RANGE RESOURCES®

Barclays CEO Energy-Power 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 – At a Glance

Unmatched Southwest Appalachia Inventory

- Approximately one half million net acres provide decades of low-risk drilling opportunities
- Contiguous position allows for efficient operations and long-lateral development
- Peer-leading well costs and productivity underpin top-tier recycle ratio
- Proved Reserve Value (PV_{10}), net of debt, equals ~$24/share at year-end 2018 strip pricing

Sustainable Free Cash Flow

- Low maintenance capital requirements support free cash flow through the cycles
- Capital allocation process starts with free cash flow as a priority
- Cost structure improvements enhance margins and durability of free cash flow

Leader on Sustainability and Environmental Practices

- Long-lateral development minimizes operational footprint
- Industry-leading water-recycling program
- Emissions improved by 70% over the last three years
- First company to voluntarily disclose fracturing fluid for each completed well

Unmatched Inventory in Southwest Appalachia

~3,700 undrilled core Marcellus wells [(a)] provide decades of low-risk drilling opportunities

Marcellus resource potential [(b)]

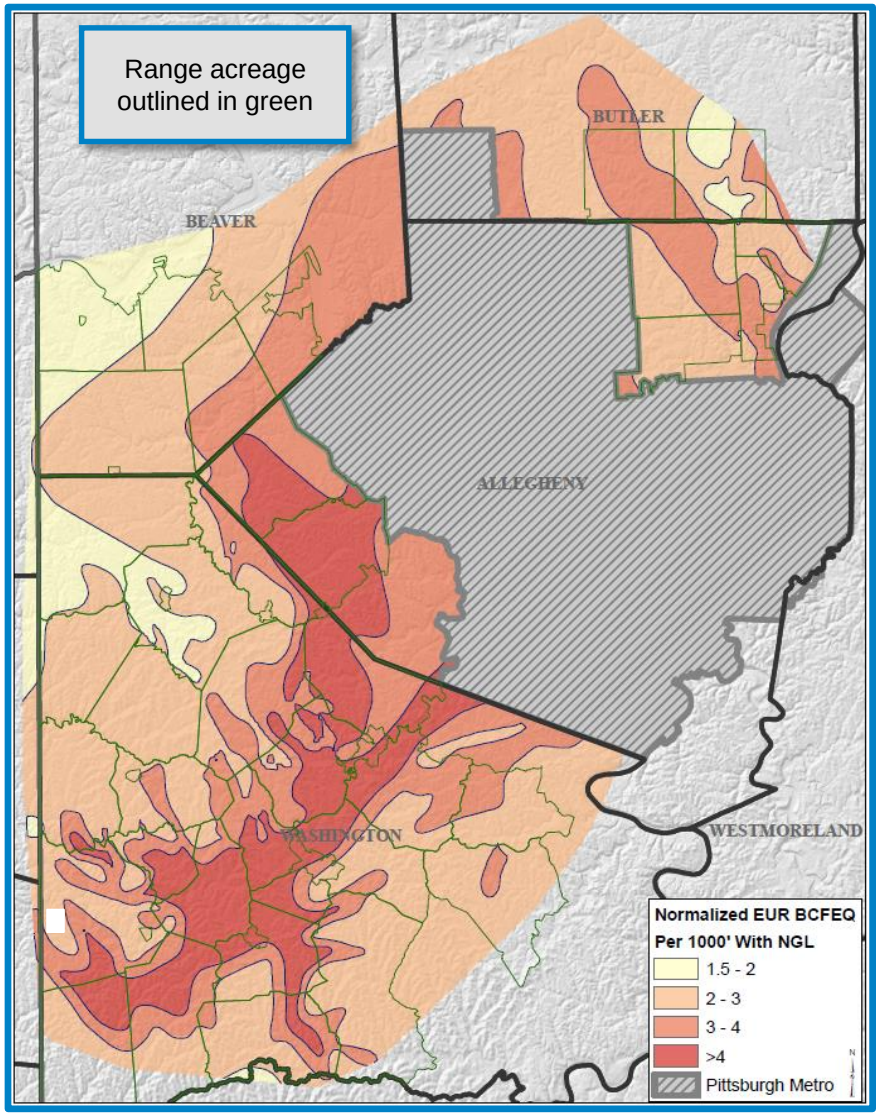
- ~ 40 Tcf of natural gas
- ~ 3 billion barrels of NGLs
- ~ 149 million barrels of condensate

Significant inventory of highly prolific Utica wells extends Range's dry gas opportunity

Existing natural gas and NGL infrastructure de-risks future development

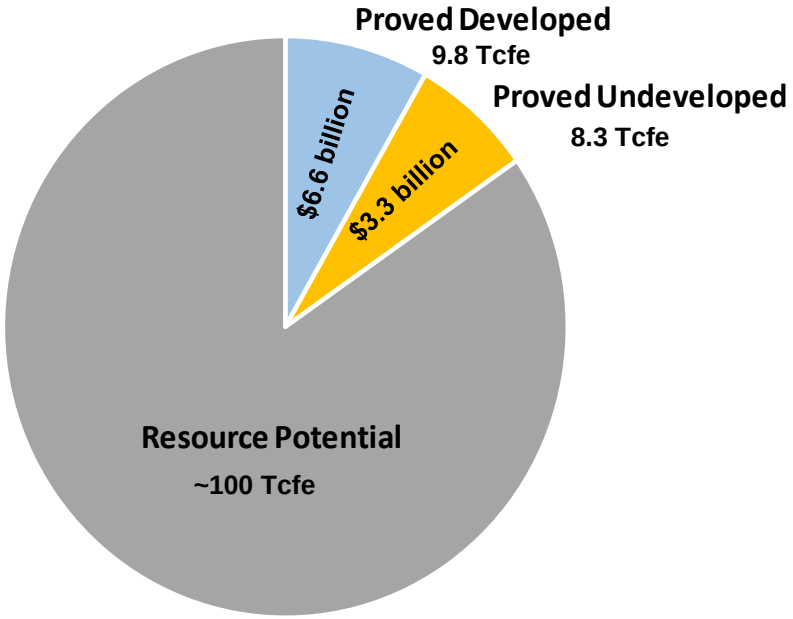
Contiguous acreage position provides for operational efficiencies and industry leading well costs:

- **Long-lateral development**
- **Efficient water handling and long-term infrastructure utilization**



(a) Estimates as of YE2018; based on production history from ~1,000 Range-drilled wells. Includes ~300 locations not shown on map. Based on 10,000 ft lateral length
(b) Does not include 18.1 Tcfe of YE2018 proved reserves.

Value of Year-end 2018 Proved Reserves - $24 per share



Included in Reserves, as defined by SEC

- Only 5 years of development activity
- 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

Reserve Value Ignores Resource Potential

- Resource Potential of ~100 Tcfe
- Approximately 3,300 undrilled core Marcellus wells, or over 35 years of inventory at current drilling pace
- Potential from ~400,000 net acres of core Utica and ~500,000 net acres of Upper Devonian

Reserve History

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

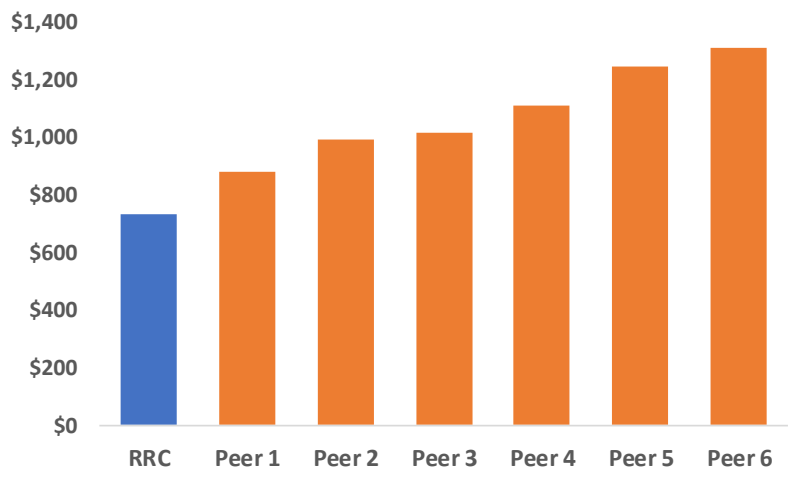
Note: PV-10 estimate assumes strip pricing. For reference, the 10-year average was $2.83/mmbtu NYMEX natural gas and $51.54/bbl WTI

Peer-Leading Development Costs

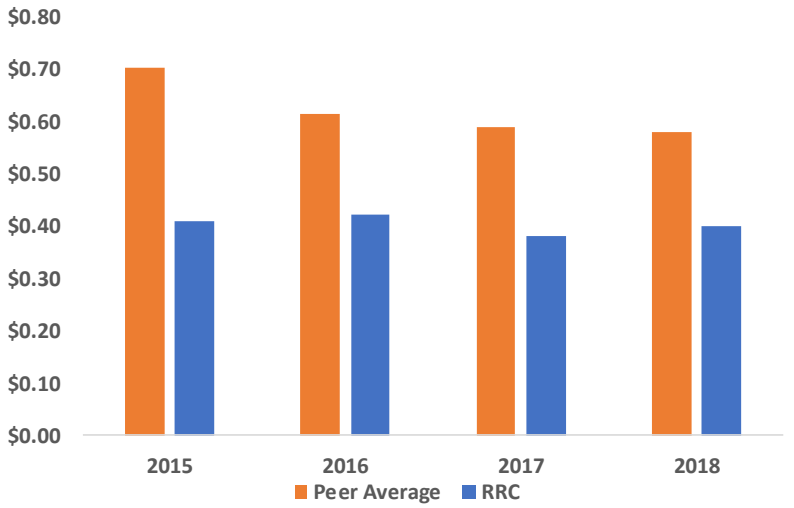
Blocked-up acreage allows for long laterals and efficient operations driving peer-leading well costs

Peer-leading well costs and recoveries result in top-tier development costs per mcfe

Appalachian Well Cost per Lateral Foot[(a)]

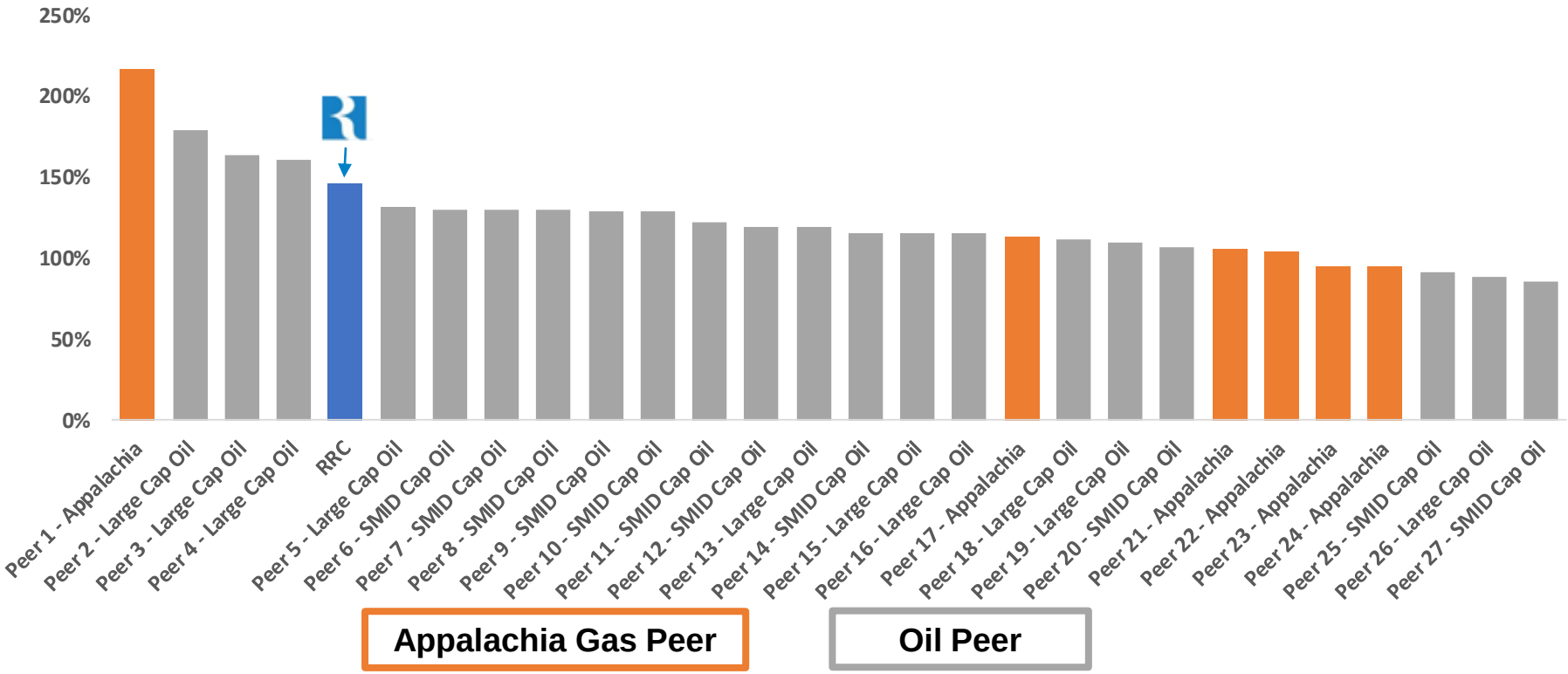


PUD Development Costs per Mcfe[(b)]



