April 28, 2016

RANGE RESOURCES®

Company Presentation

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, such as those regarding future liquidity, future production growth, future completion of ethane projects, estimated gas in place, future rates of return, future low costs, low reinvestment risk, future earnings and per-share value, future capital spending plans, increasing capital efficiency, continued utilization of existing infrastructure, gas marketability, maximized realized natural gas prices, acreage quality, access to multiple gas markets, expected drilling and development plans, improved capital efficiency, future financial position, future technical improvements, future marketing opportunities, future market improvements, maximizing future rates of return, strong inventory of uncompleted wells, expectation to create future value, expected lower well costs, acreage prospective for other horizons, expected future asset sales and future guidance information are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. 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, including, but not limited to, the volatility of oil and gas prices, the results of our hedging transactions, the costs and results of actual drilling and operations, the timing of production, mechanical and other inherent risks associated with oil and gas production, weather, the availability of drilling equipment, changes in interest rates, litigation, uncertainties about reserve estimates, environmental risks and regulatory changes. Range undertakes no obligation to publicly update or revise any forward-looking statements. Further information on risks and uncertainties is available in Range's filings with the Securities and Exchange Commission ("SEC"), which are incorporated by reference.

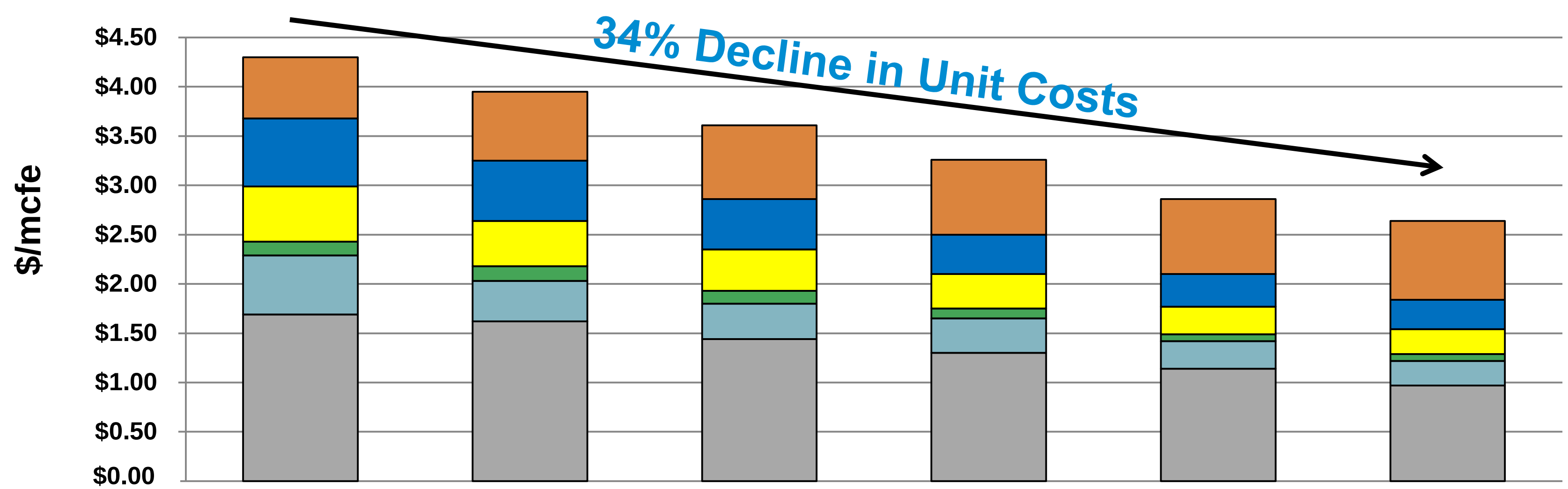
The SEC permits oil and gas companies, in filings made with the SEC, to disclose proved reserves, which are estimates that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions as well as the option to disclose probable and possible reserves. Range has elected not to disclose the Company's 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 and completion services and equipment, lease expirations, transportation constraints, regulatory approvals, field spacing rules, recoveries of gas in place, length of horizontal laterals, actual drilling and completion 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's Keys for Success

- Low cost structure with ability to continue driving costs down
- Improving capital efficiency
- Shallow base decline rate, 19% in 1st year, allows a minimal level of capex to hold production flat, ~$300 million for 2017
- New takeaway capacity projected to improve realizations for natural gas, NGLs and condensate
- Low-cost takeaway capacity with built-in flexibility
- Strong 2016 hedges and ample liquidity with no near-term debt maturities
- High quality, large scale acreage position containing repeatable projects with good returns improving further as costs are reduced

Driving Down Unit Costs



	2011	2012	2013	2014	2015	2016E
DD&A	$1.69	$1.62	$1.44	$1.30	$1.14	$0.96[2]
LOE[1]	$0.60	$0.41	$0.36	$0.35	$0.26	$0.23
Prod. Taxes	$0.14	$0.15	$0.13	$0.10	$0.07	$0.06
G&A[1]	$0.56	$0.46	$0.42	$0.35	$0.27	$0.24
Interest	$0.69	$0.61	$0.51	$0.40	$0.33	$0.29
Trans. & Gathering	$0.62	$0.70	$0.75	$0.76	$0.78	$1.05[3] ($0.25)[4]
Total	$4.30	$3.95	$3.61	$3.26	$2.85	$2.58

(1) Excludes non-cash stock compensation
(2) 1Q 2016 DD&A was $0.96
(3) Includes additional NGL & natural gas firm transport agreements. Propane transport costs were previously netted against NGL revenue. Incremental natural gas & NGL revenue, including additional ethane production, will more than offset the 2016 increase in transport expense
(4) Expected improvement in differentials as a result of additional transportation capacity

Appalachian Peers Well Cost Comparison

	Average Well Cost*	Average Lateral Length	Cost per 1,000 ft.
	($000's)	*(feet)*	*(per 1,000 feet)*
Range	**$5,630**	**6,876**	**$819**
Peer A	6,300	7,000	900
Peer B	8,500	9,000	944
Peer C	6,700	7,000	957
Peer D	7,350	7,500	980
Peer E	8,000	7,000	1,143
Peer Average	**$7,370**	**7,500**	**$983**

Peer group includes AR, COG, EQT, RICE, SWN. Peer data comes from most recent presentations.
*** Costs should include surface facilities.**

Unhedged Recycle Ratio

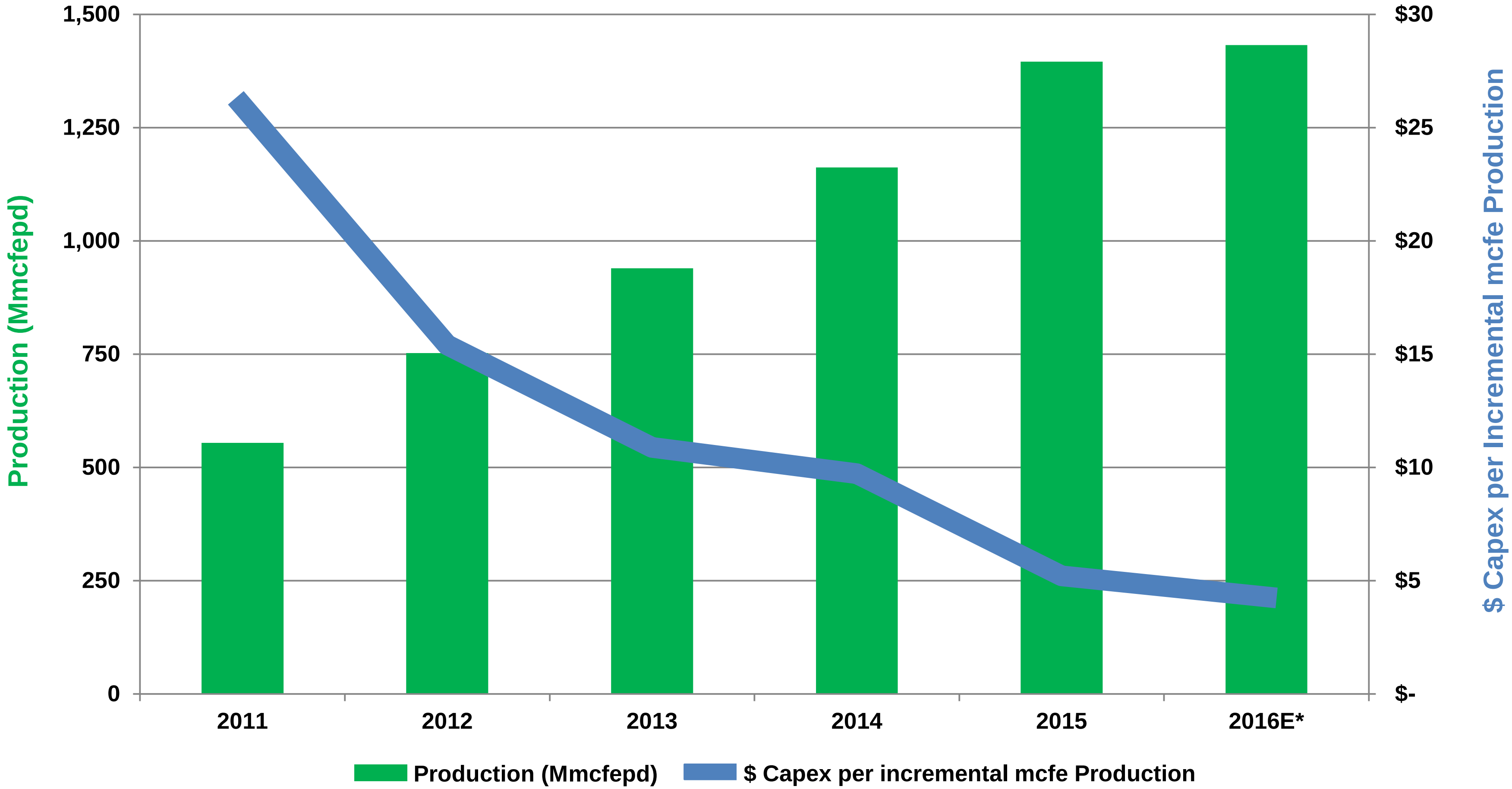
Recycle Ratio: (Margin divided by F&D)

Assumed 2017 Natural Gas price*:	**~$3.00**
Less: 2016 Expected Corp. differential	**$0.42**
2016 Expected All-in cash unit costs	**$1.87**
Adjusted Margin	**~$0.71**
Expected future development Cost for PUD reserves	**$0.40**
Unhedged Recycle Ratio	**1.8**

*** Natural gas strip price as of 4/27/16**

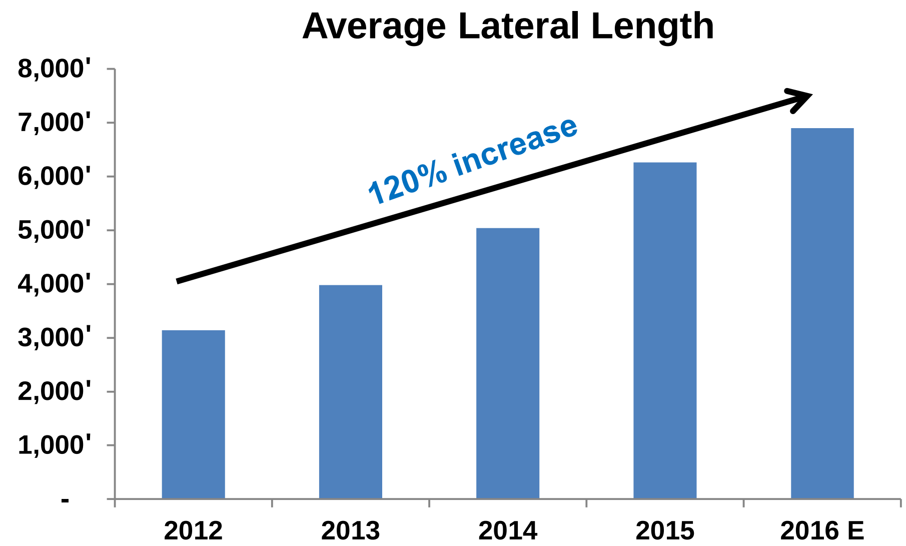
Sustained Growth with Improving Capital Efficiency

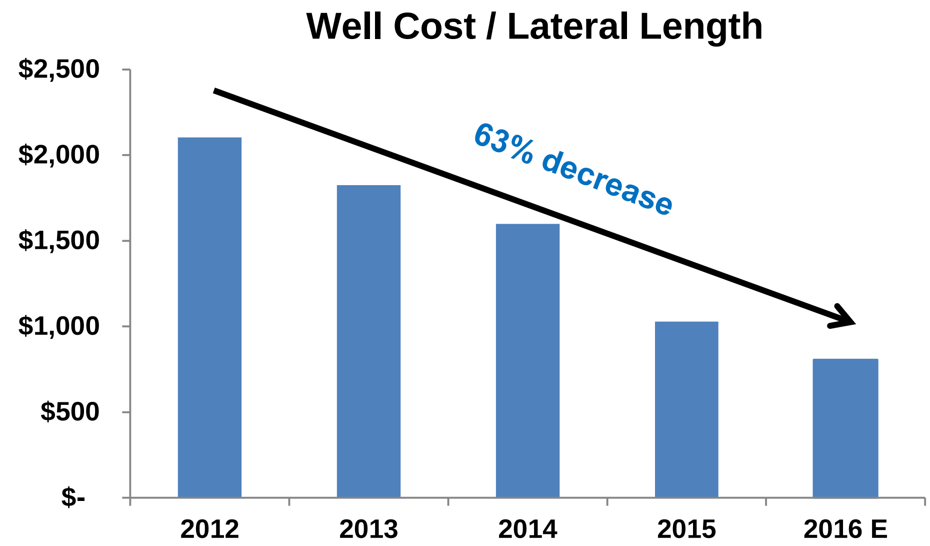
Range has one of the most capital efficient spending programs in the sector

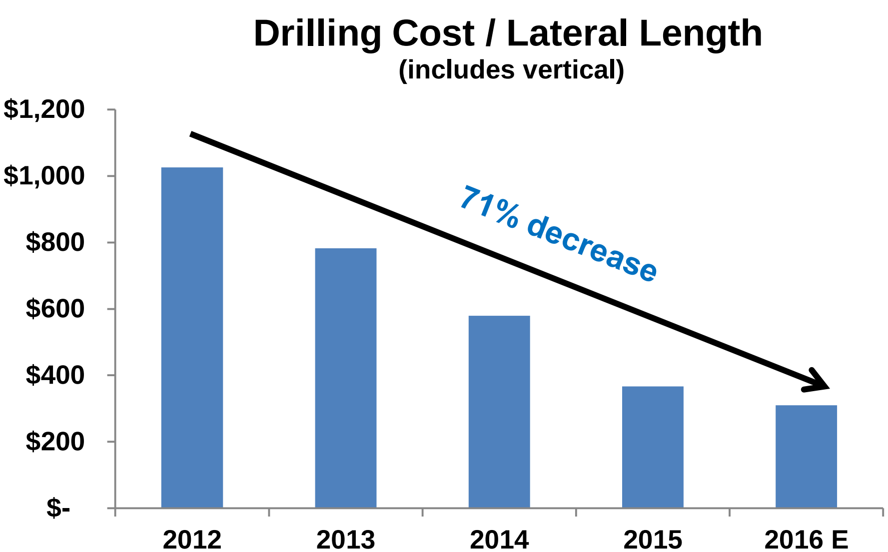


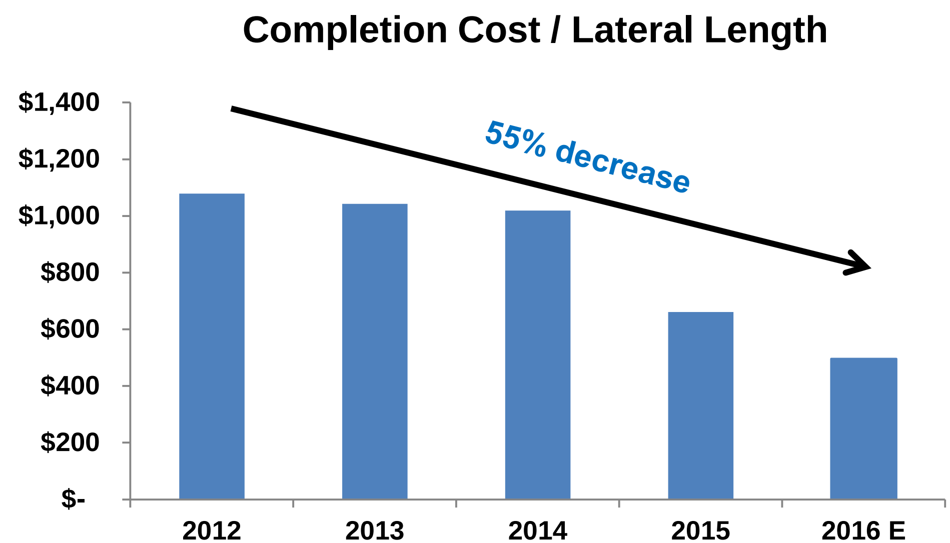
*** 2016 production estimated at midpoint of guidance with capital budget of $495 million**

Cost & Efficiency Improvements – SW Pennsylvania

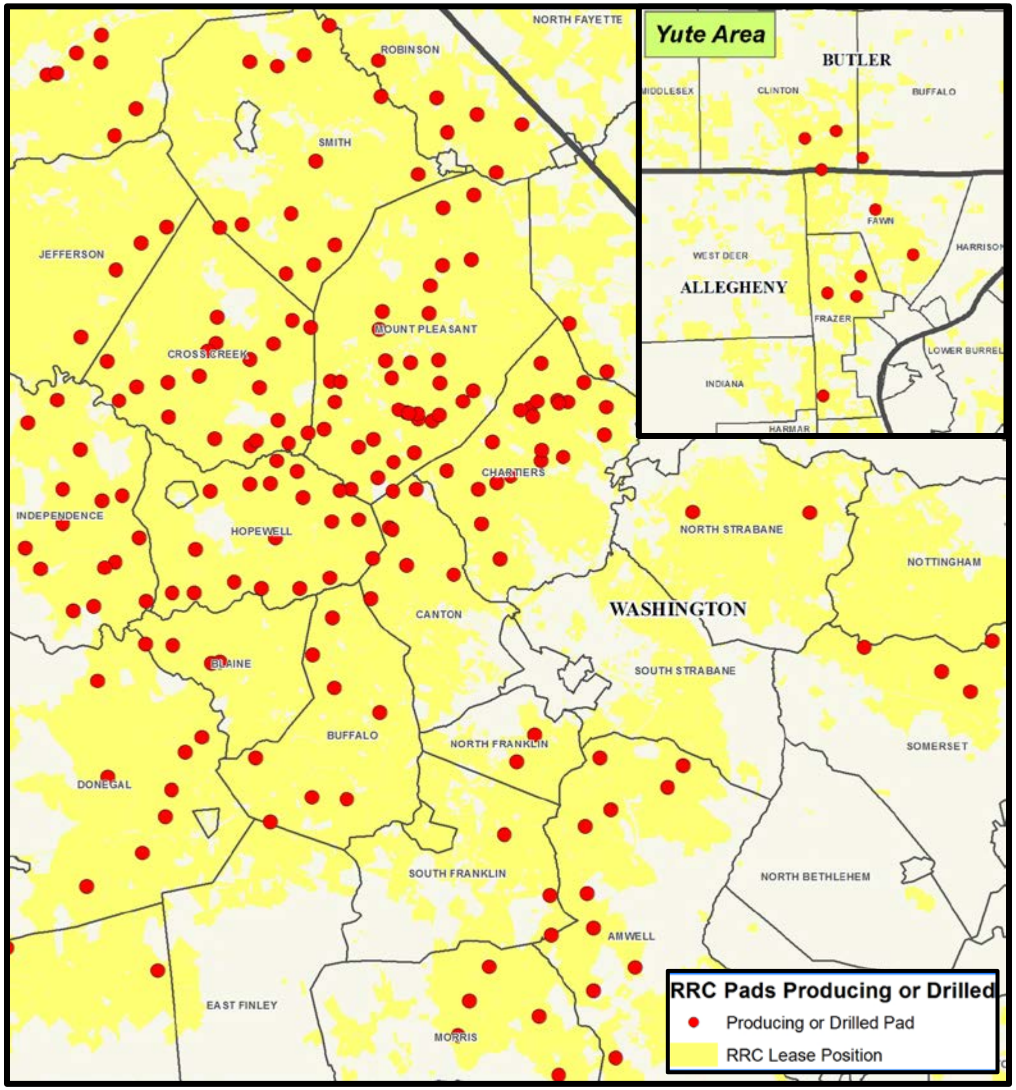








Over 180 Existing Pads Facilitate Future Development



- 124 pads with 5 or fewer wells, 59 pads with 6 to 9 wells
- Most pads designed to accommodate ~20 wells with the flexibility to drill Marcellus, Utica/Point Pleasant or Upper Devonian formations
- Significant time and cost savings are realized
  - minimal permitting required
  - reuse of existing roads, surface facilities and gathering system

Near-Term Price Enhancements

Natural Gas Differential

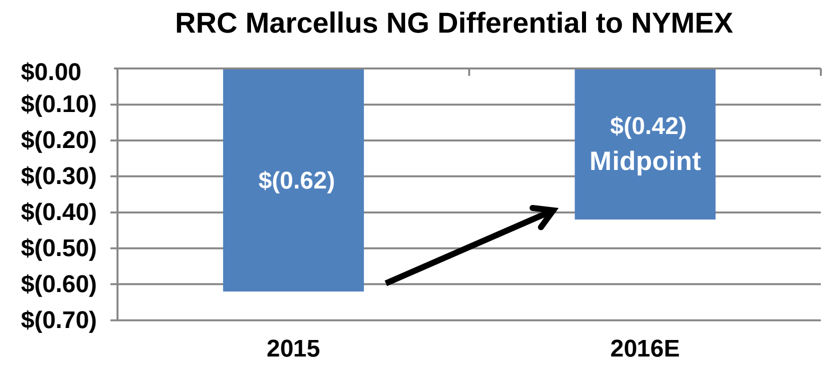
- Range will be able to utilize a full year of Spectra's Uniontown to Gas City project, which takes ~200 Mmcf per day of Range gas production from local Appalachia M2 to Midwest markets
- Additional takeaway projects could strengthen local pricing differentials

