June 3, 2015

RANGE RESOURCES®

Company Presentation

Forward-Looking Statements

Certain statements and information in this presentation may constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. The words "anticipate," "believe," "estimate," "expect," "forecast," "plan," "predict," "target," "project," "could," "should," "would" or similar words are intended to identify forward-looking statements, which are generally not historical in nature. Statements concerning well drilling and completion costs assume a development mode of operation; additionally, estimates of future capital expenditures, production volumes, reserve volumes, reserve values, resource potential, resource potential including future ethane extraction, number of development and exploration projects, finding costs, operating costs, overhead costs, cash flow, NPV10, EUR and earnings are forward-looking statements. Our forward looking statements, including those listed in the previous sentence are based on our assumptions concerning a number of unknown future factors including commodity prices, recompletion and drilling results, lease operating expenses, administrative expenses, interest expense, financing costs, and other costs and estimates we believe are reasonable based on information currently available to us; however, our assumptions and the Company's future performance are both subject to a wide range of risks including, production variance from expectations, the volatility of oil and gas prices, the results of our hedging transactions, the need to develop and replace reserves, the costs and results of drilling and operations, the substantial capital expenditures required to fund operations, exploration risks, competition, our ability to implement our business strategy, 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, access to capital, litigation, uncertainties about reserve estimates, environmental risks and regulatory changes, and there is no assurance that our projected results, goals and financial projections can or will be met. This presentation includes certain non-GAAP financial measures. Reconciliation and calculation schedules for the non-GAAP financial measures can be found on our website at www.rangeresources.com.

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," or "unproved resource potential," "upside" and "EURs per well" 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 being actually 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, unrisked 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 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.

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly update or revise any forward-looking statements after the date they are made, whether as a result of new information, future events or otherwise. 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 the Form 10-K by calling the SEC at 1-800-SEC-0330.

Large Scale Growth Story with Low Cost and Low Risk

Focused on PER SHARE GROWTH of production and reserves at top-quartile or better cost structure

1. **Largest acreage position in <u>core</u> of Marcellus, Upper Devonian and Utica**

2. **Unit costs down over 40% since 2008**

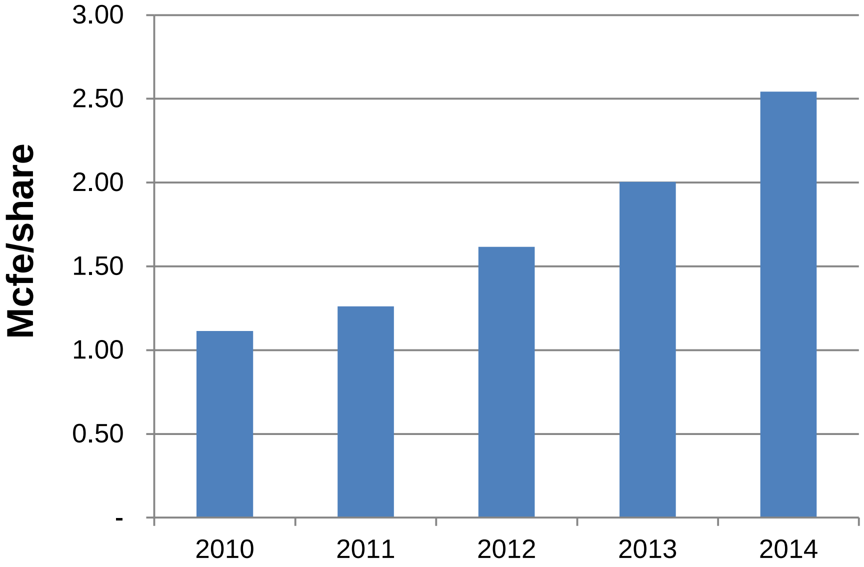
3. **Marcellus well costs down 57% or more on a per lateral foot basis**

4. **Continued efficiencies expected from technical improvements, stacked pay acreage and drilling in areas of existing infrastructure**

5. **Disciplined financial approach and liquidity supports development plans**

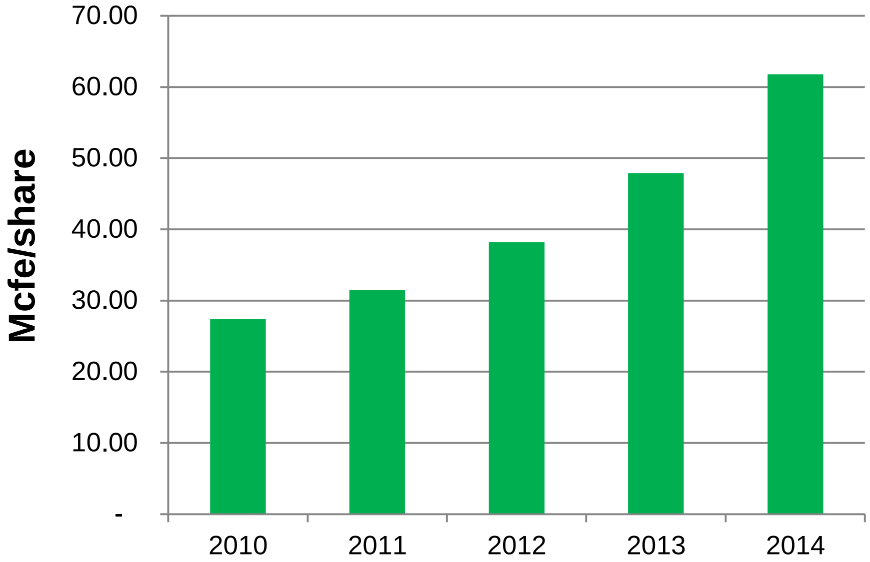
Range is Focused on Per Share Growth, on a Debt-Adjusted Basis

Production/share – debt adjusted



2014 Increase of 27%

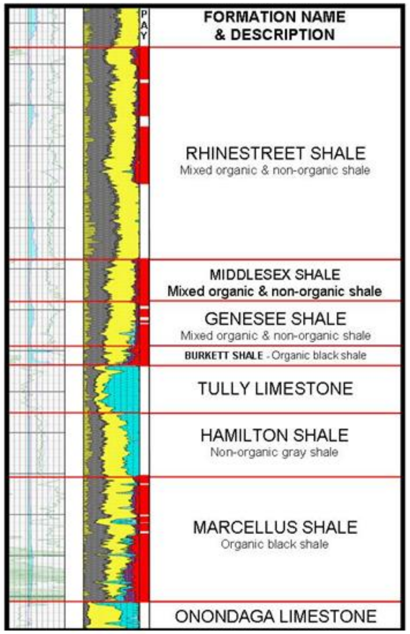
Reserves/share – debt adjusted

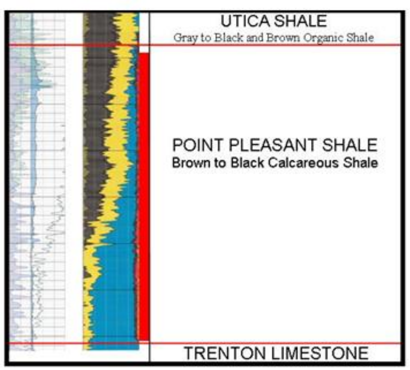


2014 Increase of 29%

- **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**

SW/NE Pennsylvania Stacked Pays



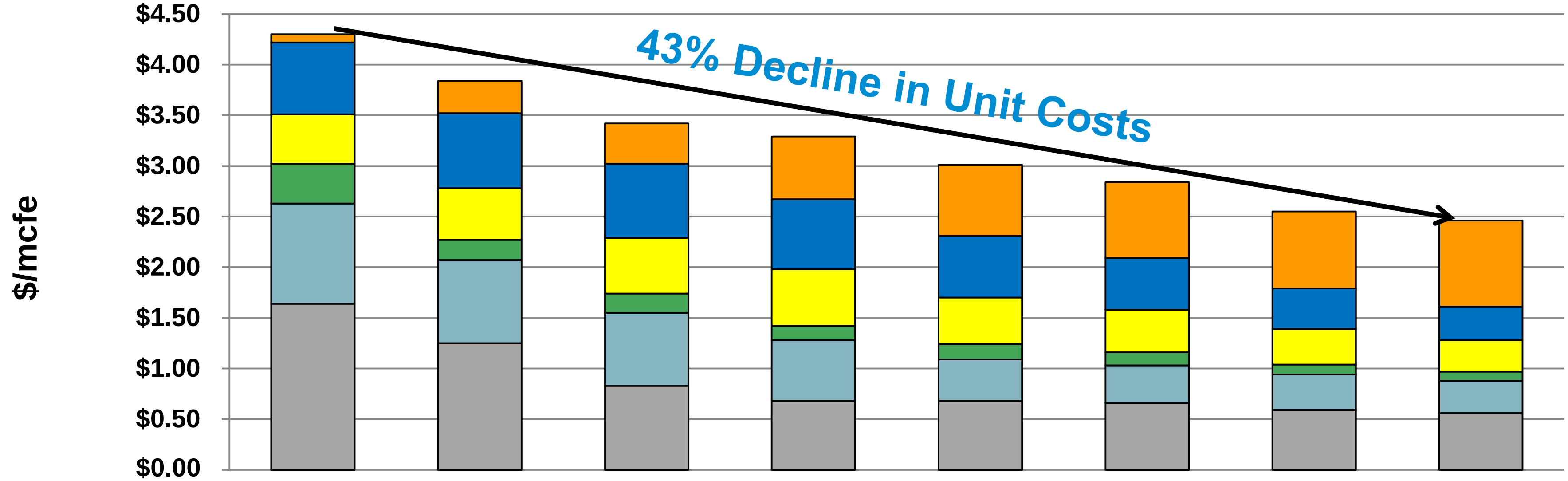


	Wet Acreage	Dry Acreage	Total [1] Net Acreage
Upper Devonian	330,000	195,000	525,000
Marcellus	330,000	310,000	640,000
Utica/Point Pleasant	-	400,000	400,000
	660,000	905,000	1,565,000

Stacked pays allow for multiple development opportunities at 1,000 foot spacing between wells and later with 500 foot spacing prospective on most acreage

(1) Excludes Northwest PA - 285,000 net acres, largely HBP

Driving Down Unit Costs



	2008	2009	2010	2011	2012	2013	2014	2015E
Reserve Replacement(1)	$1.64	$1.25	$0.83	$0.68	$0.68	$0.66	$0.59	$0.56
LOE (2)	$0.99	$0.82	$0.72	$0.60	$0.41	$0.36	$0.35	$0.32
Prod. taxes	$0.39	$0.20	$0.19	$0.14	$0.15	$0.13	$0.10	$0.09
G&A (2)	$0.49	$0.51	$0.55	$0.56	$0.46	$0.42	$0.35	$0.31
Interest	$0.71	$0.74	$0.73	$0.69	$0.61	$0.51	$0.40	$0.33
Trans. & Gathering (2)	$0.08	$0.32	$0.40	$0.62	$0.70	$0.75	$0.76	$0.85(3)
Total	$4.30	$3.84	$3.42	$3.29	$3.01	$2.84	$2.55	$2.46

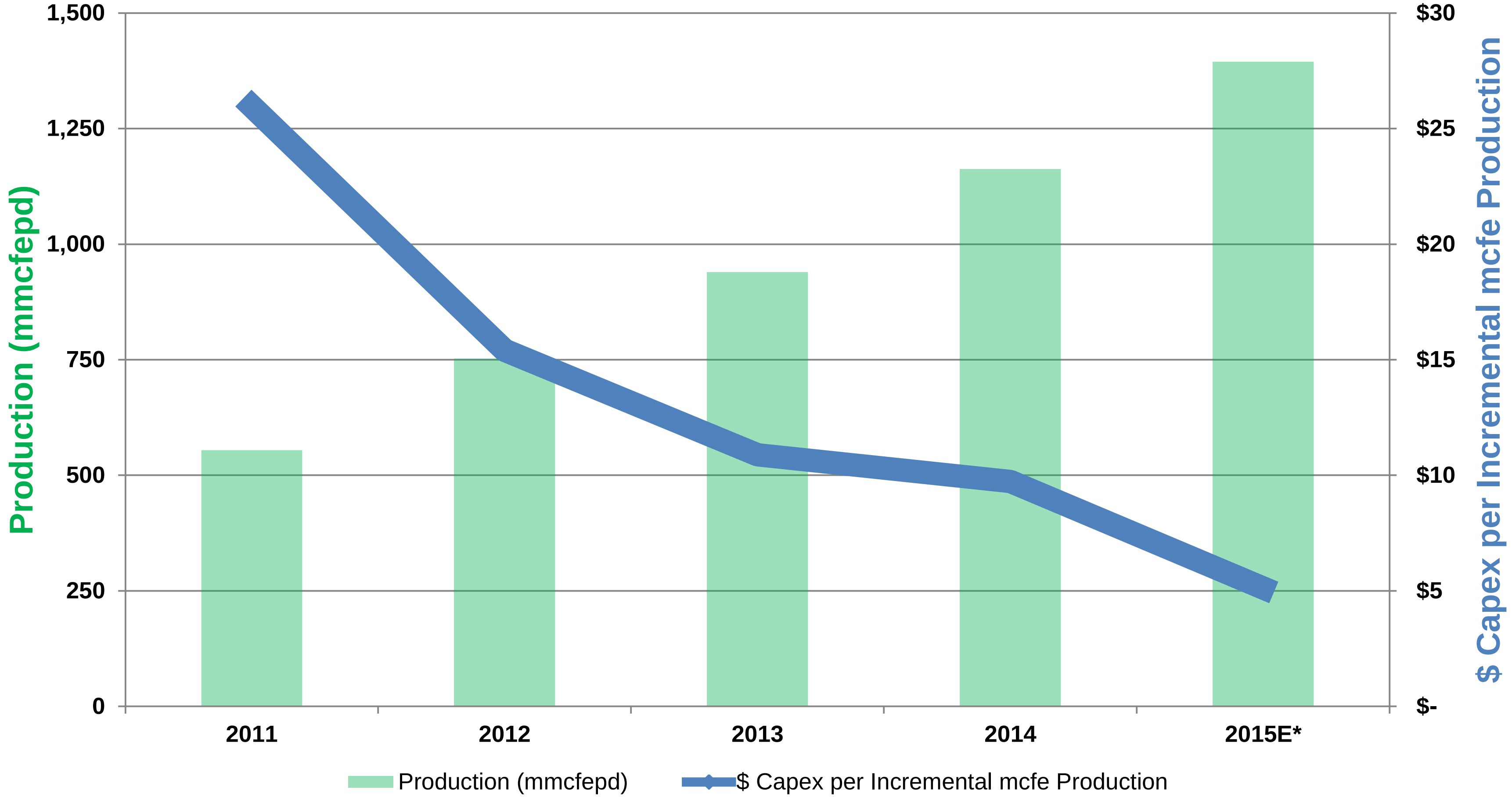
(1) Three-year average of drill bit F&D costs, excluding acreage

(2) Excludes non-cash stock compensation

(3) Includes additional NGL & natural gas firm transport agreements & propane transport cost previously netted against NGL revenue. Incremental natural gas & NGL revenue will more than offset the 2015 increase in transport expense

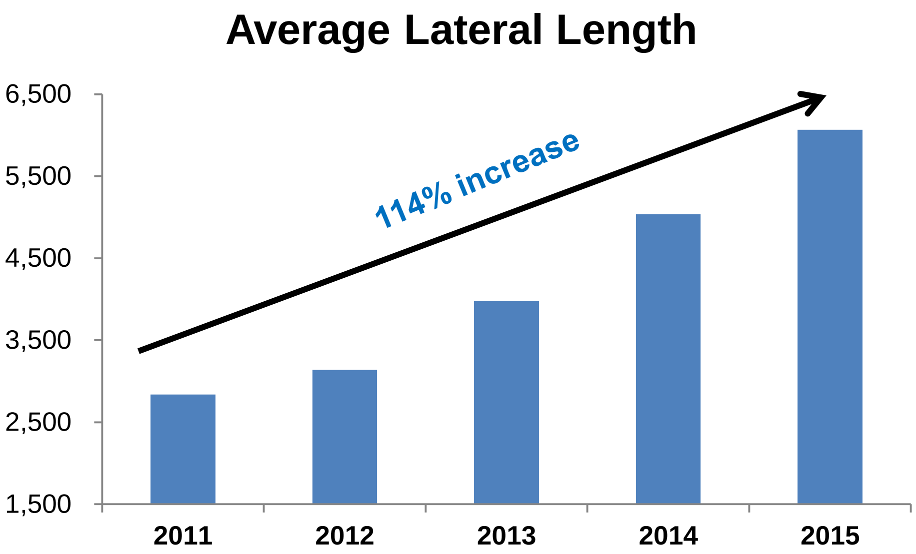
Sustained Growth with Improving Capital Efficiency

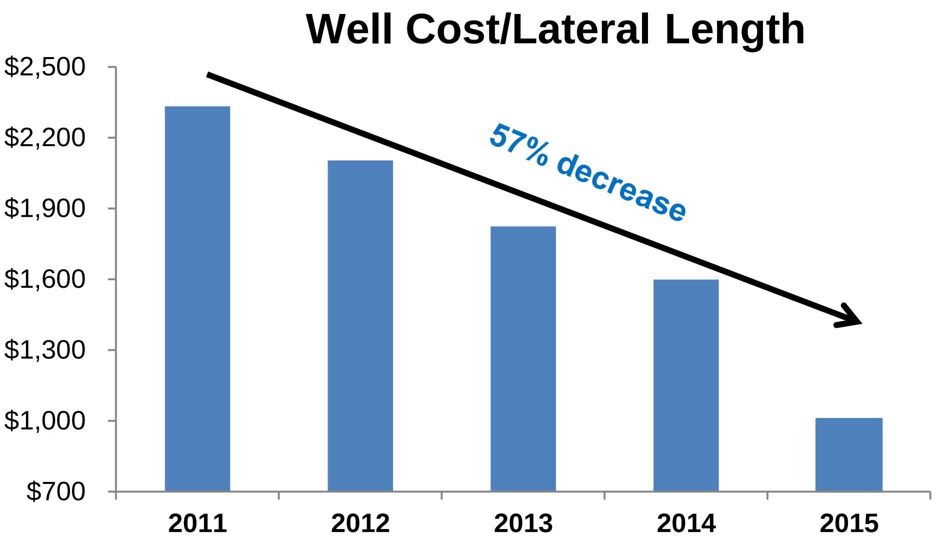
Growth achieved despite reducing capital, demonstrating improved efficiency

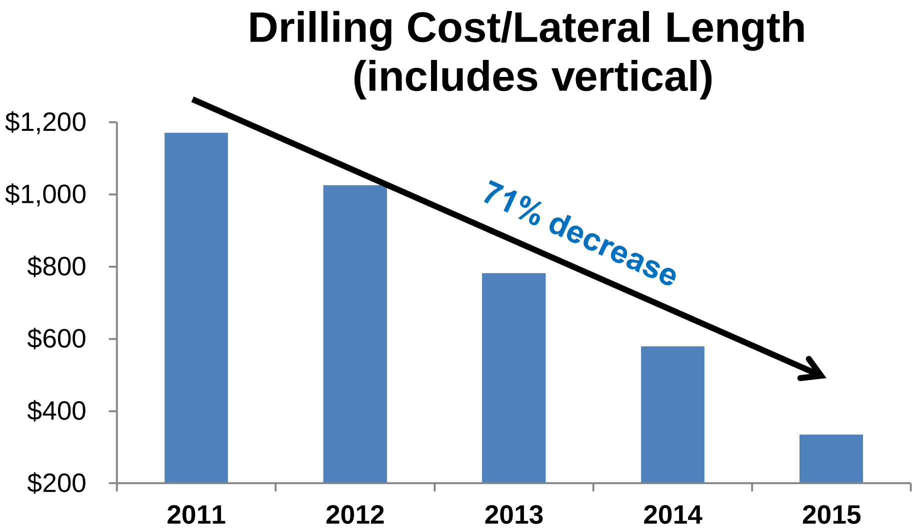


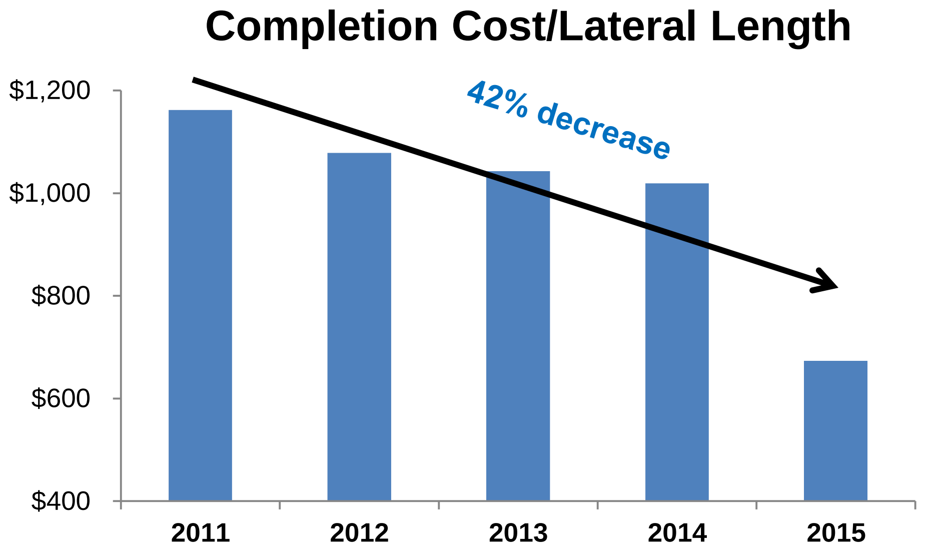
* 2015 estimated production assuming announced target of 20% production growth and capital budget of $870 million

