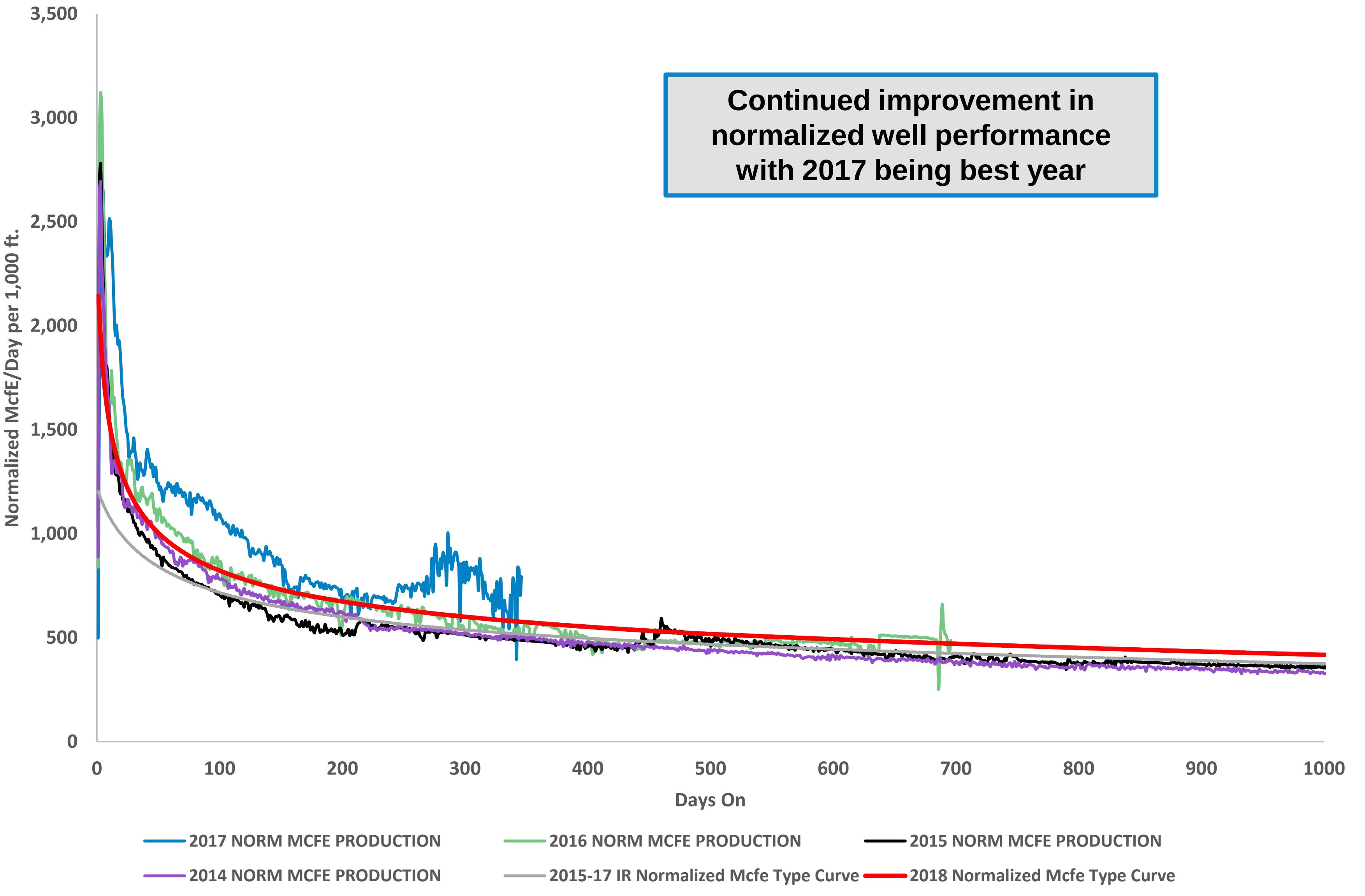
NYMEX Gas Price	Rate of Return
Strip -	62%
$3.00 -	72%

Estimated Cumulative Recovery for 2018 Production Forecast

	Condensate (Mbbls)	Residue (Mmcf)	NGL w/ Ethane (Mbbls)
1 Year	100	1,328	223
2 Years	141	2,251	378
3 Years	168	3,046	512
5 Years	206	4,379	736
10 Years	266	6,842	1,150
20 Years	336	10,029	1,686
EUR	416	13,734	2,309

- Includes current and expected differentials less gathering and transportation costs
- For flat pricing case, gas price assumed to be $3.00/mcf and oil price assumed to be $60/bbl
- Strip dated 12/29/17 with 10-year average $53.45/bbl and $2.94/mcf
- Not updated for 1% ORRI sale (announced October 2018), though impact is minimal

SW PA – Super-Rich Area 2018 Production Forecast



SW PA Dry Area Marcellus 2018 Well Economics

- Southwestern PA – (Dry Gas case)
- ~170,000 Net Acres
- EUR / 1,000 ft. – 2.52 Bcf
- EUR – 24.8 Bcf
- Drill and Complete Capital $6.5 MM
  ($656 K per 1,000 ft.)
- Average Lateral Length – 9,830 ft.
- F&D - $0.32/mcf

