RANGE RESOURCES®

RBC Capital Markets Global Energy and Power Executive Conference 2019

Forward Looking Statements

All statements, except for statements of historical fact, made in this presentation regarding activities, events or developments the Company expects, believes or anticipates will or may occur in the future 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.

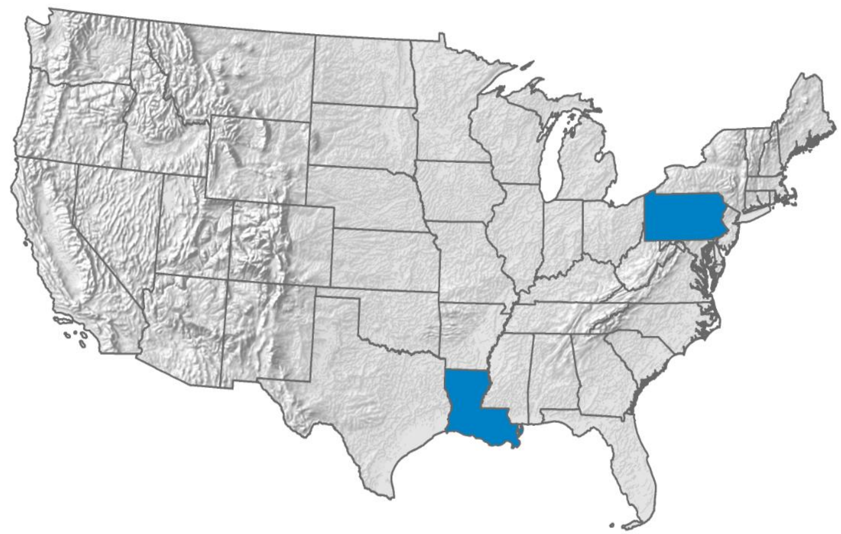
The SEC permits oil and gas companies, in filings made with the SEC, to disclose proved reserves, which are estimates that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions as 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):	$2.0B
Net Debt (b):	$3.8B
Enterprise Value:	$5.8B
Proved Reserves PV-10 at YE18 Strip (c):	$9.9B
Proved Developed PV-10 at YE18 Strip (c):	$6.6B



Recent Highlights

2019 Capital Program of $756 million

- >$100 million in free cash flow with ~6% corporate growth
- Approximately 90% allocated to Marcellus

2018 Year-End Proved Reserves of 18.1 Tcfe

- Future Development cost of ~$0.40 per mcfe
- Marcellus comprises 94% of proved reserves

Acreage Position

- Appalachia
  - SW Marcellus = ~500,000 net acres
  - NE Marcellus = ~95,000 net acres
  - Dry Utica = ~400,000 net acres
  - Upper Devonian = ~500,000 net acres
- North Louisiana
  - ~140,000 net acres(d)

(a) As of 5/29/2019 (b) As of 3/31/2019 (c) Assumes strip pricing. For reference, the 10-year average was $2.83/mmbtu NYMEX natural gas and $51.54/bbl WTI (d) Includes acreage purchase option

Strategic Focus

Sustainable Free Cash Flow Driven by High-Return Assets

- Disciplined spending supported by low base decline and maintenance capital
- Consistent emphasis on debt-adjusted per share metrics in management incentives
- Target free cash flow yield competitive with industry and broader market

Improving Corporate Returns

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

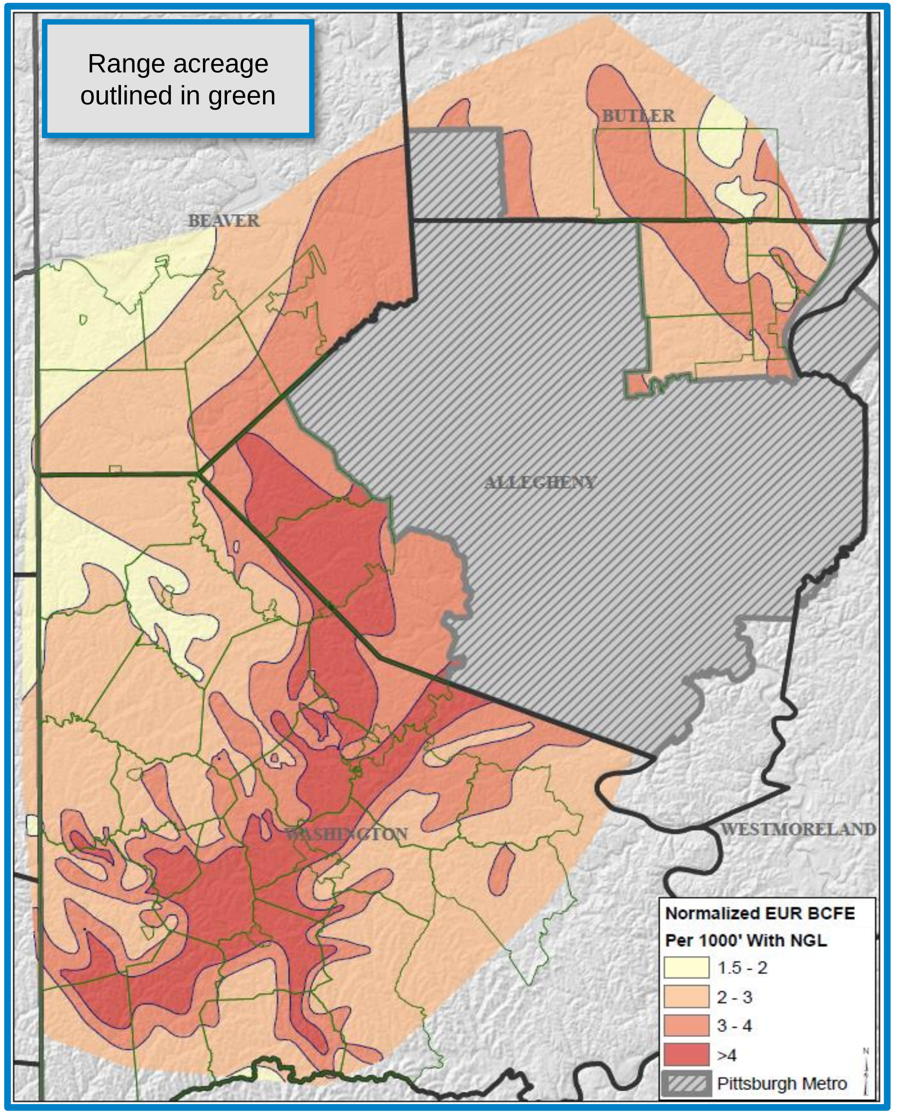
Balance Sheet Strength

- Absolute debt reduction through organic free cash flow
- Target Investment Grade leverage profile of net debt/EBITDAX below 2.0x
- Continued focus on asset sales to accelerate de-levering process

Be Good Stewards of the Environment and Operate Safely

Positions Range to Return Capital to Shareholders

Large Core Marcellus Inventory



Large contiguous acreage position allows for long-lateral development

~3,700 undrilled Core <u>Marcellus</u> wells (a)

- ~285 wells with 40+ Bcfe EUR
- ~385 wells with 30-40 Bcfe EUR
- ~1,370 wells with 20-30 Bcfe EUR
- ~1,370 wells with 15-20 Bcfe EUR(b)
- *Based on 10,000 foot average lateral lengths*

<u>Marcellus</u> resource potential (b)

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

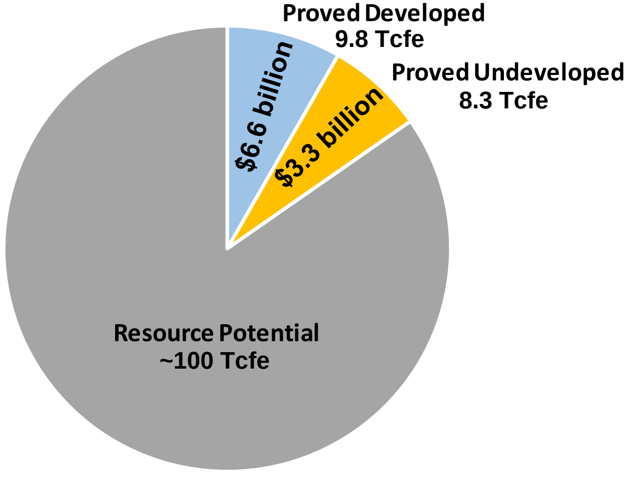
Significant inventory of highly prolific Deep Utica wells not included above

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

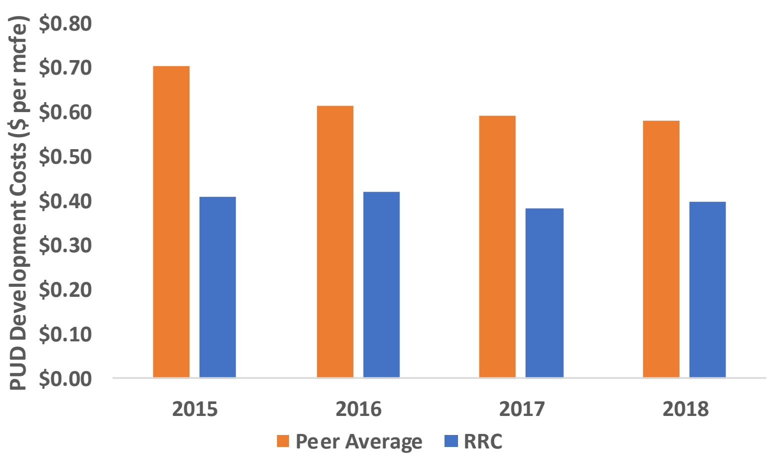
(a) *Estimates as of YE2018; based on production history from ~1,000 wells. Includes ~300 locations not shown on map. Majority of inventory of 1.5 – 2.0 Bcfe/1000' wells are downspaced locations (not in the 5-year development plan) that incorporate expected recoveries of ~75% of 1,000' spaced wells.*
(b) *Does not include 18.1 Tcfe of YE2018 proved reserves.*

High Quality Resource Base

Proved reserves valued at ~$9.9 billion PV-10 at YE18 strip. Equals ~$24/share, net of 1Q19 debt balance.



Peer-Leading Development Costs



Included in Reserves

- Proved Developed reserves of 9.8 Tcfe with PV-10 of $6.6 billion at YE18 strip
- Proved Undeveloped reserves of 8.3 Tcfe with PV-10 of $3.3 billion at YE18 strip
- Approximately 400 Marcellus locations

Resource Potential Not in Reserves:

- Resource Potential of ~100 Tcfe
- Any development in years six and beyond
- Approximately 3,300 undrilled core Marcellus wells, or over 35 years of core Marcellus inventory at current drilling pace
- Stacked pay potential from ~400,000 net acres of Dry Utica and ~500,000 net acres of Upper Devonian

Reserves History

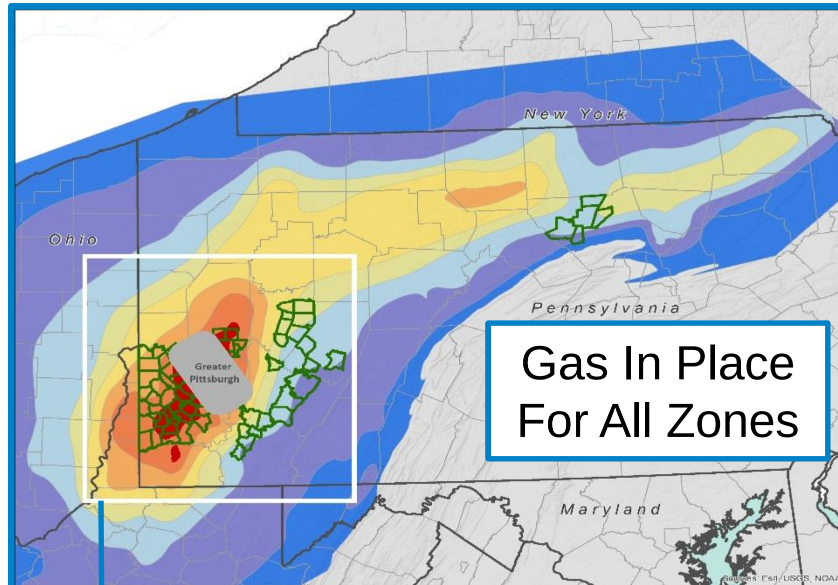
- PUD Development Costs consistently better than Appalachia peers
- Positive performance revisions to reserves each year for the last decade

Note: Peers include AR, CNX, COG, EQT, GPOR and SWN. SWN excluded from peer group in 2015 and 2016. PUD Development Costs defined as future development costs / PUD reserves.

