Dorchester Minerals, LP
Annual Meeting

May 18, 2016

Forward-Looking Statements

Portions of this document may constitute, and our officers and representatives may from time to time make, "forward-looking statements" within the meaning of the safe harbor provisions of the U.S. Private Securities Litigation Reform Act of 1995. Forward-looking statements can be identified by words such as: “anticipate”, “intend”, “plan”, “goal”, “seek”, “believe”, “project”, “estimate”, “expect”, “strategy”, “future”, “likely”, “may”, “should”, “will” and similar references to future periods. Forward-looking statements are neither historical facts nor assurances of future performance. Instead, they are based only on our current beliefs, expectations and assumptions regarding the future of our business, future plans and strategies, projections, anticipated events and trends, the economy and other future conditions. Because forward-looking statements relate to the future, such statements are subject to certain risks, uncertainties and assumptions. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may vary materially from those anticipated, estimated or projected. Therefore, you should not rely on any of these forward-looking statements. Examples of such uncertainties and risks include, but are not limited to, changes in the price or demand for oil and natural gas, changes in the operations on or development of the Partnership’s properties, changes in economic and industry conditions and changes in regulatory requirements (including changes in environmental requirements) and the Partnership’s consolidated financial position, business strategy and other plans and objectives for future operations. These and other factors are set forth in the Partnership's filings with the Securities and Exchange Commission. Any forward-looking statement made by us in this document is based only on information currently available to us and speaks only as of the date on which it is made. We undertake no obligation to publicly update any forward-looking statement, whether written or oral, that may be made from time to time, whether as a result of new information, future developments or otherwise.

Presentation Outline

- Overview of 2015
- Distributions
- Minerals NPI Status
- Reserves & Production
- Property Discussion

Overview of 2015

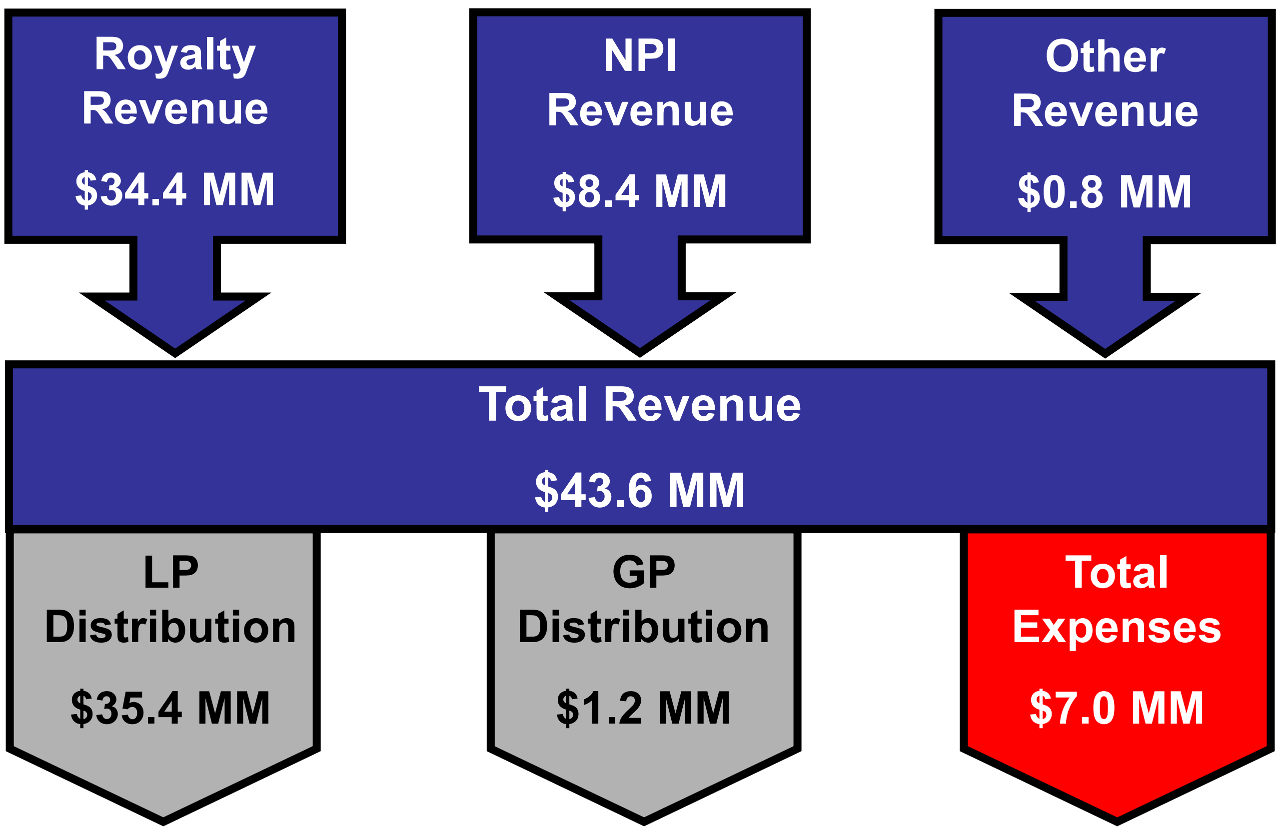
- **Challenging Price Environment**
  - Dramatic decline in resource play activity
  - Attractiveness of WI/NPI participation is minimal at best

- **Midland Basin Position is a Bright Spot**
  - Drilling and completion efficiencies result in higher recoveries

- **Active Management of our Properties**
  - Strategic leasing opportunities
  - Enhanced revenue recovery initiatives
  - Ongoing pursuit of acquisition/exchange opportunities

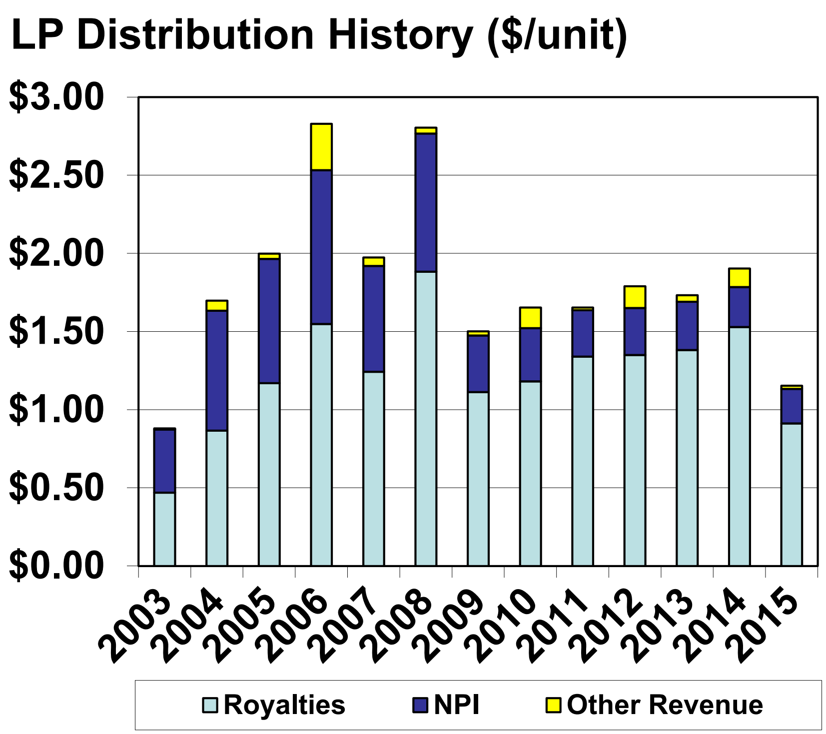
2015 Distributions

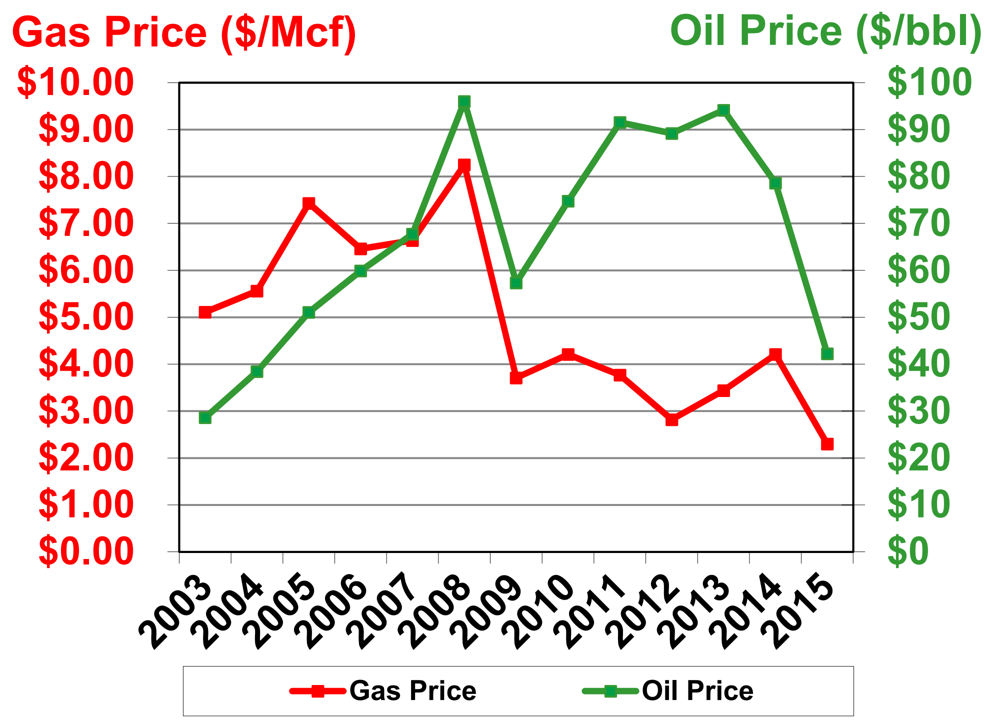
- Cash Distributions Paid in Calendar 2015
  - Reflects Q4 2014 to Q3 2015 activity



2015 Distributions

- Components and Prices
  - Royalty properties contributed 79% to total 2015 LP distributions
  - Gross Revenue → 38% gas sales, 53% oil & NGL sales, 9% KS divestiture & other
  - Minerals NPI contributed to Q4 2015 distribution which was paid in Q1 2016

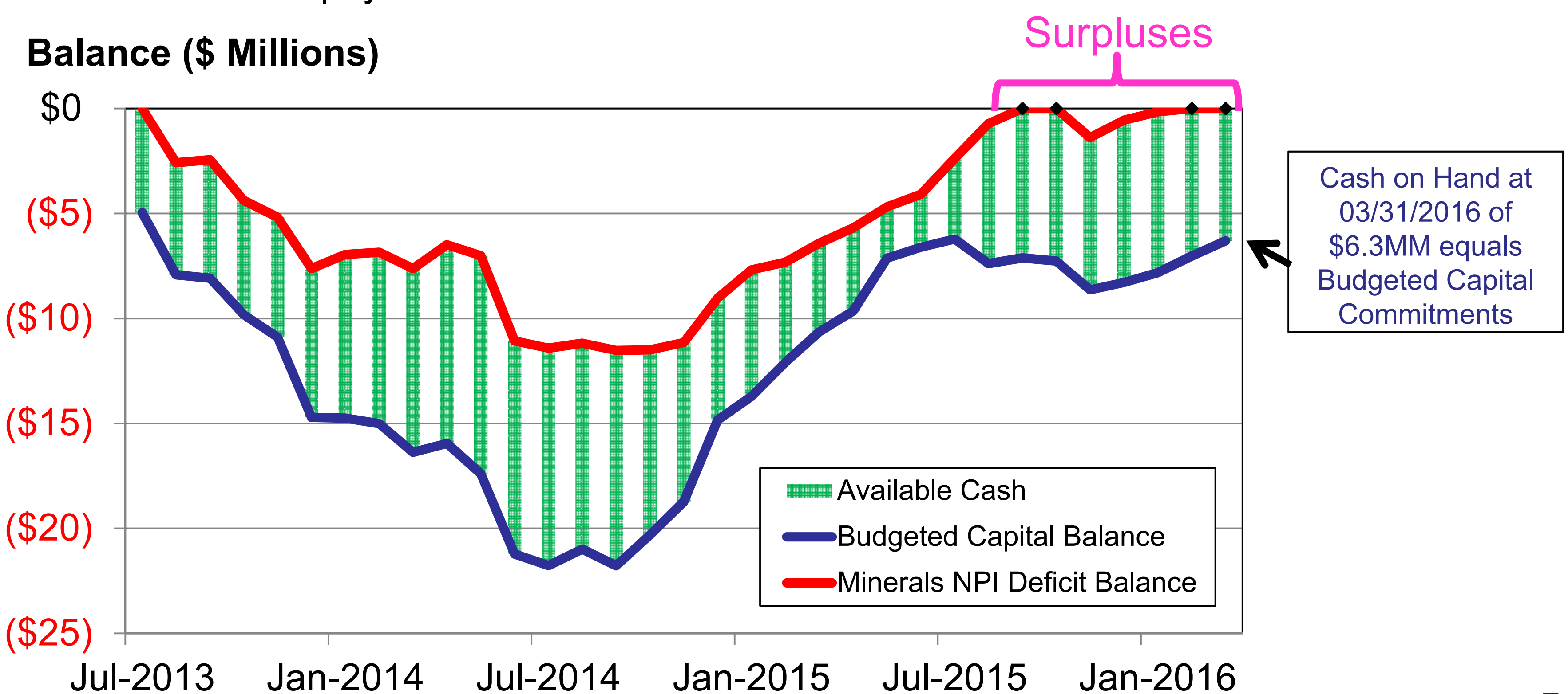




Note: Oil and gas prices represent realized prices from royalty properties.

Minerals NPI

- Activity from August 2013 through March 2016
  - Reached surplus in September 2015 for the first time since July 2013
  - NPI payments totaling $1.5MM for Sept 2015, Oct 2015, Feb 2016 and Mar 2016
  - March 2016 payment to be included in the Q2 2016 distribution



Note: Aug 1, 2013 to Aug 31, 2015 represents the time period the Minerals NPI was in deficit status.