NYMEX Gas Price	Rate of Return
Strip -	58%
$3.00 -	70%

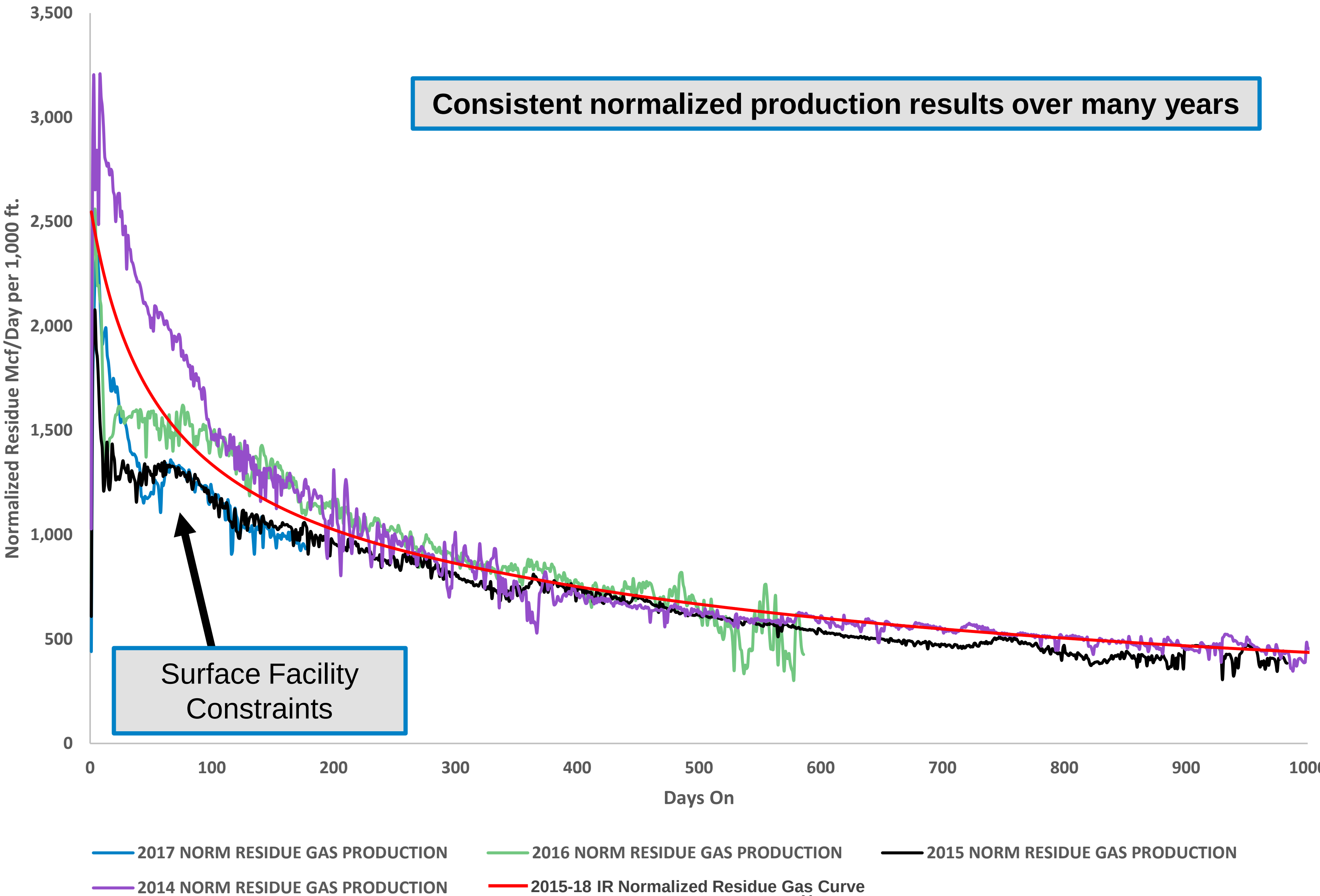
Estimated Cumulative Recovery for 2018 Production Forecast

	Residue (Mmcf)
1 Year	4,267
2 Years	6,563
3 Years	8,237
5 Years	10,686
10 Years	14,593
20 Years	19,156
EUR	24,771

- Includes current and expected differentials less gathering and transportation costs
- For flat pricing case, gas price assumed to be $3.00/mcf and oil price assumed to be $60/bbl
- Strip dated 12/29/17 with 10-year average $53.45/bbl and $2.94/mcf
- Not updated for 1% ORRI sale (announced October 2018), though impact is minimal