Appalachia Assets – Stacked Pay

- ~1.5 million net effective acres [(a)] in PA leads to decades of drilling inventory
- Gas In Place analysis shows the greatest potential is in Southwest Pennsylvania
- Approximately 1,000 producing Marcellus wells demonstrate high quality, consistent results across Range’s position
- Near-term activity led by <u>Core Marcellus</u> development in Southwest PA
- Range’s Utica wells continue to produce strongly and our most recent well continues to be one of the best in the play
- Adequate takeaway capacity in Southwest PA

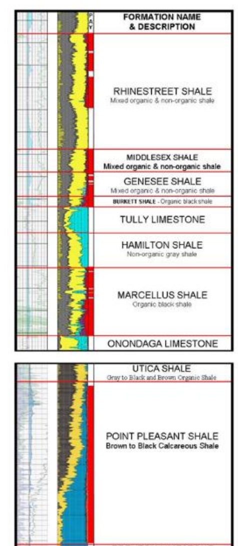
Stacked Pay and Existing Pads Allow for Multiple Development Opportunities



Upper Devonian

Marcellus

Utica/Point Pleasant

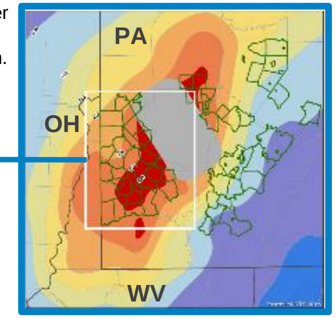


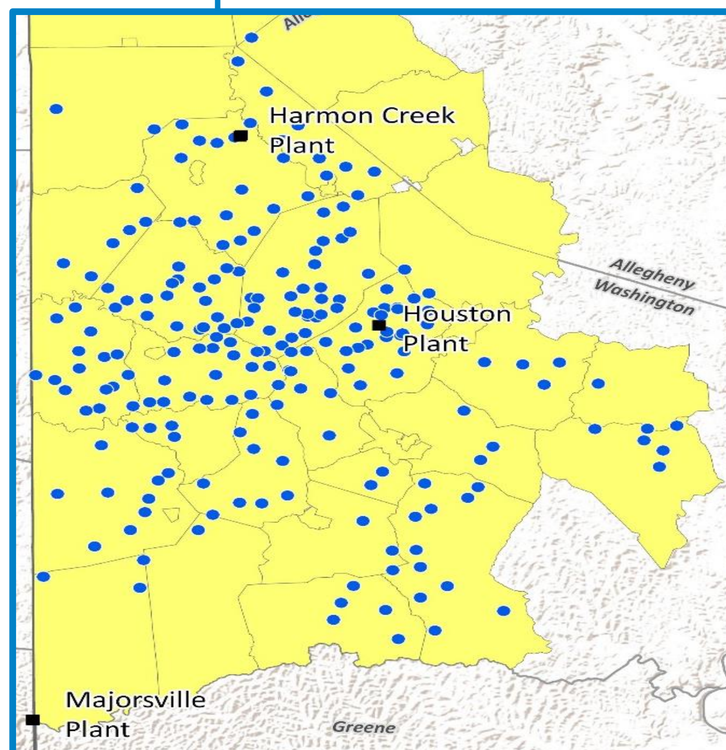
(a) Assumes stacked pay opportunities in Marcellus, Utica and Upper Devonian

Southwest Appalachia Acreage Position

- Longer laterals and existing pads in 2019 provide low-risk efficiency gains
- Liquids and dry optionality with existing pads across acreage position
- Concentrated acreage position simplifies water logistics and drives further cost savings, as Range continues to recycle ~100% of produced water

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





= Existing Pad

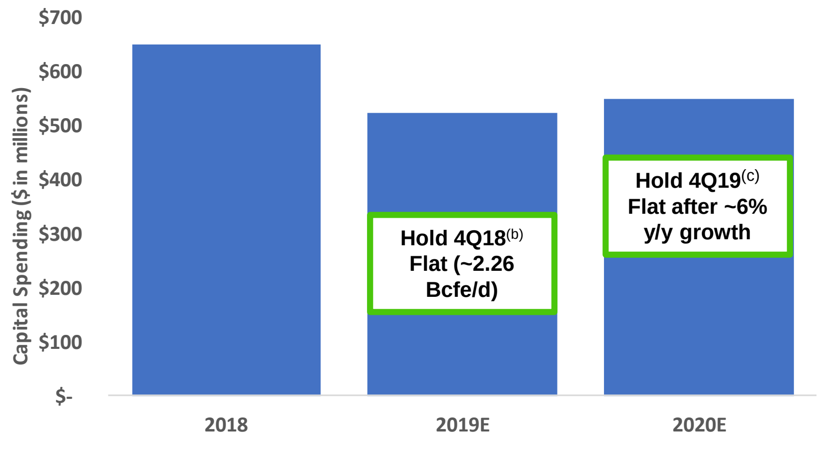
Southwest Marcellus Economics

	Dry	Wet	Super-Rich
EUR	25.2 Bcf	29.6 Bcfe	26.0 Bcfe
EUR/1,000 ft. lateral	2.52 Bcf	2.96 Bcfe	2.60 Bcfe
Well Cost	$6.6 MM	$7.7 MM	$8.5 MM
Cost/1,000 ft. lateral	$661 K	$756 K	$845 K
Lateral Length	10,000 ft.	10,000 ft.	10,000 ft.
IRR* - $3.00	61%	69%	68%
IRR* at Strip as of 1/31/2019	46%	51%	52%

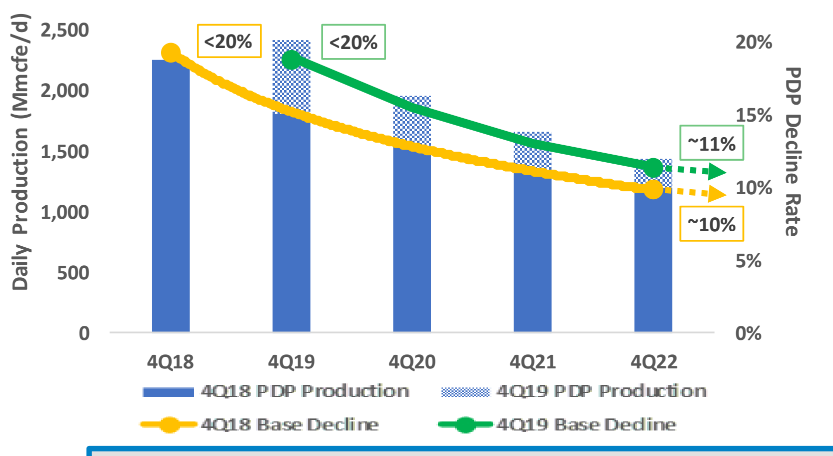
** Returns as of 1/31/19. For flat pricing case, gas price assumed to be $3.00/mcf and oil price assumed to be $60/bbl to life.*

Low Base Decline Supports Low Maintenance Capital

D&C Maintenance Capital[a]



Corporate Decline Rate



Significant improvement in Maintenance Capital post-2018

- 2019 maintenance capital improves significantly following steady 2018 capital development cadence
- Production profile of longer laterals generates a lower base decline
- 2019 D&C Maintenance Capital expected to be ~$525 million[a] to hold 4Q18[b] production flat
- 2020 D&C Maintenance Capital expected to be ~$550 million to hold 4Q19 production flat

Base Decline Rate Shallows Over Time

- Corporate base decline <20% in 2019
- Base decline remains <20% entering 2020 despite higher base production level

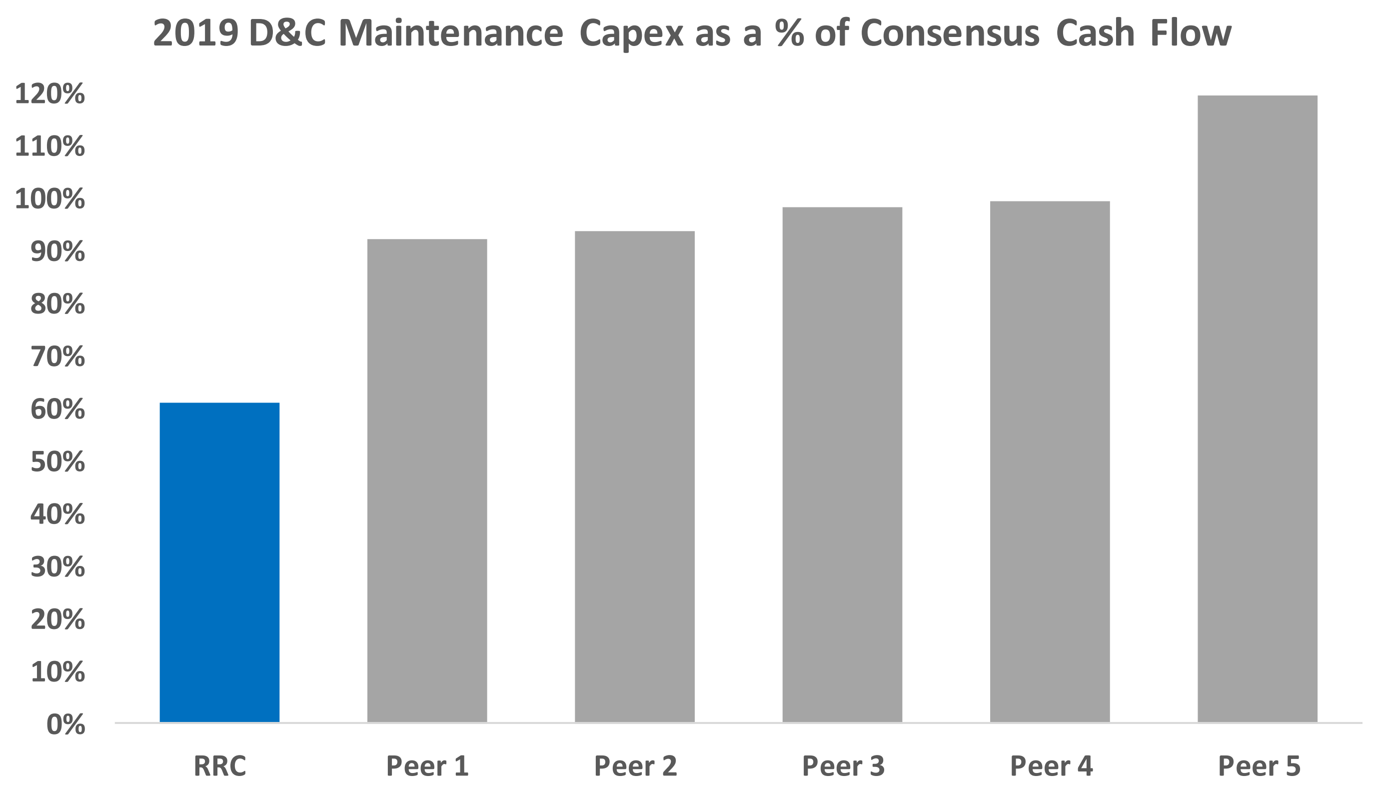
Over 3,700 undrilled Marcellus wells

- 60-70 wells per year holds production flat
- Decades of core Marcellus inventory

Shallow Base Decline Drives Sustainably-Low Maintenance Capital

(a) D&C capital includes facilities costs. (b) Actual 4Q18 production was 2,149 Mmcfe/d. Adjusted 4Q18 production was 2,260 Mmcfe/d, which includes 10 Bcfe of curtailments in 4Q18 from third-party processing downtime. (c) Assumes steady operational and production cadence in 2019.

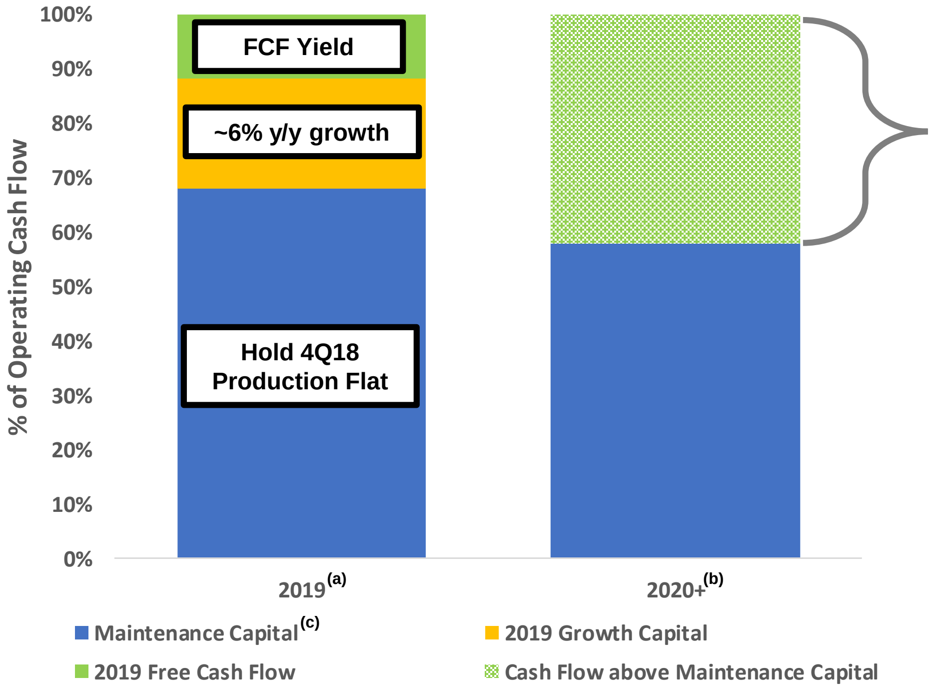
Peer-Leading Maintenance Capital Profile



Range Is the Only Operator in Southwest Appalachia Generating Free Cash Flow and Growing from Exit 2018 to Average 2019

Note: Southwest Appalachia peers include AR, CNX, EQT, GPOR and SWN. Peer estimates based on company guidance and statements on 2019 decline rate. Consensus operating cash flow estimates as of 5/8/19, adjusted for capitalized G&A and interest. Range's D&C maintenance capital estimate is based off 4Q18 production of 2,260 Mmcfe/d, which includes 10 Bcfe in curtailments related to third-party processing downtime.

