Dorchester Minerals, LP
Annual Meeting

May 20, 2015

Forward-Looking Statements

Portions of this document may constitute "forward-looking statements" as defined by federal law. 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. Examples of such uncertainties and risk factors 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.

Overview of 2014 Results

Activity → Reserves → Production → Distributions

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2014 Activity

- **Minimal activity in most dry gas plays**
  - Mid-Continent, Fayetteville and Barnett Shale
- **Fever-pitch in Bakken and Midland Basin**
  - Confirmation of prospectivity of multiple benches
  - Efficiency and technology enhancements
- **Fulfillment of Minerals NPI strategy**
  - Bakken non-consent returns > market rate leasing
  - Midland Basin participation and non-consent results early, but encouraging
- **Prudent acquisition parameters restrict competitiveness**
  - Bakken and Midland Basin potential
- **Fall 2014 price drop results in significant drop in activity**

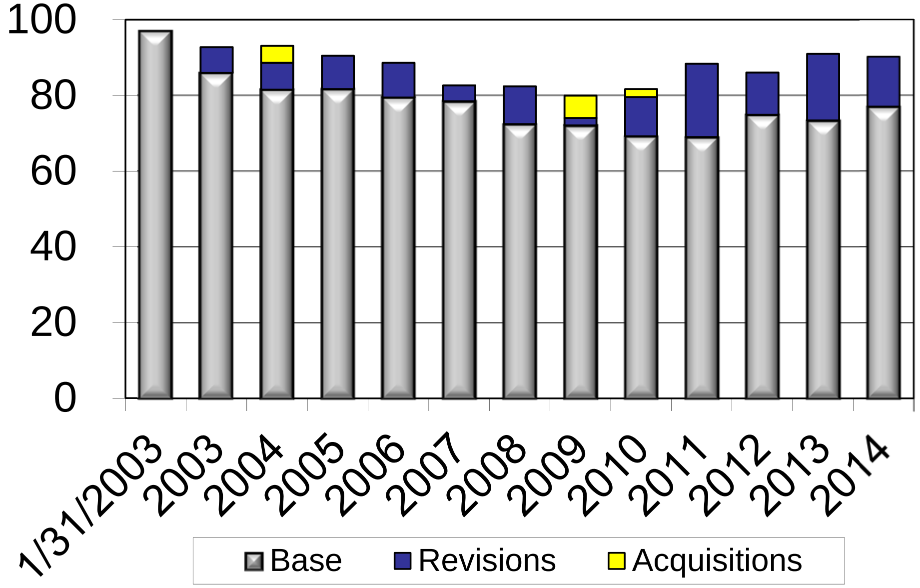
Overview of 2014 Results

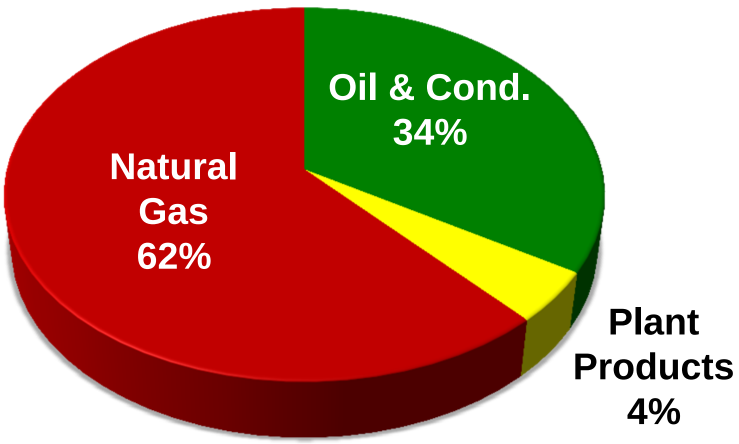
Activity → **Reserves** → Production → Distributions

2014 Reserves

- Total Proved Reserves of 90.2 Bcfe on 12/31/2014
  - All reserves are Proved Developed Producing (PDP)
  - Demonstrated history of positive revisions
  - Cumulative revisions since inception account for 133% of total reserves at year-end
  - Driving factors including new plays, field extensions, infill drilling, and new technology

Year-end Reserves (Bcfe)

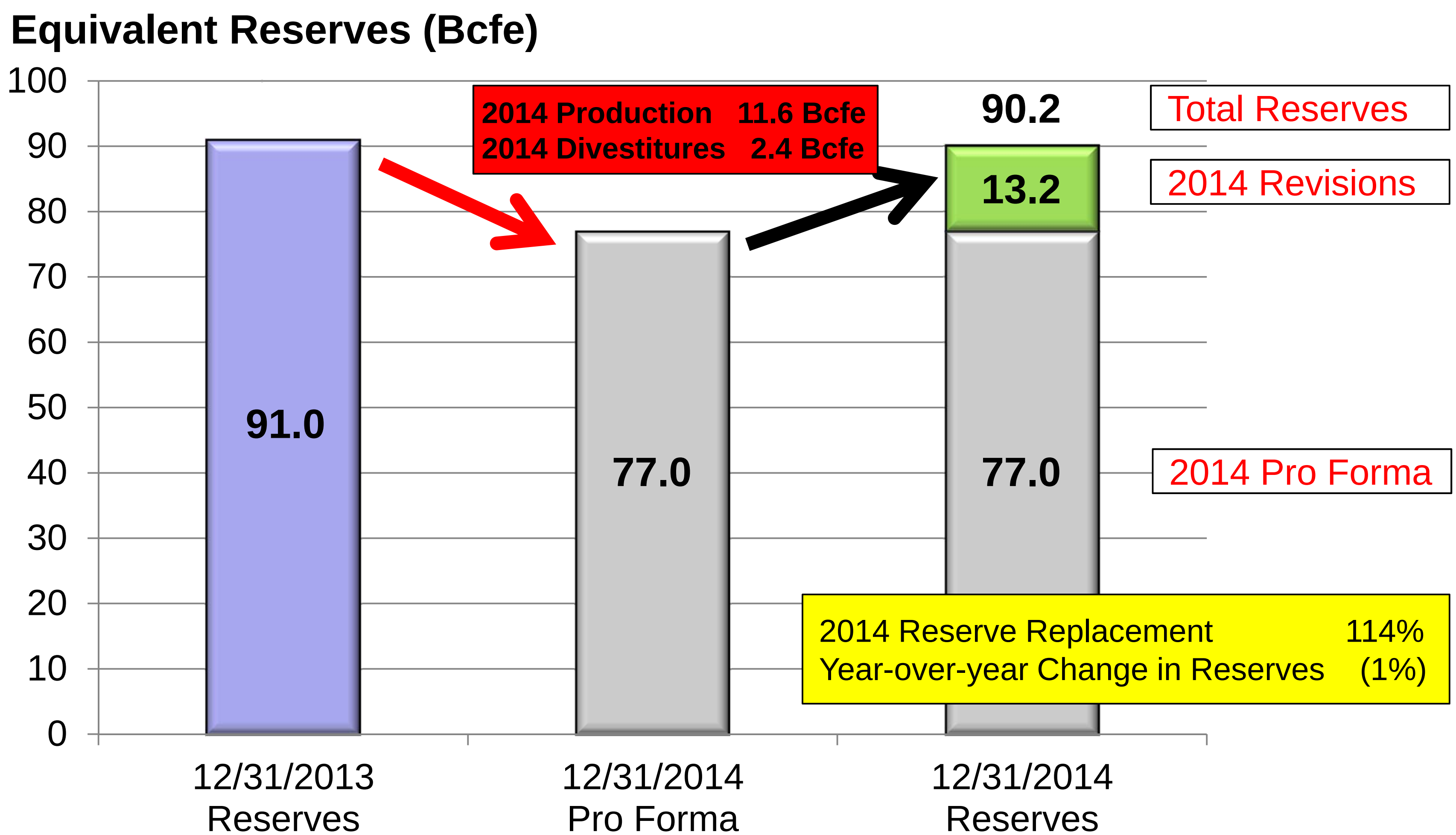




Note: 12.5 Bcfe of acquired reserves at time transactions closed. Gas-Oil equivalency of 6:1 ratio is used throughout this presentation