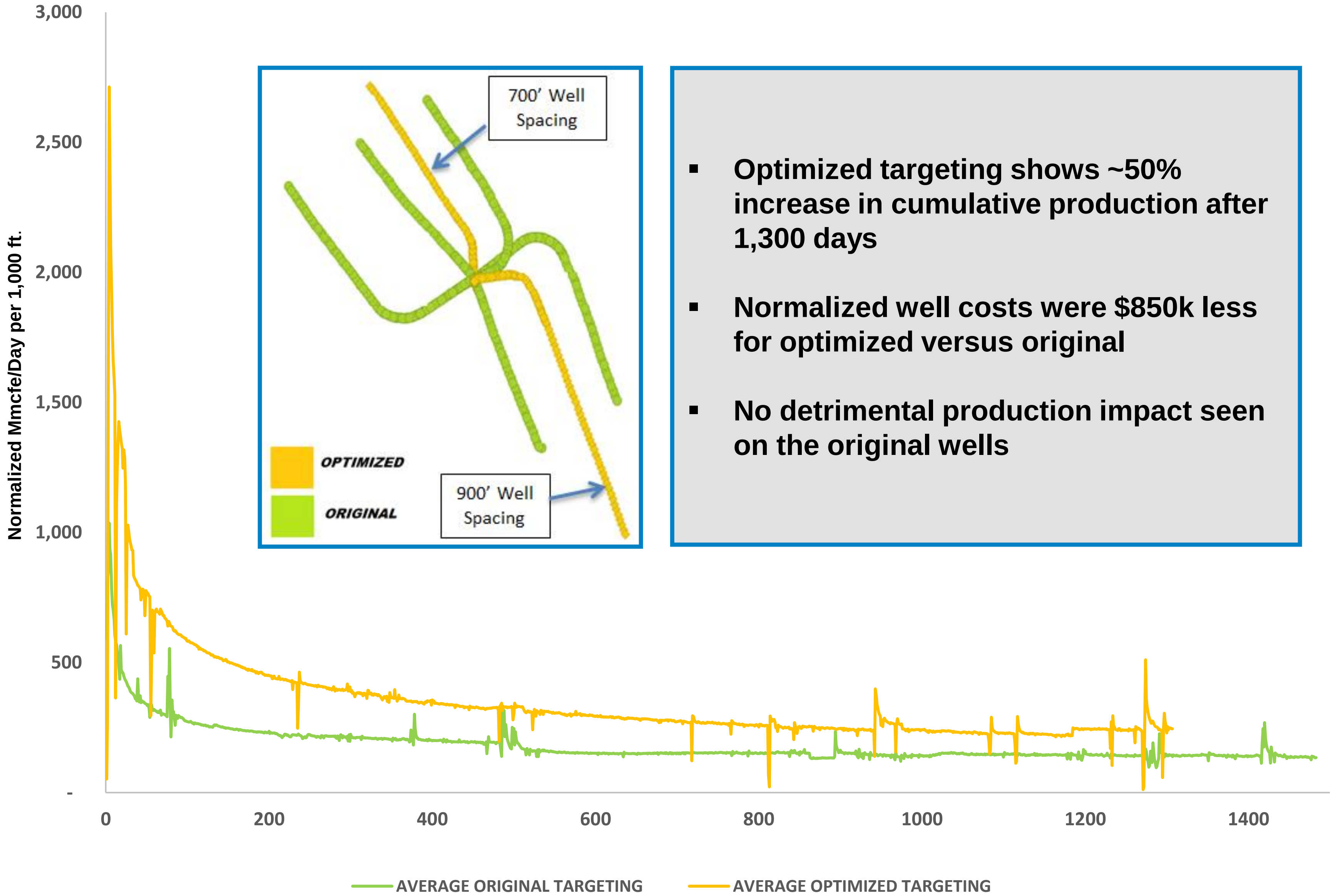
Based on Washington County well data

SW PA - Dry Area 2018 Production Forecast



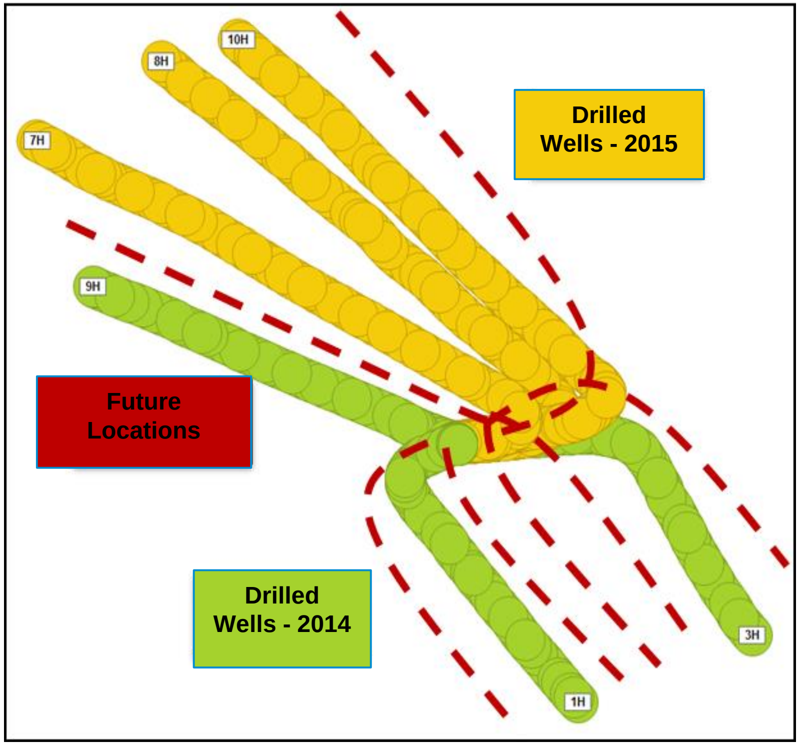
Based on Washington County well data

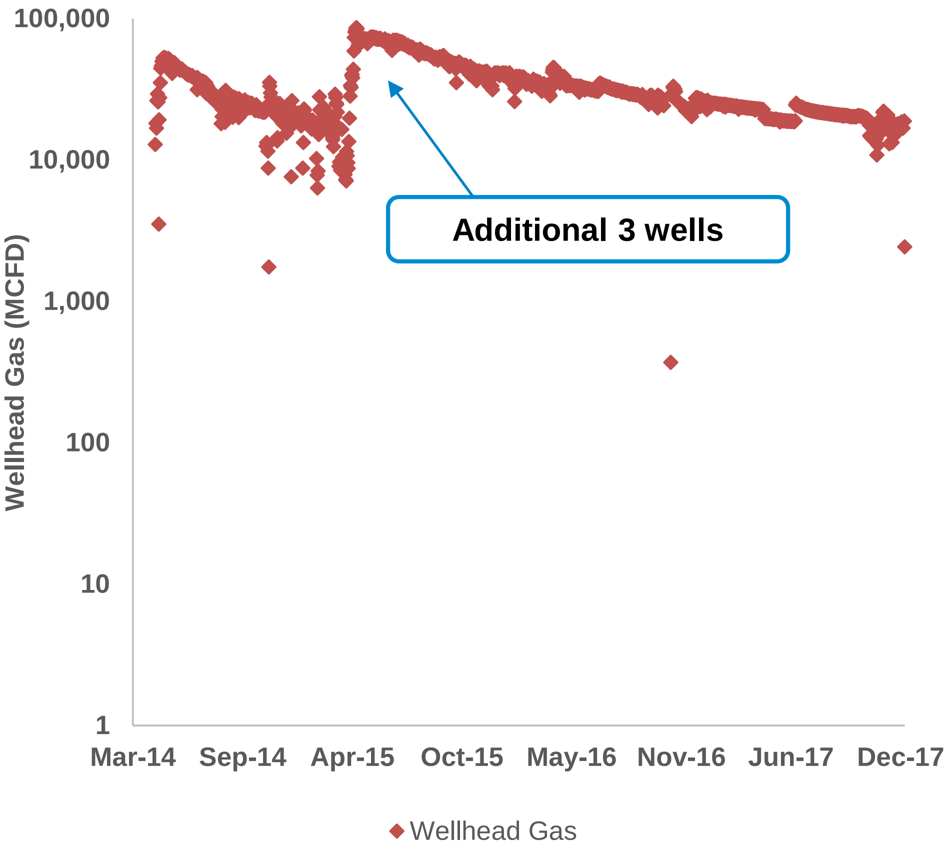
Targeting / Downspacing Production Results



- **Optimized targeting shows ~50% increase in cumulative production after 1,300 days**
- **Normalized well costs were $850k less for optimized versus original**
- **No detrimental production impact seen on the original wells**