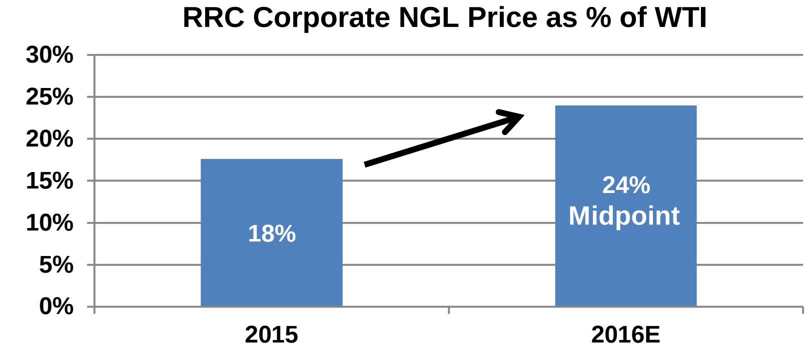
NGL (Natural Gas Liquids) Differential

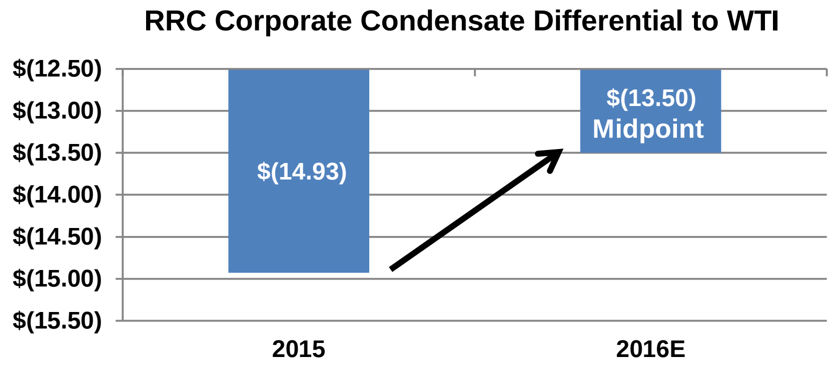
- Range is the only producer with capacity on the Mariner East project to Marcus Hook
  - 20,000 barrels per day of ethane transportation to fulfill contract with INEOS
  - 20,000 barrels per day of propane transportation with access to international propane markets

Condensate Differential

- Range initiated a new marketing arrangement in 3Q15 which improved Marcellus condensate net realized prices







Mariner East: Opening New Lanes

First Ethane Shipments – Faster Propane Loading Combined with VLGC Ships

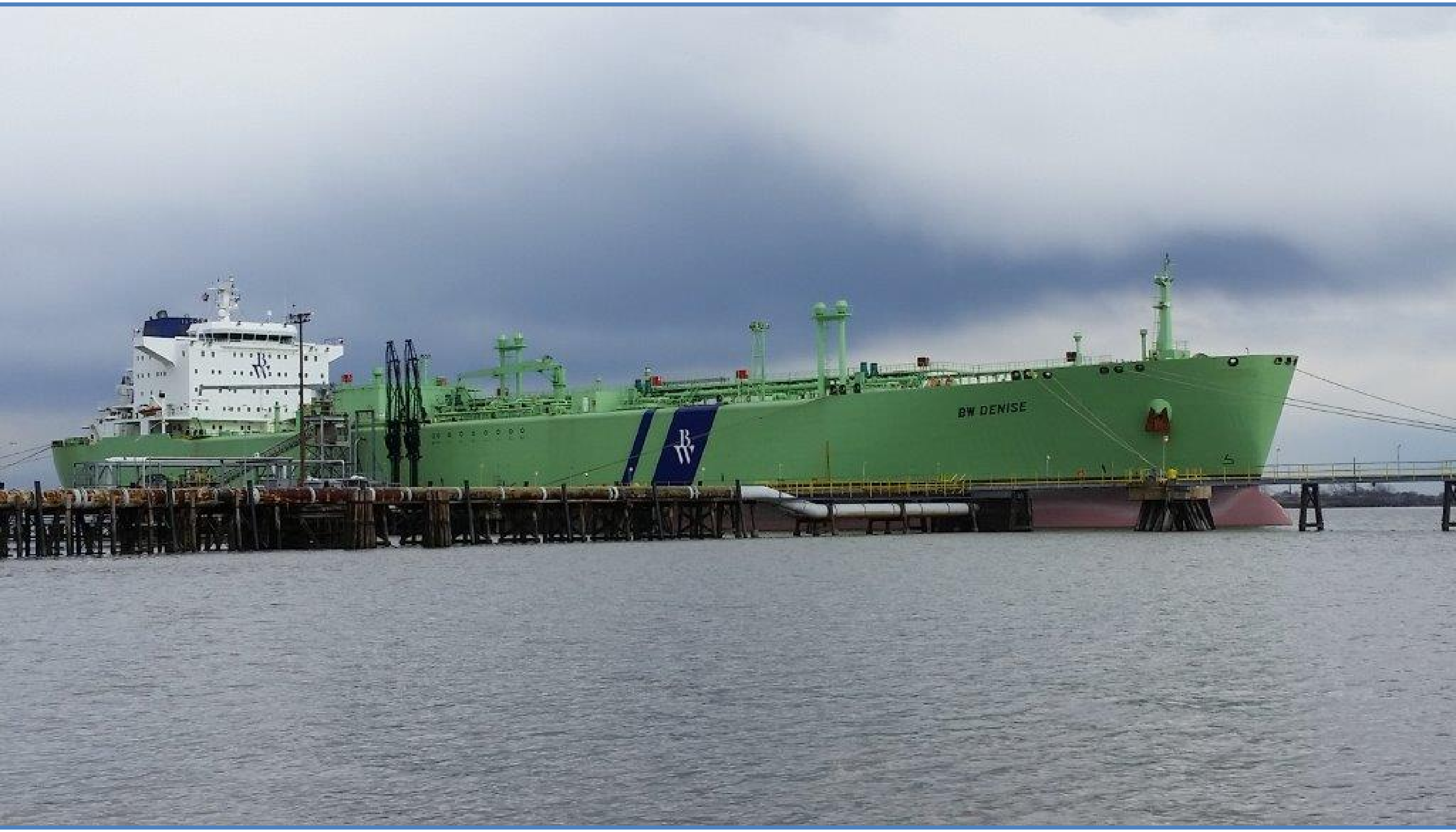
- **Range is the only producer with current capacity on Mariner East**
- **Historic first shipments of ethane from U.S. to Europe**
- **Optionality of selling propane internationally or in local markets**
- **Expect uplift in ethane and propane realizations in 2016 for Range**

Ethane loading in progress


A ship waits in the harbor as another ship is being loaded.

Mariner East: Loading Ethane

First VLGC Loading of Range Propane for Export



Appalachia Gas Transportation Arrangements

Transportation Portfolio additions improve Range's differentials to NYMEX

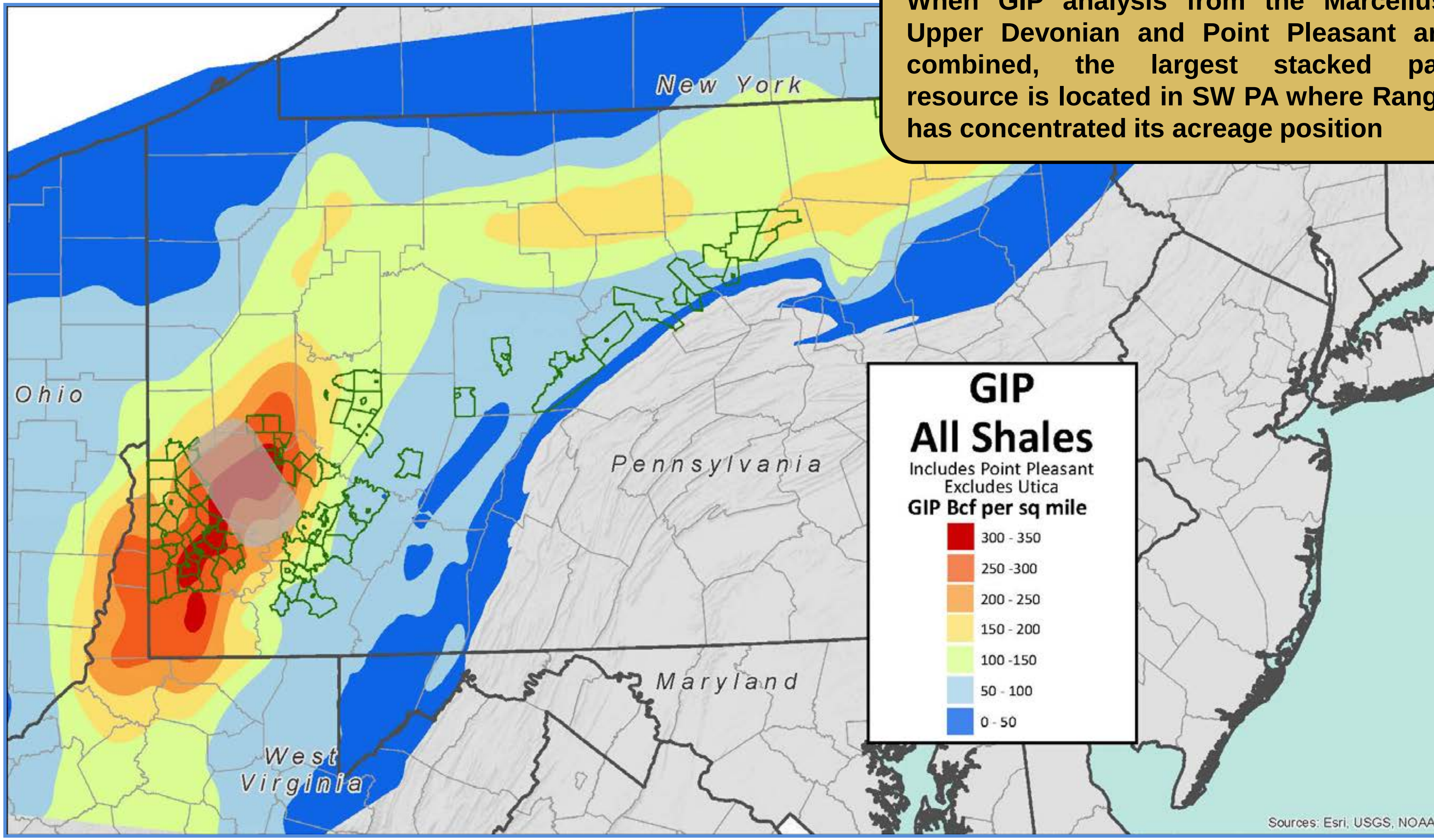
Regional Direction	Projected Avg. 2016		Projected Avg. 2017	
	Mmbtu/day	Transport Cost per Mmbtu	Mmbtu/day	Transport Cost per Mmbtu
Firm Transportation				
Appalachia/Local	390,000	$ 0.20	325,000	$ 0.21
Gulf Coast	295,000	$ 0.30	510,000	$ 0.31
Midwest/Canada	285,000	$ 0.28	330,000	$ 0.30
Northeast	210,000	$ 0.59	210,000	$ 0.59
Total Gross Takeaway Capacity	**1,180,000**	**$ 0.31**	**1,375,000**	**$ 0.35**
Total Net Takeaway Capacity	**980,000**	**$ 0.31**	**1,140,000**	**$ 0.35**
Estimated Marcellus Differential to NYMEX(1)	**($0.40) – ($0.45)**		**($0.25) – ($0.35)**	

Does not include current intermediary pipeline capacity (gathering) of >650,000 Mmbtu/day and assumes full utilization. Based on pipeline operator's anticipated project start dates.

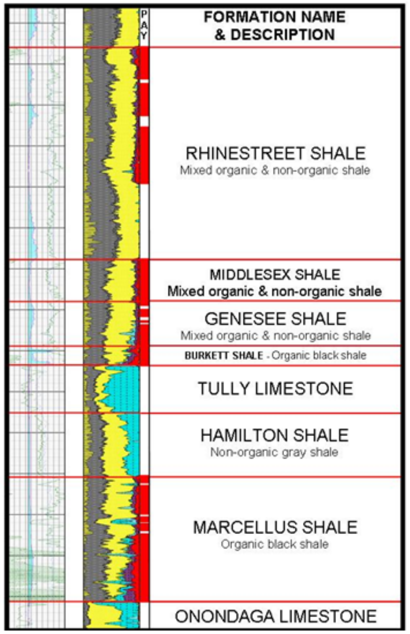
(1) Based on expected utilization of capacity and forward pricing with differentials as of April 2016

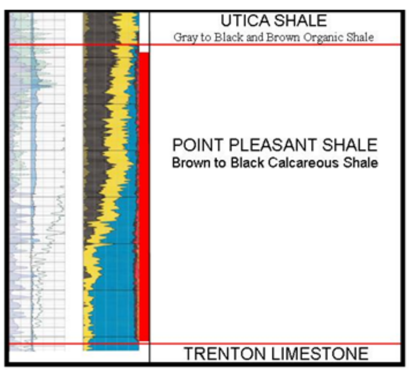
Gas In Place (GIP) Analysis Shows Greatest Potential in SW PA

When GIP analysis from the Marcellus, Upper Devonian and Point Pleasant are combined, the largest stacked pay resource is located in SW PA where Range has concentrated its acreage position



Note: Townships where Range holds ~2,000+ acres (as of January 2016) and estimated as prospective, are outlined green. GIP – Range estimates.





	Wet Acreage	Dry Acreage	Total Net Acreage (1)
Upper Devonian	335,000	180,000	515,000
Marcellus	335,000	290,000	625,000
Utica/Point Pleasant	-	400,000	400,000
	670,000	870,000	1,540,000

Stacked pays allow for multiple development opportunities

(1) Excludes Northwest PA - 280,000 net acres, largely HBP

Range Marcellus – 2016 Well Economic Summary

Industry leading EUR/1,000 ft. and Cost/1,000 ft. in SW Appalachia

	SW Super-Rich	SW Wet	SW Dry	NE Dry
EUR	16.0 Bcfe 1,450 Mbbls & 7.3 Bcf	20.6 Bcfe 1,756 Mbbls & 10.1 Bcf	17.6 Bcf	14.1 Bcf
EUR/1,000 ft. lateral	2.4 Bcfe	3.0 Bcfe	2.5 Bcf	2.5 Bcf
EUR/stage	485 Mmcfe	589 Mmcfe	503 Mmcf	504 Mmcf
Well Cost	$5.9 MM	$5.8 MM	$5.2 MM	$2.9 MM
Cost/1,000 ft. lateral	$881 K	$832 K	$743 K	$518 K
Stages	33	35	35	28
Lateral Length	6,660 ft.	6,970 ft.	7,000 ft.	5,660 ft.
IRR - $3.00	26%	25%	54%	58%

See appendix for complete assumptions and data on each area

Liquidity and Leverage Outlook

- **At March 31, 2016, Range had $1.7 billion liquidity under bank commitments, which is currently limited to $1.2 billion by senior subordinated note indentures**

- **$3 billion borrowing base and $2 billion commitment amount under $4 billion credit facility unanimously reaffirmed by bank group, next scheduled redetermination by May 1, 2017**

- **No note maturities until 2021**

- **Bank facility subject to renewal in 2019, with annual redeterminations**

- **Bradford County non-operated interest sold 3/28/16 for $110 million of proceeds**

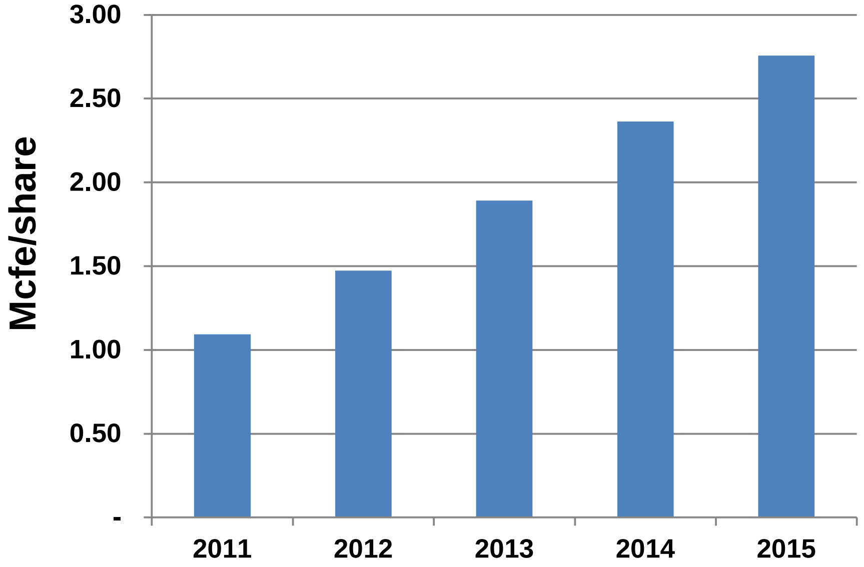
- **Signed agreement to sell 9,200 acres in the STACK play for ~$77 million**

- **Solid, stable coverage on debt covenants**
  - **EBITDAX to interest – minimum of 2.5x (1Q Actual 4.8x)**
  - **PV9 proved reserves value to debt – minimum of 1.5x (1Q Actual 2.4x)**

- **Hedges on 80% of 2016 production at ~$3.24**

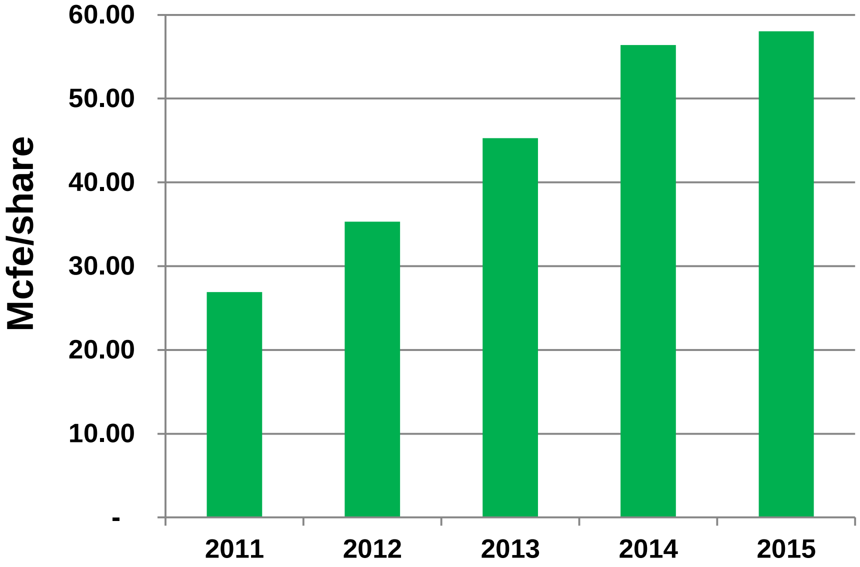
Per Share Growth, on a Debt-Adjusted Basis

Production/share – debt adjusted



5-Year CAGR 23%

Reserves/share – debt adjusted



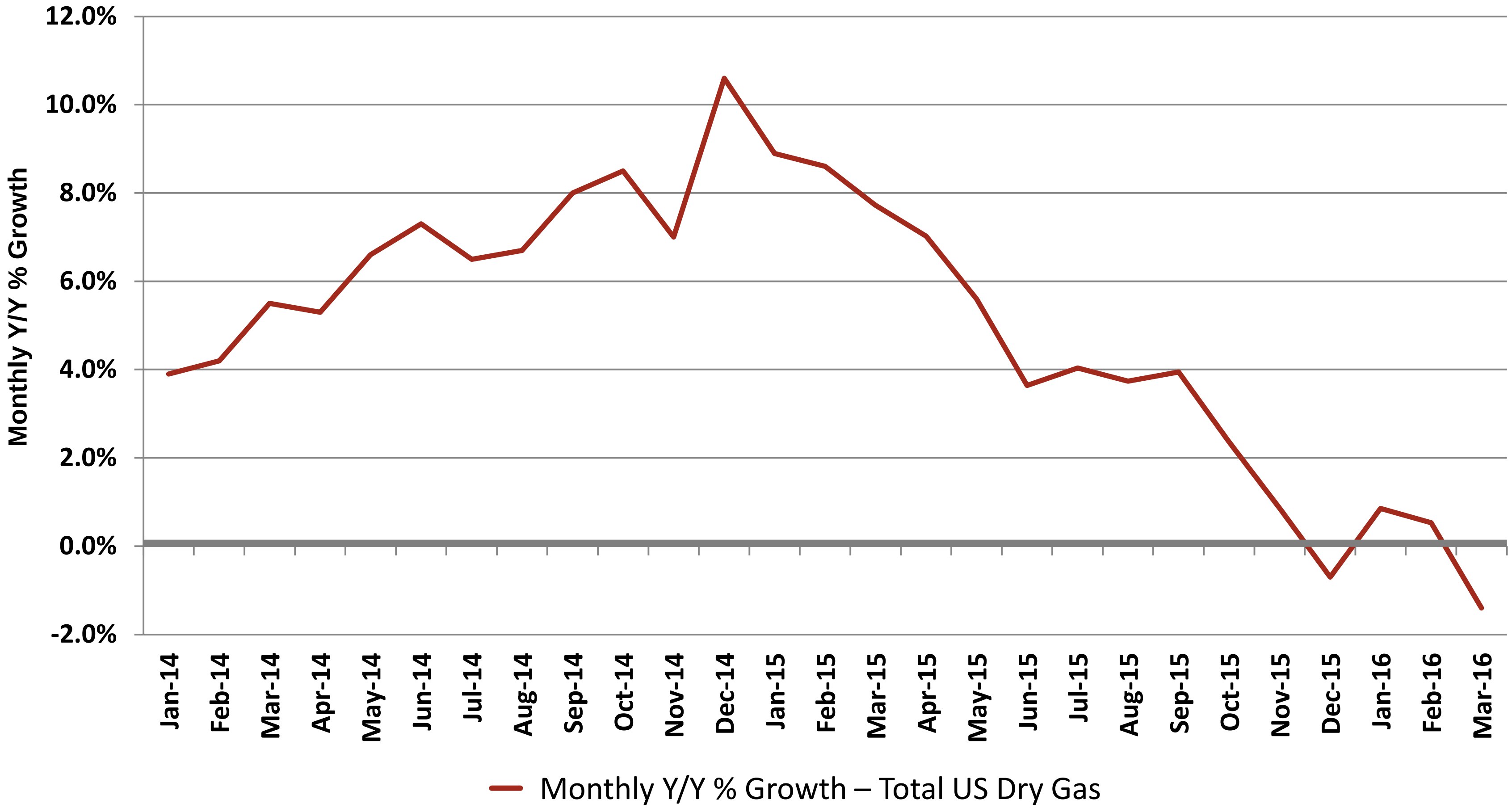
5-Year CAGR 20%

- **Production/share = annual production divided by debt-adjusted year-end diluted shares outstanding**
- **Reserves/share = year-end proven reserves divided by debt-adjusted year-end diluted shares outstanding**

Nora production and reserves excluded

U.S. Natural Gas Production Growth has Slowed Considerably

December 2015 marked the first Y/Y supply decrease since February 2010



Source – Bentek, Jefferies as of April 2016

Range's Keys for Success – Assets, Team, Agreements & Strategy

Low cost structure with ability to continue driving costs lower

- High-grading asset sales lowered operating costs
- Lower debt balances reduce interest expense
- Headcount reduced by 31% YoY

Improving capital efficiency

- Longer laterals; 2016 plan average ~7,000', 2017 plan est. to average ~8,000'
- Improved targeting and completions
- Existing pad locations with facilities and gathering
- 2017 maintenance capex estimated at ~$300 million

Better realizations from additional takeaway capacity and sales agreements

- Unique marketing arrangements coming on line
- Ability to reach premium markets and deliver products outside Marcellus, including international exports

Low-cost takeaway capacity with built-in flexibility

- First-mover advantage allowed Range to secure capacity on low-cost expansion projects
- Anticipated excess infrastructure build-out and avoided contracting for excessive firm transport

Strong 2016 hedges and ample liquidity

- Approximately 80% hedged on natural gas at ~$3.24 Mmbtu
- At 3/31/16, only $31 million drawn on $2 billion credit facility
- 2016 program expected to use cash flow and asset sales, preserving liquidity

High quality, large scale acreage position containing repeatable projects with good returns

- Optionality and flexibility due to quality of acreage position, gathering system, available locations on existing pads
- Further improvements expected