Cost & Efficiency Improvements – SW Pennsylvania

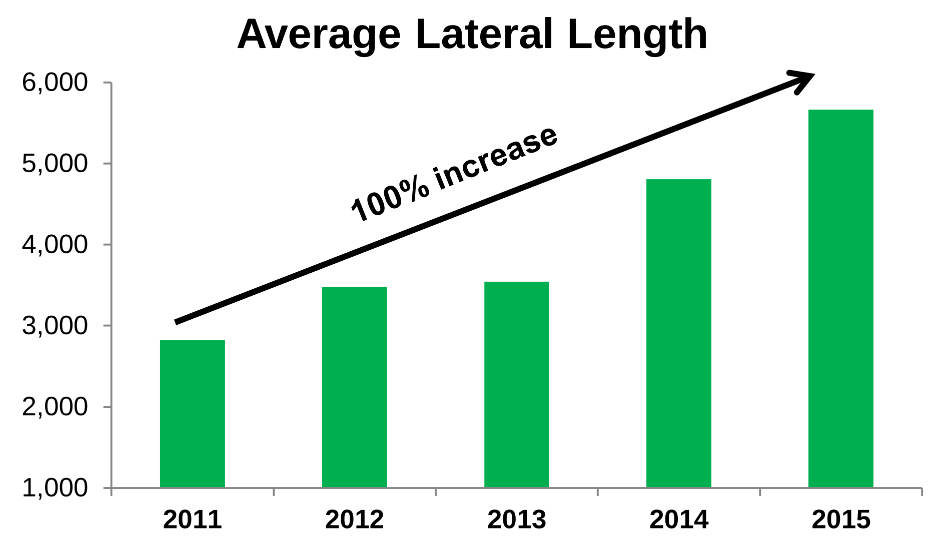


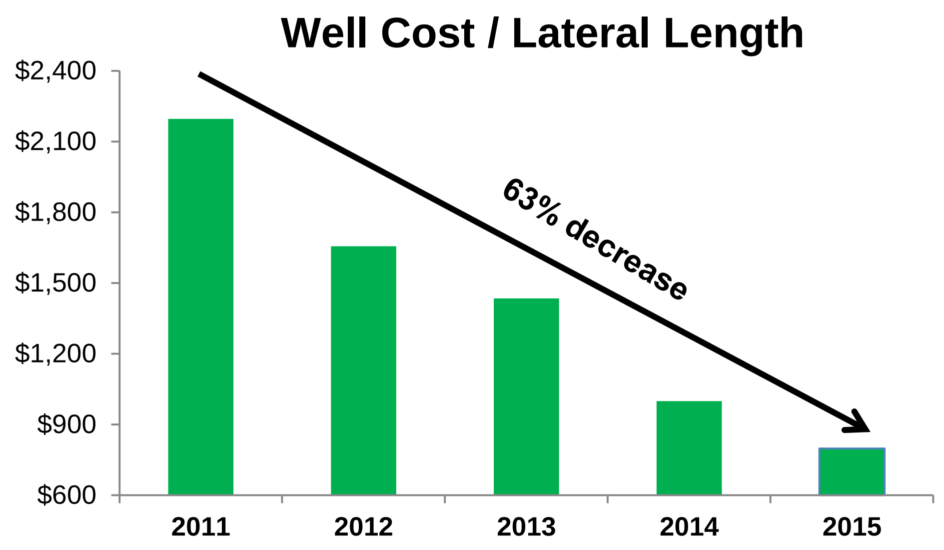


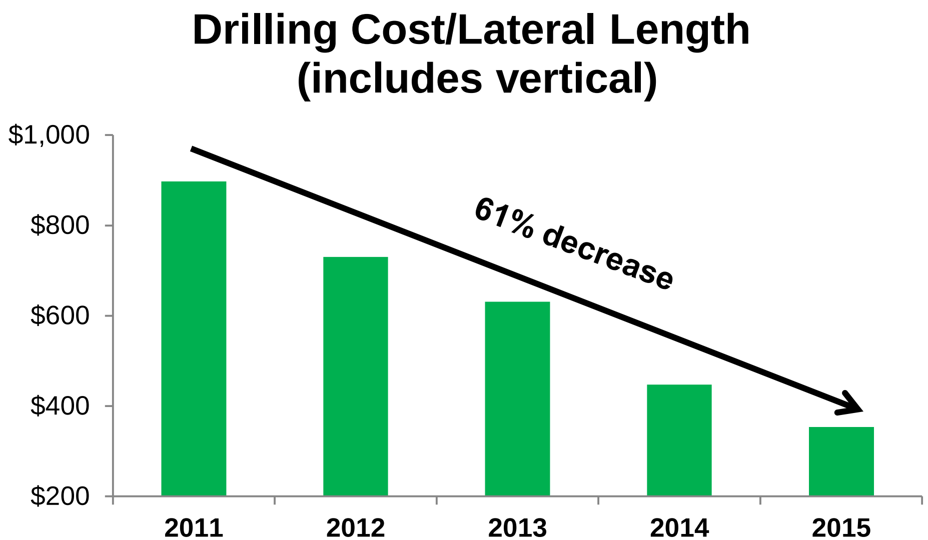


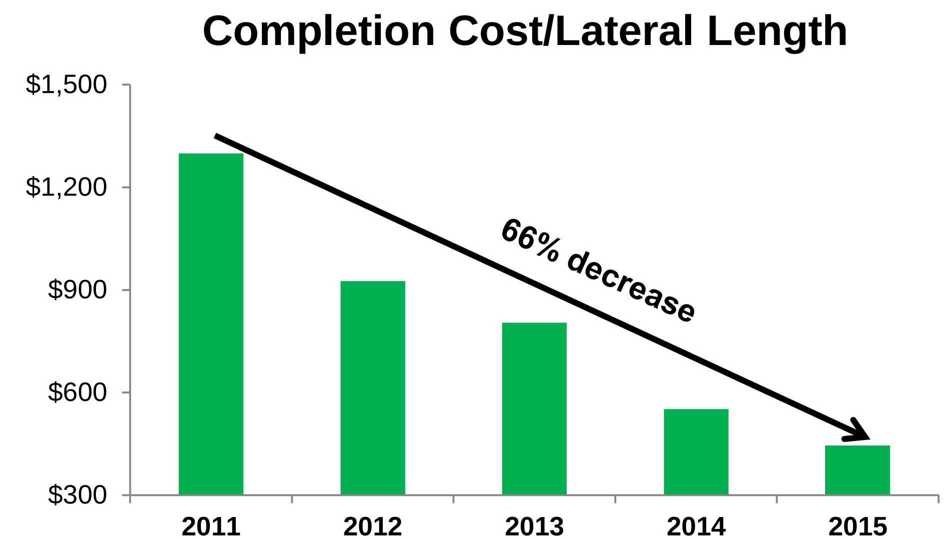


Cost & Efficiency Improvements – NE Pennsylvania









Disciplined Financial Approach

Strong, Simple Balance Sheet

- Bank debt, long-term bonds and common stock
- No near term maturities, first bond maturity in 2021, after the expected call of 2020's. Bank credit facility matures in 2019
  - Recent senior notes offering met with strong investor demand, resulting in the lowest coupon achieved by Range of 4.875%
- Liquidity of $1.2 billion under commitment amount; $2.2 billion under the approved borrowing base (pro forma for senior notes offering)

Solid Hedge Position

- Range hedges a significant portion of projected upcoming 12 months of production
- 2015 Gas is over 85% hedged at an average floor of $3.77
- 2015 Oil is over 85% hedged at a floor of $87.44
- 2015 NGLs are over 50% hedged

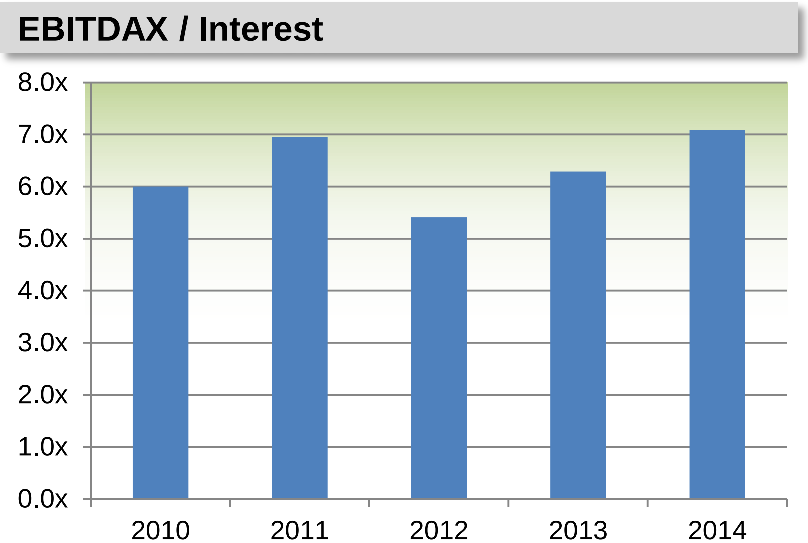
Debt Metrics

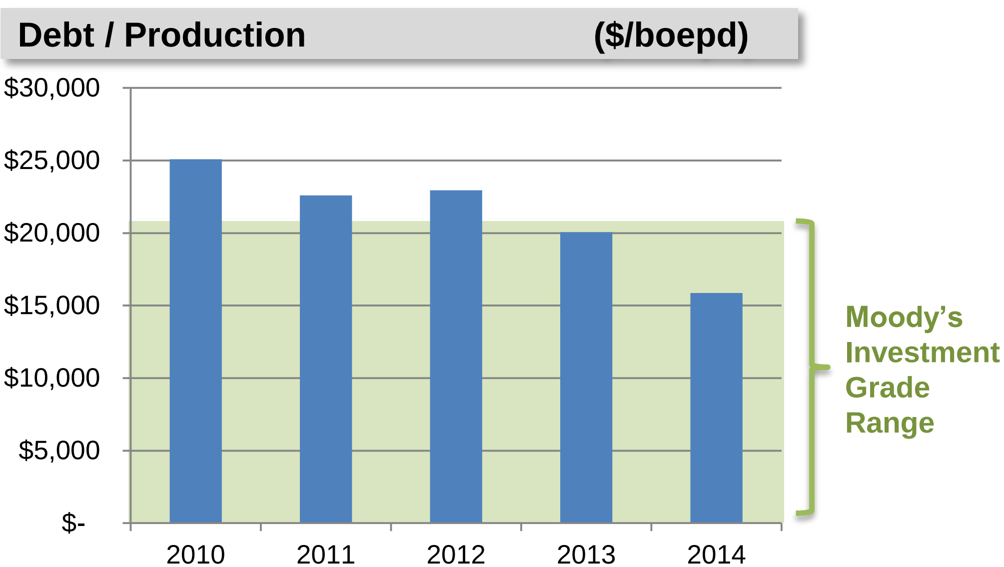
- Debt trades at or near investment grade
- Annual borrowing base unanimously approved
- Debt Covenants with ample flexibility:
  - EBITDAX/Interest expense - minimum of 2.5x
  - PV9 proved reserves value to debt - minimum of 1.5x

Well Structured Bank Credit Facility

- 29 banks with no bank holding more than 6% of total
- Commitment amount of $2.0 billion; current borrowing base of $3.0 billion

A History of Strong Credit Metrics





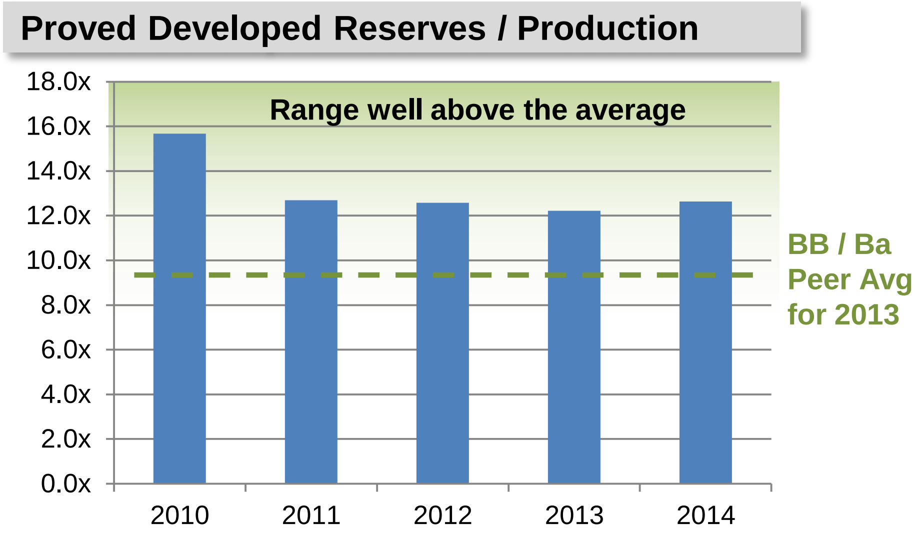
- Range has a long history of disciplined financial management
- Strong EBITDAX coverage of interest expense evidences the low cost structure and Range's resiliency
- While developing an unrivaled project inventory in terms of size and scale, Range has consistently grown production while prudently managing debt
- Debt/Production is consistent with Moody's Investment Grade rankings

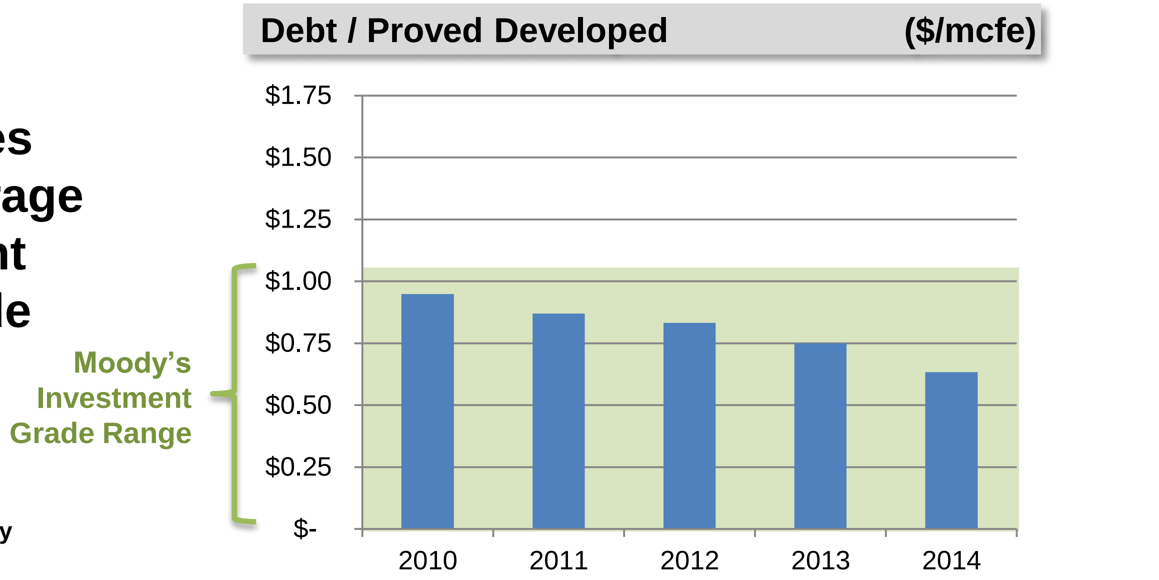
Long Life Reserves Enhances Credit Profile

- With a best-in-class reserve life index, Range's low production decline provides more stable cash flow and both low capital reinvestment and low reinvestment risk

- Low production decline also allows Range to grow more efficiently

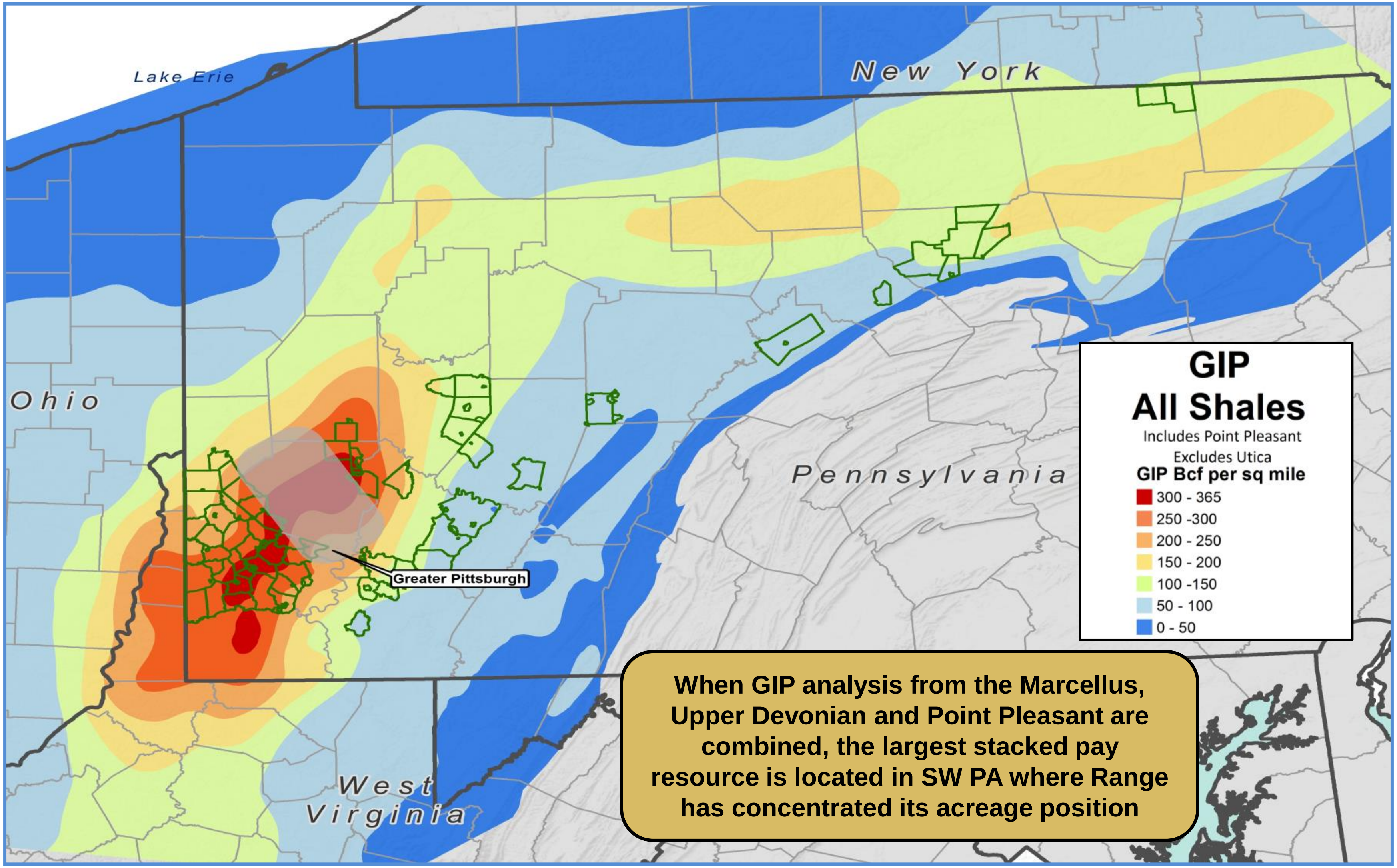
- Proved developed reserves provide exceptional coverage of debt at levels consistent with high investment grade measures





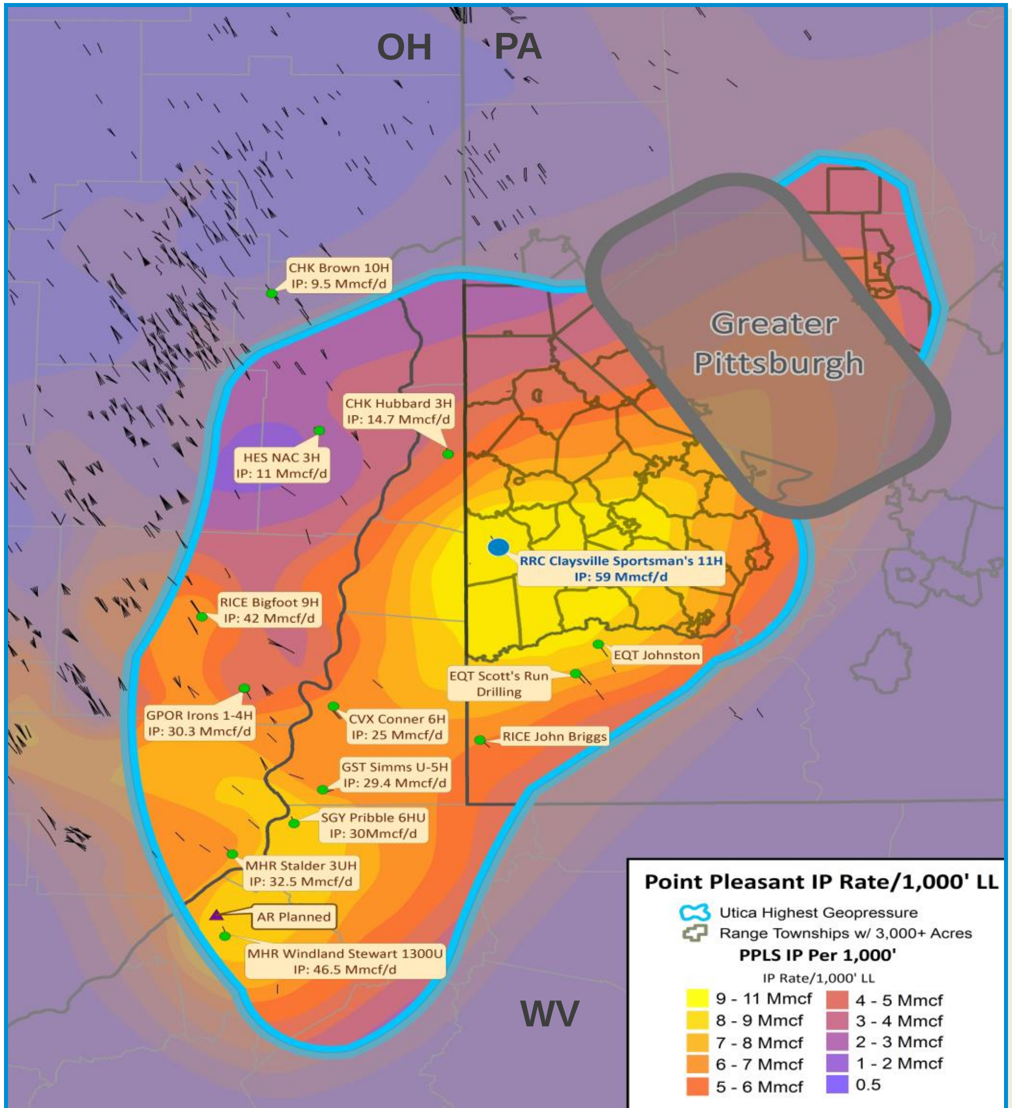
The peer group is comprised of companies in the GICS Oil & Gas Exploration & Production sub-industry with a corporate family rating between Ba3 and Ba1 from Moody's and between BB- and BB+ from S&P.