2014 Reserves

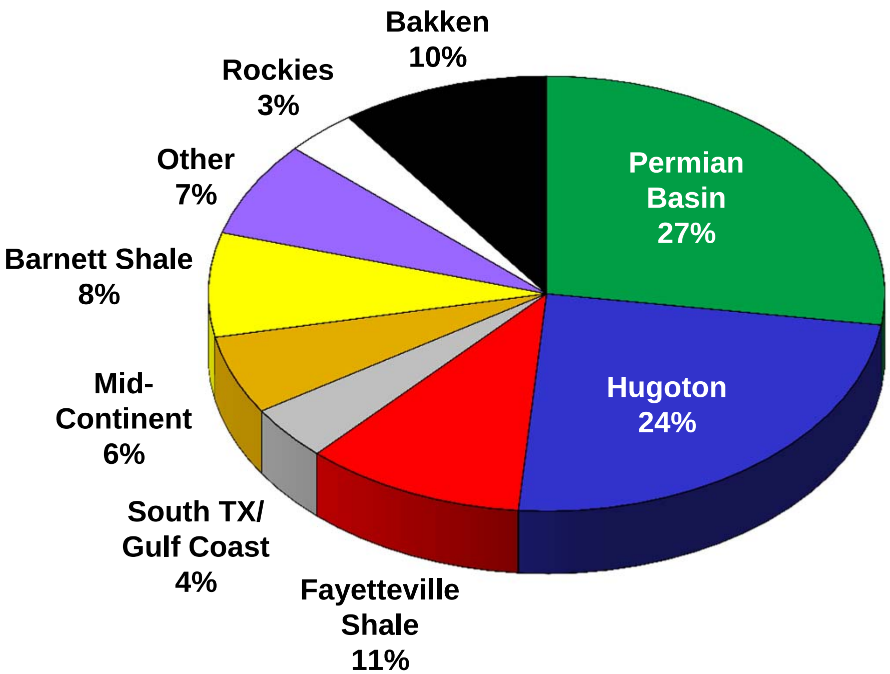
- Revisions to Reported PDP Reserves



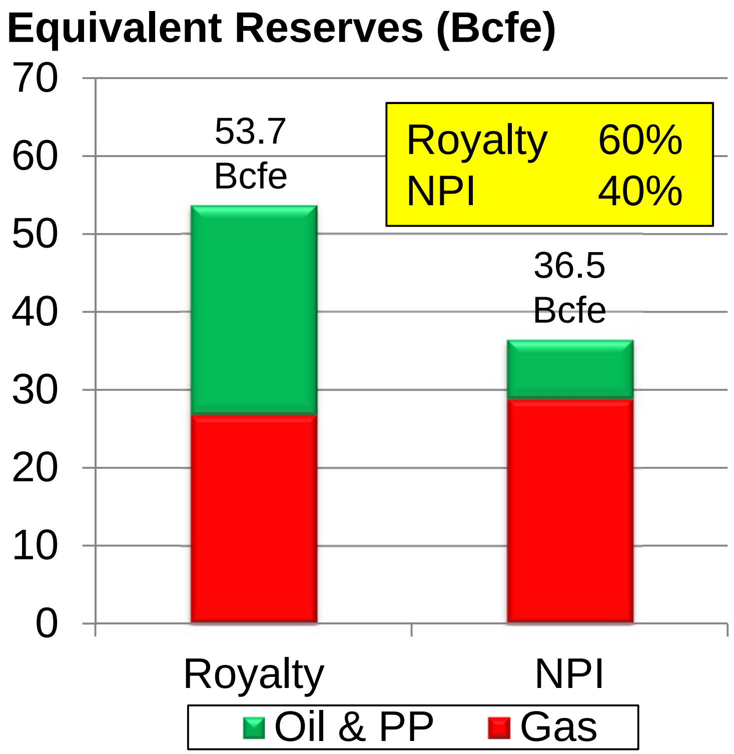
2014 Reserves

- Composition of Proved Reserves

Geographic Breakdown



Royalty-NPI Split

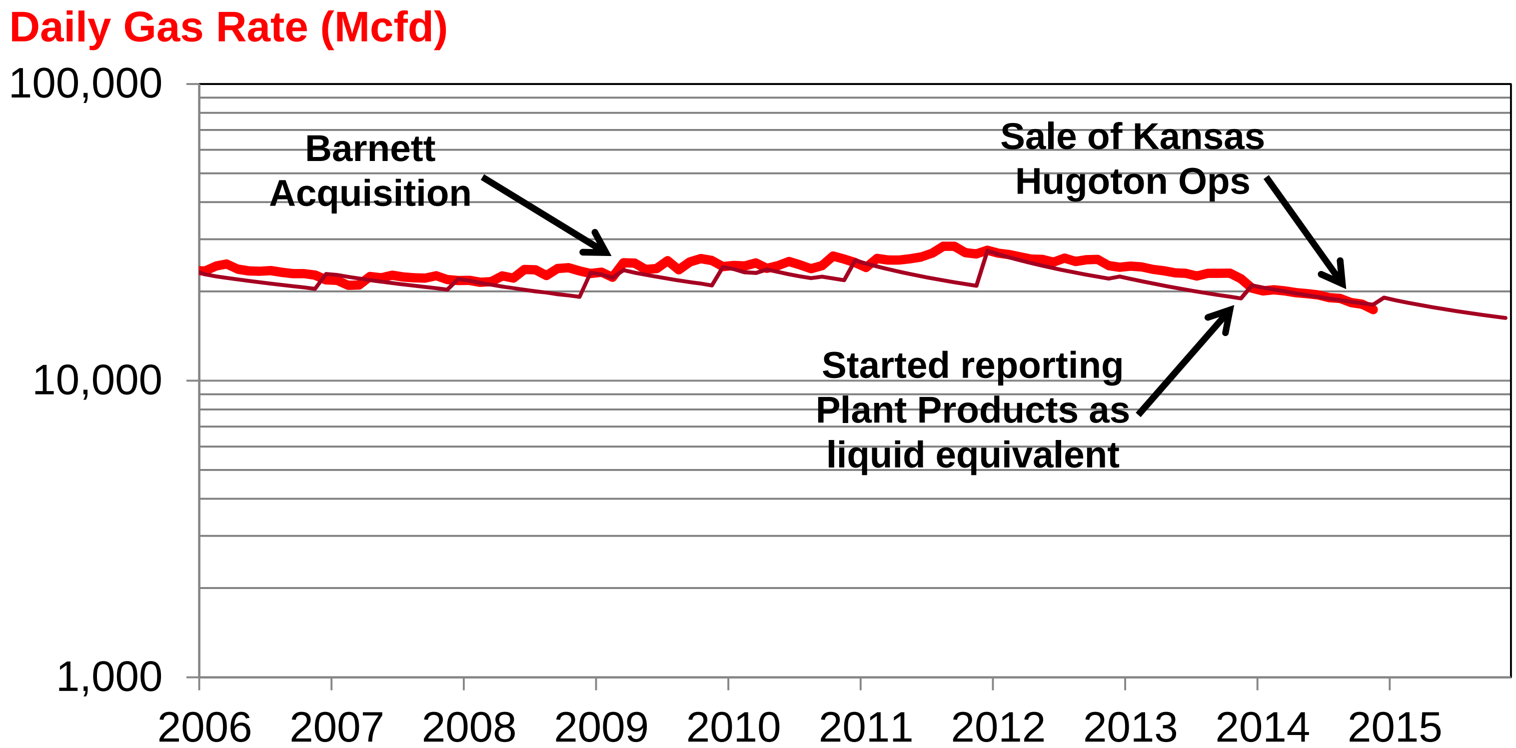


Overview of 2014 Results

Activity → Reserves → **Production** → Distributions

2014 Production

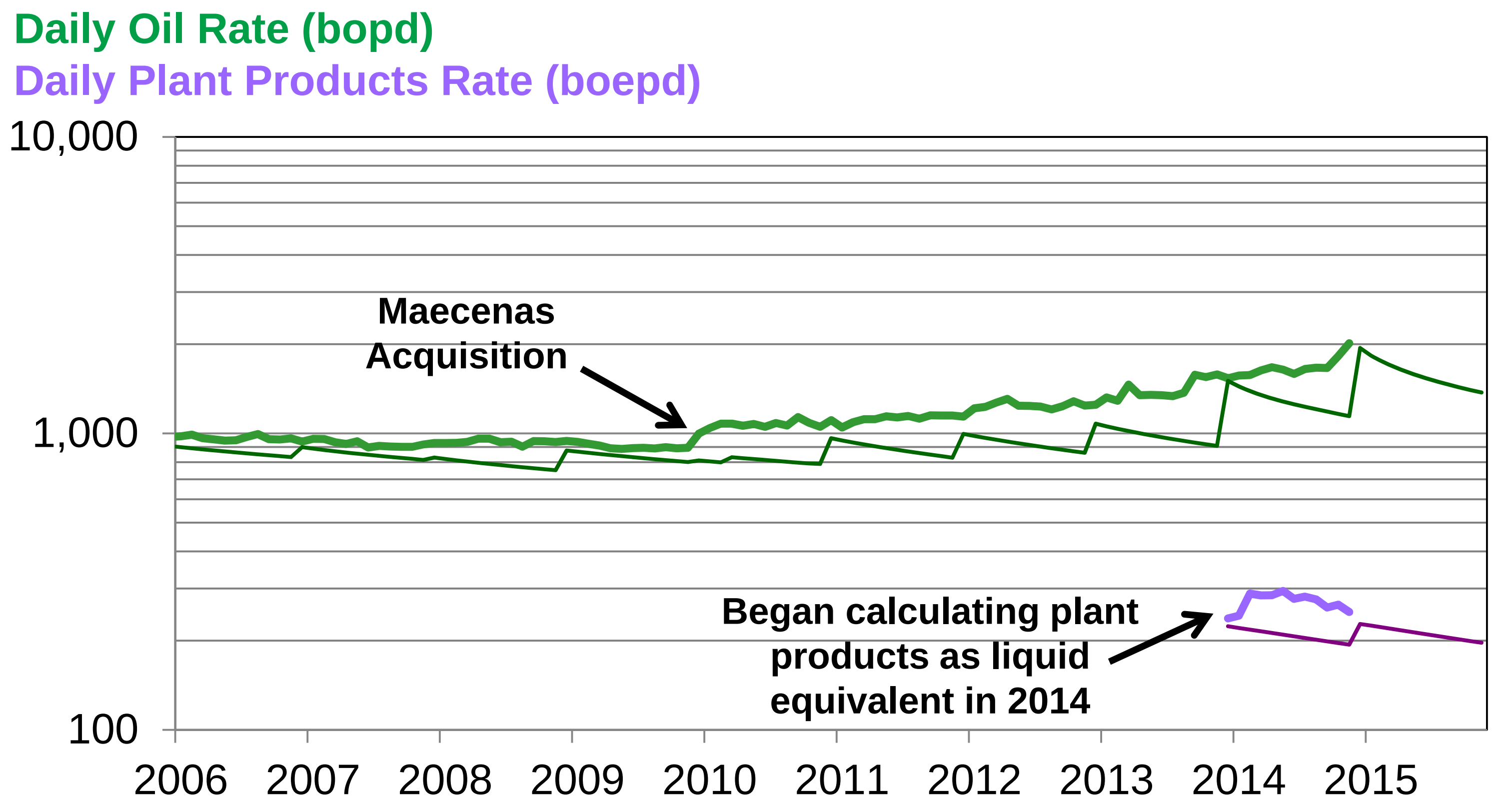
- Natural Gas Production
  - Gas production has decreased due to natural decline in the Hugoton field and reduced Barnett and Fayetteville activity
  - Only 3 new Barnett wells on production since 2011



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

2014 Production

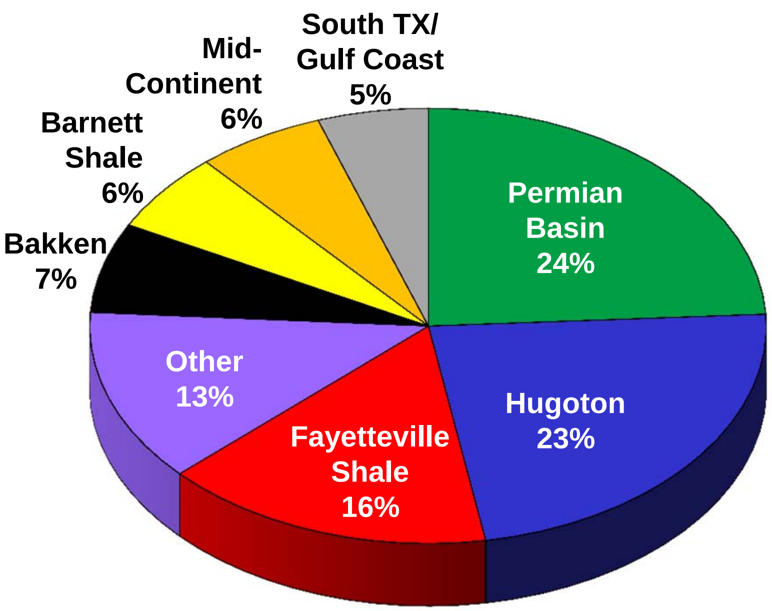
- Oil and Plant Products Production
  - Stable base production from large, mature Permian oil fields
  - Recent increase in oil production from new Bakken and Permian activity



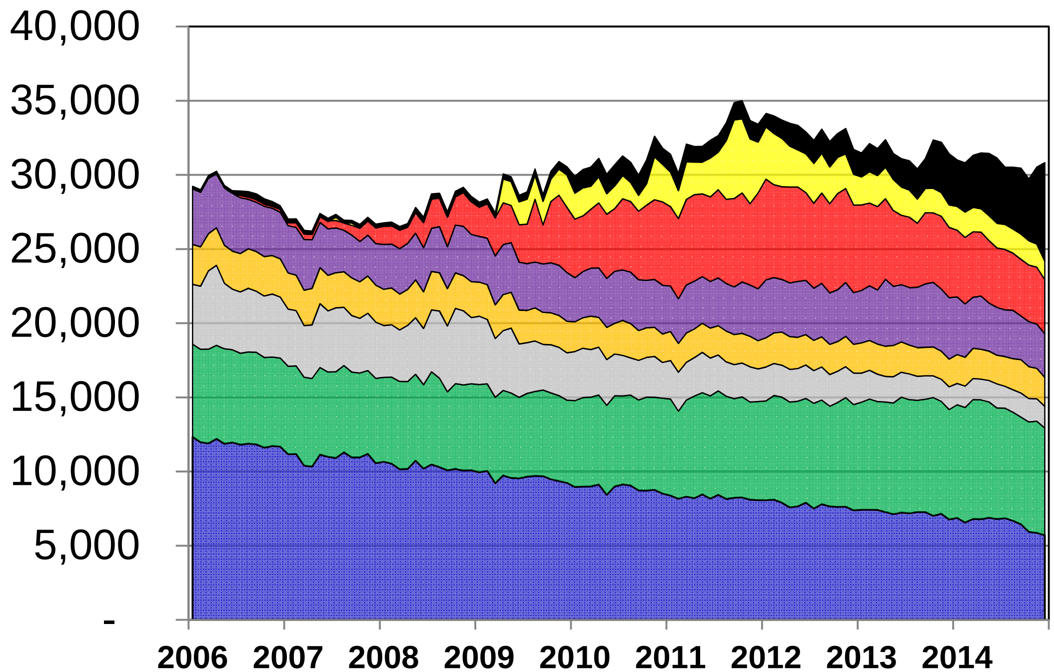
Note: Plant Product volumes calculated from Plant Products revenue based on Mt. Belvieu propane prices. Prior to 2014 Products included as gas equiv.

2014 Production

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



Daily Equivalent Rate (Mcfed)

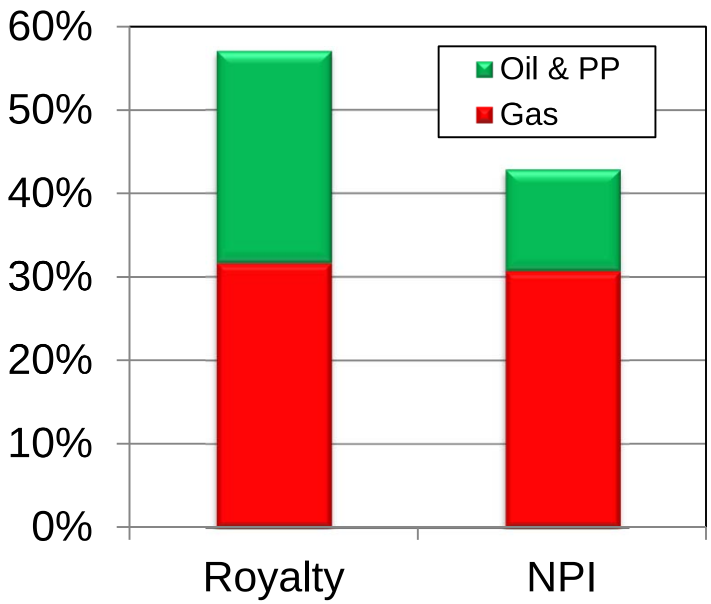


Note: Volumes attributable to NPI's are included regardless of surplus/deficit status and are burdened by lease operating costs and capital expenses

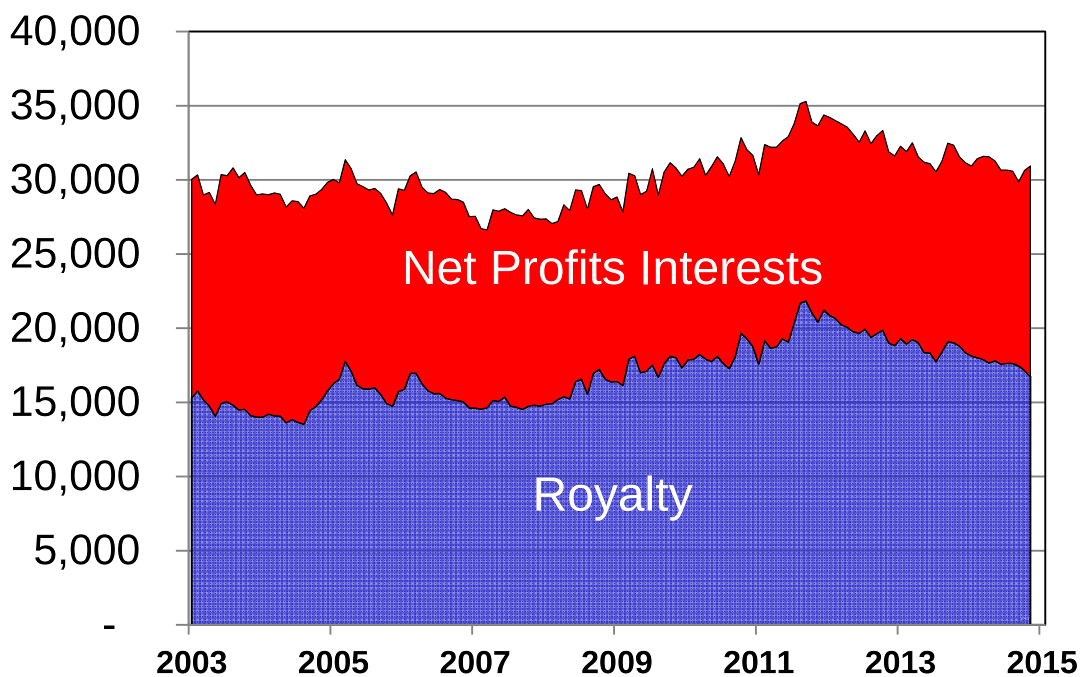
2014 Production

- Portfolio Has Shifted Over Time
  - 2003-2012 → Royalties increased from 48% to 62% due to mineral acquisitions, new drilling on legacy properties, and natural declines in Hugoton field
  - 2011-2014 → Royalties decreased to 54% at year-end due to NPI participation and declines in royalty gas

2014 Royalty-NPI Production Split



Daily Equivalent Rate (Mcfed)



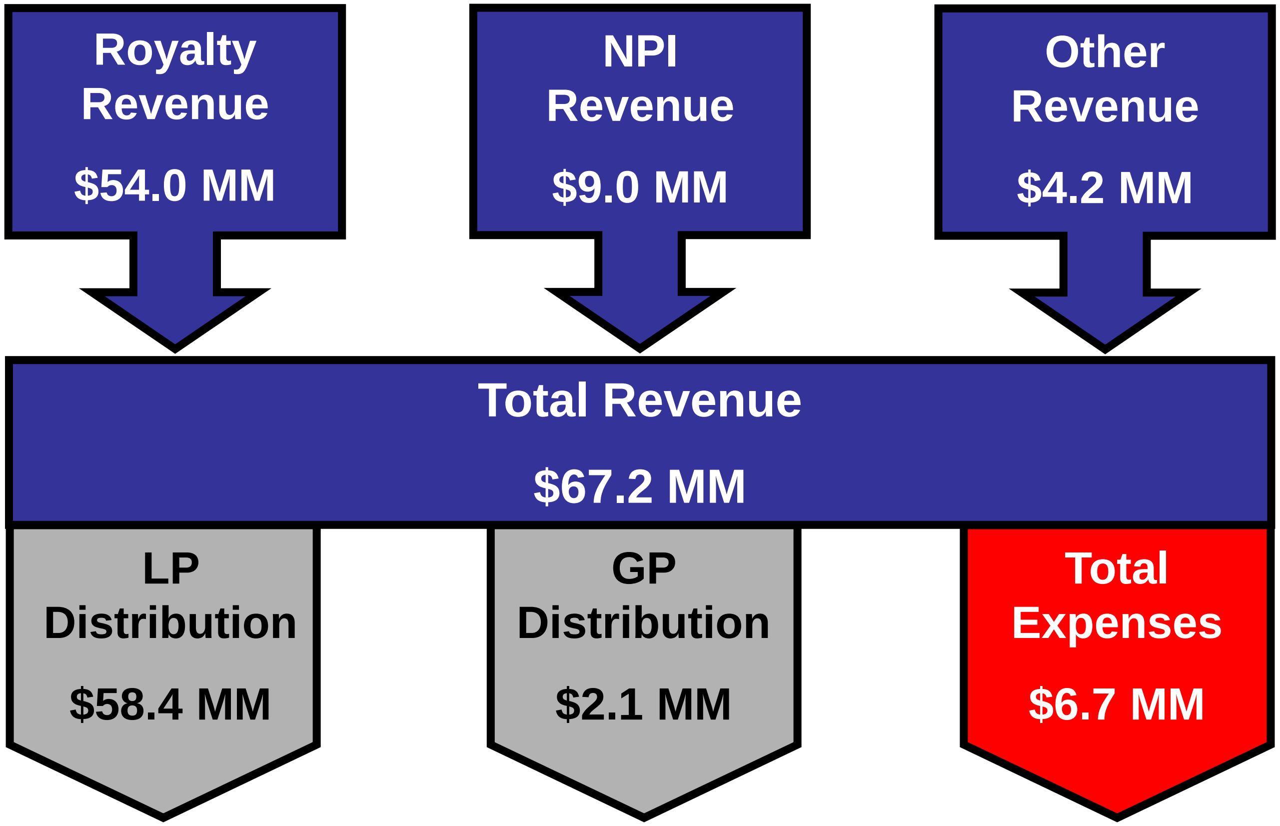
Note: Volumes attributable to NPI's are included regardless of surplus/deficit status and are burdened by lease operating costs and capital expenses