Low Maintenance Capital Supports Sustainable Free Cash Flow



2019 Plan Balances Free Cash Flow with Modest Growth

Considerations for Cash Flow above Maintenance Capital

Free Cash Flow

- Generating a free cash flow yield that is competitive versus peers as well as broader market
- Absolute debt reduction de-risks the business and better positions Range for commodity cycles

Growth Capital

- EBITDA growth can improve leverage ratio towards long-term goal of investment grade leverage profile
- Modest production growth sustains or improves current operational efficiency metrics
- Modest production growth reduces cash operating costs per mcfe, improving margins and breakevens
- FCF available to shareholders over a 5-year period is similar with moderate allocation towards growth vs. maintenance capital only

(a) Assumes midpoint of 2019 cost guidance and strip as of 2/22/19; (b) Assumes $2.70/mmbtu natural gas and $55/bbl WTI; (c) Maintenance Capital includes $60 million in non-D&C spending.

Capital Allocation Scenarios – Five-Year Outlook Summary

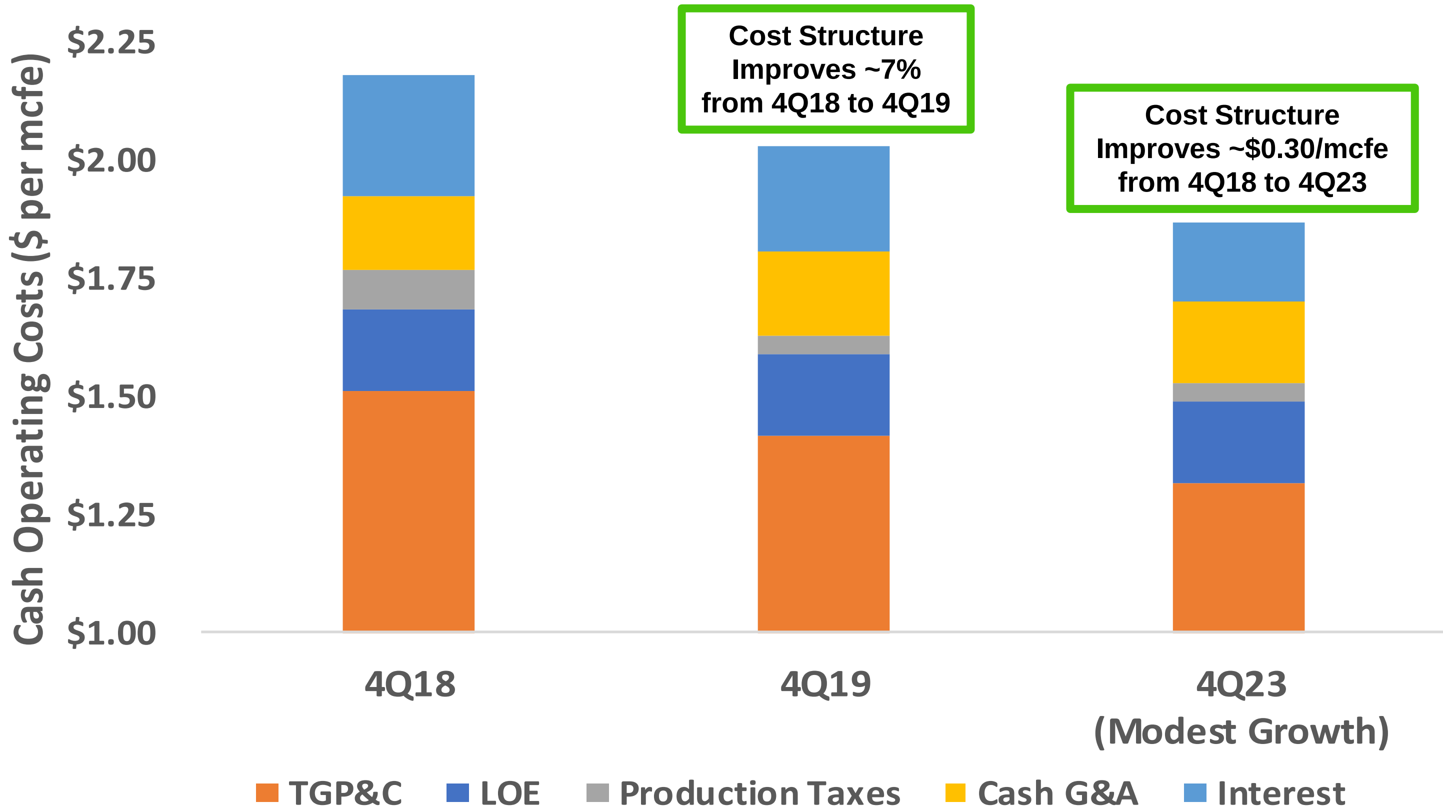
	Maintenance Capital	Balanced Approach (Base Prices @ $2.70 gas/$55 WTI)	Full Reinvestment	Balanced Approach (Upside Prices @ $2.85 gas/$60 WTI)
2019-2023 Cumulative Free Cash Flow	$1.2-$1.3 billion	$1.2-$1.3 billion	$0	$2.0-$2.1 billion
Ending Net Debt (Year-End 2023)	$2.7-$2.8 billion	$2.7-$2.8 billion	~$4.0 billion	$1.9-$2.0 billion
Year-End 2023 Net Debt/EBITDAX	3.0x - 3.1x	2.0x - 2.1x	1.9x - 2.0x	1.1x - 1.2x
2023 Cash Unit Costs per Mcfe	$2.10 - $2.15	$1.87 - $1.92	$1.70 - $1.75	$1.85 - $1.90
Base Decline (Exit 2023)	<15%	<20%	~20%	<20%

As planned for 2019, a balanced approach towards capital allocation allows Range to decrease debt while improving unit costs and leverage.

FCF generation provides corporate optionality for uses of cash (share buybacks, dividends, etc.) after near-term leverage targets are realized.

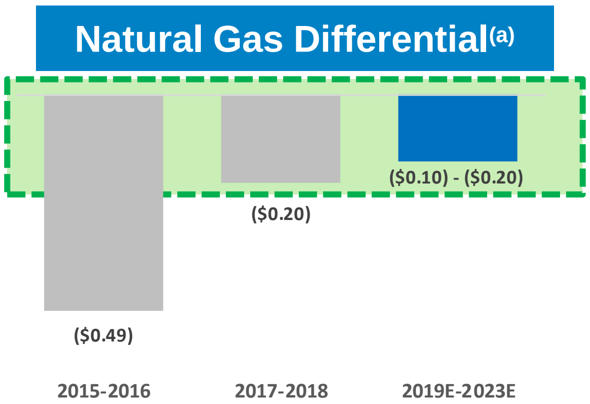
Note: Five-year outlook projections assume midpoint of cost guidance and strip as of 2/22/19 in 2019, and $2.70/mmbtu natural gas and $55/bbl WTI in 2020-2024. Upside Case projections assume midpoint of cost guidance and strip as of 2/22/19 in 2019, and $2.85/mmbtu natural gas and $60/bbl WTI in 2020-2024. Additional assumptions on slide 17.

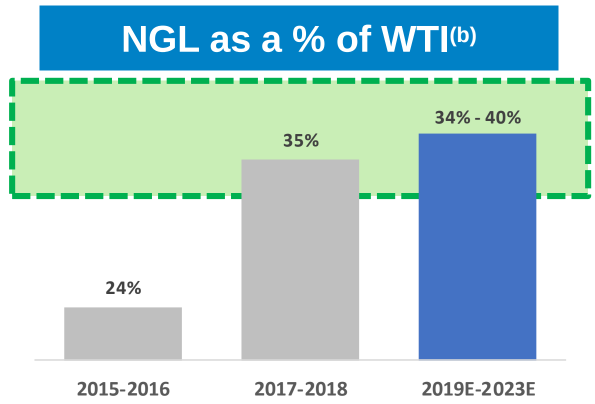
Improving Cost Structure Drives Cash Flow & Margin Growth

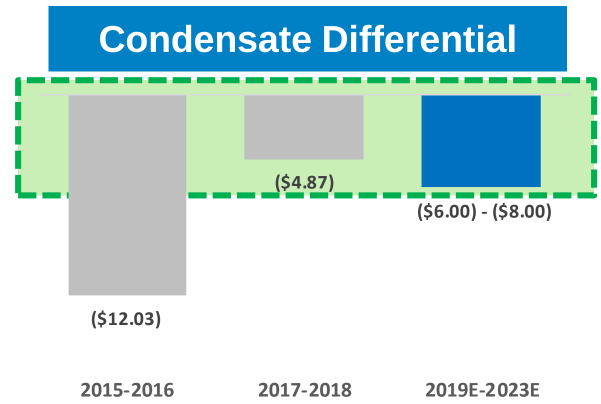


Cost structure improves as Range utilizes existing gathering, contracts expire and interest expense improves as free cash flow reduces debt.

Differentials Have Stabilized and Improved vs Historical Levels







Natural Gas

- Differentials stabilizing closer to NYMEX as pipeline transportation projects were completed in 2018, providing access to Midwest, Gulf Coast and Southeast markets
- With long-haul transport projects completed in 2H18, TGC&P expense per mcfe expected to peak in 4Q 2018 before trending downward

Natural Gas Liquids

- Range has sent 20,000 barrels per day of ethane to Marcus Hook export facilities since early 2016 using Mariner East I
- Range is also sending propane and butane out of Marcus Hook, using a combination of pipe and rail.
- Beginning in 2020, Range expects to have Mariner East pipe capacity to move 40,000 barrels per day combined of propane and butane to export markets
- Tightness in fractionation capacity at Mont Belvieu supports NGL product pricing in 2019

Condensate (Oil)

- 2018 oil price drove highest condensate realizations since 2014

(a) NG estimate includes basis hedges and is based on strip pricing at 4/12/19 (b) 2019E based on NGL strip pricing at 4/12/19. 2018 represents recent accounting change.

Current Enterprise Value a Discount to YE18 PV-10

YE18 PV-10 at Strip Pricing[a]	$9.9 billion
Enterprise Value[b]	$5.8 billion

YE18 PV_{10} > Enterprise Value. Excludes the value of ~58 Tcfe Marcellus resource potential[c].

YE18 Proved Reserves	18.1 Tcfe
Enterprise Value[b]/Proved Reserves	~$0.34 per mcfe

Trading at ~$0.34 per Proved Mcfe which excludes ~58 Tcfe of Marcellus resource potential[c].

(a) Strip pricing as of 12/29/2018 (b) Enterprise Value as of 5/29/2019 (c) Marcellus resource potential of 58 Tcfe excludes ~500k net acres prospective for the Upper Devonian and ~400k net acres prospective for the Utica

RANGE RESOURCES

Appendix

Five-Year Outlook Assumptions

Assumptions:

- Production growth is driven by de-risked Marcellus inventory.
- Commodity Price Assumptions (strip pricing as of February 2019):
  - Henry Hub: $2.90 (2019), $2.70 (2020-2023)
  - Natural Gas Differential: $(0.14) in 2019, $(0.11) in 2020-2023
  - WTI: $57.50 (2019), $55 (2020-2023)
  - NGL: 37% of WTI (2019), 40% (2020-2023 average)
- Free cash flow used to reduce debt.
- 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 accelerate timeframe for de-levering and returning capital to shareholders.
- 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 for calculating efficiencies.
- 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.
- Capital savings from operational efficiencies assumed to be minimal.
- Minimal capital spent in North Louisiana.