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



Note: Townships where Range holds ~3,000 or more acres (as of 12/31/2014), and estimated as prospective, are outlined green. GIP – Range estimates.

Additional Upside – Utica/Point Pleasant

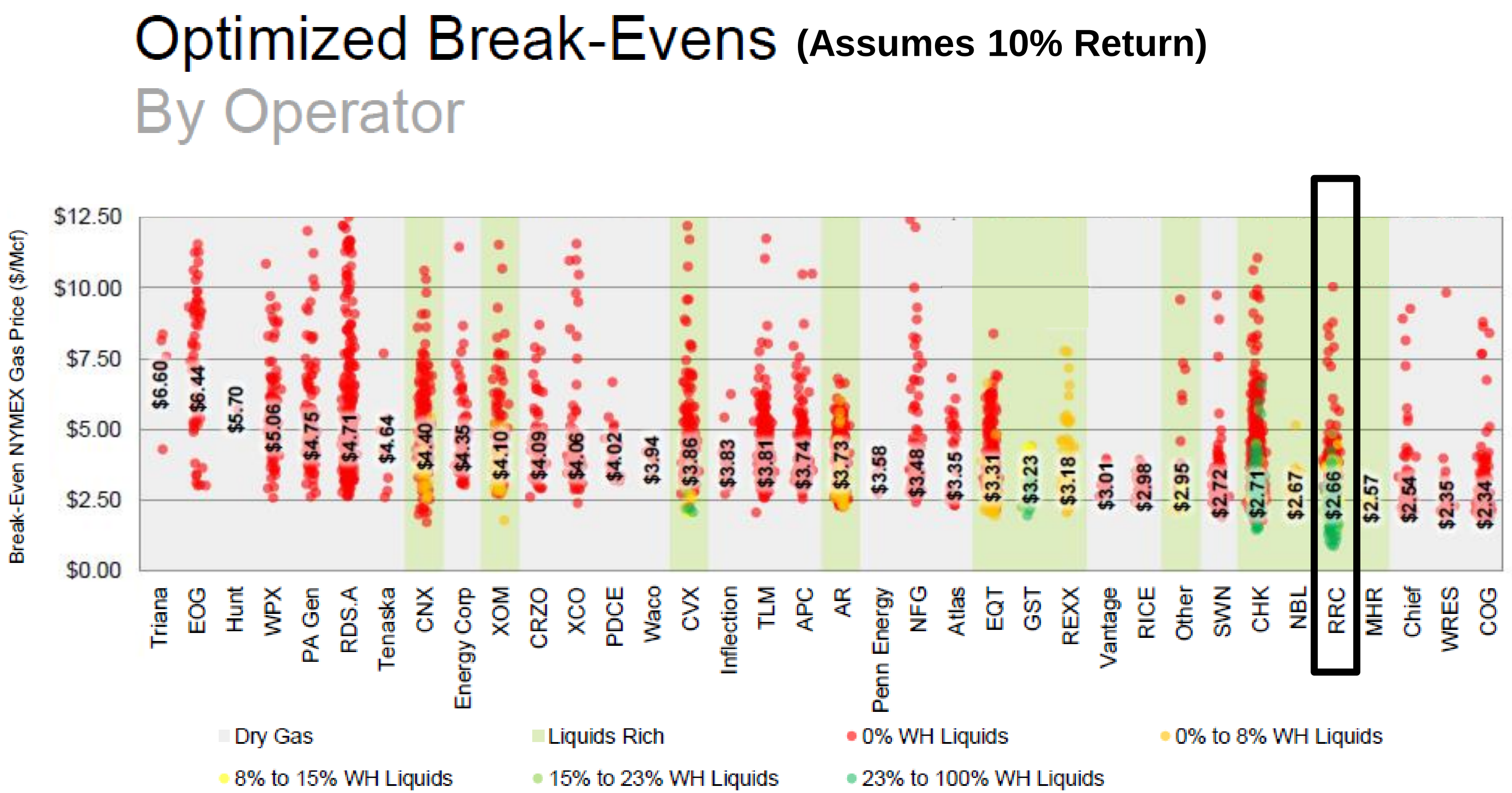


Note: Townships where Range holds ~3,000 or more acres are shown outlined above (As of 12/31/2014)

Record 24 hour IP of 59 Mmcf/d at Claysville Sportsman's Club

- **Currently producing 20 Mmcf/day under designed conditions**
- **2 wells planned to be drilled in 2015**
- **400,000 net acres in SW PA prospective**
- **Core analysis and petrographic analysis show RRC Claysville well has highest GIP**
- **Range has 20% to 40% more GIP than best areas in eastern Ohio**

Range Marcellus/Utica Acreage Top Tier



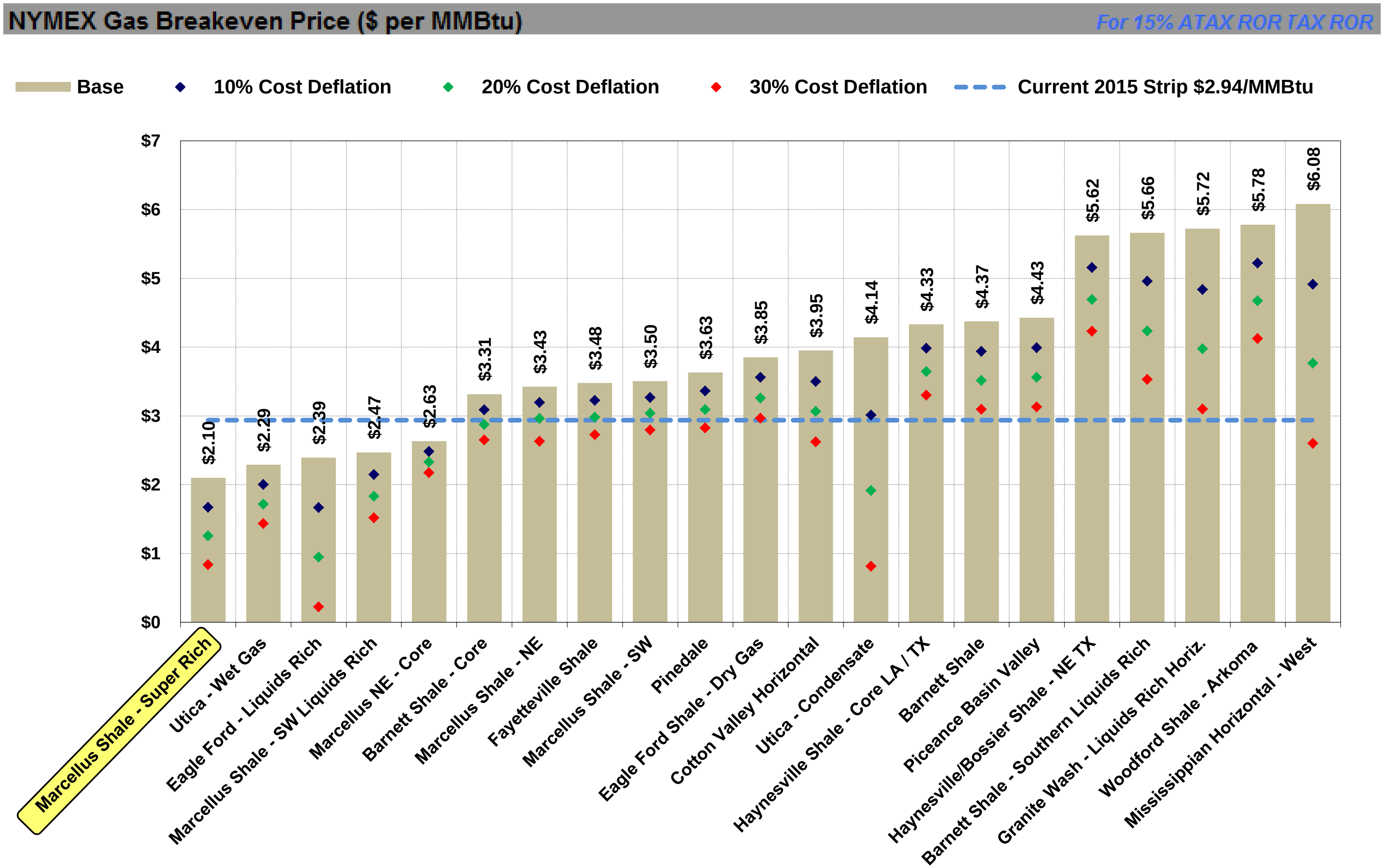
*Optimized values assume 5,500 ft laterals and 200 ft stage spacing
**Post-processing EURs assume ethane extraction

Source: ITG IR, raw data provided by state agencies and Drillinginfo, Inc.

Marcellus/Utica 12/2014

ITG

Marcellus has Low Break Even Costs



CREDIT SUISSE

Per Credit Suisse research as of February 12, 2015. Assumes $60.00 oil price

Range Marcellus – 2015 Well Economic Summary

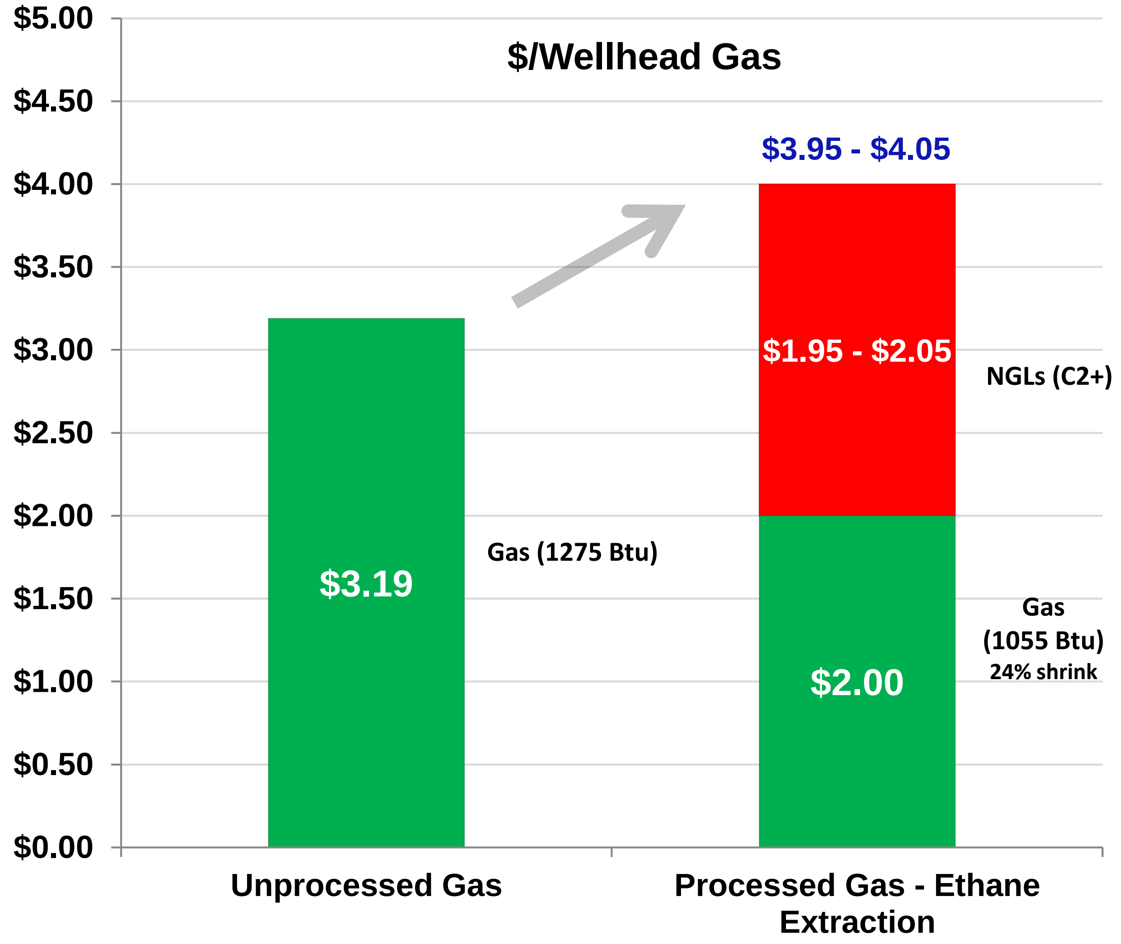
The different Marcellus areas provide optionality and a balanced approach to developing acreage and growing overall Marcellus production

	SW Super-Rich	SW Wet	SW Dry	NE Dry
EUR	12.9 Bcfe 1,169 Mbbls & 5.9 Bcf	17.6 Bcfe 1,501 Mbbls & 8.6 Bcf	17.1 Bcf	15.2 Bcf
EUR/1,000 ft lateral	2.40 Bcfe	2.95 Bcfe	2.52 Bcf	2.67 Bcf
EUR/stage	477 Mmcfe	586 Mmcfe	504 Mmcf	542 Mmcf
Well Cost	$5.9 MM	$5.9 MM	$6.0 MM	$4.9 MM
Stages	27	30	34	28
Lateral Length	5,367 ft.	5,955 ft.	6,798 ft.	5,663 ft.
IRR – Strip (as of 12/31/2014)	34%	39%	49%	63%
IRR – $4.00	39%	48%	80%	147%

See appendix for complete assumptions and data on each area

Range's Natural Gas Liquids Provide Revenue Uplift

- Range is the largest NGL producer in Appalachia, with the highest Btu inlet gas
- Higher Btu gas receives increased uplift as it contains heavier NGLs
- In 2nd half of 2015, over 85% of ethane is expected to be priced off gas or oil-linked indices, rather than Mont Belvieu ethane index
- This revenue uplift is unique to Range's contracts



Projected – 2H 2015

Assumptions: $3.00 NYMEX Gas, Local NG differential ($0.50) , $55.00 WTI, 35% WTI (C3+), 5.60 GPM (ethane extraction), processing and shrink included, ethane transport reported separately. Based on SWPA wet gas quality (1,275 processing plant inlet Btu). Based on full utilization of current ethane/propane agreements. NOTE: Wet Gas (Ethane Extraction) equals 1.56 mcfe.

Two Key Marketing Events

Mariner East

- Range has 20,000 barrels per day of ethane and 20,000 barrels per day of propane transportation to Marcus Hook
- Access (80%) to 1 million barrels of propane cavern storage at Marcus Hook
- Net increase in cash flow from Mariner East, Mariner West and ATEX of ~$90 million per year, when all are fully operational
- Starts during 3Q 2015

Spectra - Uniontown to Gas City Pipeline

- Moves ~200 Mmcf/day of Range gas production as anchor shipper from local Appalachia M2 to Midwest markets
- Under current strip prices this project is expected to capture an uplift of $1.00 per Mmbtu in 4Q
- Starts 4Q 2015

Significant Natural Gas Demand Growth Projected – Beginning in 2015

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

	2015	2016	2017	2018	2019	2020	Cumulative 2015-2020
LNG Exports							
Sabine Pass		1.2	1.2		0.6		3.0
Freeport				0.5	1.0	0.4	1.9
Cove Point			0.4	0.4			0.8
Cameron				1.2	0.6		1.8
Corpus Christi					0.6	0.6	1.2
Lake Charles						0.6	0.6
LNG Sub-Total	***-***	***1.2***	***1.6***	***2.2***	***2.9***	***1.7***	***9.5***
Mexico/Canada Exports							
Mexico Net Exports	0.7	0.3	0.3	0.3	0.3	0.3	2.2
Canada net Exports	0.3	0.3	0.2	0.2	0.2	0.1	1.3
Mexico/Canada Sub-Total	***1.0***	***0.6***	***0.5***	***0.5***	***0.5***	***0.4***	***3.5***
Power Generation							
Coal Plant Retirements	0.7	0.8	0.3	0.3	0.3	0.1	2.5
Incremental Electricity Demand	0.1	0.1	0.1	0.2	0.2	0.2	0.9
Power Generation Sub-Total	***0.8***	***0.9***	***0.4***	***0.5***	***0.5***	***0.3***	***3.4***
Industrial							
Methanol	0.1	0.2	0.1	0.2	0.1	0.1	0.8
Ethylene	-	0.1	0.4	0.1	-	0.1	0.7
Ammonia	0.1	0.3	0.6	0.2	0.1	0.4	1.7
Industrial Sub-Total	***0.2***	***0.6***	***1.1***	***0.5***	***0.2***	***0.7***	***3.2***
Transportation							
New Fueling Opportunities	-	-	-	0.1	0.1	0.1	0.3
Transportation Sub-Total	***-***	***-***	***-***	***0.1***	***0.1***	***0.1***	***0.3***
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2020**
Total	**2.1**	**3.3**	**3.5**	**3.7**	**4.2**	**3.1**	**19.9**

Research report dated 9/2014

SIMMONS & COMPANY INTERNATIONAL

Gas Production Response May Occur Sooner than Expected

~16 Bcf per day of Associated Gas with Oil Plays

- **~8 Bcf per day of associated gas with shale oil plays**
- **Capital budgets in oil plays typically reduced by 40-50%**
- **Oil rig count down 56%**
- **First year decline on horizontal shale oil wells ~80%**
- **Expecting response in second half of 2015**

Marcellus-Utica Natural Gas Production

- **Capital budgets typically reduced 40-50%**
- **Rig count down 44% in Utica and 42% in Marcellus**
- **Continuing infrastructure constraints in NE PA where production has been flat for extended time**

Range Resources – Concluding Summary

1. **Largest acreage position in <u>core</u> of Marcellus, Upper Devonian and Utica**

2. **Marcellus development has driven down unit costs over 40%; capital costs down 57% or more on a per lateral foot basis**

3. **Continued efficiencies expected from longer laterals, technical improvements, stacked pay development and drilling in areas of existing infrastructure**

4. **Balance sheet and $1.2 billion of liquidity support planned production growth of 20%-25%**

Portfolio Detail

SW PA Super-Rich Area Marcellus Projected 2015 Well Economics

- **Southwestern PA – (High Btu case)**
- **EUR / 1,000 ft. – 2.40 Bcfe**
- **EUR – 12.9 Bcfe**

  (182 Mbbls condensate, 987 Mbbls NGLs, and 5.9 Bcf gas)
- **Drill and Complete Capital – $5.9 MM**
- **Average Lateral Length – 5,367 ft.**
- **F&D – $0.55/mcfe**