Return to Existing Pads – Marcellus



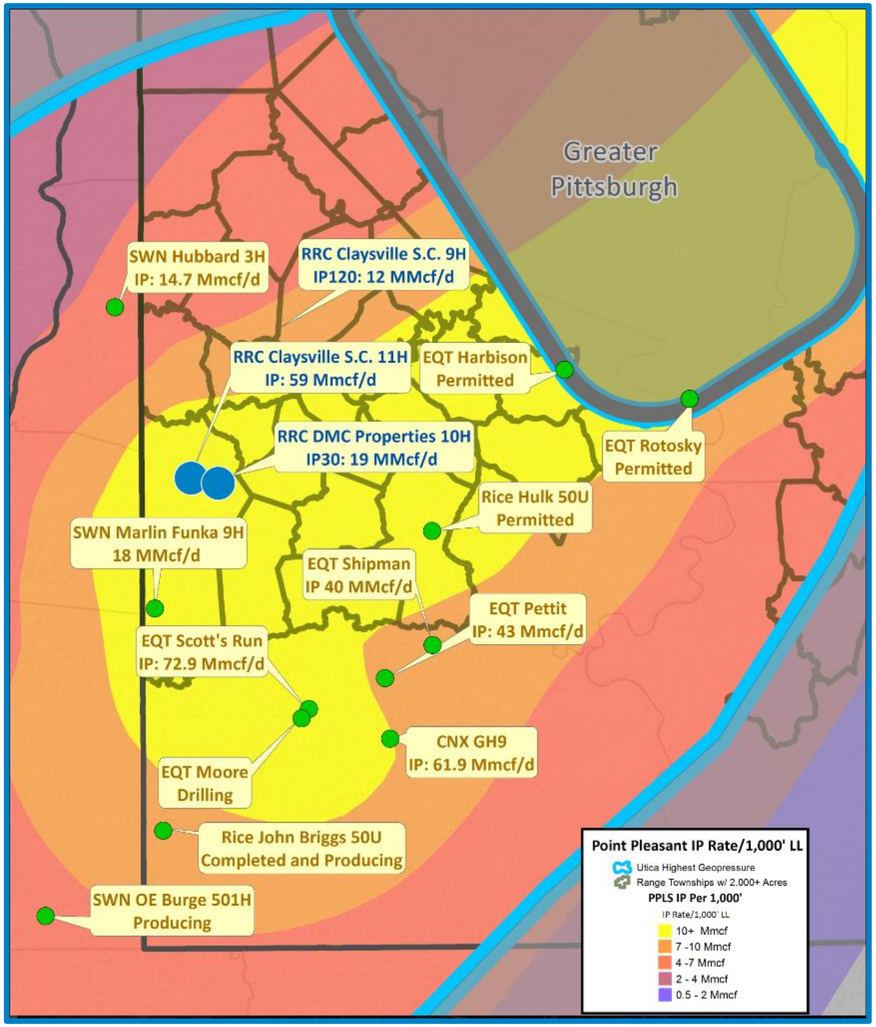


Ability to target our best areas with significant cost savings

Deep Utica

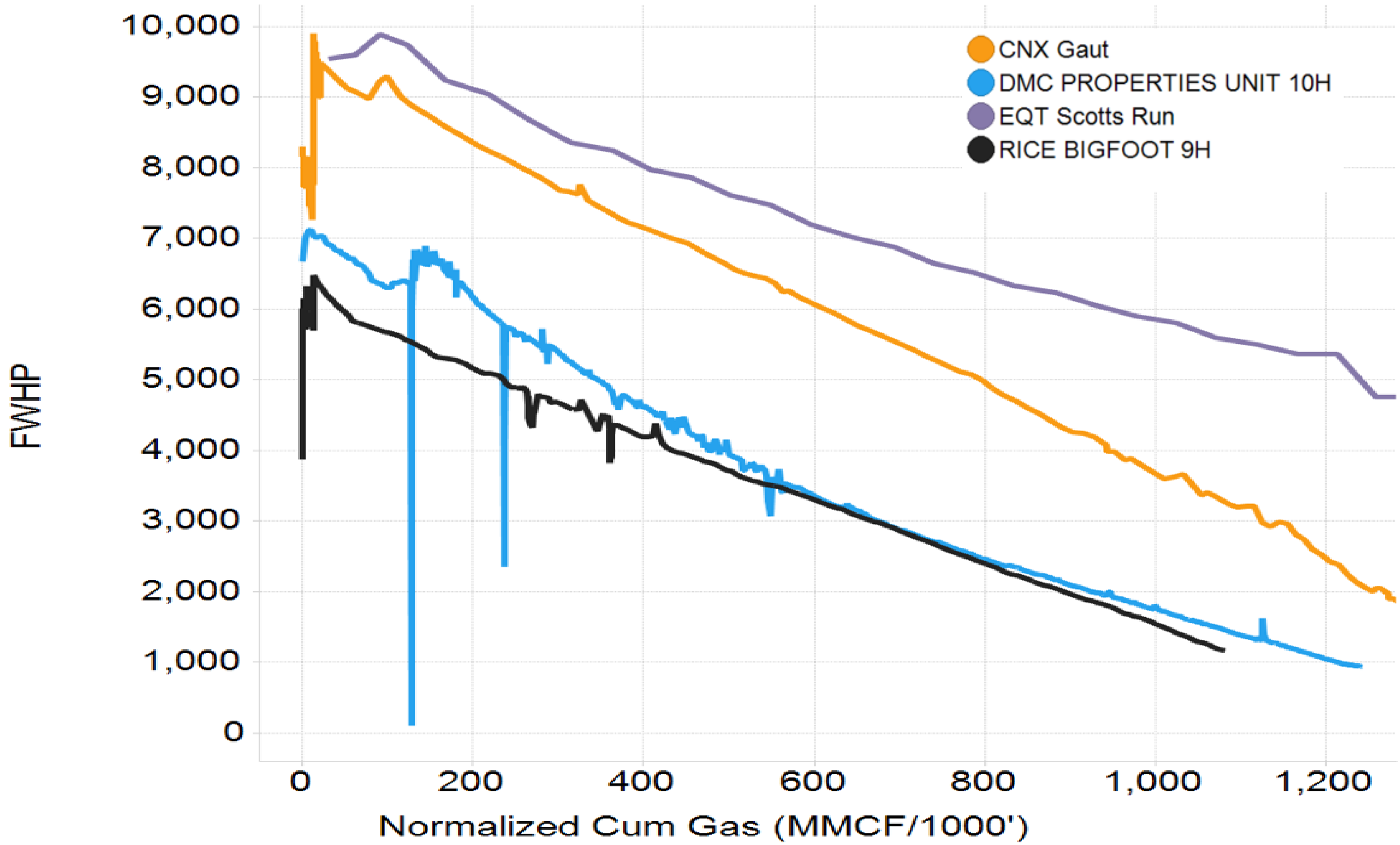
- Range has drilled three Deep Utica wells
- Range's third well appears to be one of the best dry gas Utica wells in the basin (next slide)
- Continued improvement in well performance due to higher sand concentration and improved targeting
- 400,000 net acres in SW PA prospective

