Dorchester Minerals, LP
Annual Meeting

May 14, 2014

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 2013 Results

Activity → Reserves → Production → Distributions

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2013 Activity

- Decreased activity in dry gas plays
  - Fayetteville Shale and Barnett Shale
- Sustained Bakken activity
  - Transition to infield development and downspacing
- Expanding Permian activity
  - Increased vertical and initial horizontal development
- Evolving strategy in the Minerals NPI
  - Increased working interest participation to capture additional value

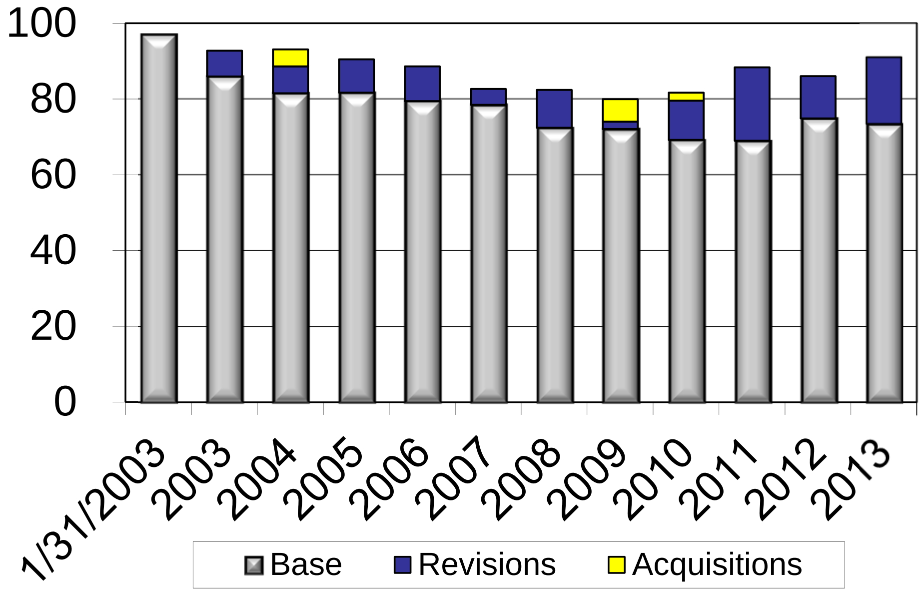
Overview of 2013 Results

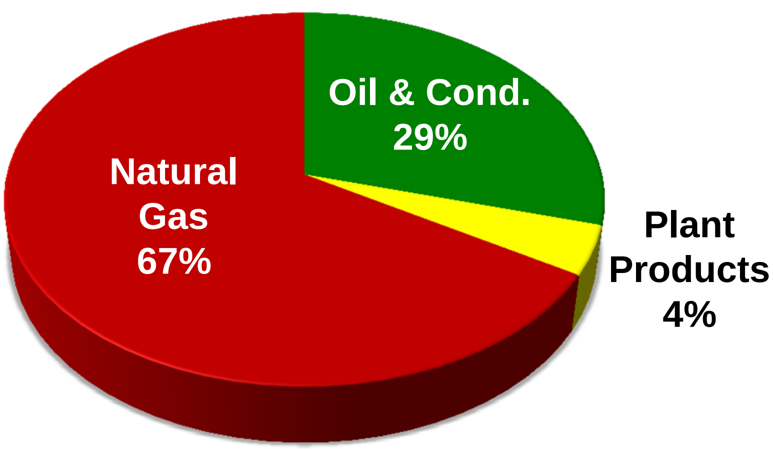
Activity → **Reserves** → Production → Distributions

2013 Reserves

- Total Proved Reserves of 91.0 Bcfe on 12/31/2013
  - All reserves are Proved Developed Producing (PDP)
  - Demonstrated history of positive revisions
  - Cumulative revisions since inception account for 117% of total reserves at year-end
  - Driving factors including new plays, field extensions, infill drilling, and new technology

Year-end Reserves (Bcfe)