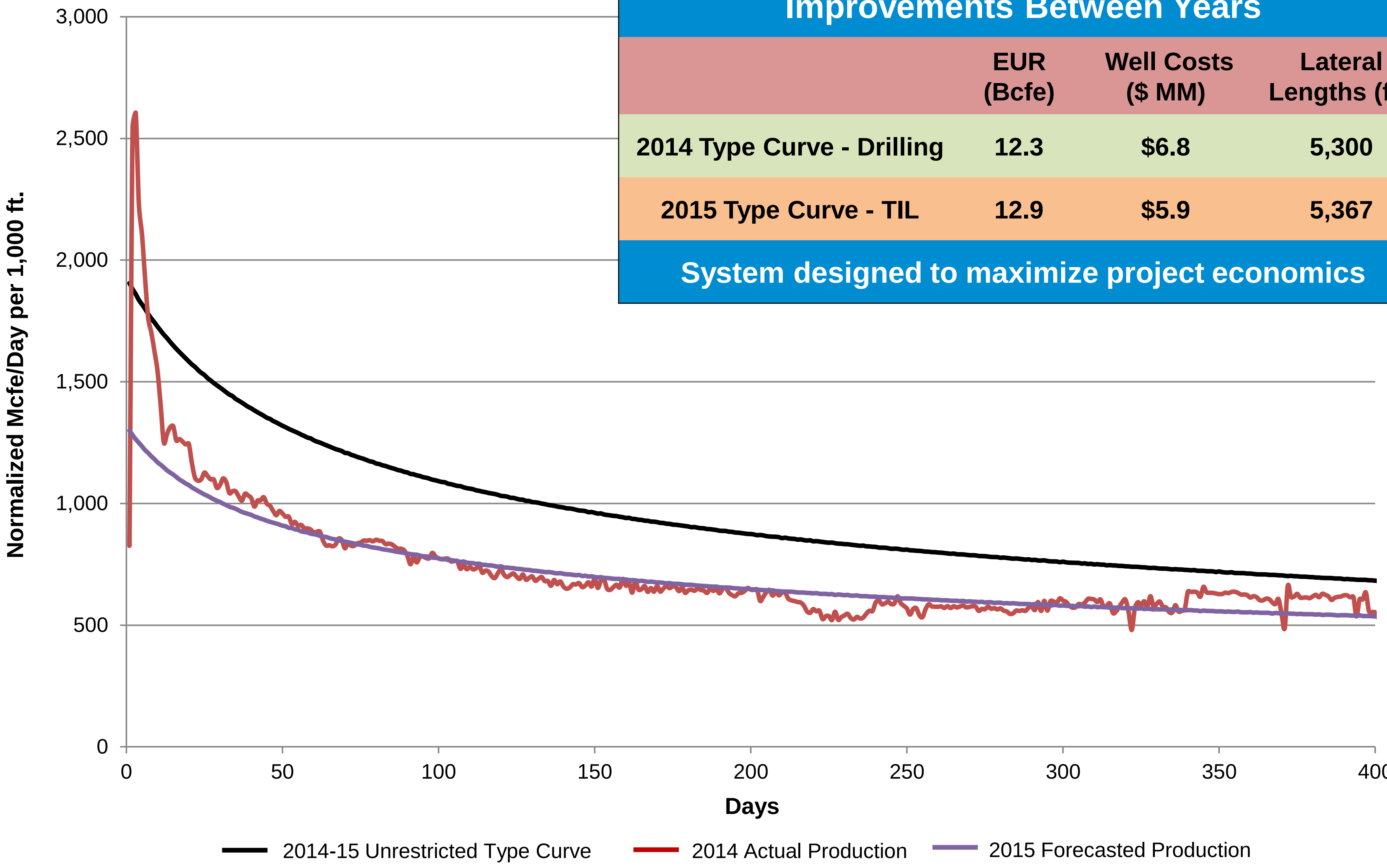
Estimated Cumulative Recoveries for 2015 TIL Forecast			
	Condensate (Mbbls)	Residue (Mmcf)	NGL w/ Ethane (Mbbls)
1 Year	39	533	90
2 Years	59	920	155
3 Years	74	1,253	211
5 Years	97	1,810	304
10 Years	129	2,836	477
20 Years	157	4,159	699
EUR	182	5,872	987

NYMEX Gas Price		12.9 Bcfe
Strip	-	34%
$3.00	-	31%
$4.00	-	39%

Strip pricing NPV10 = $7.3 MM

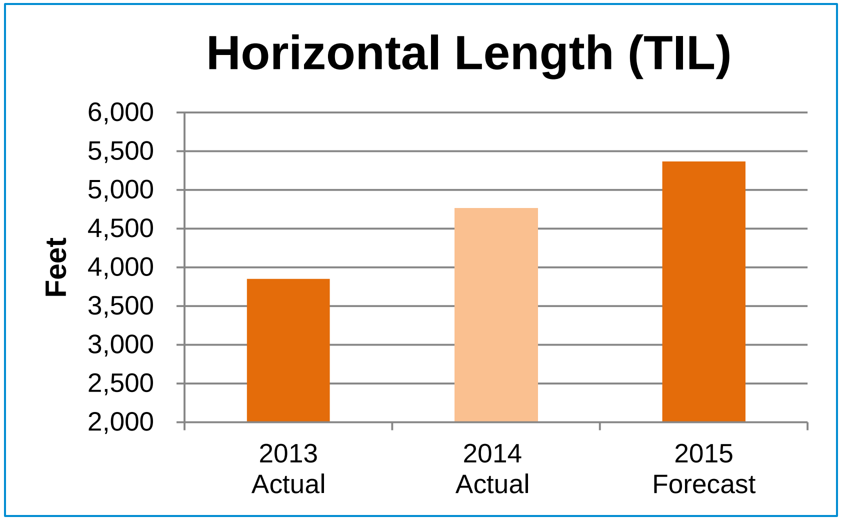
- **Price includes current and expected differentials less gathering, transportation and processing costs**
- **For flat pricing, oil price assumed to be $55/bbl for 2015, $65/bbl for 2016 then $75/bbl to life with no escalation**
- **NGL price includes ethane contracts plus escalation**
- **Strip dated 12/31/14 with 10 year average $67.92/bbl and $4.07/mcf**

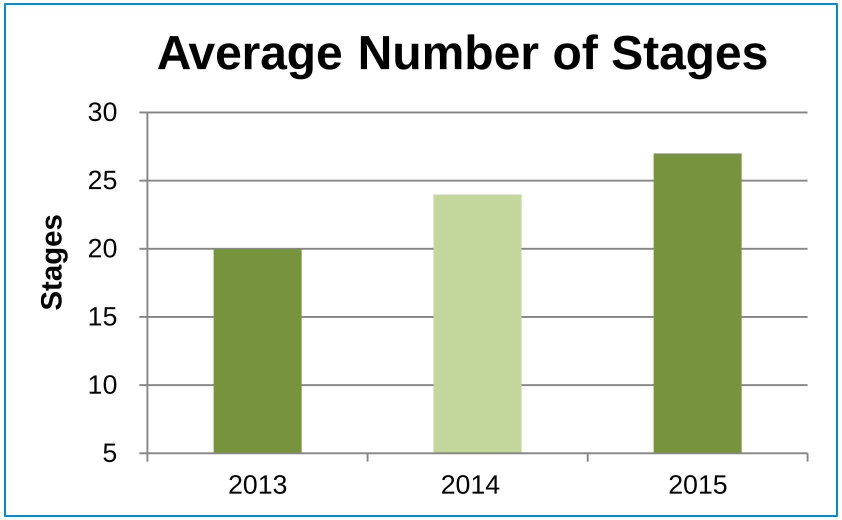
Southwest PA - Super-Rich Area 2015 Turn in Line Forecast

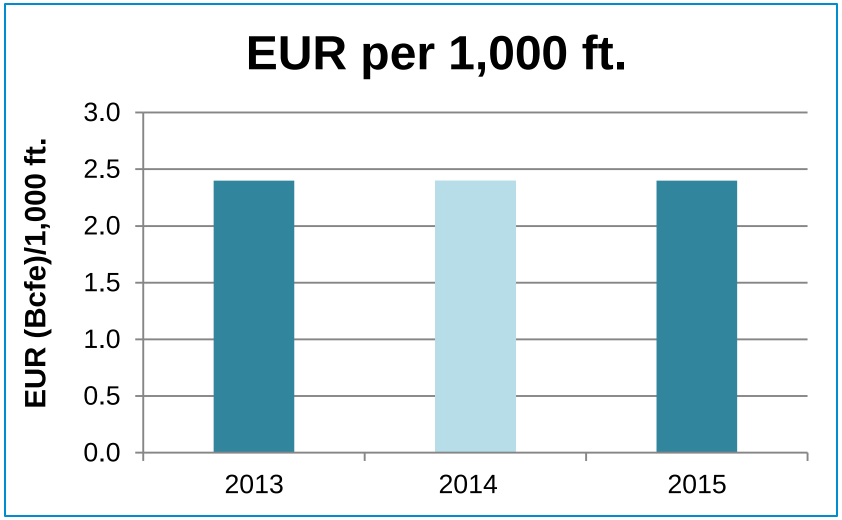


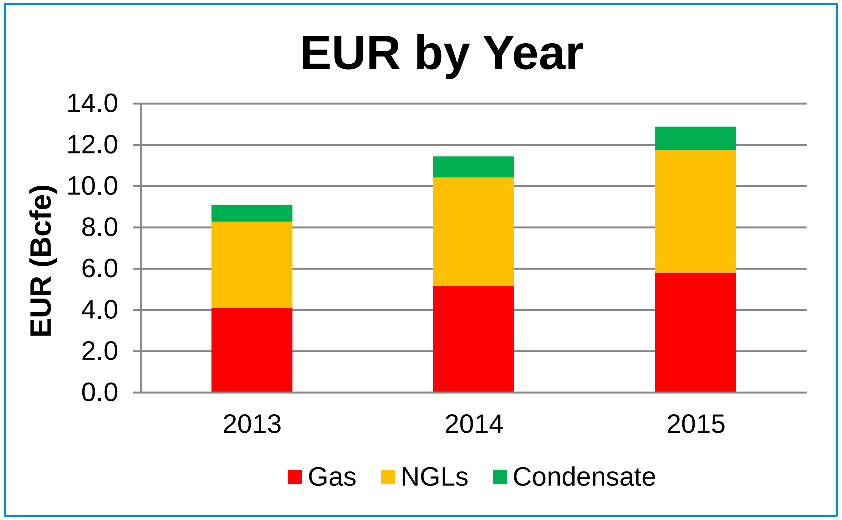
Improvements Between Years			
	EUR (Bcfe)	Well Costs ($ MM)	Lateral Lengths (ft.)
2014 Type Curve - Drilling	12.3	$6.8	5,300
2015 Type Curve - TIL	12.9	$5.9	5,367
System designed to maximize project economics			

Southwest PA – Super Rich Marcellus









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

SW PA Wet Area Marcellus Projected 2015 Well Economics

- **Southwestern PA – (Wet Gas case)**
- **EUR / 1,000 ft. – 2.95 Bcfe**
- **EUR – 17.6 Bcfe**
  (48 Mbbls condensate, 1,453 Mbbls NGLs, and 8.6 Bcf gas)
- **Drill and Complete Capital – $5.9 MM**
- **Lateral Length – 5,955 ft.**
- **F&D – $0.41/mcfe**

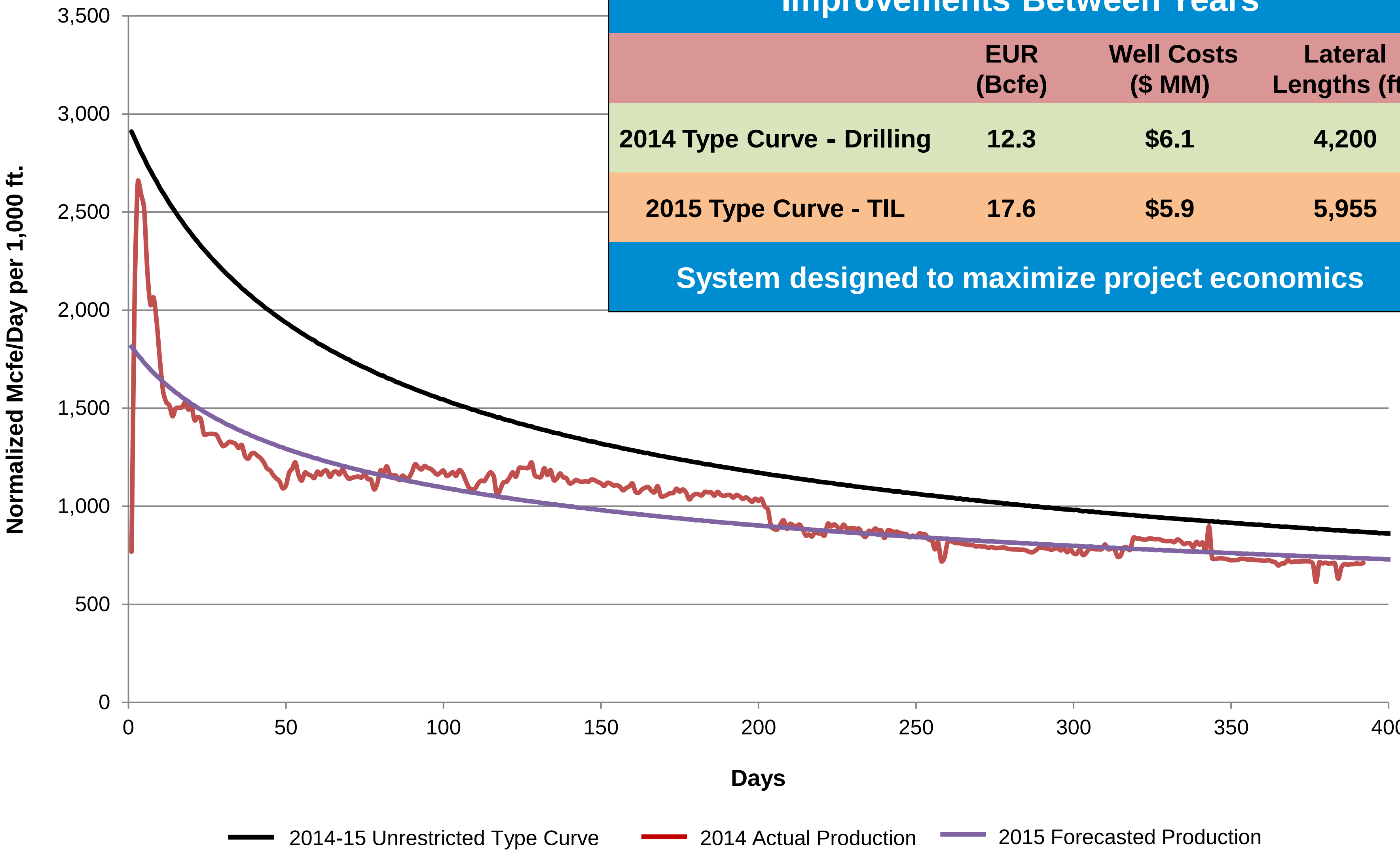
NYMEX Gas Price	17.6 Bcfe
Strip -	39%
$3.00 -	34%
$4.00 -	48%

Strip pricing NPV10 = $9.2 MM

Estimated Cumulative Recoveries for 2015 TIL Forecast			
	Condensate (Mbbls)	Residue (Mmcf)	NGL w/ Ethane (Mbbls)
1 Year	17	1,035	174
2 Years	26	1,721	290
3 Years	31	2,277	383
5 Years	37	3,154	531
10 Years	43	4,666	786
20 Years	47	6,524	1,098
EUR	48	8,629	1,453

- **Price includes current and expected differentials less gathering, transportation and processing costs**
- **For flat pricing, oil price assumed to be $55/bbl for 2015, $65/bbl for 2016 then $75/bbl to life with no escalation**
- **NGL price includes ethane contracts plus escalation**
- **Strip dated 12/31/14 with 10 year average $67.92/bbl and $4.07/mcf**

Southwest PA - Wet Area 2015 Turn in Line Forecast

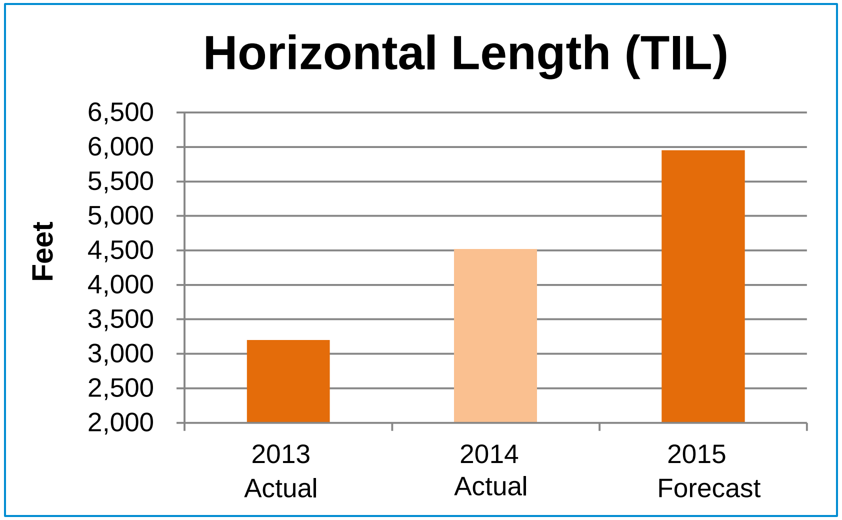


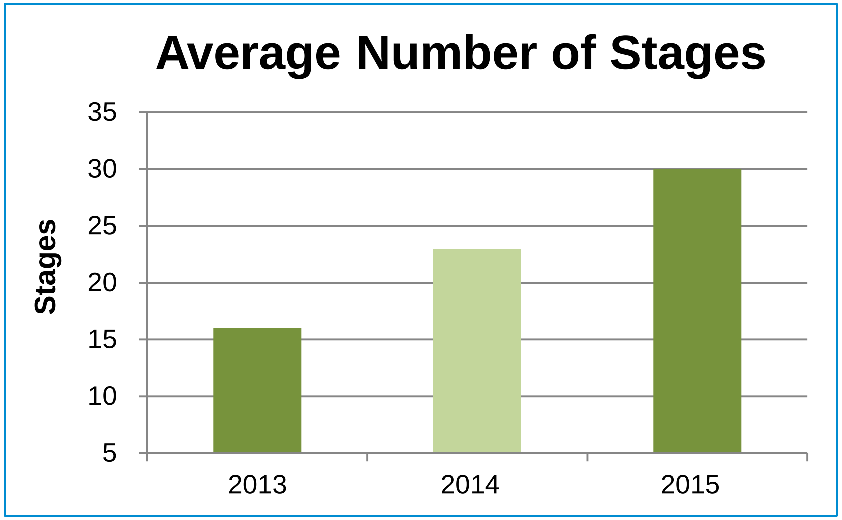
Improvements Between Years

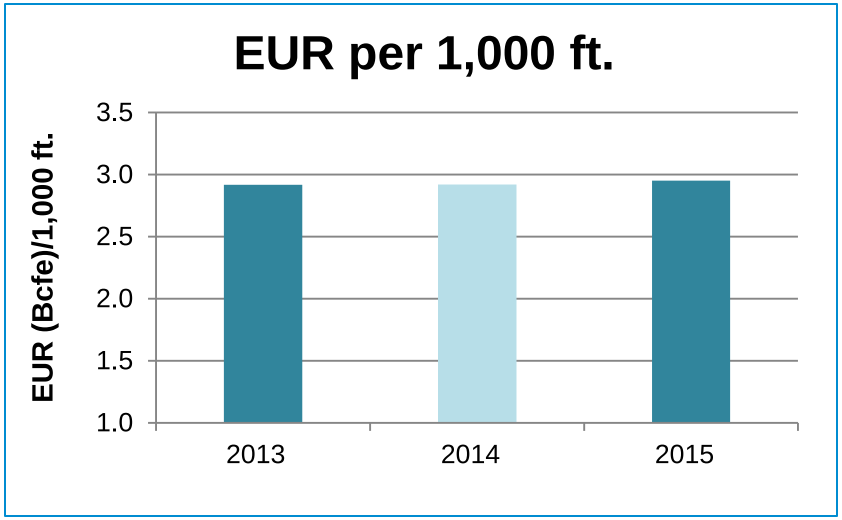
	EUR (Bcfe)	Well Costs ($ MM)	Lateral Lengths (ft.)
2014 Type Curve - Drilling	12.3	$6.1	4,200
2015 Type Curve - TIL	17.6	$5.9	5,955

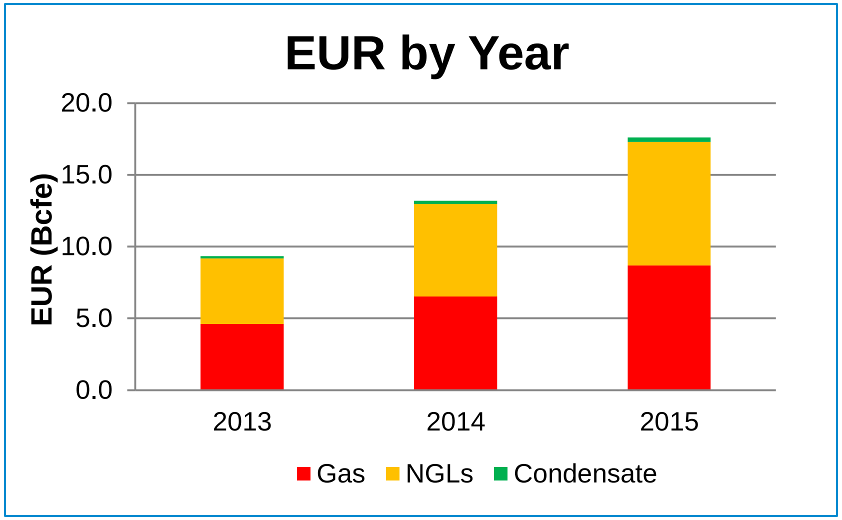
System designed to maximize project economics