Overview of 2014 Results

Activity → Reserves → Production → **Distributions**

2014 Distributions

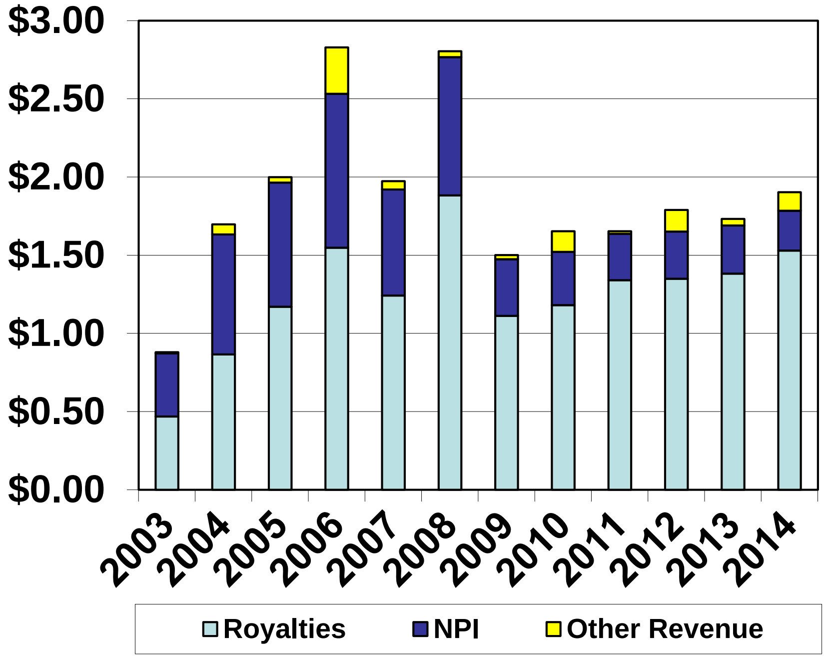
- Cash Distributions Paid in Calendar 2014
  - Reflects Q4 2013 to Q3 2014 activity



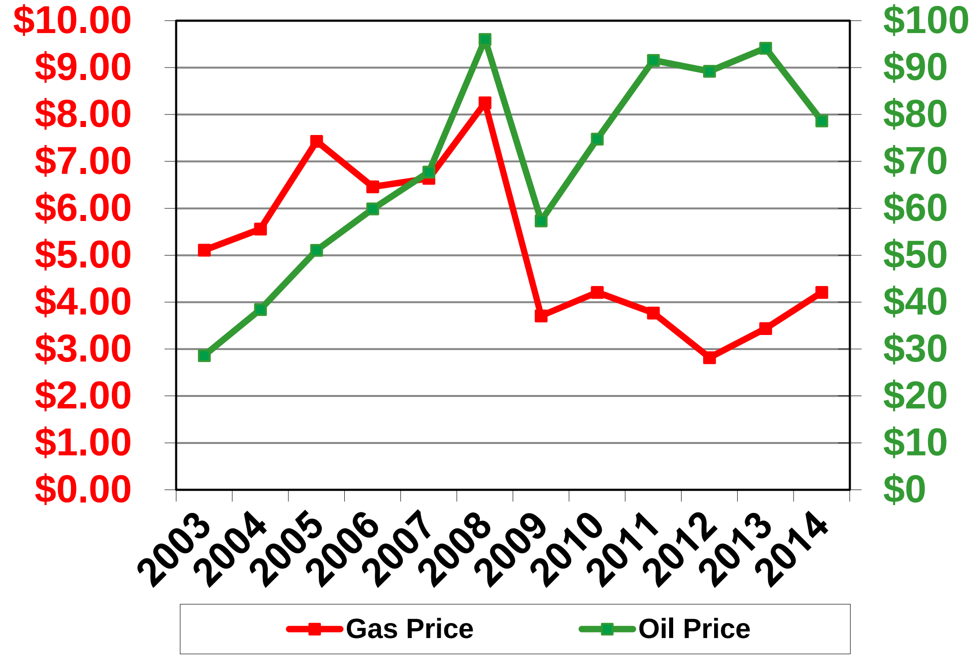
2014 Distributions

- Components and Prices
  - Royalty properties contributed 80% to total 2014 LP distributions
  - Gross Revenue → 18% gas sales, 80% oil & NGL sales, 2% other revenue
  - NPI contribution has decreased → No Minerals NPI payment since July 2013

LP Distribution History ($/unit)



Gas Price ($/Mcf) **Oil Price ($/bbl)**



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

Property Discussion

- Activity Overview
- Minerals NPI
- Core Midland Basin
- Bakken/Three Forks
- Fayetteville
- Hugoton

Royalty Overview

- Leasing and Development Activity
  - Consummated 107 leases in 32 counties/ parishes in five states
  - Lease bonus payments up to $3,750/acre
  - Initial royalty terms up to 25%
  - Identified 442 new wells on royalty properties in eight states
  - Fayetteville Shale activity decreased in 2014
  - 94 active lease offers as of May 2015

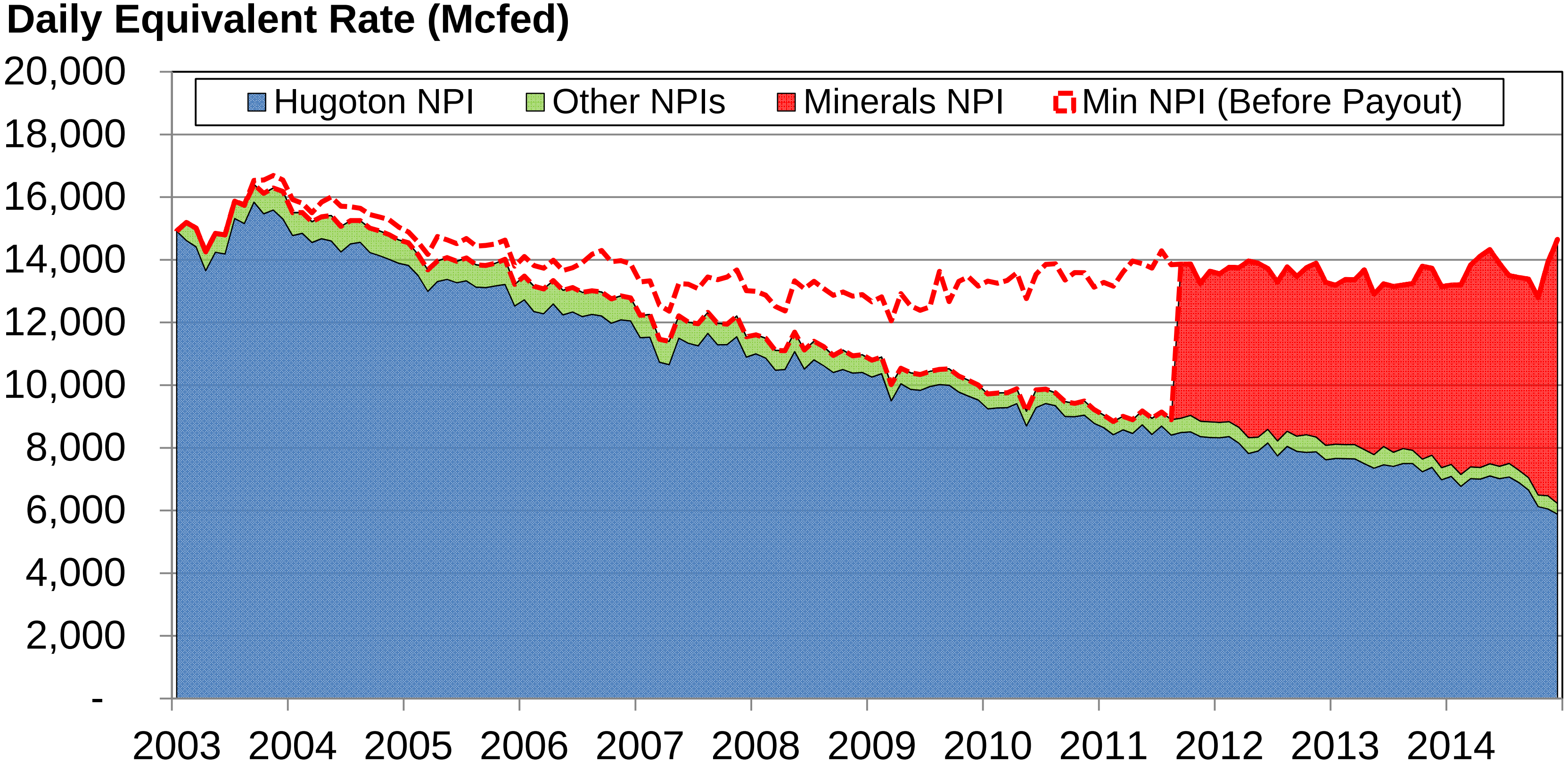
Net Profits Interests Overview

- 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 124 new wells located in Arkansas, Montana, North Dakota, New Mexico, Oklahoma and Texas

Note: New well count based on division orders and initial revenue payments received in 2014

Net Profits Interests Production

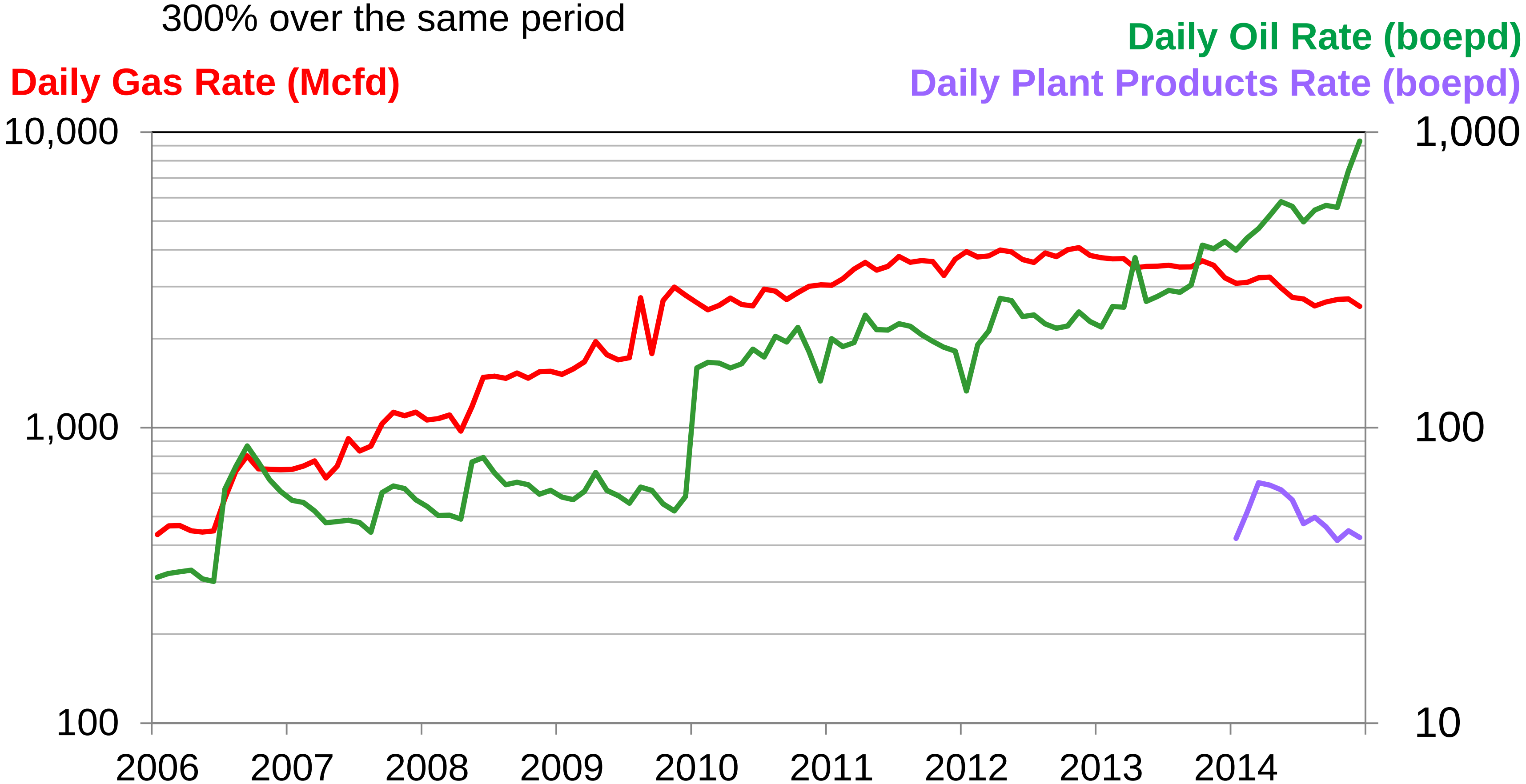
- Relative contribution of NPIs has shifted over time
  - Hugoton accounted for 96% of NPI production at inception → 44% in Q4 2014
  - Minerals NPI volumes prior to Q3 2011 were not included in DMLP results