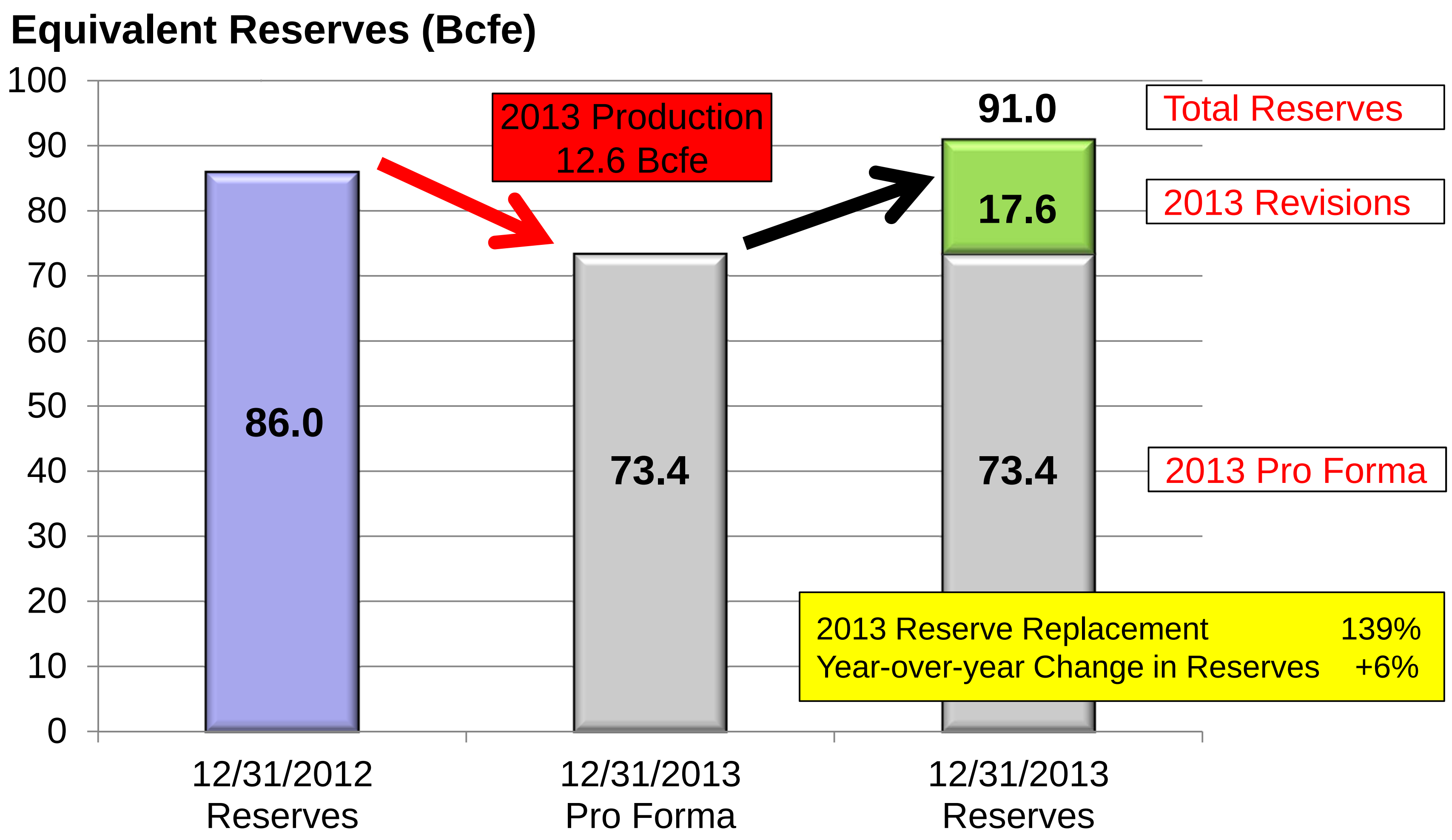




Note: 12.5 Bcfe of acquired reserves at time transactions closed. Gas-Oil equivalency of 6:1 ratio is used throughout this presentation