Minerals NPI

- Inception-To-Date Activity through March 2016

Cumulative Revenue	$112.7 MM
Cumulative Expense (LOE, taxes, etc.)	($ 26.3 MM)
Cumulative Operating Income	$ 86.4 MM
Cumulative CAPEX Spent	($ 72.9 MM)
Cumulative Cash Flow	$ 13.5 MM
Cumulative Distributions	($ 7.2 MM)
Cash on Hand @ 03/31/2016	$ 6.3 MM
Capital Commitments @ 03/31/2016	($ 6.3 MM)
Cumulative Surplus Payments	**$ 7.2 MM**

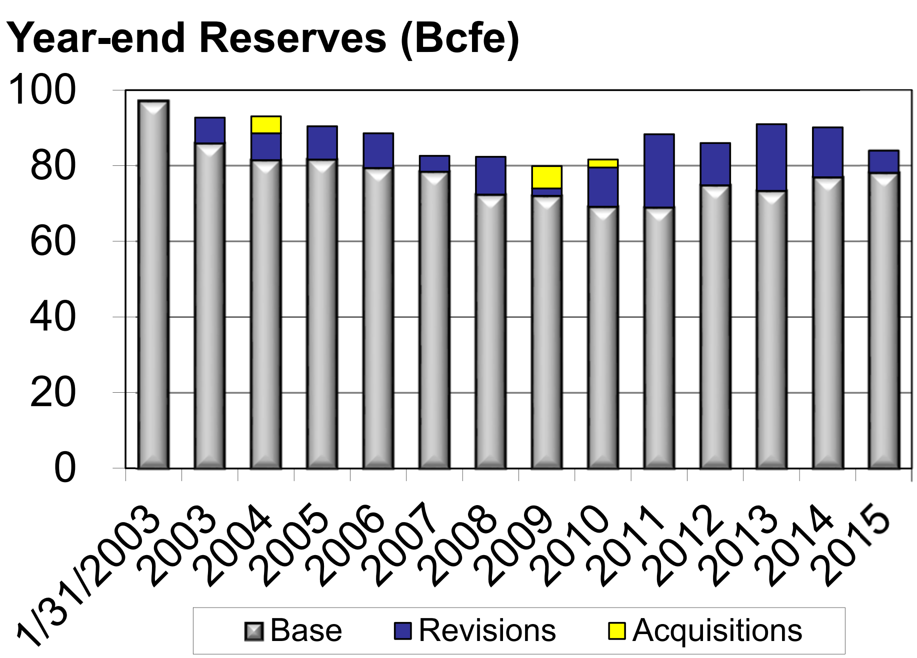
Outstanding Capital Commitments

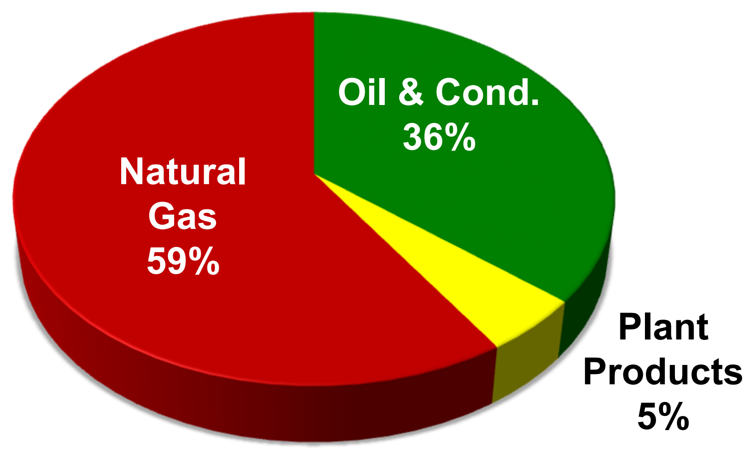
By Play	
Bakken	($ 5.7 MM)
Other Basins	($ 0.6 MM)
Total Capital Commitments	($ 6.3 MM)

By Status	
Wells in Pay Status	($ 4.3 MM)
Wells not in Pay Status	($ 2.0 MM)
Total Capital Commitments	($ 6.3 MM)

2015 Reserves

- Total Proved Reserves of 83.4 Bcfe on 12/31/2015
  - All reserves are Proved Developed Producing (PDP)
  - Demonstrated history of positive revisions
  - Cumulative revisions since inception account for 154% of total reserves at year-end
  - Driving factors including new plays, field extensions, infill drilling, and new technology

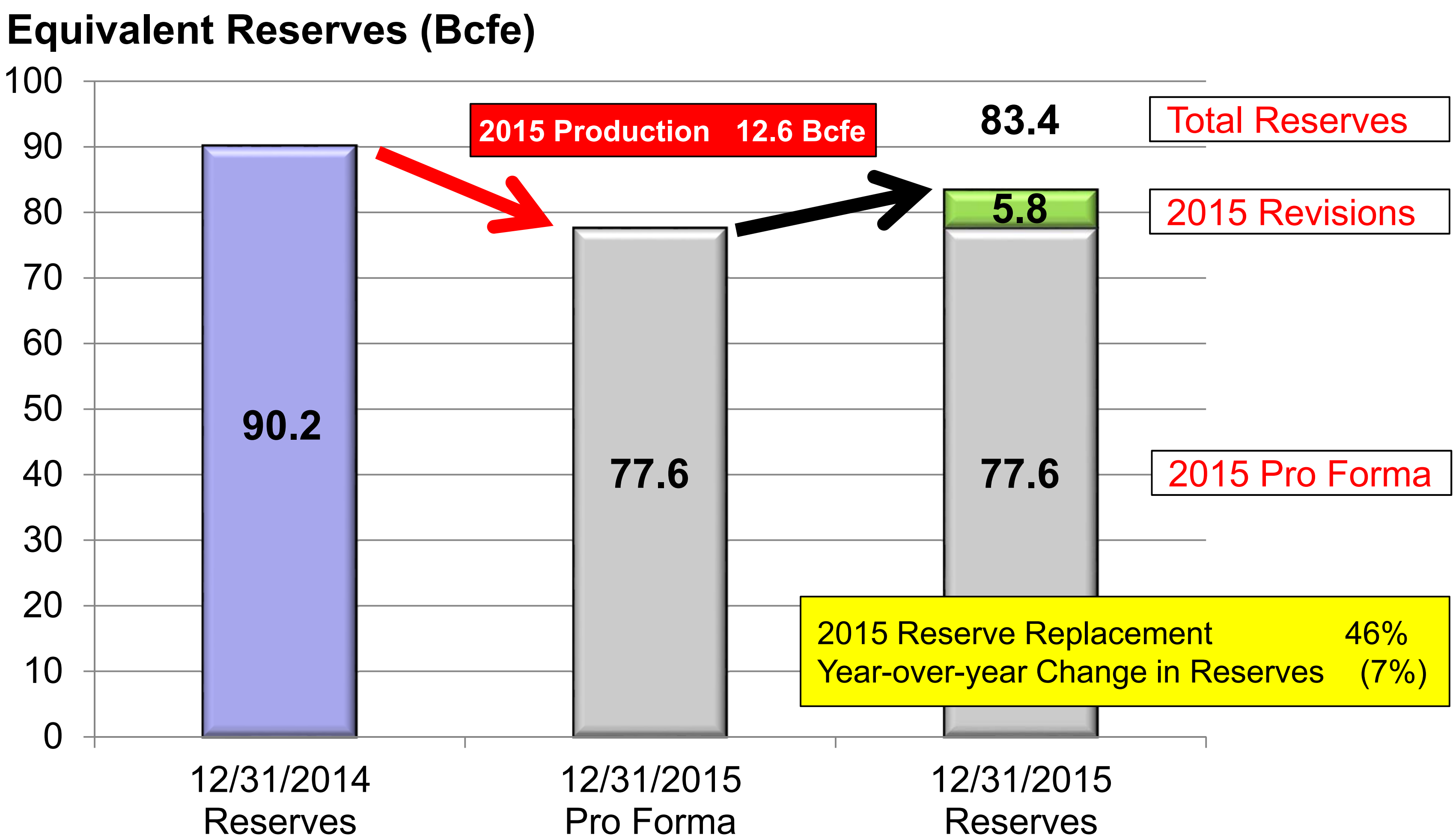




Note: 12.5 Bcfe of acquired reserves at time transactions closed. Gas-Oil equivalency of 6:1 ratio is used throughout this presentation

2015 Reserves

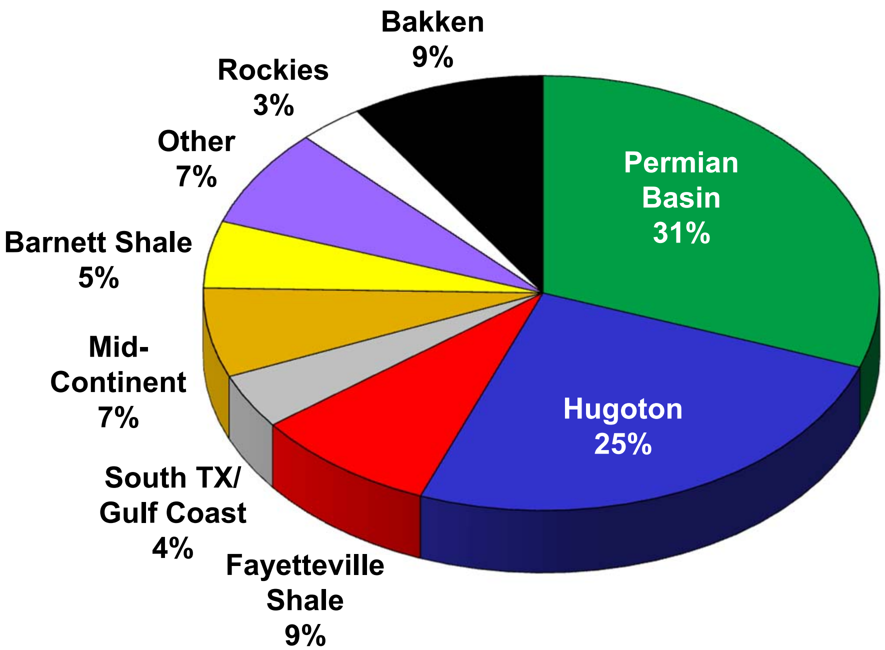
- Revisions to Reported PDP Reserves



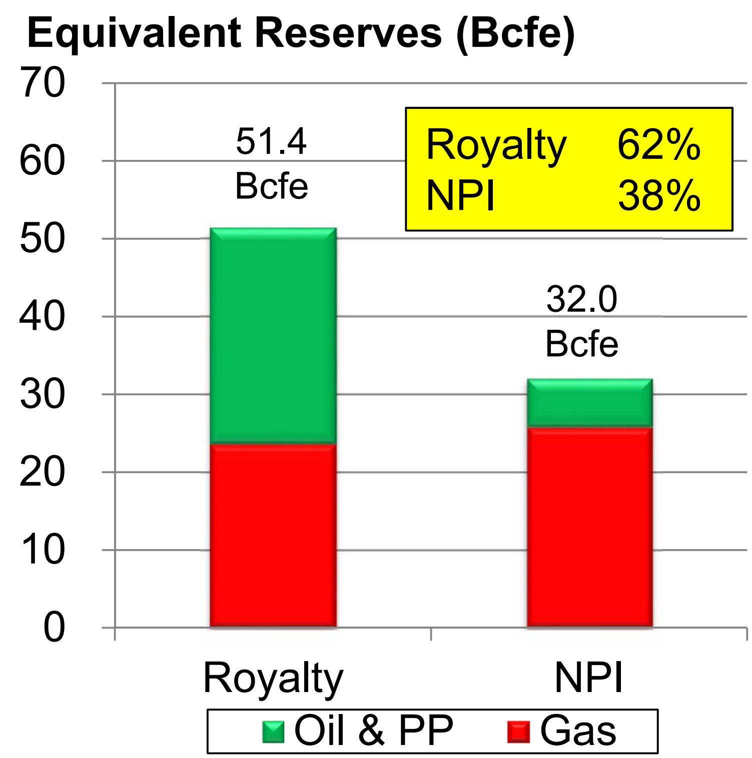
2015 Reserves

- Composition of Proved Reserves
  - Royalty reserves increased from 60% at YE 2014 to 62% at YE 2015