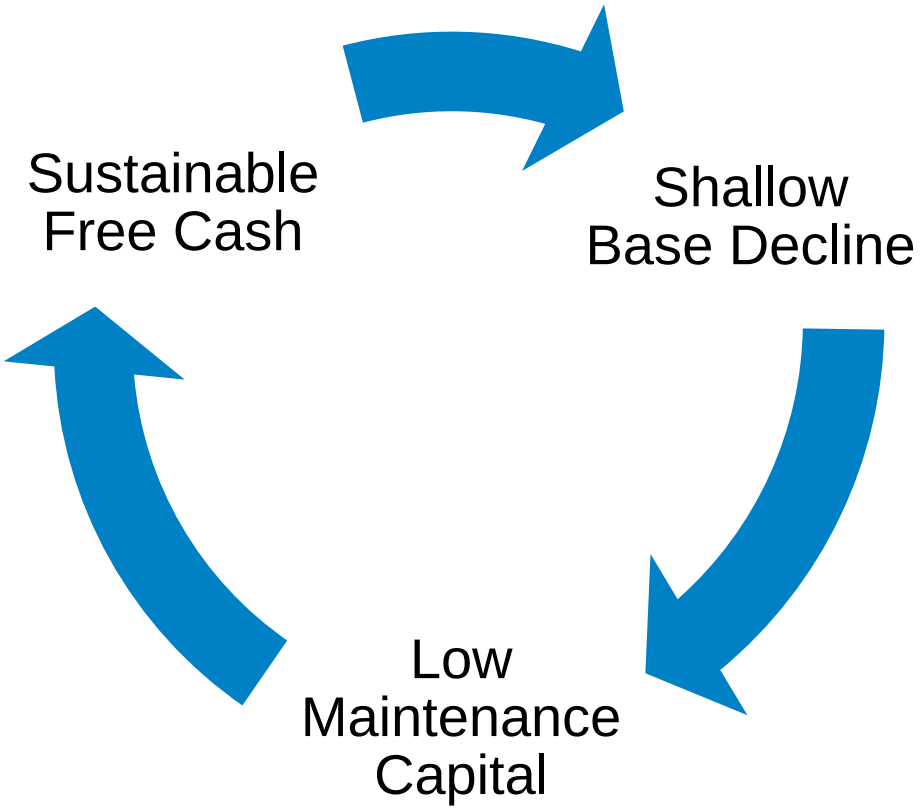
(a) *Peers include AR, CNX, COG, EQT, GPOR and SWN. Peer estimates calculated based on operator guidance and statements for 2019.*
(b) *Peers include AR, CNX, COG, EQT, GPOR and SWN. SWN excluded from peer group in 2015 and 2016. PUD Development Costs defined as future development costs / PUD reserves.*

Cash Recycle Ratio Shows Quality and Durability of Asset Base



Source: MKM Partners. "Energy/Exploration & Production Outlook". June 2019. Cash Recycle Ratio = Cash Operating Margin divided by Capital Intensity. Companies shown include APC, AR, CHK, CLR, CNX, COG, CRZO, CXO, DVN, ECA, EOG, EQT, GPOR, HES, HPR, LPI, MRO, MTDR, MUR, PDCE, PXD, SM, SRCI, SWN, WLL, WPX and XEC.

Maintenance Capital Drives Free Cash Flow Through the Cycles



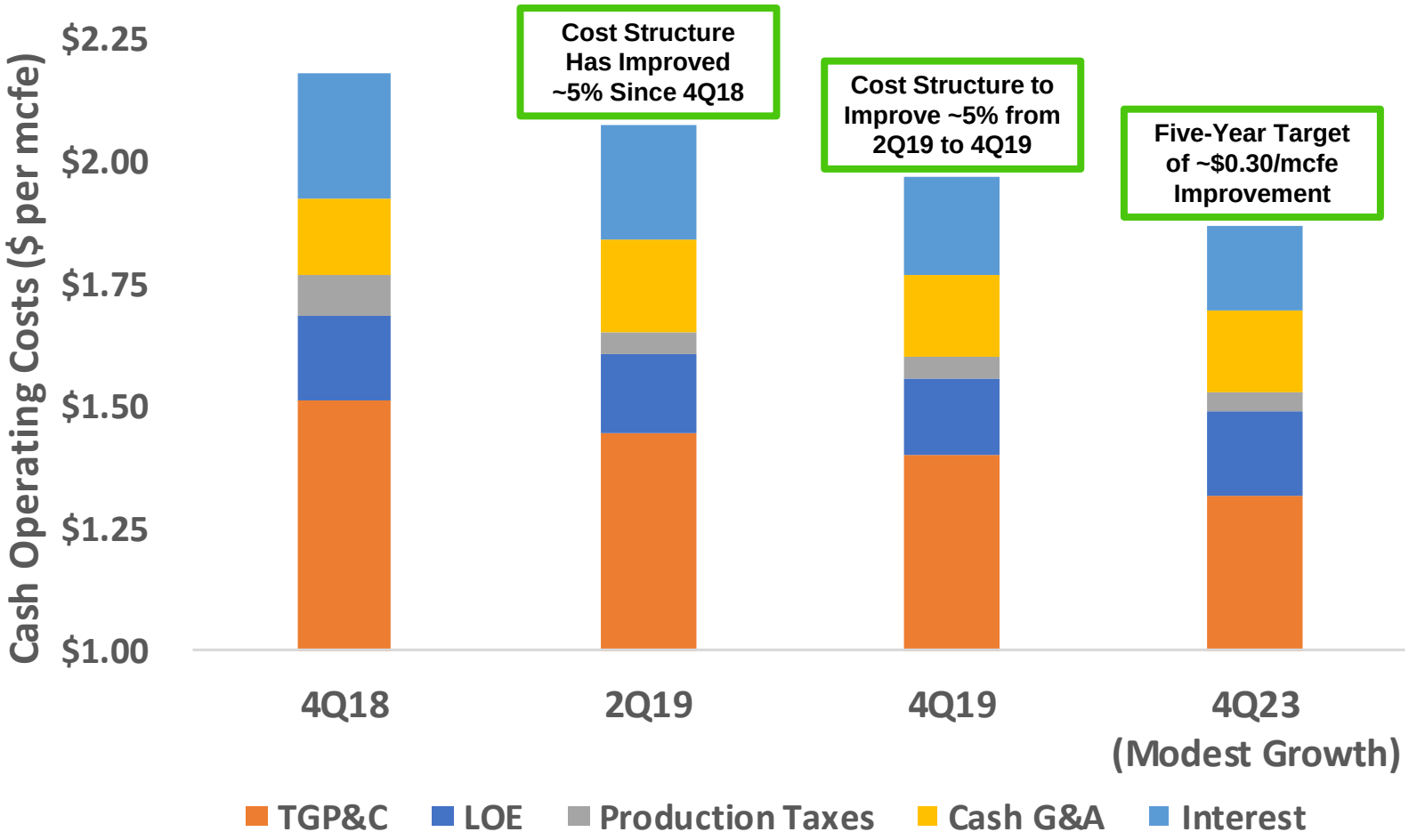
Shallow Base Decline Driven by:

- **Core Marcellus position**
- **10+ years of drilling history in Marcellus provides solid base of low-decline wells**
- **Infrastructure built to maximize returns, not peak initial rates**
- **2019 base decline rate of ~20% is sustainable, even with modest growth in base production**
- **Shallow base decline, coupled with efficient operations allows for low maintenance capital**

Low Maintenance Capital Supports Sustainable Free Cash Flow

- **Minimum capital requirements to maintain existing production levels compared to peers**
- **Generating free cash flow is priority in capital allocation process**
- **Free cash flow is durable given Range's multi-decade core Marcellus inventory**

Improving Cost Structure Enhances Cash Flow & Margin Growth



Two-Thirds of Targeted Unit Cost Improvement in Five-Year Outlook to Be Achieved by Year-End 2019, Driven by Improving GP&T and Interest Expense per Mcfe. Additional Improvements Expected in 2020 and Beyond.

Corporate Sustainability Report Highlights

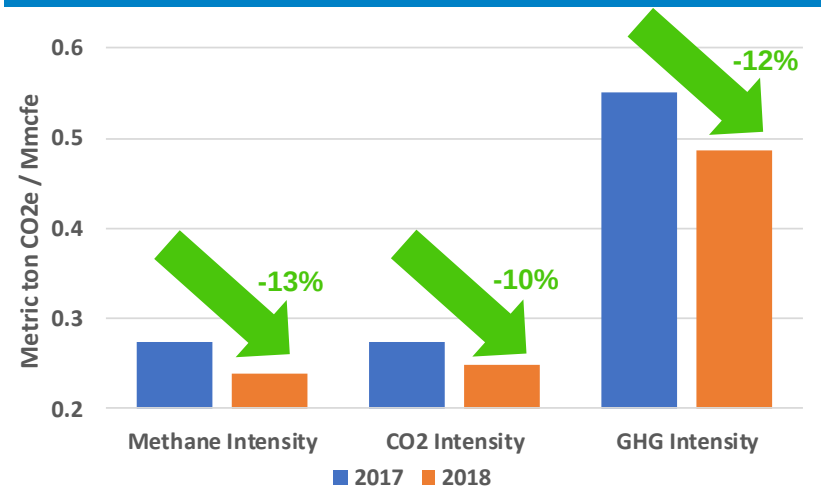
Emissions Target Across Operations

- Range proactively works to optimize facility designs to reduce environmental footprint and improve production
- Design changes drove a ~12% reduction in greenhouse gas emissions per mcfe in 2018
- Ranked in the top tier of operators on methane emissions management and reporting by As You Sow, a nonprofit that promotes ESG-related shareholder advocacy

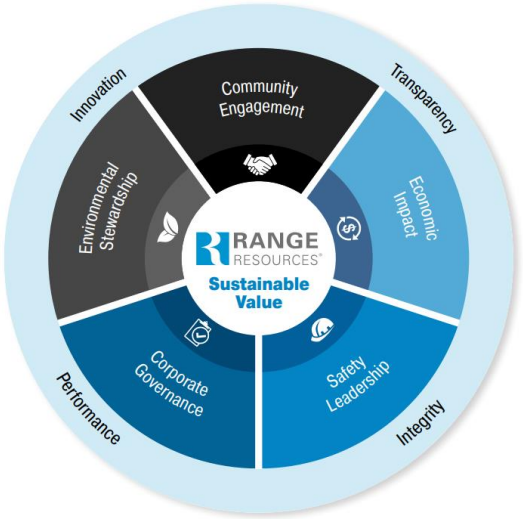
Industry Leader in Water Management

- Range achieved a ~153% water recycle rate in Appalachia by recycling effectively all of Range's produced water as well as water from 10+ other operators through a Water Sharing Program
- Reduced total truck trips in Pennsylvania by more than 100,000 trips to locations in 2018 through new technologies and improved logistics
- Range's water management efforts provided capital savings in excess of $10 million for 2018 and improved LOE

2018 Emission Reduction Results



Focus on Responsible ESG Practices



More information on Range's efforts regarding Environmental, Social and Governance issues can be found at the Sustainability page on the Company website.

Natural Gas Demand – Increases 21 Bcf/d in Next 5 Years

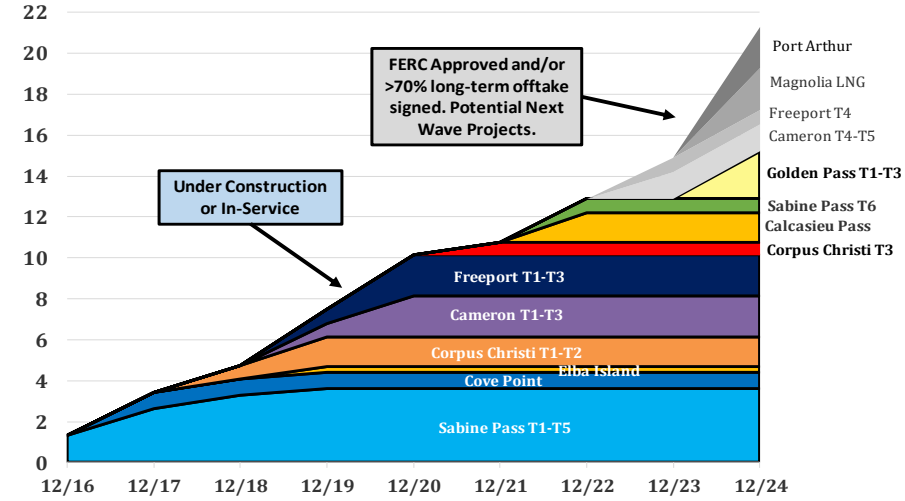
2019-2024 Demand Outlook

- Total demand growth of +21 Bcf/d through 2024 from LNG and Mexican exports, industrial and electric power demand growth
- LNG export capacity to increase by mid-2020 to 10 Bcf/d from projects under-construction
- Second Wave LNG Projects could add another +10 Bcf/d of exports by 2025
- Continued coal (currently ~30% of power stack) and nuclear retirements (~20% of power stack)

U.S. LNG Export Demand Outlook

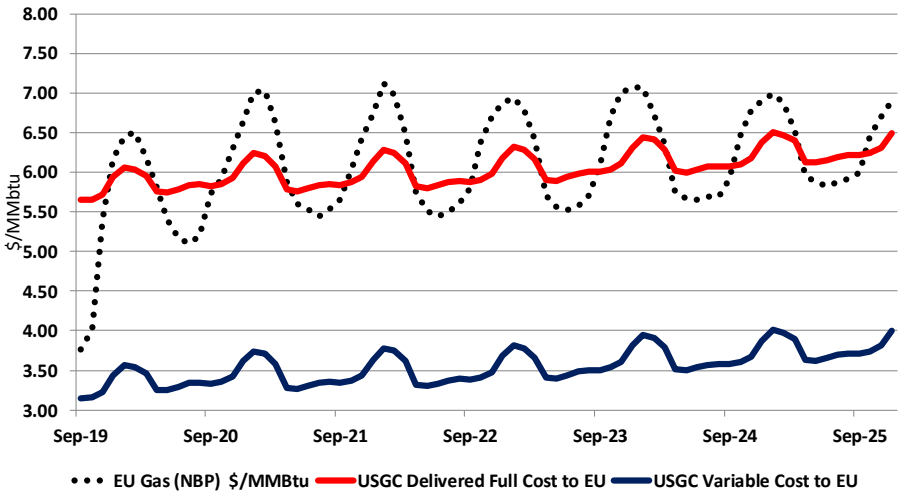
- Second Wave of U.S. LNG Projects has started, with 5.1 Bcf/d already under-construction and another +5 Bcf/d likely to FID in 2019-2020
- Over 30 Bcf/d of Second-Wave LNG projects have been proposed
- Futures prices support additional LNG exports
- Range forecasts U.S. LNG export capacity to reach ~13 Bcf/d in 2022 and ~18 Bcf/d by late 2023-early 2024

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



Source: EIA, LNG Operator announcements

Futures Market Indicates LNG Arb is OPEN



Bloomberg prices as of 8/22/19.