Southwest PA – Wet Marcellus









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

SW PA Dry Area Marcellus Projected 2015 Well Economics

- Southwestern PA – (Dry Gas case)
- EUR / 1,000 ft. – 2.52 Bcf
- EUR – 17.1 Bcf
- Drill and Complete Capital $6.0 MM
- Average Lateral Length – 6,798 ft.
- F&D – $0.43/mcf

Estimated Cumulative Recoveries for 2015 TIL Forecast	
	Residue (Mmcf)
1 Year	2,975
2 Years	4,567
3 Years	5,722
5 Years	7,407
10 Years	10,088
20 Years	13,205
EUR	17,132

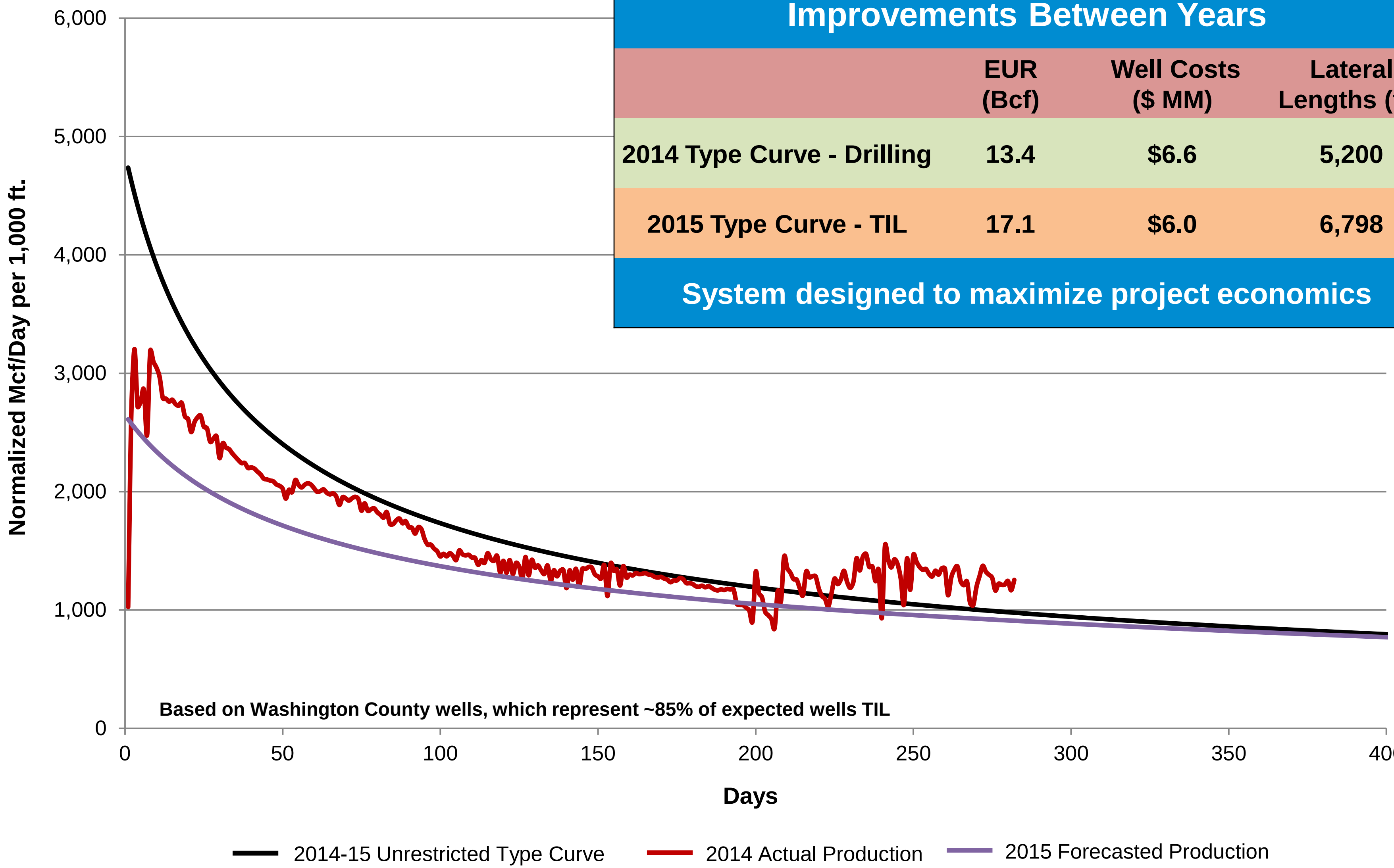
NYMEX Gas Price		17.1 Bcf
Strip	-	49%
$3.00	-	29%
$4.00	-	80%

Strip pricing NPV10 = $9.7 MM

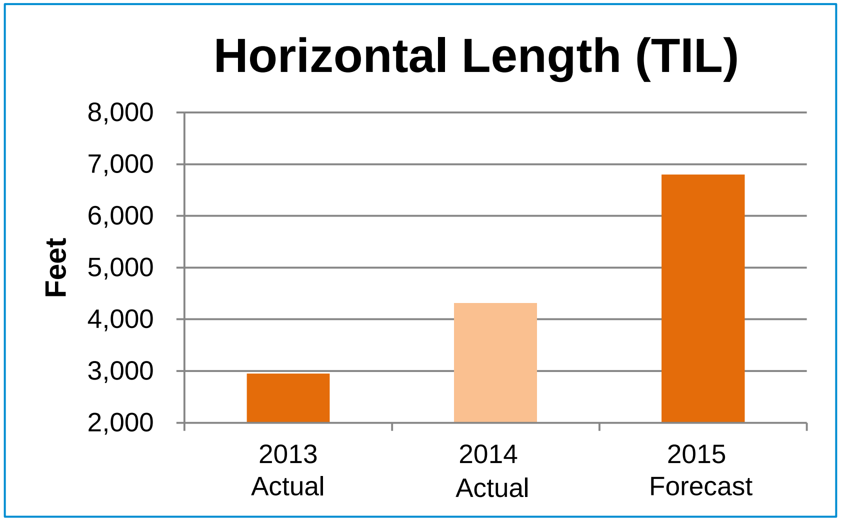
- Price includes current and expected differentials less gathering and transportation costs
- Strip dated 12/31/14 with 10 year average $67.92/bbl and $4.07/mcf
- Based on Washington County wells, which represent ~85% of expected SW PA dry activity in 2015

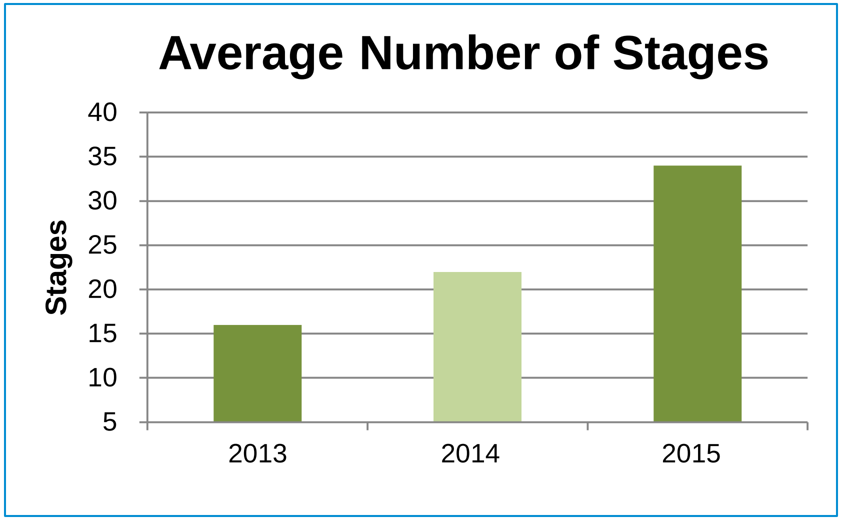
Southwest PA – Dry Area 2015 Turn in Line Forecast

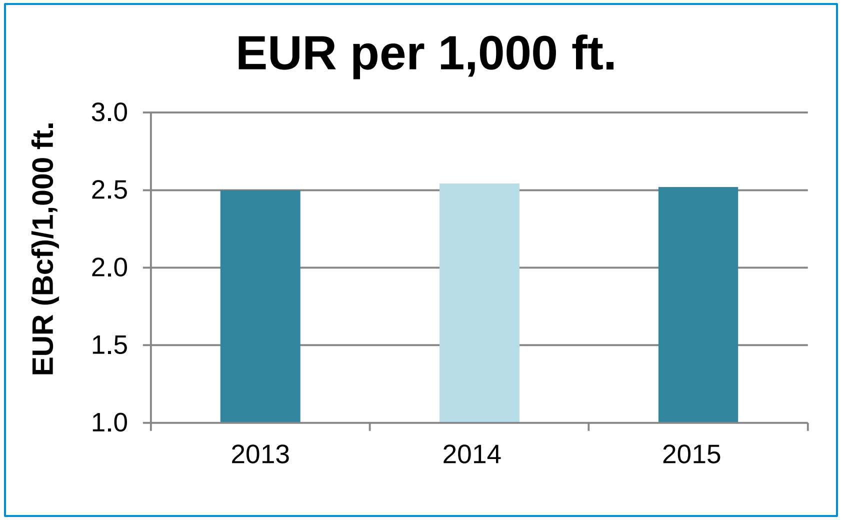
Improvements Between Years			
	EUR (Bcf)	Well Costs ($ MM)	Lateral Lengths (ft.)
2014 Type Curve - Drilling	13.4	$6.6	5,200
2015 Type Curve - TIL	17.1	$6.0	6,798
System designed to maximize project economics			

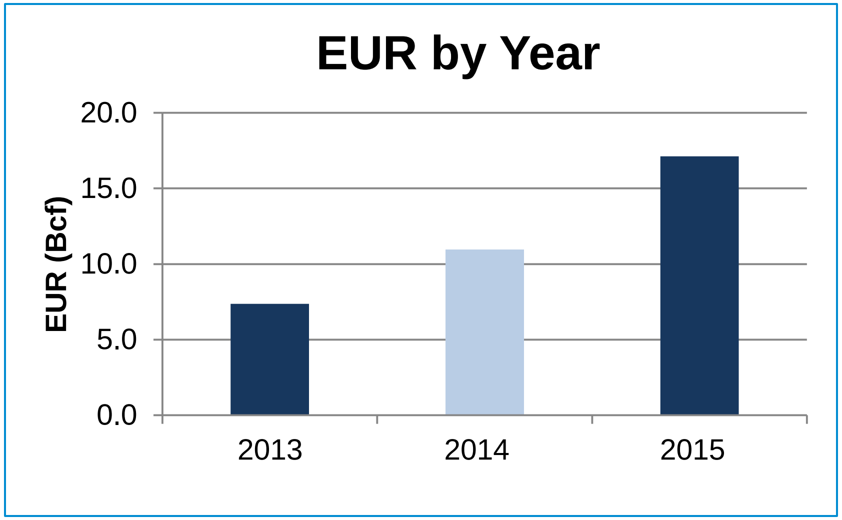


Southwest PA – Dry Marcellus









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

NE PA Dry Area Marcellus Projected 2015 Well Economics

- Northeastern PA – (Dry Gas case)
- EUR / 1,000 ft. – 2.67 Bcf
- EUR – 15.2 Bcf
- Drill and Complete Capital $4.9 MM
- Average Lateral Length – 5,663 ft.
- F&D – $0.38/mcf

NYMEX Gas Price		15.2 Bcf
Strip	-	63%
$3.00	-	35%
$4.00	-	147%

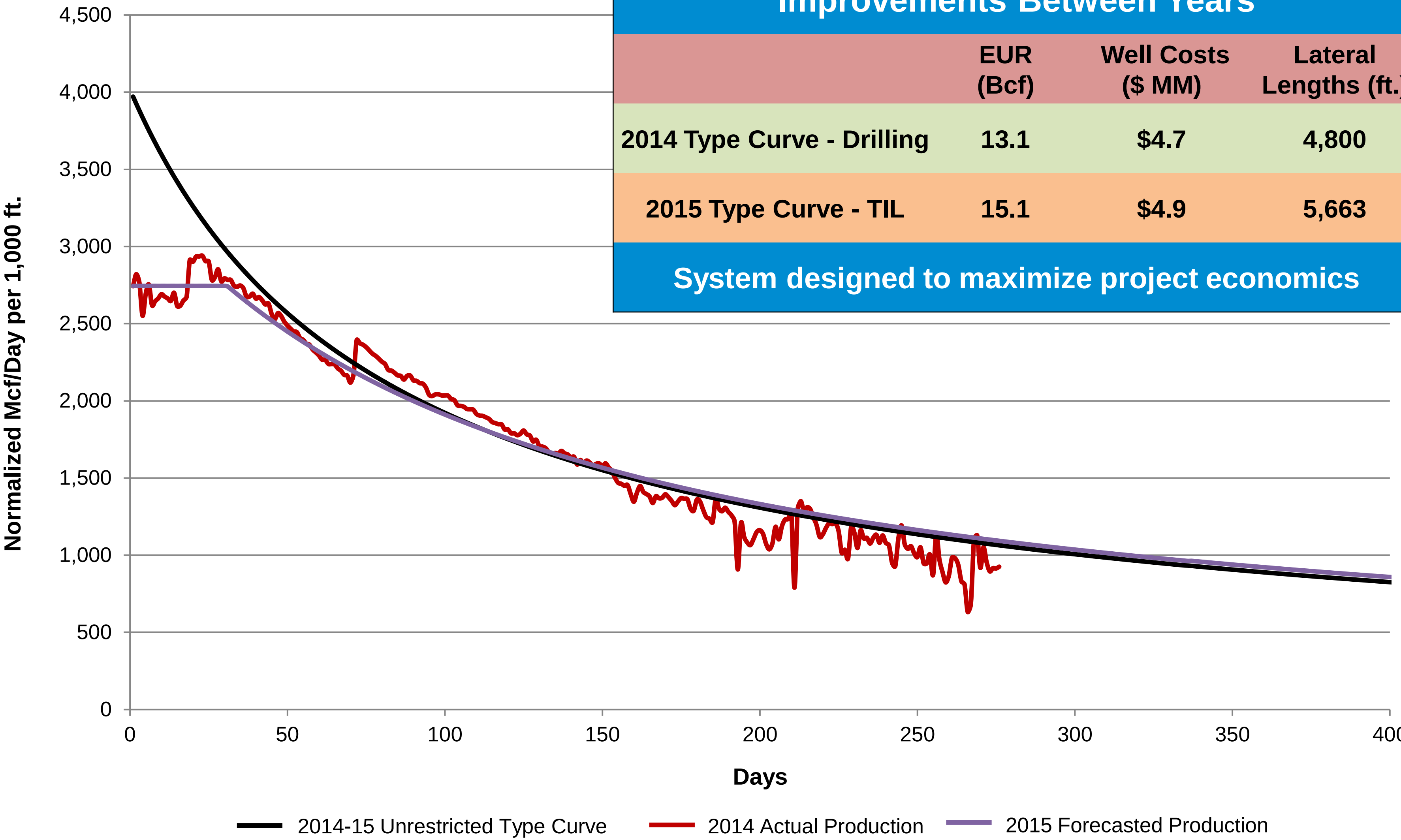
Strip pricing NPV10 = $8.8 MM

Estimated Cumulative Recoveries for 2015 TIL Forecast	
	Residue (Mmcf)
1 Year	3,282
2 Years	4,735
3 Years	5,725
5 Years	7,123
10 Years	9,302
20 Years	11,823
EUR	15,172

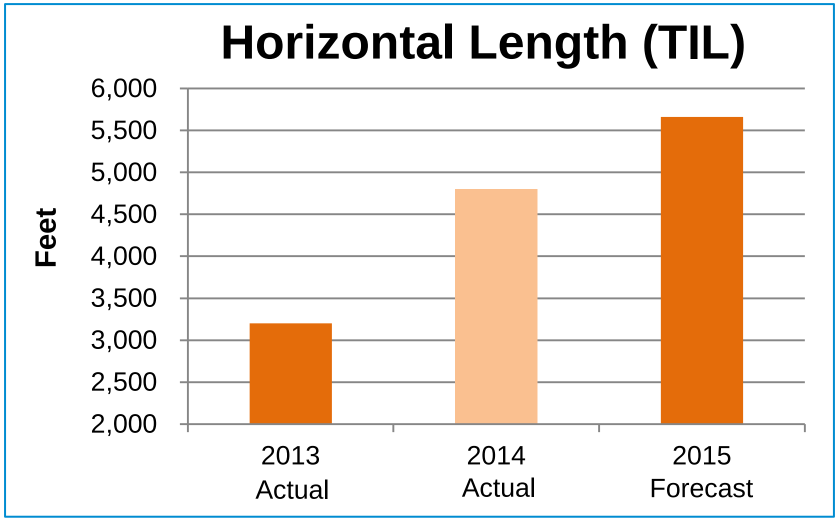
- Price includes current and expected differentials less gathering and transportation costs
- Strip dated 12/31/14 with 10 year average $67.92/bbl and $4.07/mcf
- All 2015 TIL wells are located in Lycoming County

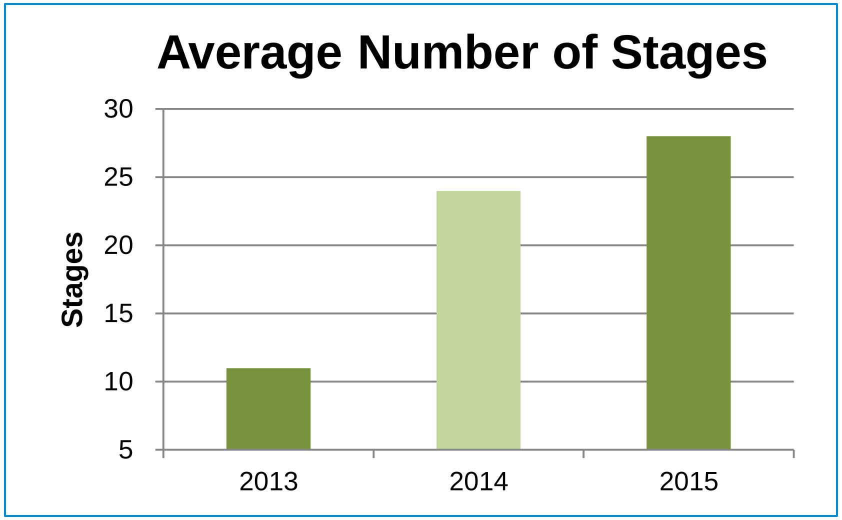
Northeast PA – Dry Area 2015 Turn in Line Forecast

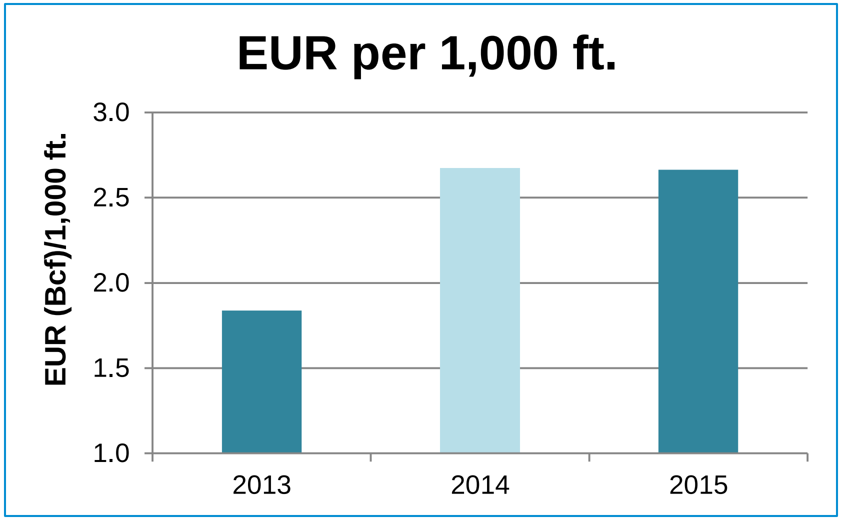
Improvements Between Years			
	EUR (Bcf)	Well Costs ($ MM)	Lateral Lengths (ft.)
2014 Type Curve - Drilling	13.1	$4.7	4,800
2015 Type Curve - TIL	15.1	$4.9	5,663
System designed to maximize project economics			