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

Minerals NPI

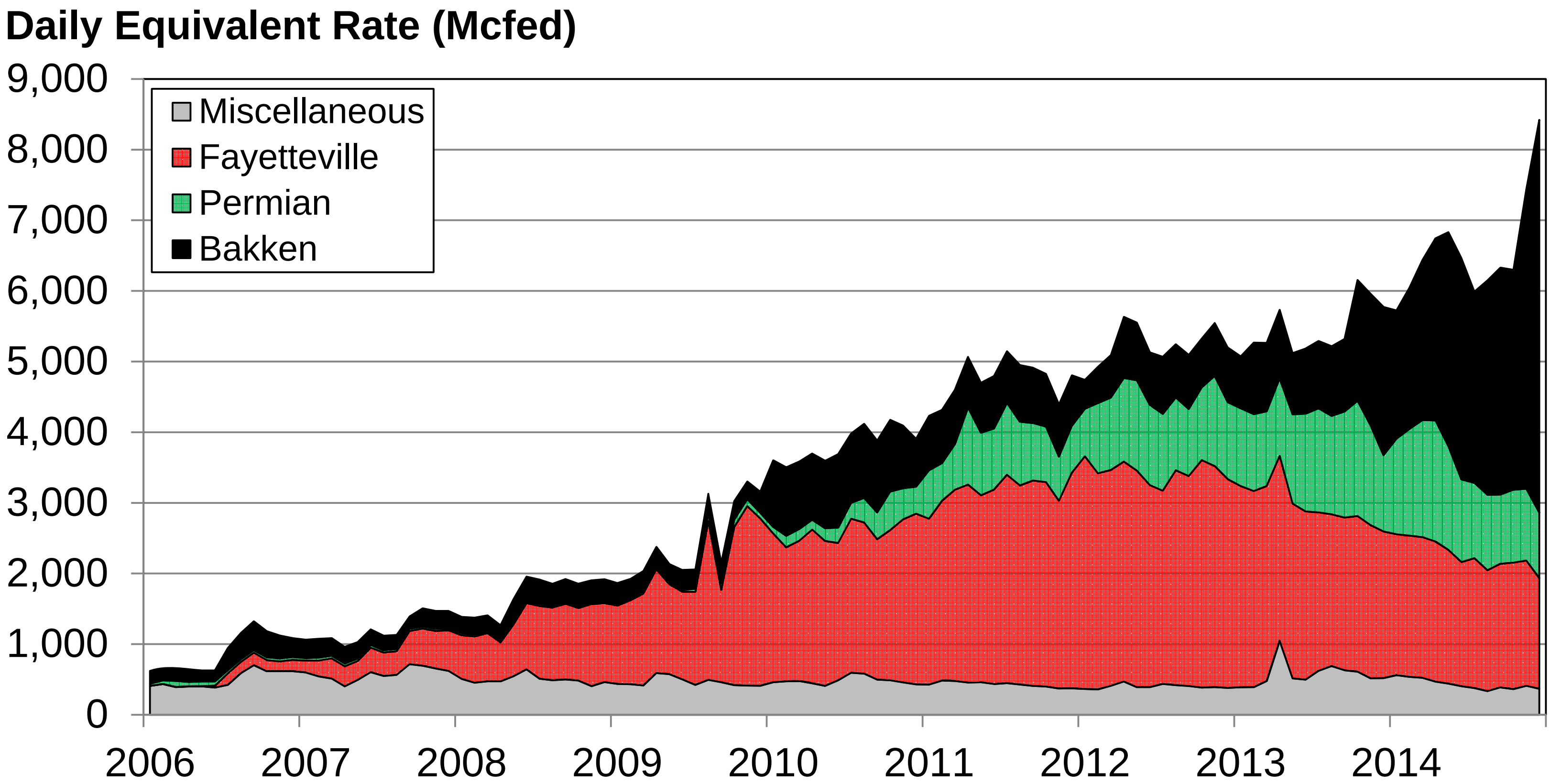
- Production by Product
  - Gas production has declined since 2012, but oil production has increased by 300% over the same period



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

Minerals NPI

- Components of Production
  - New Areas: MT Bakken (2006), Fayetteville (2007), ND Bakken (2009), Permian (2010)
  - Additional working interest opportunities in Bakken and Permian



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

Minerals NPI

- Activity from August 2013 through March 2015

Cash on Hand @ 07/31/2013	$ 5.0 MM
Cumulative Revenue	$33.7 MM
Cumulative Expense (LOE, taxes, etc)	($ 8.3 MM)
Cumulative Operating Income	$25.4 MM
Cumulative CAPEX Spent	($26.1 MM)
Cash Flow During Period	($ 0.7 MM)
Cash on Hand @ 03/31/2015	$ 4.3 MM
Capital Commitments @ 07/31/2013	($ 5.0 MM)
Additional Commitments During Period	($ 5.7 MM)
Capital Commitments @ 03/31/2015	($10.7 MM)
Cumulative Surplus (Deficit)	**($ 6.4 MM)**

Outstanding Capital Commitments

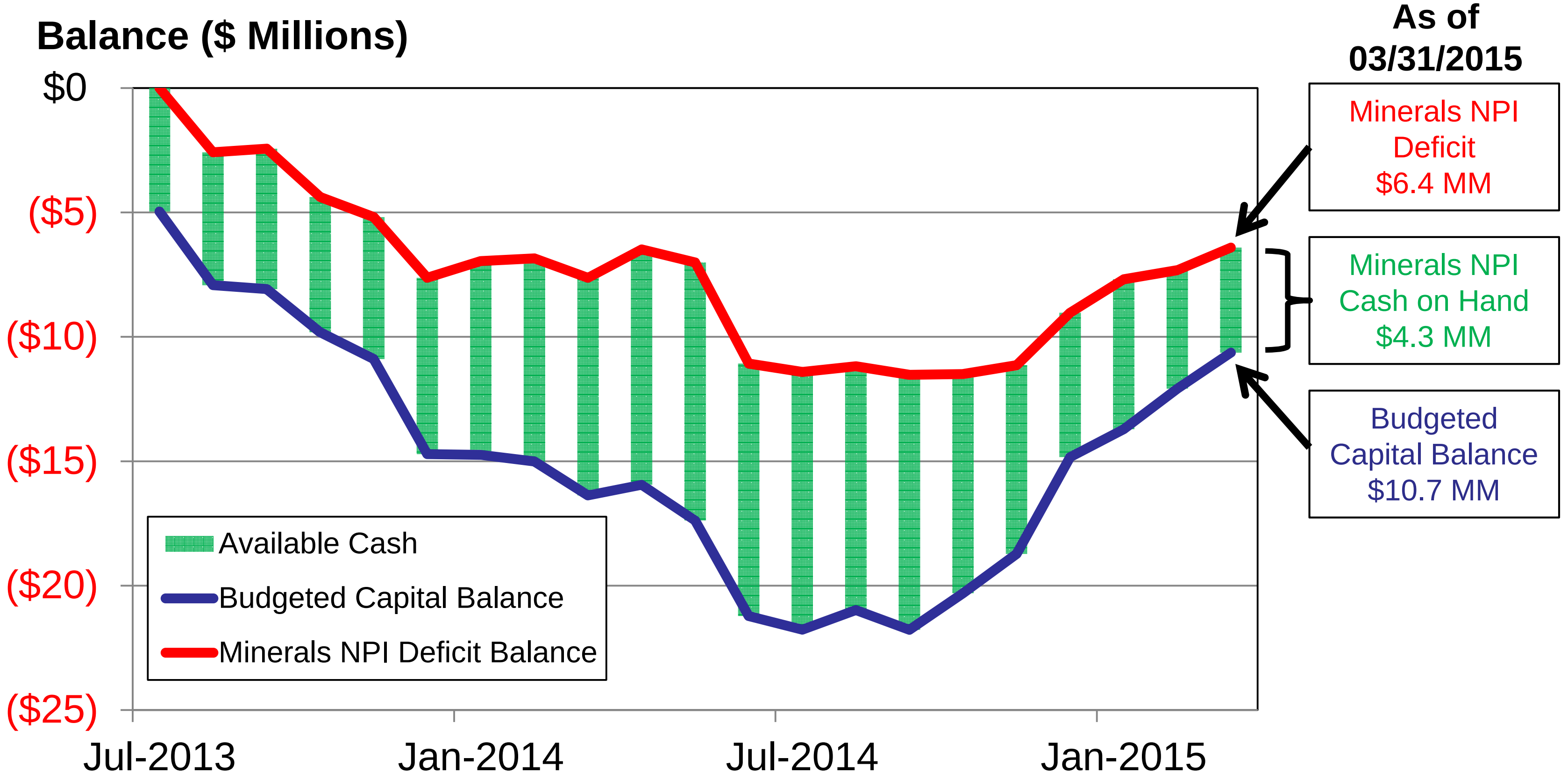
By Play	
Bakken	($ 9.8 MM)
Other Basins	($ 0.9 MM)
Total Capital Commitments	($10.7 MM)

By Status	
Wells in Pay Status	($ 4.8 MM)
Wells not in Pay Status	($ 5.9 MM)
Total Capital Commitments	($10.7 MM)

Note: Aug 1, 2013 to Mar 31, 2015 represents the time period since the last Minerals NPI payment during which the Minerals NPI has been in deficit status.

Minerals NPI

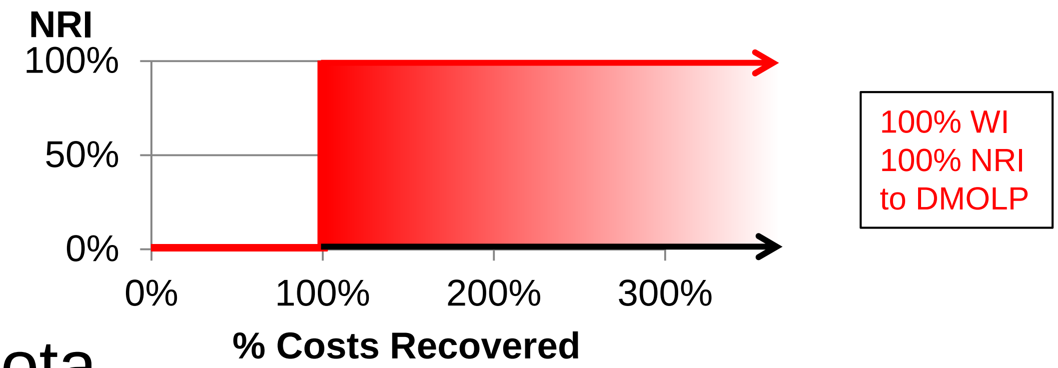
- Activity from August 2013 through March 2015
  - Deficit has improved since September 2014
  - Revenue from recent wells and declining capital commitments



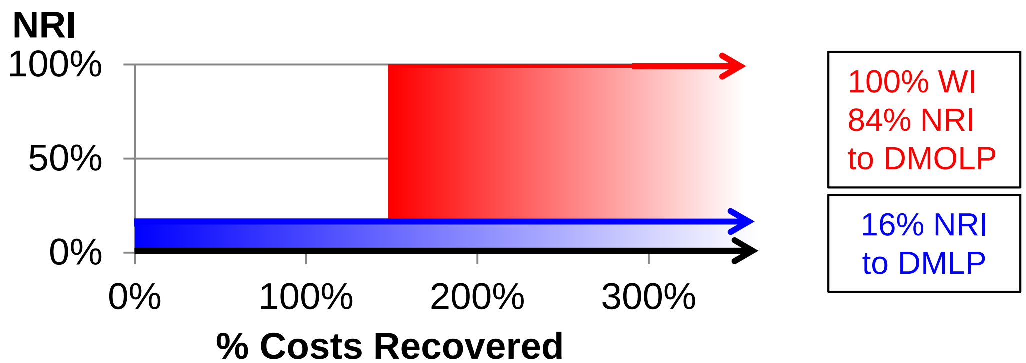
Note: Aug 1, 2013 to Mar 31, 2015 represents the time period since the last Minerals NPI payment during which the Minerals NPI has been in deficit status.

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	58	20	0.000%	13.015%
Gaines	16	6	0.000%	3.331%
Midland	65	4	0.000%	3.798%
Upton	188	74	0.000%	2.763%
Total	327	104	0.000%	4.815%

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

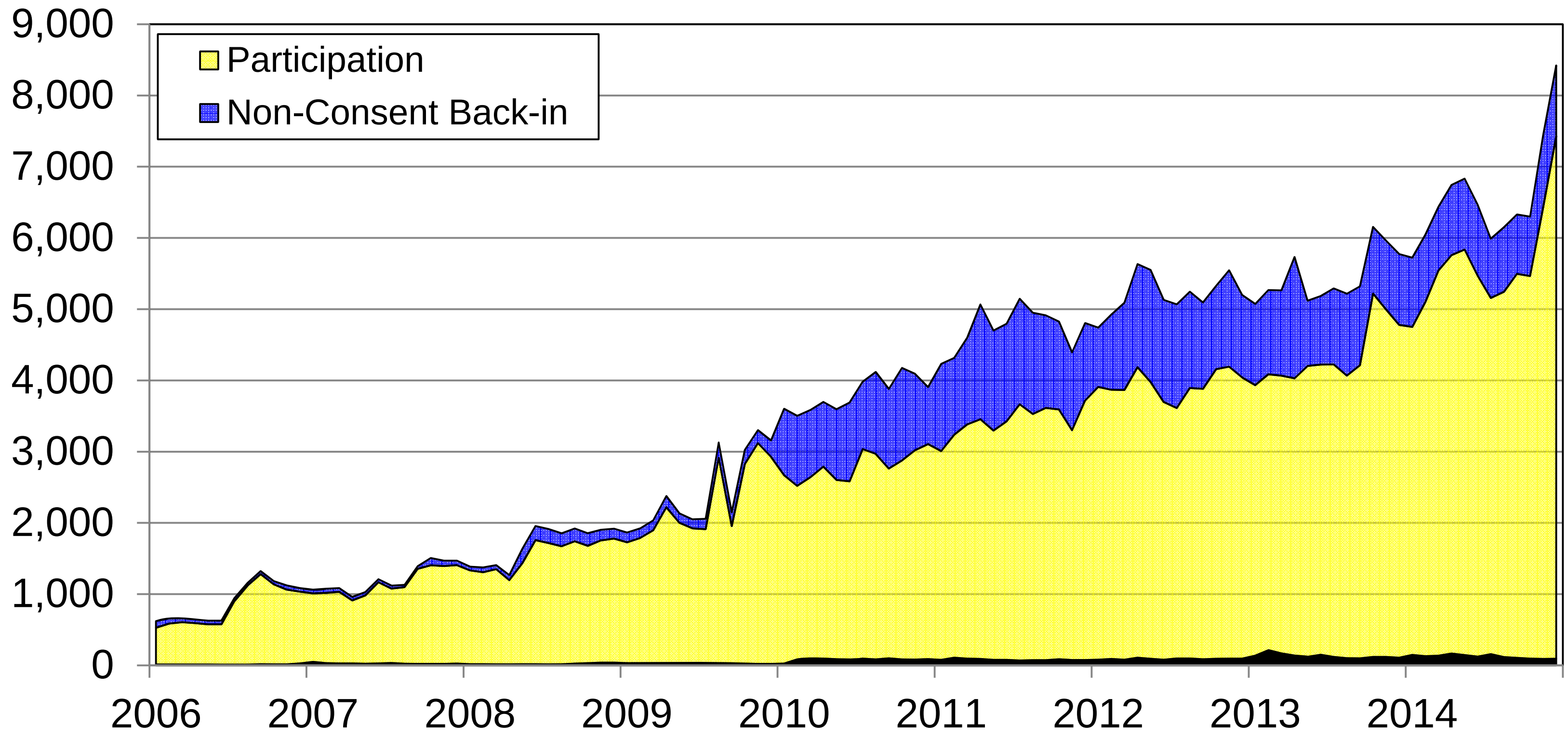
Selected North Dakota Counties	N/C Well Count	Paid Out Well Count	Average BPO NRI	Average APO NRI
Burke	26	0	0.165%	0.702%
Divide	38	2	0.267%	1.551%
Dunn	31	3	0.706%	4.326%
McKenzie	79	16	0.297%	1.851%
Mountrail	79	14	0.752%	3.631%
Williams	83	8	0.481%	2.977%
Total	336	43	0.474%	2.653%

Note: Only 41 of 43 ND paid out wells are “in pay” status

Minerals NPI

- Production by Interest Type
  - First Bakken Non-consent payout in 2009, Texas payouts ongoing since 2006
  - Production decline rates are lower when payout occurs