Natural Gas Supply - Base Decline & Capital Discipline

Base Declines Offset Current Activity

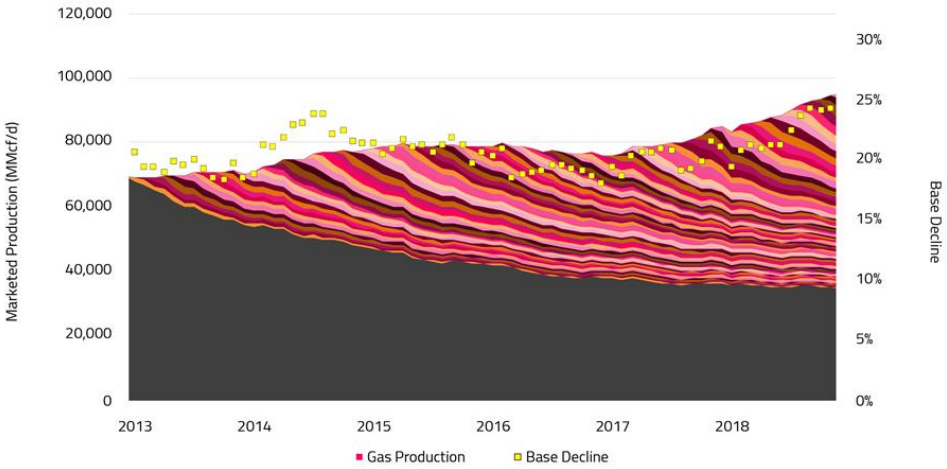
- Average U.S. decline rate of 24% equates to ~23 Bcf/d of new gas required each year to simply hold production flat
- U.S. decline rate likely increase given large ramp in 4Q18 TILs
- After drawing down DUCs, industry growth should slow meaningfully into exit 2019 and 2020 if strip prices hold

Producer Discipline Materially Impacts Supply Forecast

- Industry spending being limited to cash flow in 2019 and beyond
- 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 a free cash flow model as traditional exit strategies become challenged (IPO, corporate M&A, etc.)

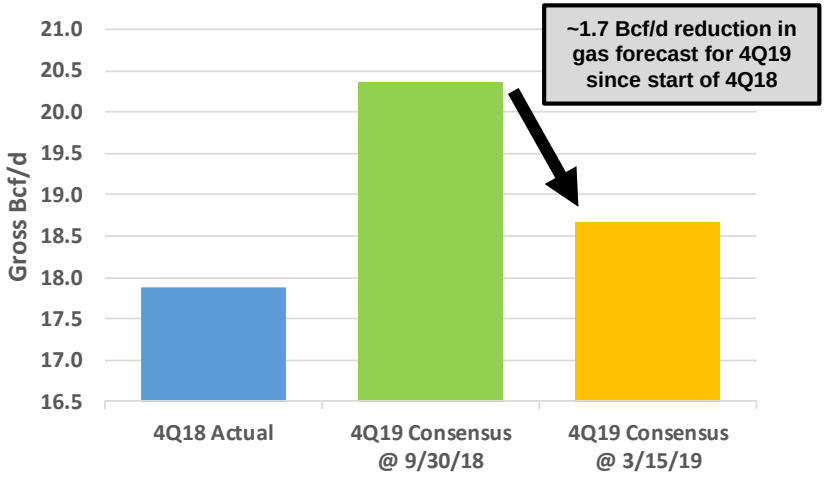
Associated Gas Growth Not Capable of Offsetting Dry Gas Decline and Expected Demand Growth

U.S. Natural Gas Base Decline Rate



Source: RS Energy

Consensus 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.

NGL Macro Improving

New Infrastructure

- U.S. waterborne export capacity increases equivalent to ~15% of U.S. LPG supply, which should tighten balances going forward
- 2019 export capacity to increase by ~355 MBPD (Targa Galena Park, Enterprise Houston Ship Channel, Mariner East 2 / Marcus Hook) versus EIA gas plant LPG supply estimate of 2,381 MBPD at 4/30/19
- Local Northeast propane differentials have narrowed since start up of Mariner East 2

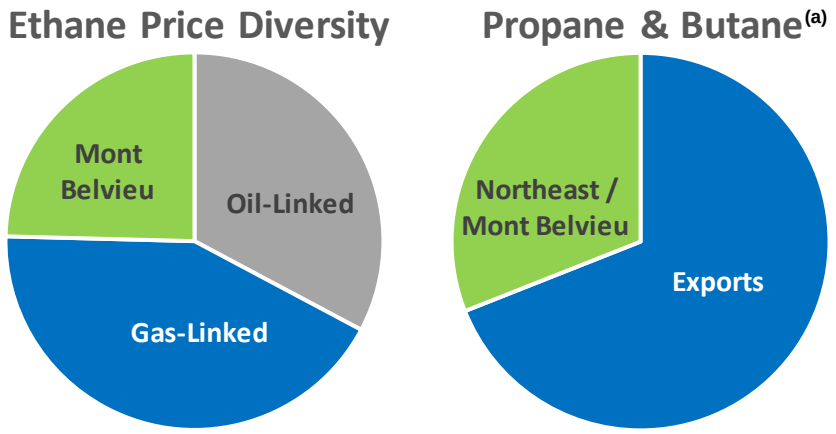
Storage & Supply

- Export-adjusted storage days of supply remains below the five-year average
- NGL supply growth to slow in 2020 with slowing U.S. crude and natural gas supply

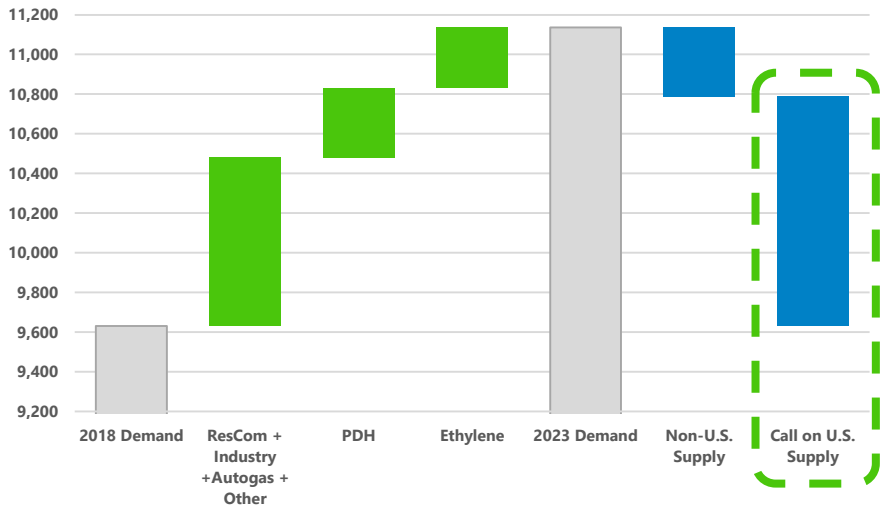
New Demand

- Indian LPG import terminals with capacity of 400 MBPD start up in 2019
- 3 PDH plants in China start up with combined capacity of 80 MBPD in 2019
- Relative economics support use of LPG over naphtha for international steam crackers

Range's Ability to Export Provides Price Diversity



Global LPG Supply/Demand Outlook (MBL/D)(b)



(a) Pie chart represents annual average. Range has the ability to increase domestic sales in winter months when local prices are strong. (b) Additional details on slide 39.

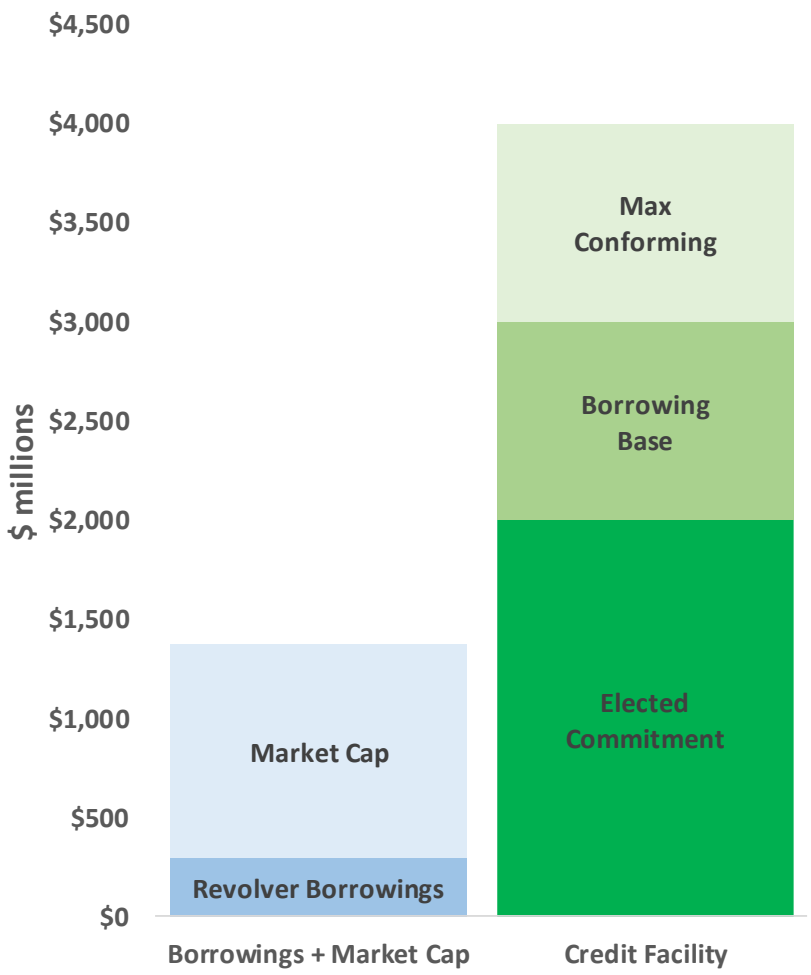
Range is Positioned Well for Low Commodity Prices

Self-Funded Business Model

- Range is growing, generating free cash flow and reducing absolute debt
- Flexible capital program as all of Range's firm transportation commitments have been met
- Shallow base decline supports low maintenance capital requirement
- Low maintenance capital and high capital efficiency promote free cash flow generation through the cycles
- Marcellus inventory enables multi-decade, sustainable free cash flow profile

Liquidity Exceeds Market Cap

- Ample liquidity given sustainable free cash flow profile
- $4B credit facility unanimously ratified in March 2019
- Revolver borrowings expected to be reduced via free cash flow generation and potential asset sales



Note: Revolver borrowings as of 6/30/19, pro forma 2% ORRI sale. Market capitalization as of 8/6/19.

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Appendix

Capital Allocation Framework

Five-Year Outlook @ $2.70 gas / $55 WTI

	Maintenance Capital	Balanced Approach
2019-2023 Cumulative Free Cash Flow	$1.2-$1.3 billion	$1.2-$1.3 billion
Ending Net Debt (Year-End 2023)	$2.7-$2.8 billion	$2.7-$2.8 billion
Year-End 2023 Net Debt/EBITDAX	3.0x - 3.1x	2.0x - 2.1x
2023 Cash Unit Costs per Mcfe	$2.10 - $2.15	$1.87 - $1.92
Base Decline (Exit 2023)	<15%	<20%

Range's capital allocation process begins with **free cash flow** as a priority

Range has **flexibility** to adjust capital spending given:
- shallow base decline
- low maintenance capital and
- firm commitments that have been met

Debt reduction targets have been accelerated with ~$634 million in asset sales in 2019

Unit cost improvement well ahead of schedule. Year-end 2019 cash unit costs expected to be <$2 per mcfe

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

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.
- 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***

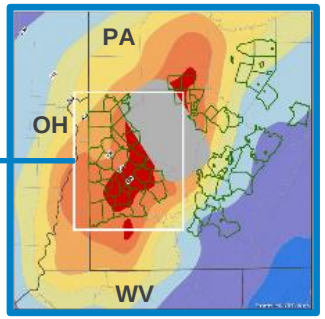
Free cash flow yield - ***Free cash flow / Market Cap***

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

Southwest Appalachia Acreage Position

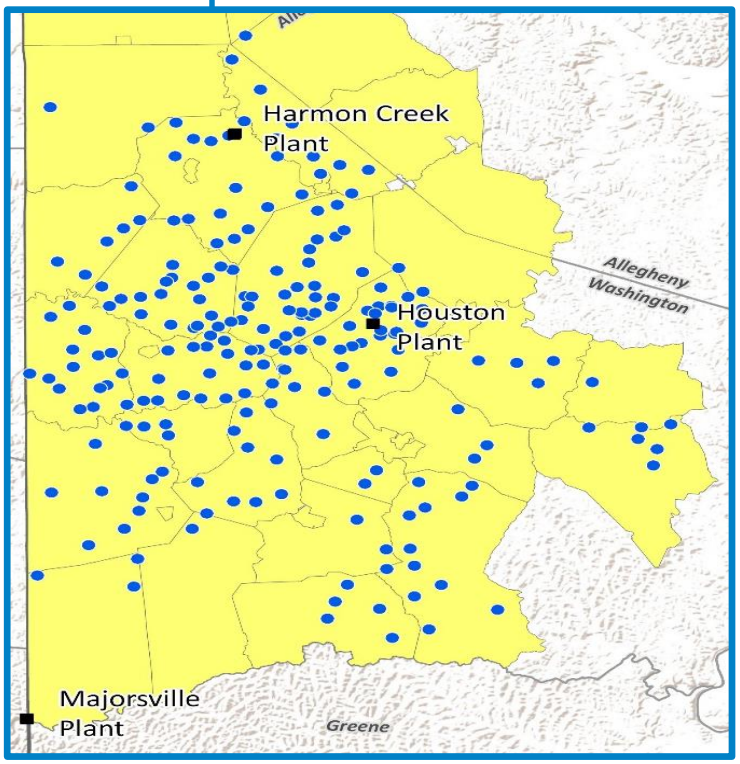
- Longer laterals and existing pads in 2019 provide low-risk efficiency gains
- Liquids and dry optionality with existing pads across acreage position
- Concentrated acreage position simplifies water logistics and drives further cost savings, as Range continues to recycle ~100% of produced water