The Industry Continues to Delineate the Utica around Range's Acreage



Note: Townships where Range holds ~2,000+ or more acres are shown outlined above (as January 2018)

Utica Wells – Wellhead Pressure vs. Cumulative Production



Range's DMC Properties well one of the best in the Utica

N. LA Combined Lower Cotton Valley Well Economics

- Combined Lower Cotton Valley
- ~140,000[a] Net Acres
- EUR / 1,000 ft. – 1.61 Bcfe
- EUR – 12.1 Bcfe
  (11 Mbbls condensate, 408 Mbbls NGLs & 9.6 Bcf gas)
- Drill and Complete Capital $8.4 MM
  ($1,120 K per 1,000 ft.)
- Average Lateral Length – 7,500 ft.
- F&D - $0.89/mcfe

NYMEX Gas Price	Rate of Return
Strip -	27%
$3.00 -	33%

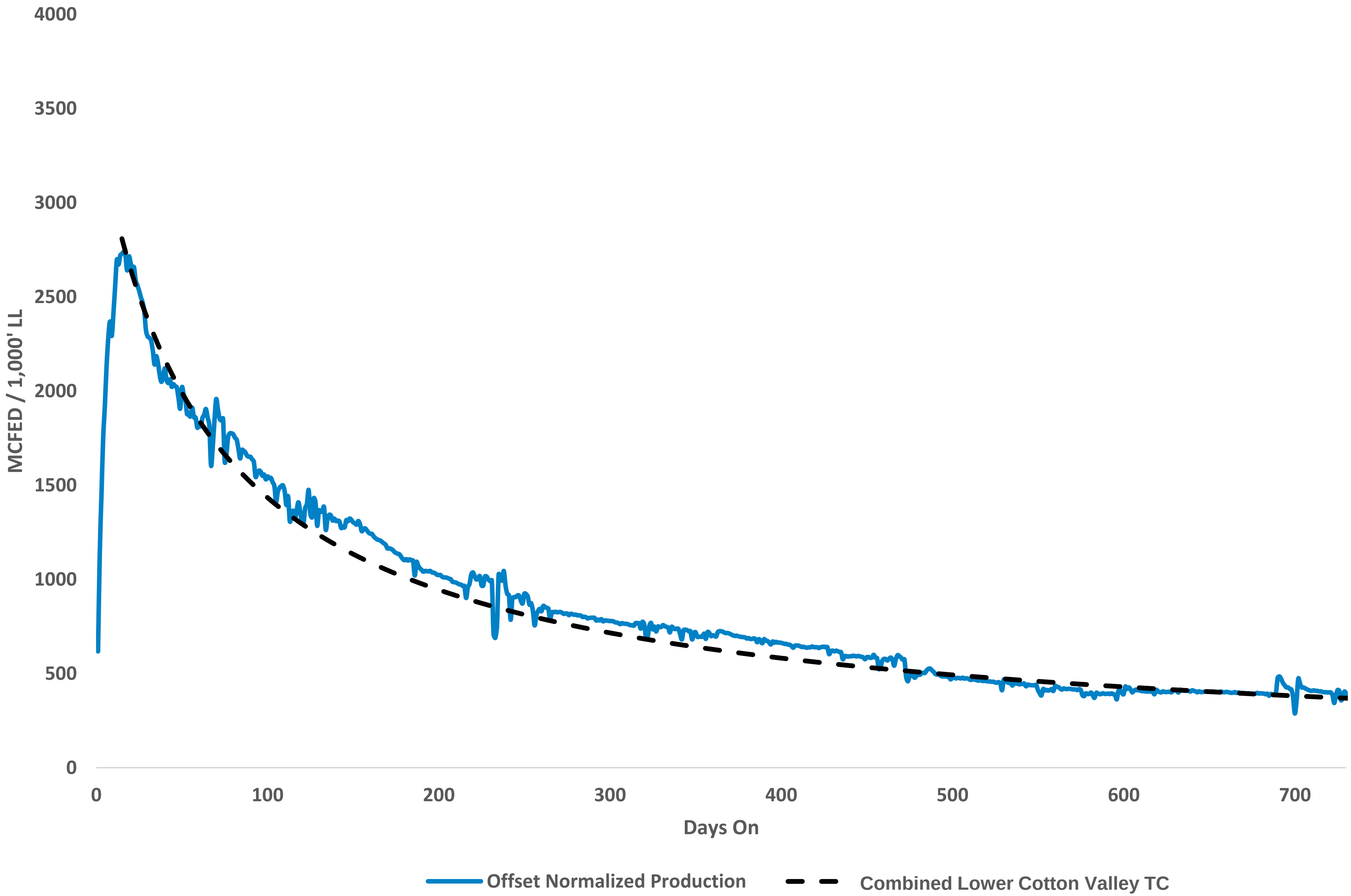
Estimated Cumulative Recovery for 2018 Production Forecast