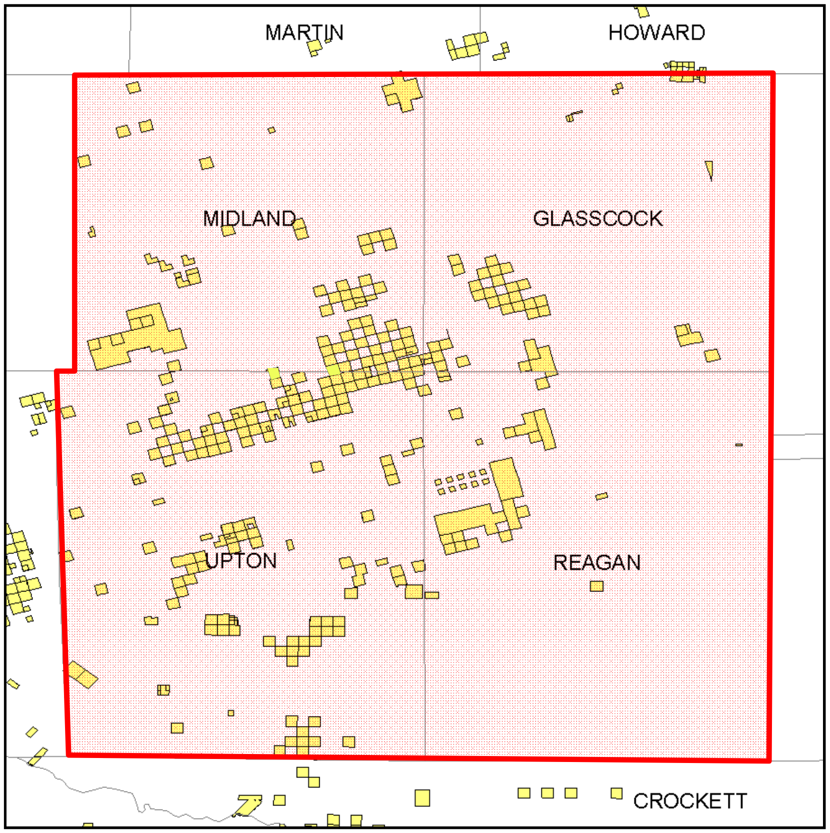
Daily Equivalent Rate (Mcfed)



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

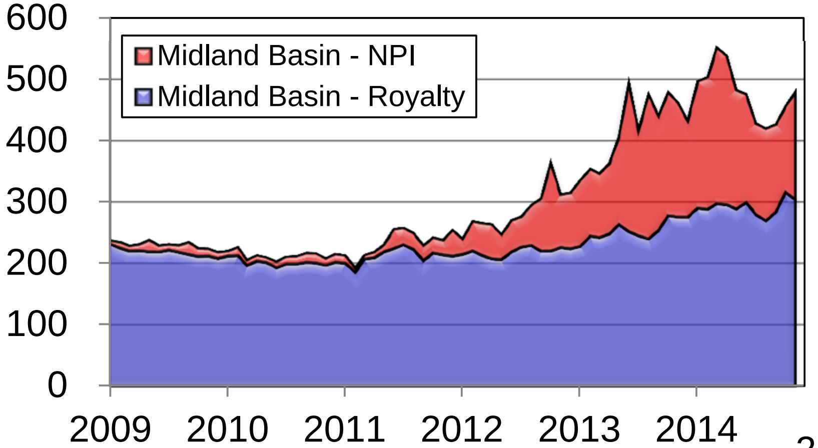
Core Midland Basin

- Emerging Horizontal Wolfcamp Play



– Varying undivided interests in ~200,000 gross acres
– Unleased below the Spraberry in numerous tracts

Core Midland Basin Production (boepd)

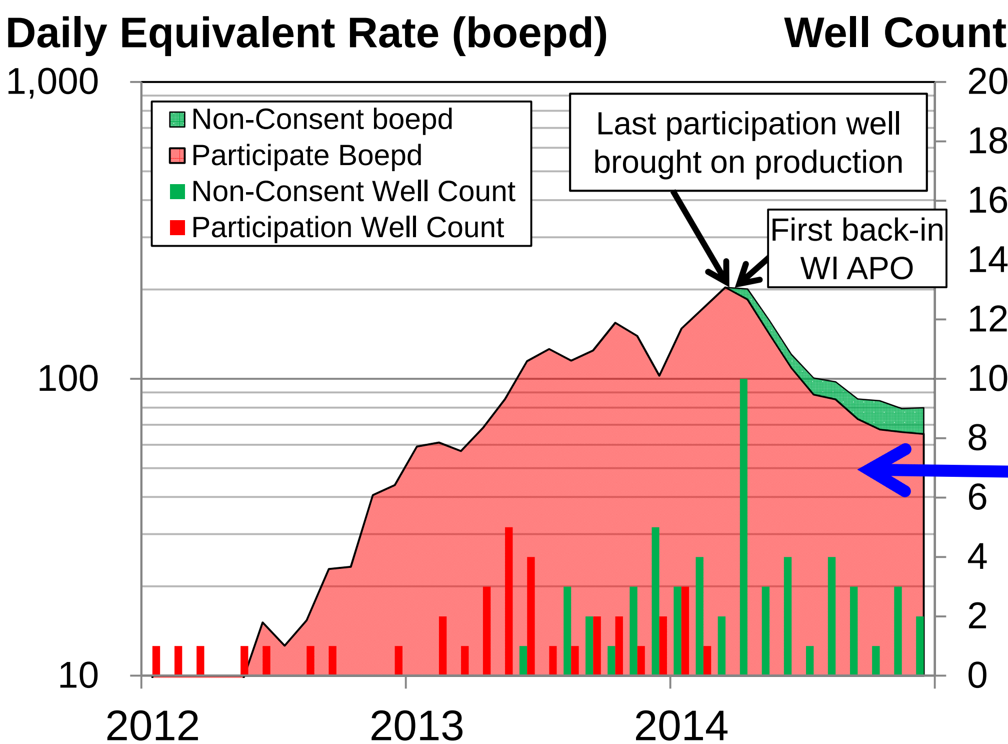


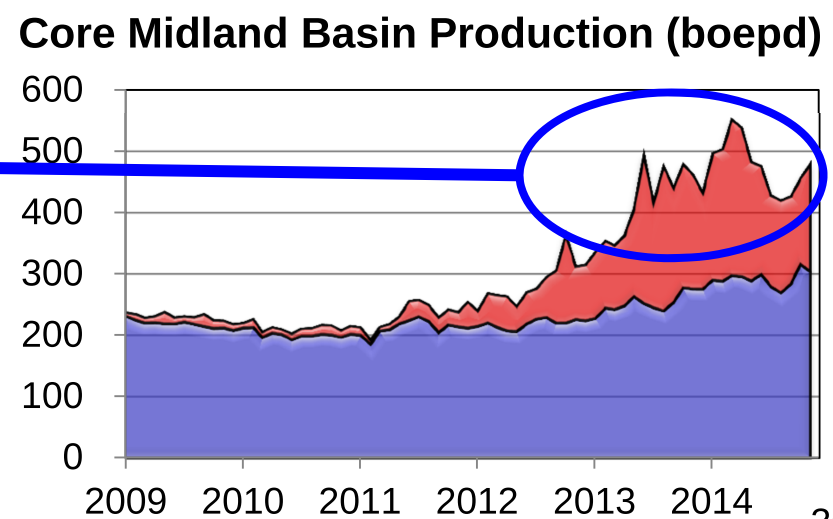
Note: Production graph limited to "in pay" volumes from Glasscock, Midland, Reagan, and Upton Counties. Acreage total limited to the same counties.

Core Midland Basin

- Effect of well elections on production profile
  - Single Operator in Upton Co, Texas

- NPI participation in 36 wells
- Operator declined DMLP's elections to participate after 2013
- Production decline begins early 2014
- Wells continue to be added but DMLP has no interest until payout
- Incremental volumes added as non-consent wells reach payout status

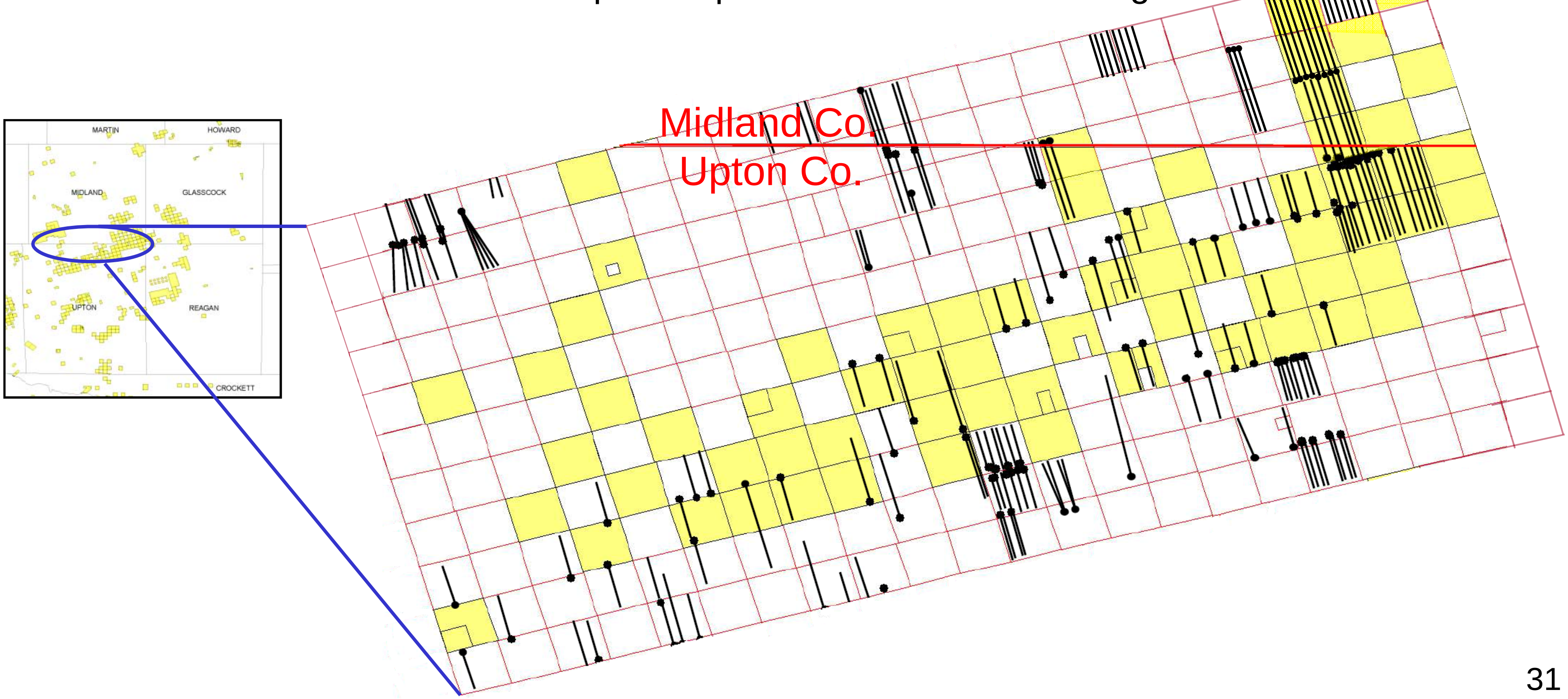




Note: Production graph limited to "in pay" volumes from Glasscock, Midland, Reagan, and Upton Counties. Acreage total limited to the same counties.

Core Midland Basin

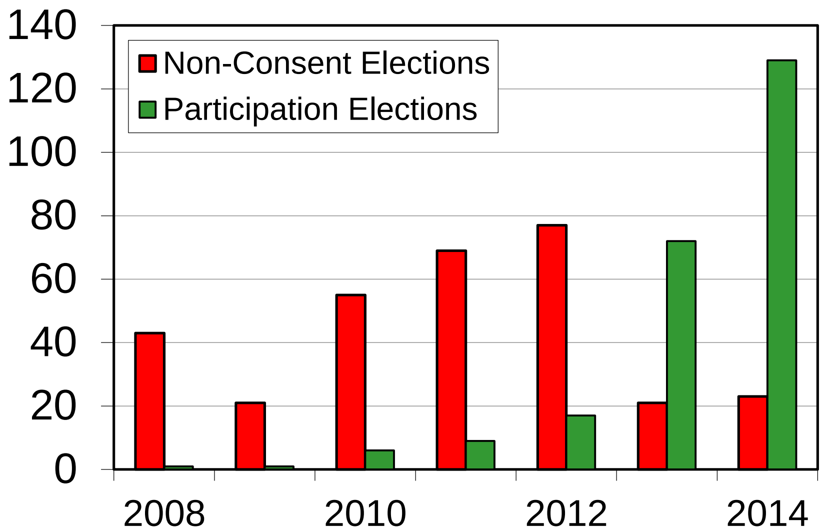
- Example: Selected Upton/Midland County Holdings
  - Varying undivided interests – 4.2% interest in 42,800 gross acres
  - Unleased below the Spraberry in numerous tracts
  - Over 70 Horizontal Wolfcamp wells permitted on DMLP acreage



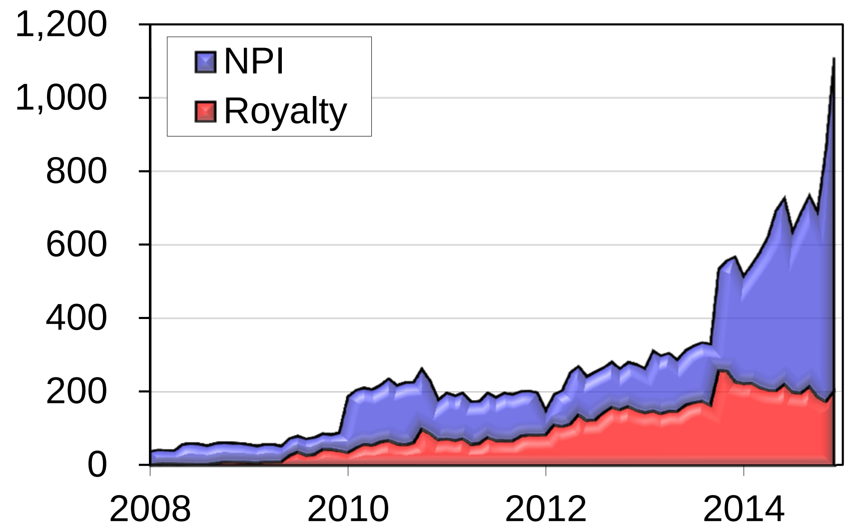
Bakken/Three Forks

- Williston Basin – Northwestern North Dakota
  - DMLP owns 70,390 gross acres/8,905 net acres
  - Producing 1,100 boepd at year-end 2014 → 82% from Working Interests
  - Production increases driven by continued participation and improved completions
  - 2015 activity focused on core acreage

Well Count



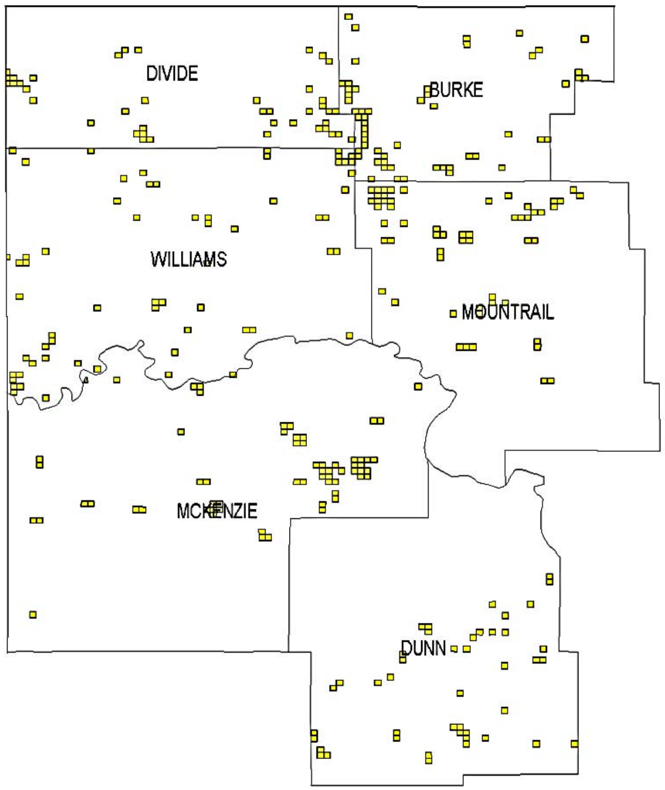
Net Daily Production (boepd)



Note: Production graph limited to “in pay” volumes from six county core area.