2013 Reserves

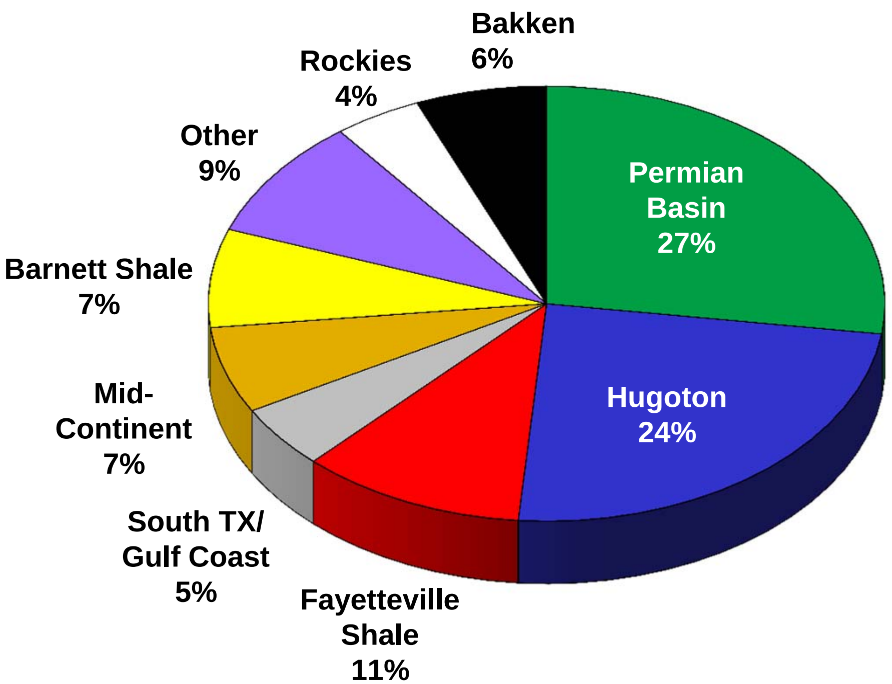
- Revisions to Reported PDP Reserves



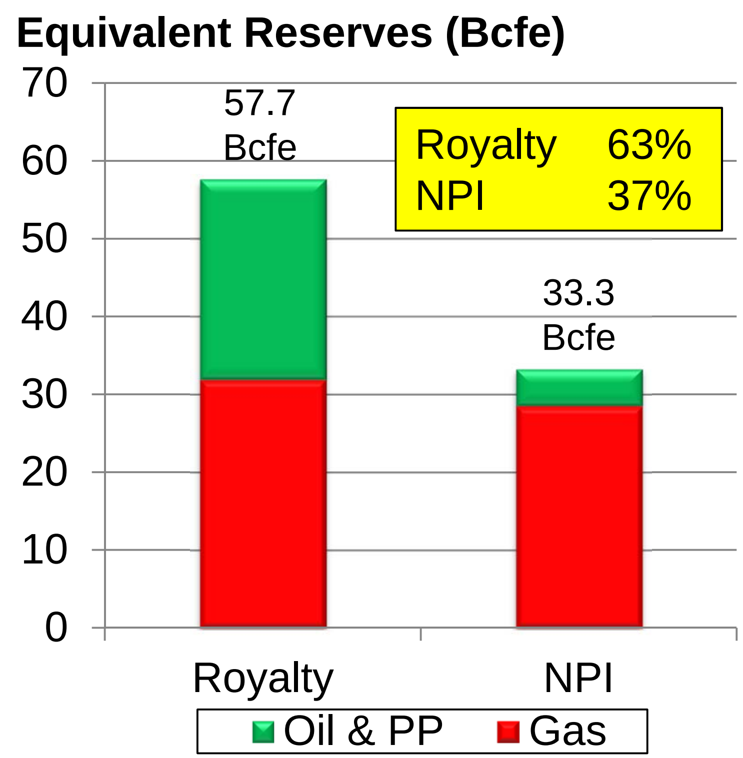
2013 Reserves

- Composition of Proved Reserves

Geographic Breakdown



Royalty-NPI Split



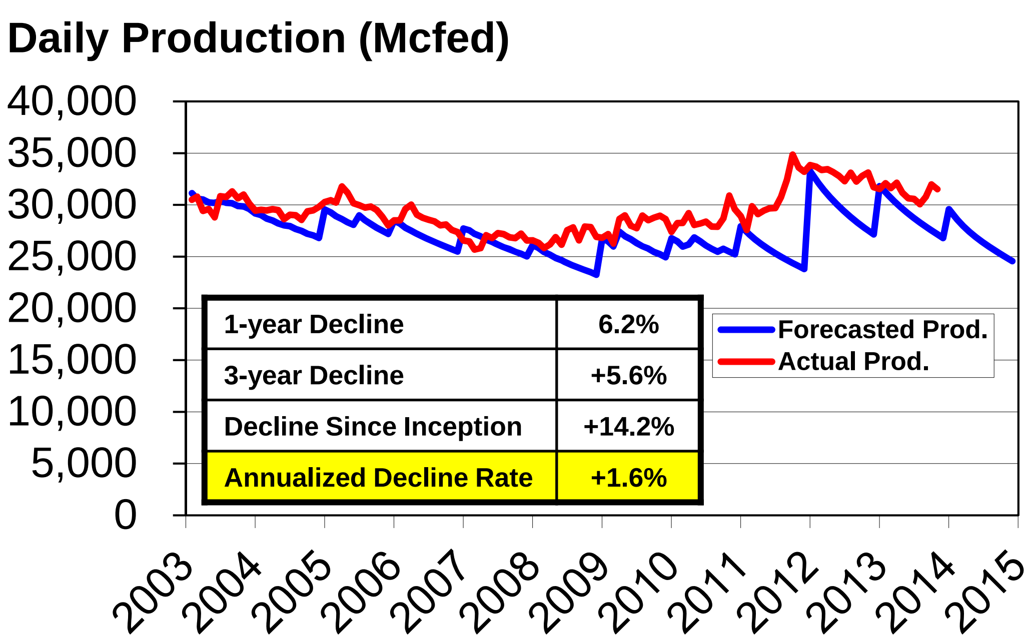
Overview of 2013 Results

Activity → Reserves → **Production** → Distributions

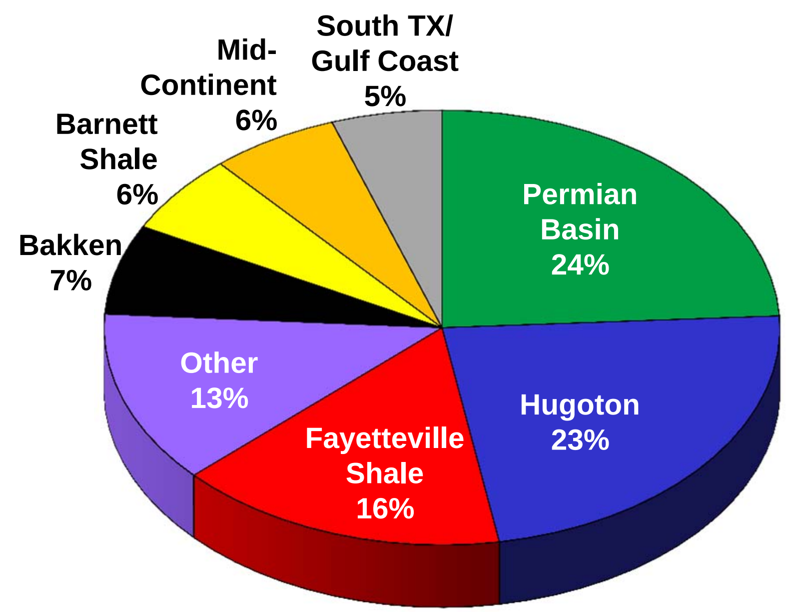
2013 Production

- Total Production of 12.6 Bcfe
  - 75% of total production was natural gas, 25% oil, condensate and NGLs
  - High quality properties + Diverse portfolio → Low decline rate

Historical Production



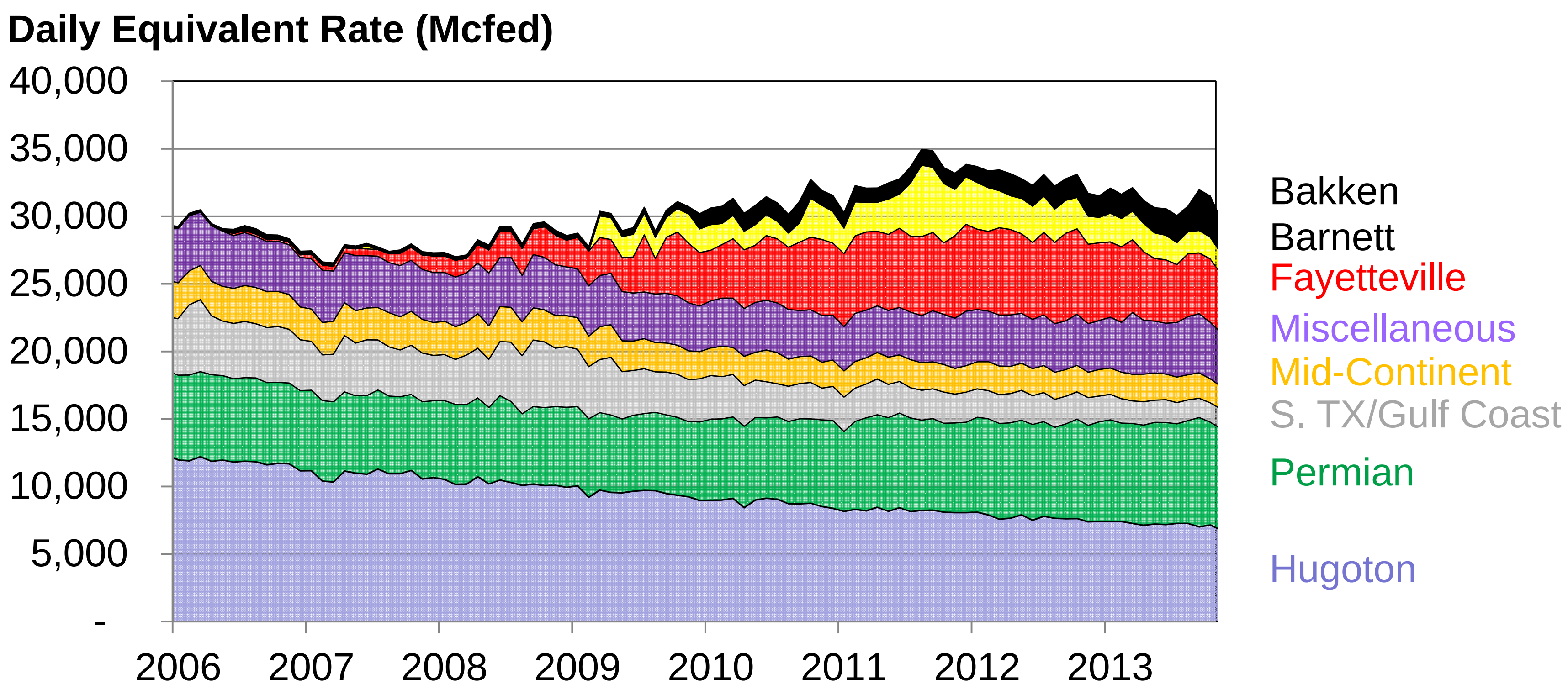
Geographic Breakdown



Note: Total production on wellhead basis, daily production on sales basis. Minerals NPI production/reserves included beginning Oct 2011.