Geographic Breakdown

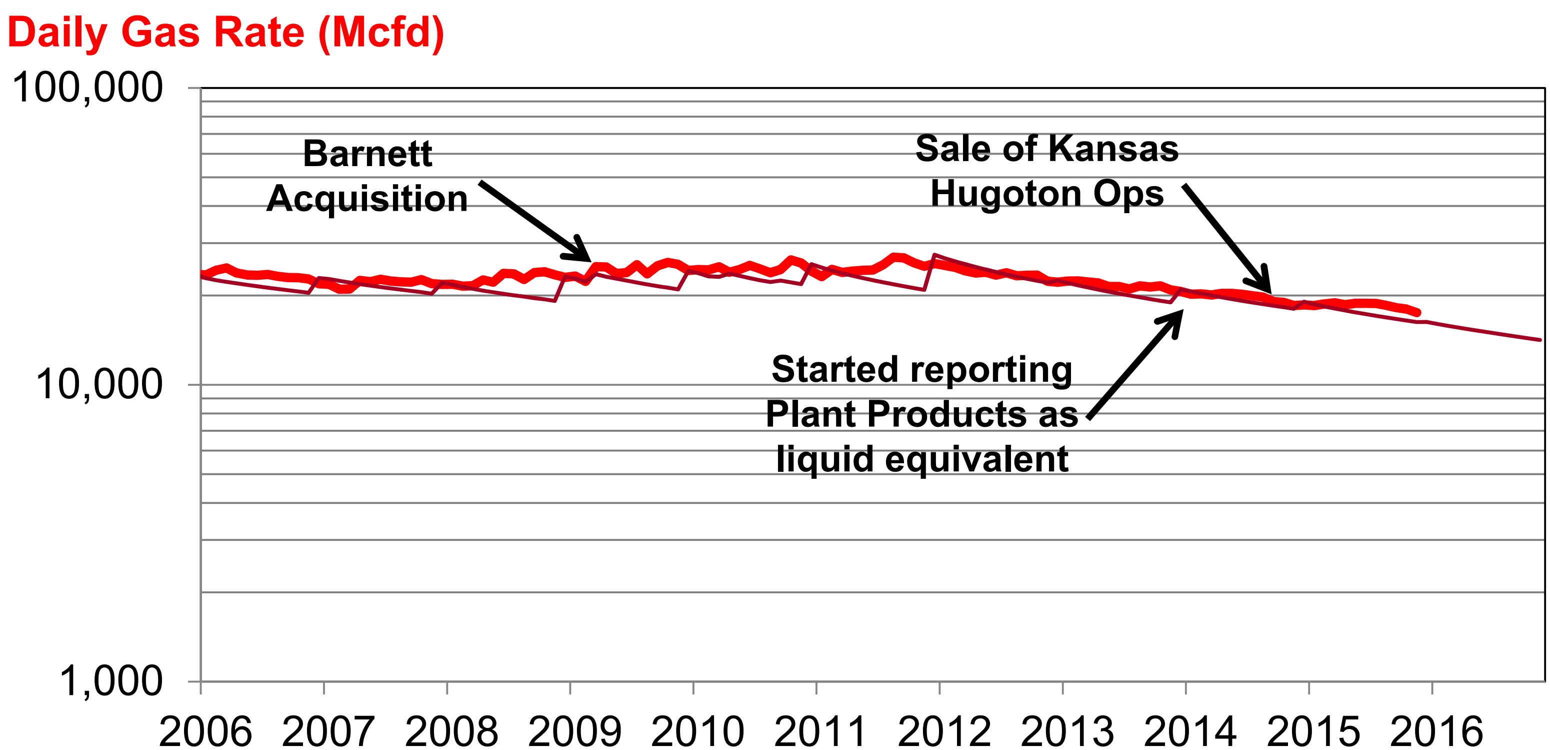


Royalty-NPI Split



2015 Production

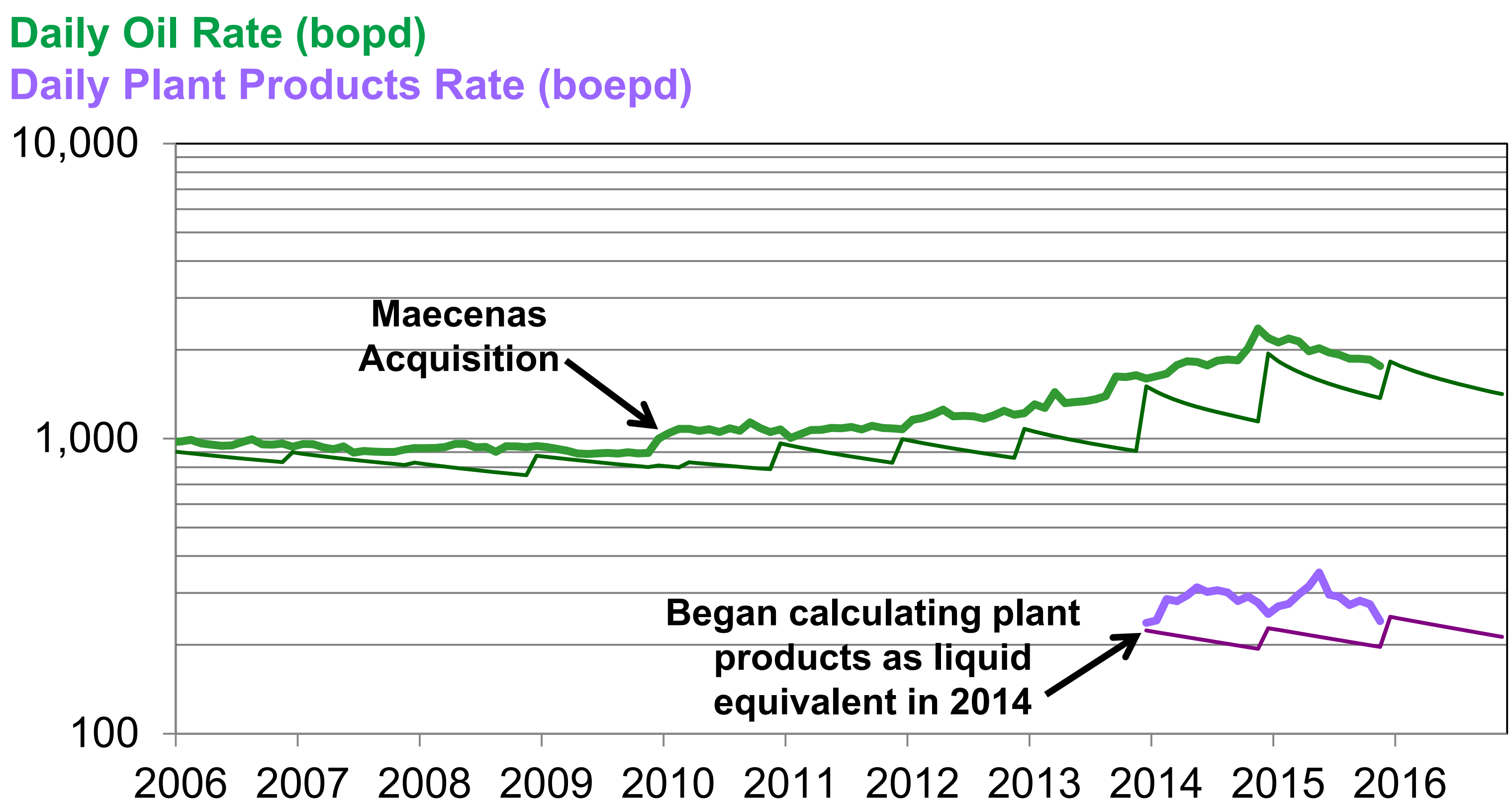
- Natural Gas Production
  - Production trend reflects reduced activity in dry gas plays and natural reservoir declines



Note: Plant Product volumes included as gas equivalent prior to 2014. Graphs include NPI volumes for all periods, regardless of surplus/deficit status.

2015 Production

- Oil and Plant Products Production
  - Stable base production from large, mature Permian oil fields
  - Recent Bakken declines have been partially offset by new development in Permian

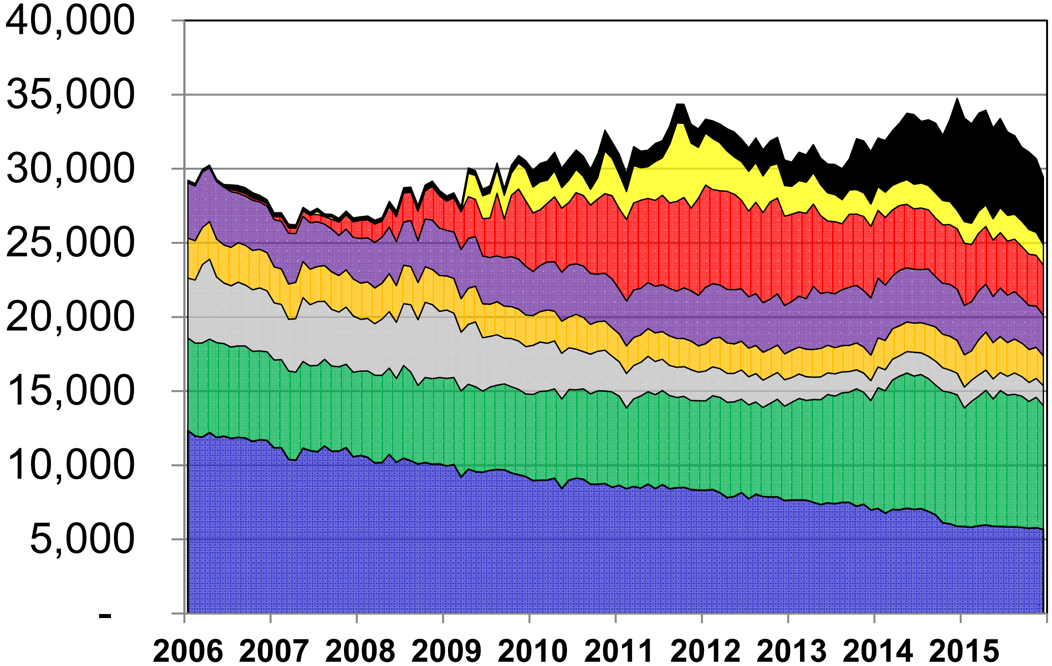


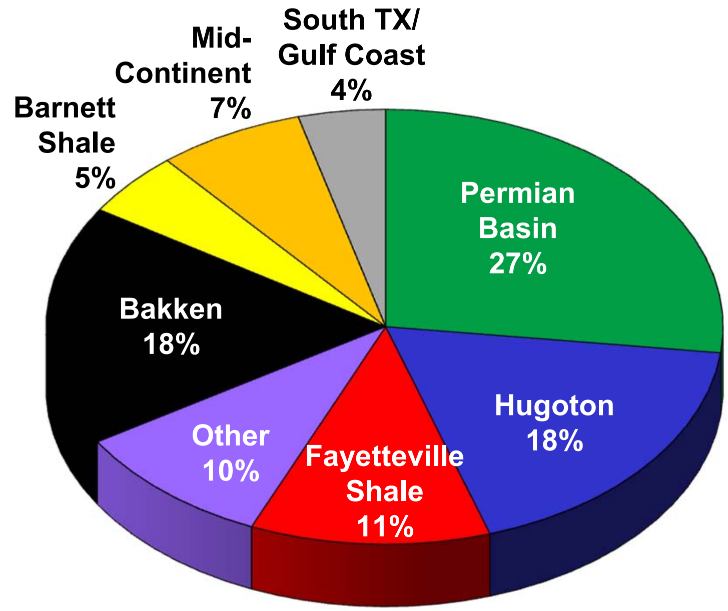
Note: Plant Product volumes calculated from Plant Products revenue based on Mt. Belvieu propane prices. Prior to 2014 Products included as gas equiv.

2015 Production

- Contribution from Diverse Sources
  - New plays have replaced declines in legacy assets
  - Opportunities for production growth in mature basins

Daily Equivalent Rate (Mcfed)



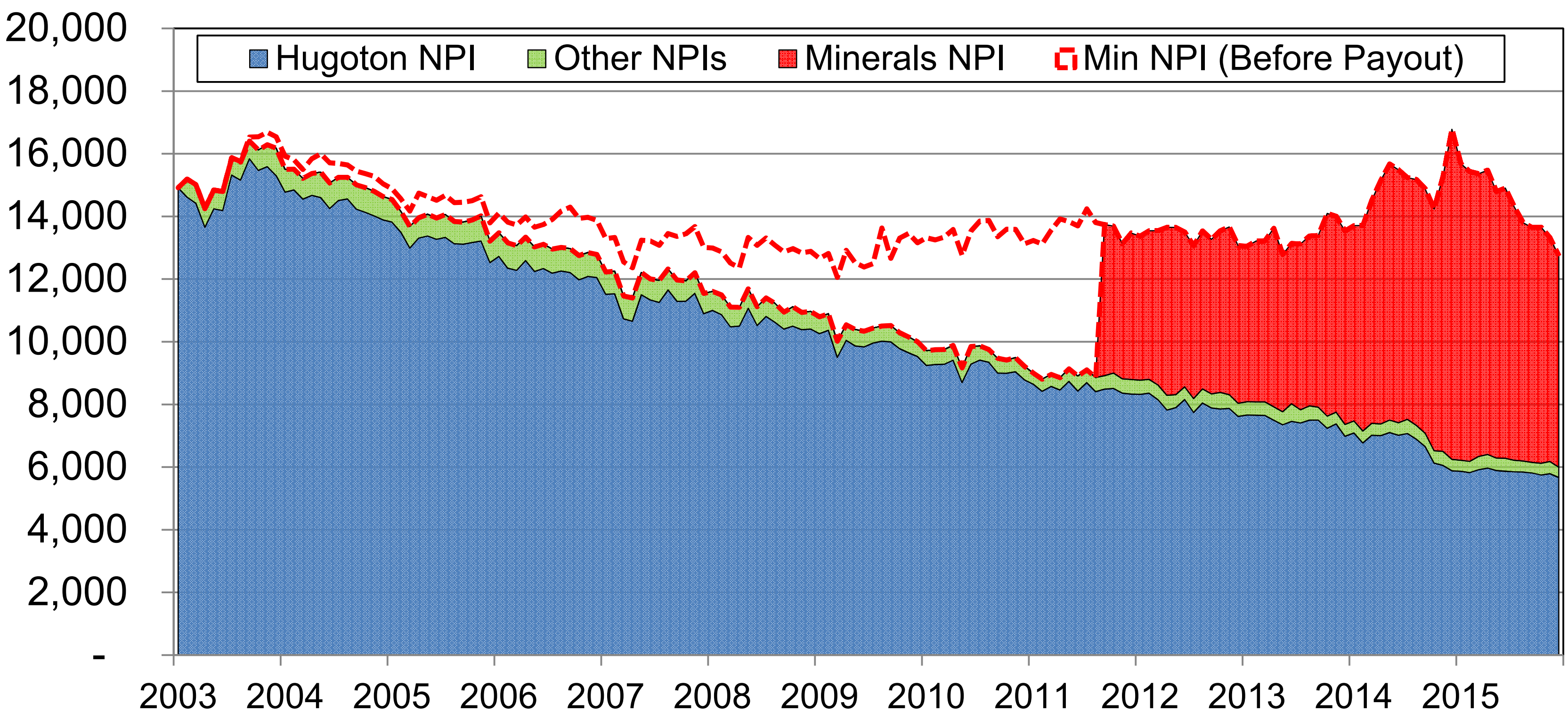


Note: Volumes attributable to NPI's are included regardless of surplus/deficit status and are burdened by lease operating costs and capital expenses

Net Profits Interests Production

- Relative contribution of NPIs has shifted over time
  - Hugoton accounted for 96% of NPI production at inception → 43% in Q4 2015
  - Minerals NPI volumes prior to Q3 2011 were not included in DMLP results

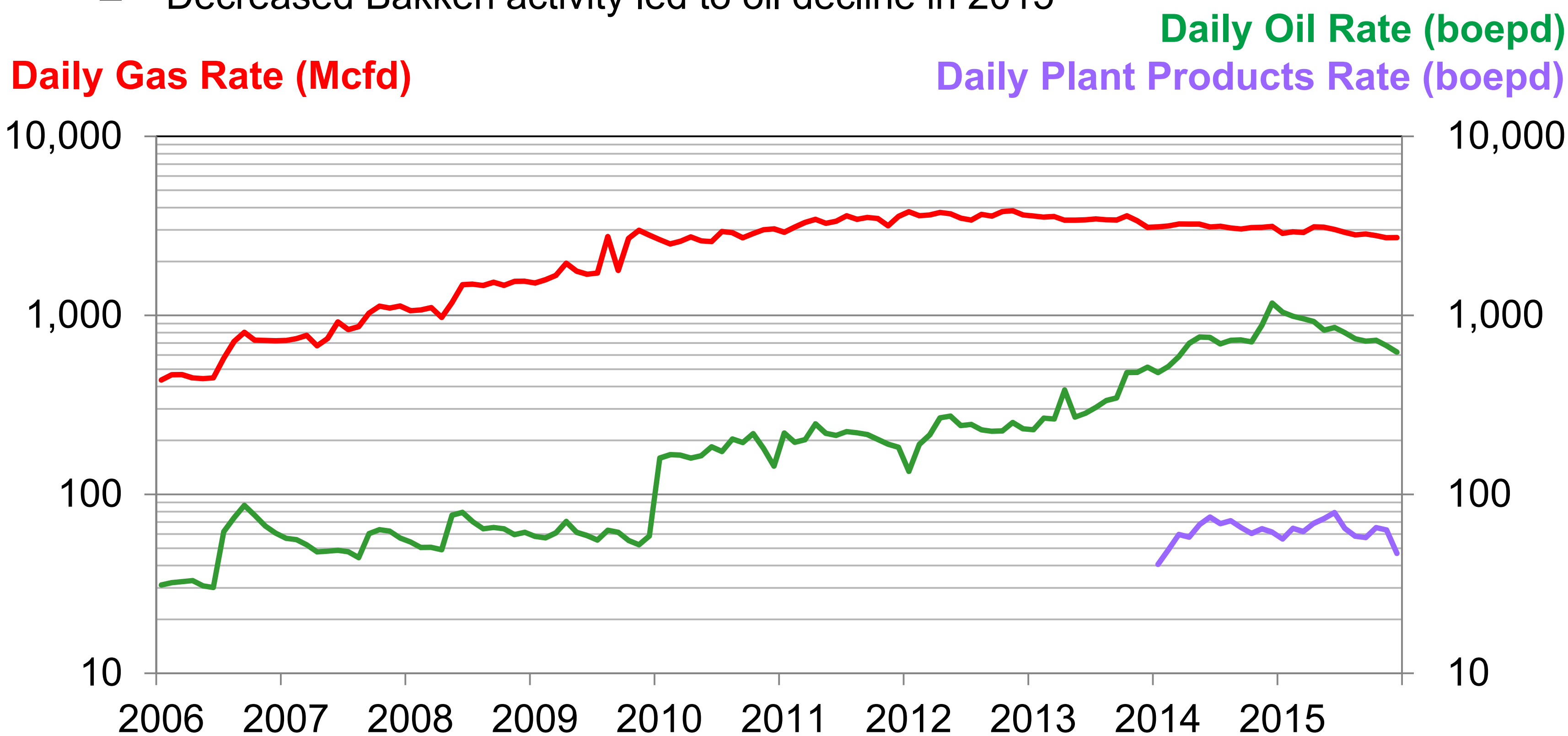
Daily Equivalent Rate (Mcfed)



Note: Production graph limited to “in pay” volumes.