Appendix

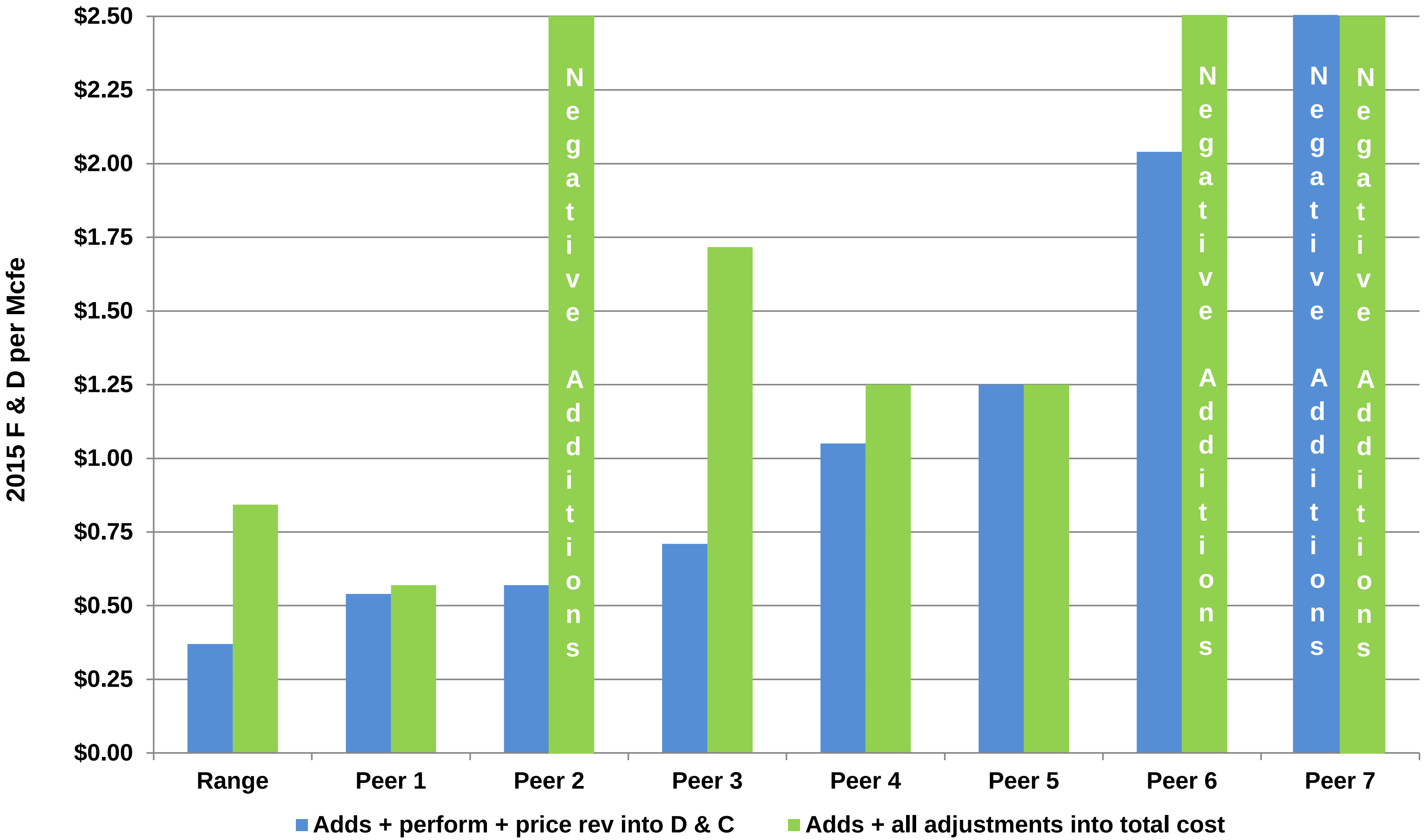
Track Record of Impressive Reserve Replacement at Low Cost

	2011	2012	2013	2014	2015	3-Year Average	5-Year Average
Reserve Replacement							
All sources – excluding PUD removals[1]	849%	680%	745%	793%	436%	638%	669%
All sources[2]	849%	680%	636%	649%	207%	469%	546%
Finding Costs							
Drill bit only – without acreage[1]	$0.76	$0.76	$0.47	$0.44	$0.37	$0.43	$0.53
Drill bit only – with acreage[1]	$0.89	$0.86	$0.52	$0.51	$0.40	$0.48	$0.60
All sources – excluding PUD removals[2]	$0.89	$0.86	$0.52	$0.54	$0.40	$0.50	$0.61
All sources[2]	$0.89	$0.76	$0.61	$0.67	$0.84	$0.68	$0.75

(1) Includes performance and price revisions, excludes SEC required PUD removal due to 5-year rule
(2) From all sources, including price, performance and SEC required PUD removal due to 5-year rule
(3) Percentages shown are compounded annual growth rate

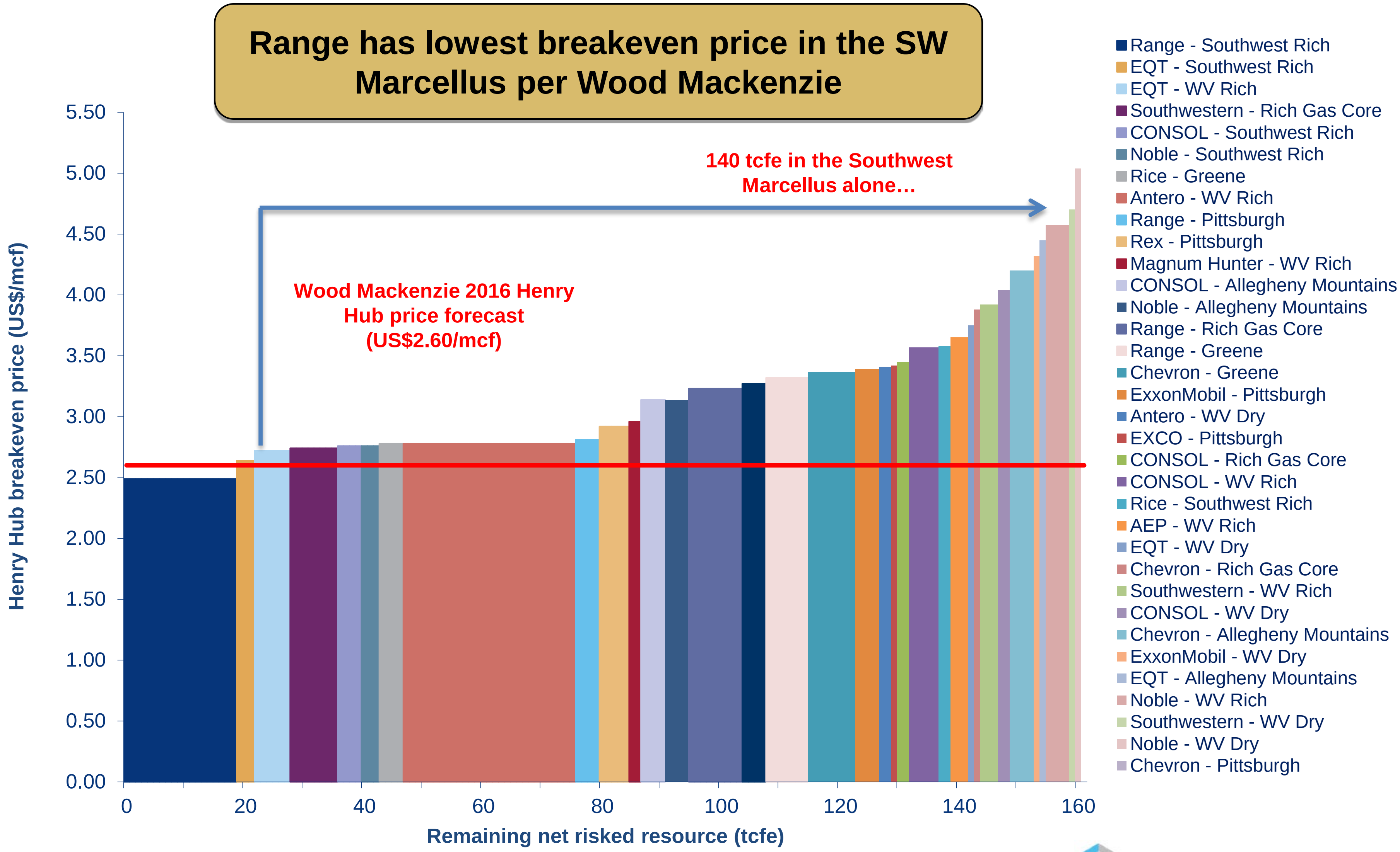
Appalachia Producer's 2015 F & D Costs

Core Acreage Has Big Impact on Value of Reserves



Peers included – Antero, Cabot, Consol, EQT, Gulfport, Rice & Southwestern

Range: Low-Cost, Large Scale



Source: Wood Mackenzie – February 2016

SW PA Super-Rich Area Marcellus Projected 2016 Well Economics

- Southwestern PA – (High Btu case)
- 110,000 Net Acres
- EUR / 1,000 ft. – 2.40 Bcfe
- EUR – 16.0 Bcfe
  (226 Mbbls condensate, 1,224 Mbbls NGLs & 7.3 Bcf gas)
- Drill and Complete Capital – $5.87 MM
  ($881 K per 1,000 ft.)
- Average Lateral Length – 6,660 ft.
- F&D – $0.44/mcfe

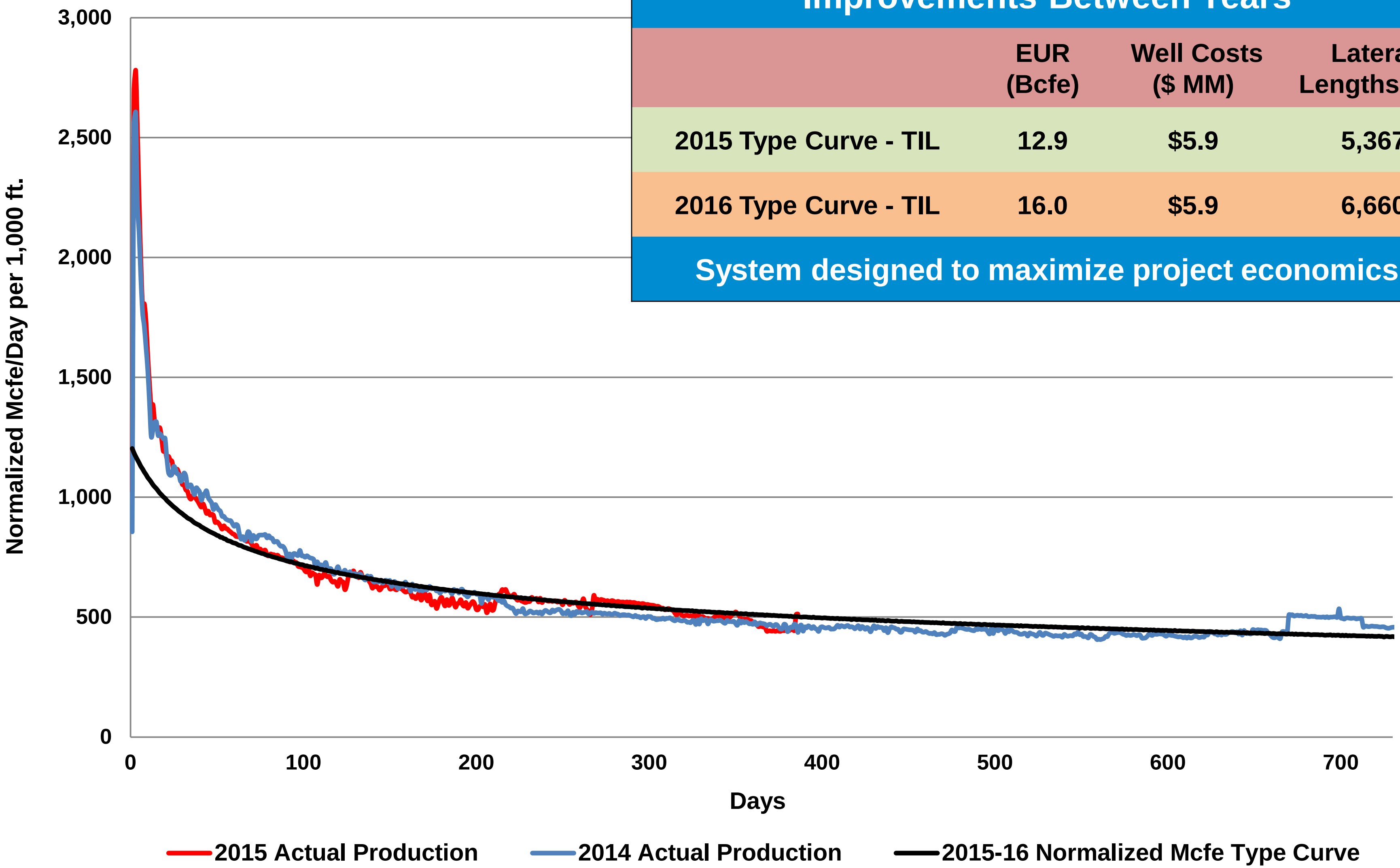
Estimated Cumulative Recovery for 2016 Production Forecast			
	Condensate (Mbbls)	Residue (Mmcf)	NGL w/ Ethane (Mbbls)
1 Year	48	661	111
2 Years	73	1,142	192
3 Years	92	1,555	261
5 Years	120	2,246	378
10 Years	161	3,517	591
20 Years	195	5,157	867
EUR	226	7,279	1,224

NYMEX Gas Price	ROR
Strip -	22%
$3.00 -	26%

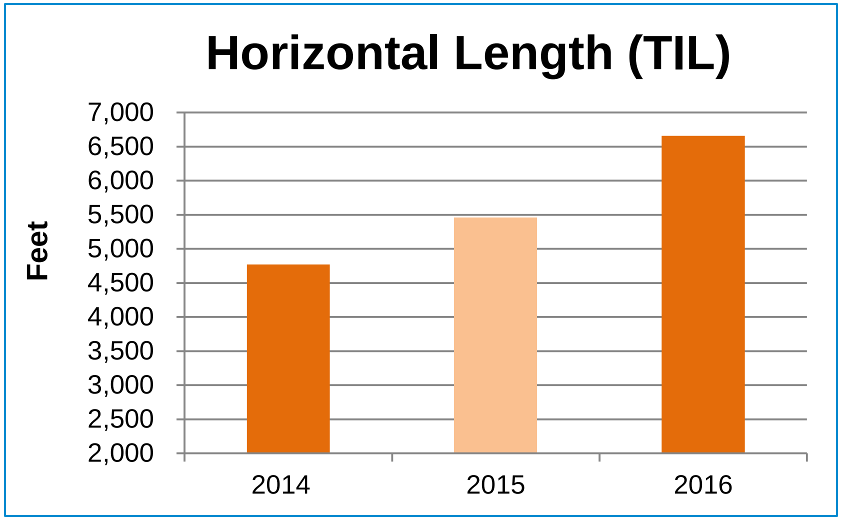
- Price includes current and expected differentials less gathering, transportation and processing costs
- For flat pricing, oil price assumed to be $40/bbl for 2016, $50/bbl for 2017 then $65/bbl to life with no escalation
- NGL is average price including ethane with escalation
- Ethane price tied to ethane contracts plus same comparable escalation
- Strip dated 12/31/15 with 10-year average $52.14/bbl and $3.25/mcf

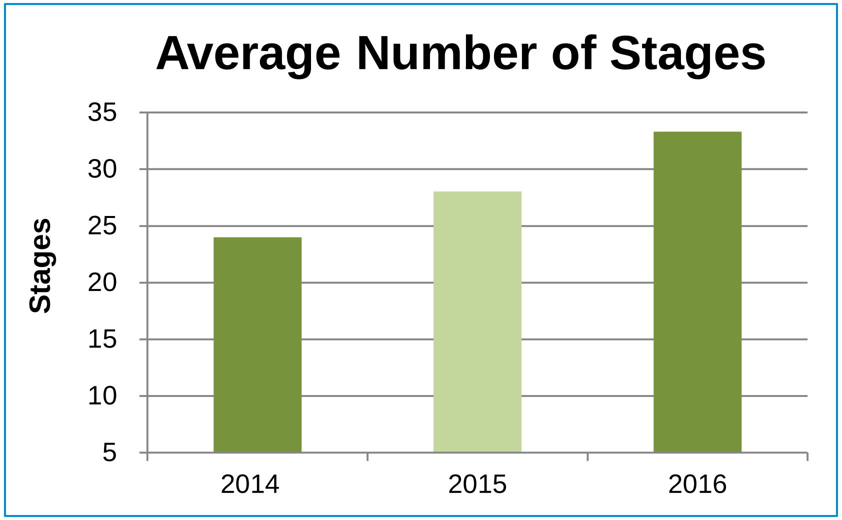
Southwest PA - Super-Rich Area 2016 Turn in Line Forecast

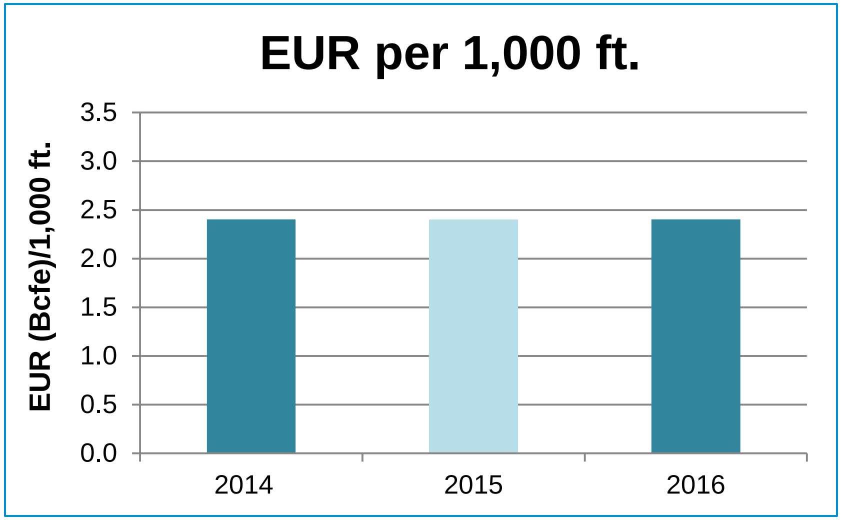
Improvements Between Years			
	EUR (Bcfe)	Well Costs ($ MM)	Lateral Lengths (ft.)
2015 Type Curve - TIL	12.9	$5.9	5,367
2016 Type Curve - TIL	16.0	$5.9	6,660
System designed to maximize project economics			

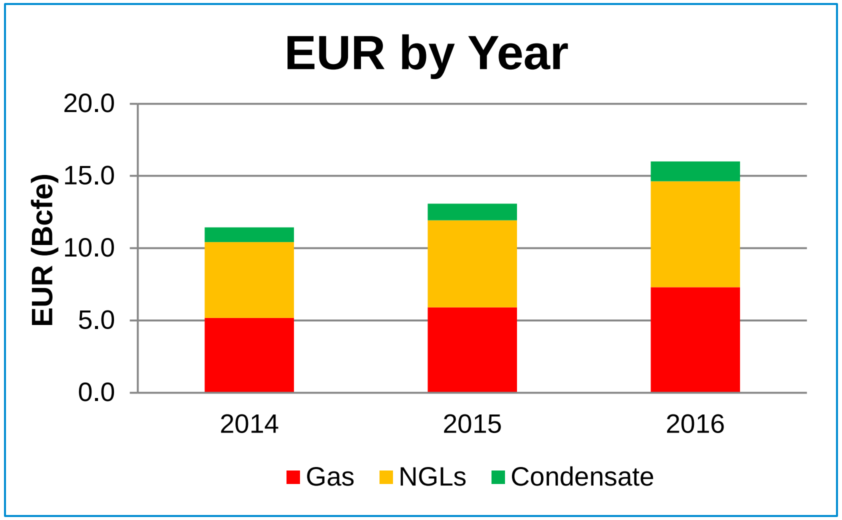


Southwest PA – Super-Rich Marcellus









All comparisons based on Turned in Line (TIL) wells for each year

SW PA Wet Area Marcellus Projected 2016 Well Economics

- **Southwestern PA – (Wet Gas case)**
- **225,000 Net Acres**
- **EUR / 1,000 ft. – 2.95 Bcfe**
- **EUR – 20.6 Bcfe**
  (56 Mbbls condensate, 1,700 Mbbls NGLs & 10.1 Bcf gas)
- **Drill and Complete Capital – $5.8 MM**
  ($832 K per 1,000 ft.)
- **Lateral Length – 6,970 ft.**
- **F&D – $0.34/mcfe**

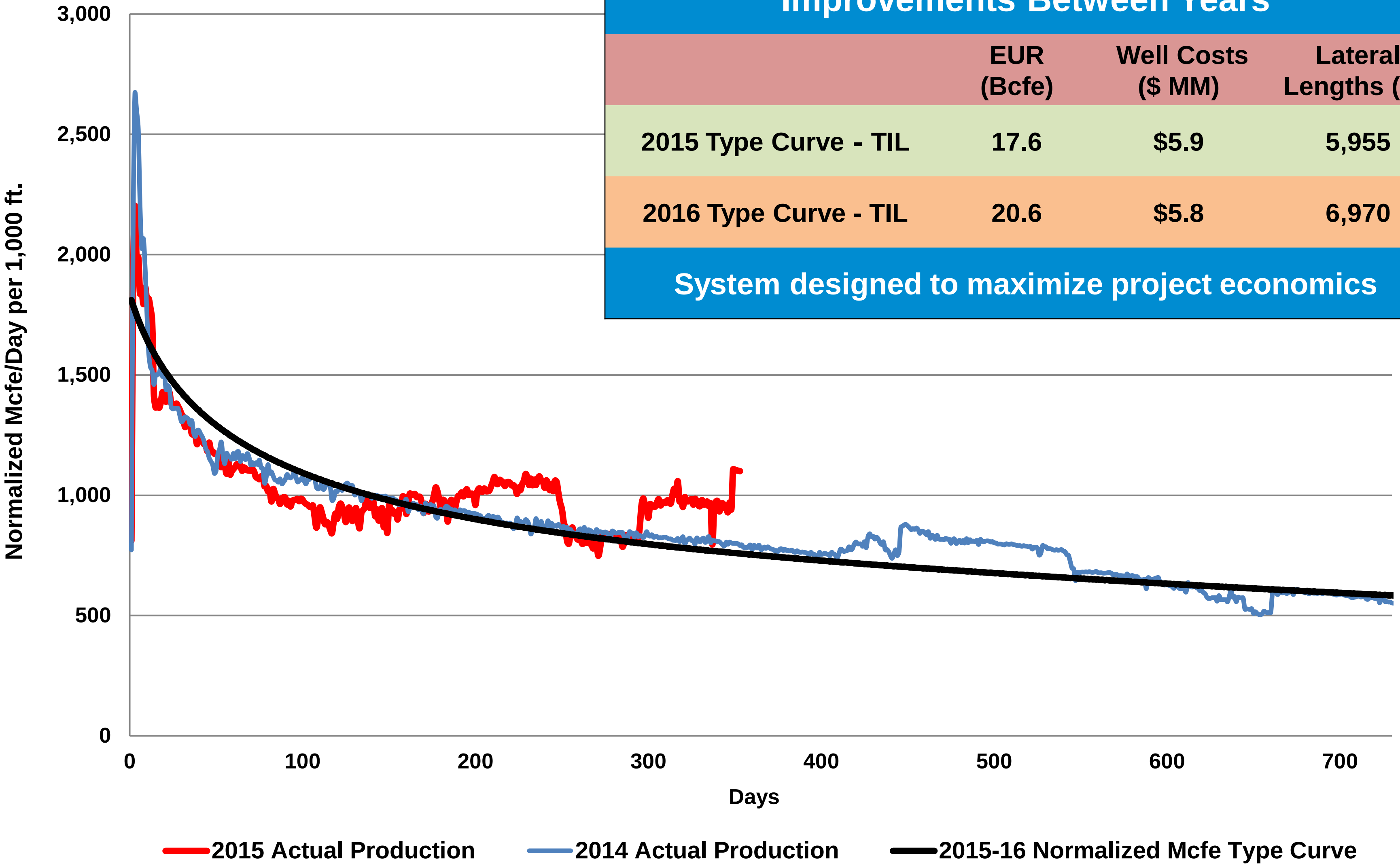
Estimated Cumulative Recovery for 2016 Production Forecast			
	Condensate (Mbbls)	Residue (Mmcf)	NGL w/ Ethane (Mbbls)
1 Year	20	1,211	204
2 Years	30	2,014	339
3 Years	36	2,665	449
5 Years	44	3,694	622
10 Years	51	5,470	921
20 Years	55	7,654	1,289
EUR	56	10,100	1,700