2013 Production

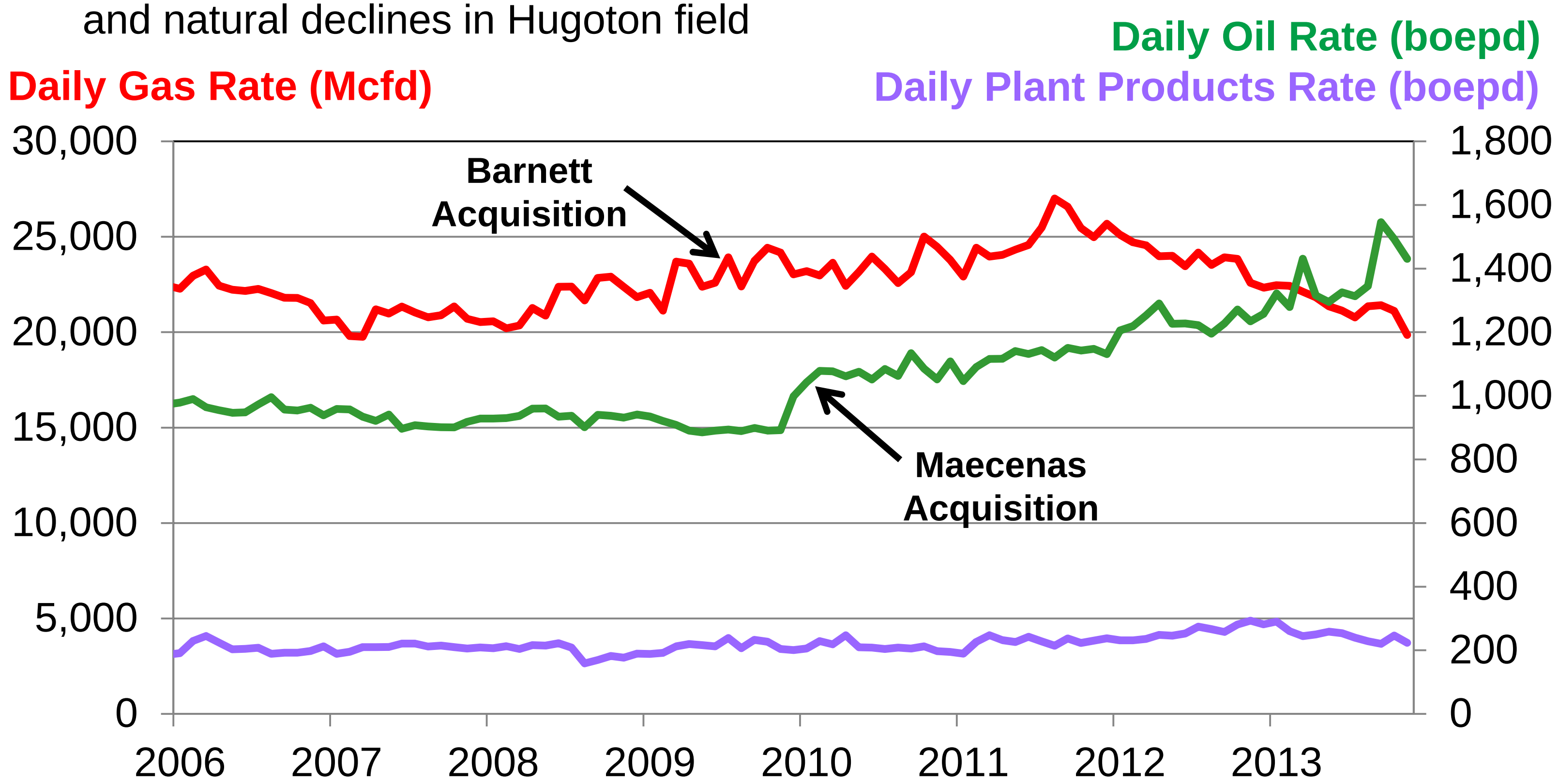
- Diverse Sources of Production
  - New plays have replaced declines in legacy assets
  - Opportunities for production growth in mature basins



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

2013 Production

- Components of Production
  - Oil production has increased due to robust Bakken and Permian activity
  - Gas production has decreased due to reduced Barnett and Fayetteville activity and natural declines in Hugoton field



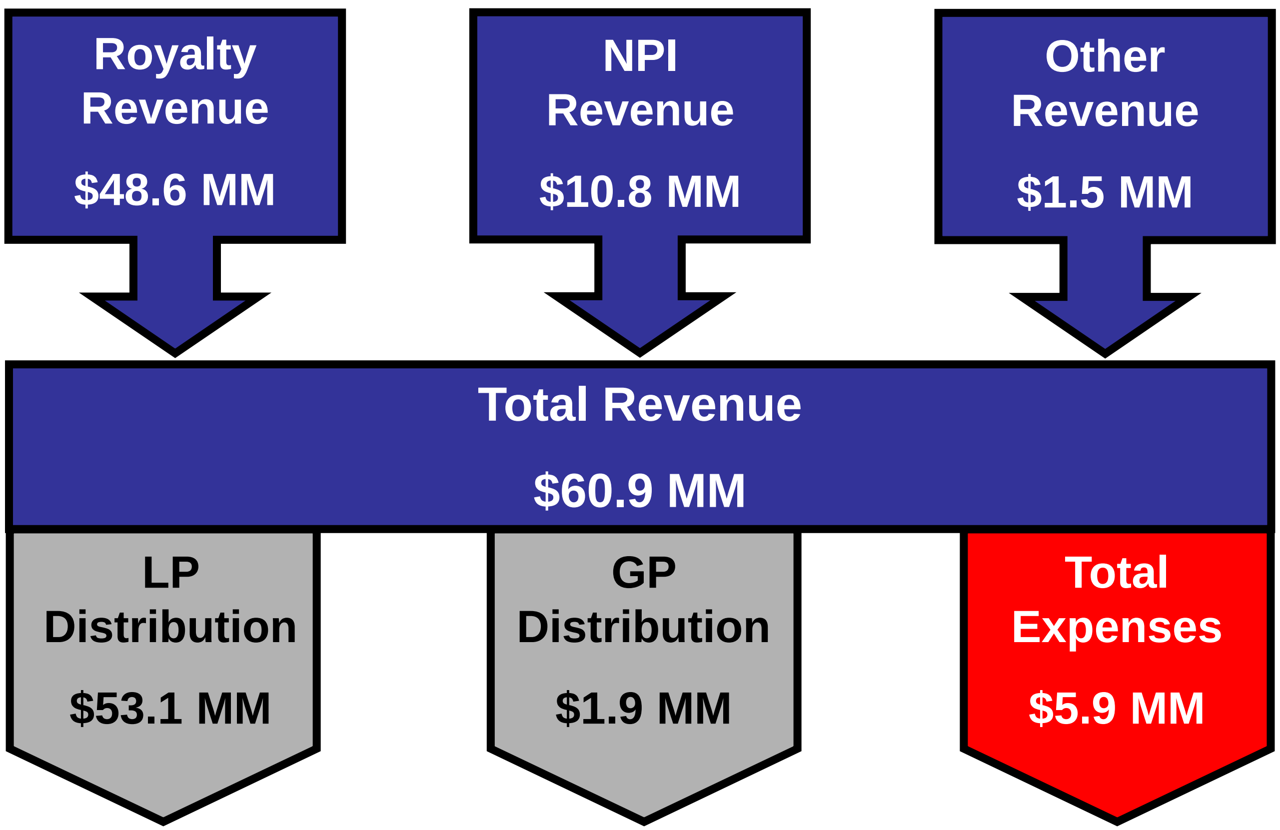
Note: Plant Product volumes are calculated from Plant Products revenue based on Mt. Belvieu propane prices.