Bakken/Three Forks

- Williston Basin – Northwestern North Dakota
  - DMLP owns 70,390 gross acres/8,905 net acres



	Well Count	Average BPO NRI	Average APO NRI
Completed as Producers	509	0.848%	2.173%
Drilling/Completion (or confidential)	82	1.089%	1.253%
Permitted AND Proposed	11	0.130%	0.145%
Permitted NOT Proposed	63	TBD	TBD
Total	**665**	**0.869%**	**2.013%**

Note: NRI values are the sum of DMLP and DMOLP NRIs.

Bakken/Three Forks

- Non-Consent Elections – A Look Back

	302 Non-Consent Wells		41 Back-in WI Wells
	~16% Royalty	*Incremental 4% Royalty*	*84% NRI After Payout*
Revenue	$17.8 MM	$4.5 MM	$14.3 MM
LOE/Tax	($2.3 MM)	($0.6 MM)	($2.9 MM)
CAPEX	---	---	($0.3 MM)
Net Cash	$15.5 MM	$3.9 MM	$11.1 MM
Other Considerations	• Lease Bonus		• Working Interest Upside • Well Information/Risk Mitigation • Lease Bonus

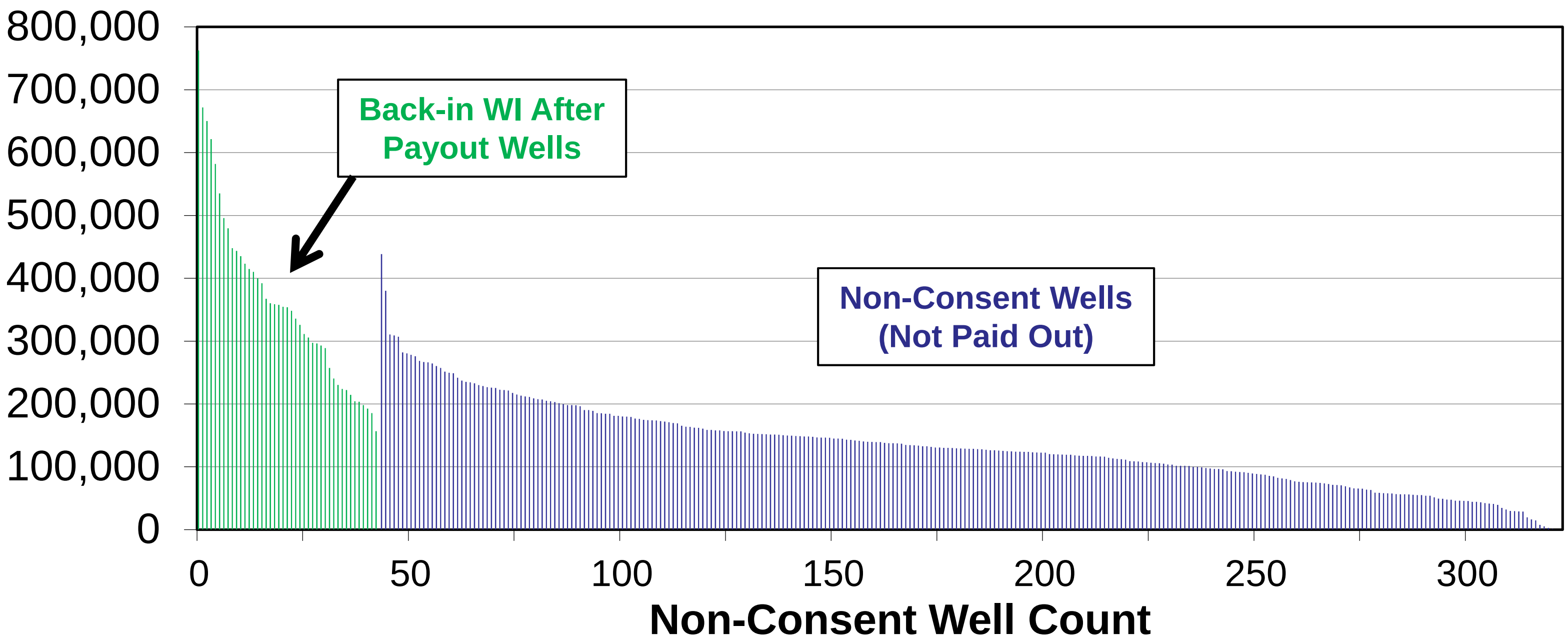
  - Incremental 4% Royalty reflects the difference between statutory rate (16%) and assumed “Market Rate” (20%)
  - Cashflow attributable to 84% NRI APO in 41 wells equals 2.8X cashflow from 4% Incremental Royalty from ALL non-consent wells
  - Preserves the option to participate (or lease) in the future

Note: Revenue and well count only include wells in pay status.

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

Cumulative Production (BOE)



Note: Cumulative production volumes through February 2015 for all non-consent wells, regardless of pay status.

Bakken/Three Forks

- Example: 22-155N-94W, Mountrail Co. (149 net acres)

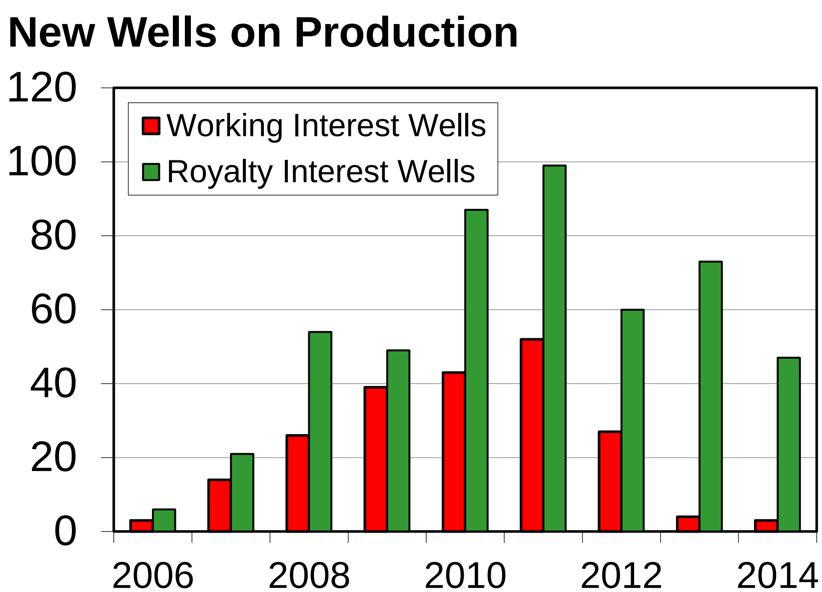
Well Name (Operator)	Election	BPO NRI	APO NRI	Peak Avg. Rate (boepd)
EN-Jeffrey 155-94-2215H-1 (Hess)	Participate	5.825%	5.825%	1,526
EN-Jeffrey 155-94-2215H-2 (Hess)	N/C	0.932%	5.825%	1,266
EN-Jeffrey 155-94-2215H-3 (Hess)	N/C	0.932%	5.825%	1,030
EN-Jeffrey 155-94-2215H-4 (Hess)	Permitted - Waiting on Proposal			
EN-Jeffrey 155-94-2215H-5 (Hess)	Permitted - Waiting on Proposal			
EN-Jeffrey 155-94-2215H-6 (Hess)	Permitted - Waiting on Proposal			
EN-Jeffrey 155-94-2215H-7 (Hess)	Permitted - Waiting on Proposal			
EN-Jeffrey 155-94-2215H-8 (Hess)	Permitted - Waiting on Proposal			
EN-Jeffrey 155-94-2215H-9 (Hess)	Permitted - Waiting on Proposal			
EN-Jeffrey A 155-94-2734H-1 (Hess)	N/C	0.932%	5.825%	1,265
EN-Jeffrey A 155-94-2734H-2 (Hess)	N/C	0.932%	5.825%	1,866
EN-Jeffrey A 155-94-2734H-3 (Hess)	Participate	5.825%	5.825%	1,021
EN-Jeffrey A 155-94-2734H-4 (Hess)	Participate	5.825%	5.825%	1,071
EN-Jeffrey A 155-94-2734H-5 (Hess)	Participate	5.825%	5.825%	1,034
EN-Jeffrey A 155-94-2734H-6 (Hess)	Participate	5.825%	5.825%	1,205
EN-Jeffrey A 155-94-2734H-7 (Hess)	Participate	5.825%	5.825%	2,013
EN-Jeffrey A 155-94-2734H-8 (Hess)	Participate	5.825%	5.825%	983
EN-Jeffrey A 155-94-2734H-9 (Hess)	Participate	5.825%	5.825%	1,304

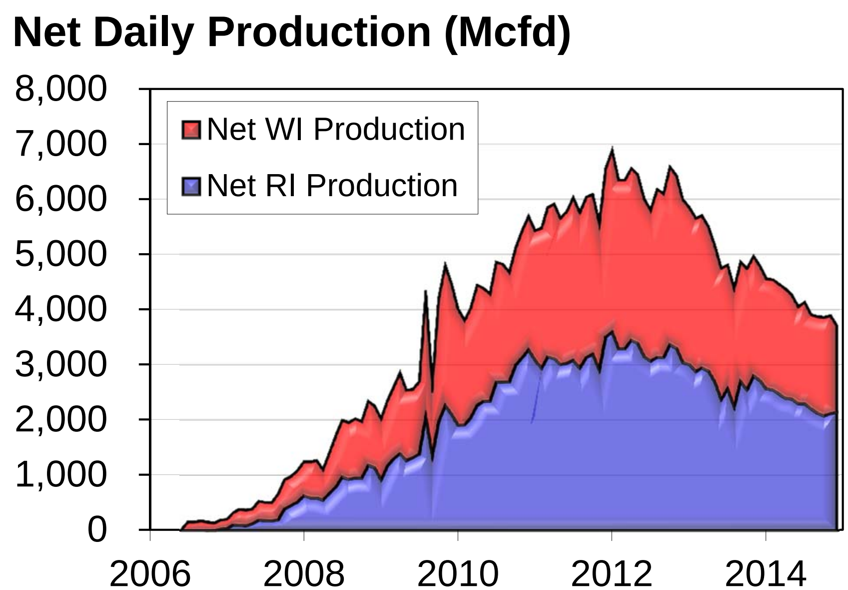
Produced 975,000 boe from 12 wells since Jan 2013

Note: NRI values are the sum of DMLP and DMOLP NRIs. “N/C” indicates Non-Consent election.

Fayetteville Shale

- Eastern Arkoma Basin – Northern Arkansas
  - DMLP owns 23,336 gross/11,464 net acres in 196 sections
  - 457 wells producing 3.9 MMcfd at year-end 2014 → 46% from Working Interests
  - Production has decreased as a result of decreased activity



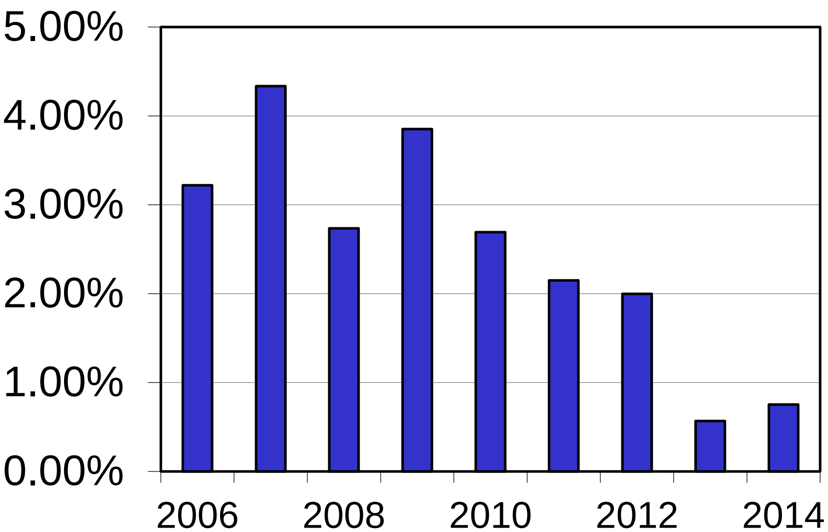


Note: Production graph limited to "in pay" volumes.