Definitions:

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

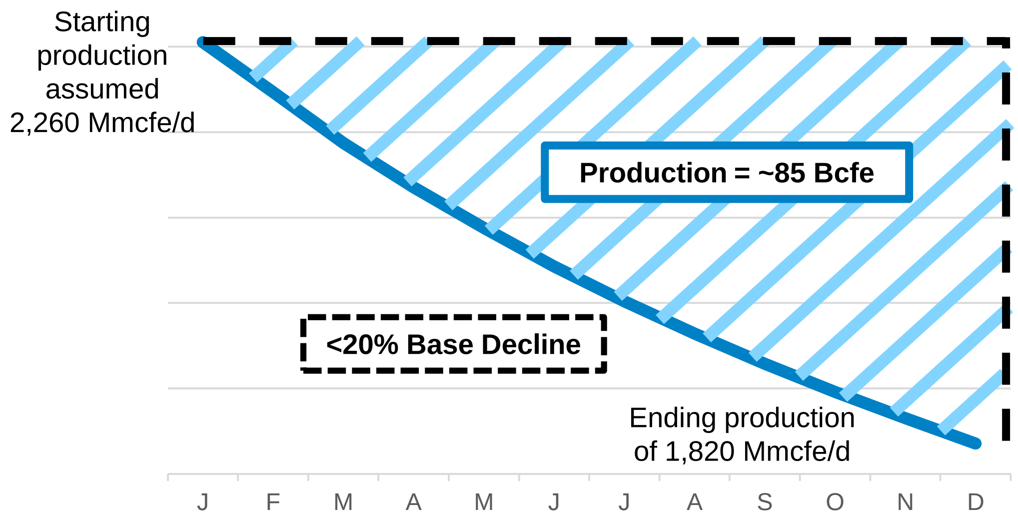
Non-GAAP cash flow - ***Net cash from operations before changes in working capital***

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

Free cash flow yield - ***Free cash flow / Market Cap.***

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

Maintenance Capital Example



1st year recoveries[a] for SW PA wells:

- Super Rich = 2.8 Bcfe gross (2.3 Bcfe net)
- Wet = 3.7 Bcfe gross (3.0 Bcfe net)
- Dry = 4.3 Bcf gross (3.5 Bcf net)

Simple Average: ~2.9 Bcfe net per well

Well Costs[a] for SW PA:

- Super Rich: $8.5 million
- Wet : $7.7 million
- Dry: $6.6 million

Average: $7.6 million cost per well

Blue-Sky Example[b]

- Average well contributes ~1.45 Bcfe net in calendar year if brought on mid-year under perfect conditions
- Production can be held flat with ~60 wells

  60 wells x 1.45 Bcfe recovery = ~85 Bcfe
- 60 wells x $7.6 average well cost = $455 million

~$455 million Maintenance D&C Capital

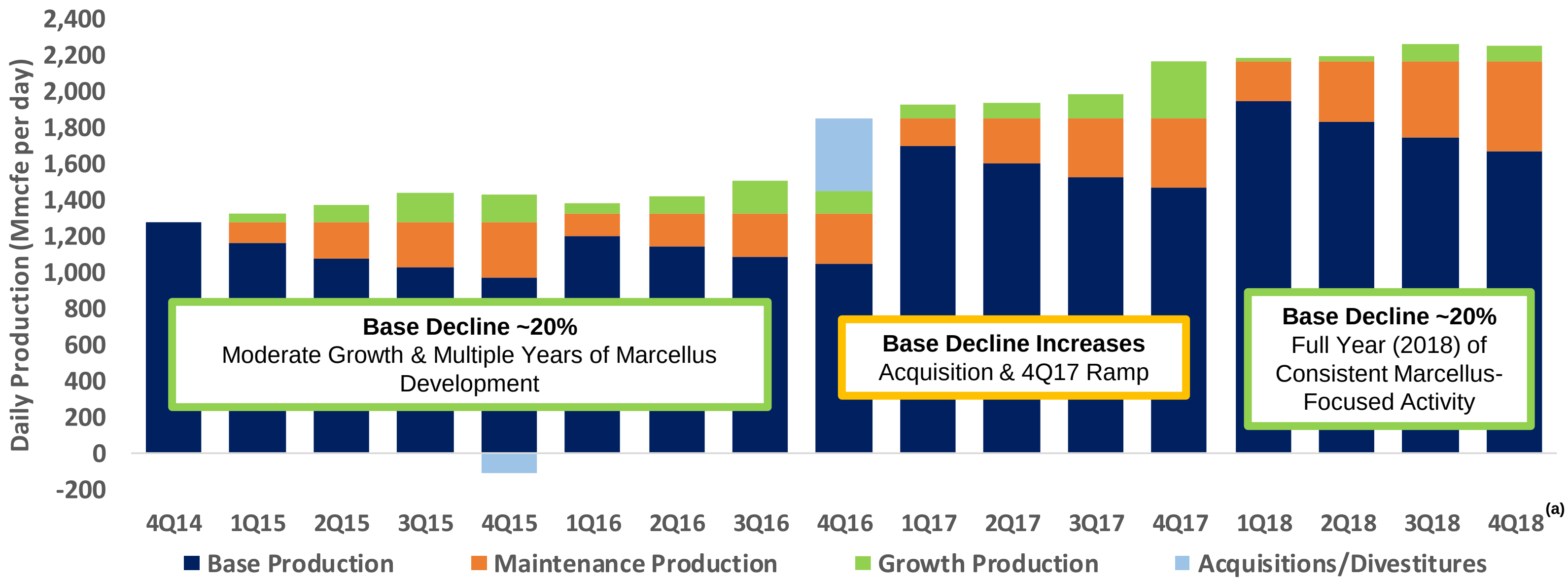
Typical Operating Adjustments[b]

- Considerations impacting annual development
  - Ethane flexibility
  - TIL allocation (wet vs. dry)
  - Timing of TILs
  - Maintenance
  - Weather

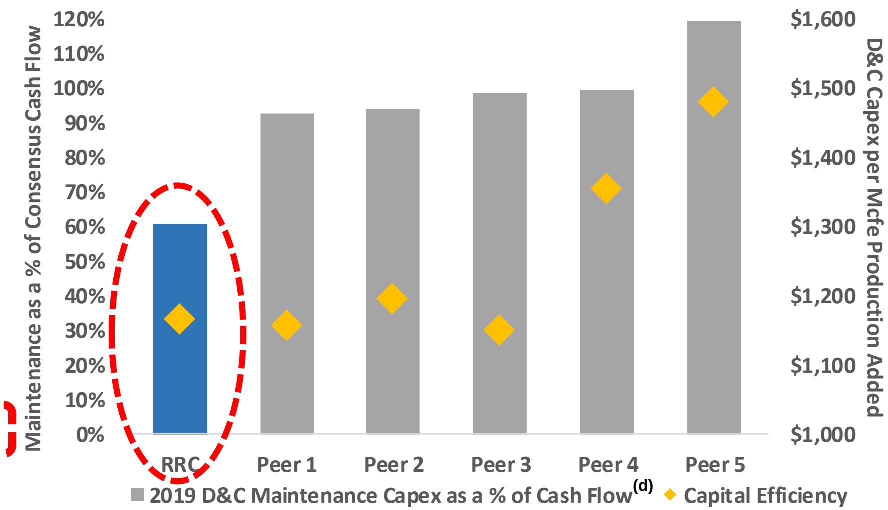
~$525 million Maintenance D&C Capital

(a) Assumes 10,000 ft. laterals (b) Assumes constant DUC inventory

Base Decline & Capital Efficiency Improving



	2015	2016	2017	2018	2019E
4Q Production (Mmcfepd)	1,435	1,854	2,170	2,260[a]	
Decline Rate from Prior Year 4Q		20%	24%	23%	~20%
4Q-4Q Base Decline (Mmcfepd)		287[b]	449	508	
4Q-4Q Growth (Mmcfepd)		129[c]	316	90	
Total Production Added (Mmcfepd)		416	765	597	
D&C Costs Incurred ($ millions)		$535	$1,180	$836	
D&C Capex per mcfe Production Added		**$1,286**	**$1,542**	**$1,399**	**~$1,200**



Note: Southwest Appalachia peers include AR, CNX, EQT, GPOR and SWN. (a) Includes 10 Bcfe of curtailments in 4Q18 from third-party processing downtime. (b) Pro-forma sale of Nora. (c) Pro-forma sale of Nora and excludes volumes added from North Louisiana acquisition. (d) Peer D&C maintenance capital and capital efficiency estimates based on company guidance and statements on 2019 decline rate. Consensus cash flow estimates as of 5/8/19, adjusted for capitalized G&A and interest.

SW PA Super-Rich Area Marcellus 2019 Well Economics

- Southwestern PA – (Wet Gas case)
- ~110,000 Net Acres
- EUR / 1,000 ft. – 2.6 Bcfe
- EUR – 26.0 Bcfe
  (360 Mbbls condensate, 1,999 Mbbls NGLs & 11.9 Bcf gas)
- Drill and Complete Capital $8.5 MM
  ($845 K per 1,000 ft.)
- Average Lateral Length – 10,000 ft.
- F&D - $0.39/mcf

NYMEX Gas Price	Rate of Return
Strip -	52%
$3.00 -	68%

Estimated Cumulative Recovery for 2019 Production Forecast

	Condensate (Mbbls)	Residue (Mmcf)	NGL w/ Ethane (Mbbls)
1 Year	87	1,150	193
2 Years	122	1,949	328
3 Years	146	2,637	443
5 Years	179	3,791	637
10 Years	230	5,942	996
20 Years	291	8,683	1,460
EUR	360	11,890	1,999

- 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 1/31/19 with 10-year average $53.98/bbl and $2.85/mcf

SW PA Wet Area Marcellus 2019 Well Economics

- Southwestern PA – (Wet Gas case)
- ~240,000 Net Acres
- EUR / 1,000 ft. – 2.96 Bcfe
- EUR – 29.6 Bcfe
  (80 Mbbls condensate, 2,440 Mbbls NGLs & 14.5 Bcf gas)
- Drill and Complete Capital $7.7 MM
  ($756 K per 1,000 ft.)
- Average Lateral Length – 10,000 ft.
- F&D - $0.31/mcf

NYMEX Gas Price	Rate of Return
Strip -	51%
$3.00 -	69%

Estimated Cumulative Recovery for 2019 Production Forecast

	Condensate (Mbbls)	Residue (Mmcf)	NGL w/ Ethane (Mbbls)
1 Year	29	1,737	292
2 Years	43	2,890	486
3 Years	52	3,823	644
5 Years	63	5,300	892
10 Years	73	7,849	1,321
20 Years	78	10,982	1,849
EUR	80	14,491	2,440

- 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 1/31/19 with 10-year average $53.98/bbl and $2.85/mcf

SW PA Dry Area Marcellus 2019 Well Economics

- Southwestern PA – (Dry Gas case)
- ~150,000 Net Acres
- EUR / 1,000 ft. – 2.52 Bcf
- EUR – 25.2 Bcf
- Drill and Complete Capital $6.6 MM
  ($661 K per 1,000 ft.)
- Average Lateral Length – 10,000 ft.
- F&D - $0.32/mcf

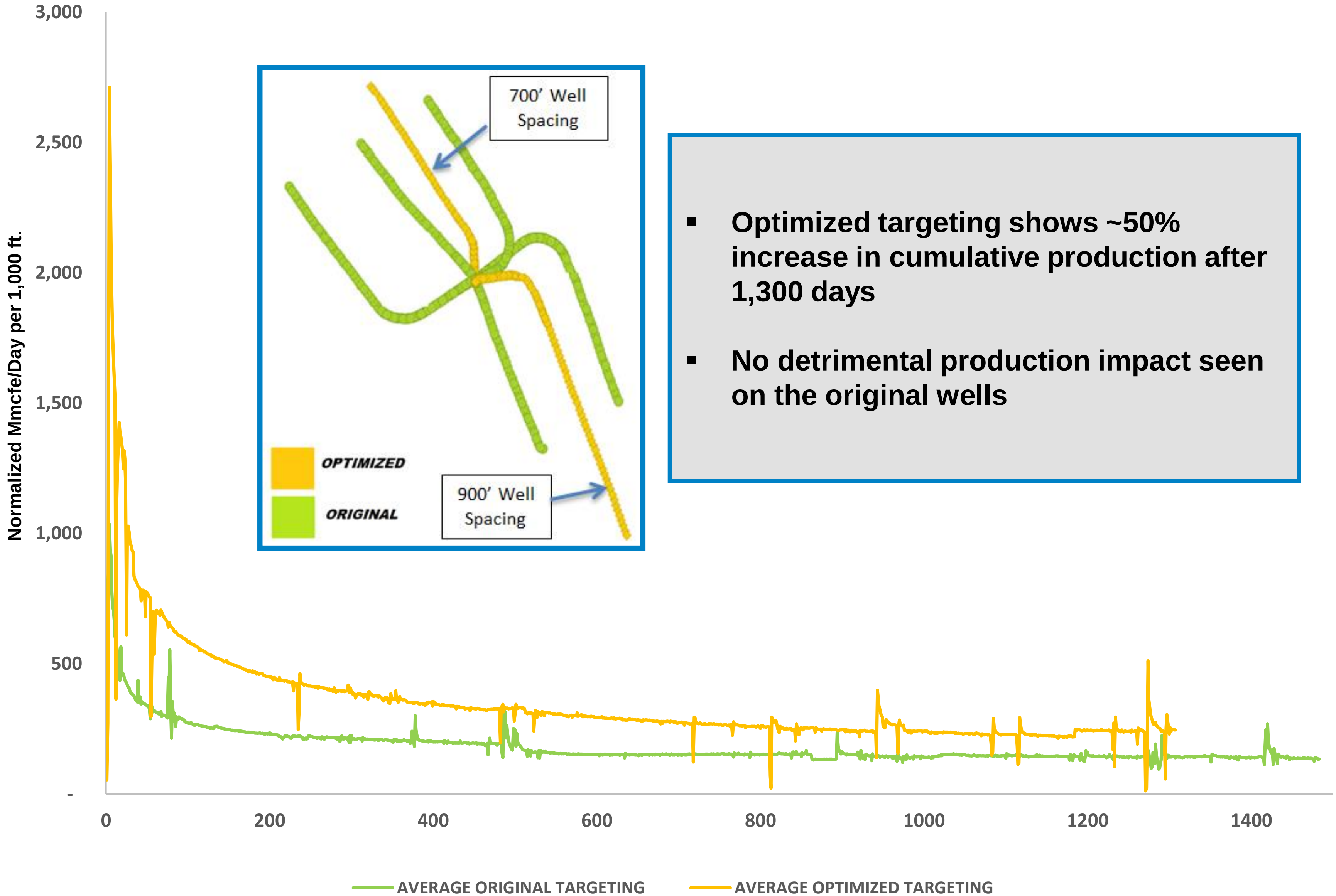
NYMEX Gas Price	Rate of Return
Strip -	46%
$3.00 -	61%