Minerals NPI

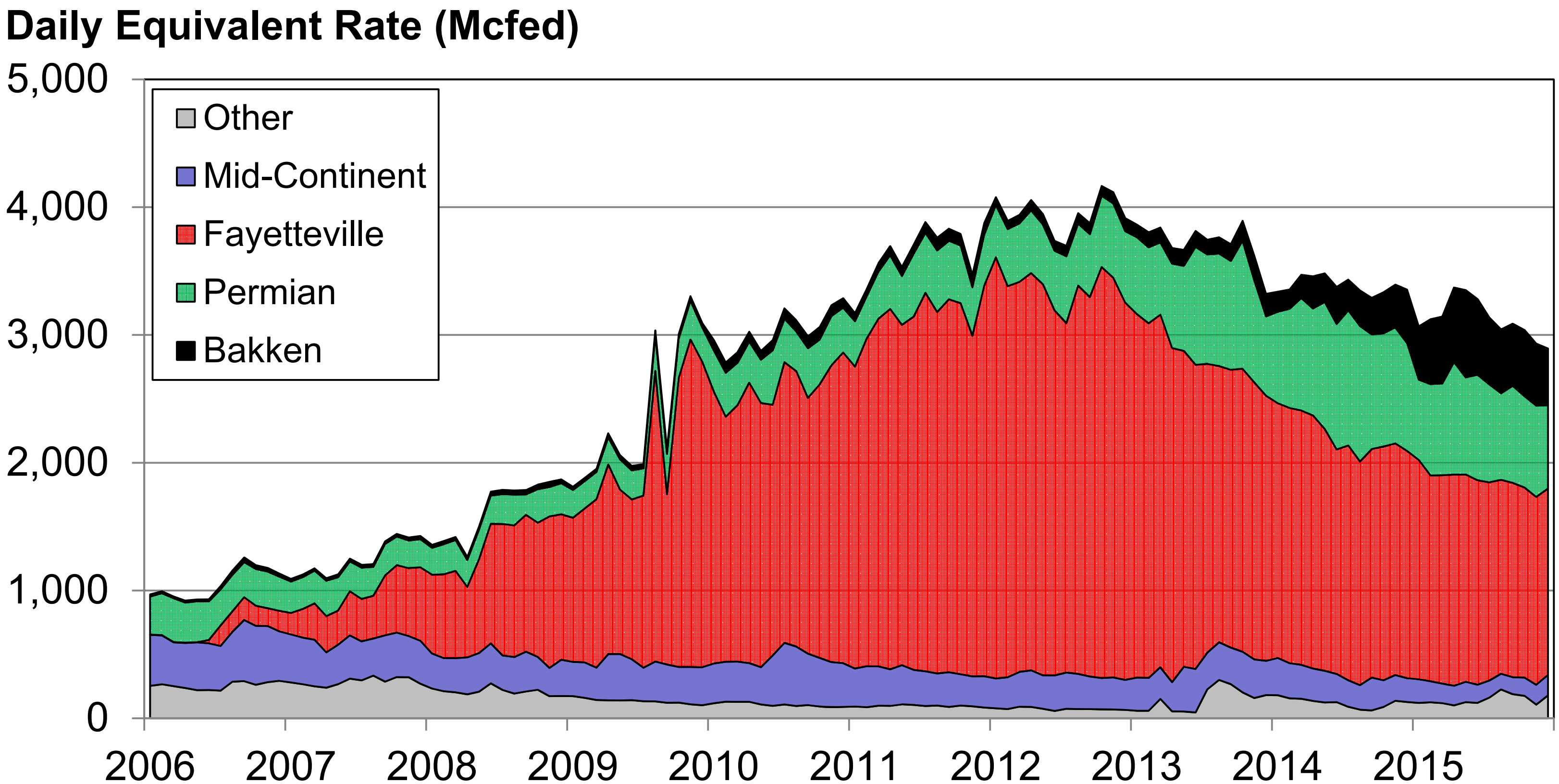
- Production by Product
  - Gas production has declined since 2012, but oil production has increased by over 250% during the same period
  - Decreased Bakken activity led to oil decline in 2015



Note: Production graph limited to “in pay” volumes. Prior to 2014 Plant Products included as gas equivalent.

Minerals NPI

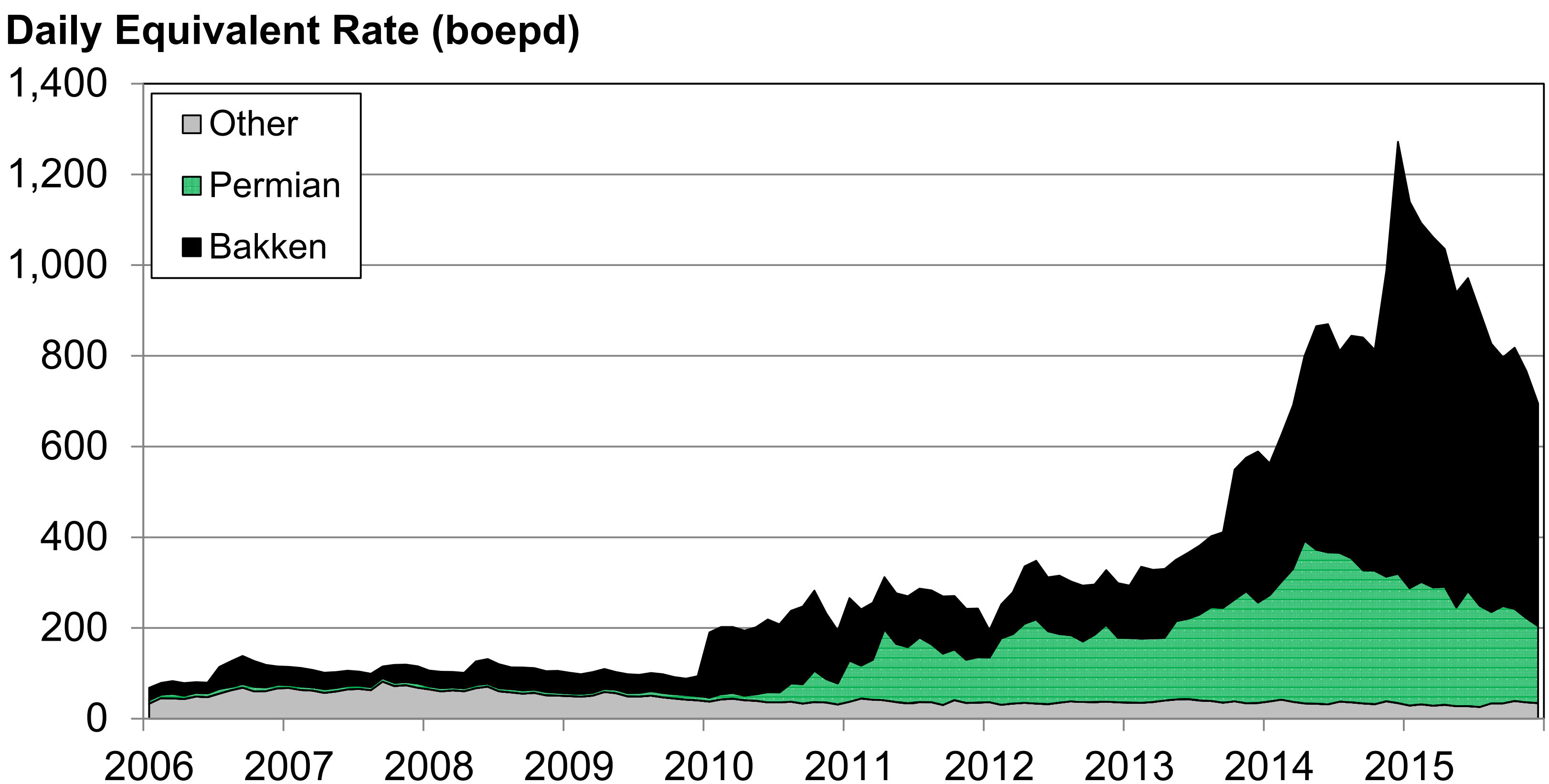
- Natural Gas Production by Area
  - Dry gas from Fayetteville has dominated historical production
  - High-BTU associated gas from the Bakken/Permian has increased in recent years



Note: Production graph limited to “in pay” volumes.

Minerals NPI

- Oil and Plant Products Production by Area
  - Production spike in late 2014 was a result of multi-well pads in Bakken
  - Reduction of working interest participation in Permian (2014) and Bakken (2015)

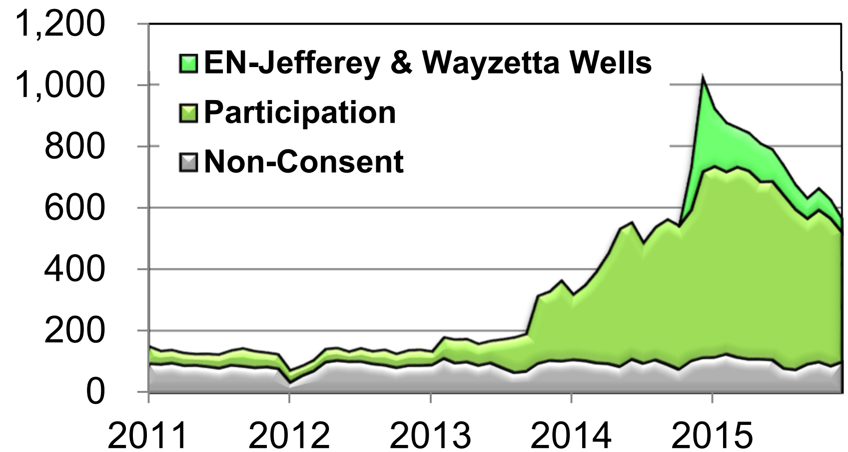


Note: Production graph limited to "in pay" volumes.

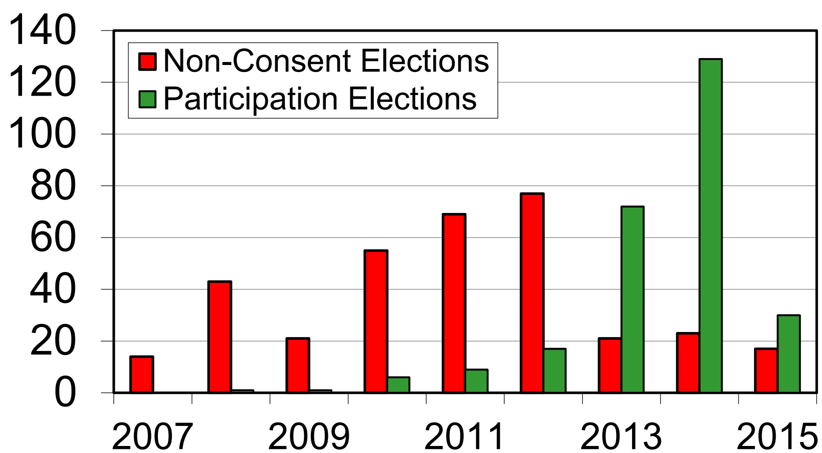
Bakken/Three Forks

- Williston Basin
  - 70,390 gross ac (8,905 net ac)
  - 2015 exit rate → 770 boepd (73% NPI) from 565 wells
  - 32 wells producing but not in pay
  - 38 wells drilling/WOC/confidential
  - Bakken rig count dropped from 181 at YE 2014 to 27 in May 2016
  - Zero participation elections YTD 2016

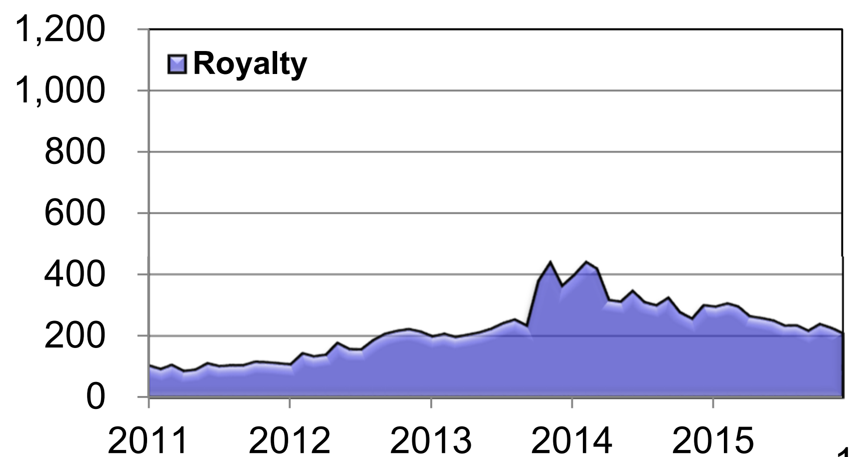
NPI Production (boepd)