NYMEX Gas Price	ROR
Strip -	20%
$3.00 -	25%

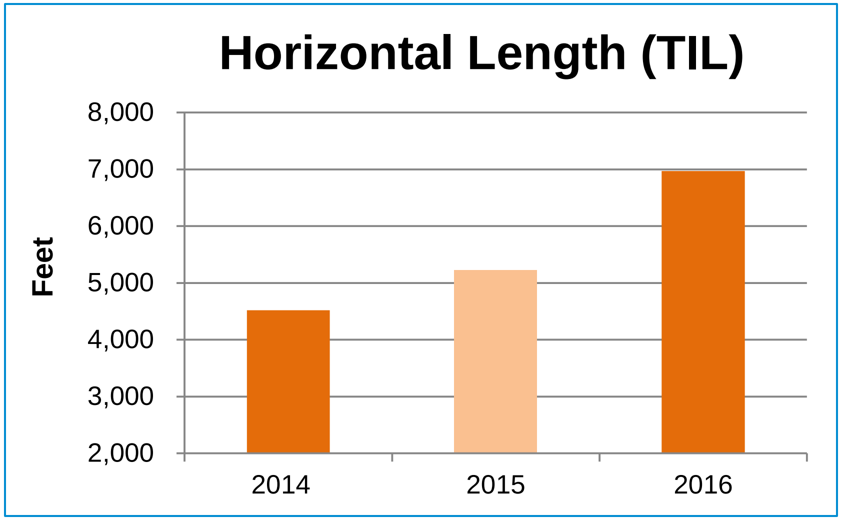
- **Price includes current and expected differentials less gathering, transportation and processing costs**
- **For flat pricing, oil price assumed to be $40/bbl for 2016, $50/bbl for 2017 then $65/bbl to life with no escalation**
- **NGL is average price including ethane with escalation**
- **Ethane price tied to ethane contracts plus same comparable escalation**
- **Strip dated 12/31/15 with 10-year average $52.14/bbl and $3.25/mcf**

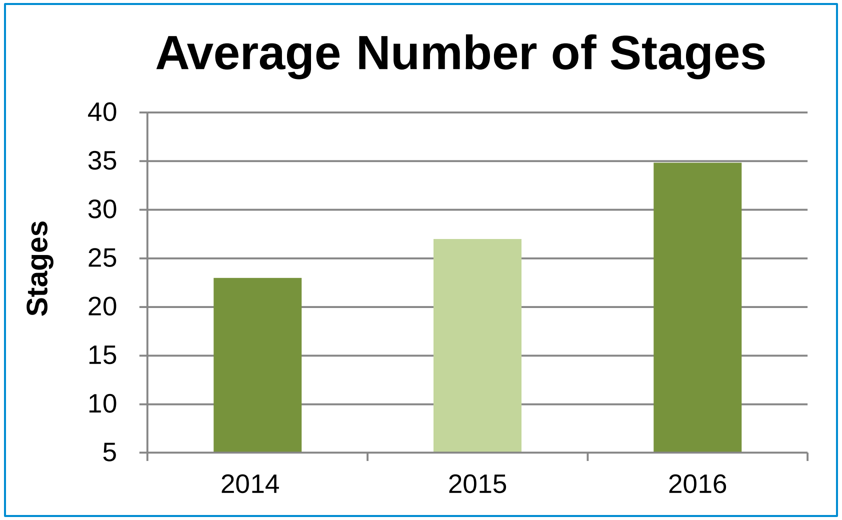
Southwest PA - Wet Area 2016 Turn in Line Forecast

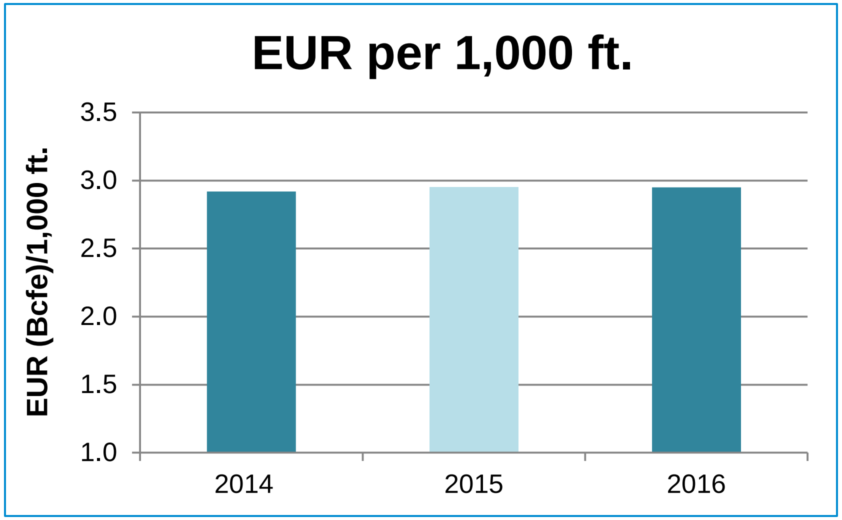
Improvements Between Years			
	EUR (Bcfe)	Well Costs ($ MM)	Lateral Lengths (ft.)
2015 Type Curve - TIL	17.6	$5.9	5,955
2016 Type Curve - TIL	20.6	$5.8	6,970
System designed to maximize project economics			

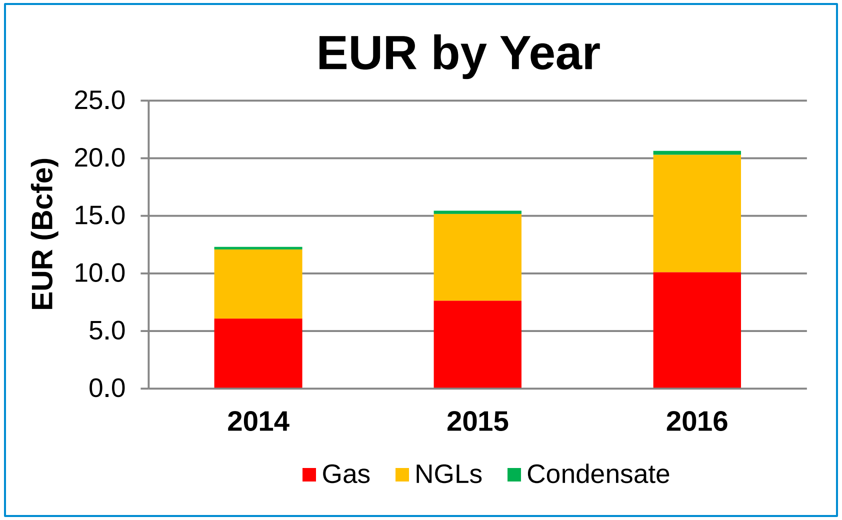


Southwest PA – Wet Marcellus









All comparisons based on Turned in Line (TIL) wells for each year

SW PA Dry Area Marcellus Projected 2016 Well Economics

- Southwestern PA – (Dry Gas case)
- 180,000 Net Acres
- EUR / 1,000 ft. – 2.52 Bcf
- EUR – 17.6 Bcf
- Drill and Complete Capital $5.2 MM
  ($743 K per 1,000 ft.)
- Average Lateral Length – 7,000 ft.
- F&D – $0.36/mcf

Estimated Cumulative Recovery for 2016 Production Forecast	
	Residue (Mmcf)
1 Year	3,039
2 Years	4,674
3 Years	5,866
5 Years	7,609
10 Years	10,392
20 Years	13,633
EUR	17,641

NYMEX Gas Price	ROR
Strip -	41%
$3.00 -	54%

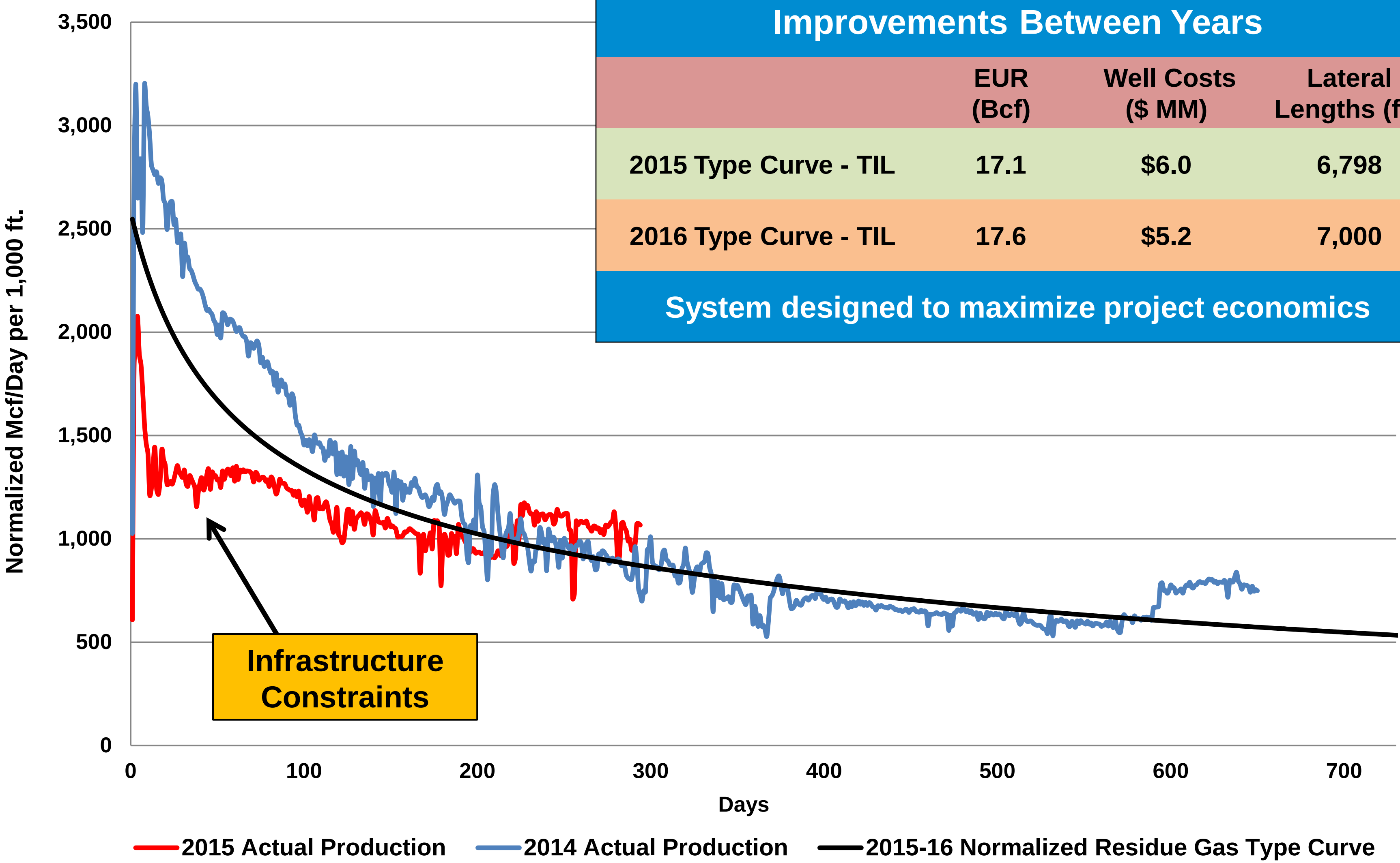
- Price includes current and expected differentials less gathering and transportation costs
- Strip dated 12/31/15 with 10-year average $52.14/bbl and $3.25/mcf

Based on Washington County well data

SW PA– Dry Area 2016 Turn in Line Forecast

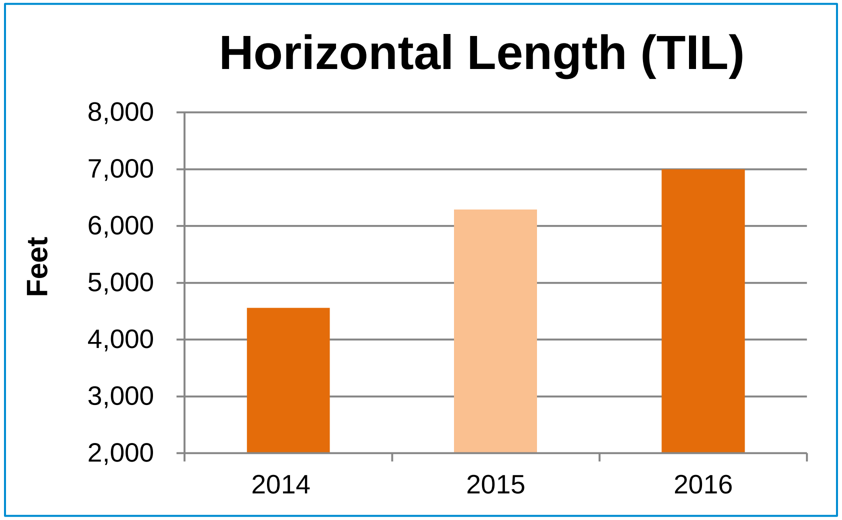
Improvements Between Years	EUR (Bcf)	Well Costs ($ MM)	Lateral Lengths (ft.)
2015 Type Curve - TIL	17.1	$6.0	6,798
2016 Type Curve - TIL	17.6	$5.2	7,000

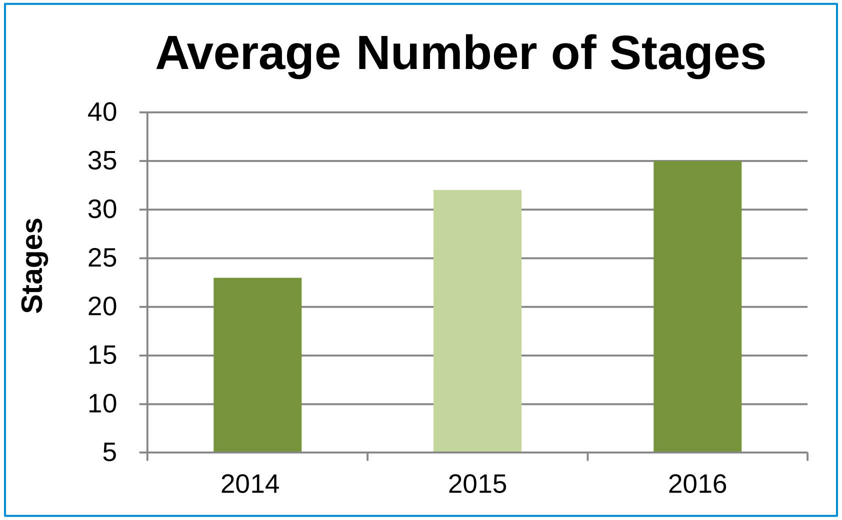
System designed to maximize project economics

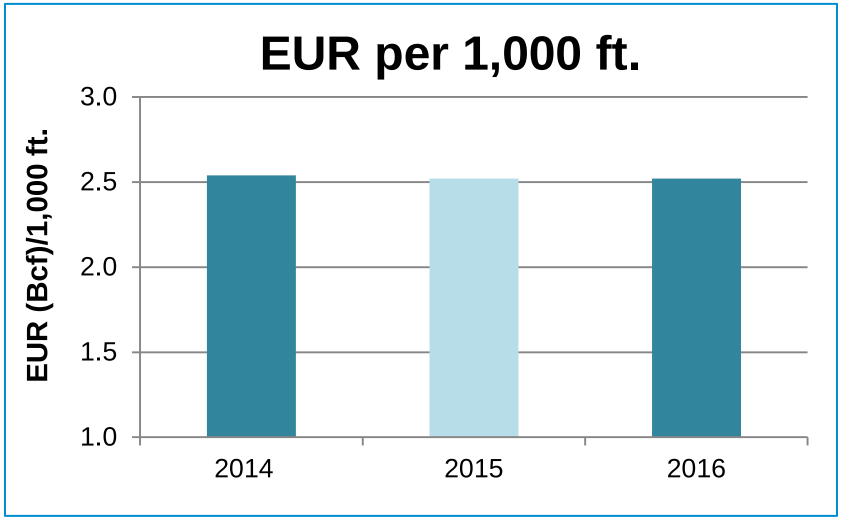


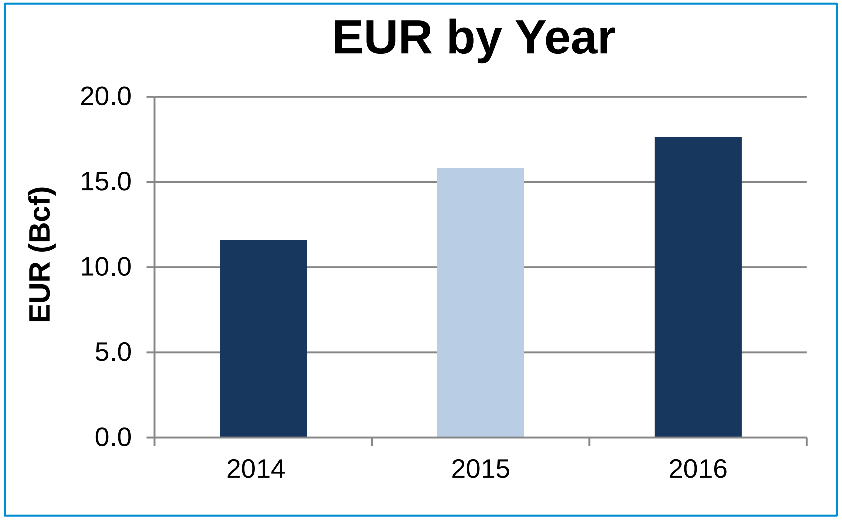
Based on Washington County well data

Southwest PA– Dry Marcellus









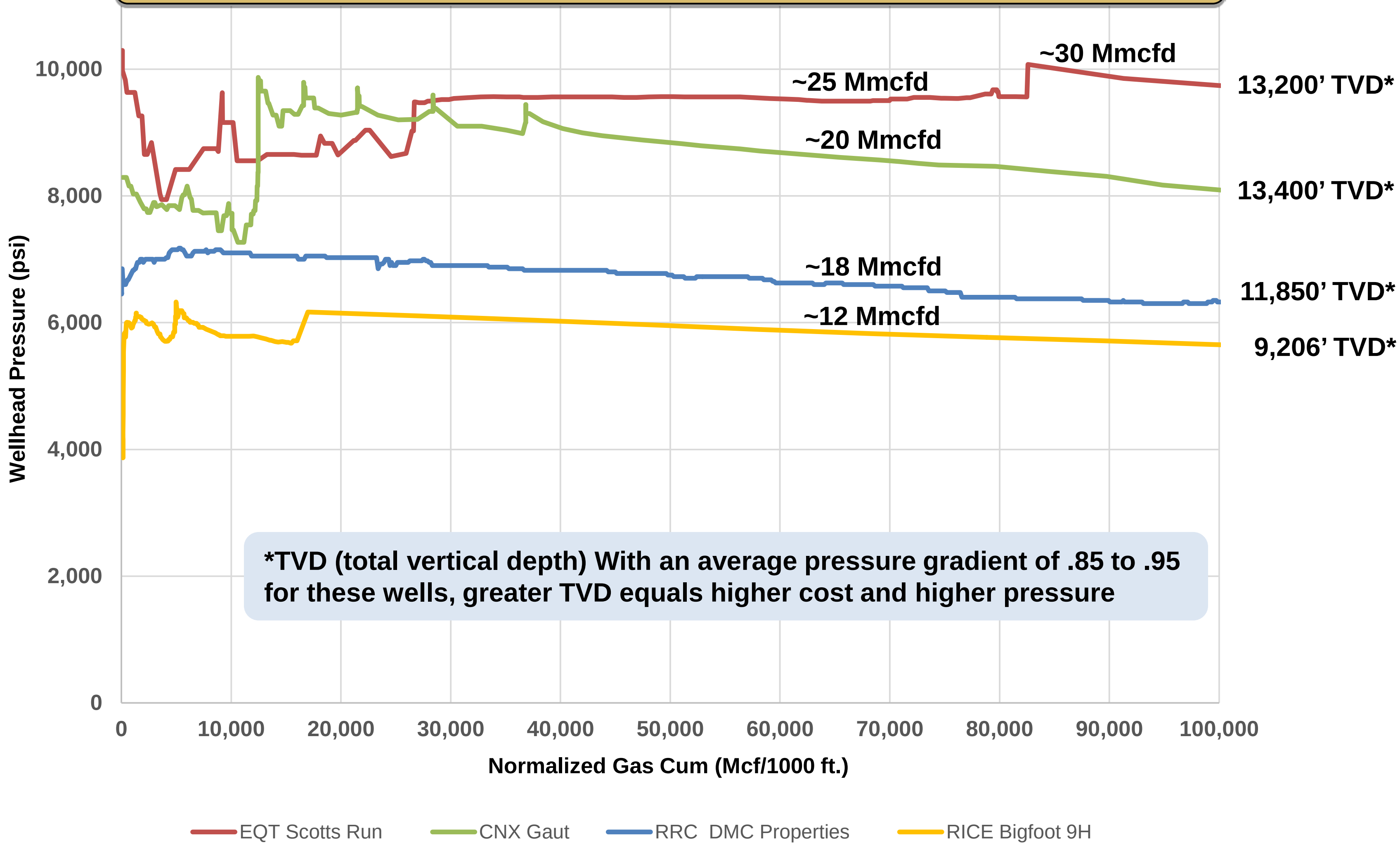
All comparisons based on Turned in Line (TIL) wells for each year