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



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	54%	61%	62%
IRR* at Strip as of 1/31/2019	39%	47%	46%



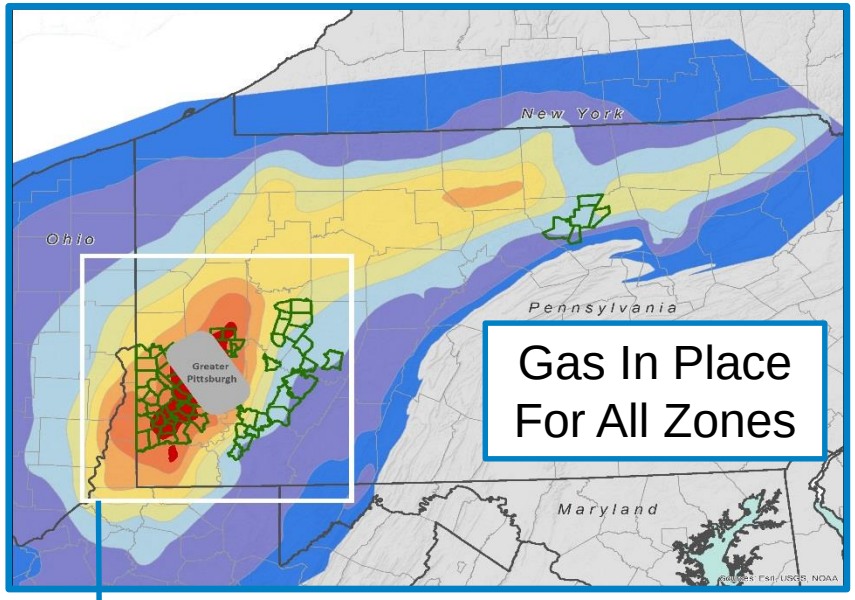
= Existing Pad

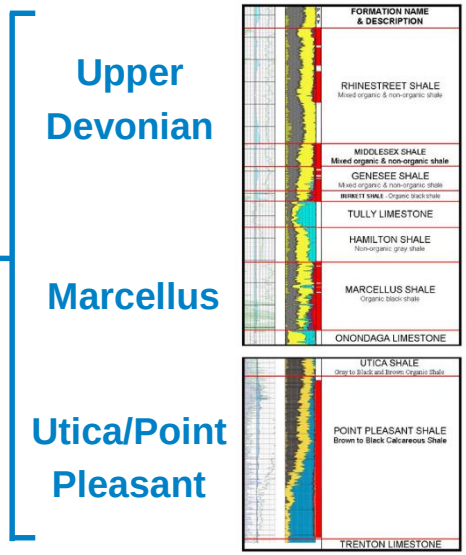
** Returns as of 1/31/19. For flat pricing case, gas price assumed to be $3.00/mcf and oil price assumed to be $60/bbl to life. IRR estimates are pro-forma 2% ORRI sale announced in July 2019.*

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 Core Marcellus 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

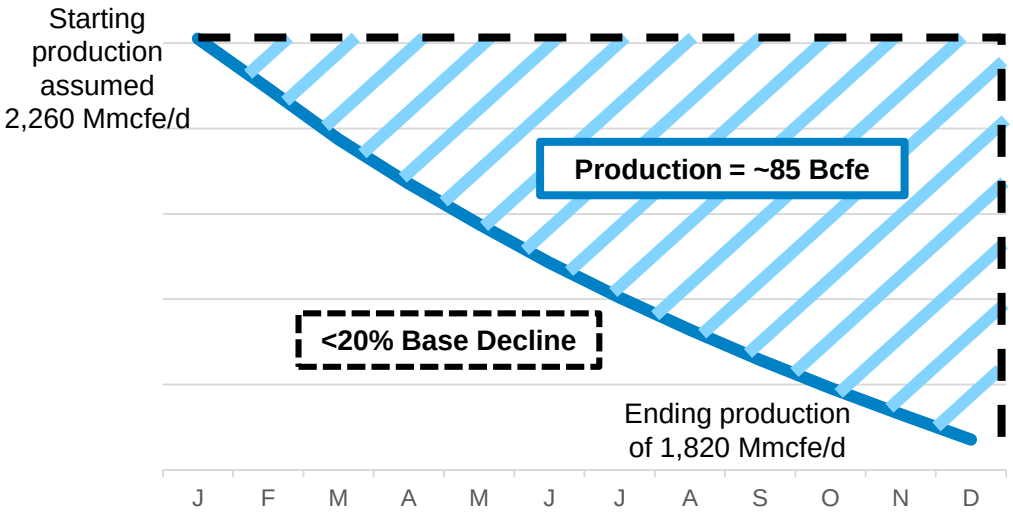
Stacked Pay and Existing Pads Allow for Multiple Development Opportunities





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

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

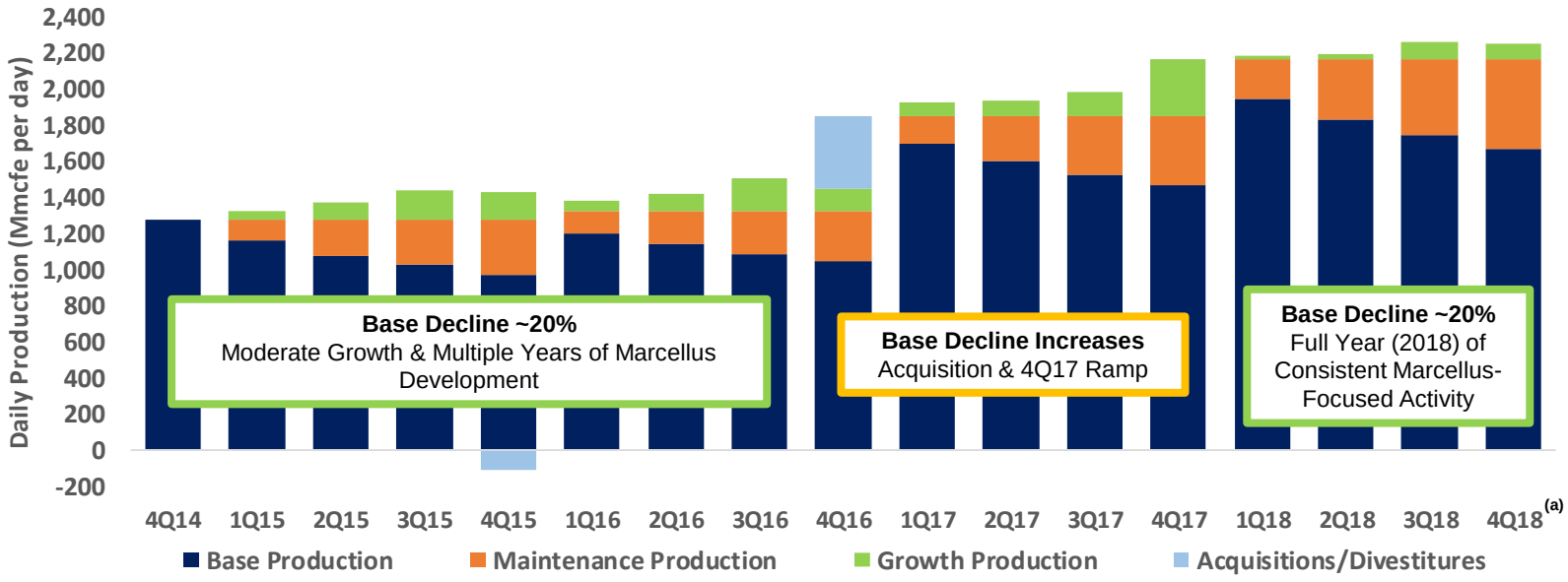
Typical Operating Adjustments[(b)]

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

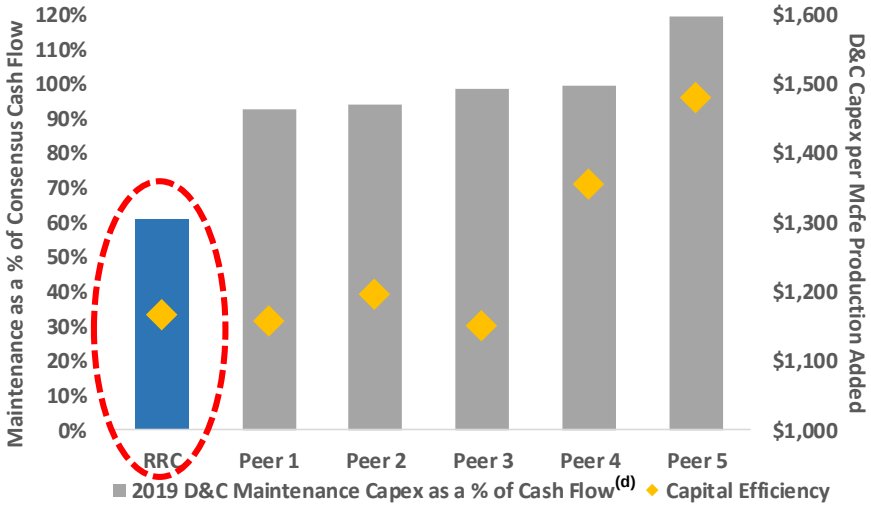
~$525 million Maintenance D&C Capital

(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 - $0.40/mcf

NYMEX Gas Price	Rate of Return
Strip -	**47%**
$3.00 -	**61%**

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

Note: IRR and F&D estimates are pro-forma 2% ORRI sale announced in July 2019.

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 - $0.32/mcf

NYMEX Gas Price	Rate of Return
Strip -	**46%**
$3.00 -	**62%**

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

Note: IRR and F&D estimates are pro-forma 2% ORRI sale announced in July 2019.

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 - $0.33/mcf

NYMEX Gas Price	Rate of Return
Strip -	**39%**
$3.00 -	**54%**

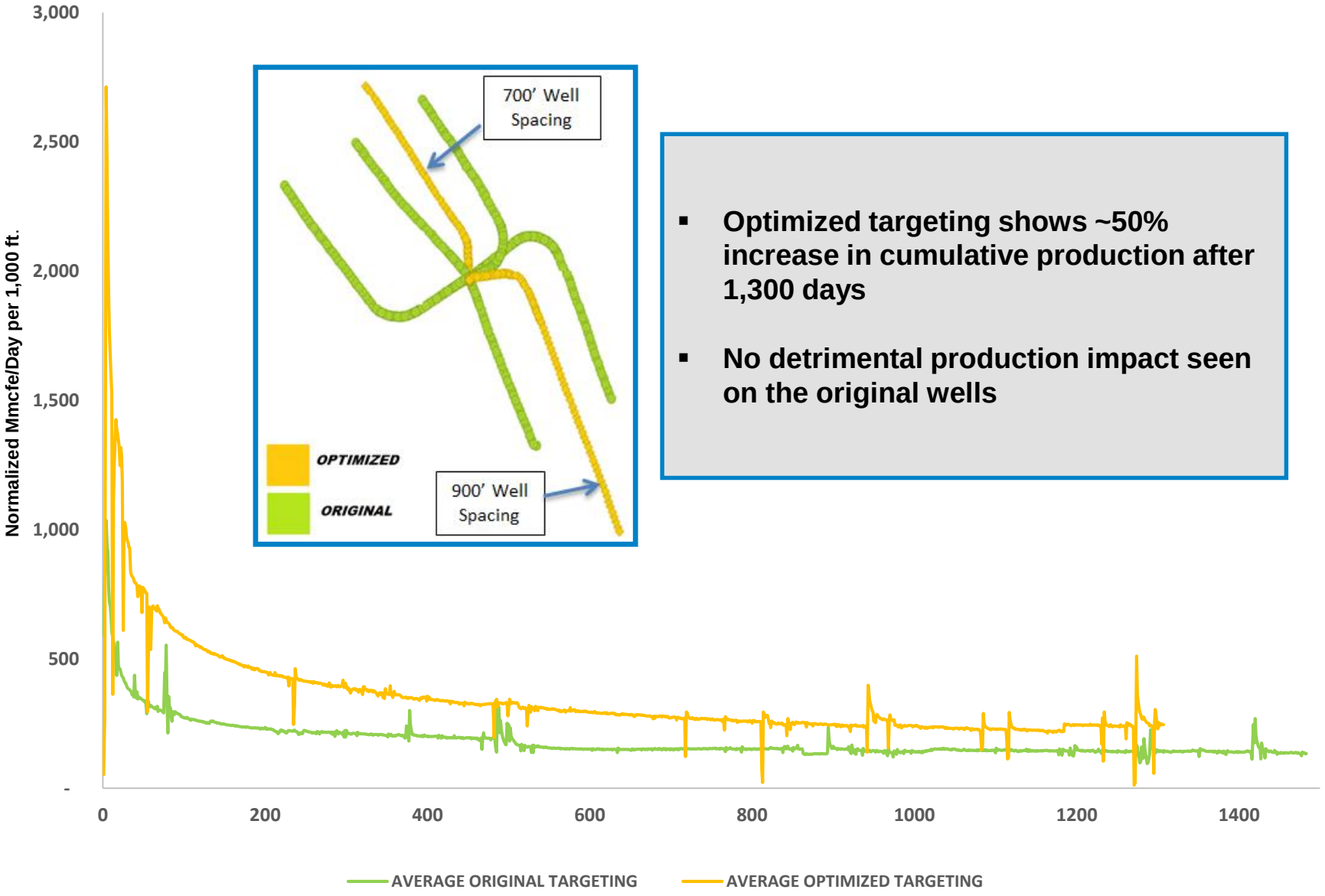
Estimated Cumulative Recovery for 2019 Production Forecast

	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

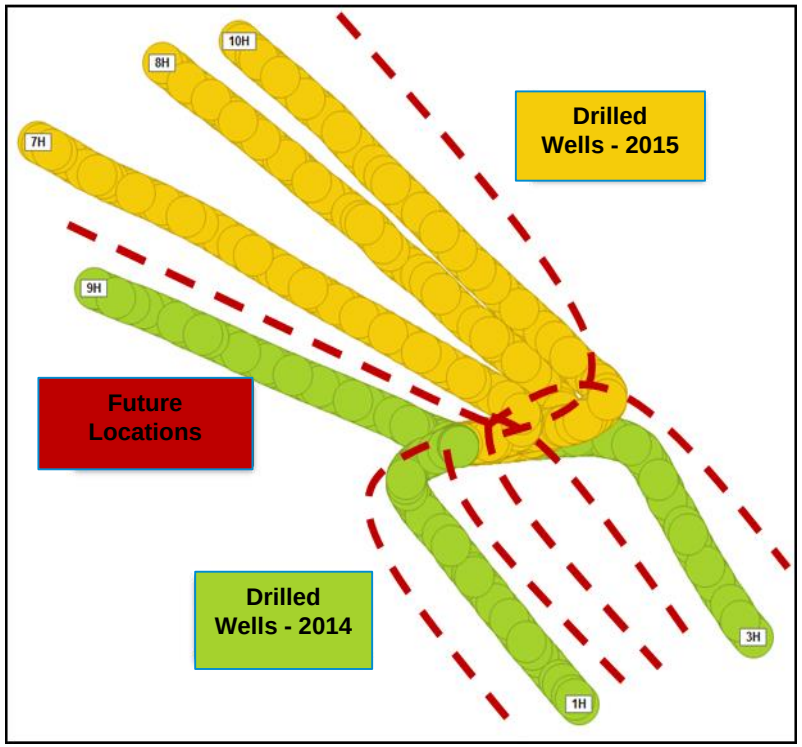
Note: IRR and F&D estimates are pro-forma 2% ORRI sale announced in July 2019.