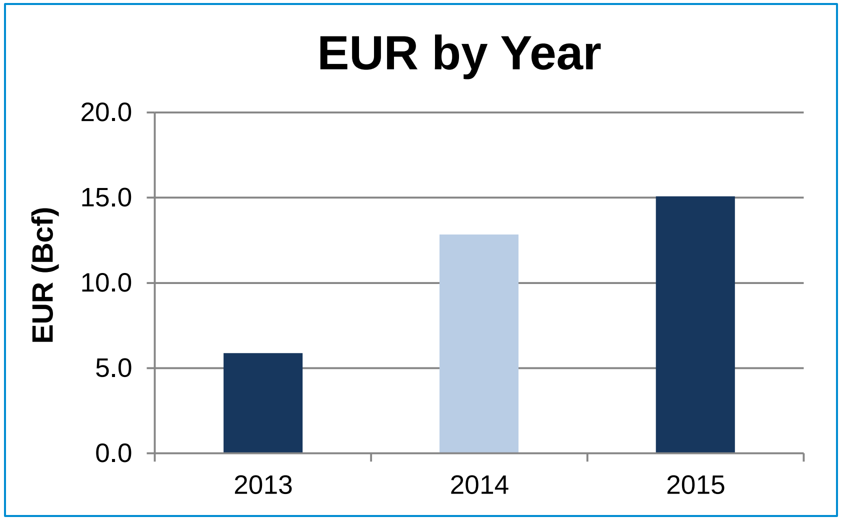


Northeast PA – Dry Marcellus



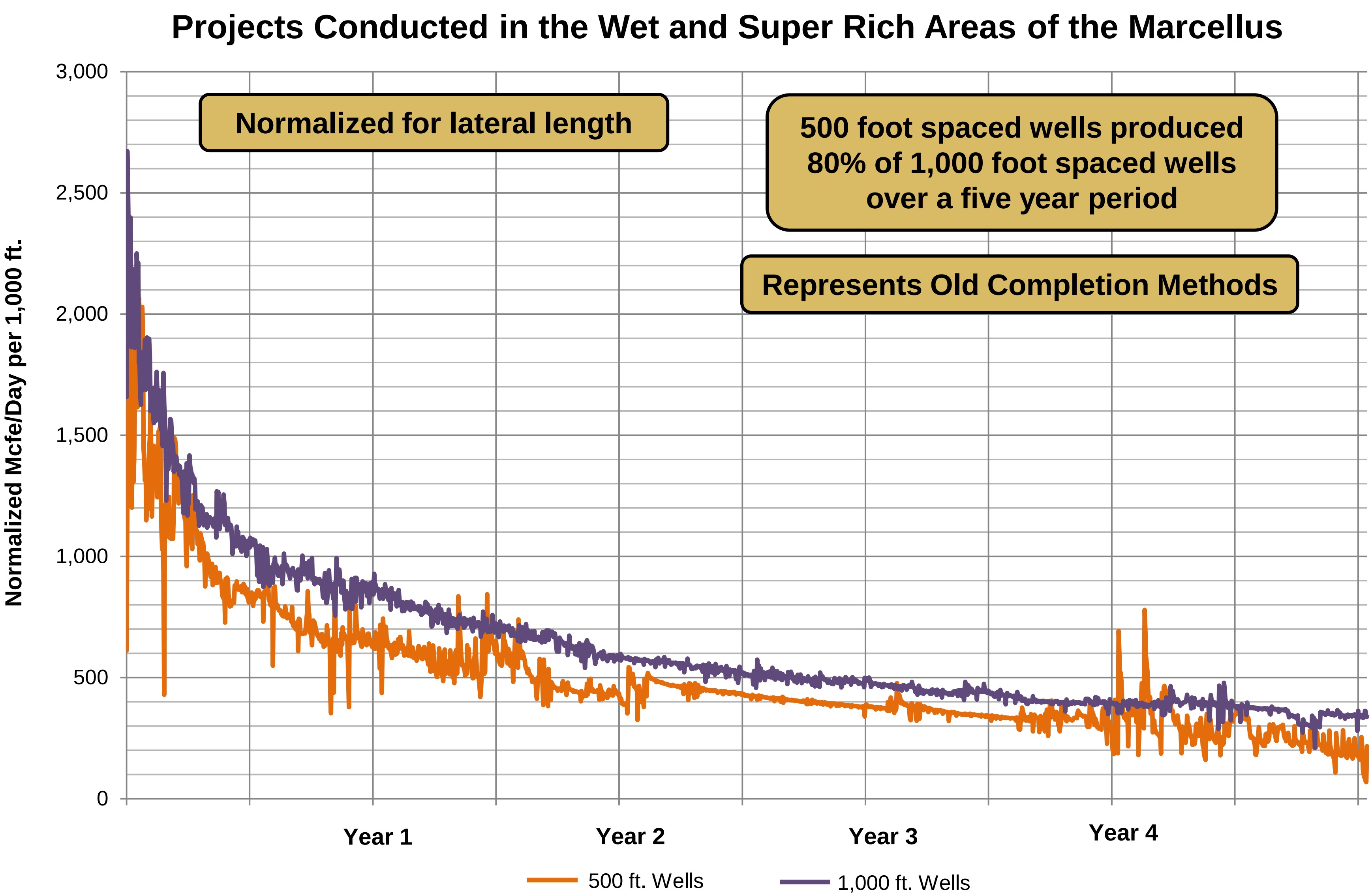




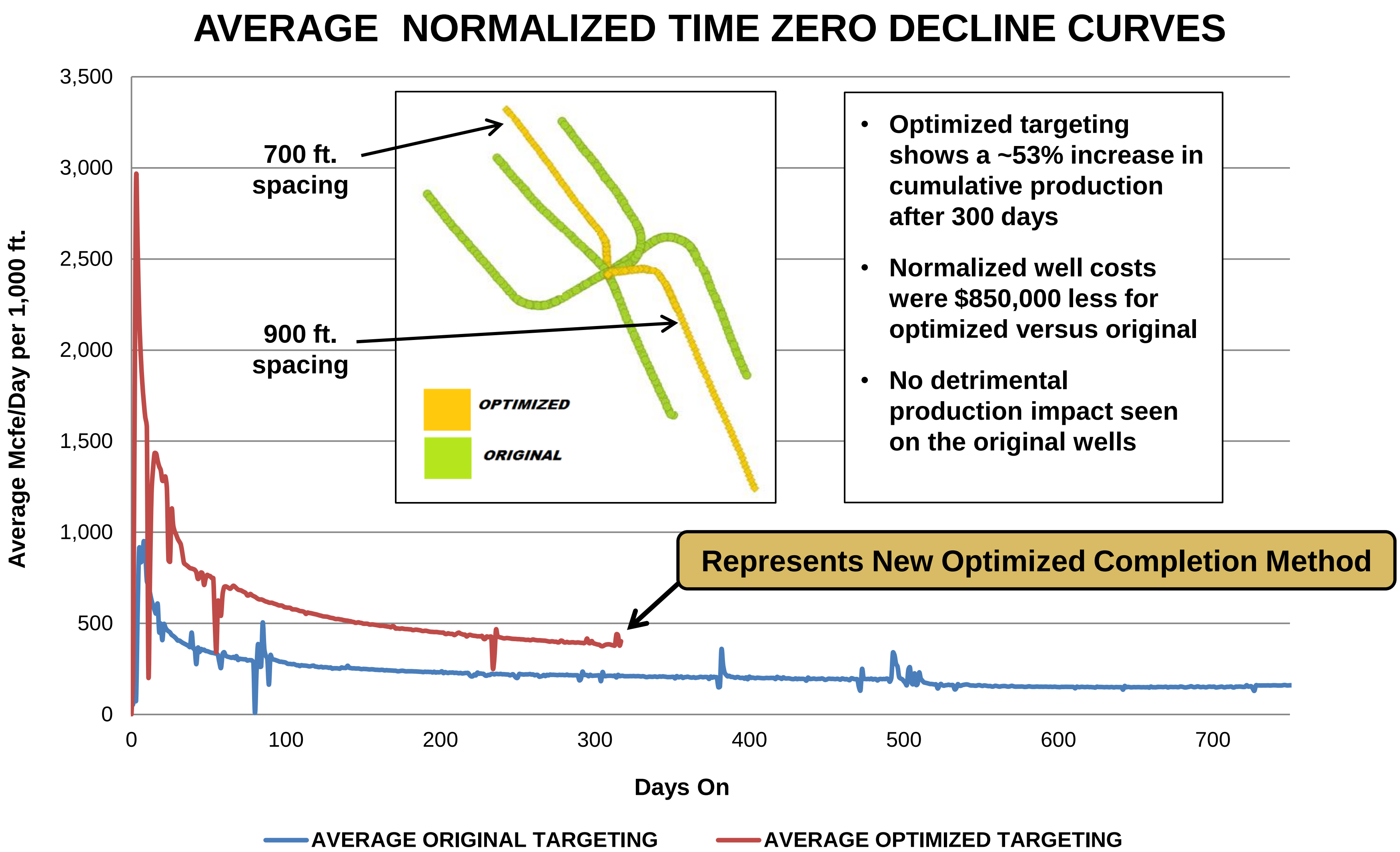


All comparisons based on Turned In Line (TIL) wells for each year

Results of Marcellus Tighter Spacing Pilot Projects



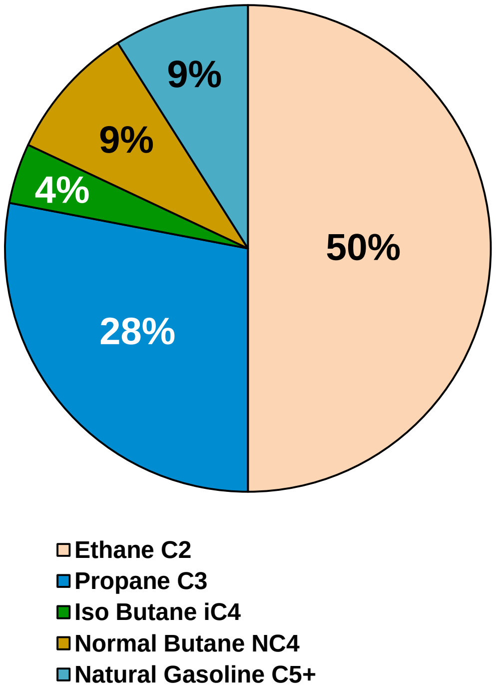
Targeting/Down Spacing Test Results Encouraging



- Optimized targeting shows a ~53% increase in cumulative production after 300 days
- Normalized well costs were $850,000 less for optimized versus original
- No detrimental production impact seen on the original wells

Marcellus NGL Pricing

Weighted Avg. Composite Barrel [1]



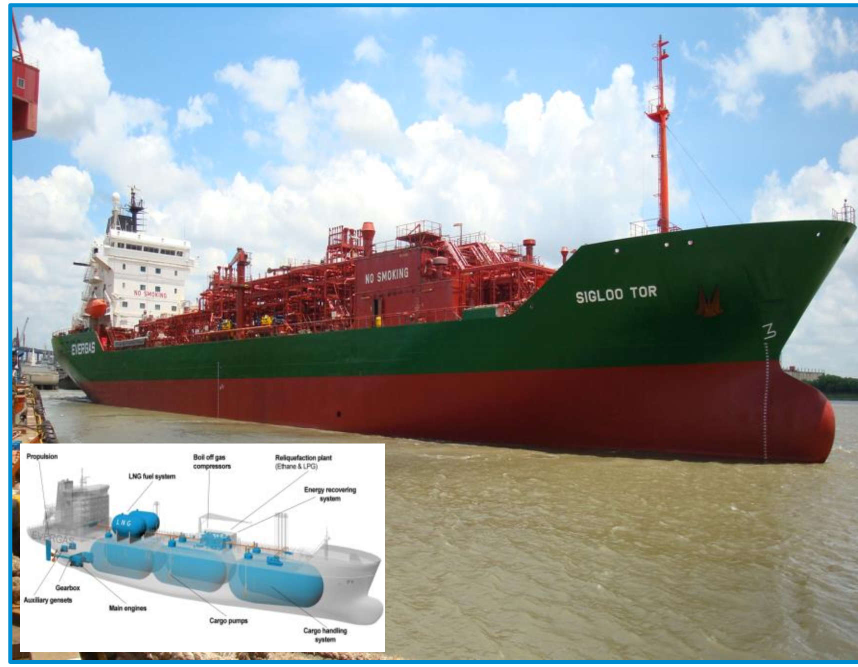
Realized Marcellus NGL Prices

	2014				2015
	1Q	2Q	3Q	4Q	1Q
NYMEX – WTI (per bbl)	$98.61	$102.97	$96.99	$73.11	$48.62
Mont Belvieu Weighted Priced Equivalent[2]	$37.22	$33.43	$32.14	$24.38	$17.99
Plant Fees plus Diff.	(8.02)	(9.79)	(10.53)	(6.77)	(7.10)
Marcellus average price before NGL hedges	$29.20	$23.64	$21.61	$17.61	$10.89
% of WTI (NGL Pre-hedge / Oil NYMEX)	30%	23%	22%	24%	22%
% of Mont Belvieu Weighted Equivalent	78%	71%	67%	72%	61%

(1) Based on NGL volumes in 4Q 2014
(2) Based on Mont Belvieu NGL prices and weighted average barrel composition for Marcellus

Range NGLs Add Cash Flow

- **Range has the highest Btu gas and a large liquids resource base**
  - **Range has size and scale**
  - **Range has a competitive advantage in pricing as most large projects require/benefit from Range's participation**
  - **Range's unique contracts provide a value uplift**
- **Range has a diverse portfolio of contracts with an expected substantial uplift in price realizations in 3Q 2015**
  - **Mariner West – 15,000 bbls/day of ethane - Gas price index - no transportation cost**
  - **Mariner East – 20,000 bbls/day propane - provides cost savings versus truck & rail when fully operational**
  - **20,000 bbls/day ethane to Ineos - supplying crackers in Norway at advantaged pricing**
  - **Expected $90 million of added annualized cash flow beginning in 3Q 2015**



- **Benefits for Range upon Marcus Hook harbor facilities completion later in 2015**
  - **Improved efficiencies from loading larger vessels**
  - **Access to 800,000 bbls of cavern storage for propane**
  - **Possible export of butane and other products**

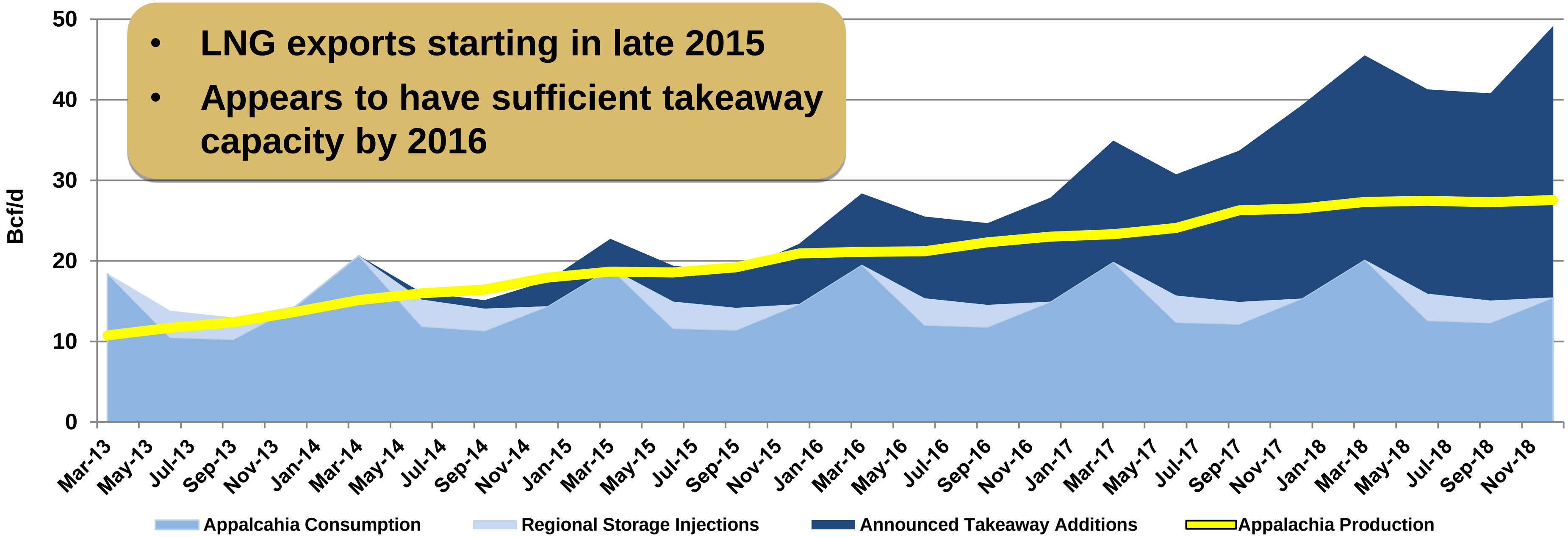
Appalachia Gas Transportation Arrangements

	Projected YE 2015		Projected YE 2016		Projected YE 2018	
Regional Direction	**Mmbtu/day (Gross)**	**Transport Cost per Mmbtu**	**Mmbtu/day (Gross)**	**Transport Cost per Mmbtu**	**Mmbtu/day (Gross)**	**Transport Cost per Mmbtu**
Firm Transportation						
Appalachia/Local	360,000	$ 0.22	360,000	$ 0.18	360,000	$ 0.18
Gulf Coast	270,000	$ 0.30	420,000	$ 0.41	945,000	$ 0.48
Midwest/Canada	285,143	$ 0.26	285,000	$ 0.26	585,000	$ 0.50
Northeast	210,000	$ 0.57	210,000	$ 0.57	210,000	$ 0.57
Southeast	100,000	$ 0.39	100,000	$ 0.39	100,000	$ 0.39
Firm Sales/Released Capacity	175,000	--	270,000	--	300,000	--
Total Take-Away Capacity	**1,400,000**	**$ 0.28**	**1,645,000**	**$ 0.28**	**2,500,000**	**$ 0.39**

Capacity listed above reflects actual amounts of production that can flow under these arrangements. We believe these firm arrangements provide adequate capacity to meet our growth projections through 2018

Range net production would be approximately 83% of the gross amounts shown. Does not include current intermediary pipeline capacity of > 650,000 Mmbtu/day, and assumes full utilization. Cost associated with Firm Sales/Released Capacity is assumed as a deduction to price. Based on anticipated project start dates.

Takeaway Largely Overbuilt by 2016-2017



		2013	2014	2015	2016	2017	2018
	Appalachia Production Year End Exit Rate	13.7	17.9	20.9	23.0	26.5	27.6
	Appalachia Consumption + Injections	13.4	14.6	14.2	14.6	15.0	15.2
A	**Appalachia Gas Surplus for Export**	**0.3**	**3.4**	**6.7**	**8.4**	**11.6**	**12.4**
	Fully Committed Takeaway Projects (cumulative year end)		3.4	7.3	10.8	20.5	25.0
	Other Proposed Takeaway Projects (cumulative year end)			0.8	3.5	4.7	8.2
B	**Total Takeaway Projects (cumulative year end)**		**3.4**	**8.1**	**14.3**	**25.2**	**33.2**
	Excess Takeaway (B – A)		**0.0**	**1.3**	**5.8**	**13.7**	**20.8**

As of Year End | **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
2014	Northeast Connector	Williams	Transco	NE	Q4'14	0.1	Y	Y
	Iroquois Access	Dominion	Iroquois	NE	Q4'14	0.3	Y	Y
	Rose Lake Expansion	Kinder Morgan	TGP	NE	Q4'14	0.2	Y	Y
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	Northern Access 2016	NFG	National Fuel	Canada	2016	0.4	Y	Y
	SoNo Iroquois Access	Dominion	Iroquois	Canada	Q2'16	0.3	N	N
	Constitution	Williams	Constitution	NE	H1'16	0.7	Y	Y
	Algonquin AIM	Spectra	Algonquin	NE	Q4'16	0.4	Y	Y
2017	Atlantic Sunrise	Williams	Transco	Mid-Atlantic/SE	H2'17	1.7	Y	Y
	PennEast	AGT		NE	H2'17	1.0	Y	Y
	Atlantic Bridge	Spectra	Algonquin	NE	H2'17	0.7	N	N
2018	Access Northeast	Spectra	Algonquin	NE	H2'18	1.0	N	N
	Diamond East	Williams	Transco	NE	H2'18	1.0	N	N
	TGP Northeast Expansion	Kinder Morgan	TGP	NE	H2'18	1.0	Y	Y

	Southwest	Operator	Main Line	Market	Start-up	Capacity – Bcf/d	Fully Committed	Approved or with FERC
2014	Lebanon Lateral Reversal	Transcanada	ANR	Midwest	Q1'14	0.4	Y	Y
	Utica Backhaul	Kinder Morgan	TGP	Midwest	Q2'14	0.5	Y	Y
	REX Seneca Lateral	Tall Grass	REX	Midwest	H1'14	0.6	Y	Y
	TEAM 2014	Spectra	TETCO	Gulf Coast	Q4'14	0.6	Y	Y
	TEAM South	Spectra	TETCO	Gulf Coast	Q4'14	0.3	Y	Y
	West Side Expansion	Nisource	Columbia	Gulf Coast	Q4'14	0.4	Y	Y
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	Q4'15	0.4	Y	Y
	Glen Karn 2015	Transcanada	ANR	Midwest	Q4'15	0.8	N	N