Based on Washington County well data

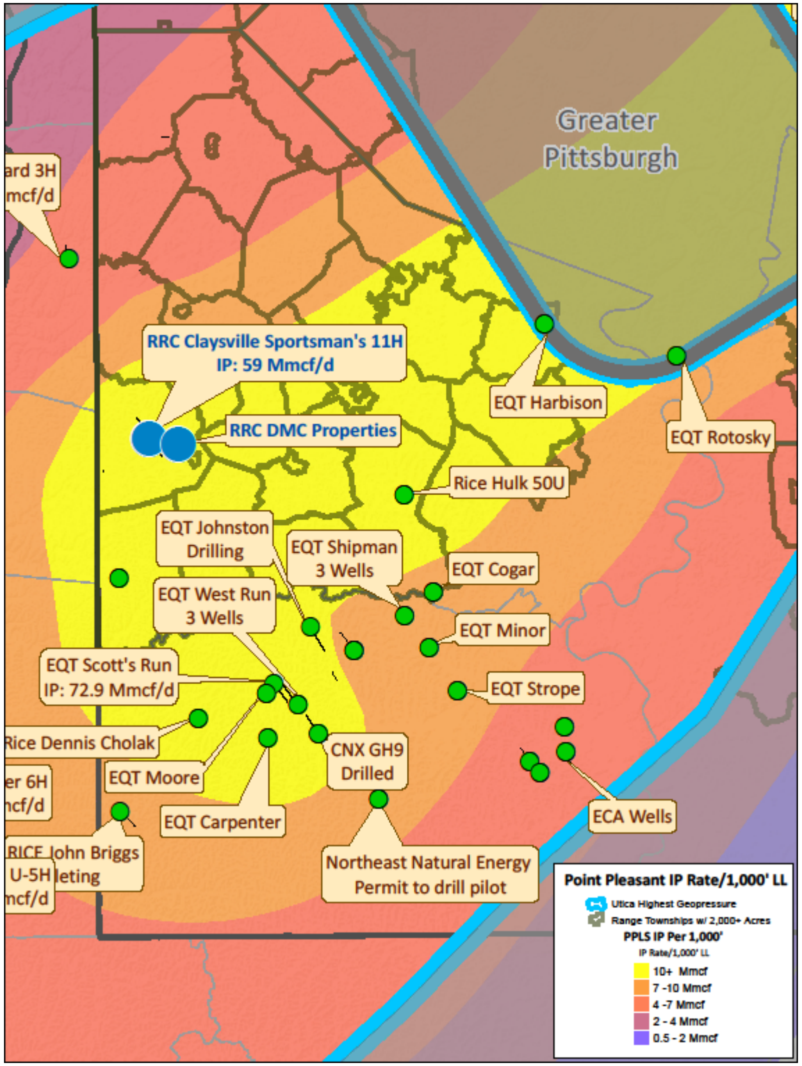
Utica Wells – Wellhead Pressure vs. Cumulative Production

Early Time Production Data (Including Flowback/Test Data)

RRC DMC Properties well one of the best in the Utica



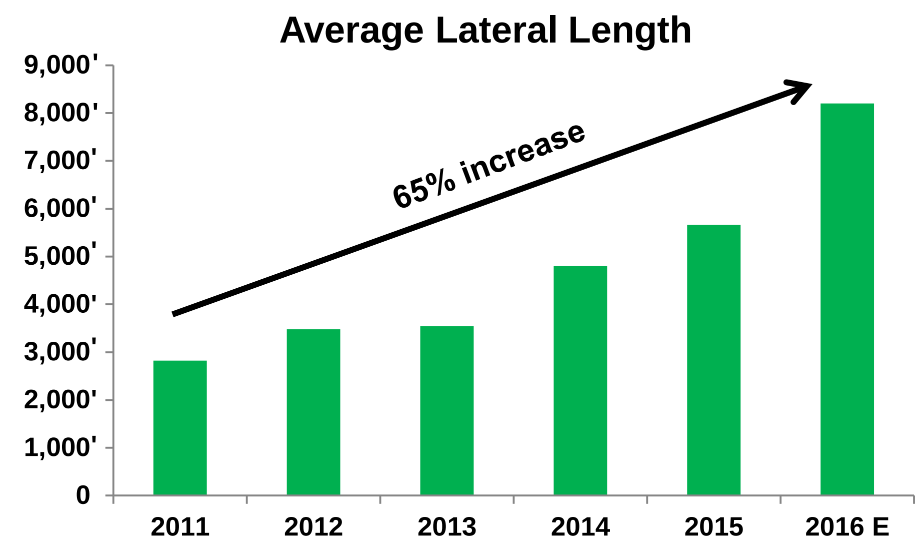
Utica/Point Pleasant Update

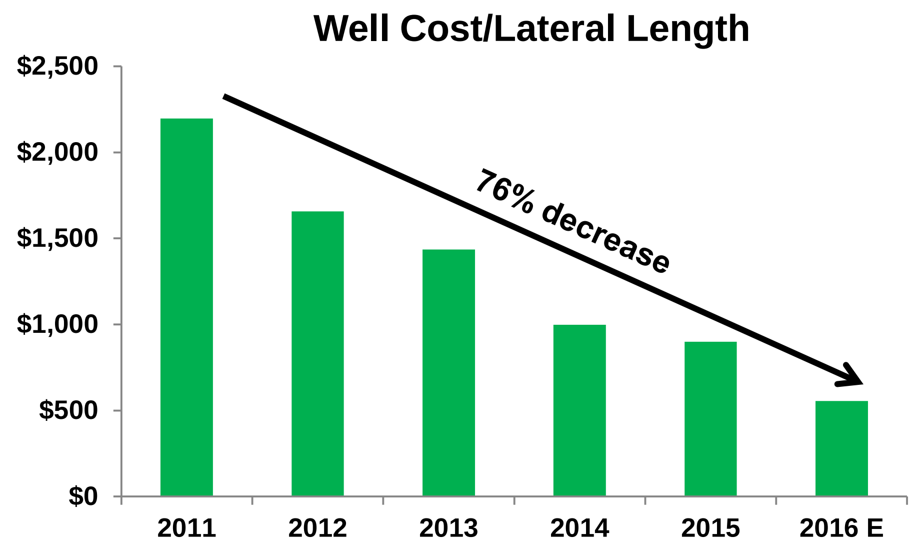


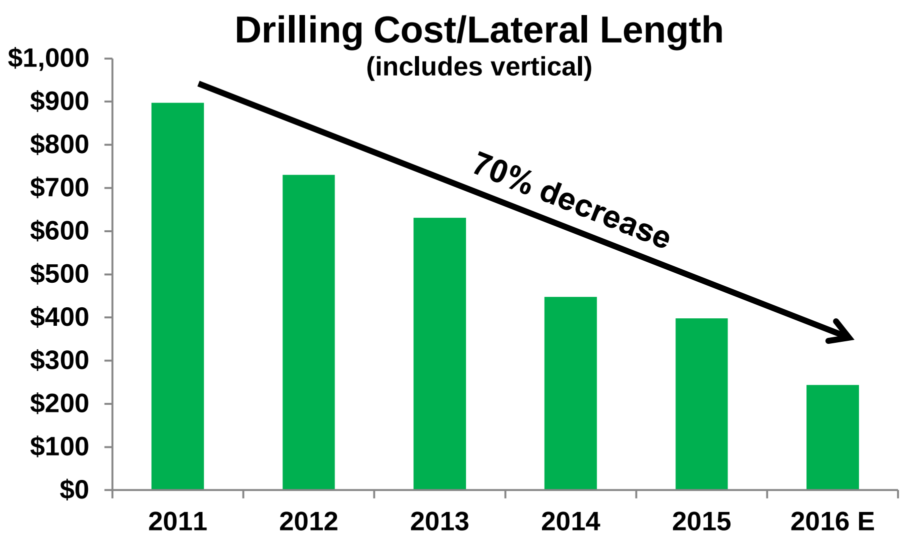
- **1st well estimated to have 15 Bcf EUR, or 2.8 Bcf per 1,000 lateral foot**
- **2nd well completed with higher sand concentration and brought online in Q3 2015 with choke management at 13 Mmcf per day**
- **2nd well EUR appears to be greater than the first well**
- **3rd well appears to be one of the best dry gas Utica wells in the basin**
- **400,000 net acres in SW PA prospective**

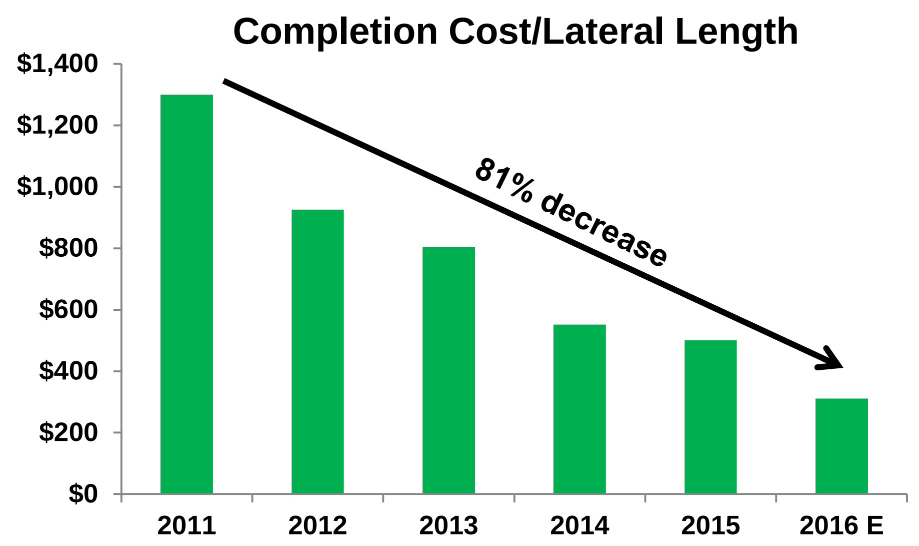
Note: Townships where Range holds ~2,000+ or more acres are shown outlined above (as January 2016)

Cost & Efficiency Improvements – Northern Marcellus



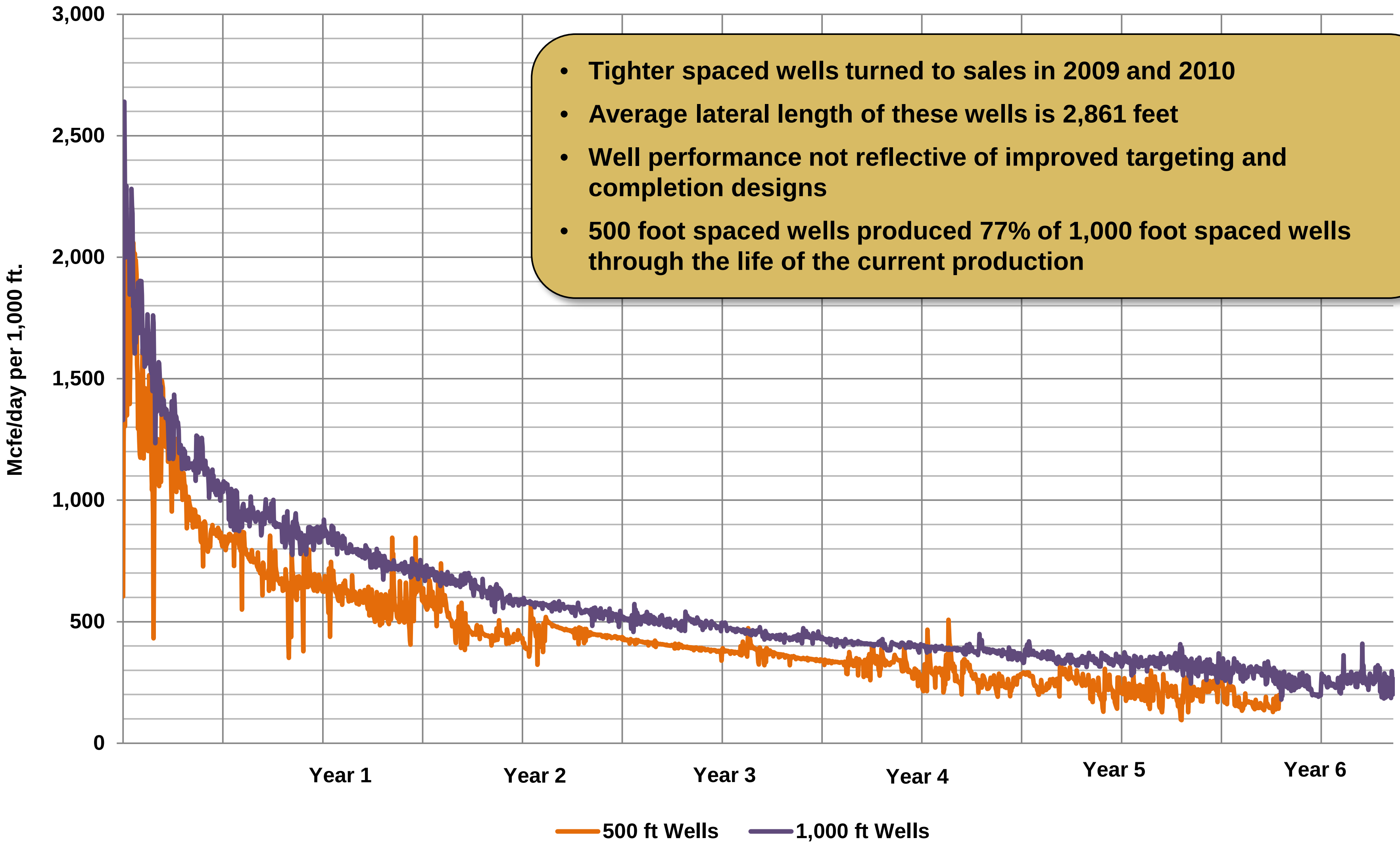






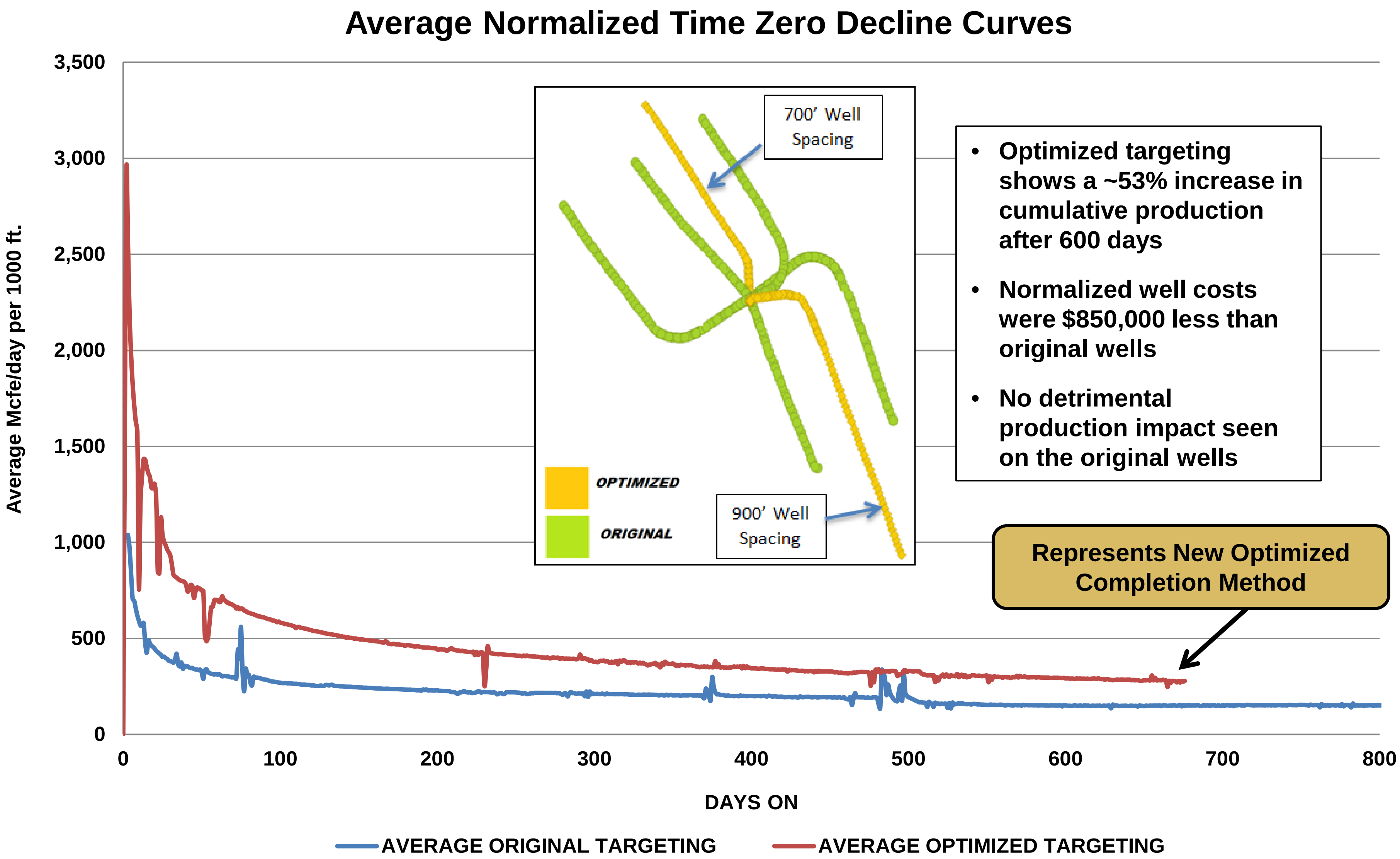
Normalized Production Results of Marcellus Tighter Spacing Projects

Projects conducted in the Wet and Super Rich areas of the Marcellus



- Tighter spaced wells turned to sales in 2009 and 2010
- Average lateral length of these wells is 2,861 feet
- Well performance not reflective of improved targeting and completion designs
- 500 foot spaced wells produced 77% of 1,000 foot spaced wells through the life of the current production

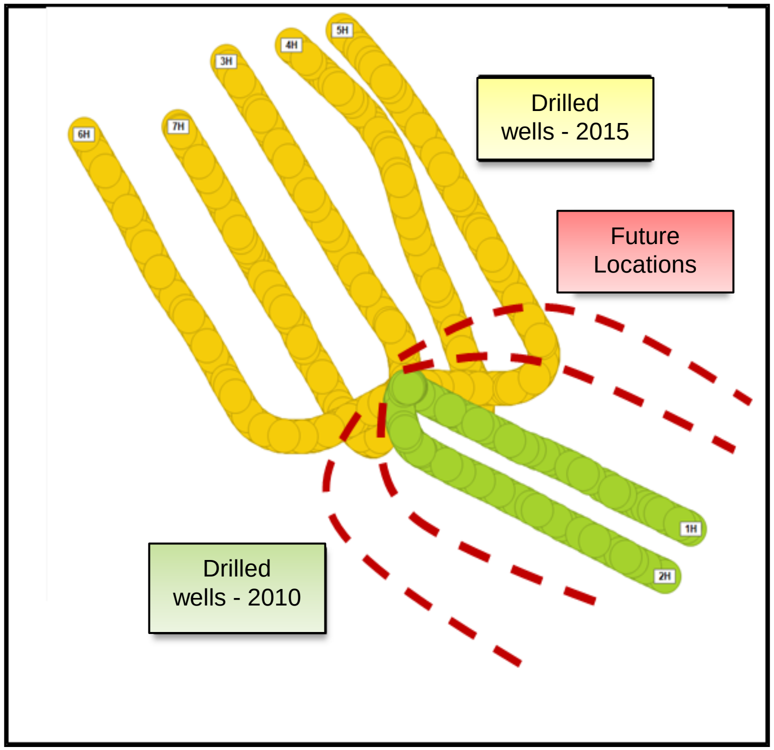
Targeting/Down Spacing Test Results Encouraging



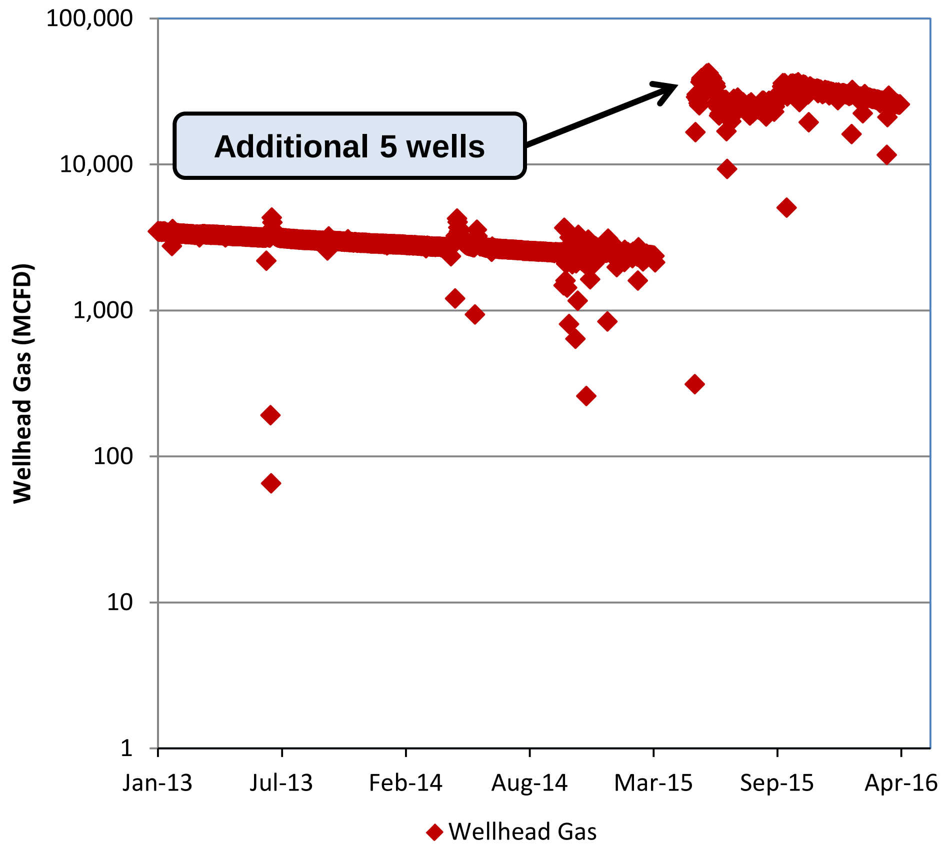
- Optimized targeting shows a ~53% increase in cumulative production after 600 days
- Normalized well costs were $850,000 less than original wells
- No detrimental production impact seen on the original wells

Returning to Existing Pads – SW Wet

- Ability to target our best areas with 3.6+ Bcfe/1,000 ft.
- New wells have EURs 22% higher than the average wet well
- Significant cost savings