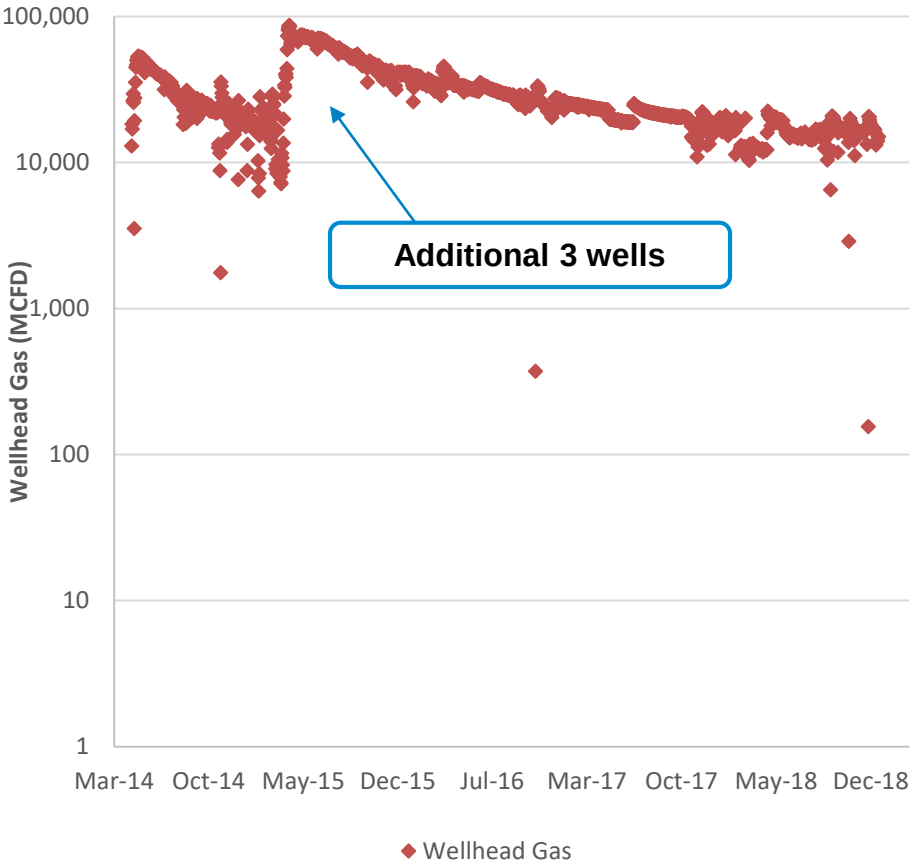
Targeting / Downspacing Production Results



- **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



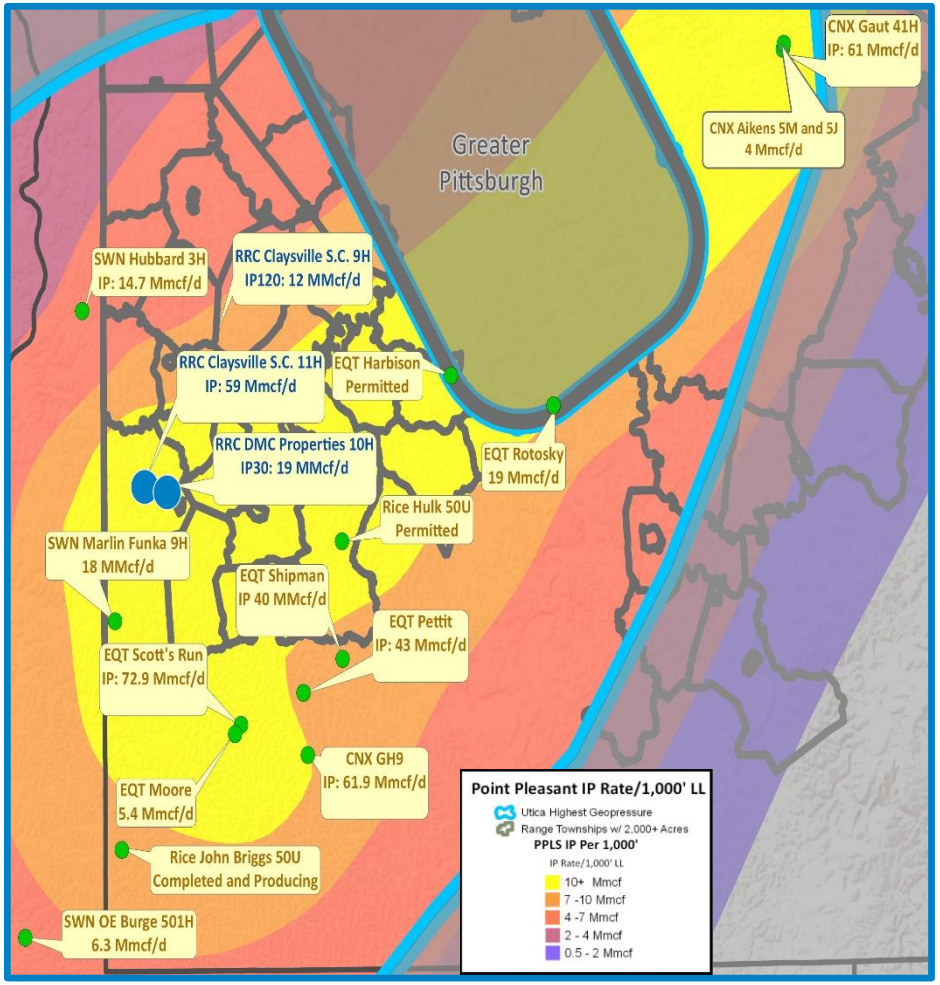


Ability to target our best areas with significant cost savings

Utica Activity

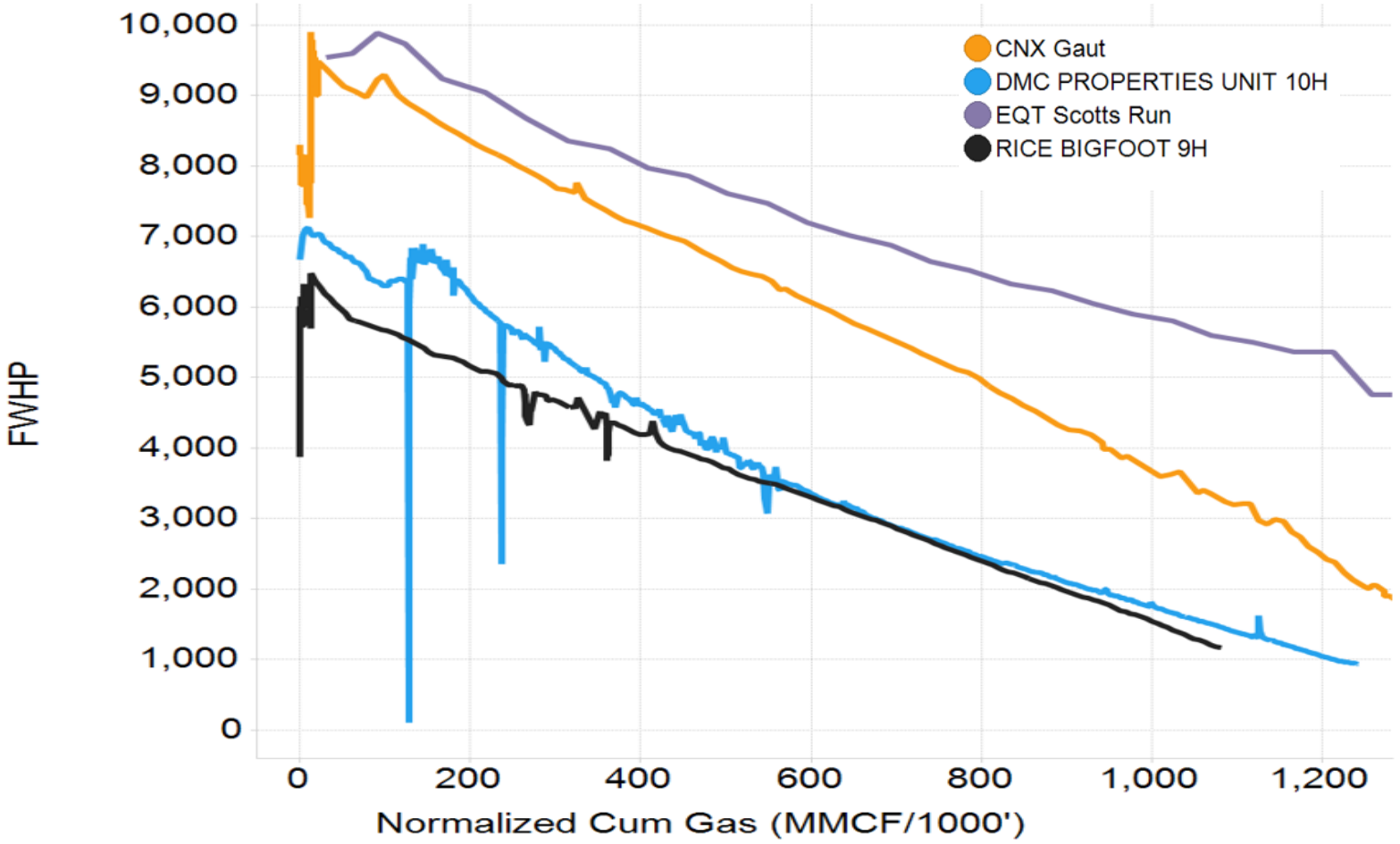
- Range has drilled three Utica wells
- Range's third well appears to be one of the best dry gas Utica wells in the basin (next slide)
- Continued improvement in well performance due to higher sand concentration and improved targeting
- 400,000 net acres in SW PA prospective

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

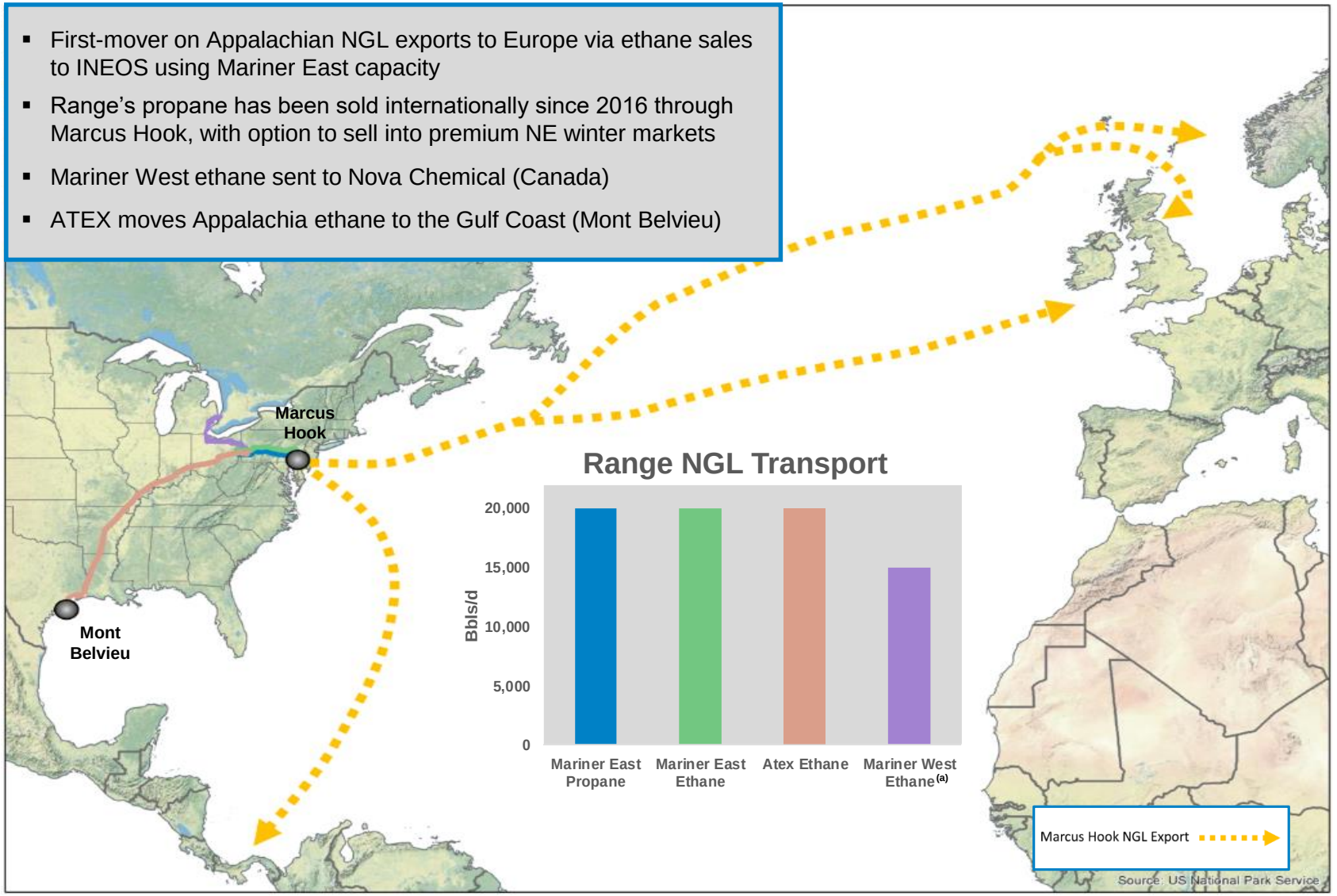
Utica Wells – Wellhead Pressure vs. Cumulative Production