Estimated Cumulative Recovery for 2019 Production Forecast	
	Residue (Mmcf)
1 Year	4,341
2 Years	6,677
3 Years	8,379
5 Years	10,870
10 Years	14,846
20 Years	19,487
EUR	25,199

- 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 1/31/19 with 10-year average $53.98/bbl and $2.85/mcf

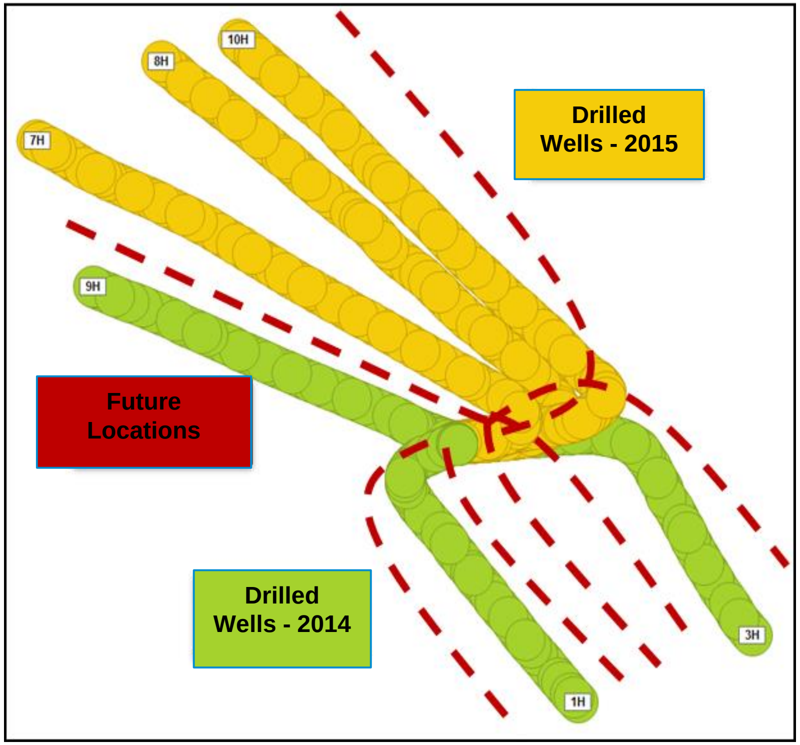
Based on Washington County well data

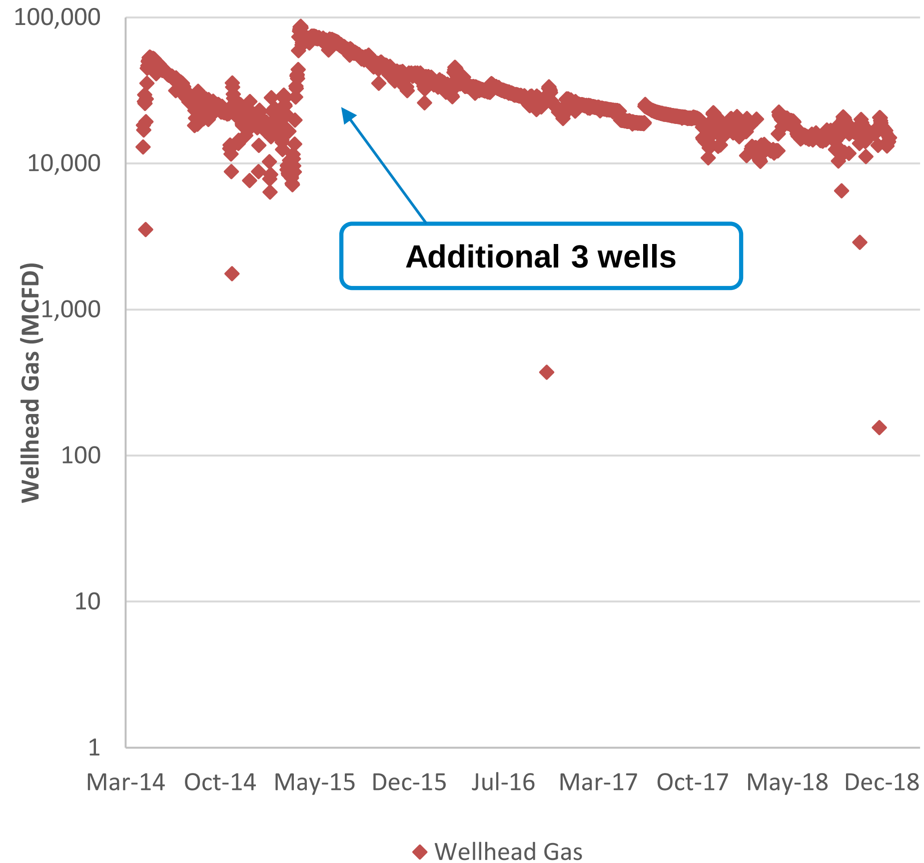
Targeting / Downspacing Production Results



- Optimized targeting shows ~50% increase in cumulative production after 1,300 days
- No detrimental production impact seen on the original wells

Return to Existing Pads – Marcellus



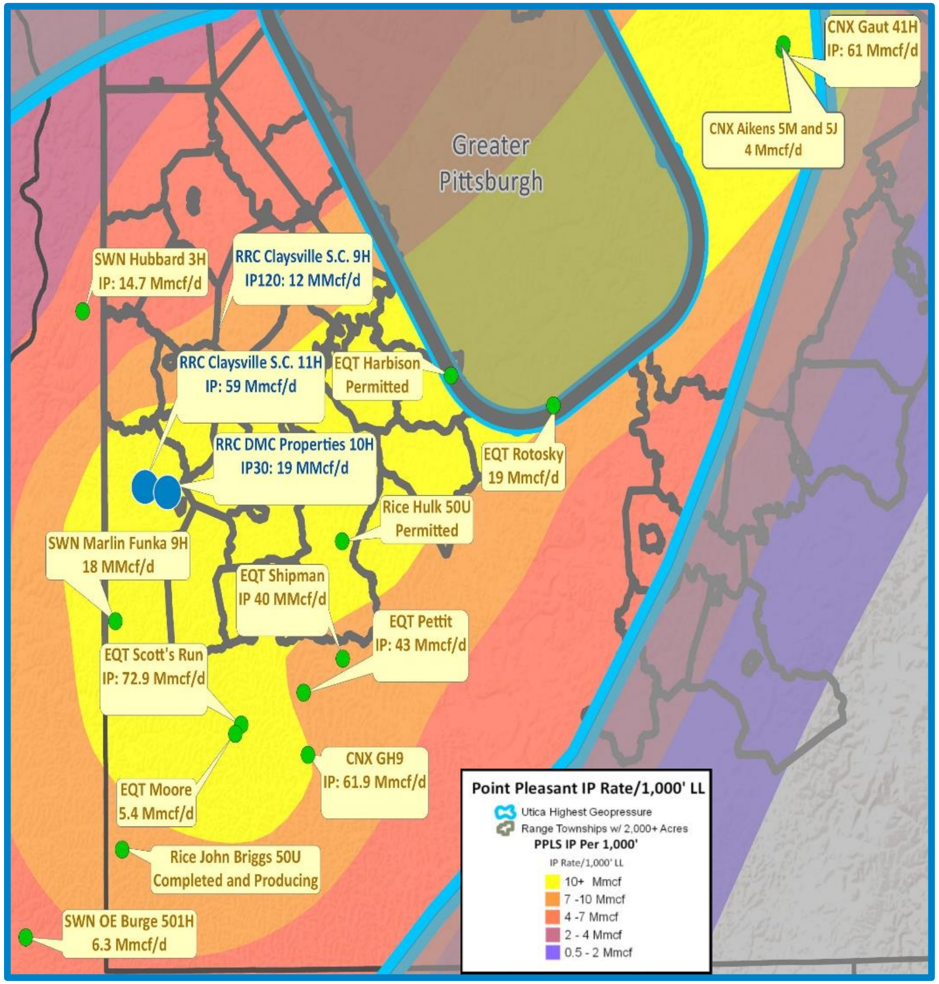


Ability to target our best areas with significant cost savings

Deep Utica

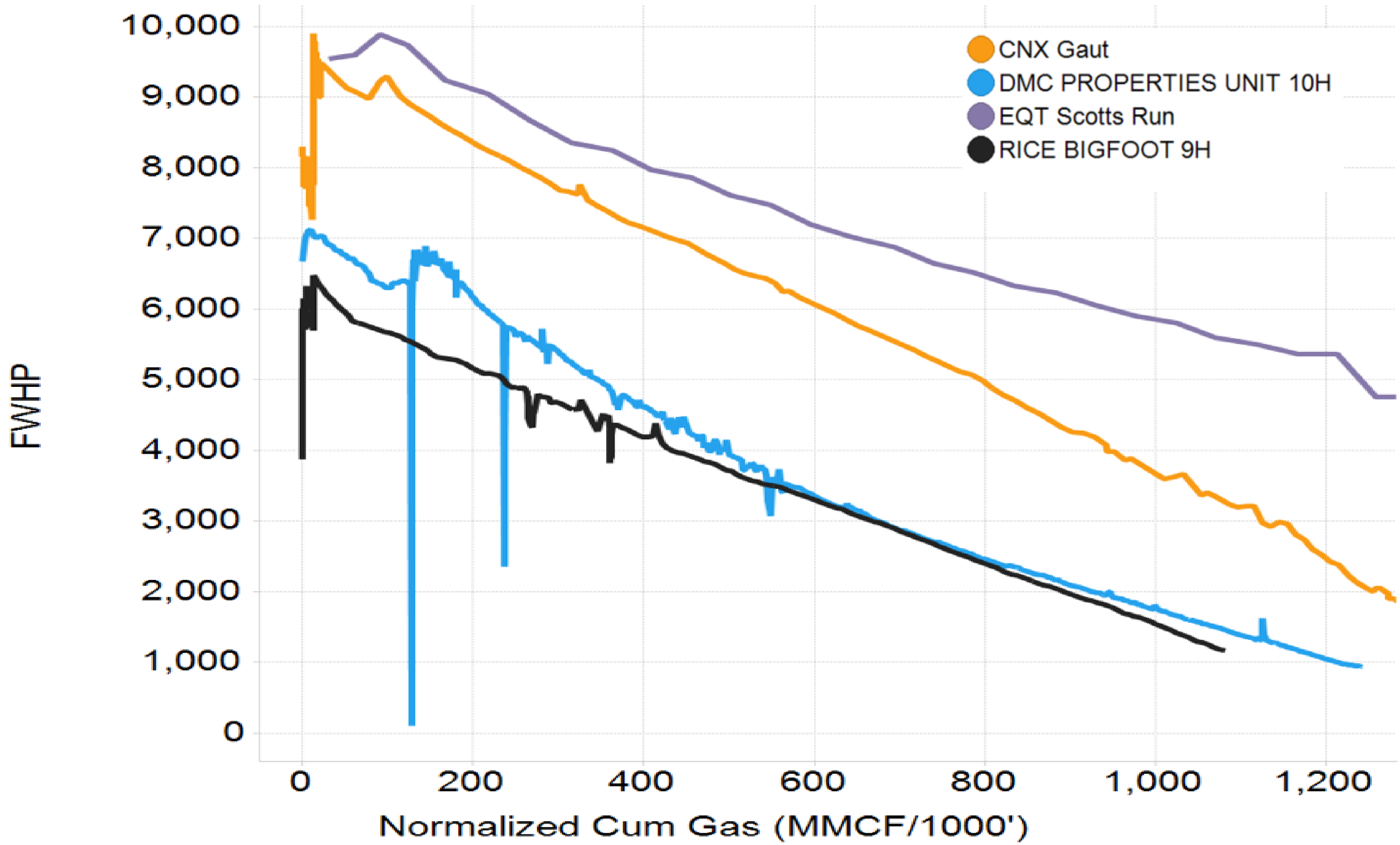
- Range has drilled three Deep Utica wells
- Range's third well appears to be one of the best dry gas Utica wells in the basin (next slide)
- Continued improvement in well performance due to higher sand concentration and improved targeting
- 400,000 net acres in SW PA prospective