	Condensate (Mbbls)	Residue (Mmcf)	NGL w/ Ethane (Mbbls)
1 Year	3	2,470	105
2 Years	4	3,470	148
3 Years	5	4,139	177
5 Years	6	5,069	216
10 Years	7	6,490	277
20 Years	9	8,078	345
EUR	11	9,550	408

- Includes current and expected differentials less gathering and transportation costs
- For flat pricing case, gas price assumed to be $3.00/mcf and oil price assumed to be $60/bbl
- Strip dated 12/29/17 with 10-year average $53.45/bbl and $2.94/mcf

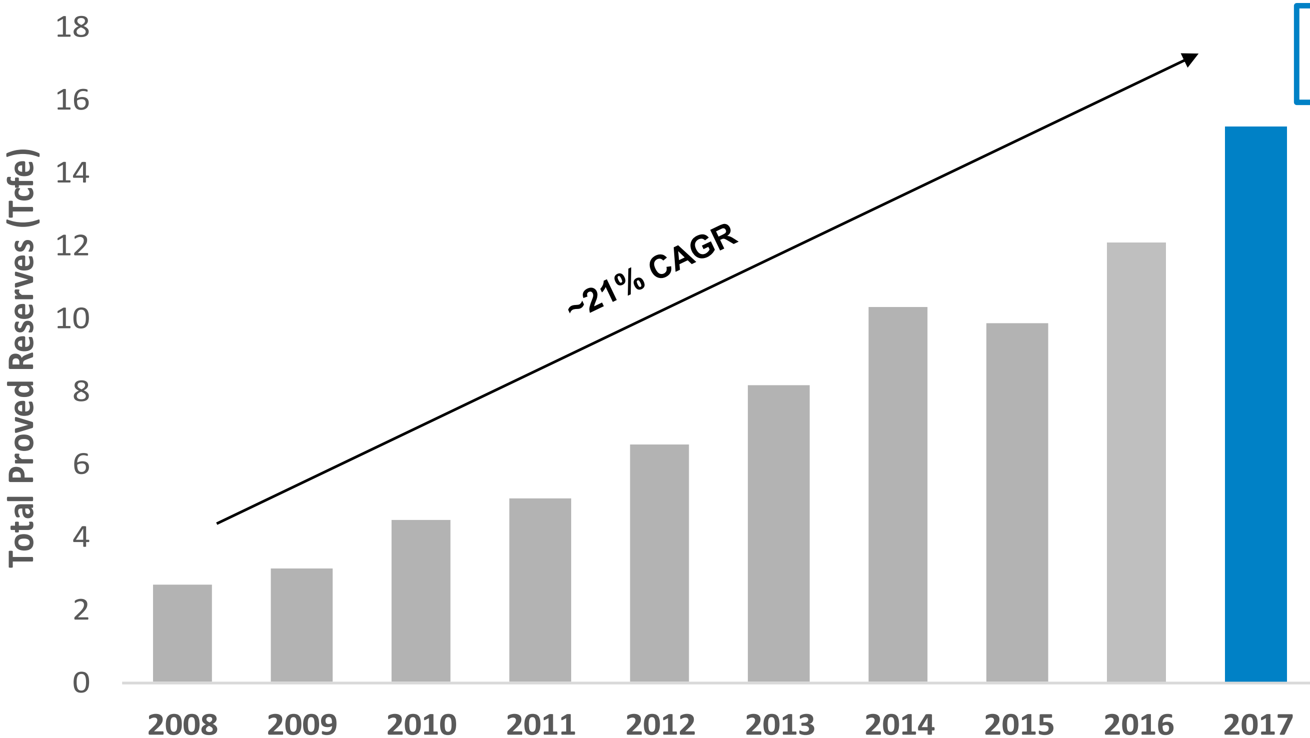
(a) Estimated YE18 acreage

N. LA 2018 Combined Lower Cotton Valley Production Forecast



2017 Proved Reserves

Track Record of Reserve Growth



Year-End 2017 SEC PV_{10} of \$8.1 billion

- Proved reserves of 15.3 Tcfe as of year end 2017
- Proved reserves increased ~26% y/y excluding acquisitions and divestitures
- 545% reserve replacement from drilling activities
- Future development costs for proved undeveloped reserves are estimated to be \$0.38 per Mcfe at YE2017

RANGE RESOURCES®

Financial Detail

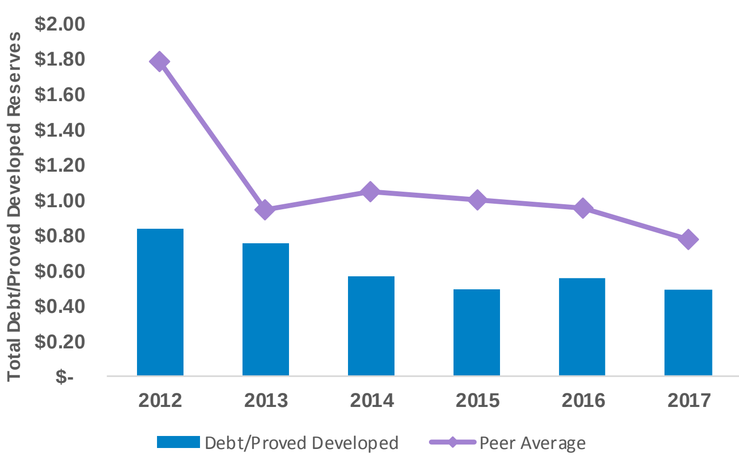
Well-Structured, Resilient Balance Sheet