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

Innovative NGL Marketing Agreements Enhance Pricing

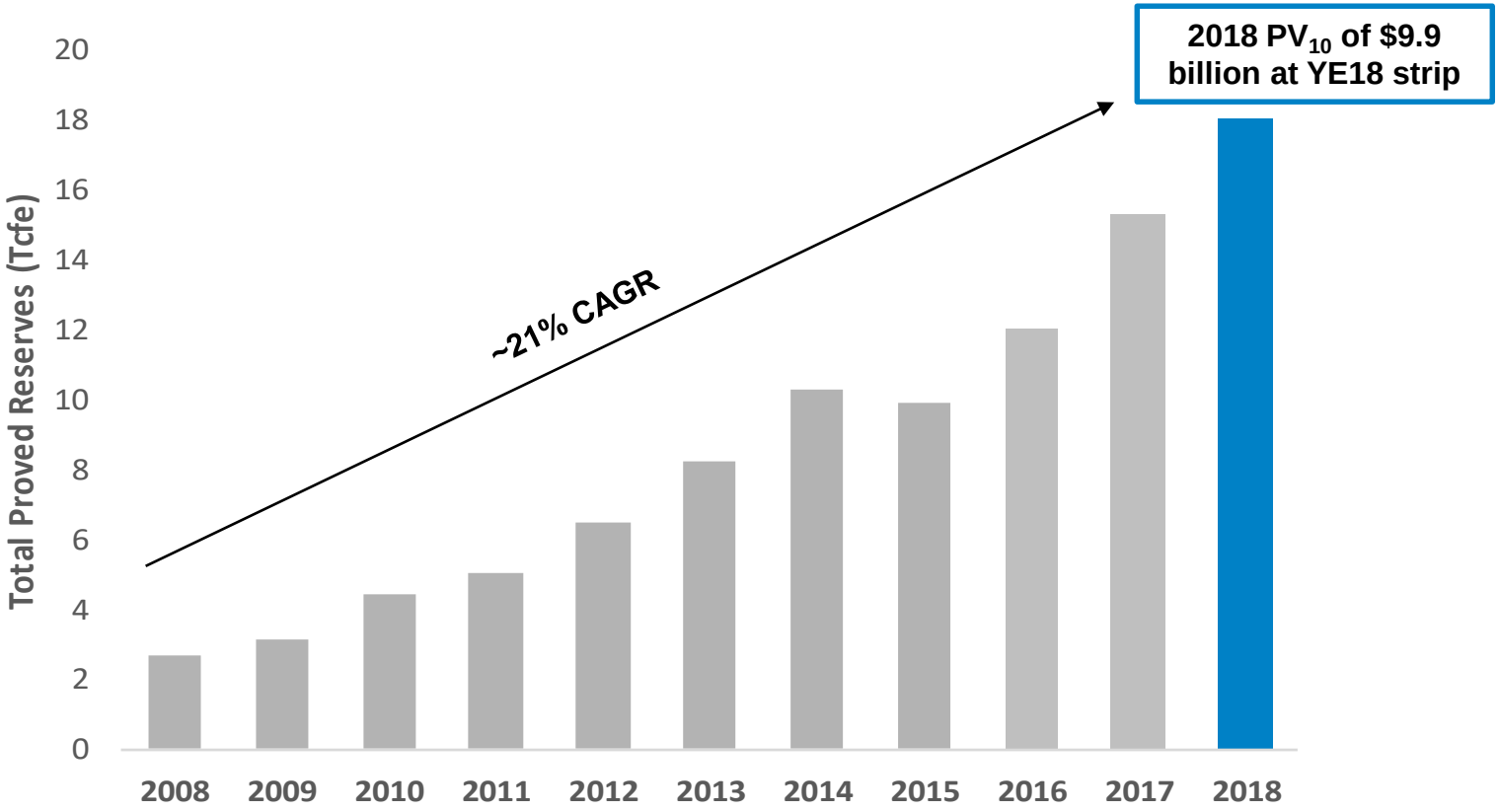
- First-mover on Appalachian NGL exports to Europe via ethane sales to INEOS using Mariner East capacity
- Range's propane has been sold internationally since 2016 through Marcus Hook, with option to sell into premium NE winter markets
- Mariner West ethane sent to Nova Chemical (Canada)
- ATEX moves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

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

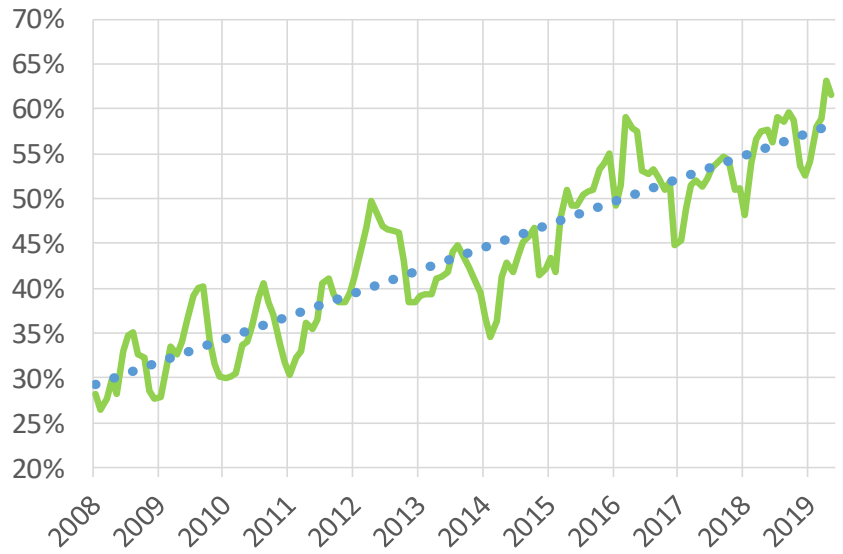
Growing Market Share in Power Gen.

- **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

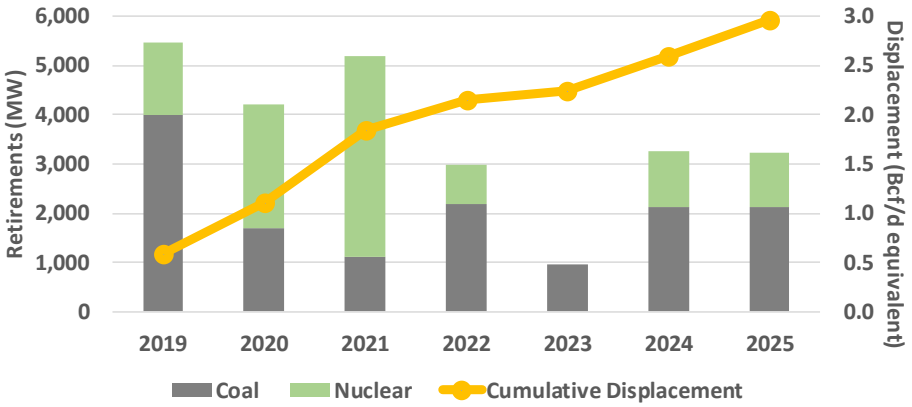
- **25 Bcf/d of coal generation remains to be displaced, or ~27% of U.S. Power Generation Mix**
- **53 GW of coal plant capacity retired from 2013-2018, and another 22 GW of plant retirements have already been announced for 2019-2024**
  - **More retirement announcements expected to occur in coming months/years**
- **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



Source: EIA

(a) Assumes 7x Heat Rate for gas equivalence

Shale Efficiency Gains Are Slowing

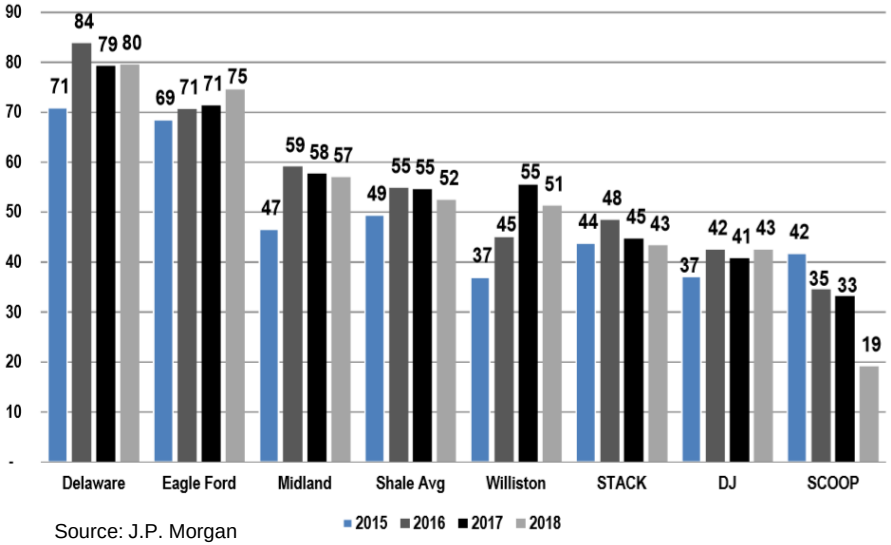
Oil Basins

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

Haynesville

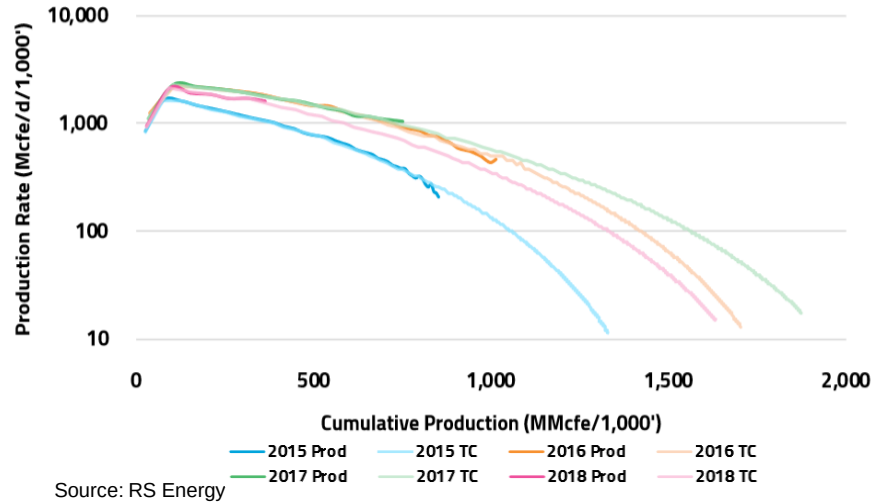
- Well productivity in the Haynesville appears to have plateaued
- Runway for current productivity may be limited given current pace of development in the play and that the core is known to be small
- Private operators may be forced to reduce growth as traditional exit strategies have become challenged

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

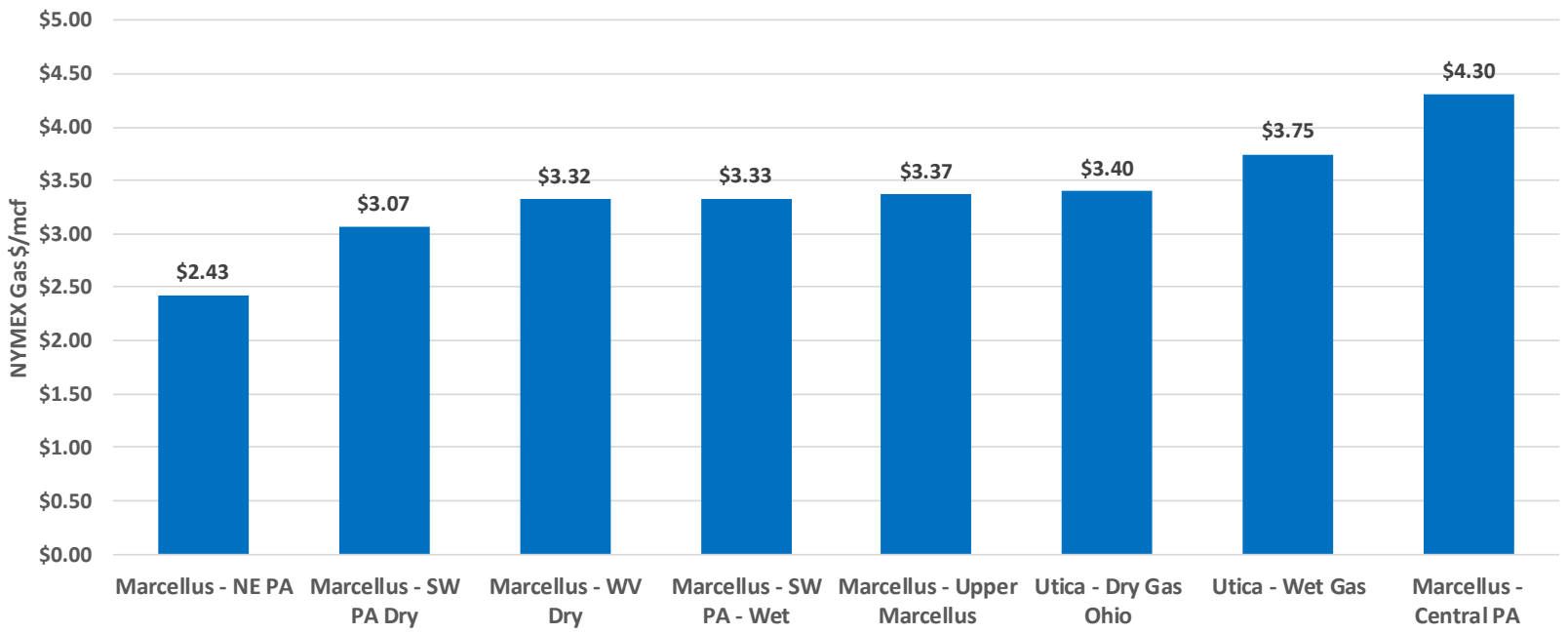
Supply Growth Needed from Dry Gas Basins