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

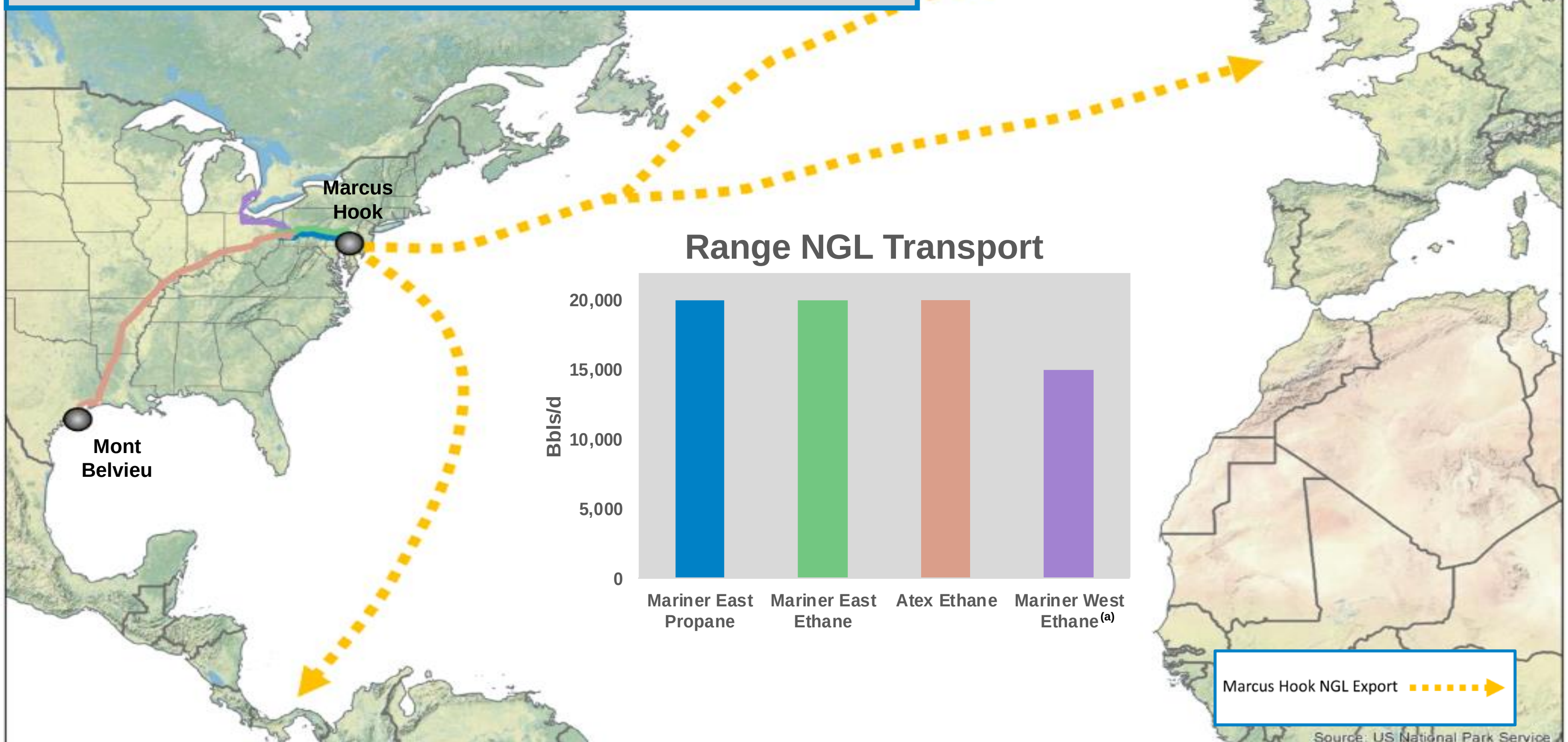
Utica Wells – Wellhead Pressure vs. Cumulative Production



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

Innovative NGL Marketing Agreements Enhance Pricing

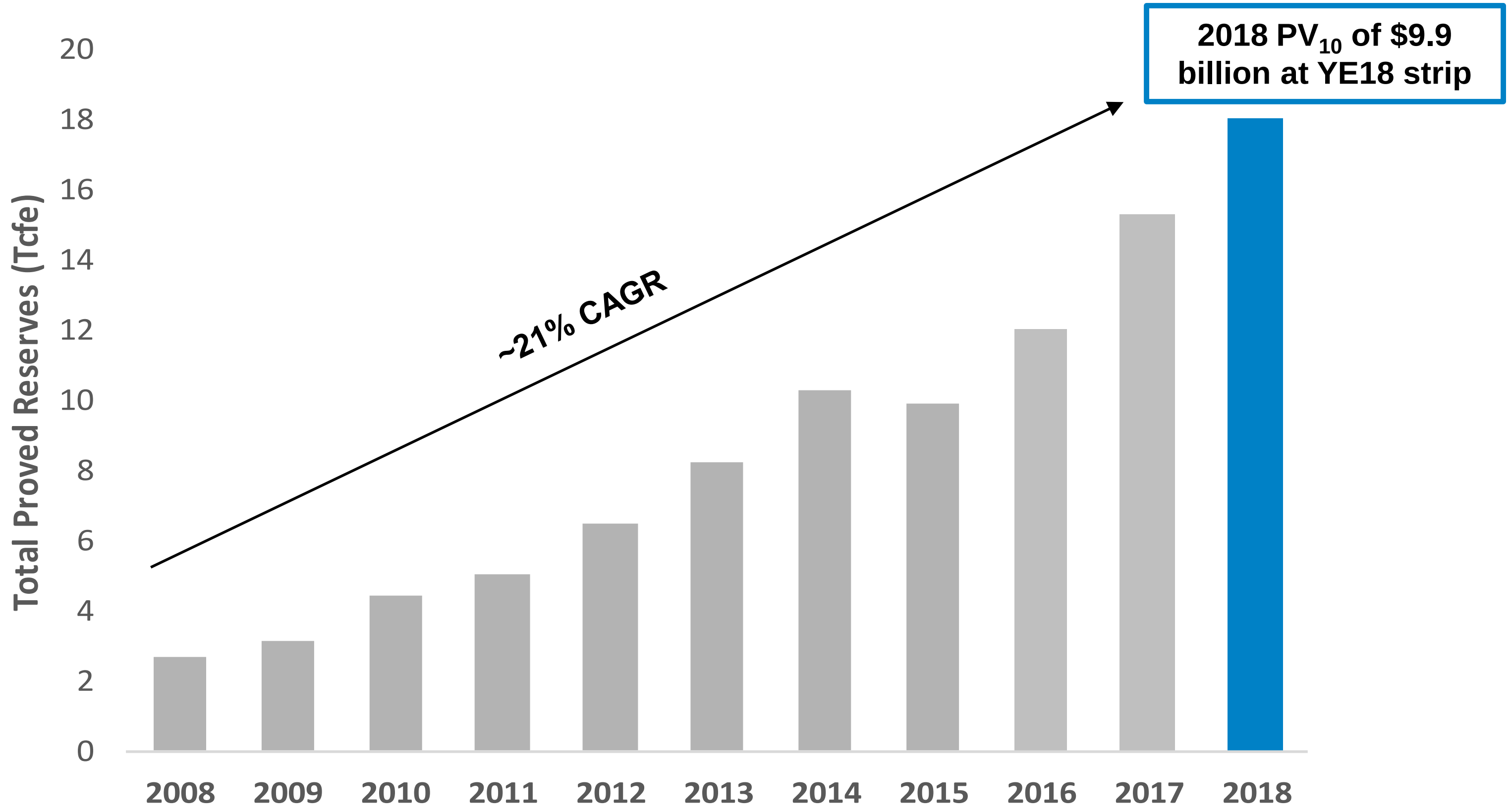
- First-mover on Appalachian NGL exports to Europe via ethane sales to INEOS using Mariner East capacity
- Range's propane has been sold internationally since 2016 through Marcus Hook, with option to sell into premium NE winter markets
- Mariner West ethane sent to Nova Chemical (Canada)
- ATEX moves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



(a) FOB Houston Plant

Consistent Track Record of Reserve Growth

- Proved reserves of 18.1 Tcfe as of year end 2018
- YE18 proved reserves increased ~18% y/y
- Future development costs for proved undeveloped reserves are estimated to be $0.40 per Mcfe at YE2018



Positive Performance Revisions for Last Decade Indicate Quality of Reserves

RANGE RESOURCES®

Natural Gas & NGL Macro Outlook

U.S. Natural Gas Demand Outlook: +21 Bcf/d 2019-24

2019-2021 Demand Outlook

- Demand growth led by U.S LNG Projects and build-out of Mexican pipeline infrastructure

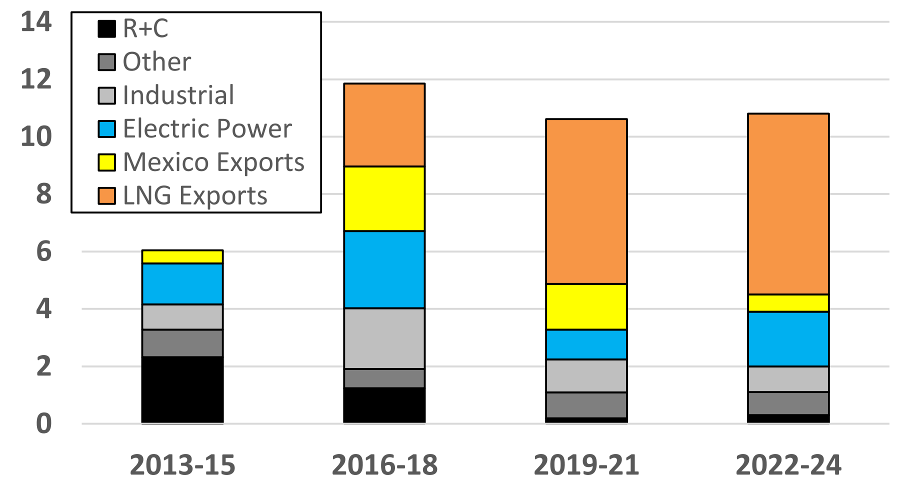
2022-2024 Demand Outlook

- Continued coal (currently ~30% of power stack) and nuclear retirements (~20% of power stack)
- Second Wave LNG Projects add 7 Bcf/d of exports

U.S. LNG Export Demand Outlook

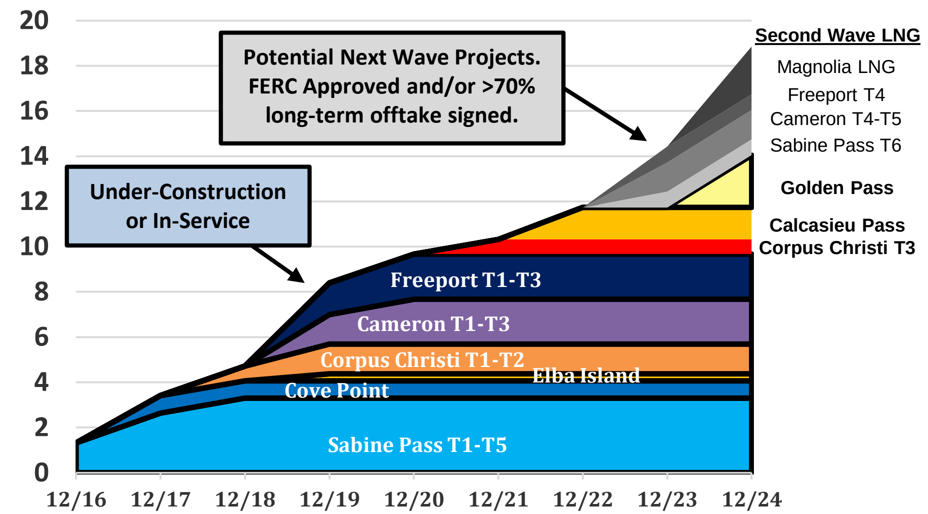
- Export capacity to more than double by mid-2020 to 10 Bcf/d from projects under-construction
- Second Wave of U.S. LNG Projects has started, with 4.3 Bcf/d already under-construction and another 3 Bcf/d likely to FID in 2019-2020
- Over 30 Bcf/d of Second-Wave LNG projects have been proposed, so potential for upside to Range's forecasts
- Range forecasts U.S. LNG export capacity to reach 16-18 Bcf/d by late 2023-early 2024, much larger and sooner than most estimates
- LNG Canada could potentially help gas balances by consuming 2.0 Bcf/d of gas otherwise destined for U.S. consumers

U.S. Gas Demand Growth Forecast (Bcf/d)



Source: Range Interpretation of various Analyst/Agency Forecasts, EIA. "Other" category includes Lease/Plant/Liquefication Fuel and Pipeline Use.