Well Count



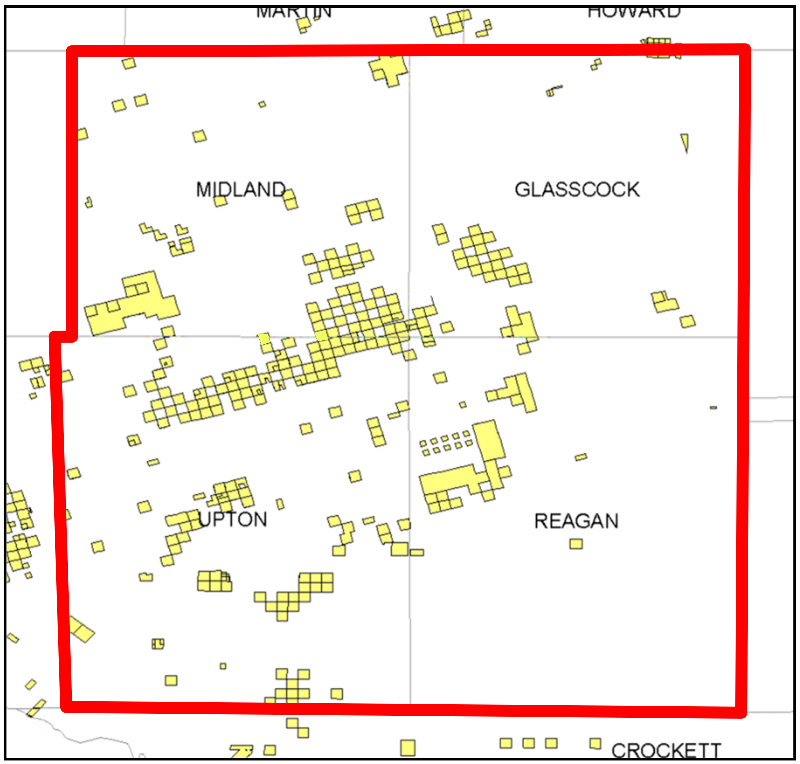
Royalty Production (boepd)



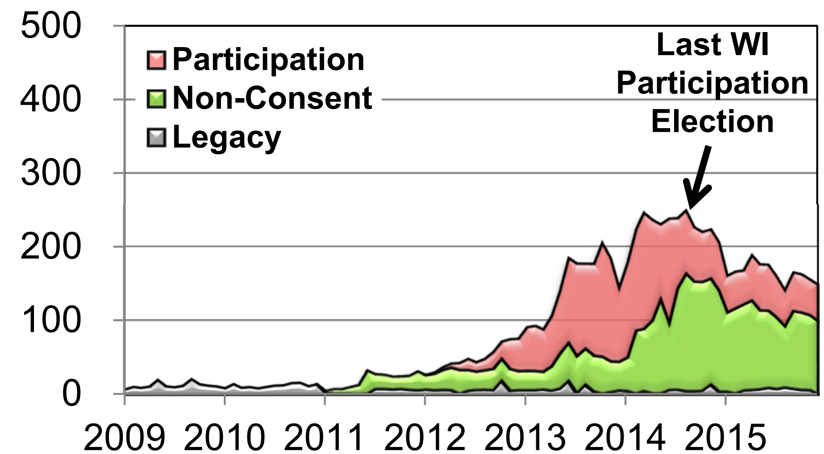
Note: Production graphs limited to "in pay" volumes from six county core area.

Core Midland Basin

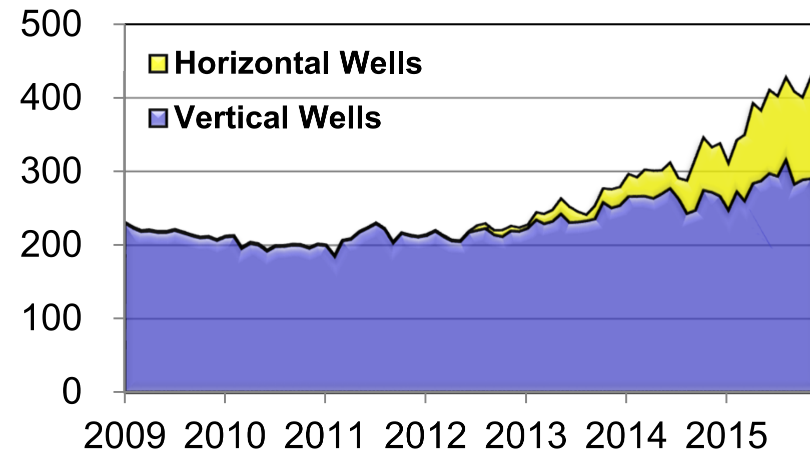
- Wolfcamp/Spraberry
  - 229,000 gross ac (11,500 net ac)
  - Unleased at some depth in numerous tracts



NPI Production (boepd)



Royalty Production (boepd)



Note: Production graph limited to "in pay" volumes from Glasscock, Midland, Reagan, and Upton Counties. Acreage total limited to the same counties.

Core Midland Basin

- Glasscock County Example
  - 10,240 gross ac (1,120 net ac) with average NRI of 1.688%
  - Horizontal activity on 4 of 16 sections

RSP Permian

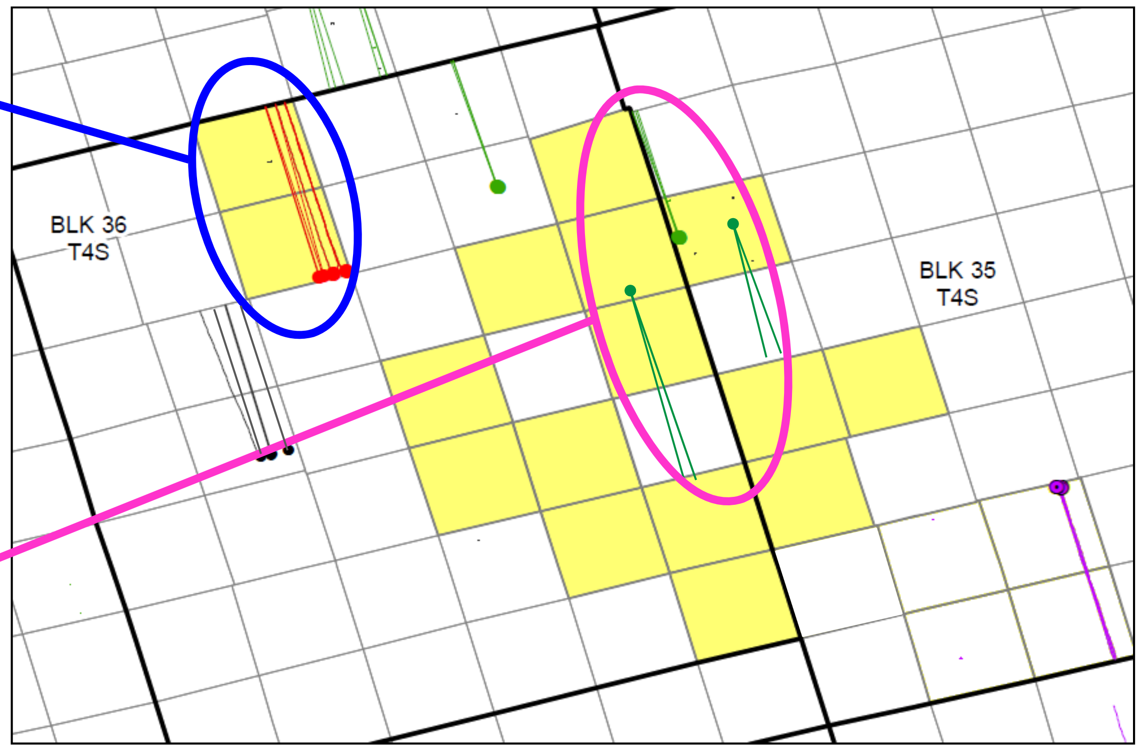
Calverley 9-4 (8 wells)

- 4 wells producing - in pay
- 2 wells drilling/WOC
- 2 wells permitted not spud
- IP30 range: 587–1,877 boepd

Diamondback

Riley & Tomahawk (7 wells)

- 2 wells producing - not in pay
- 1 well drilling/WOC
- 4 wells permitted not spud
- IP30 range: 1,025–1,309 boepd



Note: IP30 data from public company investor presentations.

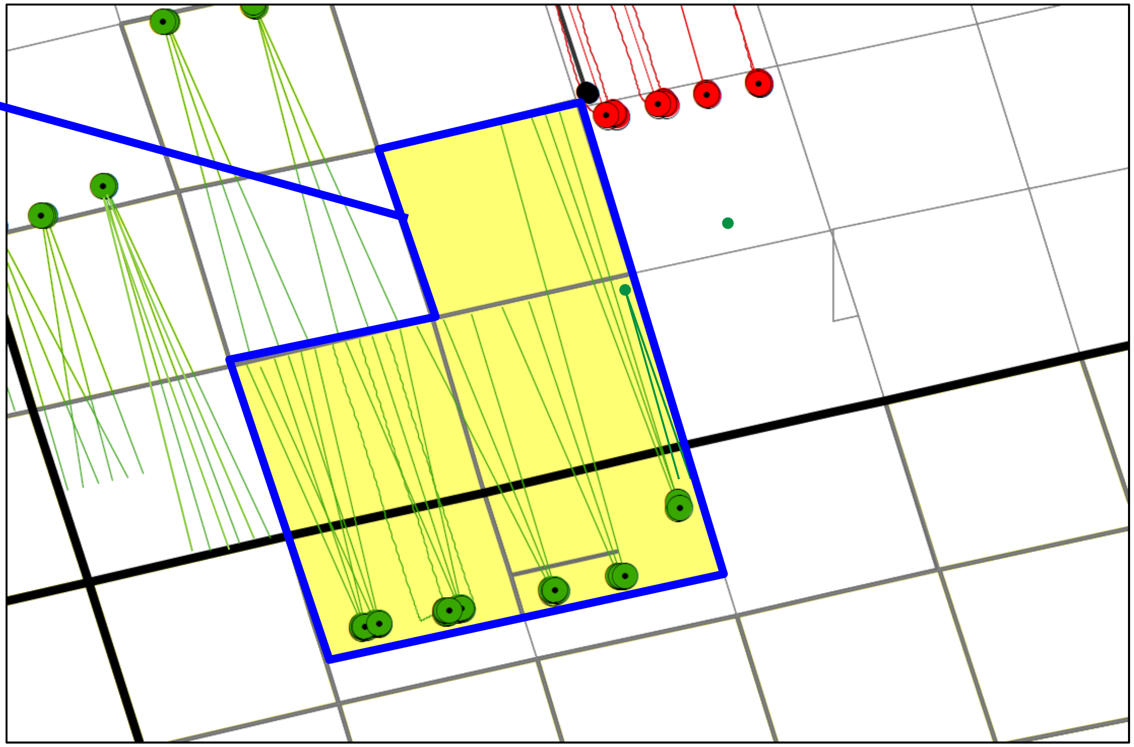
Core Midland Basin

- Midland County Example
  - 2,749 gross ac (412 net ac) with average NRI of 1.875%
  - Produced 518,000 boe from six wells in first four months

Pioneer Natural Res.

Preston 5 (24 wells)

- 6 wells producing NOT in pay
- 10 wells drilling/WOC
- 8 wells permitted not spud
- IP range: 1,551–2,319 boepd



Note: IP's as reported on RRC W-2

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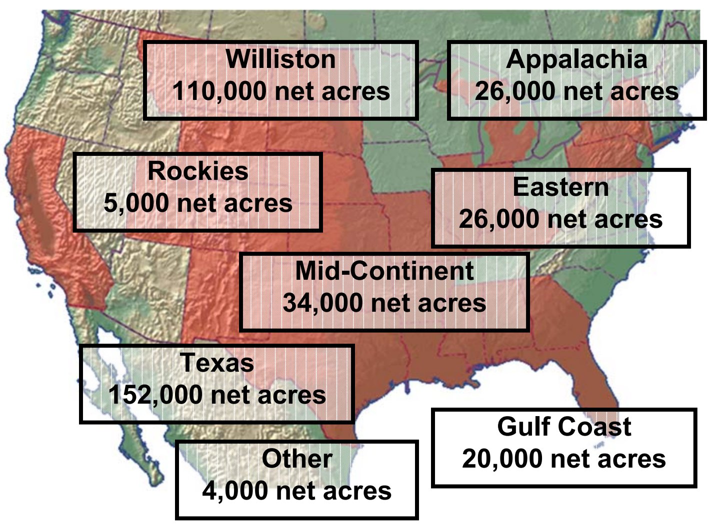
Appendix

Portfolio Overview

- Geographically Diverse – 574 counties in 25 states
  - 377,000 net mineral acres (2,307,000 gross acres)
  - Varying NPRI's, ORRI's and leasehold interests in an additional 859,000 gross acres
  - Majority of acreage is undeveloped – deep rights unleased in multiple tracts
  - Wide geographic spread including most major producing basins
  - Assets range from mature legacy production to areas with exploratory potential

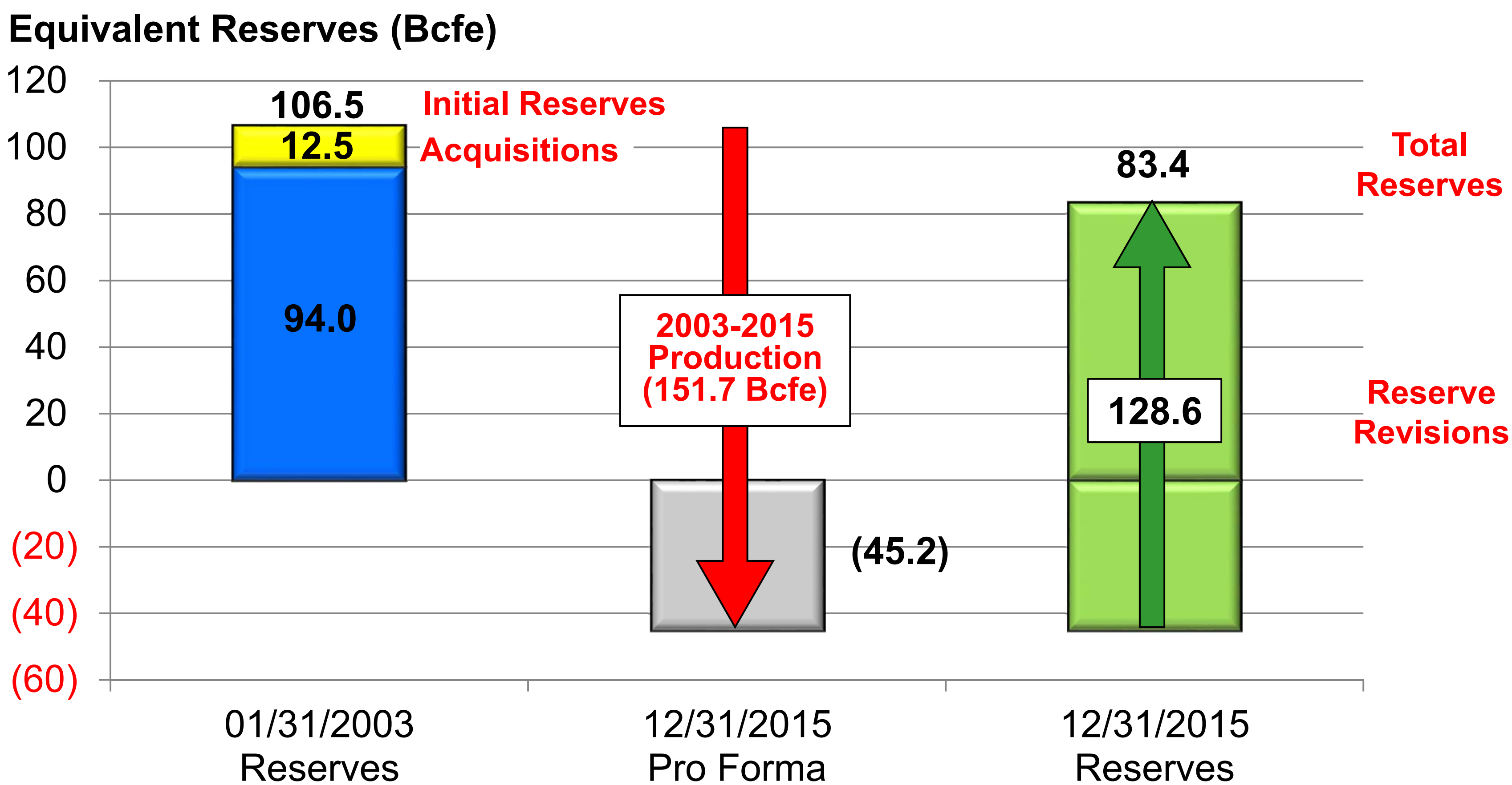


Basin/Area	Legacy Production	Ongoing Development	Expansion Potential
West Texas Southeast NM	Denver Unit Wasson	Wolfberry Bone Springs	Delaware Basin West TX Overthrust
Gulf Coast South Texas	Jeffress McAllen Ranch		Horizontal Wilcox
Mid-Continent	Hugoton	SCOOP Granite Wash	Springer
Williston Basin	Nesson Anticline	Bakken /TF Red River	Three Forks (lower benches)
Appalachia		Marcellus	Utica Upper Devonian