Overview of 2013 Results

Activity → Reserves → Production → **Distributions**

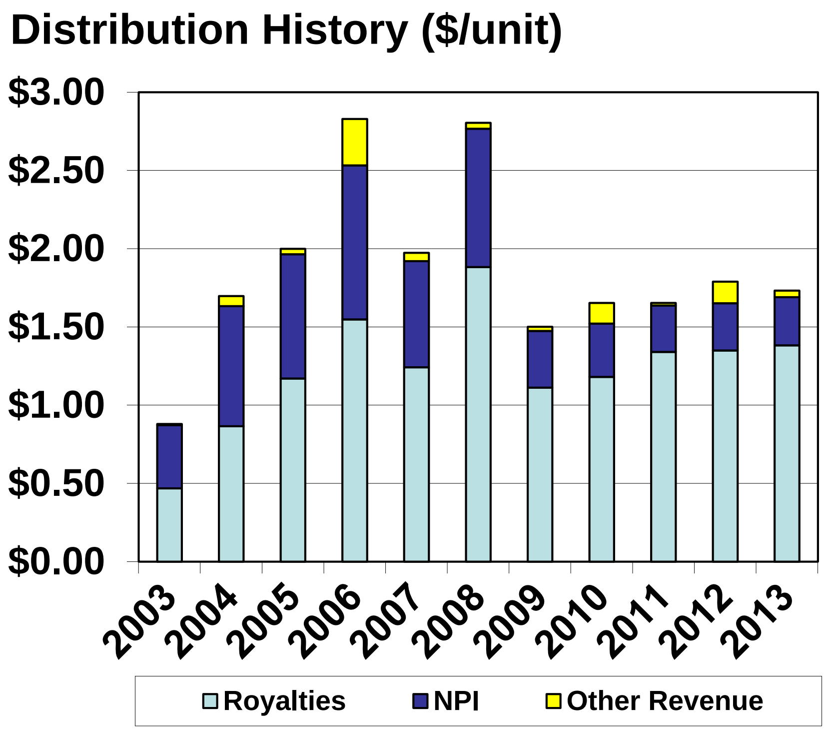
2013 Distributions

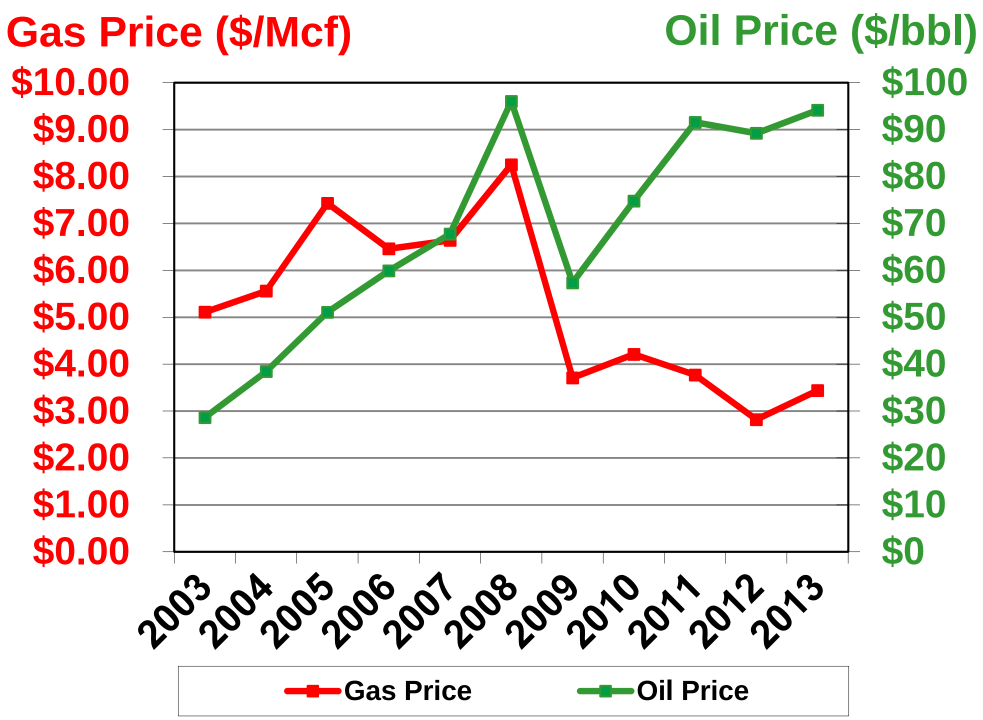
- Cash Distributions Paid in Calendar 2013
  - Reflects Q4 2012 to Q3 2013 activity



2013 Distributions

- Distribution Components and Prices
  - Royalty properties contributed 78% to total 2013 distributions
  - Gross Revenue → 26% gas sales, 70% oil & NGL sales, 4% other revenue
  - Relative contributions from NPI's has decreased → gas weighted, CAPEX exposure





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

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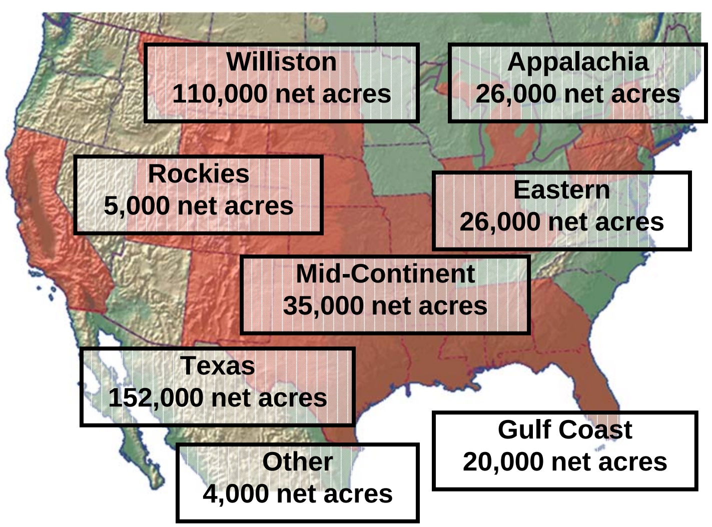
Appendix

Portfolio Overview

- Geographically Diverse – 574 counties in 25 states
  - 378,000 net mineral acres (2,308,000 gross acres)
  - Varying NPRI's, ORRI's and leasehold interests in an additional 860,000 gross acres
  - Majority of acreage is undeveloped
  - Wide geographic spread including most major producing basins
  - Assets range from mature legacy production to areas with exploratory potential