U.S. LNG Export Terminal Capacity (Bcf/d)



Source: EIA, LNG Operator announcements

Natural Gas - 35% of the U.S. Generation Mix in 2018

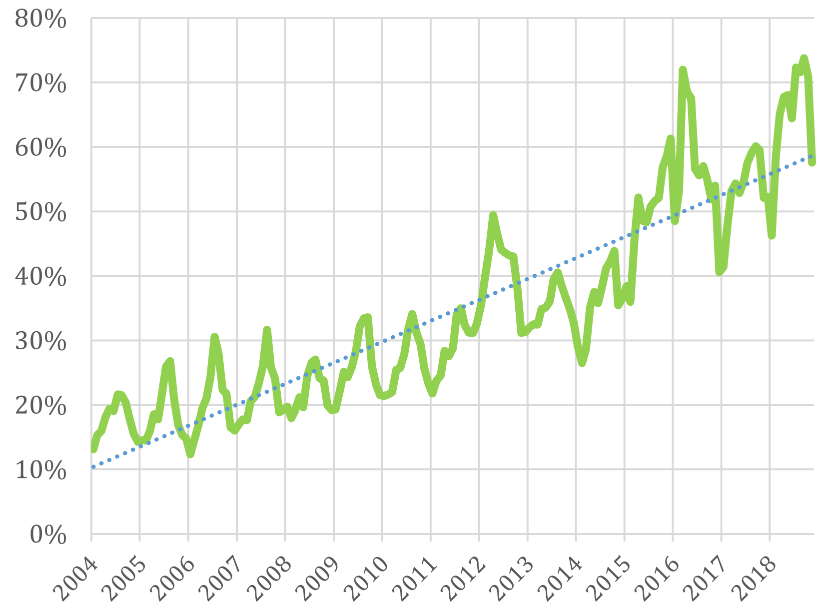
Growing Market Share in Power Gen.

- Gas power demand grew by 11 Bcf/d from 2009-2018, while coal declined 11 Bcf/d[(a)] and renewables grew 5.3 Bcf/d[(a)]

Market Share Growth Should Continue

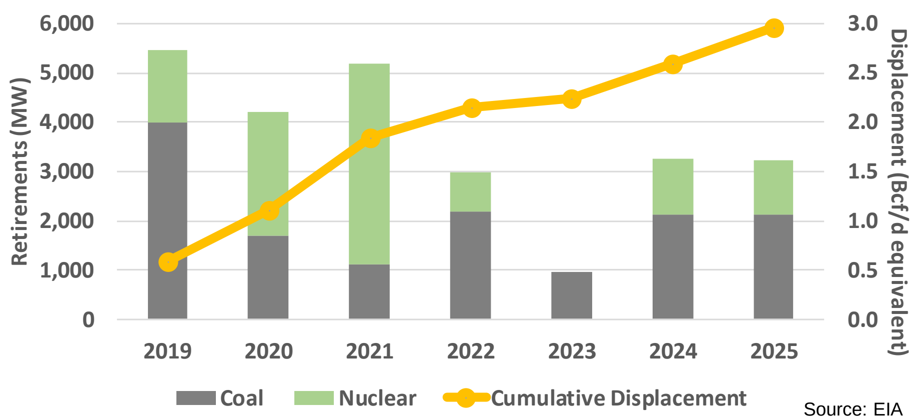
- 25 Bcf/d of coal generation remains to be displaced, or ~27% of U.S. Power Generation Mix
- 53 GW of coal plant capacity retired from 2013-2018, and another 12 GW of plant retirements have already been announced for 2019-2024
  - More retirement announcements expected to occur in coming months/years
- Planned nuclear retirements also remove large base-load of power generation
- New gas-fired reciprocating engines being added to balance grid instability issues created by renewables

U.S. Natural Gas Generation as a % of Gas + Coal



Source: EIA

Announced Coal & Nuclear Reactor Retirements



(a) Assumes 7x Heat Rate for gas equivalence

Source: EIA

Supply Growth Battles Declines & Producer Capital Discipline

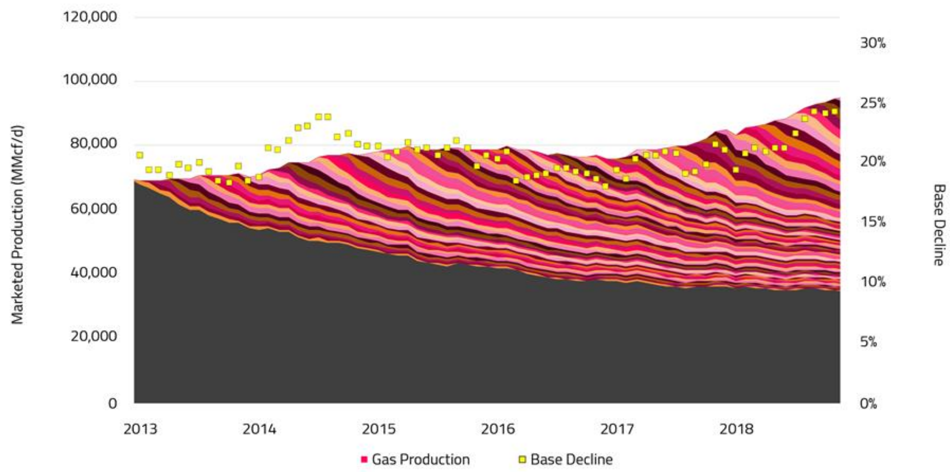
Growing Supply Requires More than Offsetting Base Declines

- Average U.S. decline rate of 24% equates to ~23 Bcf/d of new gas required to hold production flat
- Large number of 4Q18 TILs likely increases average U.S. decline rate above 24% in 2019
- After drawing down DUCs, industry growth rates could slow meaningfully into exit 2019 and 2020 if strip prices hold
- Industry spending being limited to cash flow in 2019 makes steep declines more difficult to offset

Producer Discipline Materially Impacts Supply Forecast

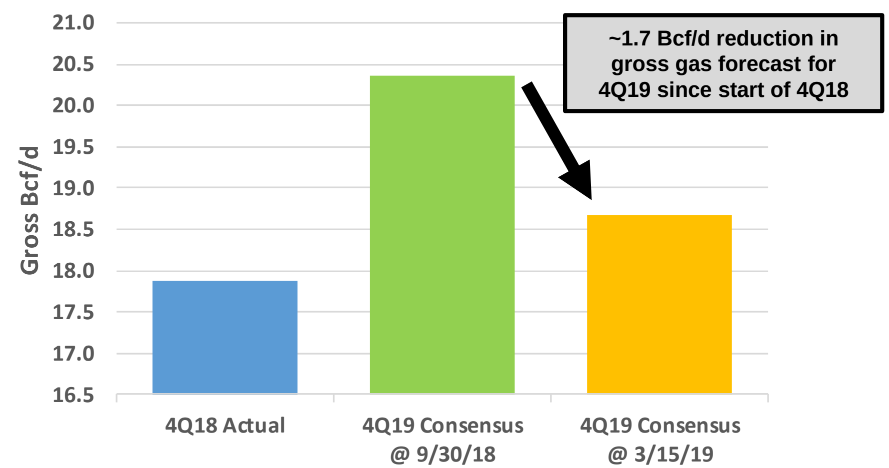
- Consensus 4Q19 gross gas estimates for Appalachia peer group (~65% of basin gas production) have been cut ~1.7 Bcf/d since start of 4Q18
- Consensus 4Q-4Q growth forecast now just ~4% (0.8 Bcf/d) for Appalachia peer group, significantly improving gas macro for late 2019 and 2020+
- Private Equity-backed operators may shift to more sustainable growth rates with traditional exit strategies becoming challenged (IPO, corporate M&A, etc.)

U.S. Natural Gas Base Decline Rate



Source: RS Energy

Consensus Gross Gas Production for Appalachia Producers



Source: Bloomberg. Assumes average NRI of 80%. Appalachia producers include AR, CNX, COG, EQT, GPOR, RRC and SWN. SWN excludes Fayetteville.

Shale Efficiency Gains Are Slowing

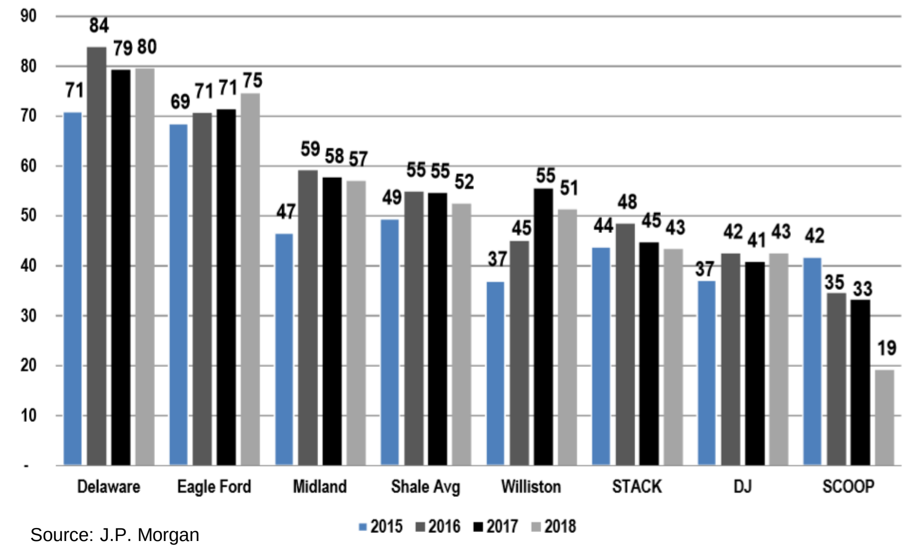
Oil Basins

- Limited Tier-1 runway left in Williston and Eagle Ford as cores are believed to have been heavily drilled
- Up-spacing across several plays reduces core inventory life
- Efficiency gains from lateral length and proppant intensity now seeing diminishing returns versus 3 years ago
- Parent-Child issues becoming more prevalent as child wells produce materially less than parent wells

Haynesville

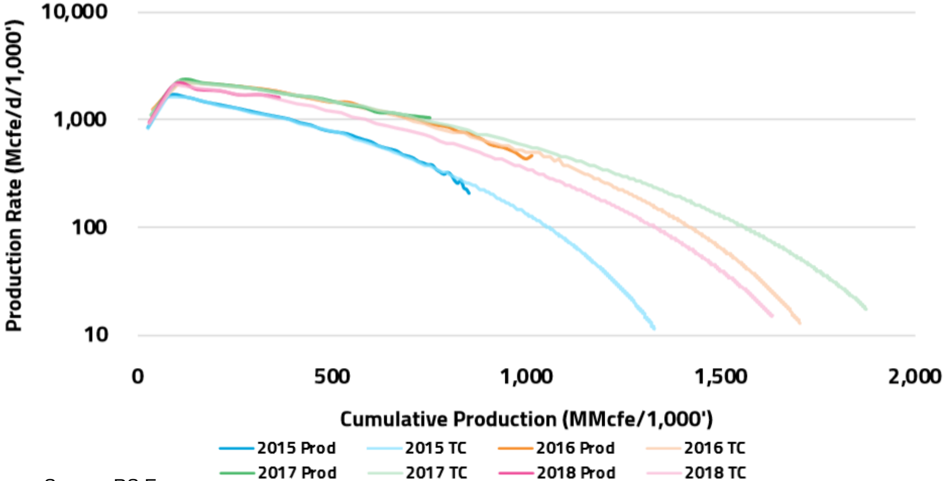
- Well productivity in the Haynesville appears to have plateaued
- Runway for current productivity may be limited given current pace of development in the play and that the core is known to be small
- Private operators may be forced to reduce growth as traditional exit strategies have become challenged

6-Month Daily Oil Production per 1,000 Lateral Ft.



Source: J.P. Morgan

Haynesville Production per 1,000 Lateral Ft.