Note: Acreage count as of 12/31/2015. Gross acres are not additive due to overlapping ownership among categories

2015 Reserves

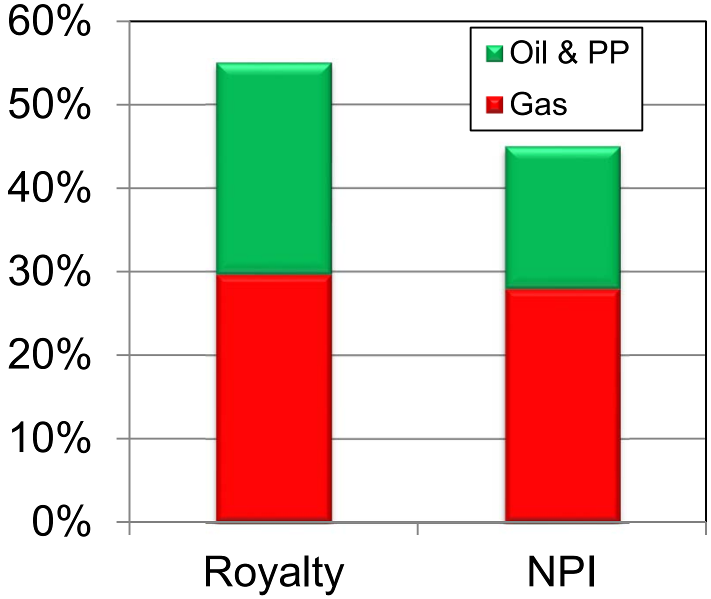
- History of Positive Reserve Revisions
  - Cumulative Reserve Revisions have exceeded 100% of Current Reserves



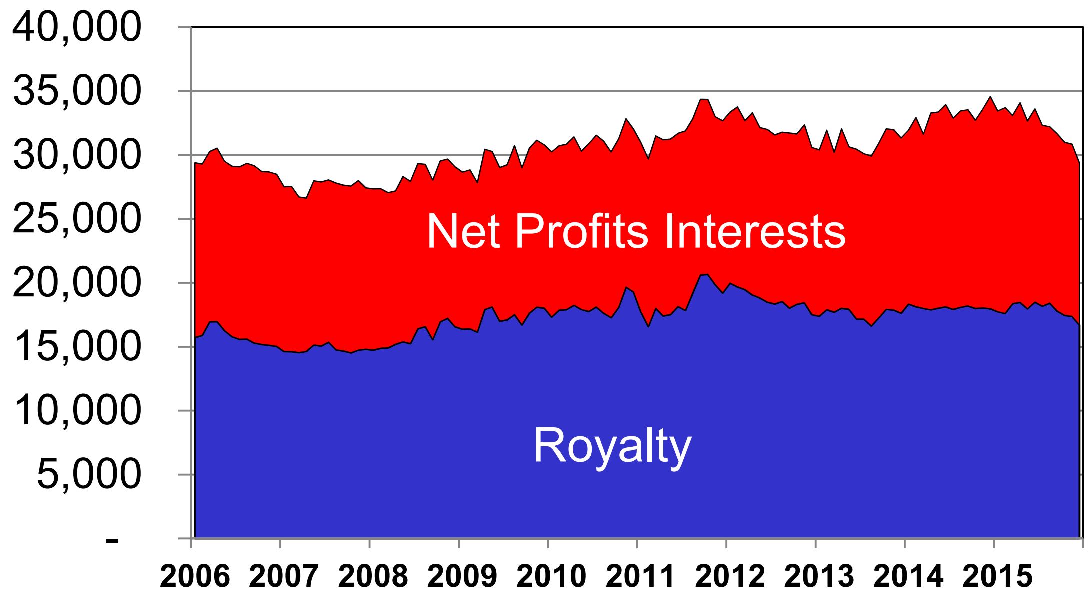
2015 Production

- Portfolio Has Shifted Over Time
  - 2003-2012 → Royalties increased from 48% to 60% due to mineral acquisitions, new drilling on legacy properties, and natural declines in Hugoton field
  - 2013-2014 → Royalties decreased to 52% due to large WI in Bakken/Fayetteville
  - 2015 → Royalties increased to 57% due reduced participation/development in Bakken/Fayetteville

2015 Royalty-NPI Production Split



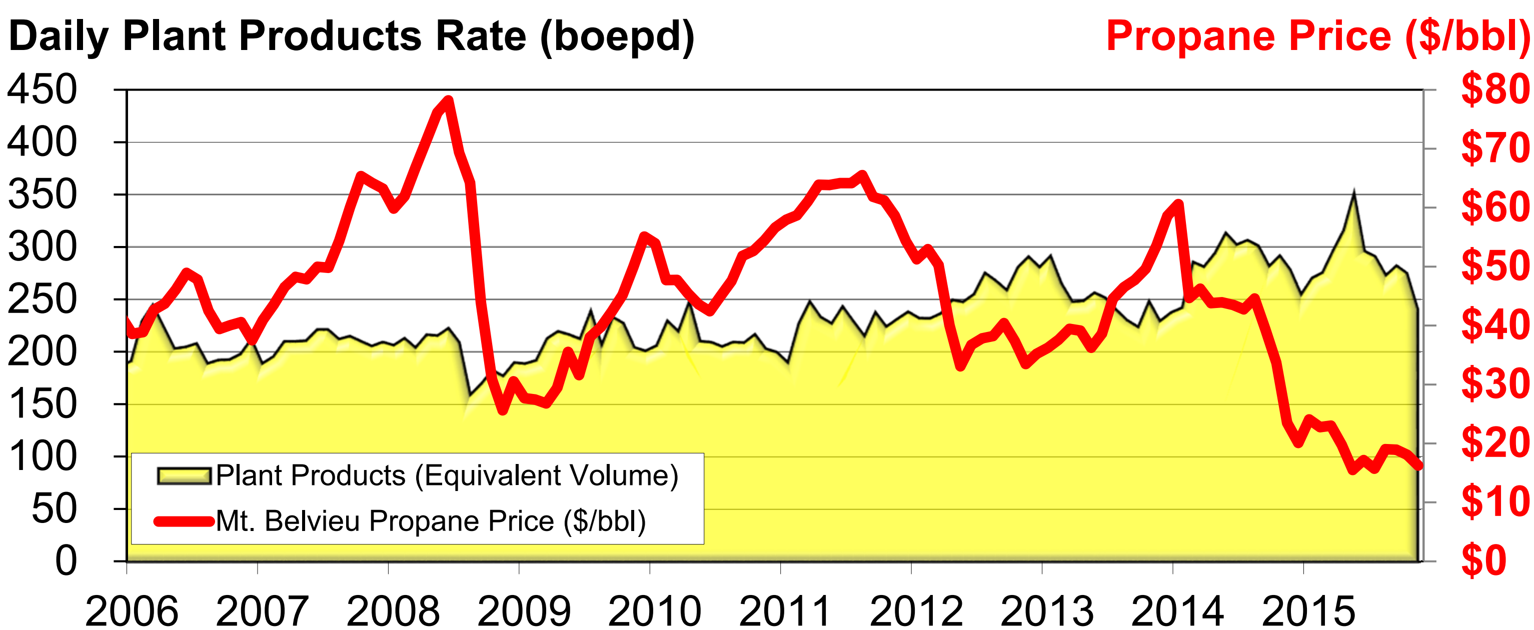
Daily Equivalent Rate (Mcfed)



Note: Volumes attributable to NPI's are included regardless of surplus/deficit status and are burdened by lease operating costs and capital expenses

2015 Production

- Plant Products Contribution
  - Plant Products (PP) includes all production revenue other than that from oil and gas
  - Volumes may be reported in barrels, cubic feet, gallons, bushels, etc. (or none)
  - Equivalent PP volumes are calculated from total PP revenue based on propane price
  - Equivalent PP volumes are sensitive to numerous factors including: gas prices, NGL prices, gas-oil price ratio, gas composition, and operator payment practices



Net Profits Interests Overview

- NPI Provides Exposure to Working Interest Potential Without Generating UBTI
  - Currently five NPI groups
  - Capitalize on strong negotiating position to capture additional value
  - Leverage information franchise
  - Working Interests derived from multiple sources
    - "Heads up" participation (North Dakota & Texas)
    - Leases with contractual participation option (Fayetteville)
    - Non-consent back-in after payout (North Dakota)
    - Unleased cotenancy (Texas)
  - Minerals NPI represents the majority of new development activity
  - Added 118 new wells located in Arkansas, Montana, North Dakota, Oklahoma and Texas

Note: New well count based on division orders and initial revenue payments received in 2015

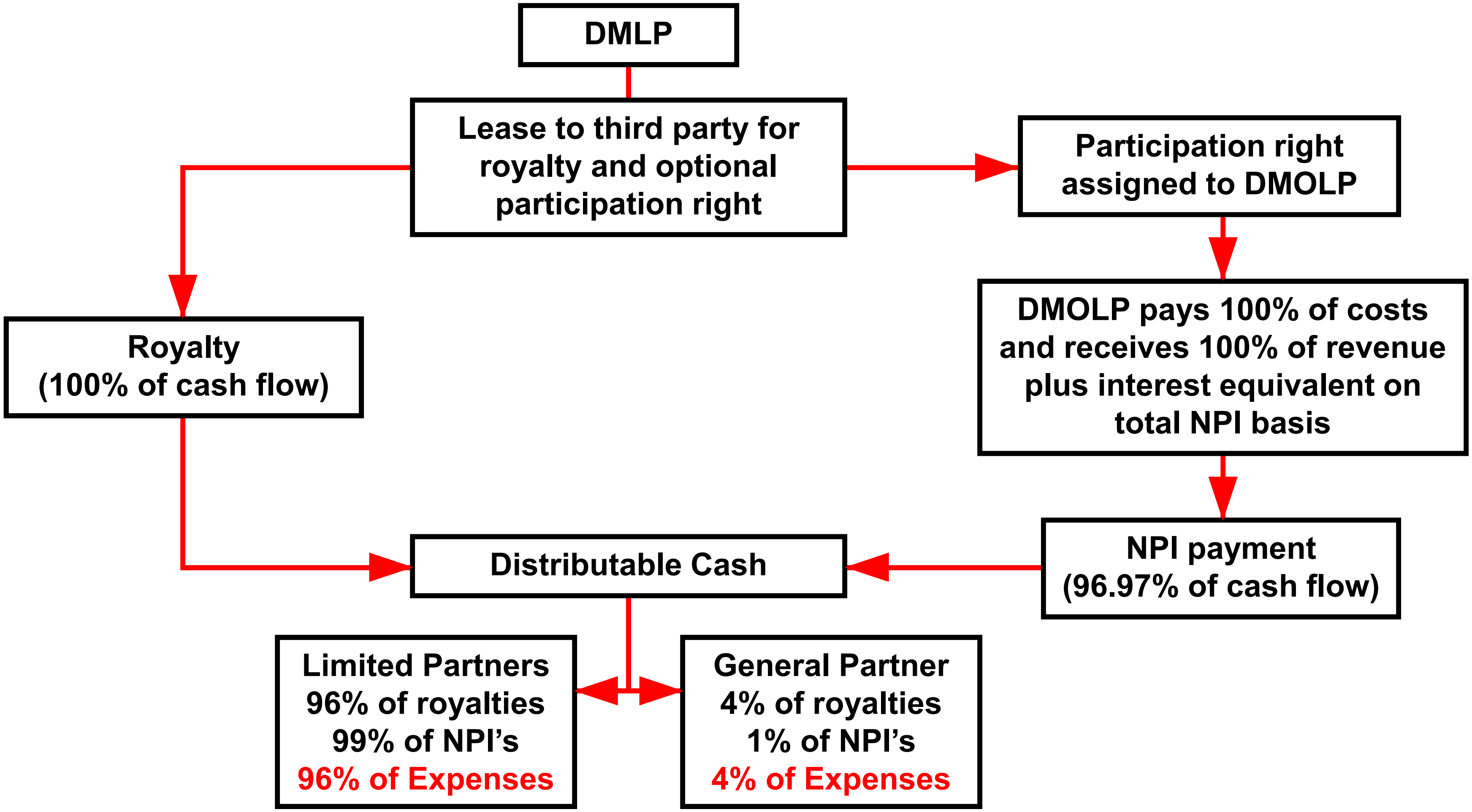
Minerals NPI

- What is the Minerals NPI and How Does it Work?