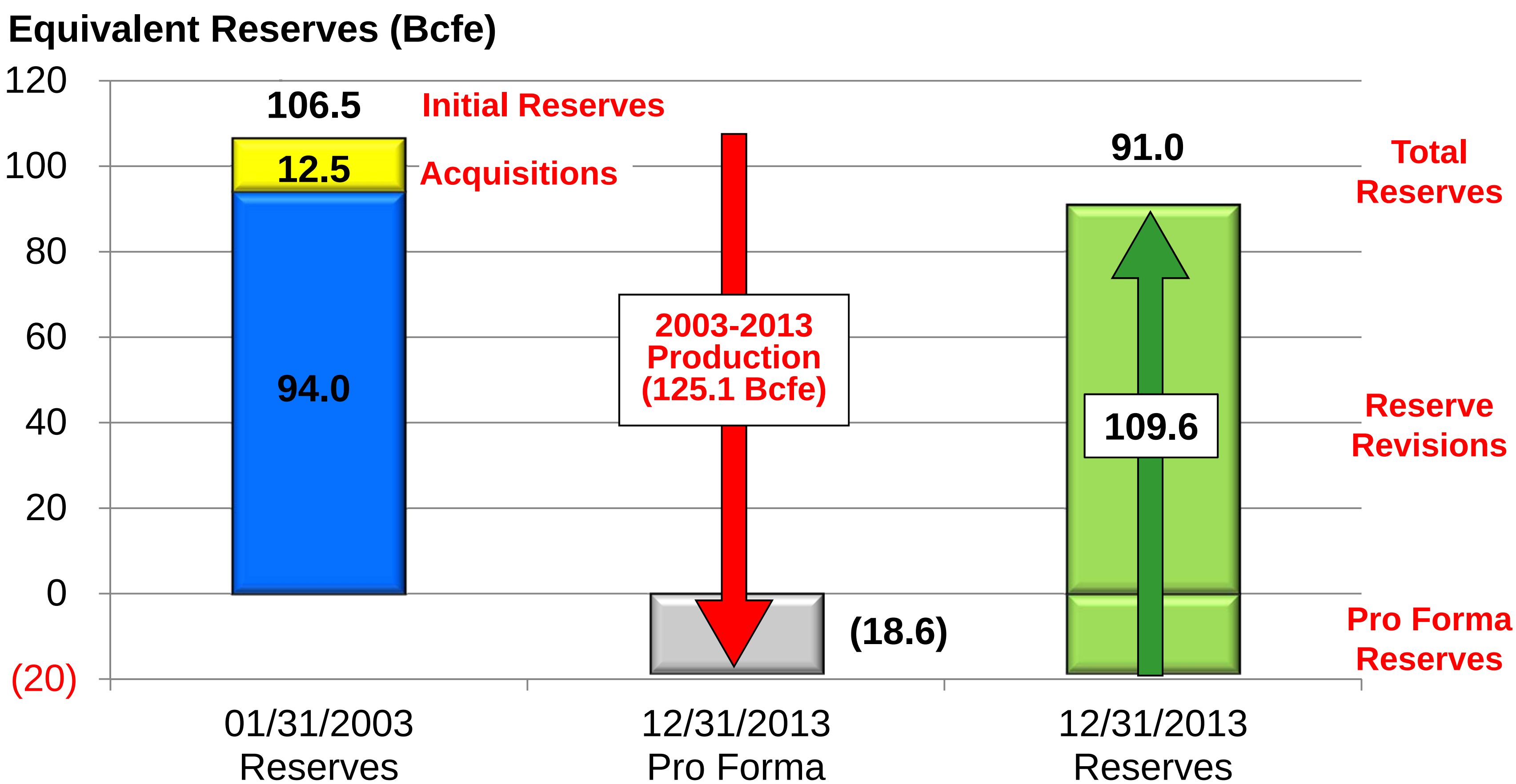


Basin/Area	Legacy Production	Ongoing Development	Expansion Potential
West Texas Southeast NM	Denver Unit Wasson	Wolfberry Bone Springs	Delaware Basin West TX Overthrust
Gulf Coast South Texas	Jeffress McAllen Ranch		Horizontal Wilcox
Mid-Continent	Hugoton	Fayetteville	Horizontal Granite Wash
Williston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

Note: Acreage count as of 12/31/2013. Gross acres are not additive due to overlapping ownership among categories