Source: RS Energy

Dry Gas Basin Economics Under Pressure at Current Strip

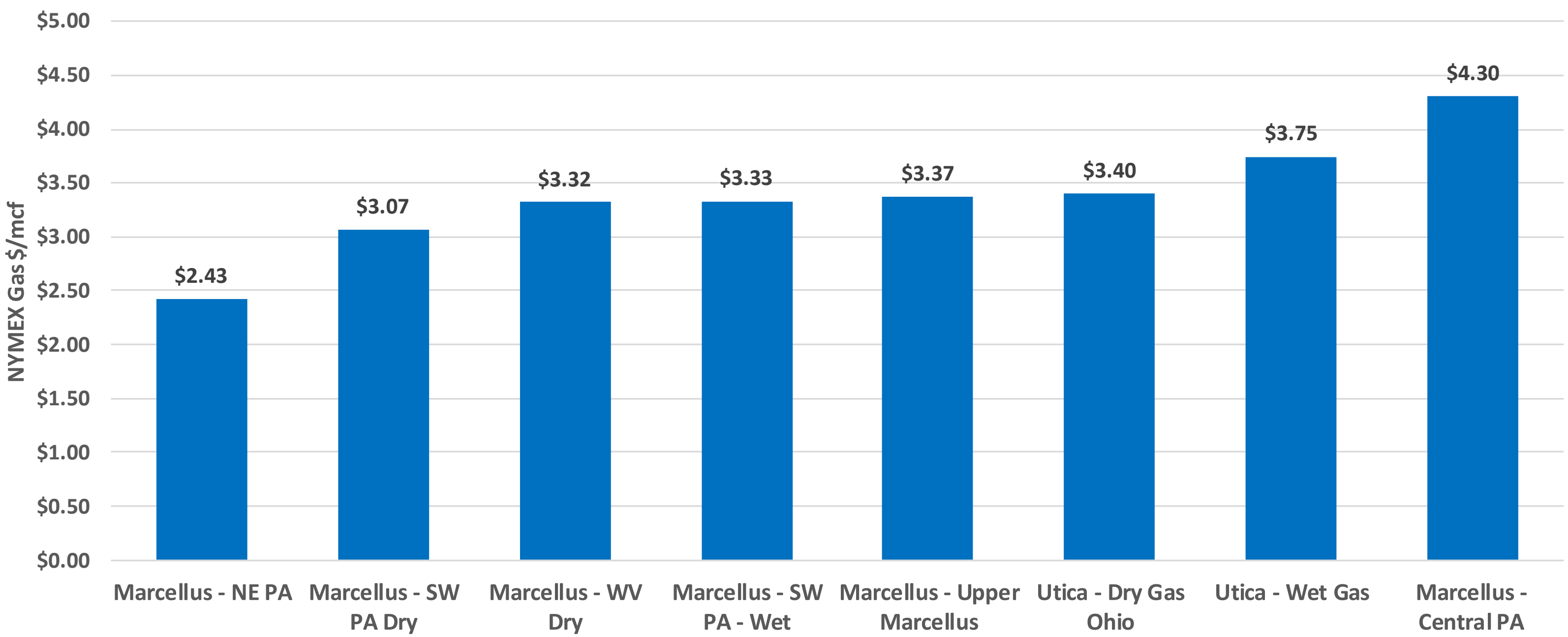
Supply Growth Needed from Dry Gas Basins

- **EIA forecasts 6.7 Bcf/d of 2019-2024 supply growth from outside of Northeast (mostly associated gas)**
- **Demand growth forecast of +21 Bcf/d from 2019-2024 will require growth from dry gas basins to balance market**

Higher-Than-Strip Prices Will Be Needed to Support Dry Gas Basin Growth

- **Northeast PA will face constraints to growing beyond 2-3 Bcf/d given current lack of infrastructure**
- **Dry gas basins likely require >$3/Mmbtu natural gas to support sustainable growth**

Basin Break-Evens Above NYMEX Futures Curve



Source: J.P. Morgan. Break-evens assume 25% pre-tax full-cycle rate of return to account for corporate G&A, interest expense and acreage costs.

NGL Macro Outlook

Fractionation Tightness to Return in 2019

- NGL price rally in Summer 2018 was driven by U.S. fractionation capacity tightness that was temporarily relieved by:
  - Winter weather driving natural gas price spikes and lower C2 recovery
  - Midwest C3 being consumed locally rather than flowing to the Gulf Coast
- Range expects fractionation tightness to return in Summer 2019 as new ethane cracker startups (demand) outpace new fractionation additions (supply)

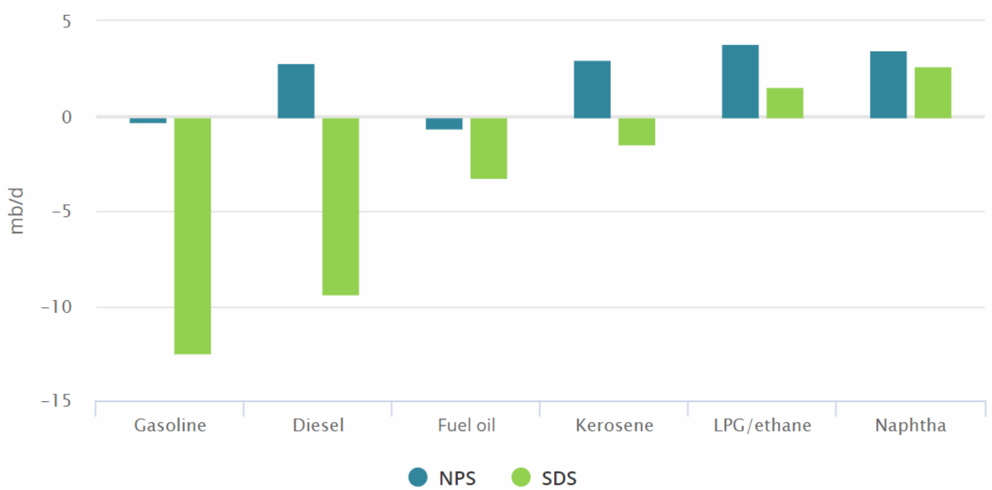
NGL Demand Forecast

- IEA forecasts LPG (propane and butane) and ethane to be the fastest growing global oil products over medium and long term
- Demand growth driven primarily by petrochemical feedstock demand and residential demand in developing countries

Mont Belvieu C2 Premium to NYMEX (cents per gallon)

Source: Bloomberg Futures pricing at 3/19/19

2017-2040 Change in Global Oil Product Demand by Scenario



Source: IEA World Energy Outlook 2018 (NPS = New Policy Scenario, SDS = Sustainable Development Scenario)

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Financial Detail

Guidance

	2Q 2019	Full-Year 2019
Production (Mmcfe per day)	**2,270 to 2,280**	**2,325 to 2,345**
Capital Expenditures		**$756 million**
Operating Expense Guidance		
Direct Operating Expense per mcfe	$0.16 - $0.18	
TGP&C Expense per mcfe	$1.47 - $1.51	
Production Tax Expense per mcfe	$0.05 - $0.06	
Exploration Expense	$7 - $9 million	
Unproved Impairment Expense	$15 - $18 million	
G&A Expense per mcfe	$0.18 - $0.20	
Interest Expense per mcfe	$0.23 - $0.25	
DD&A Expense per mcfe	$0.68 - $0.74	
Net Brokered Marketing Expense	$3 million	
Pricing Guidance		
Natural Gas Differential to NYMEX	($0.24)	($0.15) - ($0.20)
NGLs (pre-hedge & including ethane)		34% - 38% of WTI
Oil/Condensate Differential to WTI		($6.00) - ($8.00)

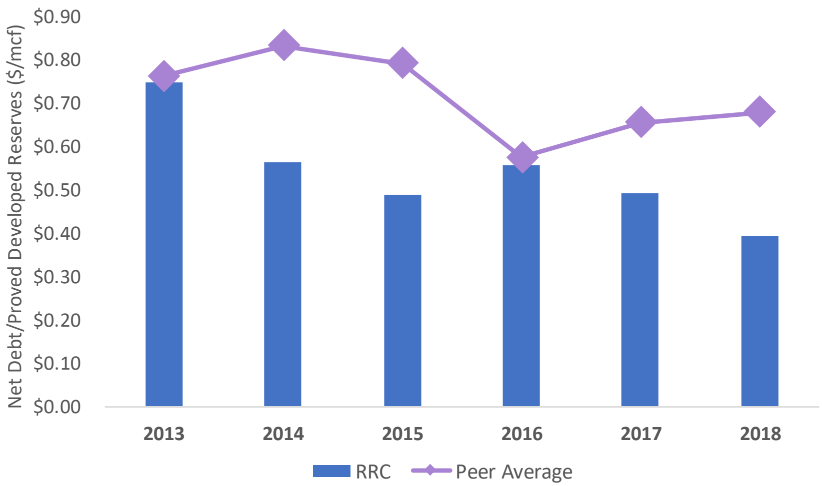
Well-Structured, Resilient Balance Sheet

- $4 billion credit facility,
  ($3B borrowing base, $2B committed)
- No note maturities until 2021
- Simple capital structure
- Near-term cash flow protected with hedges

Capital Structure[a]

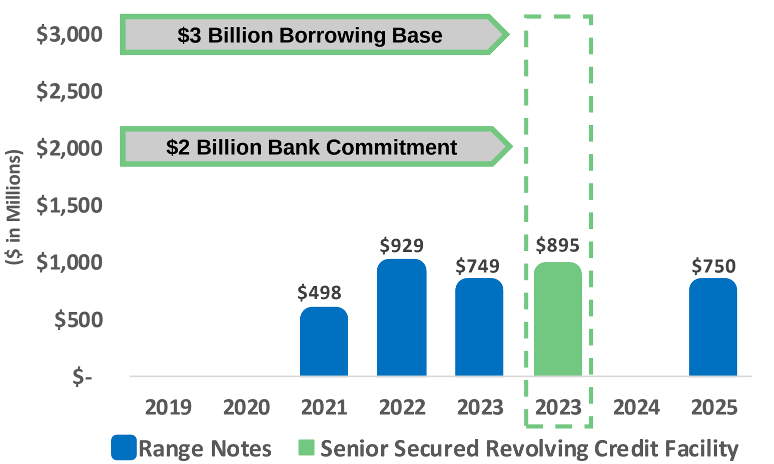
(millions)	1Q19
Bank Debt	$ 895
Senior Notes	2,877
Senior Sub Notes	49
Debt	3,821
Debt to Capitalization	48%
Debt/TTM EBITDAX	3.2x

Debt/Proved Developed Reserves



Note: Peer average includes AR, CHK, CNX, COG, EQT, GPOR and SWN.

Debt Maturity Schedule[a]



Interest Rate	2019	2020	2021	2022	2023	2023	2024	2025
			5.75%	5.3%[b]	5.0%			4.875%

(a) As of 3/31/19 (b) Weighted-average interest rate of 2022 notes

Development Cost & Recycle Ratio Calculation

Cash margin per mcfe / PUD development costs per mcfe.

Numerator:			
1Q19 Pre-Hedge Realized Price	$	3.37	per mcfe
1Q19 All-In Cash Costs	$	2.13	per mcfe
Adjusted Margin per Mcfe	$	1.23	per mcfe
Denominator:			
Future Development Costs of YE 2018 PUDs	$	3.3	billion
Proven Undeveloped (PUD) Reserves at YE 2018		8.3	Tcfe
Future Development Costs per Mcfe	$	0.40	per mcfe
Unhedged Recycle Ratio		**3.1x**	

Natural Gas & Oil Hedging Status

	Time Period	Volumes Hedged (Mmbtu/day)	Average Hedge Prices ($/Mmbtu)
Natural Gas[1] (Henry Hub)	2Q19 Swaps	1,350,000	$2.80
	3Q19 Swaps	1,425,109	$2.80
	4Q19 Swaps	1,428,261	$2.82
	FY20 Swaps	334,973	$2.77

	Time Period	Volumes Hedged (bbl/day)	Average Hedge Prices ($/bbl)
Oil (WTI)	2Q19 Collars	1,000	$63 x 73
	2H19 Collars	1,000	$63 x 73
	2Q19 Swaps	7,500	$55.25
	3Q19 Swaps	7,250	$55.50
	4Q19 Swaps	7,666	$55.64
	FY20 Swaps	1,624	$60.95

**As of 3/31/19*

1) *Range also sold call swaptions of 20,000 Mmbtu/d for winter 2019/2020 and 290,000 Mmbtu/d for calendar 2020 at average strike prices of $3.20 and $2.80 per Mmbtu, respectively.*

Liquids Hedging Status

	Time Period	Volumes Hedged (bbls/day)	Average Hedge Prices ($/gal)
Ethane (C2)	2Q19 Swaps	500	$0.35
Propane (C3)	2Q19 Collars 2Q19 Swaps	1,000 8,500	$0.90 x $0.96 $0.878
Natural Gasoline (C5)	2Q19 Swaps 3Q19 Swaps 4Q19 Swaps	5,000 1,500 1,500	$1.341 $1.472 $1.475

**As of 3/31/19*

Contact Information

Range Resources Corporation
100 Throckmorton St., Suite 1200
Fort Worth, Texas 76102

Laith Sando, Vice President – Investor Relations
(817) 869-4267
lsando@rangeresources.com

Michael Freeman, Director – Investor Relations & Hedging
(817) 869-4264
mfreeman@rangeresources.com

John Durham, Senior Financial Analyst
(817) 869-1538
jdurham@rangeresources.com

www.rangeresources.com

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