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

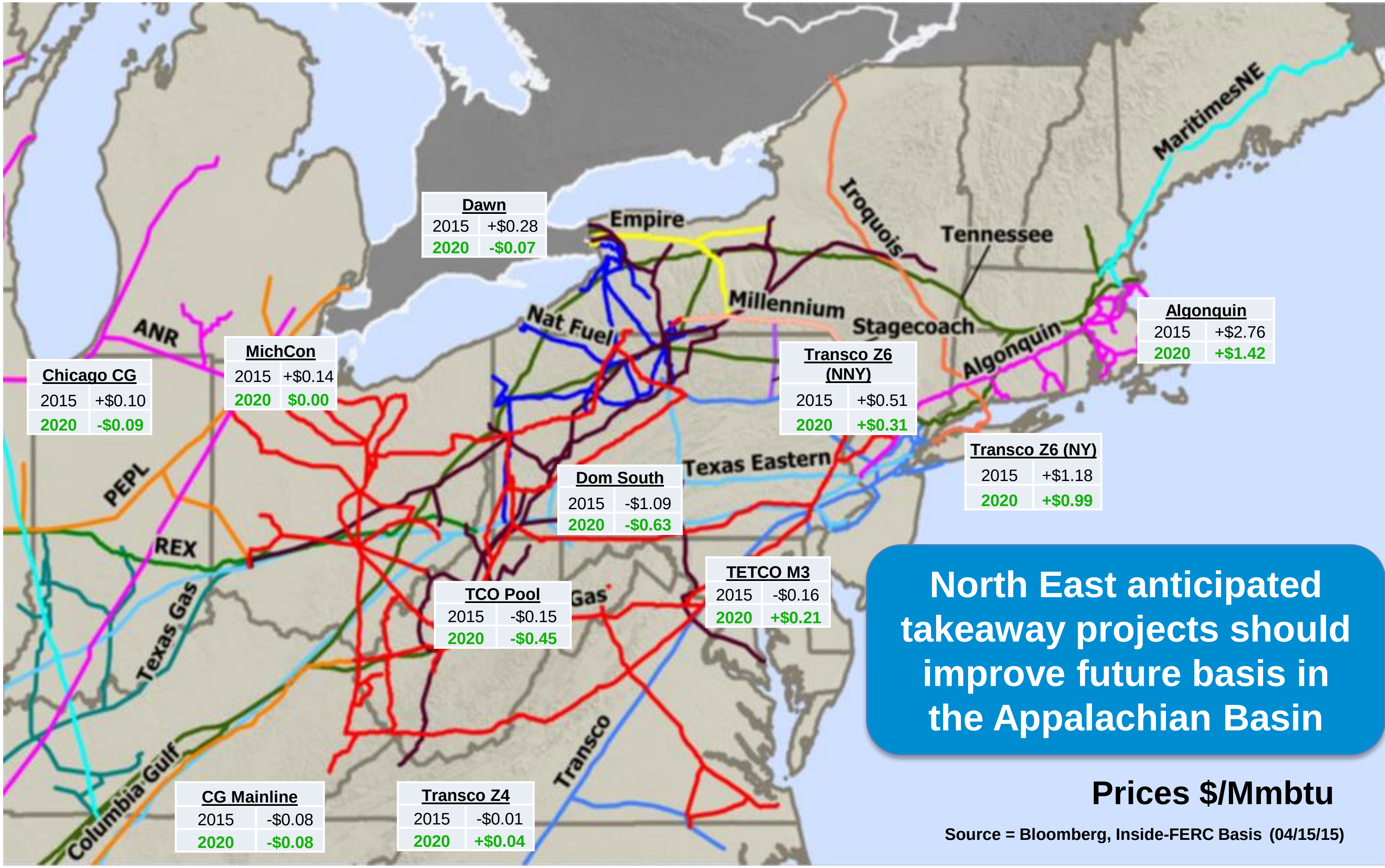
Announced Appalachian Basin Takeaway Projects – 2 of 2

	Southwest	Operator	Main Line	Market	Start-up	Capacity – Bcf/d	Fully Committed	Approved or with FERC
2016	Gulf Expansion Ph1	Spectra	TETCO	Gulf Coast	Q4'16	0.3	Y	Y
	Clarington West Expansion	Tall Grass	REX	Midwest	Q4'16	2.4	N	N
	Rover Ph1	ETP		Midwest/Canada/ Gulf Coast	Q4'16	1.9	Y	Y
2017	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	N
	Rover Ph2	ETP		Midwest/Canada/ Gulf Coast	Q3'17	1.3	Y	Y
	TGP Backhaul / Broad Run Expansion	Kinder Morgan	TGP	Gulf Coast	Q4'17	0.2	Y	Y
	Adair SW	Spectra	TETCO	Gulf Coast	Q4'17	0.2	Y	N
	Access South	Spectra	TETCO	Gulf Coast	Q4'17	0.3	Y	N
	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	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

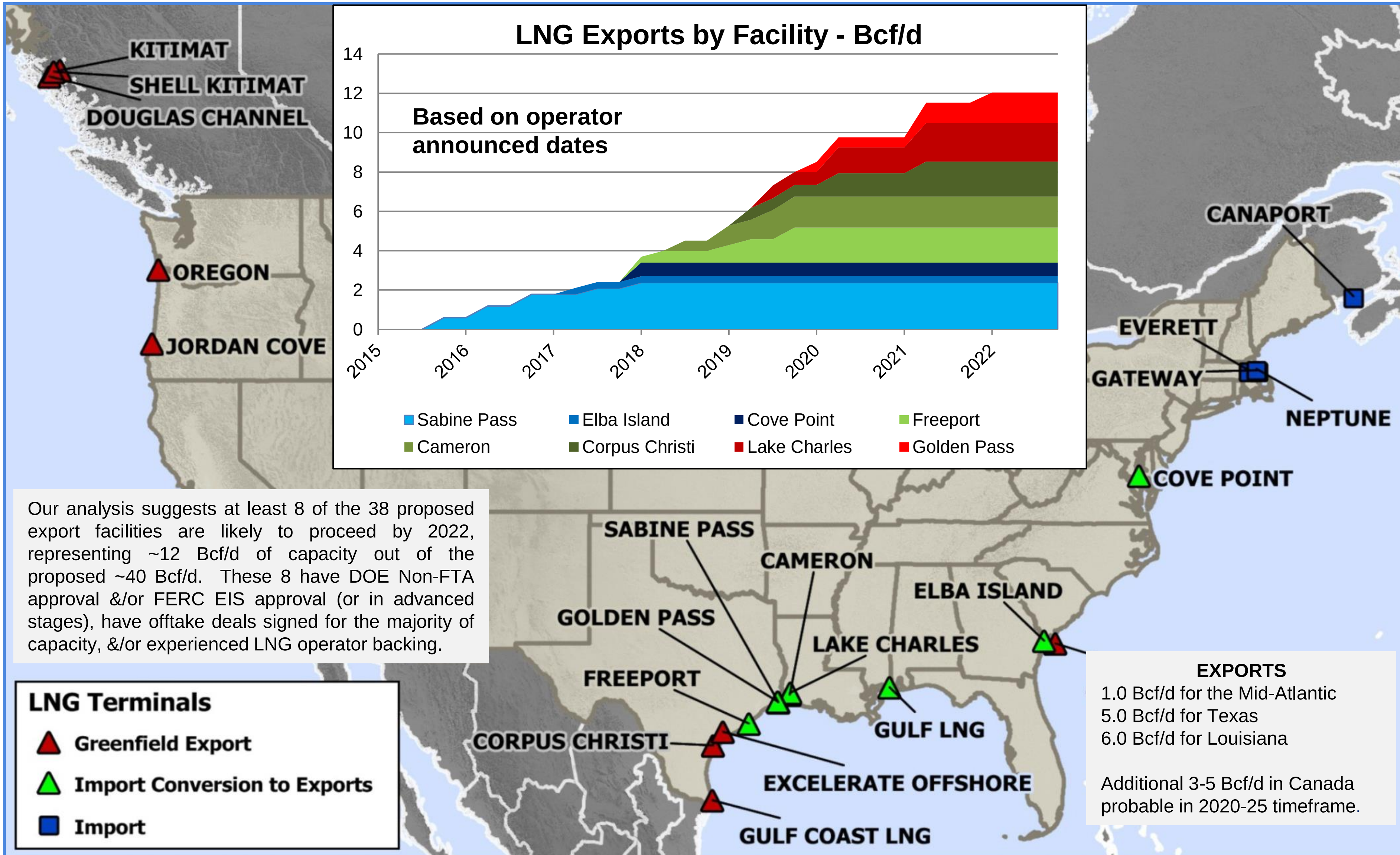
Total NE Appalachia to Canada	**1.0**
Total NE Appalachia to NE	**6.3**
Total NE Appalachia to Mid-Atlantic/SE	**2.5**
Total NE Appalachia Additions	**9.7**
Total SW Appalachia to Mid-Atlantic/SE	**5.0**
Total SW Appalachia to Midwest/Canada	**9.4**
Total SW Appalachia to Gulf Coast	**8.4**
Total SW Appalachia to NE	**0.7**
Total SW Appalachia Additions	**23.5**
Overall Total Additions for Appalachian Basin	**33.2**

**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?



LNG Exports – Developing Projects To-Date



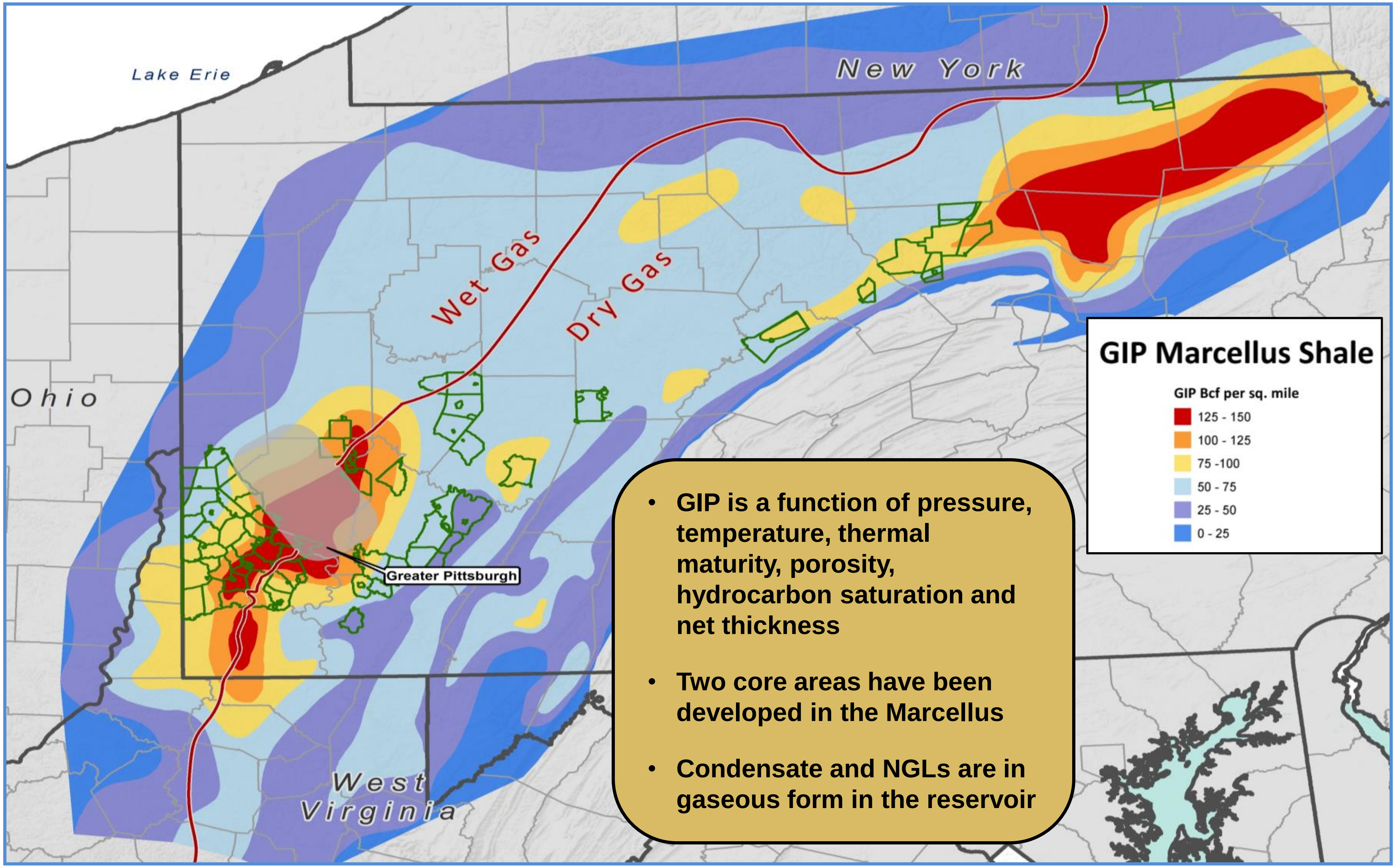
Our analysis suggests at least 8 of the 38 proposed export facilities are likely to proceed by 2022, representing ~12 Bcf/d of capacity out of the proposed ~40 Bcf/d. These 8 have DOE Non-FTA approval &/or FERC EIS approval (or in advanced stages), have offtake deals signed for the majority of capacity, &/or experienced LNG operator backing.

EXPORTS

1.0 Bcf/d for the Mid-Atlantic
5.0 Bcf/d for Texas
6.0 Bcf/d for Louisiana

Additional 3-5 Bcf/d in Canada probable in 2020-25 timeframe.

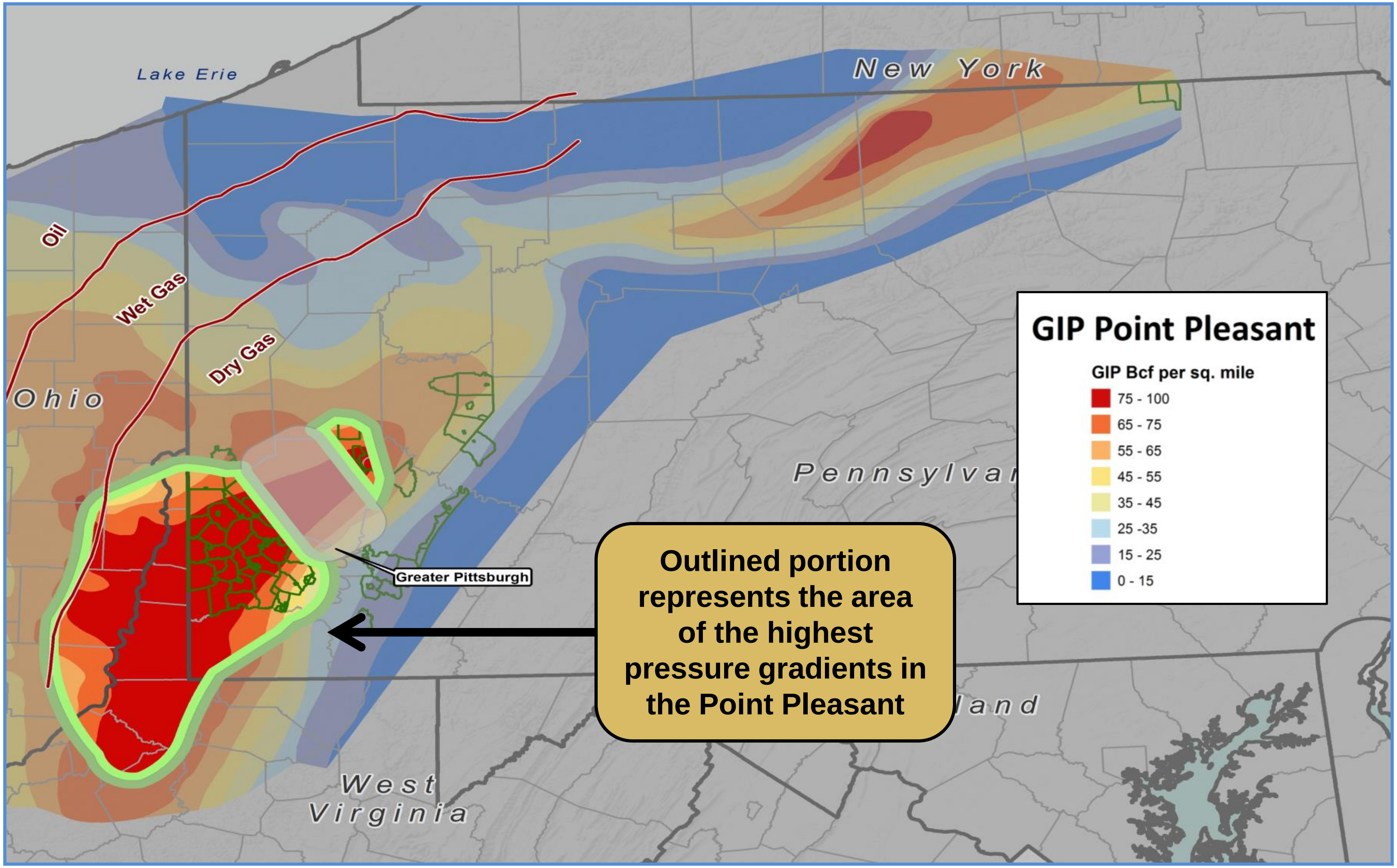
Gas In Place (GIP) – Marcellus Shale



- 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

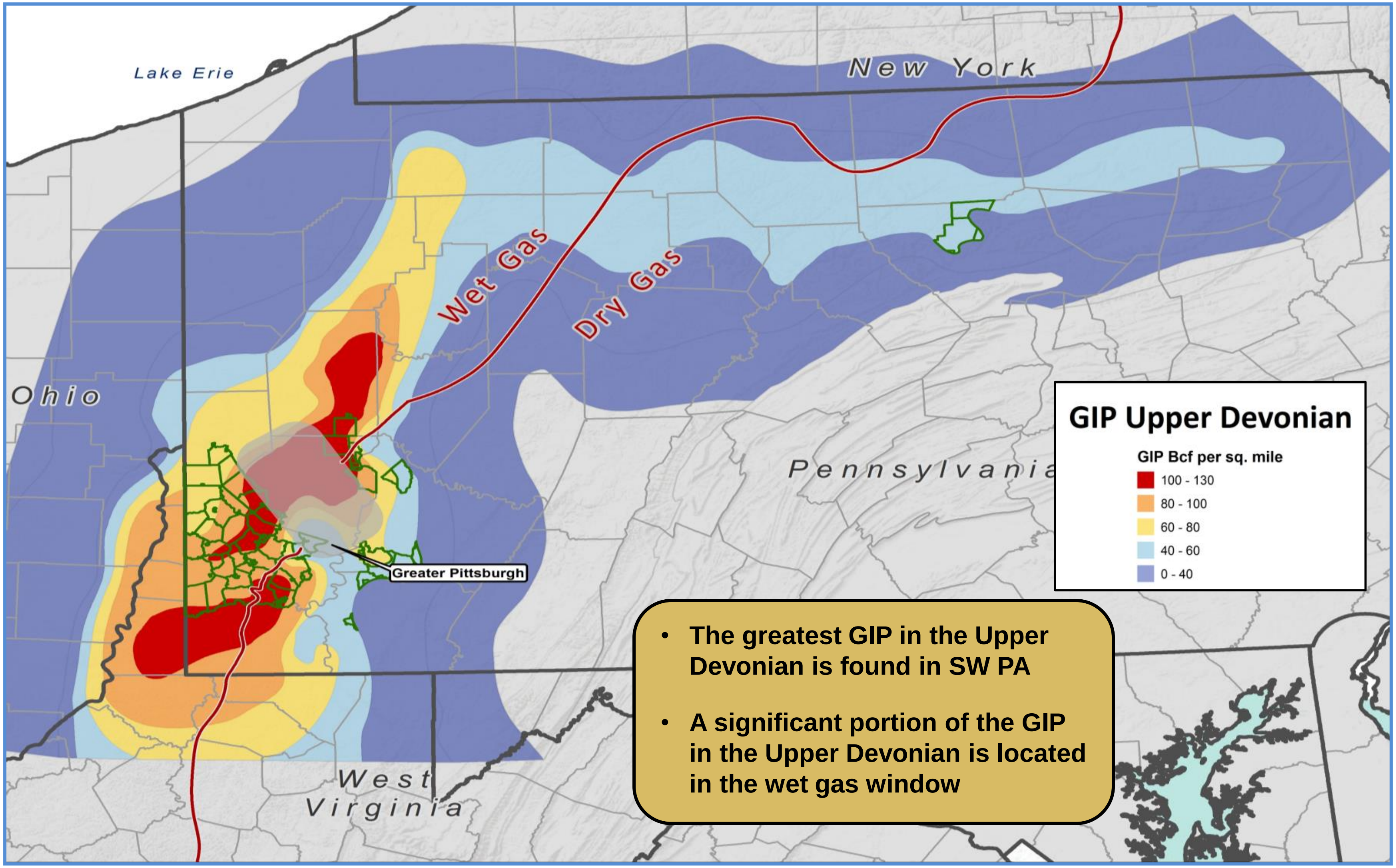
Note: Townships where Range holds ~3,000 or more acres (as of 12/31/2014), and estimated as prospective, are outlined green. GIP – Range estimates.

Gas In Place (GIP) – Point Pleasant



Note: Townships where Range holds ~3,000 or more acres (as of 12/31/2014), and estimated as prospective, are outlined green. GIP – Range estimates.