  - **Upon its formation, Dorchester Minerals, LP (DMLP, the public partnership and owner of the mineral interests) provided for future development opportunities on its undeveloped mineral interests by the creation of the Minerals Net Profits Interest (Minerals NPI).**
  - **DMLP has negotiated and may continue to negotiate the right but not the obligation to participate in development activity in addition to retaining a royalty interest.**
  - **This right may take the form of an optional heads-up (unpromoted) working interest, carried working interest or reversionary (back-in) working interest. In some instances, an unleased mineral interest may be treated as a working interest subject to statutory non-consent provisions.**
  - **DMLP assigns this right to Dorchester Minerals Operating LP (the operating partnership or DMOLP) subject to the terms of the Minerals NPI.**
  - **DMOLP is an indirect wholly owned affiliate of DMLP's General Partner.**
  - **DMOLP funds all costs associated with this right, including drilling and completion costs.**
  - **DMLP and its partners are not liable for any costs or expenses.**
  - **DMOLP pays to DMLP 96.97% of the monthly "Net Proceeds" attributable to the properties subject to the Minerals NPI.**
  - **Net Proceeds is defined as total revenues less total expenses plus an amount equivalent to interest at a prevailing rate on any prior period deficit balance. In other words, DMOLP pays 100% of all costs, receives 100% of all revenues plus interest, and thereafter (sometimes called "Payout") pays 96.97% of net cashflow to DMLP.**
  - **LP distributions reflect 96% of royalty net cashflow and 99% of NPI net cashflow → 99% x 96.97% = 96%.**

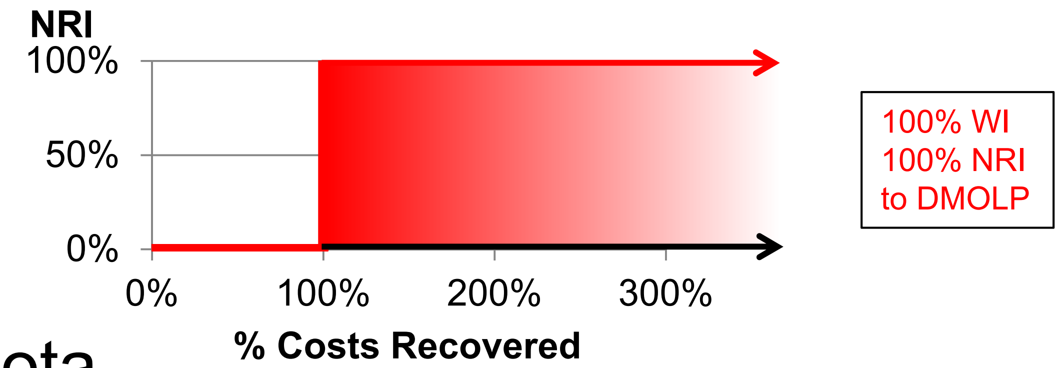
Minerals NPI

- What is the Minerals NPI and How Does it Work?

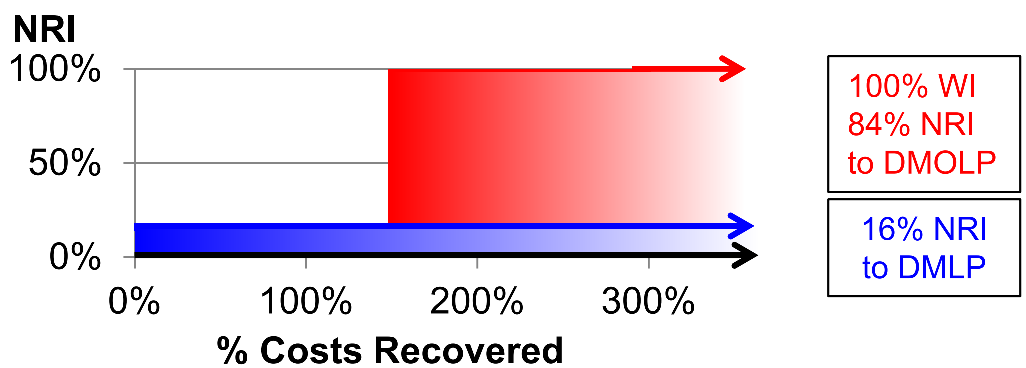


Non-Consent/Non-Participation

- Texas
  - Unleased mineral owner backs in for full working interest after operator recovers 100% of costs



- North Dakota
  - Unleased mineral owner receives 16% royalty and backs in for full working interest after operator recovers 150% of costs



Non-Consent/Non-Participation

- Texas
  - Unleased mineral owner backs in for full working interest after operator recovers 100% of costs

Selected Texas Counties	N/C Well Count	Paid Out Well Count	Average BPO NRI	Average APO NRI
Ector	63	28	0.000%	13.065%
Gaines	16	6	0.000%	3.331%
Midland	72	18	0.000%	3.658%
Upton	219	81	0.000%	2.742%
Total	**370**	**133**	**0.000%**	**4.725%**

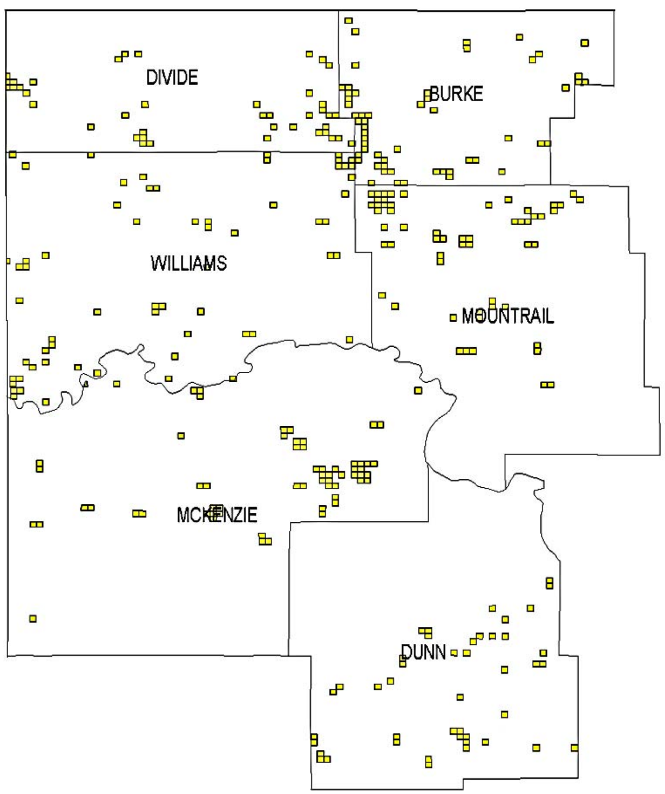
- North Dakota
  - Unleased mineral owner receives 16% royalty and backs in for full working interest after operator recovers 150% of costs

Selected North Dakota Counties	N/C Well Count	Paid Out Well Count	Average BPO NRI	Average APO NRI
Burke	25	0	0.098%	0.275%
Divide	38	3	0.257%	1.546%
Dunn	30	3	0.728%	4.464%
McKenzie	80	16	0.293%	1.835%
Mountrail	79	15	0.775%	3.654%
Williams	89	9	0.548%	3.057%
Total	**341**	**46**	**0.491%**	**2.660%**

Note: Only 45 of 46 ND paid out wells are “in pay” status

Bakken/Three Forks

- Williston Basin
  - 70,390 gross ac (8,905 net ac) in six core North Dakota counties

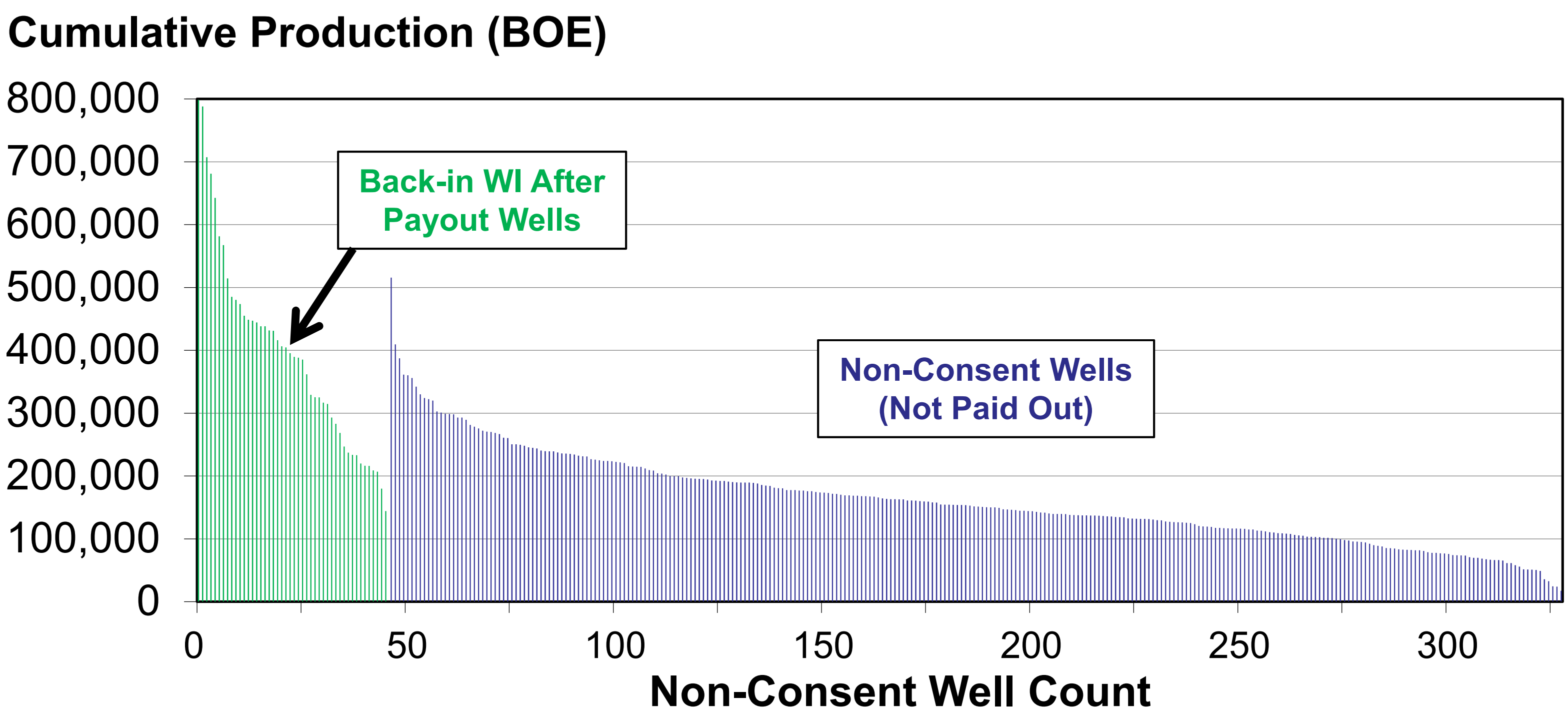


	Well Count	Average BPO NRI	Average APO NRI
Completed as Producers	597	0.874%	2.096%
Drilling/Completion (or confidential)	38	1.3947%	1.711%
Permitted AND Proposed	0	-	-
Permitted NOT Proposed	76	TBD	TBD
Total	**711**	**0.905%**	**2.073%**

Note: NRI values are the sum of DMLP and DMOLP NRIs. Well counts excludes undrilled wells permitted before 01/01/2015.

Bakken/Three Forks

- Non-Consent Elections – A Look Back
  - Payout depends on actual CAPEX spent, production, oil prices, etc.
  - Numerous wells likely to payout in the future → cannot predict how many or when

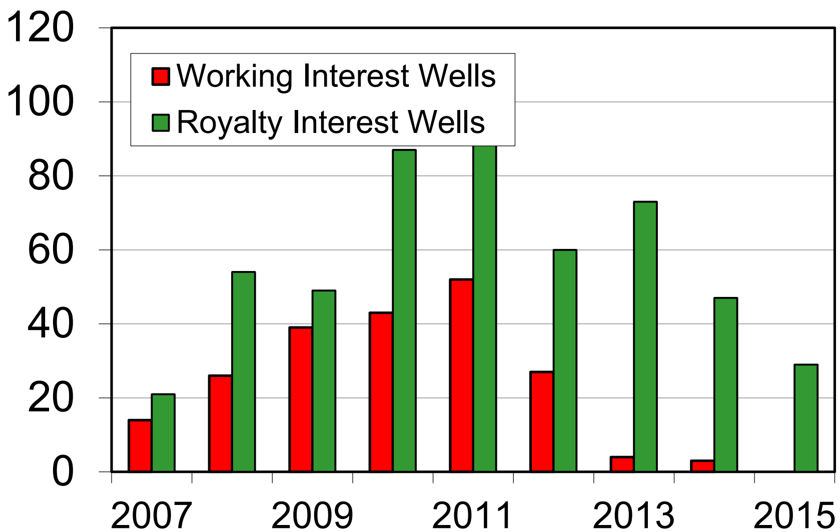


Note: Cumulative production volumes through February 2016 for all non-consent wells, regardless of pay status.