- $4 billion credit facility, ($3B borrowing base, $2B committed)
- No note maturities until 2021
- Simple capital structure
- Near-term cash flow protected with hedges
- Five-year outlook reduces leverage < 2.0X

Capital Structure[a]

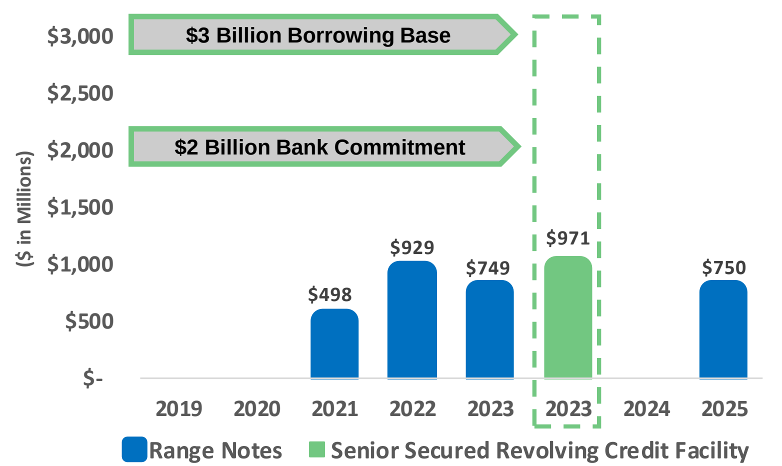
(millions)	3Q18
Bank Debt [a]	$ 971
Senior Notes	2,877
Senior Sub Notes	49
Debt	3,897
Debt to Capitalization [a]	40%
Debt/TTM EBITDAX [a]	3.1x

Debt/Proved Developed Reserves



Note: Peer average includes AR, CHK, COG, EQT, GPOR, RICE and SWN. RICE only included for 2014, 2015, and 2016

Debt Maturity Schedule[a]



Interest Rate	2021	2022	2023	2025
	5.75%	5.3%[b]	5.0%	4.875%

(a) As of 09/30/2018, pro forma 1% ORRI sale (b) Weighted-average interest rate of 2022 notes

Recycle Ratio Calculation Example

Cash margin per mcfe / PUD development costs per mcfe.

Numerator:			
Pre-Hedge Realized Price (a)	$	3.51	per mcfe
All-In Cash Costs (Mid-Point of 2018 Expectations) (b)	$	2.07	per mcfe
Adjusted Margin per Mcfe	$	1.44	per mcfe
Denominator:			
Future Development Costs of YE 2017 PUDs	$	2.6	billion
Proven Undeveloped (PUD) Reserves at YE 2017		6.9	Tcfe
Future Development Costs per Mcfe	$	0.38	per mcfe
Unhedged Recycle Ratio		**3.8x**	

(a) Assumes 2018 strip pricing as of 10/10/2018 (b) Formal 2018 unit cost guidance will be provided quarterly throughout 2018

Natural Gas & Oil Hedging Status

	Time Period	Volumes Hedged (Mmbtu/day)	Average Hedge Prices ($/Mmbtu)
Gas Swaps[1]	4Q18 Swaps 4Q18 Sold Calls	1,380,000 70,000	$2.97 $3.10
	FY19 Swaps	892,603	$2.83
	FY20 Swaps	10,000	$2.75

	Time Period	Volumes Hedged (bbl/day)	Average Hedge Prices ($/bbl)
Oil Swaps	4Q18 Swaps	8,500	$53.20
	FY19 Swaps FY19 Collars	7,000 1,000	$55.26 $63.00 x $73.00
	FY20 Swaps	1,500	$60.63

**As of 09/30/18*

1) *Range also sold call swaptions of 345,000 Mmbtu/d for calendar 2019, and 160,000 Mmbtu/d for calendar 2020 at average strike prices of $2.97 and $2.81 per Mmbtu, respectively. Sold 4Q 2018 $3.10 strike gas calls for a $0.16 per Mmbtu deferred premium.*

Liquids Hedging Status

	Time Period	Volumes Hedged (bbls/day)	Average Hedge Prices ($/gal)
Propane (C3)[1]	**4Q18 Swaps** **4Q18 Collars** **1H19 Swaps** **1Q19 Collars**	**11,668** **5,000** **7,500** **6,500**	**$0.74** **$0.95 x $1.04** **$0.92** **$0.92 x $1.02**
Normal Butane (NC4)	**4Q18 Swaps** **FY19 Swaps**	**5,500** **2,250**	**$0.91** **$1.22**
Natural Gasoline (C5)	**4Q18 Swaps** **FY19 Swaps**	**5,402** **2,178**	**$1.24** **$1.42**

**As of 09/30/18*
(1) Incorporates international propane spreads

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