- **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

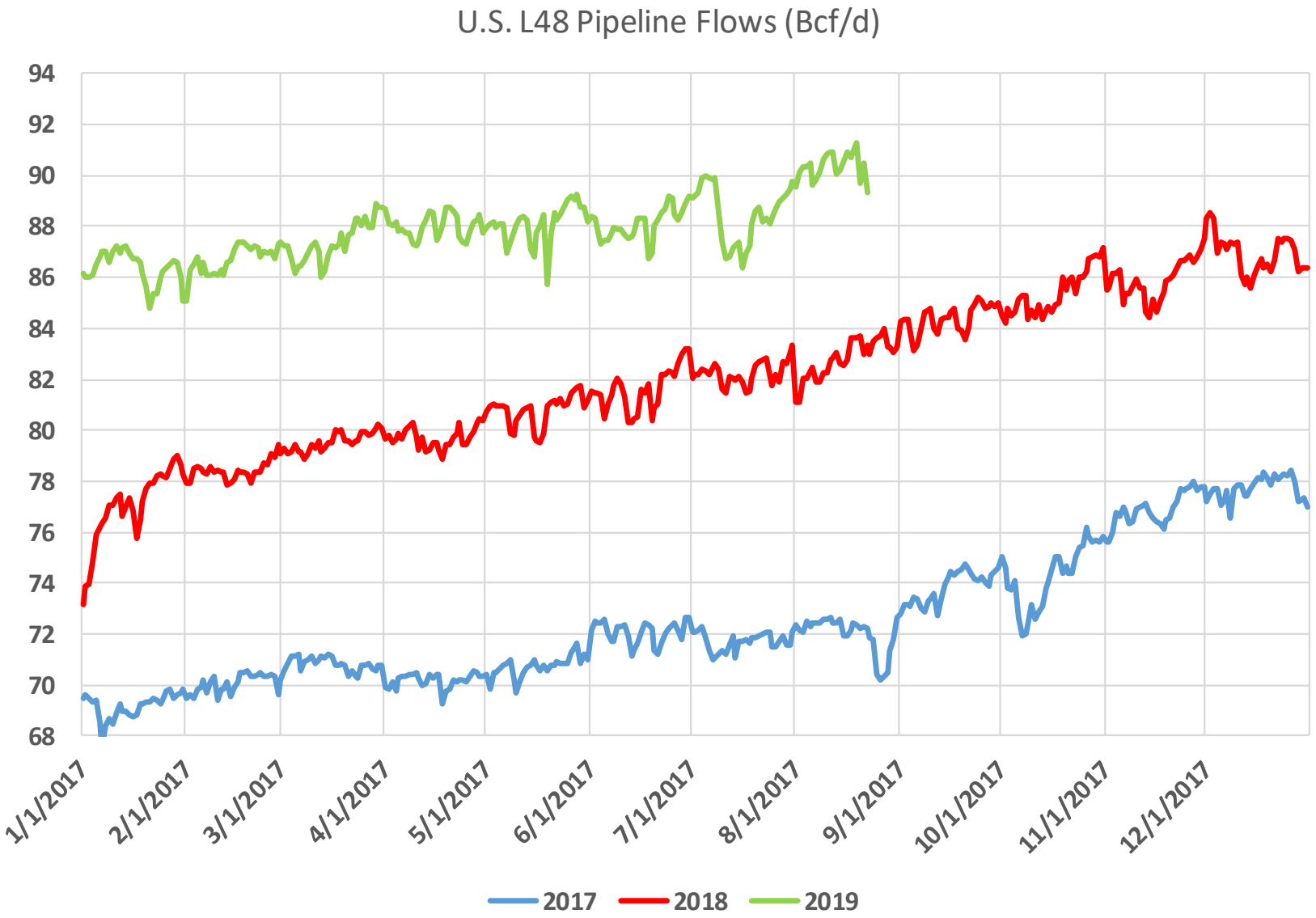
- **Northeast PA will face constraints given current lack of infrastructure**
- **Dry gas basins likely require >$3/Mmbtu natural gas to support sustainable growth**

Basin Break-Evens Above NYMEX Futures Curve



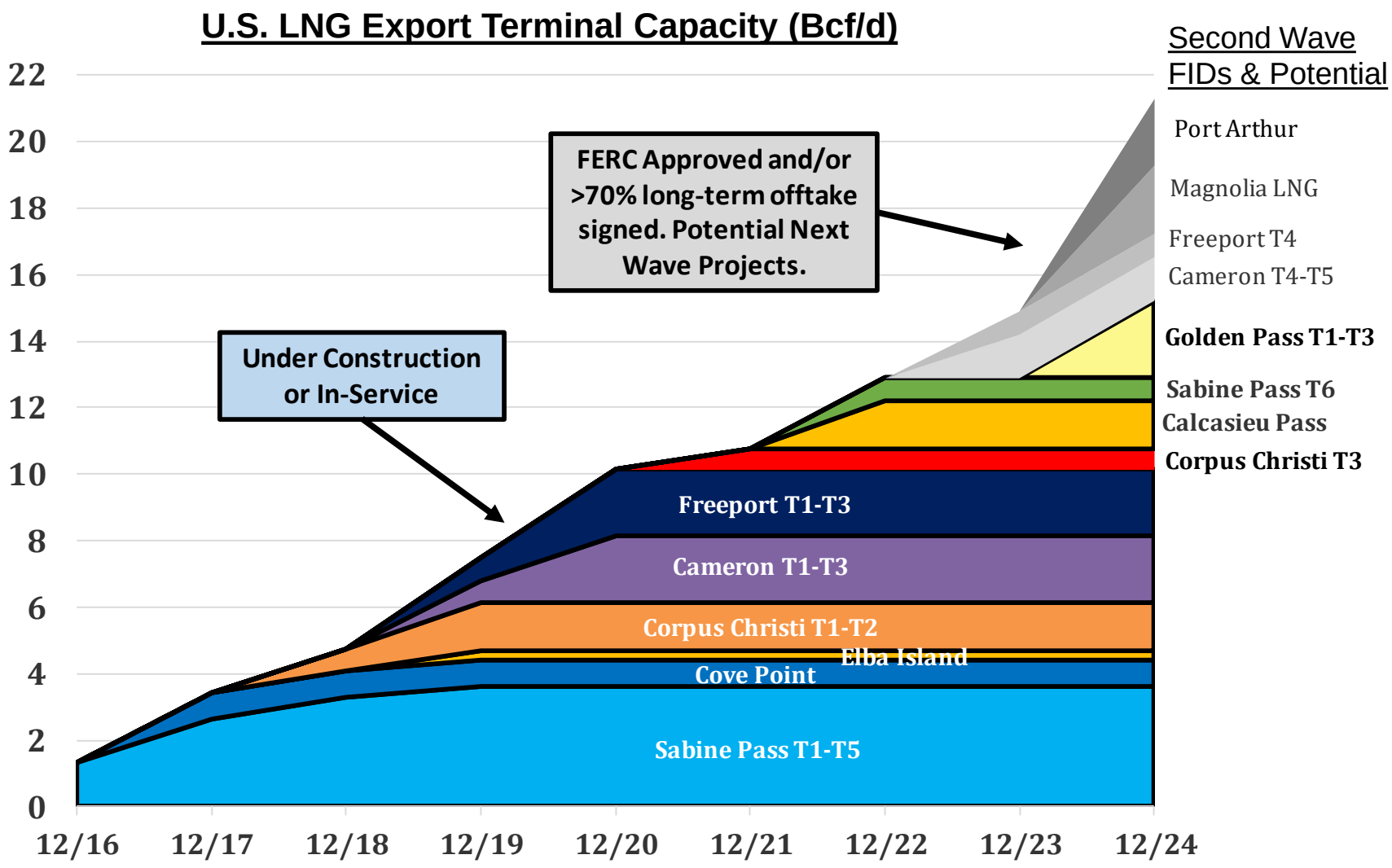
Source: J.P. Morgan. Break-evens assume 25% pre-tax full-cycle rate of return to account for corporate G&A, interest expense and acreage costs.

L48 Dry Gas Production Growth Slowing



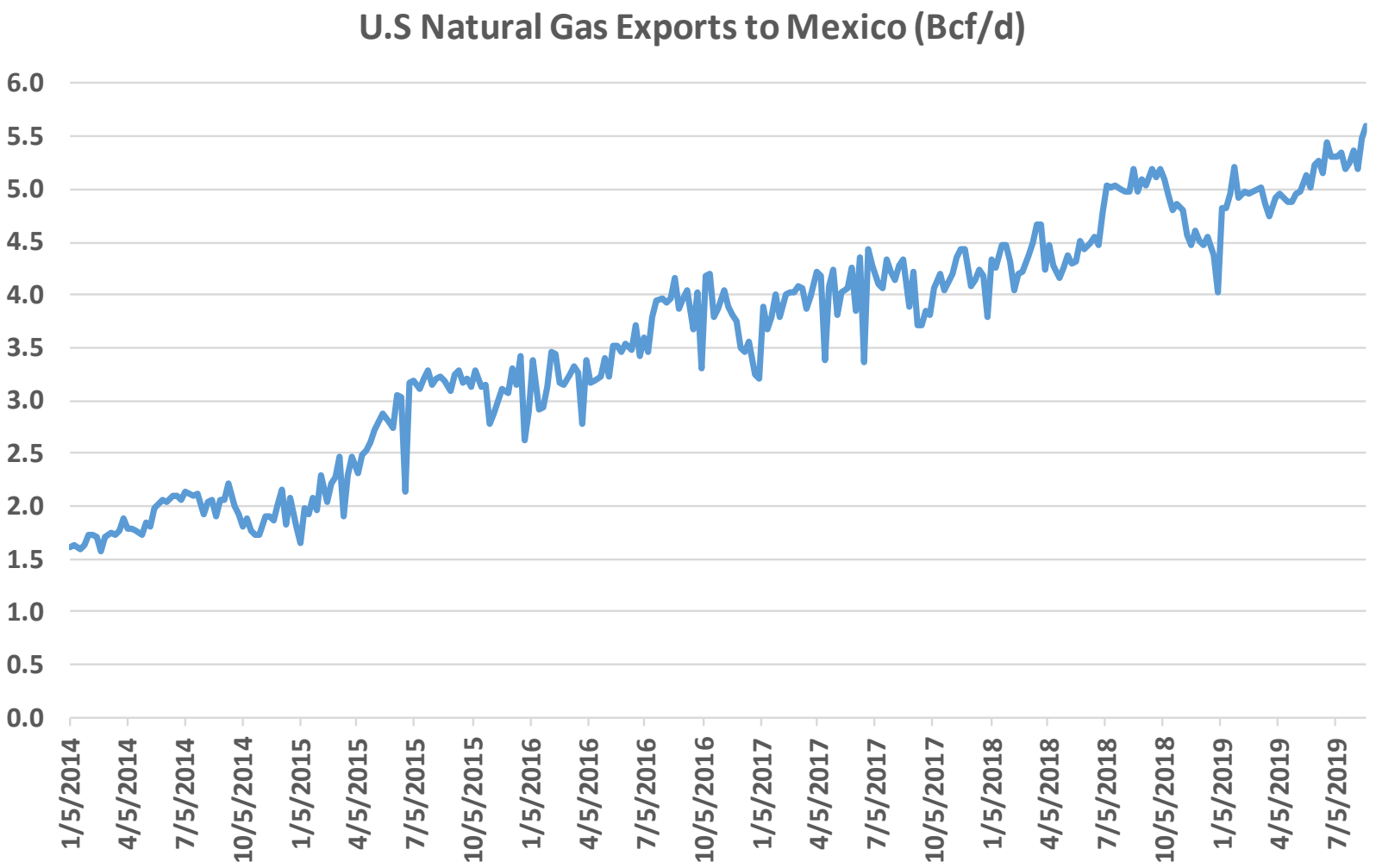
Source: Platts

LNG Growth Expected to Continue



Source: Operator Estimates

U.S. Natural Gas Exports to Mexico Making New Highs



Source: Bloomberg

NGL Macro Outlook

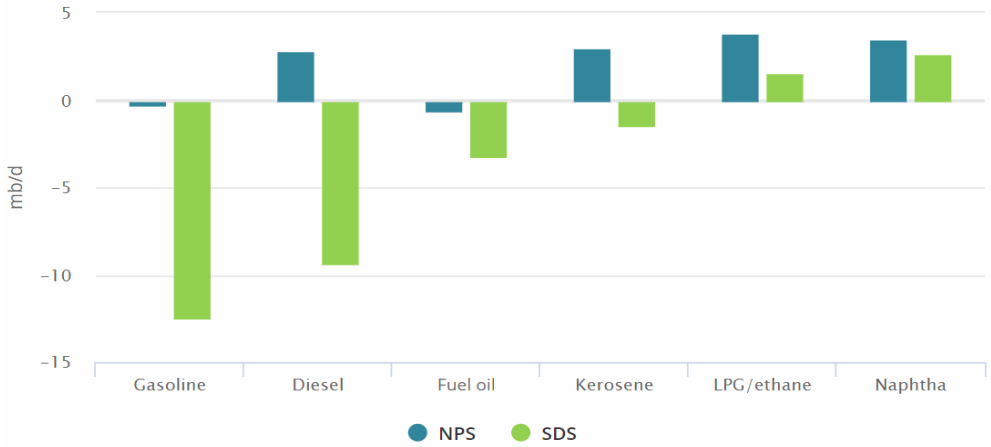
NGL Demand

- 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
- U.S. waterborne export capacity increases in 2019 equivalent to ~15% of U.S. LPG supply, which should tighten balances going forward