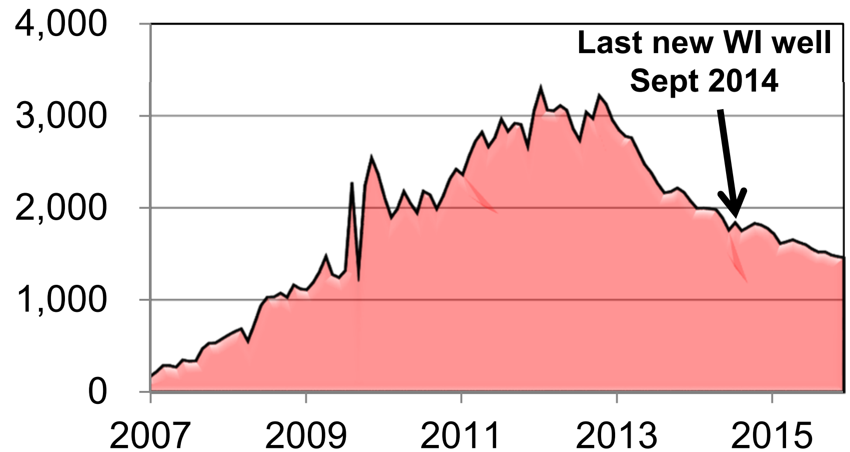
Fayetteville Shale

- Eastern Arkoma Basin
  - 23,336 gross ac (11,464 net ac) in 196 sections
  - 487 wells producing at year-end
  - 2015 exit rate → 3.4 MMcfd (43% WI)
  - Rig Count dropped to zero in 2016

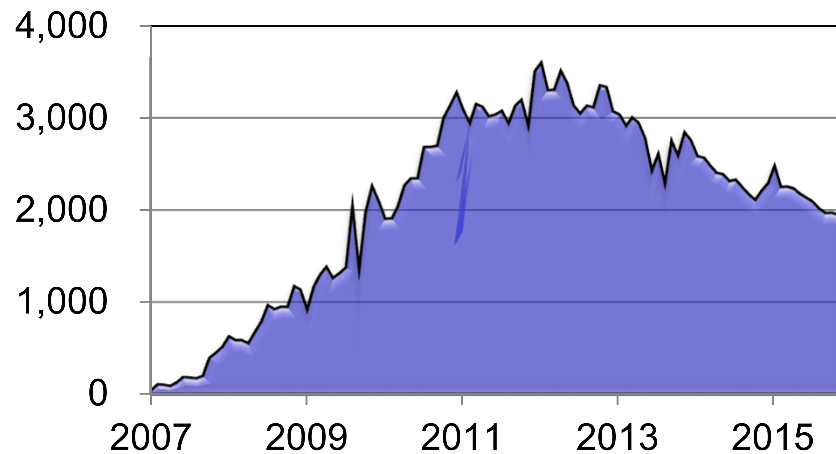
New Wells on Production



NPI Production (Mcfd)



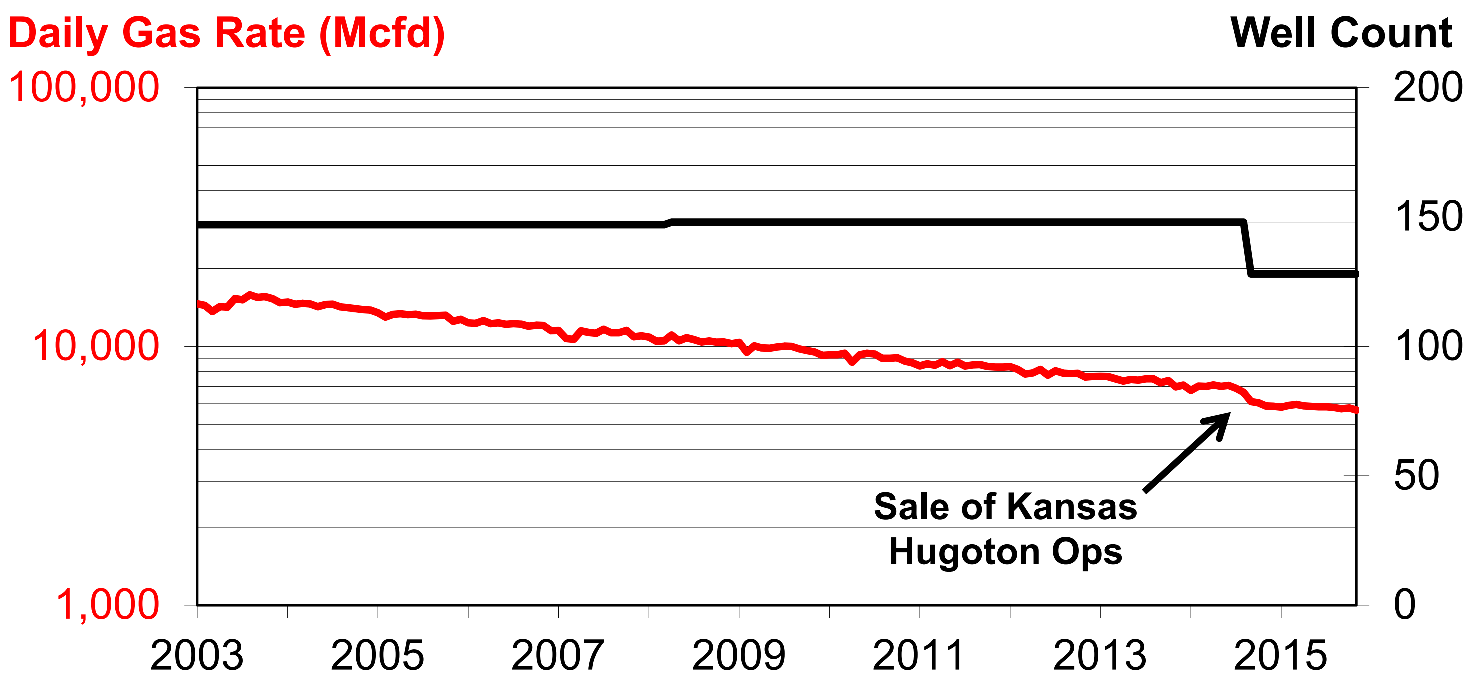
Royalty Production (Mcfd)



Note: Production graphs limited to "in pay" volumes.

Hugoton Operated Properties

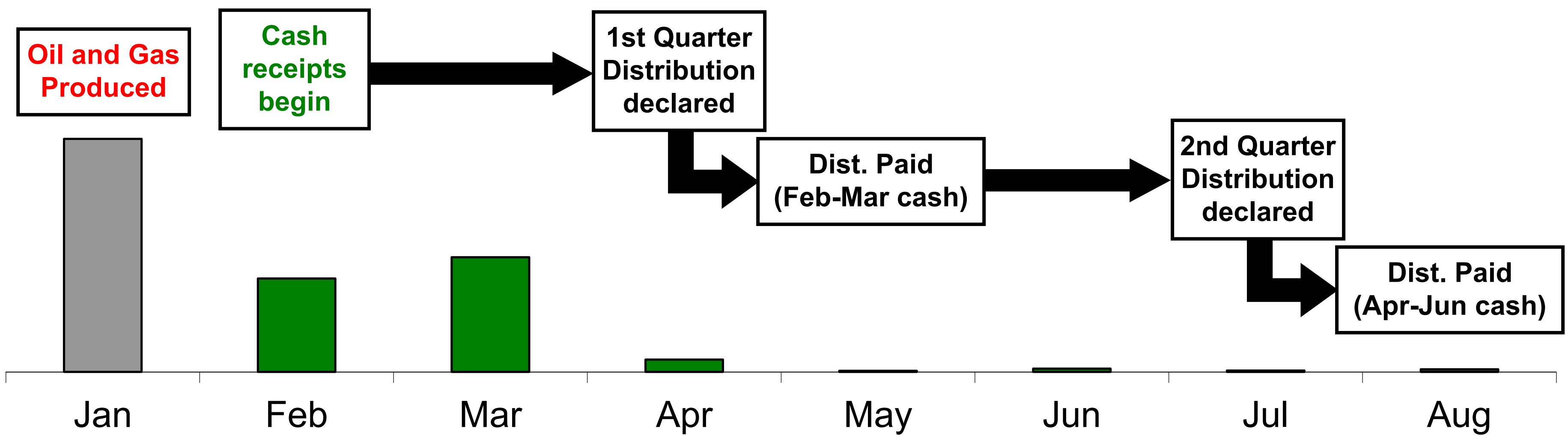
- Hugoton Field – Oklahoma Panhandle
  - Divested Kansas operations in Sept 2014 – average net sales of 2.8 MMcfd
  - 2015 production 1% above YE 2014 projection
  - Year-over-year production decline of 5% with a 3% decrease in net reserves
  - Ongoing well optimization and cost-saving initiatives, but limited upside potential



Note: Gas rate based on sales volumes. Year-over-year decline excludes Kansas assets divested in 2014.

Royalty Cash Receipts

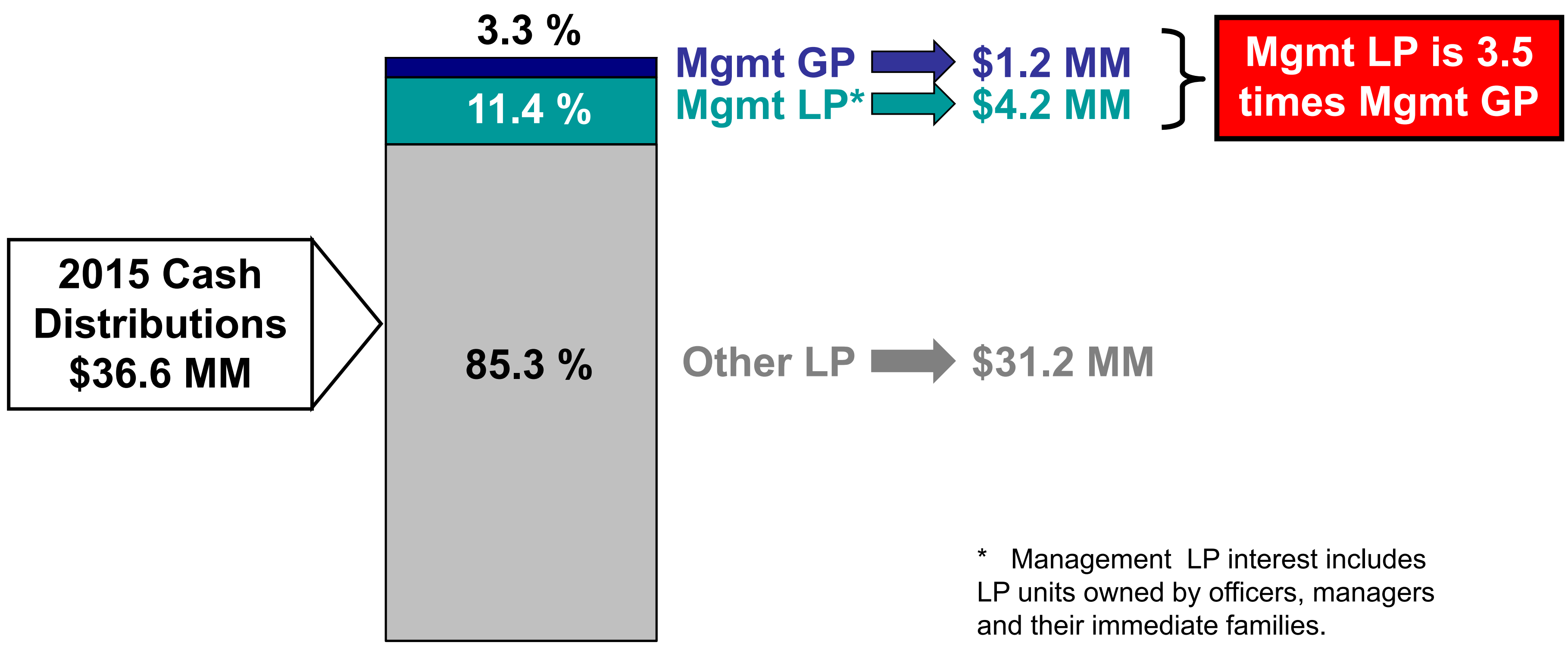
- Long delay between production and cash distribution
  - Cash receipts extend over multiple months due to adjustments, releases, etc.
  - Prices can change dramatically between production and payment of distribution
  - Example of a typical cash receipt cycle :



LP distribution of all cash attributable to January production may occur as late as August, a 7-month time lag

Management Ownership

- Alignment of GP and LP interests
  - GP has no incentive distribution rights – fixed sharing ratio
  - Management's LP interest exceeds its GP interest
  - Not incentivized to make dilutive transactions



* Management LP interest includes LP units owned by officers, managers and their immediate families.

Distributions

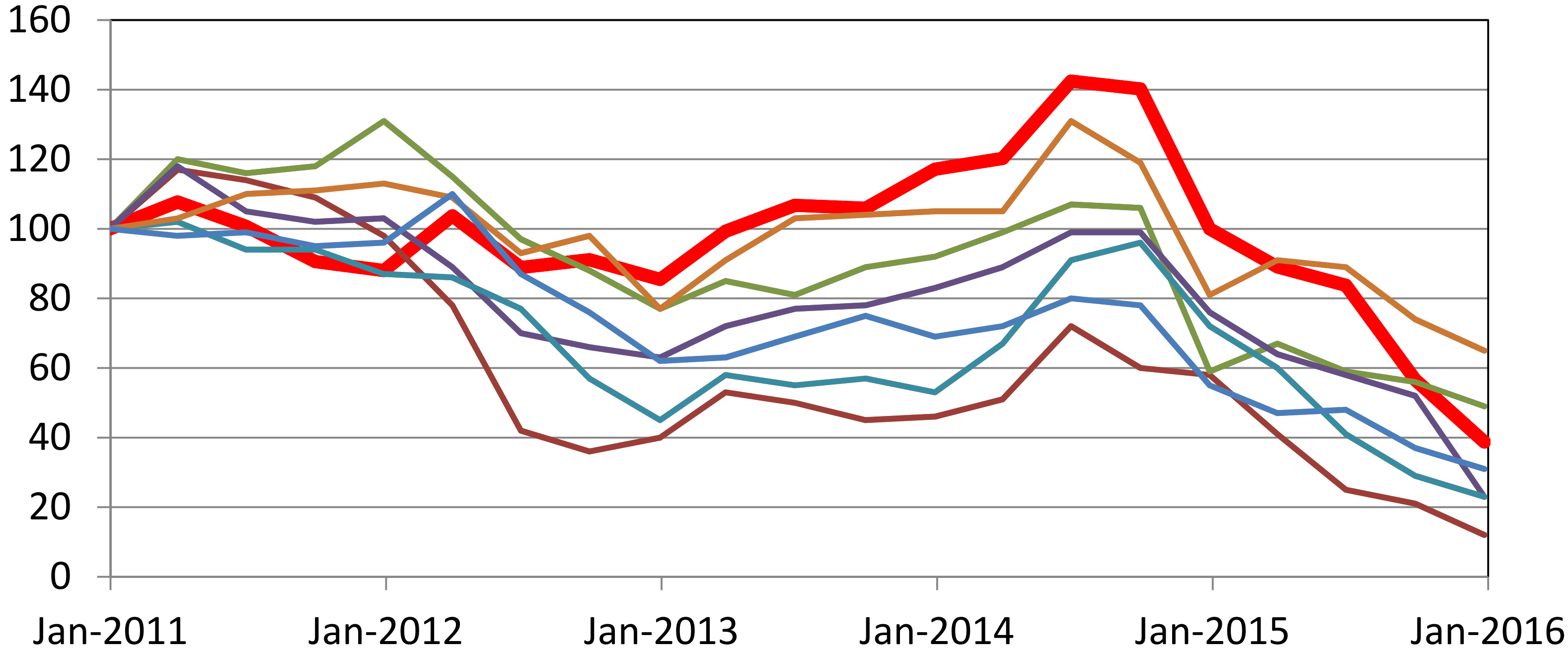
- Distribution Determinations
  - Period from October 2014 through September 2015

	($ thousands)	
	Limited Partners	**General Partner**
4% of Net Cash Receipts from Royalty Properties	$ --------	$1,124
96% of Net Cash Receipts from Royalty Properties	$26,986	$ --------
1% of Net Profits Interests Paid to our Partnership	$ --------	$ 85
99% of Net Profits Interests Paid to our Partnership	$ 8,413	$ --------
Total Distributions	**$35,399**	$1,209
Operating Partnership Share (3.03% of Net Proceeds)	$ --------	$ 266
Total General Partner Share		**$1,475**
% Total	**96%**	**4%**

Peer Group Comparison

- Market Performance
  - Pure royalties lack operating leverage inherent in net profits interests → Less volatility
  - Outperformance in low price environment due to lower fixed cost structure

5-Year Normalized Returns (distributions reinvested)



Note: Dist. reinvested on last day of quarter

Dorchester Minerals, LP Annual Meeting

May 18, 2016