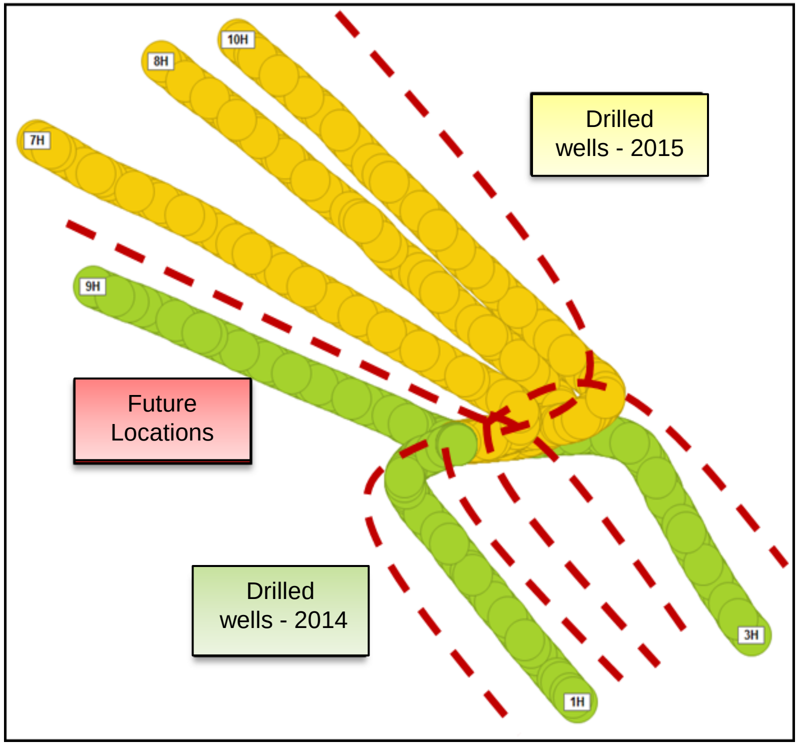


Avg EUR/1000 ft.: 3.6+ Bcfe

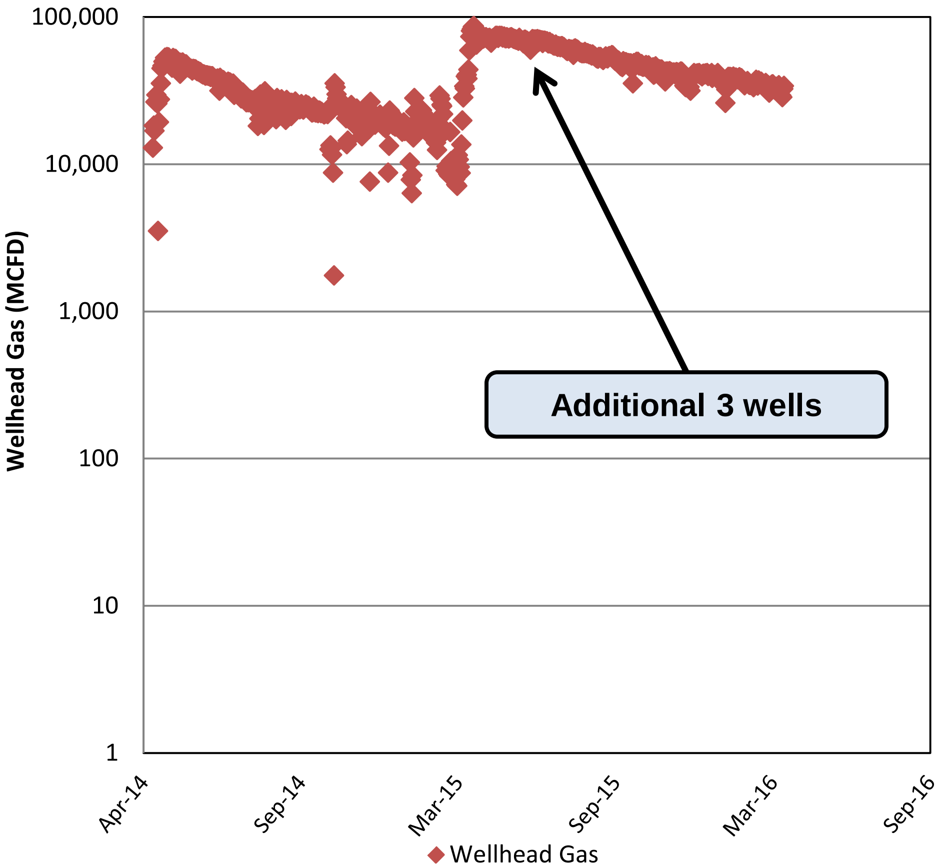


Returning to Existing Pads – SW Dry

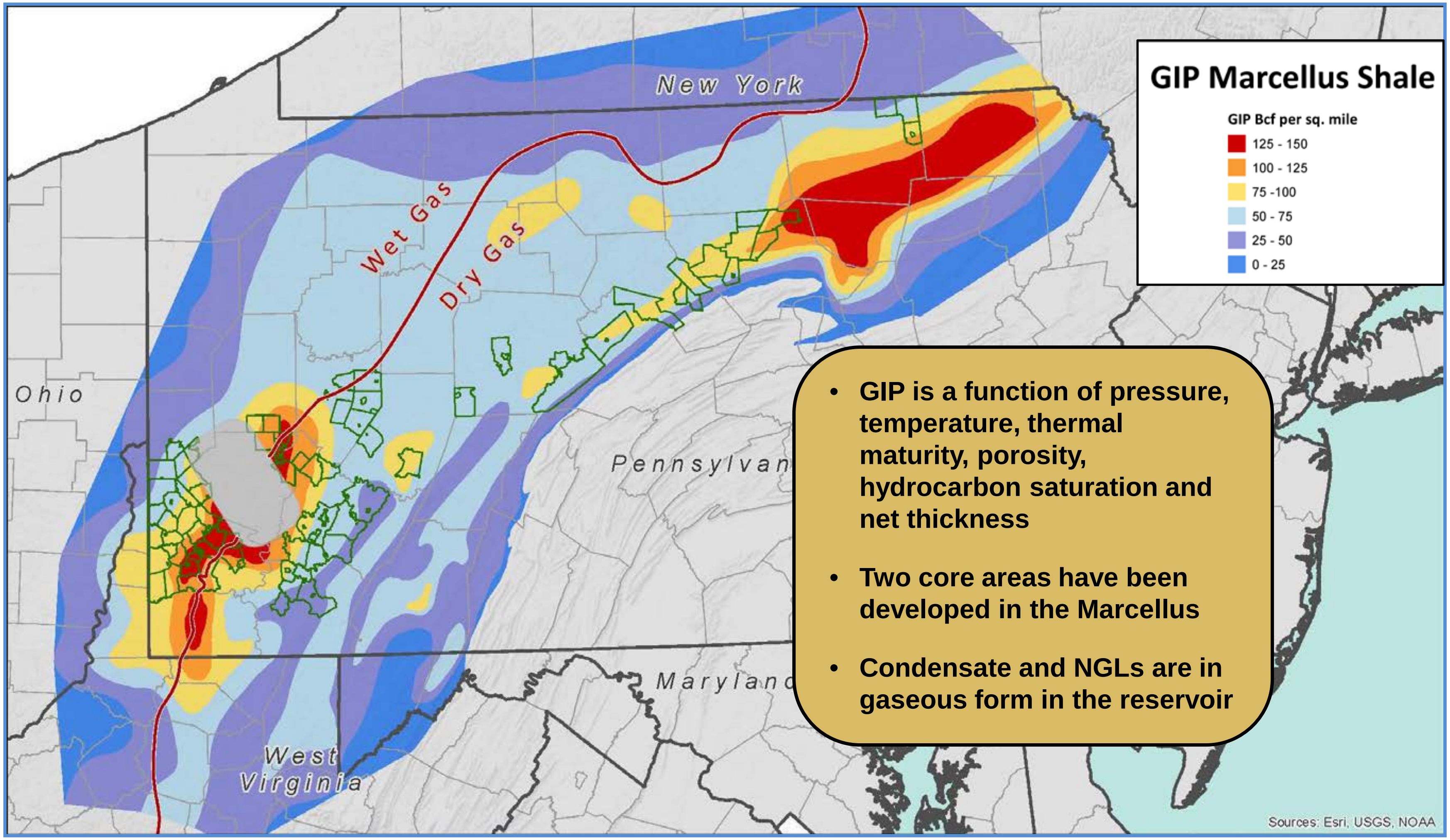
- Ability to target our best areas with 3.0+ Bcfe/1,000 ft.
- New wells have EURs 20% higher than the average dry well
- Significant cost savings



Avg EUR/1000 ft.: 3.0+ Bcfe



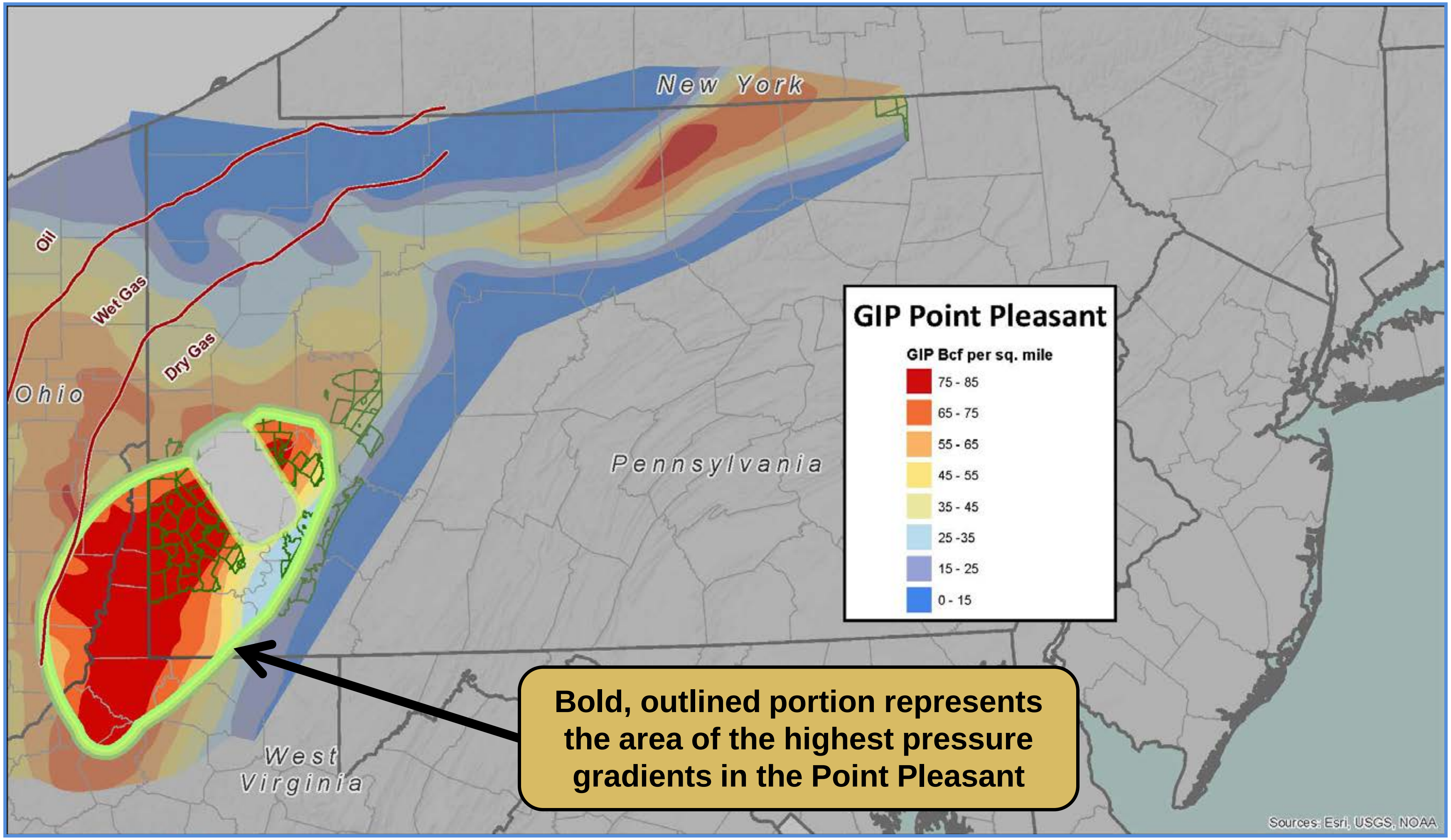
Gas In Place (GIP) – Marcellus Shale



- GIP is a function of pressure, temperature, thermal maturity, porosity, hydrocarbon saturation and net thickness
- Two core areas have been developed in the Marcellus
- Condensate and NGLs are in gaseous form in the reservoir

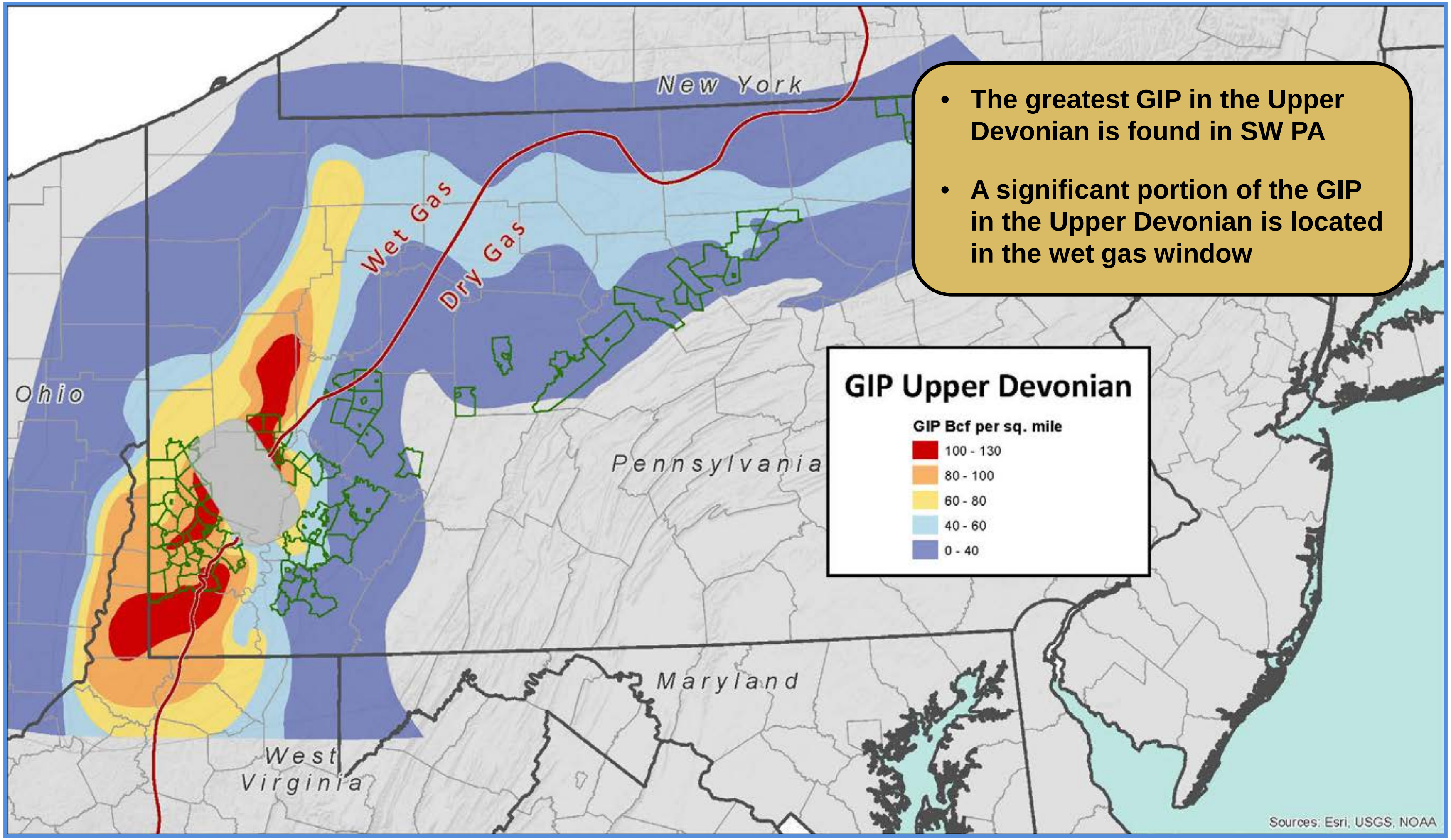
Note: Townships where Range holds ~2,000+ acres (as of January 2016) and estimated as prospective, are outlined green. GIP – Range estimates.

Gas In Place (GIP) – Point Pleasant



Note: Townships where Range holds ~2,000+ acres (as of January 2016) and estimated as prospective, are outlined green. GIP – Range estimates.

Gas In Place (GIP) – Upper Devonian Shale



- **The greatest GIP in the Upper Devonian is found in SW PA**
- **A significant portion of the GIP in the Upper Devonian is located in the wet gas window**

Note: Townships where Range holds ~2,000+ acres (as of January 2016) and estimated as prospective, are outlined green. GIP – Range estimates.

Macro Section

Significant Natural Gas Demand Growth Projected – Beginning in 2016

LONG TERM US NATURAL GAS DEMAND ROADMAP (BCF / D)

	2016	2017	2018	2019	2020	Cumulative 2015-2020
LNG Exports						
Sabine Pass	1.2	1.2		0.7		3.1
Freeport			0.5	1.0		1.5
Cove Point			0.8			0.8
Cameron			1.2	0.6		1.8
Corpus Christi				0.8	0.8	1.6
LNG Sub-Total	***1.2***	***1.6***	***2.6***	***3.1***	***0.8***	***8.9***
Mexico / Canada Exports						
Mexico Net Exports	0.5	0.3	0.3	0.3	0.4	1.8
Canada net Exports	0.1	0.1	0.1	0.1	0.1	0.5
Mexico / Canada Sub-Total	***0.6***	***0.4***	***0.4***	***0.4***	***0.5***	***2.3***
Power Generation						
Coal Plant Retirements	0.4	0.3	0.1	0.0	0.3	1.1
Nuclear Retirements	-	-	01.1	0.1	0.2	0.4
Incremental Electricity Demand	0.1	0.1	0.1	2.0	2.0	4.3
Power Generation Sub-Total	***0.5***	***0.4***	***0.4***	***0.3***	***0.7***	***2.3***
Industrial						
Methanol	0.3	0	0	0	0	0.4
Ethylene	0	0.4	0.1	-	0.1	0.6
Ammonia	0.5	0.1	0.2	0.1	0.1	1.0
Industrial Sub-Total	***0.8***	***0.4***	***0.3***	***0.1***	***0.2***	***2.0***
Transportation						
New Fueling Opportunities	-	-	0.1	0.1	0.1	0.3
Transportation Sub-Total	***-***	***-***	***0.1***	***0.1***	***0.1***	***0.3***
	2016	**2017**	**2018**	**2019**	**2020**	**2020**
Total	**3.1**	**2.5**	**3.7**	**4.0**	**2.2**	**15.8**

Research report dated 04/08/2016

SIMMONS & COMPANY INTERNATIONAL

U.S. LNG Exports Expected to be ~8 Bcf/day by 2020 – per TPH

US LNG Export Projects Under Construction

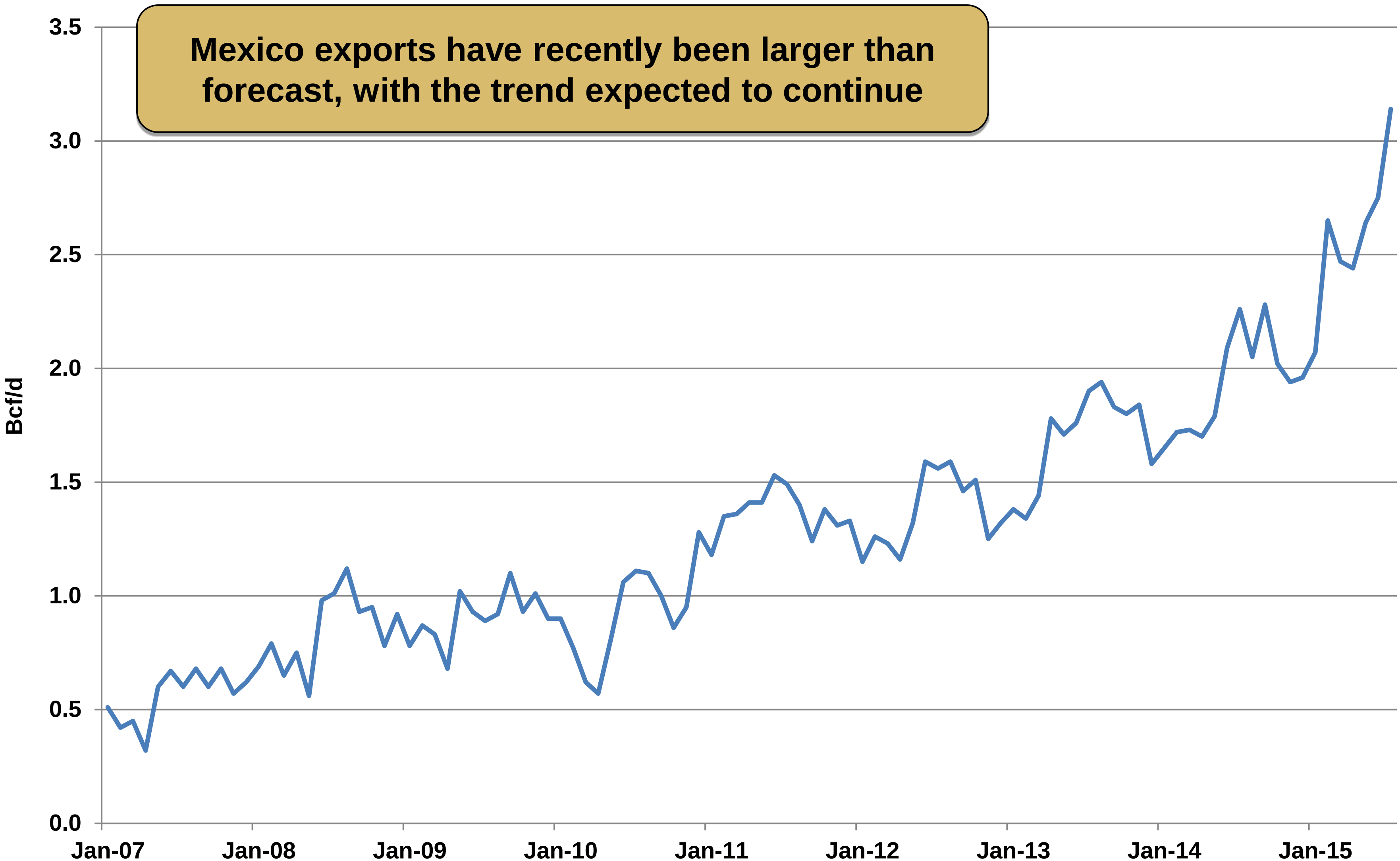
US LNG Projects Under Construction					
Projects	Uncontracted Capacity (bcf/d)	Contracted Capacity (bcf/d)	Nameplate Capacity (bcf/d)	Percent Contracted	Online Date
Sabine Pass T1-4	0.3	2.1	2.4	89%	Feb-16 - Sept-17
Cameron LNG T1-3	0	1.7	1.7	100%	Early/Mid/Late-18
Freeport LNG T1-3	0.1	1.7	1.8	97%	Sept-18 - Aug-19
Cove Point T1	0.1	0.7	0.8	92%	Dec-17
Corpus Christi T1-2	0.2	1.0	1.2	86%	Jun-19, Apr-20
Sabine Pass T5	0.1	0.5	0.6	83%	19-Jan
Total	**0.7**	**7.8**	**8.4**	**92%**	**NA**

- **Nameplate US export capacity to total 8.4bcf/d by YE 2020 with just over 8bcf/d exportable 2020**.
- **>90% or 7.9bcf/d of the capacity is contracted.**
  - What does this mean? The off-takers pay ~$3/mmbtu for any contracted LNG volumes they defer/cancel. Buyers could then buy LNG on the spot market for ~$7/mmbtu or all in cost of ~$10/mmbtu (including the cancellation fee).
  - All in US LNG landed in Asia likely runs $7.50-9.50 depending on US gas price and transport costs.
- There are 5 major US LNG export projects under construction (assumes Sabine Pass is one project).
- **There are another >4bcf/d of LNG export projects that are ~fully contracted**, which we would consider close to FID (e.g. Lake Charles, Golden Pass).