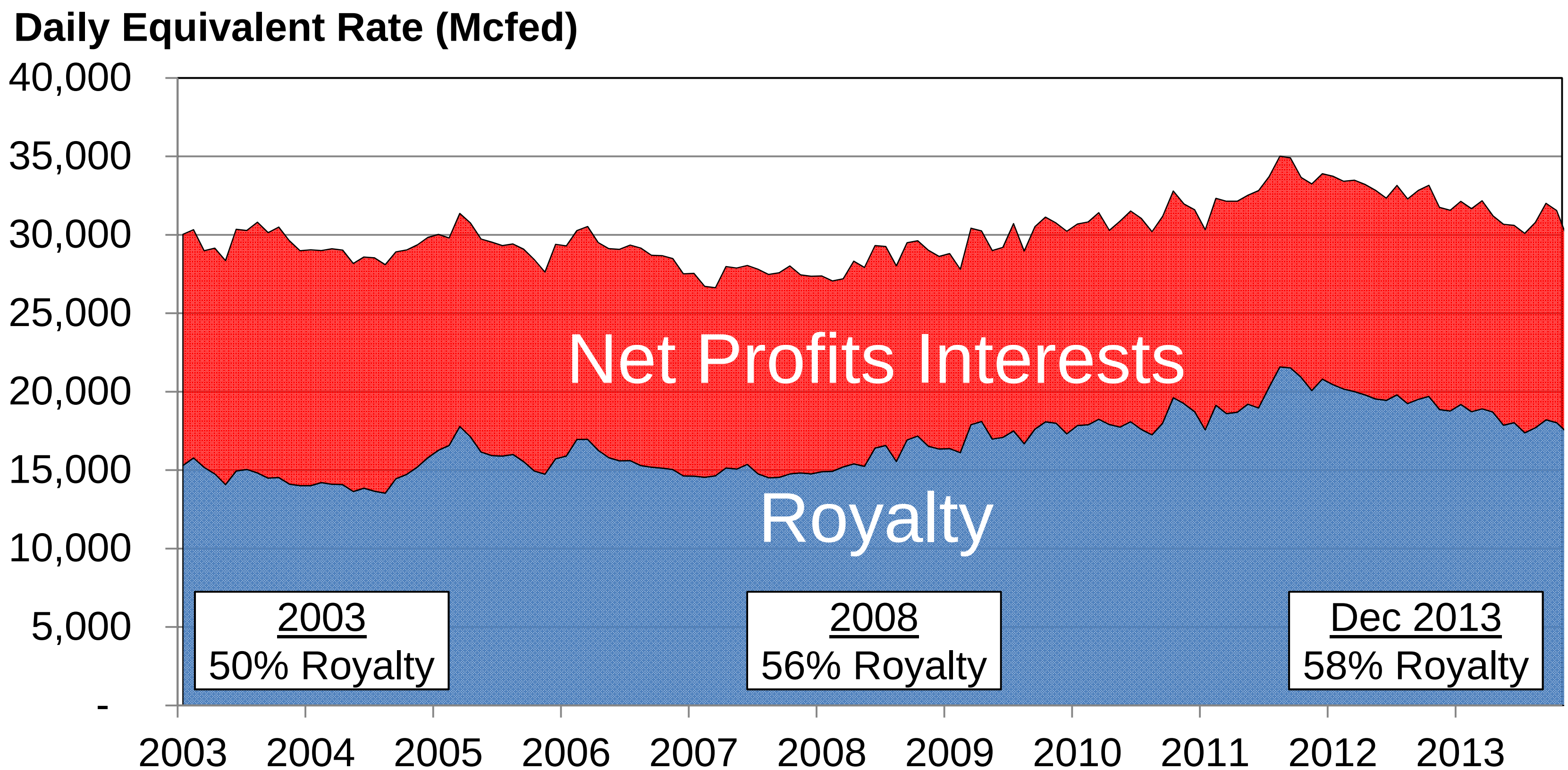
2013 Reserves

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



2013 Production

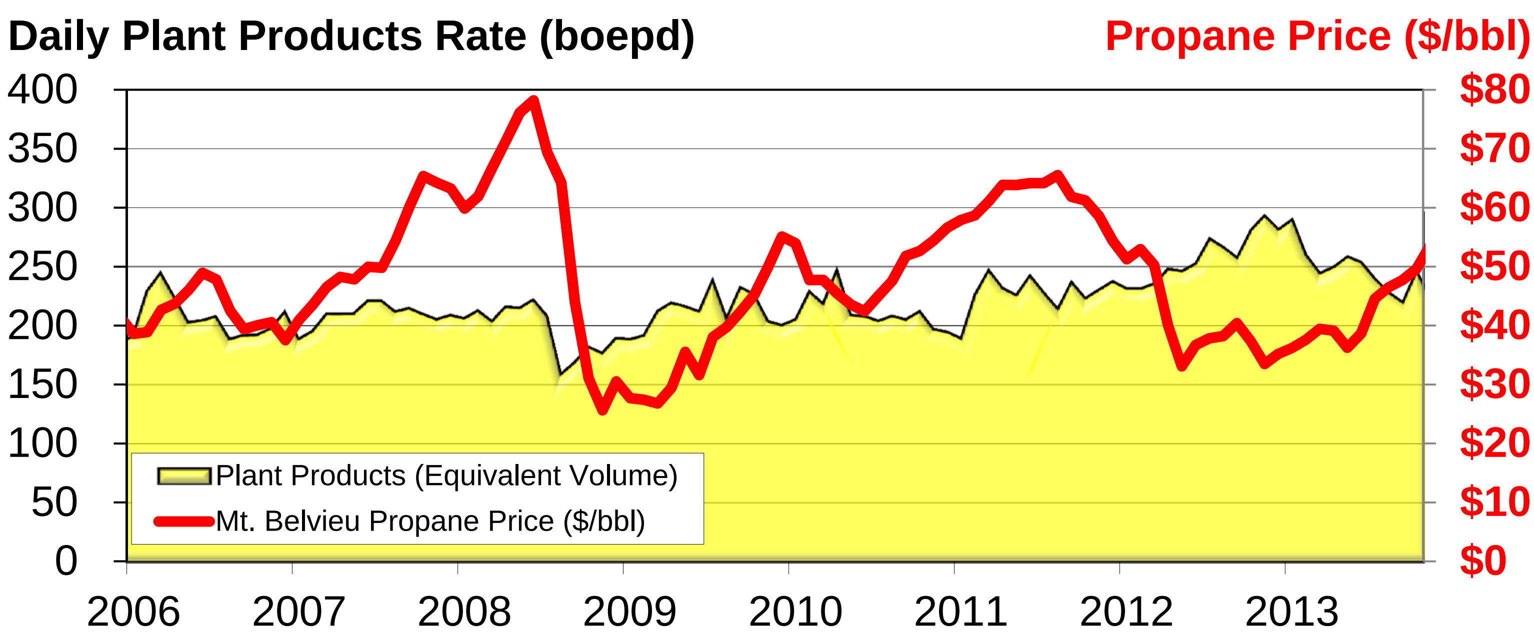
- Portfolio Has Shifted Toward Royalties
  - Largely due to mineral acquisitions, new drilling on legacy properties, and natural declines in Hugoton field → But the trend is reversing