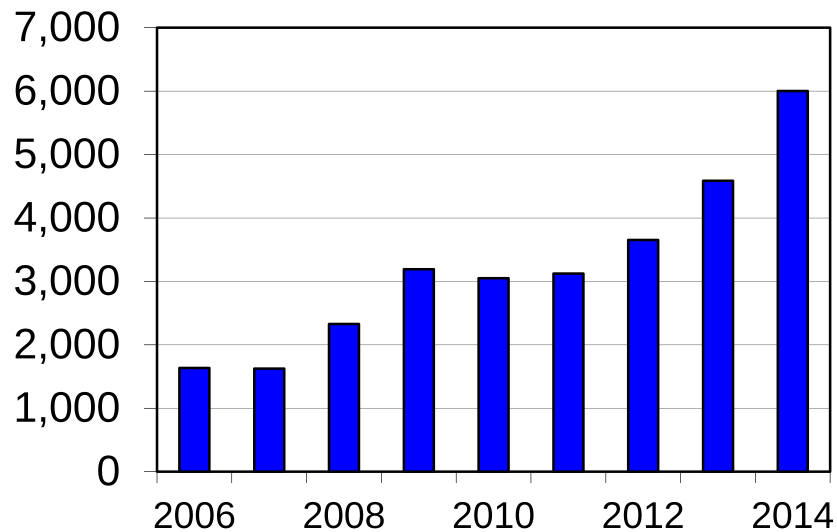
Fayetteville Shale

- Eastern Arkoma Basin – Northern Arkansas
  - Fewer wells are being drilled and average interest is smaller
  - Initial rates have improved 64% since 2012
  - Only 4 wells spud on DMLP acreage in Q1 2015 → All SEECO, 3 wells in single unit

Average NRI of New Wells



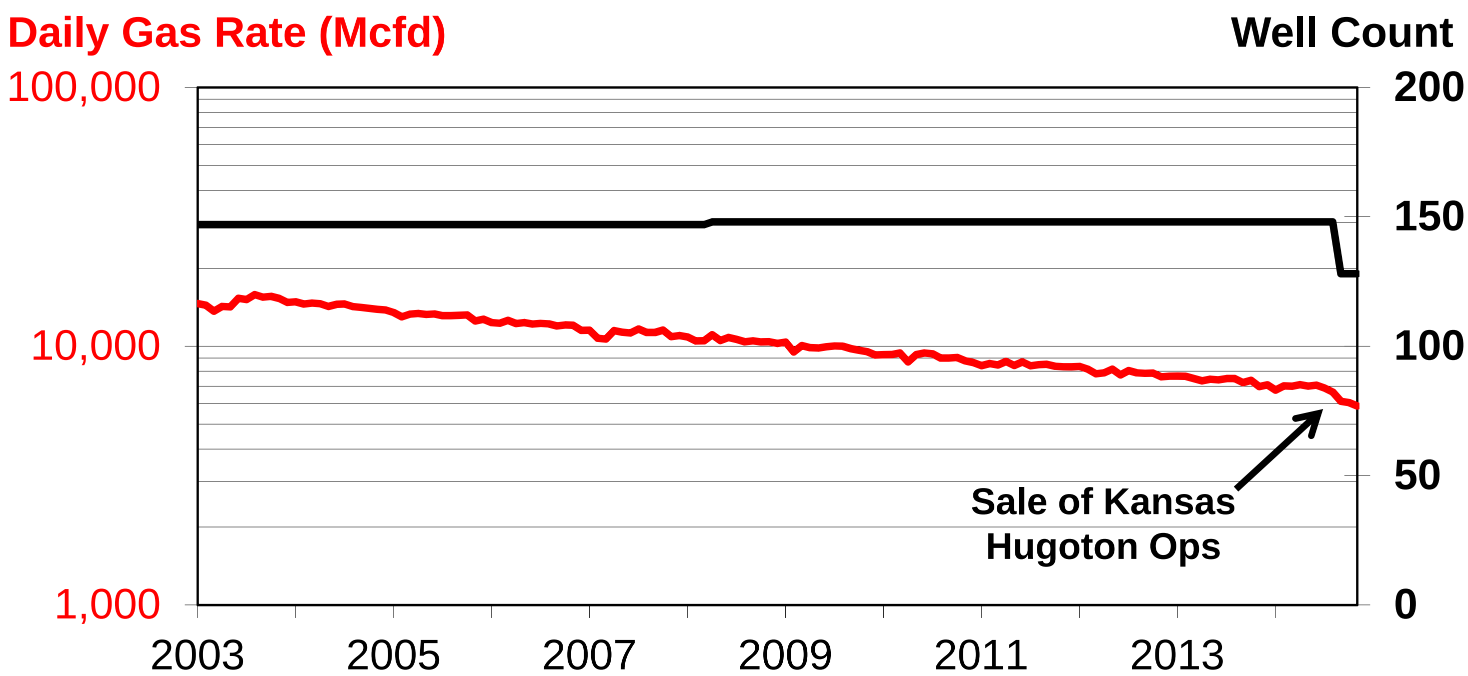
Average Initial Production Rate (Mcfd)



Note: Initial Production Rate as reported to AOGC and limited to wells in which DMLP owns an interest. Average NRI includes NPI and royalty interests.

Hugoton Operated Properties

- Hugoton Field – Oklahoma Panhandle
  - Divested Kansas operations in Sept 2014 – average net sales of 2.8 MMcfd
  - 2014 production within 1.0% of projection
  - Year-over-year production decline of 7.0% with a 1.2% decrease in net reserves
  - Ongoing well optimization and cost-saving initiatives, but limited upside potential



Note: Gas rate based on sales volumes

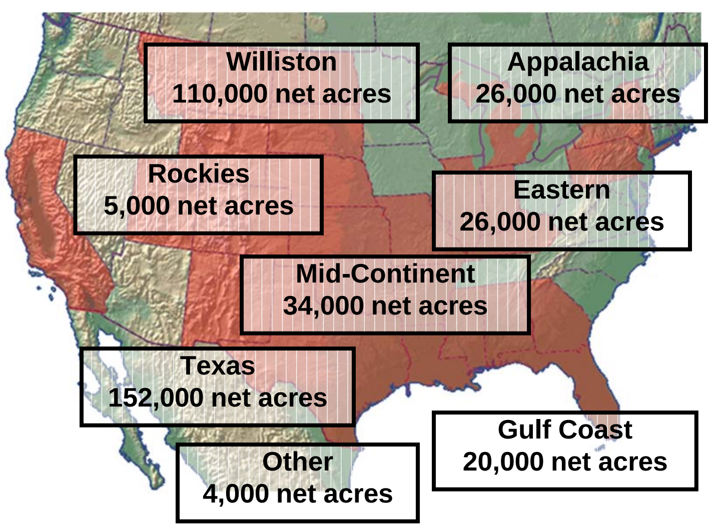
Dorchester Minerals, LP Annual Meeting

May 20, 2015

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 860,000 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

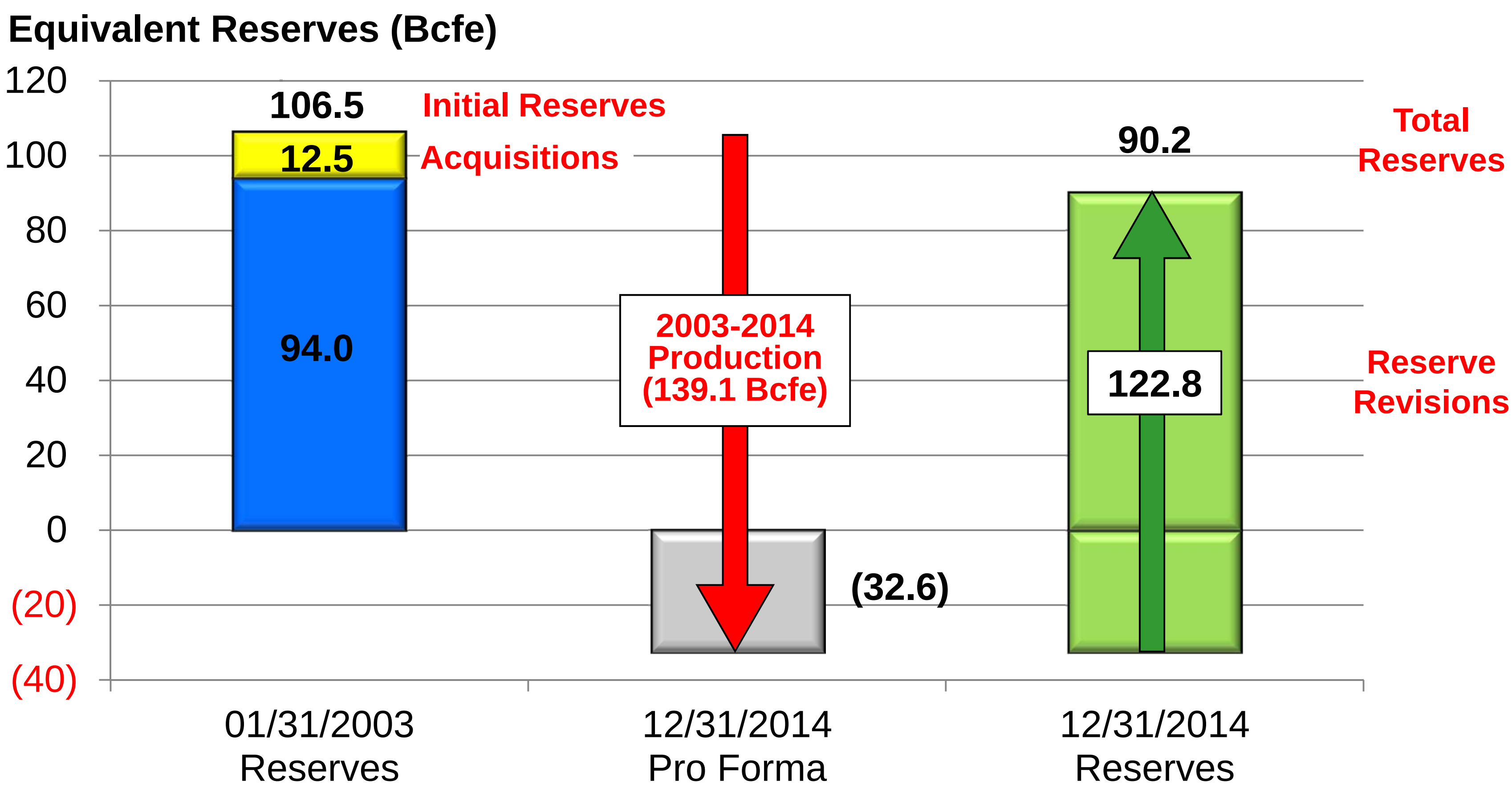


Basin/Area	Legacy Production	Ongoing Development	Expansion Potential
West Texas Southeast NM	Denver Unit Wasson	Wolfberry Bone Springs	Delaware Basin West TX Overthrust
Gulf Coast South Texas	Jeffress McAllen Ranch		Horizontal Wilcox
Mid-Continent	Hugoton	Fayetteville	Horizontal Granite Wash
Williston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

Note: Acreage count as of 12/31/2014. Gross acres are not additive due to overlapping ownership among categories

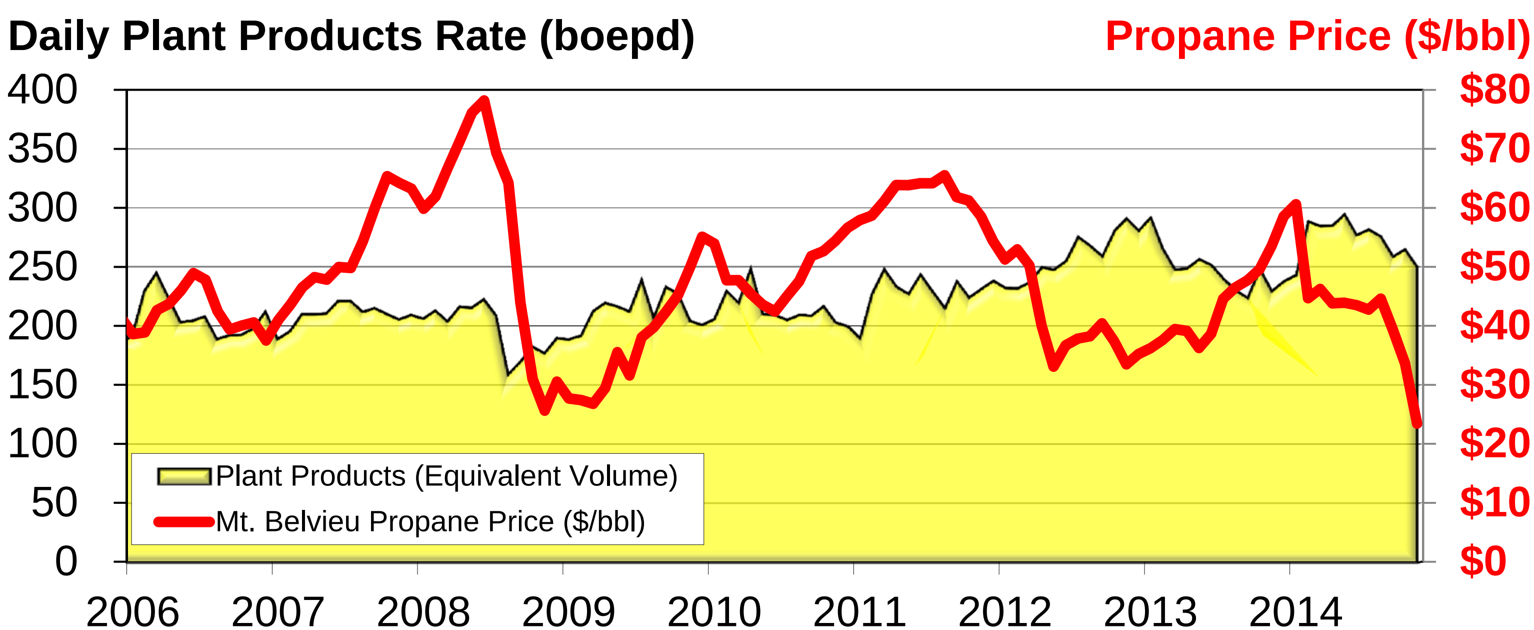
2014 Reserves

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



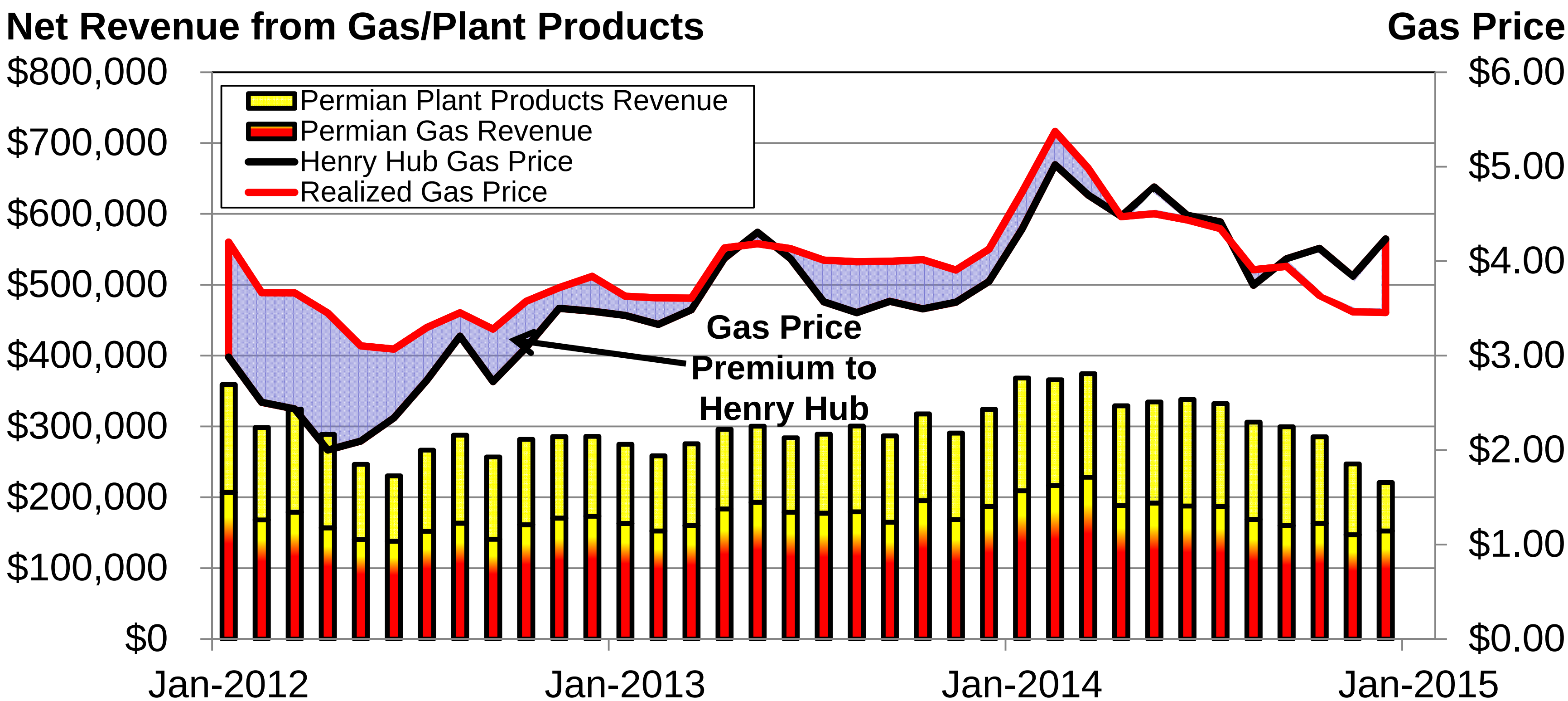
2014 Production

- 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



2014 Production

- Plant Products Example – Permian Royalty
  - Calculated PP Volumes are highly dependent on operators' marketing elections
  - May be reported by operator as a BTU adjustment to natural gas sales price (resulting in a premium to index) or a separate PP volume stream