TUDOR PICKERING HOLT & CO ENERGY INVESTMENT & MERCHANT BANKING

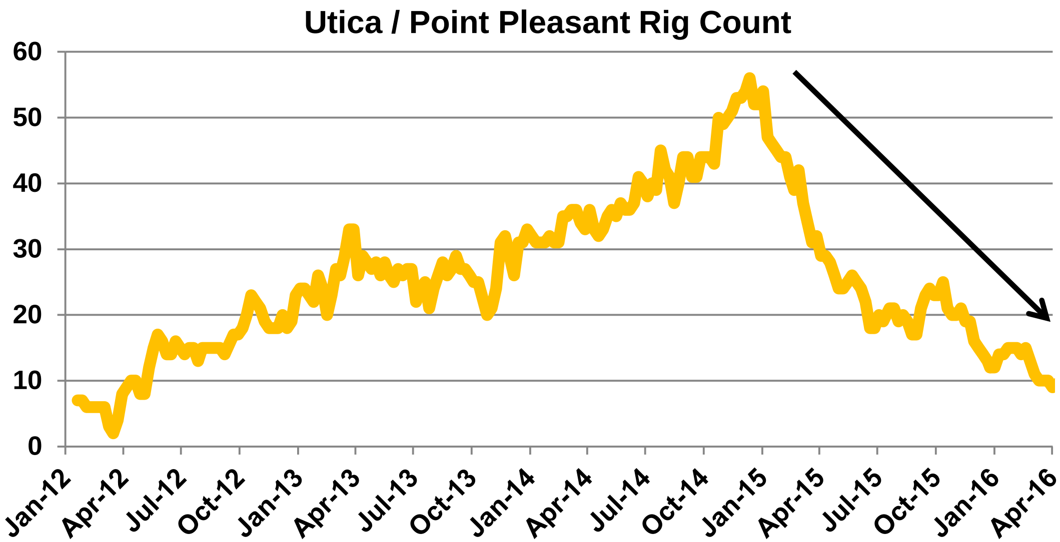
Research report dated 10/08/2015

U.S. Natural Gas Exports to Mexico



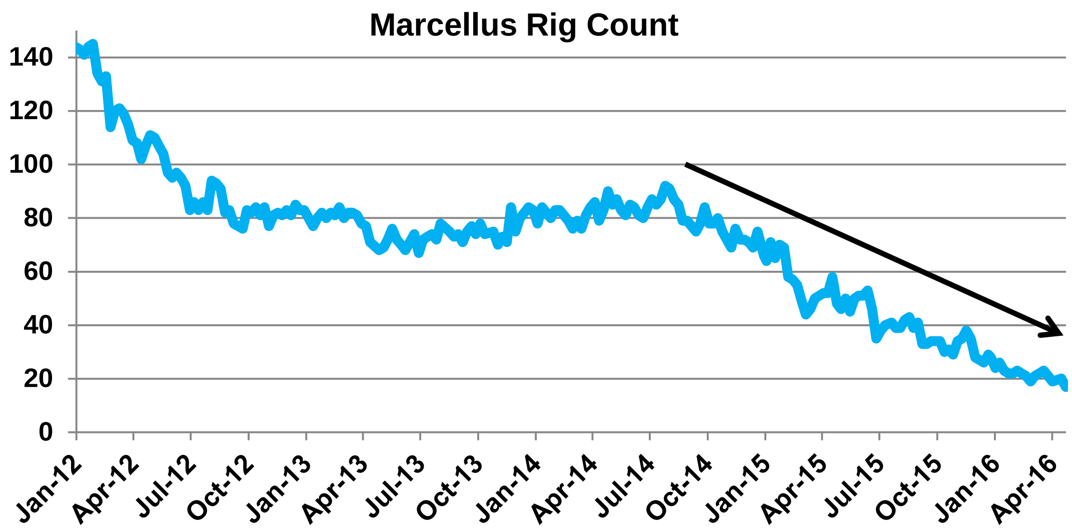
Source – PointLogic, Bloomberg

Appalachian Rig Counts Declining



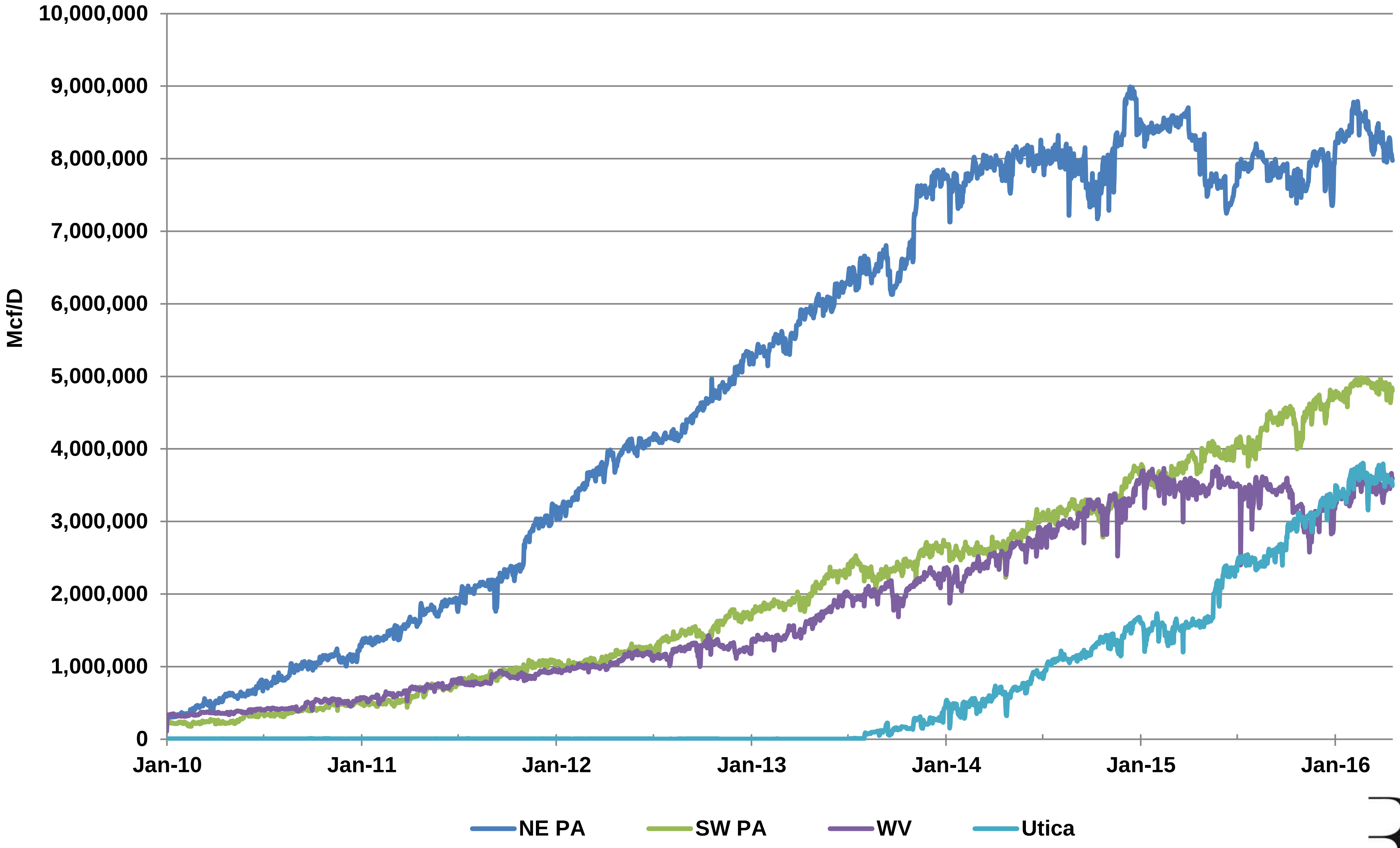
- **Utica/Point Pleasant rig count down 82% from the peak in 2014**

- **Marcellus rig count down 84% from the 2014 peak**



Source – RigData as of 4/22/2016

Appalachian Pipeline Flow Data by Region (Mcf/d)

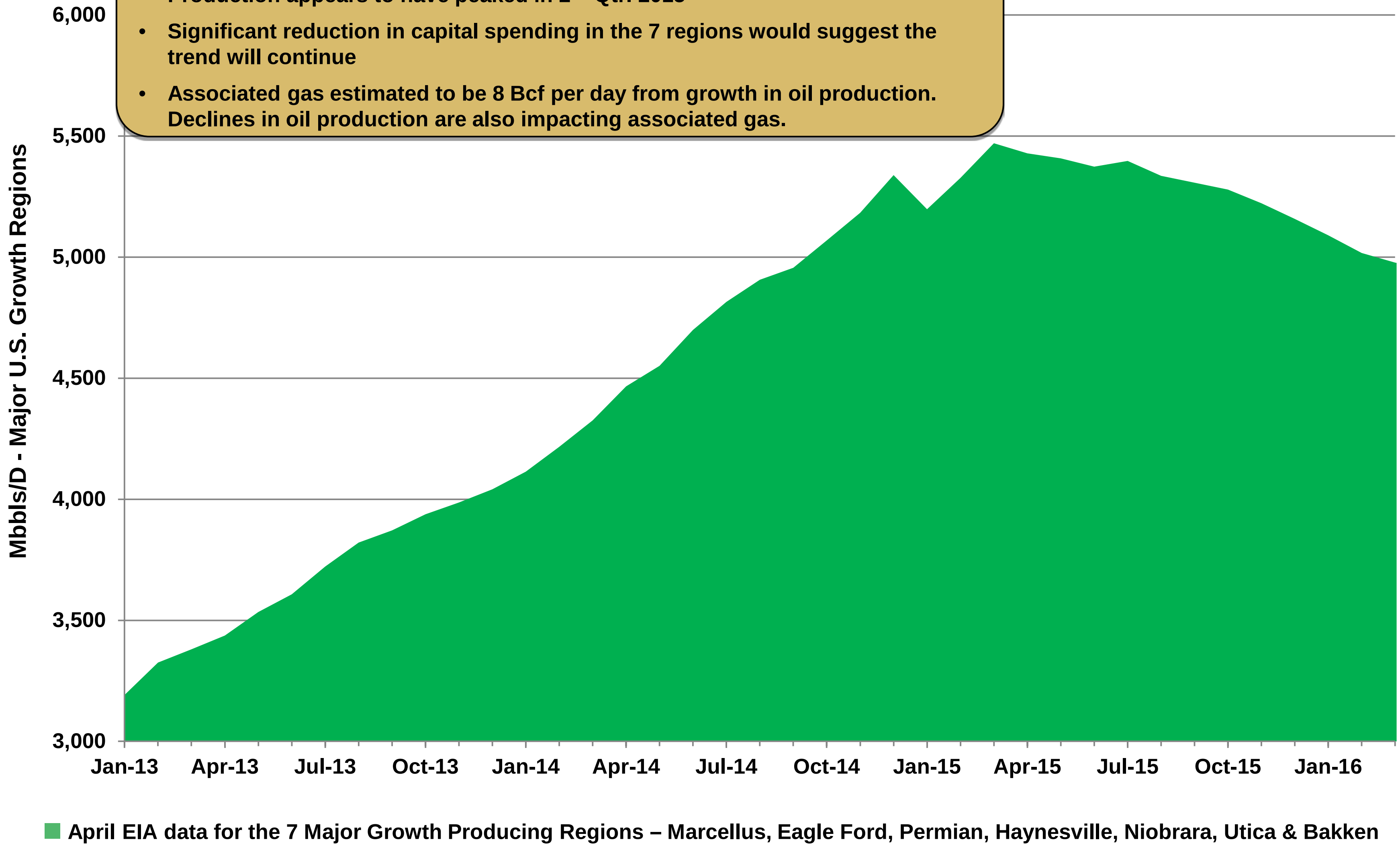


Source – RS Energy Group, raw data from Ventyx Velocity Suite and Bloomberg, as of 4/19/2016

RS ENERGY GROUP

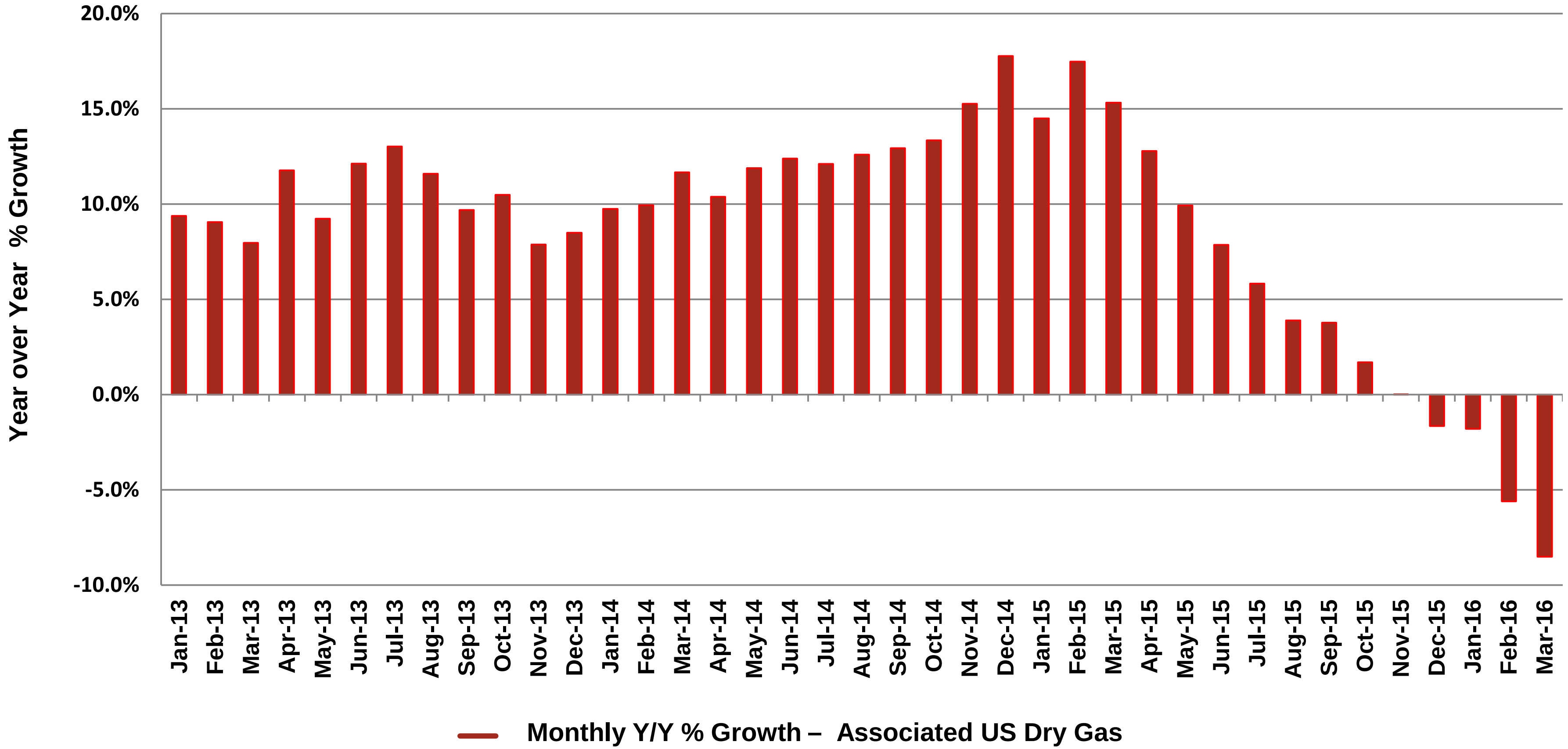
U.S. Domestic Oil Production Appears to Have Peaked

- 7 major regions account for 95% of domestic oil production growth
- Production appears to have peaked in 2nd Qtr. 2015
- Significant reduction in capital spending in the 7 regions would suggest the trend will continue
- Associated gas estimated to be 8 Bcf per day from growth in oil production. Declines in oil production are also impacting associated gas.



Associated Gas Growth Production

Gas production from ‘oil plays’ expected to continue declining in 2016 due to a lack of drilling within these plays

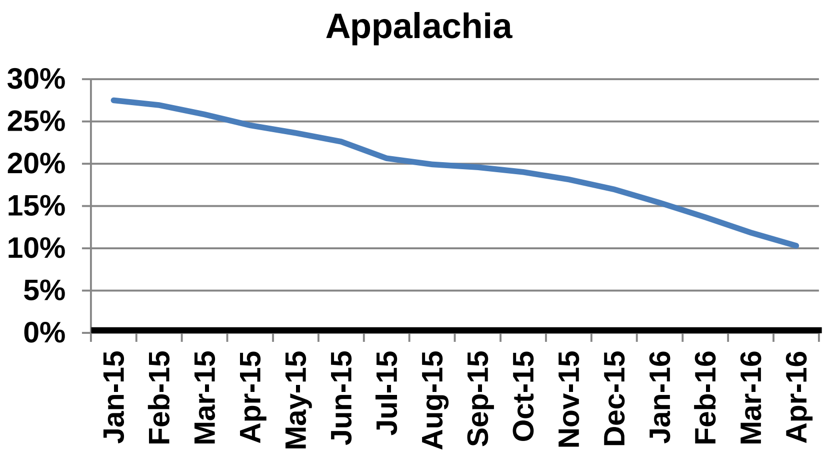


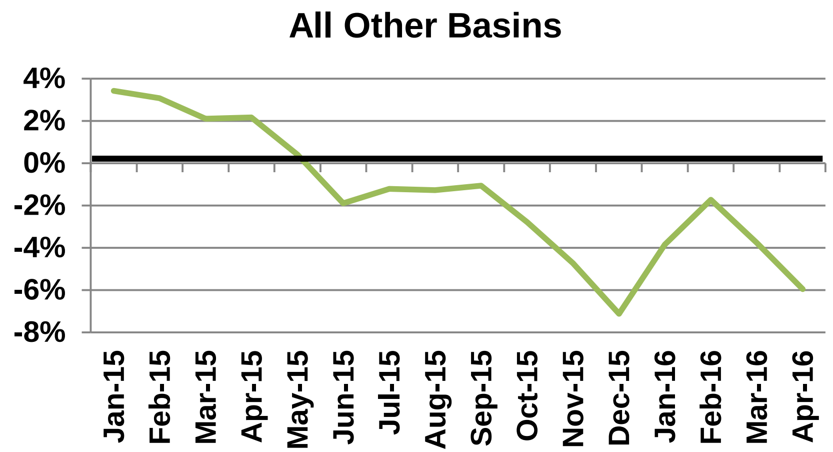
Source – Bentek, Jefferies as of April 2016

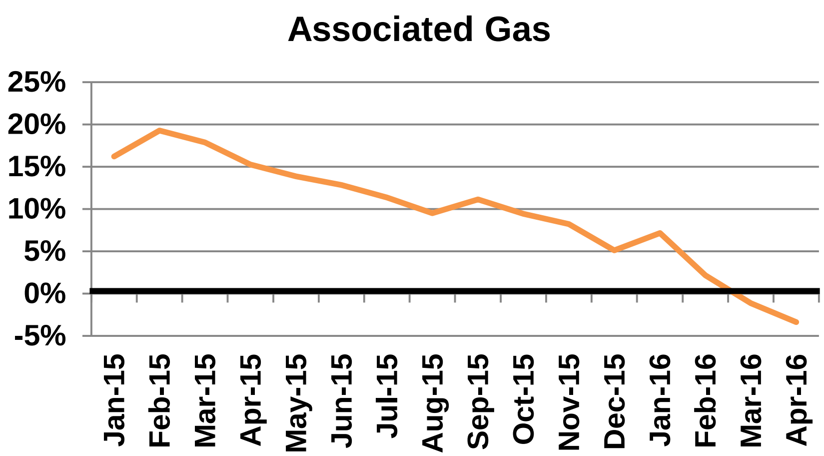
U.S. Natural Gas Production

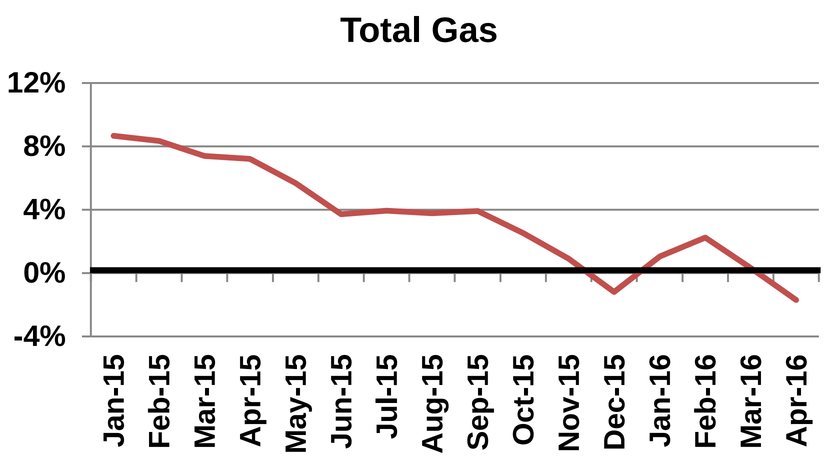
Growth by Area

Year over Year % Growth





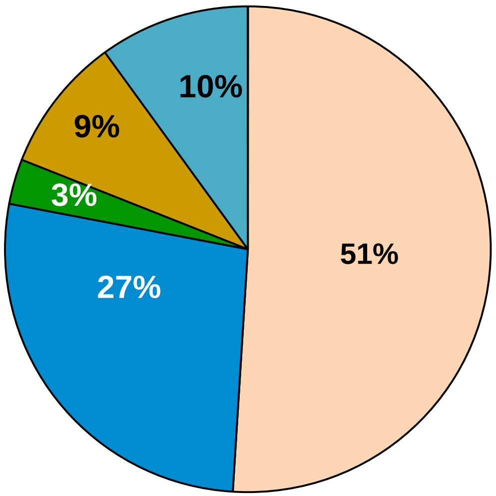




Source – Bentek, EIA

Marcellus NGL Pricing

Weighted Avg. Composite Barrel [1]

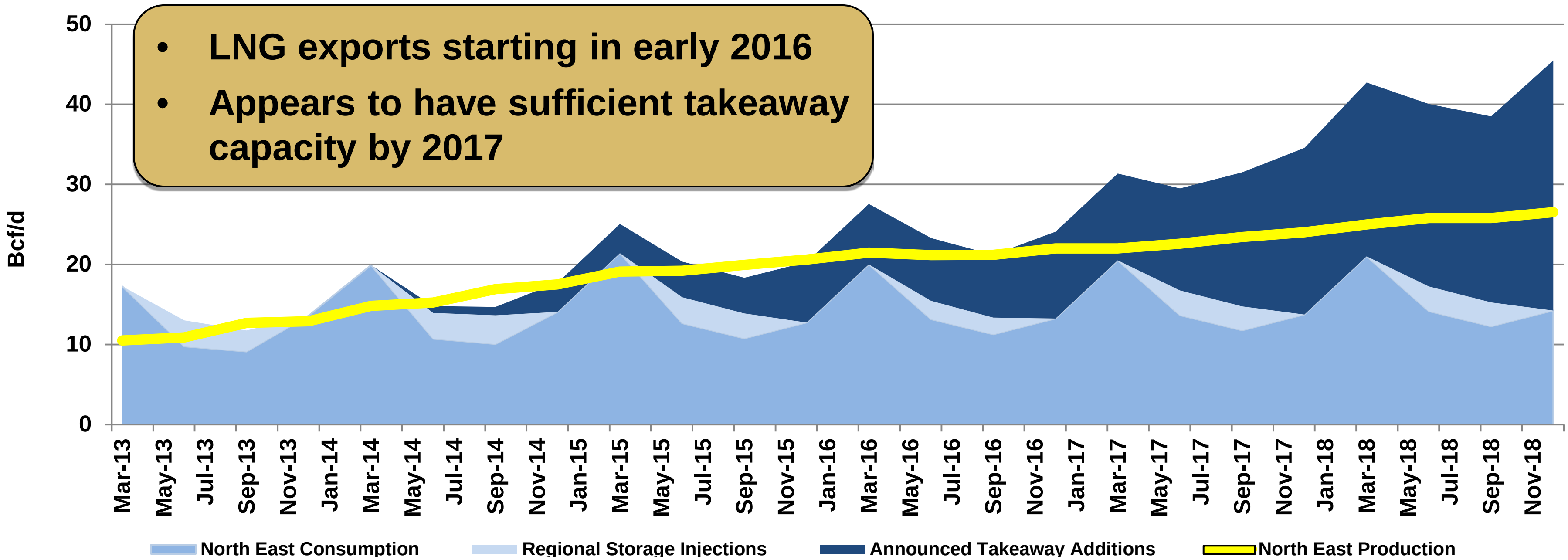


Realized Marcellus NGL Prices

	2015				2016
	1Q	2Q	3Q	4Q	1Q
NYMEX – WTI (per bbl)	$48.62	$57.88	$46.61	$42.22	$33.56
Mont Belvieu Weighted Priced Equivalent [2]	$18.05	$18.32	$17.16	$17.24	$13.60
Plant Fees plus Diff.	(7.16)	(10.64)	(11.20)	(8.43)	(5.30)
Marcellus average price before NGL hedges	$10.89	$7.71	$5.96	$8.81	$8.30
% of WTI (NGL Pre-hedge / Oil NYMEX)	22%	13%	13%	21%	25%