Fractionation Tightness to Return in 2019

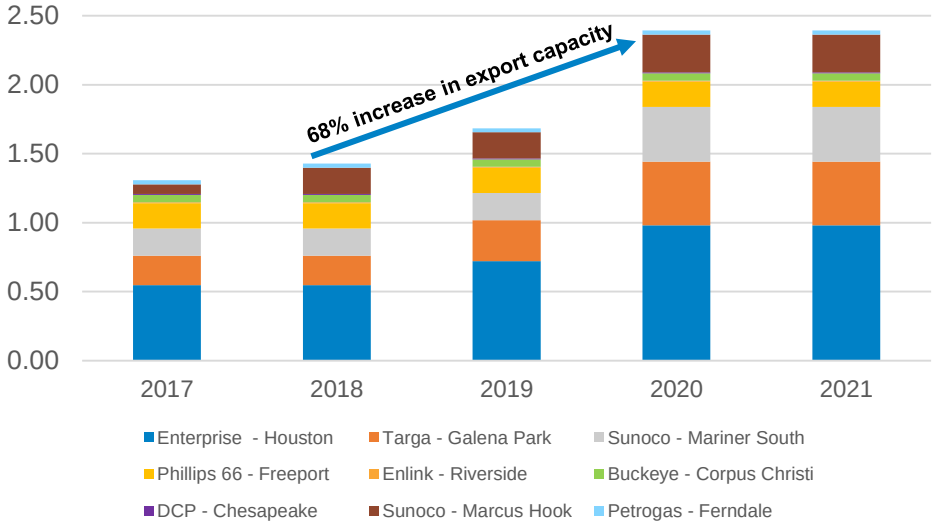
- NGL price rally in Summer 2018 was driven by U.S. fractionation capacity tightness that was temporarily relieved by:
  - Winter weather driving natural gas price spikes and lower C2 recovery
  - Midwest C3 being consumed locally rather than flowing to the Gulf Coast
- Range expects fractionation tightness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

2017-2040 Change in Global Oil Product Demand by Scenario



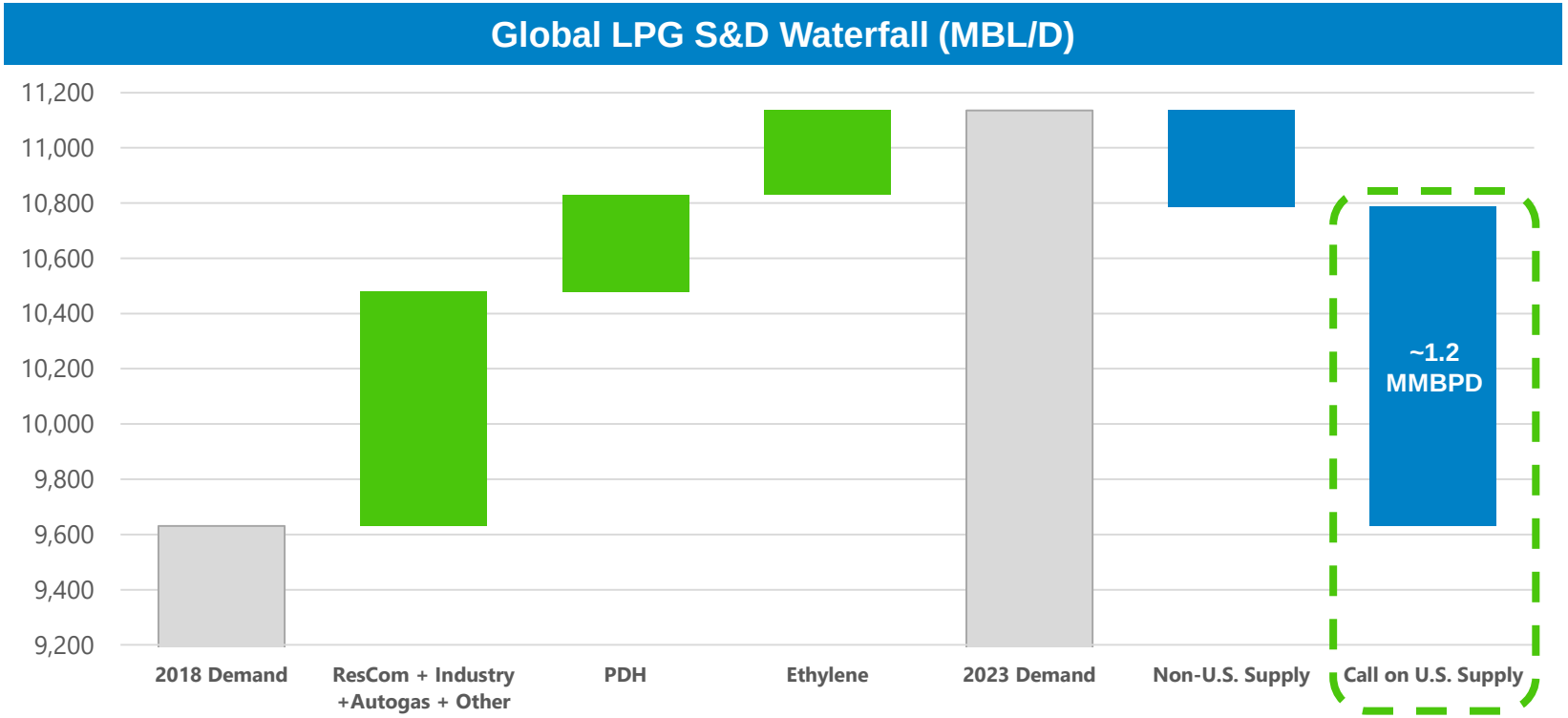
Source: IEA World Energy Outlook 2018 (NPS = New Policy Scenario, SDS = Sustainable Development Scenario)

U.S. LPG Export Capacity (MMBL/D) Set to Increase



Source: Operator Estimates

Global LPG Demand Forecast Absorbs Growing U.S. Exports



- **U.S. LPG Export Capacity to expand by 970 MBL/D (68%) by end 2020.**
- **Global LPG demand grew ~4.5% 2013-18, and is forecast to grow ~3% 2018-23, driven by ~700 MBL/D of PDH and Ethylene plants under-construction or post-FID.**
- **ResComm (~51% of demand in 2018) is driven by continued adoption rates in China, India, Indonesia and others for those without access to electricity.**
- **Indian LPG import terminals with capacity of 400 MBL/D start up in 2019.**
- **Relative economics support use of LPG over naphtha for international steam crackers. In an oversupply case, converting just 10% of the global naphtha ethylene cracking fleet would absorb a further 600 MBL/D of LPG.**
- **Call on U.S. Supply is 1,200 MBL/D 2018-23, versus consultant supply growth forecasts of ~750 MLB/D.**

Source: EIA, Energy Aspects, Genscape, IEA

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Financial Detail

Guidance

	3Q 2019	Full-Year 2019
Production (Bcfe per day)	**~2.25 to 2.26**	**~2.3**
Capital Expenditures		**$756 million**
Operating Expense Guidance		
Direct Operating Expense per mcfe	$0.16 - $0.17	
TGP&C Expense per mcfe	$1.45 - $1.48	
Production Tax Expense per mcfe	$0.04 - $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	$0.20 - $0.22	
DD&A Expense per mcfe	$0.68 - $0.72	
Net Brokered Marketing Expense	$6 million	
Pricing Guidance		
Natural Gas Differential to NYMEX	($0.29)	($0.15) - ($0.20)
Natural Gas Liquids (a)		Mont Belvieu minus $1.20 to $1.30 per barrel
Oil/Condensate Differential to WTI		($6.00) - ($8.00)

(a) Weighting based on 53% ethane, 27% propane, 7% normal butane, 4% iso-butane and 9% natural gasoline. See Supplemental Table 9 on the Company's website for more detail.

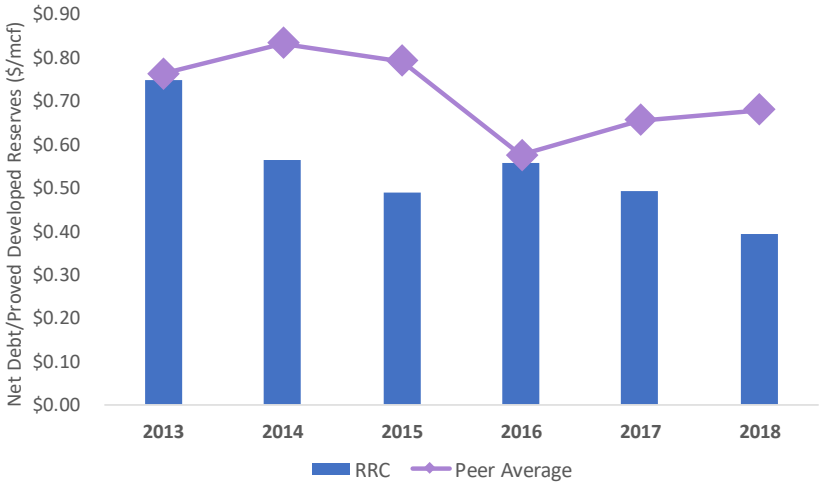
Well-Structured, Resilient Balance Sheet

- $4 billion credit facility, ($3B borrowing base, $2B committed)
- Simple capital structure
- Near-term cash flow protected with hedges
- Ample cushion on financial covenants[a]
  - Interest coverage ratio[b] of ~6.3x versus covenant of at least 2.5x
  - Current ratio[c] of ~4.4x versus covenant of at least 1.0x
  - Asset coverage test[d] of ~3.1x versus covenant of at least 1.5x

Capital Structure[a]

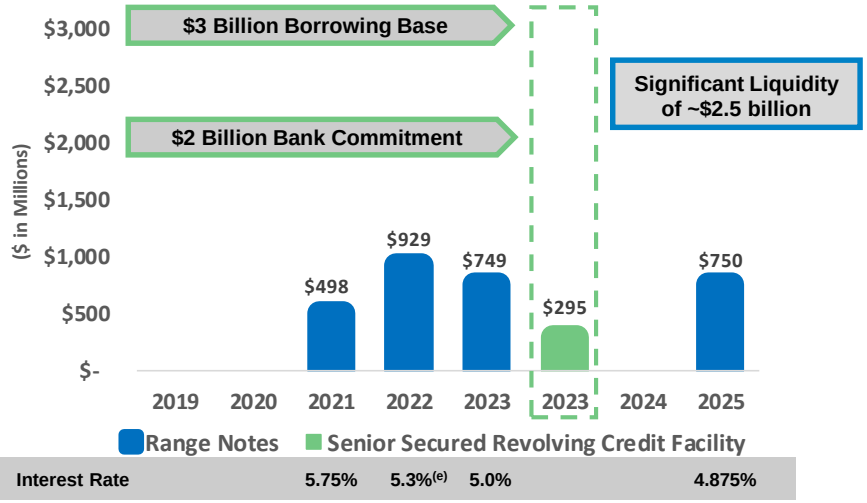
(millions)	2Q19
Bank Debt	$ 295
Senior Notes	2,877
Senior Sub Notes	49
Debt	3,221
Debt to Capitalization	43%
Debt/TTM EBITDAX	2.9x

Debt/Proved Developed Reserves



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

Debt Maturity Schedule[a]



(a) As of 6/30/19, pro forma 2% ORRI sale announced in July 2019 (b) Excludes non-cash interest expense (c) Calculated as (Current assets excluding derivatives + unused revolver capacity) / (current liabilities excluding derivatives) (d) Defined as PV-9 of reserves divided by total debt (e) Weighted-average interest rate of 2022 notes

Development Cost & Recycle Ratio Calculation

Cash margin per mcfe / PUD development costs per mcfe.

Numerator:			
1H19 Pre-Hedge Realized Price	$	3.04	per mcfe
1H19 All-In Cash Costs	$	2.11	per mcfe
Adjusted Margin per Mcfe	$	0.93	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		**2.3x**	

Natural Gas & Liquids Hedging Status

	Time Period	Volumes Hedged (Mmbtu/day)	Average Hedge Prices ($/Mmbtu)
Natural Gas[1] (Henry Hub)	3Q19 Swaps	1,409,946	$2.80
	4Q19 Swaps	1,428,261	$2.82
	FY20 Swaps	487,541	$2.77

	Time Period	Volumes Hedged (bbl/day)	Average Hedge Prices ($/bbl)
Oil (WTI)	3Q19 Collars	1,000	$63 x 73
	4Q19 Collars	1,000	$63 x 73
	3Q19 Swaps	8,500	$55.82
	4Q19 Swaps	9,000	$55.95
	FY20 Swaps	4,617	$60.48

	Time Period	Volumes Hedged (bbls/day)	Average Hedge Prices ($/gal)
Natural Gasoline (C5)	3Q19 Swaps	5,500	$1.352
	4Q19 Swaps	3,500	$1.367

**As of 6/30/19*

1) Range also sold call swaptions of 20,000 Mmbtu/d for winter 2019/2020, 290,000 Mmbtu/d for calendar 2020, and 50,000 Mmbtu/d for calendar 2021 at average strike prices of $3.20, $2.80, and $2.75 per Mmbtu, respectively.

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