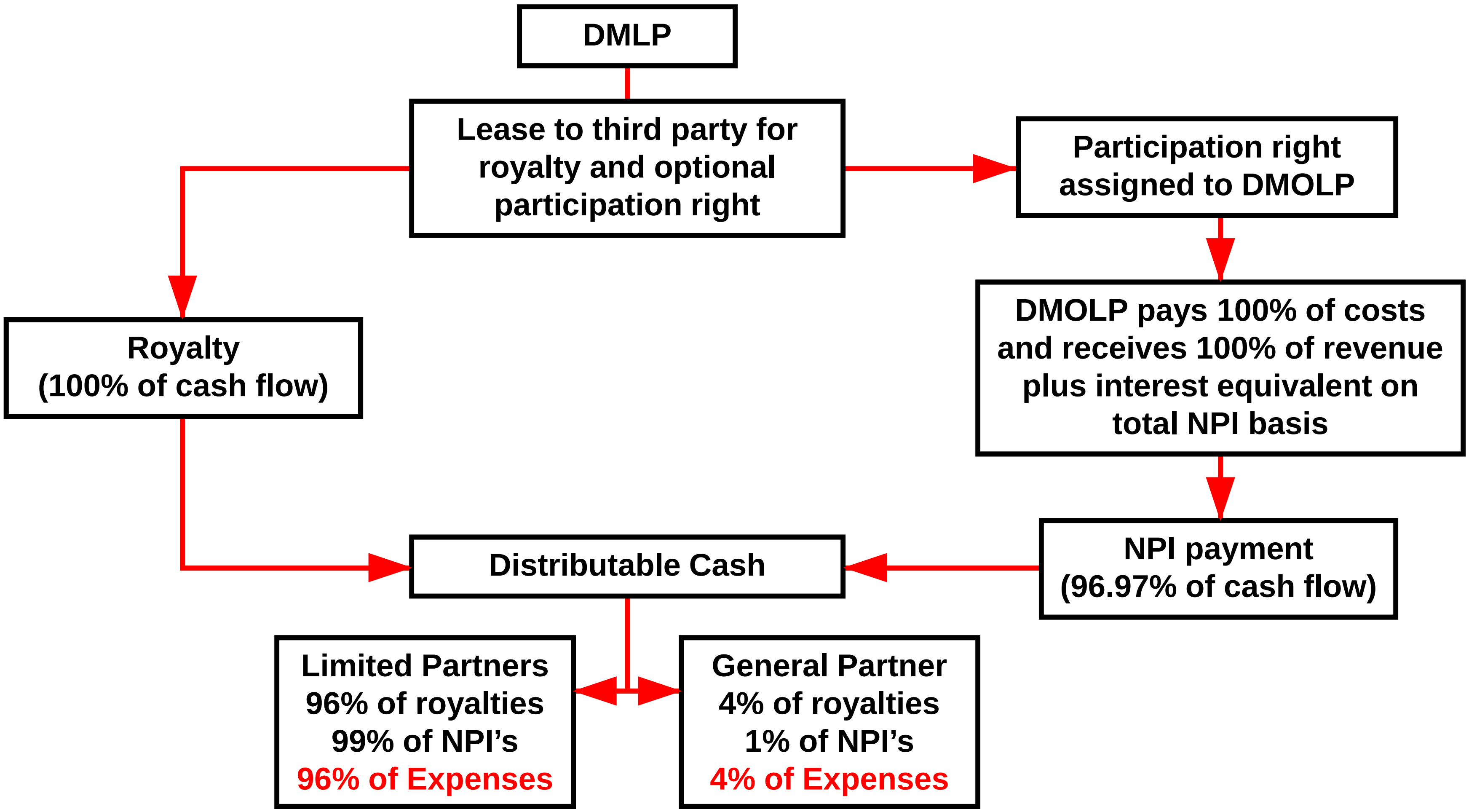
Note: Example excludes all revenue attributable to oil, condensate, and net profits interests

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%.**
  - **The Minerals NPI achieved payout status in September 2011 and contributed to our Q4 2011 distribution.**

Minerals NPI

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



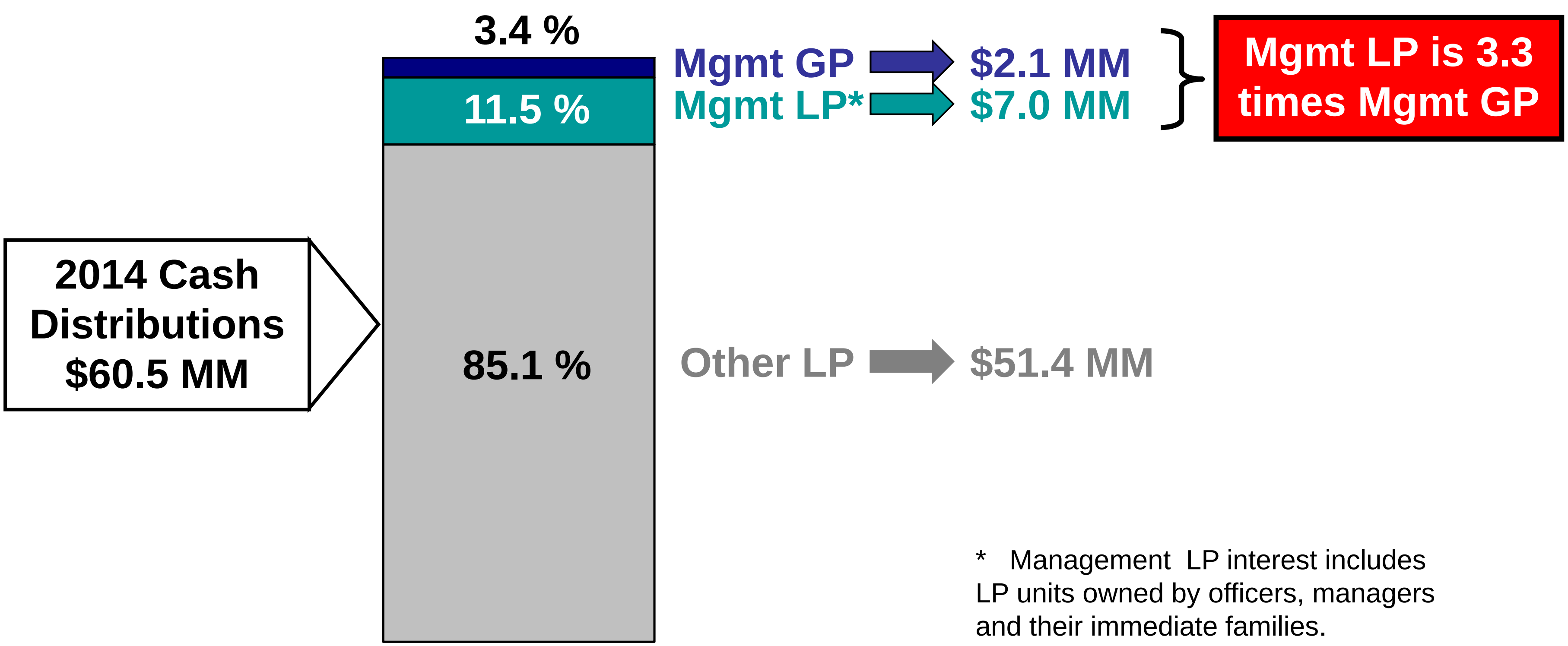
Distributions

- Distribution Determinations
  - Period from October 2013 through September 2014

	($ thousands)	
	Limited Partners	**General Partner**
4% of Net Cash Receipts from Royalty Properties	$ --------	$2,061
96% of Net Cash Receipts from Royalty Properties	$49,474	$ --------
1% of Net Profits Interests Paid to our Partnership	$ --------	$ 90
99% of Net Profits Interests Paid to our Partnership	$ 8,914	$ --------
Total Distributions	**$58,388**	$2,151
Operating Partnership Share (3.03% of Net Proceeds)	$ --------	$ 281
Total General Partner Share		**$2,432**
% Total	**96%**	**4%**

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.

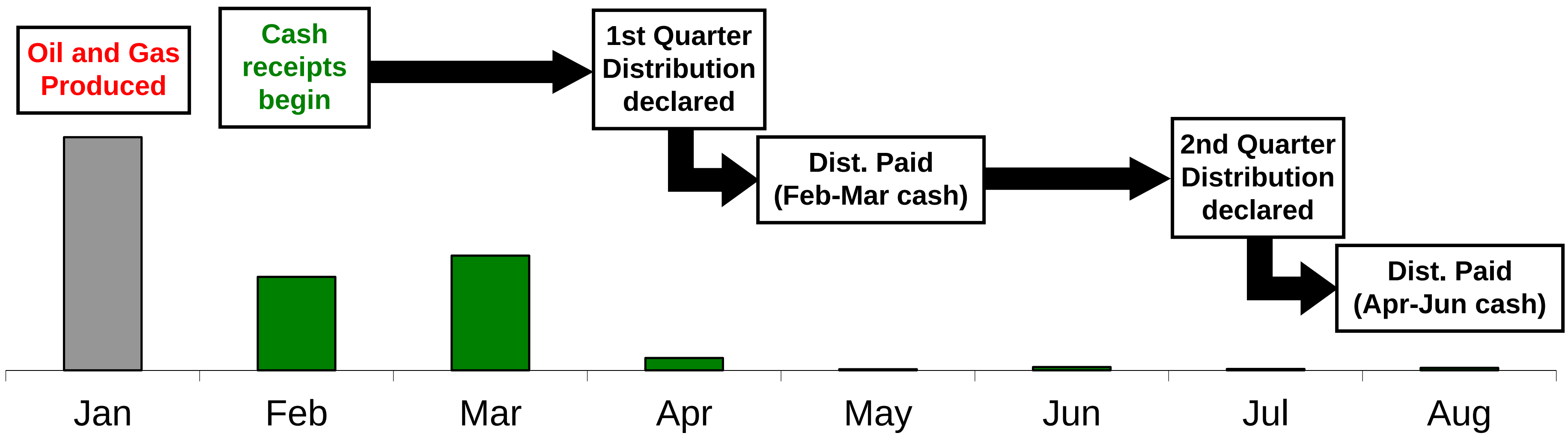
Effects of Operating Leverage

- Royalty Interest vs. NPI

	Royalty Interest	Net Profits Interest
Production Volume	1,000 Mcf	1,000 Mcf
Gas Price	$4.00/Mcf	$4.00/Mcf
Revenue	$4,000	$4,000
Fixed Production Costs	($0)	($1,000)
Operating Income	$4,000	$3,000
Net Interest	25% Royalty	25% NPI
Net Cash Flow	$1,000	$750
25% Increase in Gas Price		
Production Volume	1,000 Mcf	1,000 Mcf
Gas Price	$5.00/Mcf	$5.00/Mcf
Revenue	$5,000	$5,000
Fixed Production Costs	($0)	($1,000)
Operating Income	$5,000	$4,000
Net Interest	25% Royalty	25% NPI
Net Cash Flow	$1,250	$1,000
	25% Increase in Royalty Cash Flow	**33% Increase in NPI Cash Flow**

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 :

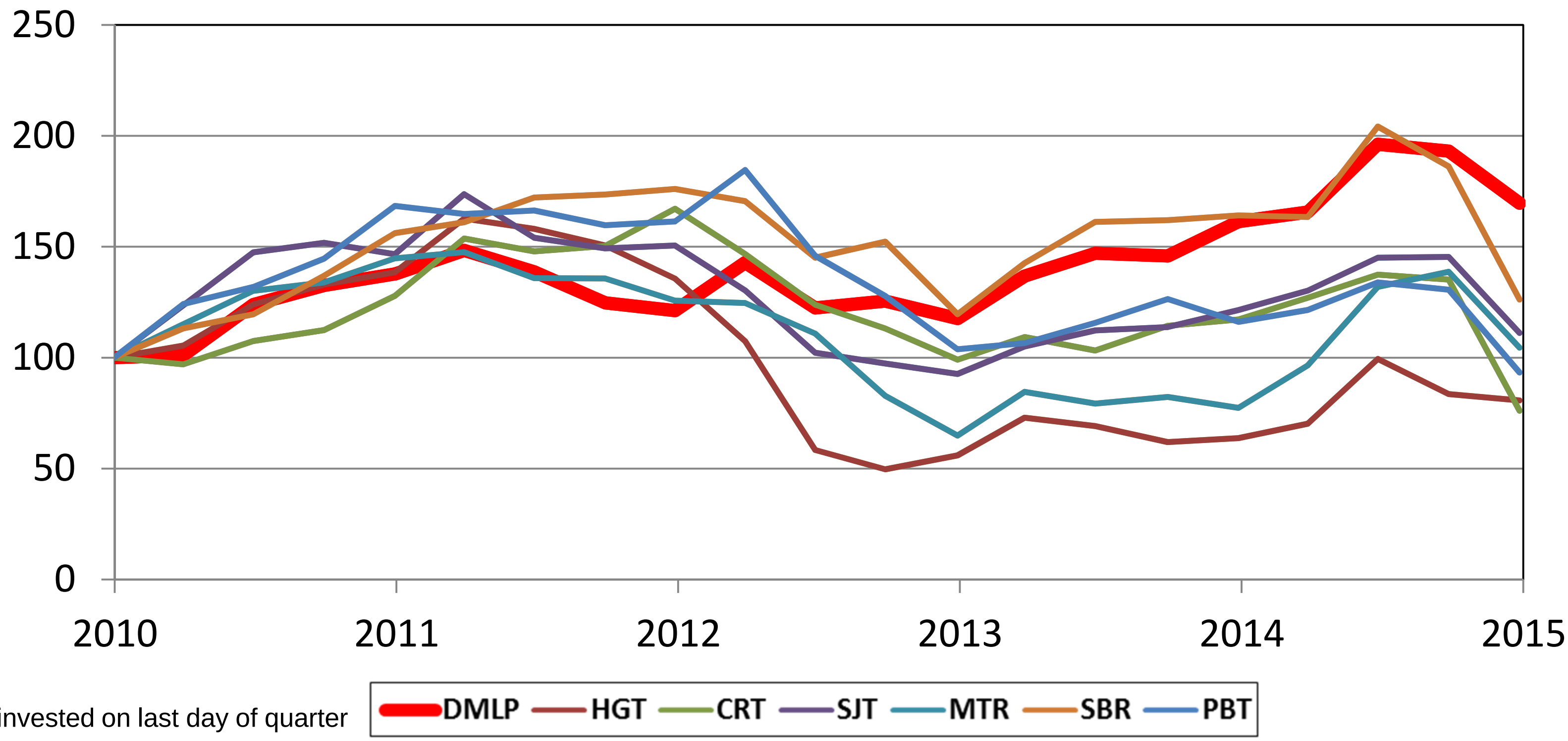


LP distribution of all cash attributable to January production may occur as late as August, a 7-month time lag

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 20, 2015