(1) Based on estimated NGL volumes in 1Q 2016
(2) Based on Mont Belvieu NGL prices and weighted average barrel composition for Marcellus

Appalachian Production, Consumption & Takeaway - 2015-2018



		2015	2016	2017	2018
	Appalachia Production Year End Exit Rate	20.6	22.0	24.0	26.5
	Appalachia Consumption + Injections	14.4	14.4	14.9	15.4
A	**Appalachia Gas Surplus for Export**	**6.2**	**7.6**	**9.1**	**11.1**
	Takeaway Projects - Northeast (cumulative)	1.1	1.8	3.1	7.8
	Takeaway Projects - Southwest (cumulative)	3.3	5.9	15.2	20.4
B	**Total Takeaway Projects (cumulative)**	**4.4**	**7.7**	**18.3**	**28.3**
	Excess Takeaway (B – A)	**(1.8)**	**0.1**	**9.2**	**17.1**

Summer Constrained → **Freely Flowing** → **Overbuilt**

Source: Analyst estimates

Announced Appalachian Basin Takeaway Projects – 1 of 2

	Northeast PA	Operator	Main Line	Market	Start-up*	Capacity – Bcf/d	Fully Committed	Approved or with FERC
2015	Niagara Expansion	Kinder Morgan	TGP	Canada	Q4'15	0.2	Y	Y
	Northern Access 2015	NFG	National Fuel	Canada	Q4'15	0.1	Y	Y
	Leidy Southeast	Williams	Transco	Mid-Atlantic/SE	Q4'15	0.5	Y	Y
	East Side Expansion	Nisource	Columbia	Mid-Atlantic/SE	Q4'15	0.3	Y	Y
2016	SoNo Iroquois Access	Dominion	Iroquois	Canada	Q2'16	0.3	N	N
	Algonquin AIM	Spectra	Algonquin	NE	Q4'16	0.4	Y	Y
2017	Northern Access 2016	NFG	National Fuel	Canada	H2'17	0.4	Y	Y
	Constitution	Williams	Constitution	NE	H2'17	0.7	Y	Y
	Atlantic Bridge	Spectra	Algonquin	NE	H2'17	0.7	N	Y
2018	Atlantic Sunrise	Williams	Transco	Mid-Atlantic/SE	H1'18	1.7	Y	Y
	Access Northeast	Spectra	Algonquin	NE	H2'18	1.0	N	Y
	Diamond East	Williams	Transco	NE	H2'18	1.0	N	N
	PennEast	AGT		NE	H2'18	1.0	Y	Y

	Southwest	Operator	Main Line	Market	Start-up	Capacity – Bcf/d	Fully Committed	Approved or with FERC
2015	REX Zone 3 Full Reversal	Tall Grass	REX	Midwest	Q2'15	1.2	Y	Y
	TGP Backhaul / Broad Run	Kinder Morgan	TGP	Gulf Coast	Q4'15	0.6	Y	Y
	TETCO OPEN	Spectra	TETCO	Gulf Coast	Q4'15	0.6	Y	Y
	Uniontown to Gas City	Spectra	TETCO	Midwest	Q3'15	0.4	Y	Y
2016	Gulf Expansion Ph1	Spectra	TETCO	Gulf Coast	Q4'16	0.3	Y	Y
	Clarington West Expansion	Tall Grass	REX	Midwest	Q4'16	1.6	N	N
	Zone 3 Capacity Enhancement	Tall Grass	REX	Midwest	Q4'16	0.8	Y	Y

*** Start-up dates reflect announced operator in-service dates**

Note: Data subject to change as projects are approved and built. Highlighted projects where Range is participating.

Announced Appalachian Basin Takeaway Projects – 2 of 2

	Southwest	Operator	Main Line	Market	Start-up*	Capacity – Bcf/d	Fully Committed	Approved or with FERC
2017	Rover Ph1	ETP		Midwest/Canada/ Gulf Coast	Q2'17	1.9	Y	Y
	Rayne/Leach Xpress	Nisource	Columbia	Gulf Coast	Q3'17	1.5	Y	Y
	SW Louisiana	Kinder Morgan	TGP	Gulf Coast	Q3'17	0.9	Y	Y
	Rover Ph2	ETP		Midwest/Canada/ Gulf Coast	Q3'17	1.3	Y	Y
	Adair SW	Spectra	TETCO	Gulf Coast	Q4'17	0.2	Y	Y
	Access South	Spectra	TETCO	Gulf Coast	Q4'17	0.3	Y	Y
	Gulf Expansion Ph2	Spectra	TETCO	Gulf Coast	Q4'17	0.4	Y	Y
	NEXUS	Spectra		Midwest/Canada	Q4'17	1.5	Y	Y
	ANR Utica	Transcanada	ANR	Midwest/Canada	Q4'17	0.6	N	N
	Cove Point LNG	Dominion		NE	Q4'17	0.7	Y	Y
2018	TGP Backhaul / Broad Run Expansion	Kinder Morgan	TGP	Gulf Coast	Q2'18	0.2	Y	Y
	Mountain Valley	NextEra/EQT		Mid-Atlantic/SE	Q4'18	2.0	Y	Y
	Western Marcellus	Williams	Transco	Mid-Atlantic/SE	Q4'18	1.5	N	N
	Atlantic Coast	Duke/Dominion		Mid-Atlantic/SE	Q4'18	1.5	Y	Y

Total NE Appalachia to Canada	**1.0**
Total NE Appalachia to NE	**4.4**
Total NE Appalachia to Mid-Atlantic/SE	**2.5**
Total NE Appalachia Additions	**7.8**
Total SW Appalachia to Mid-Atlantic/SE	**5.0**
Total SW Appalachia to Midwest/Canada	**8.2**
Total SW Appalachia to Gulf Coast	**6.5**
Total SW Appalachia to NE	**0.7**
Total SW Appalachia Additions	**20.4**
Overall Total Additions for Appalachian Basin (2015 – 2018)	**28.3**

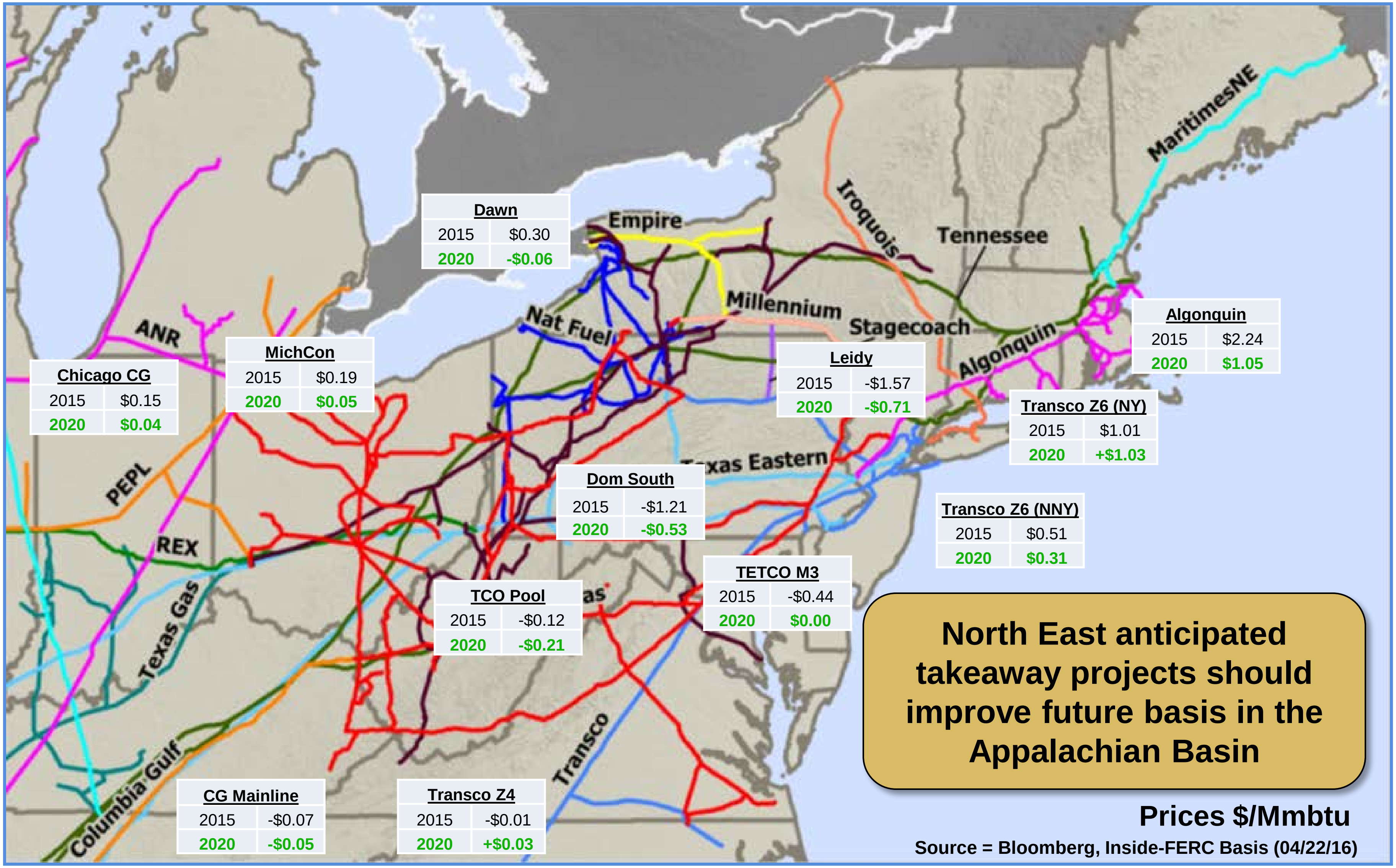
Existing capacity added by YE 2014

2.8	**SW**
.6	**NE**
3.4	**Total**

*** Start-up dates reflect announced operator in-service dates**

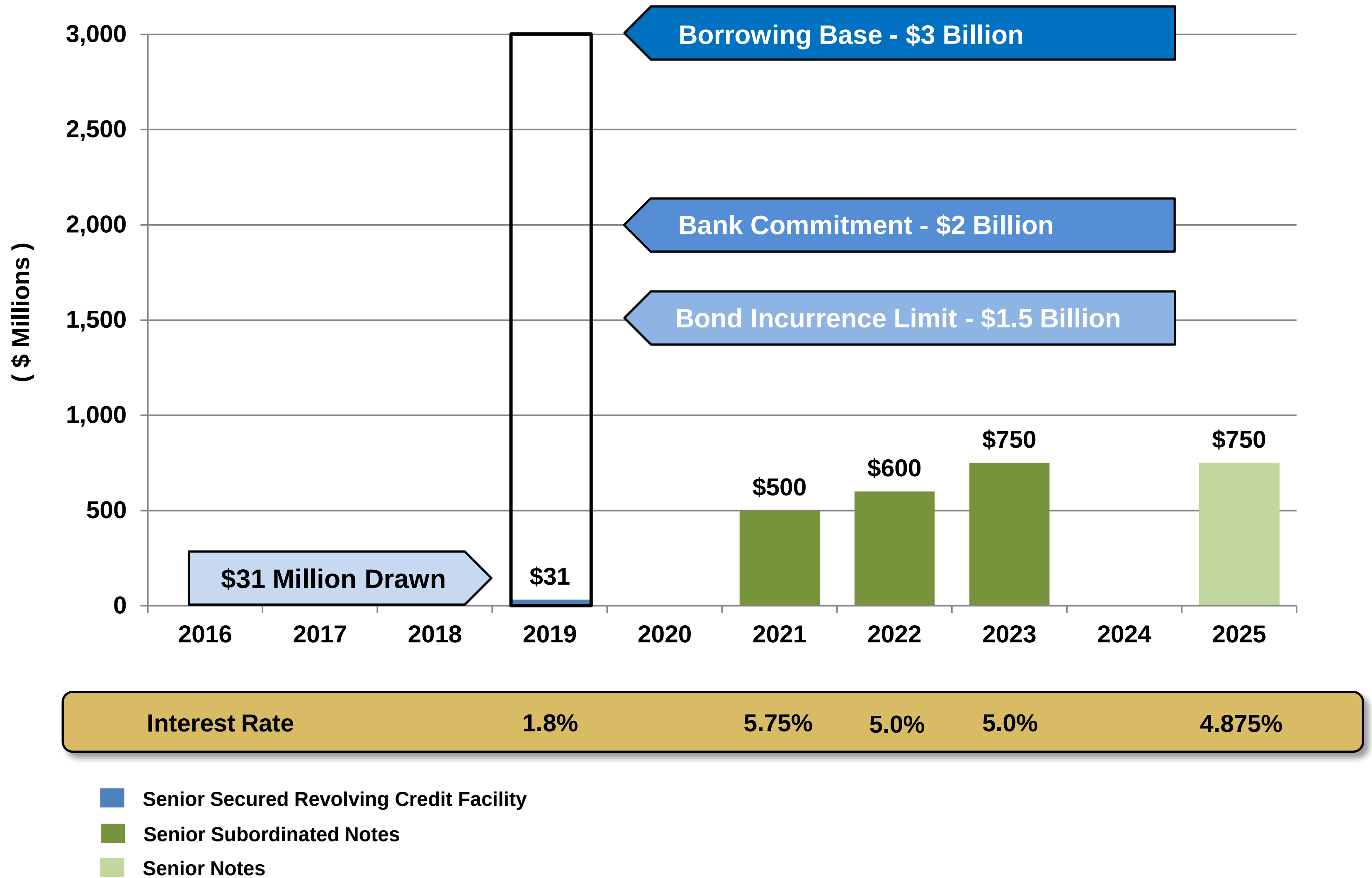
Note: Data subject to change as projects are approved and built. Highlighted projects where Range is participating.

What Does the Future's Strip Price Indicate for Regional Basis?



Financial Detail

Range Maintains an Orderly Debt Maturity Ladder



Strong, Simple Balance Sheet

Debt at lowest level in past 3 years

($ in millions)	YE 2013	YE 2014	Q1 2015	Q2 2015	Q3 2015	Q4 2015	Q1 2016
Bank borrowings[1]	$500	$723	$912	$364	$987	$95	$31
Sr. Notes[1]				750	750	750	750
Sr. Sub. Notes[1]	2,641	2,350	2,350	2,350	1,850	1,850	1,850
Less: Cash	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Net debt	3,141	3,073	3,262	3,464	3,587	2,695	2,631
Common equity	2,414	3,456	3,490	3,381	3,085	2,760	2,672
Total capitalization	$5,555	$6,529	$6,752	$6,845	$6,672	$5,455	$5,303
Debt-to capitalization	57%	47%	48%	50%	54%	49%	50%
Debt/EBITDAX	2.8x	2.6x	2.9x	3.3x	3.7x	3.0x	3.3x
Liquidity[2]	$1,166	$1,172	$980	$1,527	$876	$1,267[3]	$1,238[3]

(1) Excludes unamortized debt issuance costs
(2) Liquidity based on bank commitment amount, which excludes additional liquidity under total borrowing base
(3) Liquidity limited based on senior subordinated notes indenture provision

Early, Continuous Action Taken to Prepare for Low Prices

June 2014

- Called high cost 8% notes, reducing annual interest expense by $24 million or $0.06 mcfe
- Redemption funded by an equal sized equity offering aimed at accelerating balance sheet

October 2014

- Renewed bank credit agreement with larger facility size, borrowing base, bank group and enhanced flexibility
- Annual borrowing base redeterminations and a 5-year maturity
- Ability to release collateral during transition to investment grade

March 2015

- Unanimous reaffirmation of $3 billion borrowing base and $2 billion commitments
- Elimination of debt-to-ebitdax covenant; replaced with interest coverage test and a forward-looking asset coverage test
- Announced closure of Oklahoma City office, saving approximately $18 million annually in administrative costs

May 2015

- Opportunistically accessed a strong high yield debt market issuing $750 million 10-year notes at 4.875%
- Issued senior notes continuing to lay foundation for an investment grade balance sheet
- Coupon remains the lowest of any high yield energy issuer of any rating year-to-date

August 2015

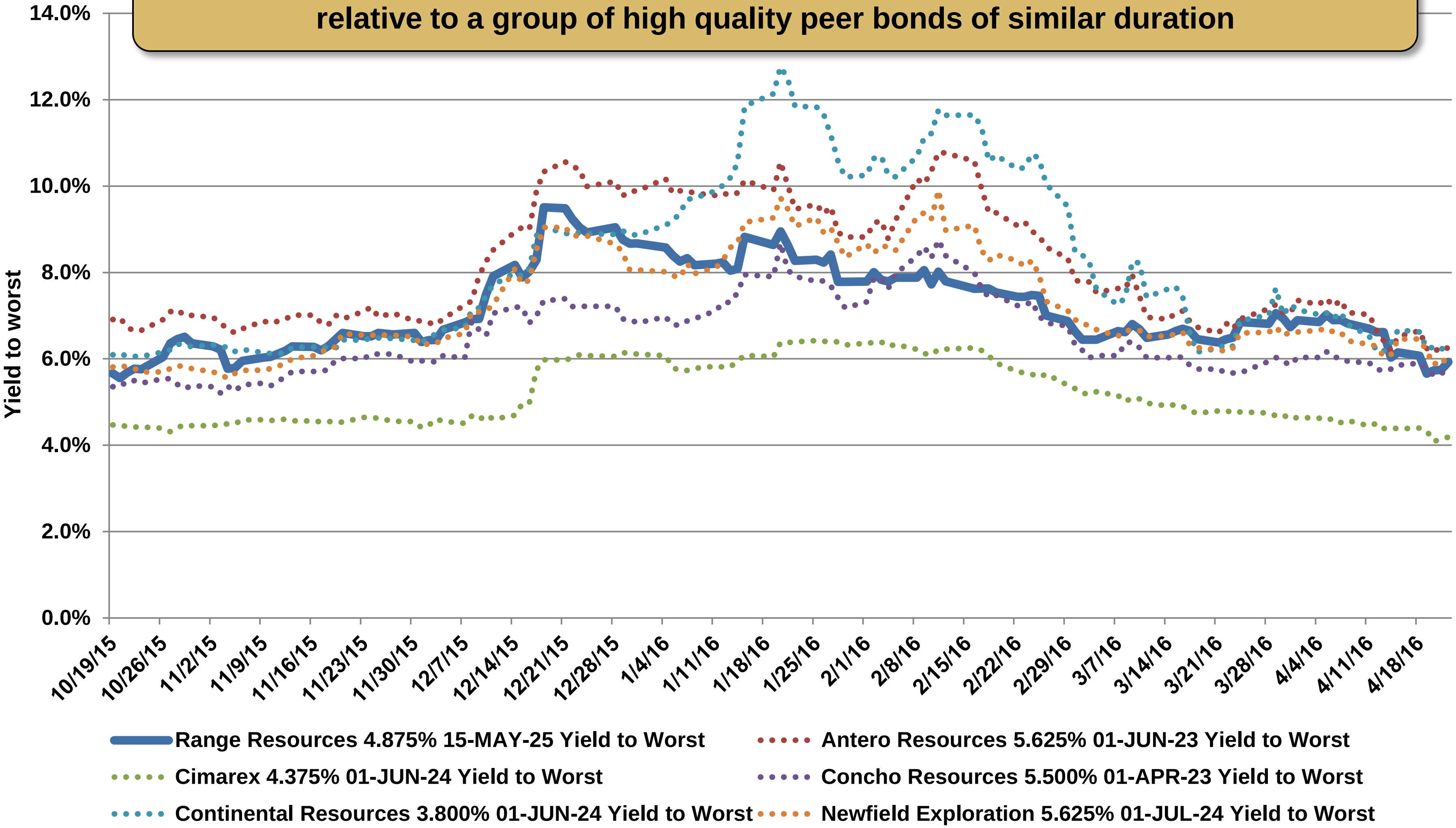
- Portion of proceeds from 4.875% senior notes offering used to redeem 6.75% senior subordinated notes due 2020
- Reduction in coupon on $500 million principal redeemed of 1.875% amounts to annual interest savings of ~$9.4 million

2016

- Sold Nora field for $876 million on 12/30/15, paying down revolving credit facility
- Bradford county assets sold 3/28/16 for $110 million
- Signed purchase and sale agreement for central Oklahoma assets for $77 million

Range Bonds Continue to Trade Well

Since December highs, Range bonds tightened significantly and continue to trade well relative to a group of high quality peer bonds of similar duration



Source: JPMorgan DataQuery (4/22/16)

Gas and Oil Hedging Status

	Period	Volumes Hedged (Mmbtu/day)	Average Floor Price ($/Mmbtu)
Gas Hedging	2Q 2016 Swaps 3Q 2016 Swaps 4Q 2016 Swaps	760,000 760,000 760,000	$3.21 $3.22 $3.24
	2017 Swaps 2018 Swaps	205,000 50,000	$2.83 $2.88
Oil Hedging	2Q 2016 Swaps 3Q 2016 Swaps 4Q 2016 Swaps	6,000 5,750 5,750	$59.21 $58.73 $58.73
	2017 Swaps	1,000	$50.13

As of 04/25/2016 – For quarterly detail of hedges, see RRC website

Natural Gas Liquids Hedging Status

	Period	Volumes Hedged (bbls/day)	Hedged Price[1] ($/gal)
Ethane (C2)	2H 2016 Swaps 2017 Swaps	500 1,000	$0.22 $0.25
Propane (C3)	2016 Swaps	5,500	$0.60
Normal Butane (NC4)	2Q 2016 Swaps 2H 2016 Swaps	3,918 4,000	$0.66 $0.66
Natural Gasoline (C5)	2Q 2016 Swaps 2H 2016 Swaps 2017 Swaps	3,250 3,500 1,000	$1.14 $1.11 $0.92

Conversion Factor:
One barrel = 42 gallons

As of 04/25/2016 – For quarterly detail of hedges, see RRC website

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