Gas In Place (GIP) – Upper Devonian Shale

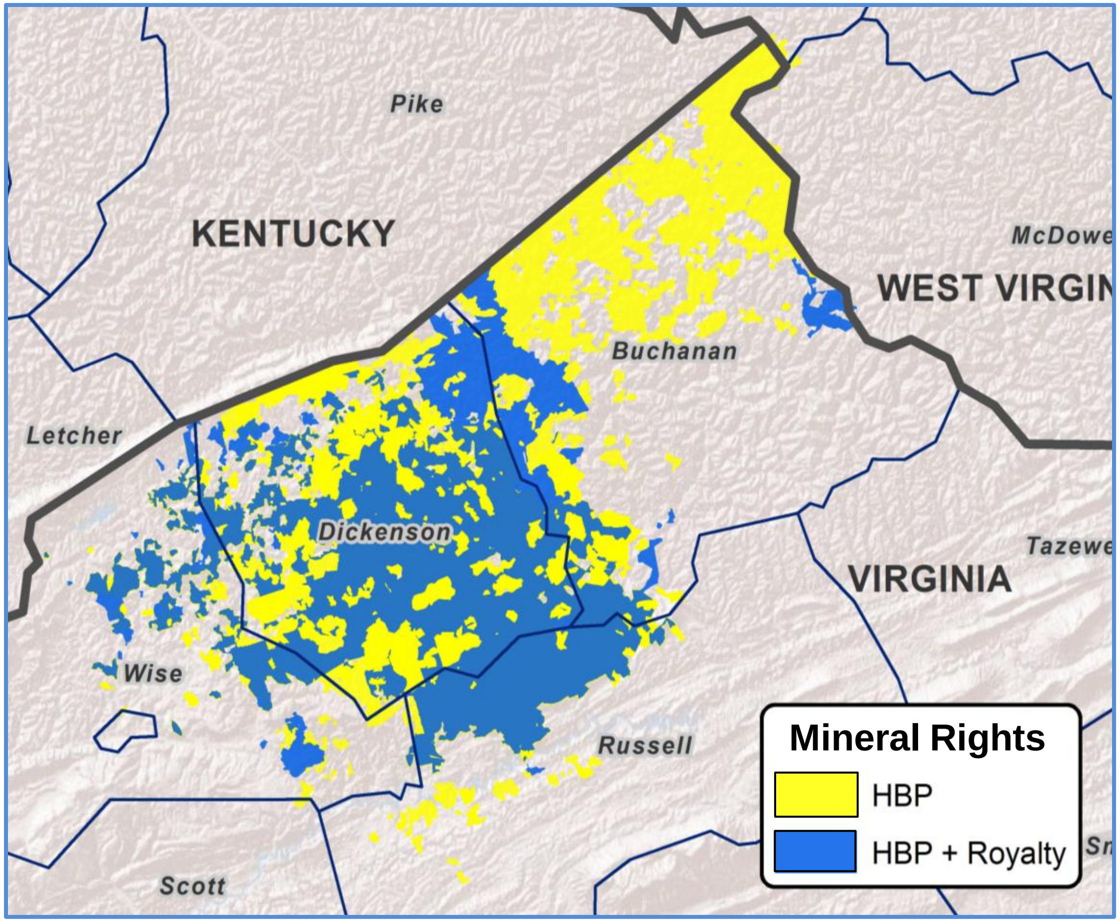


- **The greatest GIP in the Upper Devonian is found in SW PA**
- **A significant portion of the GIP in the Upper Devonian is located in the wet gas window**

Note: Townships where Range holds ~3,000 or more acres (as of 12/31/2014), and estimated as prospective, are outlined green. GIP – Range estimates.

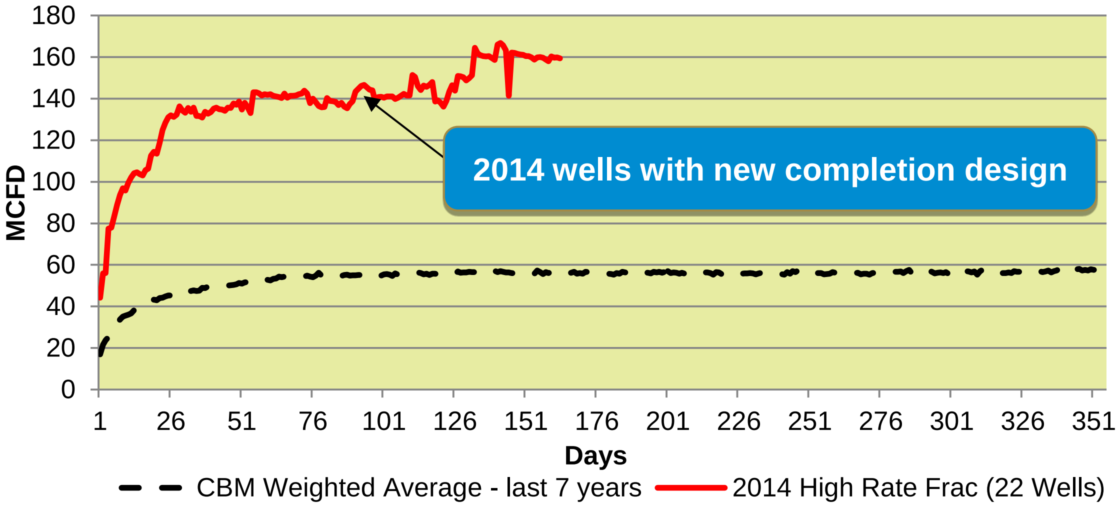
Southern Appalachia– Strategic Marketing Advantages

465,000 net acres - Range owns minerals on most of the acreage



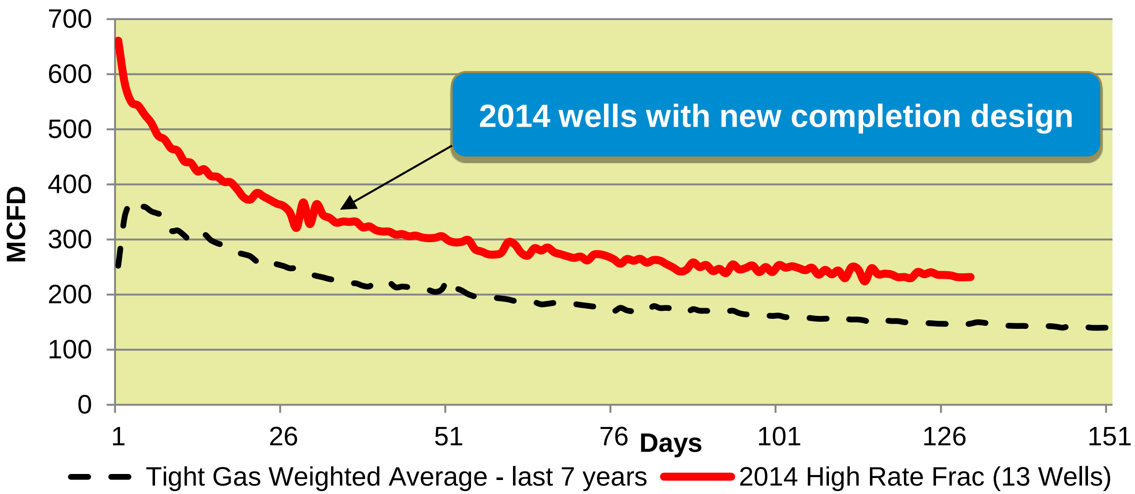
- **Nora is strategically positioned to provide gas to southeast markets**
- **Contracts in place for ~100 Mmcf/d at $0.20/Mmbtu above NYMEX for the next 12 months**
- **~50 Mmcf/d of existing unused transport capacity to allow for planned production growth**
- **Recent completion technology advances result in substantially higher returns for CBM and tight gas wells**
- **Recent CBM results are 2.5x better than the historical field average, with moderate cost increases of only $15,000 per well**
- **Deeper exploration potential upside**

2014 Nora Enhanced Results From New Completion Design



2014 CBM

- **Pumping sand at higher pressures during completion operations has significantly increased production**
- **Cost increase is only $15,000 per well, primarily to upgrade production pipe to withstand higher pressure**
- **Early results indicate that production levels are 3 times historical field average**



2014 Tight Gas

- **New completions designs for Nora tight gas, costing approximately $12,000 per well, have improved production results by over 40% over historical field results**
- **13 wells were brought online in 2014**

Midcontinent Division

- **~360,000 net acres**

- **Current development activity has been in the Mississippian Chat along the Nemaha Ridge**

- **Horizontal Granite Wash, Cleveland and Woodford potential on existing HBP acreage**

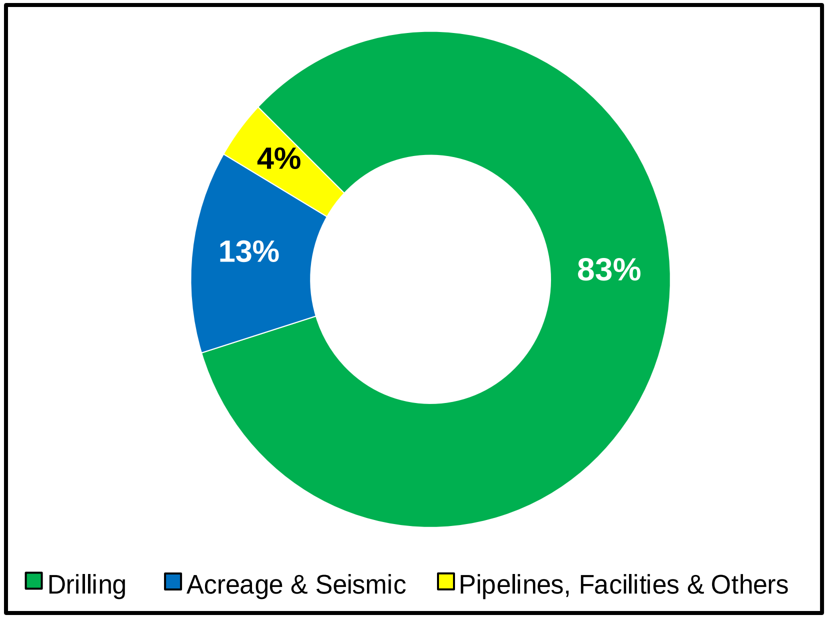
<u>2015 Planned Activity</u>

  - **Turn in line 8 Mississippian Chat wells**

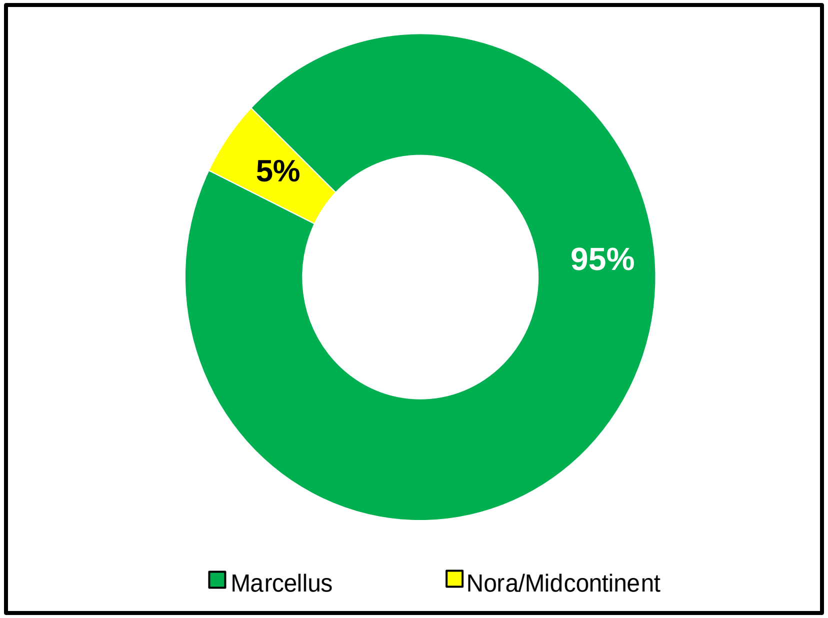
Financial and Reserve Detail

Capital Efficiencies Driving Growth

Budget = $870 Million



Budget by Area



Capital Efficiencies Driving Growth with Less Capital

Completed lateral lengths in Marcellus expected to be > 6,000 ft. in 2015

Improved targeting and completion techniques have increased recoveries significantly

95% of 2015 capital focused in Marcellus

Track Record of Building Reserves at Low Costs

	YE 2009	YE 2010	YE 2011	YE 2012	YE 2013	YE 2014
Proved Reserves (Tcfe)	3.1	4.4	5.1	6.5	8.2	10.3
Drill Bit Finding Cost (per Mcfe)	$0.69	$0.59	$0.76	$0.67	$0.57	$0.55
Net Unproved Resource Potential (Tcfe)[1]	24 - 32	35 - 52	44 - 60	48 - 68	65 - 86	66 - 87

Proved reserves have increased by 27% per year on a compounded basis since 2009

Moved 8.8 Tcfe of Resource Potential into Proved Reserves in the Last Five Years

(1) Excludes Utica/Point Pleasant potential

Successful Senior Notes Offering

Range sold $750 million of senior notes due 2025 with a 4.875% coupon

Ratings Agencies

- **Moody's assigned a Ba1 rating to the new senior unsecured bonds, affirmed its Ba2 rating on the subordinated notes, and maintained its positive rating outlook**
  - *"Range's rating affirmation and positive outlook reflect the company's strong operating efficiency and growing production profile."*
- **S&P assigned a BB+ rating to the senior unsecured bonds and affirmed its BB+ rating on the subs**

Offering Outcome

- **Despite upsizing the offering from $500 to $750 million, Range was able to achieve <u>the lowest yield of any non-investment grade energy & power new issue of any maturity in 2015</u>**
- **Bonds were placed primarily with high-quality, long-term holders (insurance companies and traditional "buy-and-hold" asset managers)**
- **Senior structure attracted a range of buyers, including new high grade and crossover investors**
- **Bonds traded modestly higher on the break, in the 100.25–100.50 range**

	Rate	3/31/2015 Actual	3/31/2015 Pro Forma
Revolver	1.68%	$ 912.0	$ 691.1
Sr Sub Notes			
2020's	6.75%	$ 500.0	$ -
2021's	5.75%	$ 500.0	$ 500.0
2022's	5.00%	$ 600.0	$ 600.0
2023's	5.00%	$ 750.0	$ 750.0
Senior Notes			
2025's	4.875%		$ 750.0
		$ 3,262.0	$ 3,291.1
Weighted Avg Bond Interest Rate:		**5.53%**	**5.11%**
Corporate Avg Interest Rate:		**4.45%**	**4.39%**

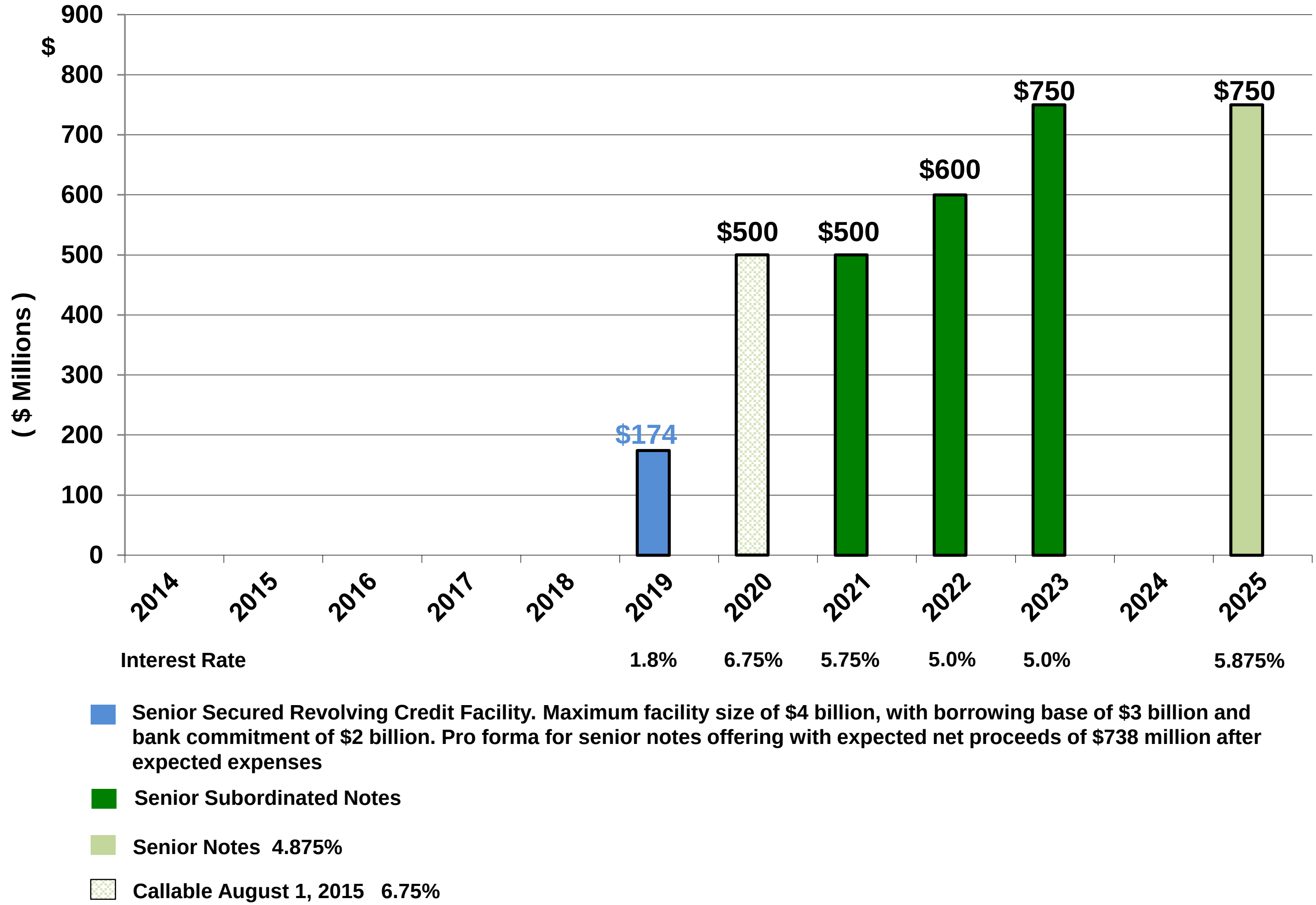
Strong, Simple Balance Sheet

($ in millions)	YE 2010	YE 2011	YE 2012	YE 2013	YE 2014	Q1 2015	Pro forma Q1 2015 [2]
Bank borrowings	$274	$187	$739	$500	$723	$912	$691
Sr. Sub. Notes	1,686	1,788	2,139	2,641	2,350	2,350	2,600
Less: Cash	(3)	(0)	(0)	(0)	(0)	(0)	(0)
Net debt	1,957	1,975	2,878	3,141	3,073	3,262	3,291
Common equity	2,224	2,392	2,357	2,414	3,456	3,490	3,476
Total capitalization	$4,181	$4,367	$5,235	$5,555	$6,529	$6,752	$6,767
Debt-to-capitalization[1]	47%	45%	55%	57%	47%	48%	49%
Debt/EBITDAX[1]	2.8x	2.3x	3.2x	2.8x	2.6x	2.9x	2.9x
Liquidity[2]	$971	$1,284	$927	$1,166	$1,172	$980	$1,201

(1) Ratios are net of cash balances.
(2) Liquidity equals cash available borrowings under the revolving credit facility.
(3) Pro forma for $750 senior note offering and calling of $500 senior subordinated note on 8/1.

Debt Maturities – Pro Forma for Notes Offering

Range maintains an orderly debt maturity ladder



Gas and Oil Hedging Status

	Period	Volumes Hedged (Mmbtu/day)	Average Floor Price ($ / Mmbtu)	Average Cap Price ($ / Mmbtu)
Gas Hedging	2Q 2015 Swaps 3Q 2015 Swaps 4Q 2015 Swaps	737,500 747,500 727,500	$3.63 $3.63 $3.63	
	2Q 2015 Collars 3Q 2015 Collars 4Q 2015 Collars	145,000 145,000 145,000	$4.07 $4.07 $4.07	$4.56 $4.56 $4.56
	2016 Swaps 2017 Swaps	630,000 20,000	$3.42 $3.49	
Oil Hedging	2Q 2015 Swaps 3Q 2015 Swaps 4Q 2015 Swaps	9,500 11,250 11,250	$90.58 $85.87 $85.87	
	2016 Swaps	3,000	$70.54	

As of 5/22/2015 – For quarterly detail of hedges, see RRC website

Natural Gas Liquids Hedging Status

	Period	Volumes Hedged (bbls/day)	Hedged [1] Price ($/gal)
Propane (C3)	2Q 2015 Swaps 3Q 2015 Swaps 4Q 2015 Swaps 2016 Swaps	14,000 14,000 12,000 5,500	$0.65 $0.61 $0.55 $0.60
Normal Butane (NC4)	2Q 2015 Swaps 3Q 2015 Swaps 4Q 2015 Swaps 2016 Swaps	3,500 3,500 3,500 2,500	$0.72 $0.72 $0.72 $0.72
Natural Gasoline (C5)	2Q 2015 Swaps 3Q 2015 Swaps 4Q 2015 Swaps 2016 Swaps	3,500 4,000 4,000 2,500	$1.16 $1.16 $1.16 $1.23

(1) NGL hedges have Mont Belvieu as the underlying index.

Conversion Factor:
One barrel = 42 gallons

As of 5/22/2015 – For quarterly detail of hedges, see RRC website

Contact Information

Range Resources Corporation
100 Throckmorton, Suite 1200
Fort Worth, Texas 76102
Main: 817.870.2601
Fax: 817.870.2316

Rodney Waller, Senior Vice President
rwaller@rangeresources.com

David Amend, Investor Relations Manager
damend@rangeresources.com

Laith Sando, Research Manager
lsando@rangeresources.com

Michael Freeman, Senior Financial Analyst
mfreeman@rangeresources.com

www.rangeresources.com