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

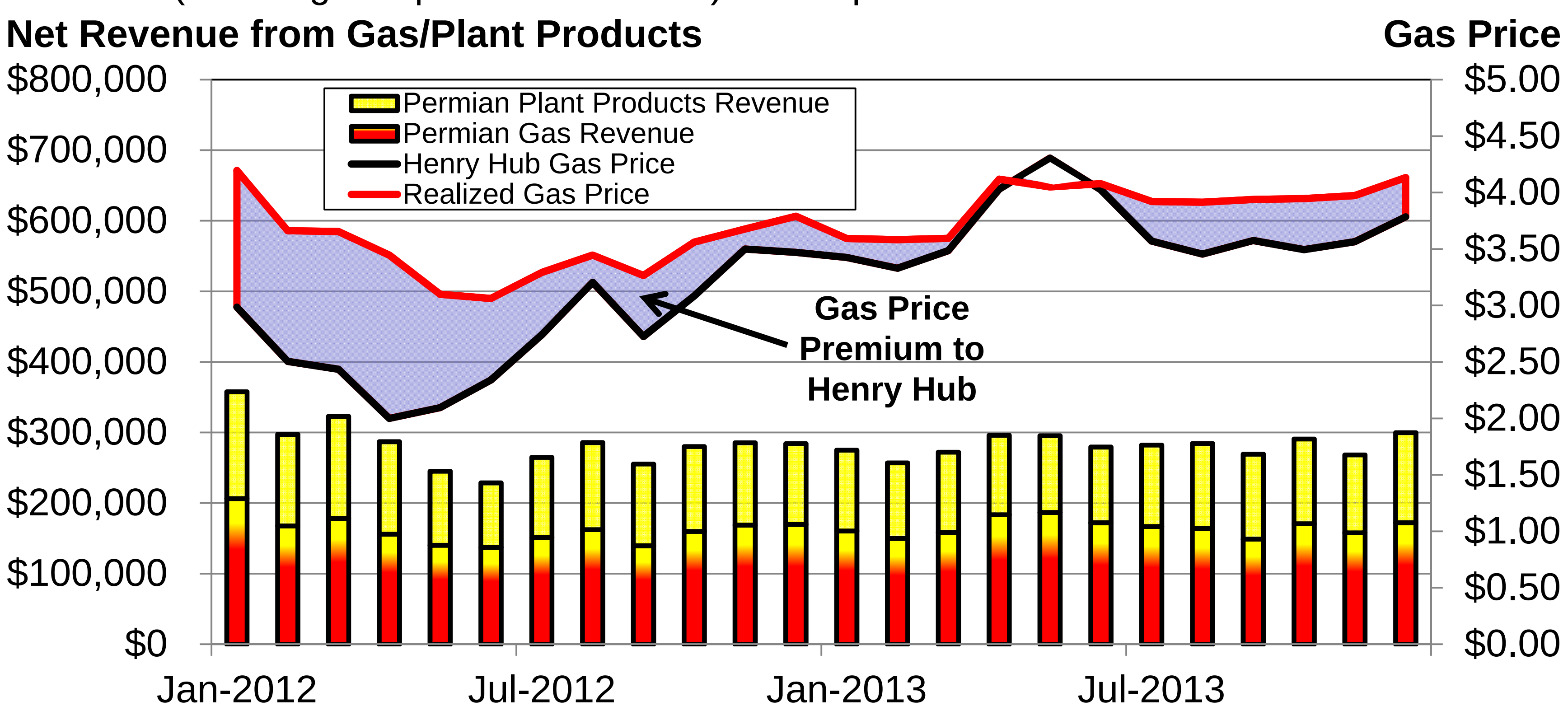
2013 Production

- 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



2013 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

Royalty Overview

- Leasing and Development Activity
  - Consummated 33 leases in 21 counties/ parishes in six states
  - Lease bonus payments up to $5,500/acre
  - Initial royalty terms up to 25%
  - Identified 503 new wells on royalty properties in ten states
  - Fayetteville Shale activity decreased in 2013
  - The price disparity between oil and gas has redistributed activity
    - Low gas prices → significant reduction of activity on gas assets
    - High oil prices → increased infill drilling and redevelopment on oil assets
  - 88 active lease offers as of May 2014

Note: New well count based on division orders and initial revenue payments received in 2013

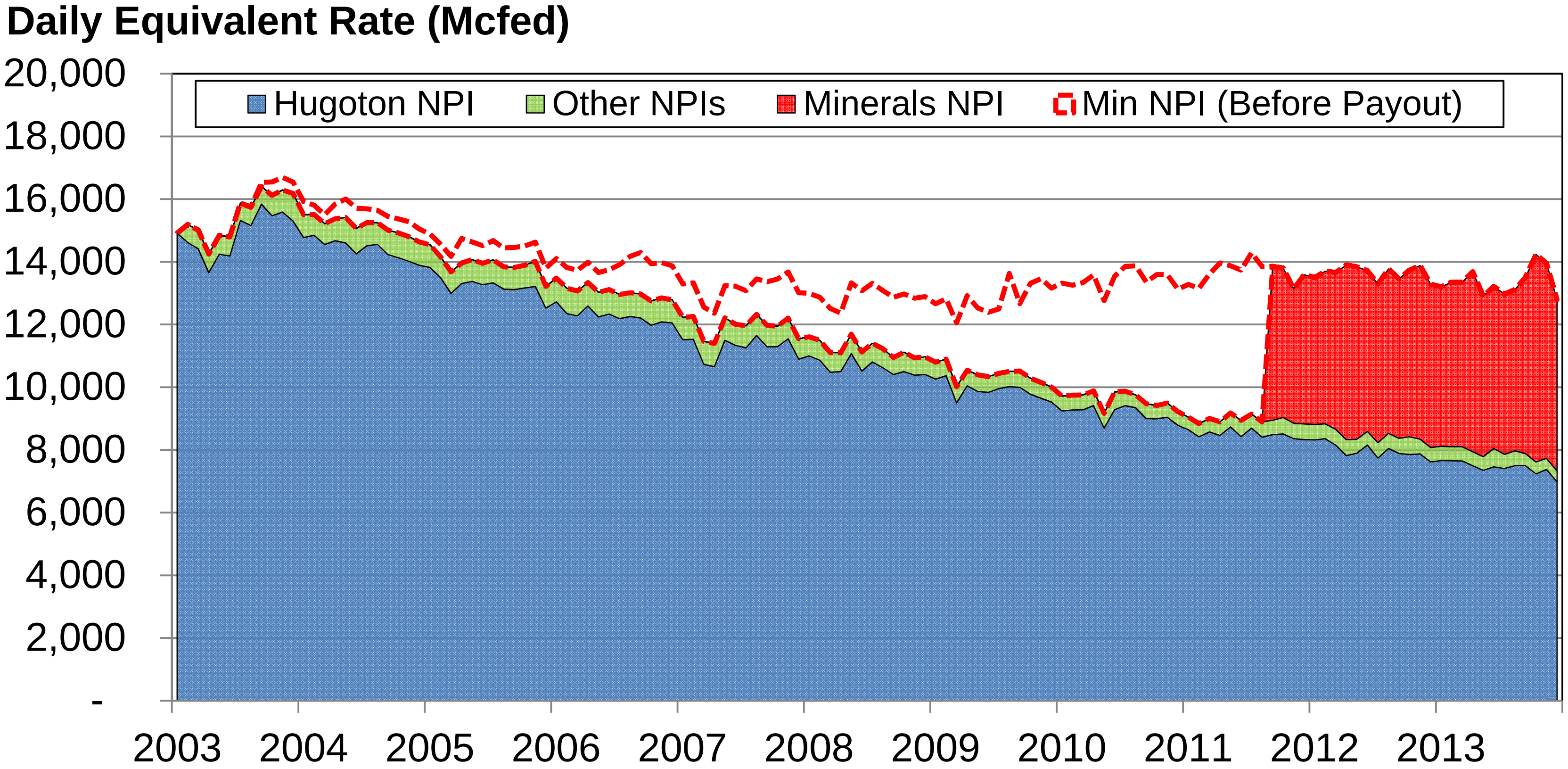
Net Profits Interests Overview

- NPI Provides Exposure to Working Interest Potential Without Generating UBTI
  - Four NPI groups were created at the time of formation in 2003 and two additional NPI groups created subsequently
  - Capitalize on strong negotiating position to capture additional value
  - Leverage information franchise
  - Optional working interest participation in numerous leases
  - Minerals NPI represents the majority of new development activity
  - Added 79 new wells located in Arkansas, Mississippi, Montana, North Dakota, Oklahoma and Texas

Note: New well count based on division orders and initial revenue payments received in 2013

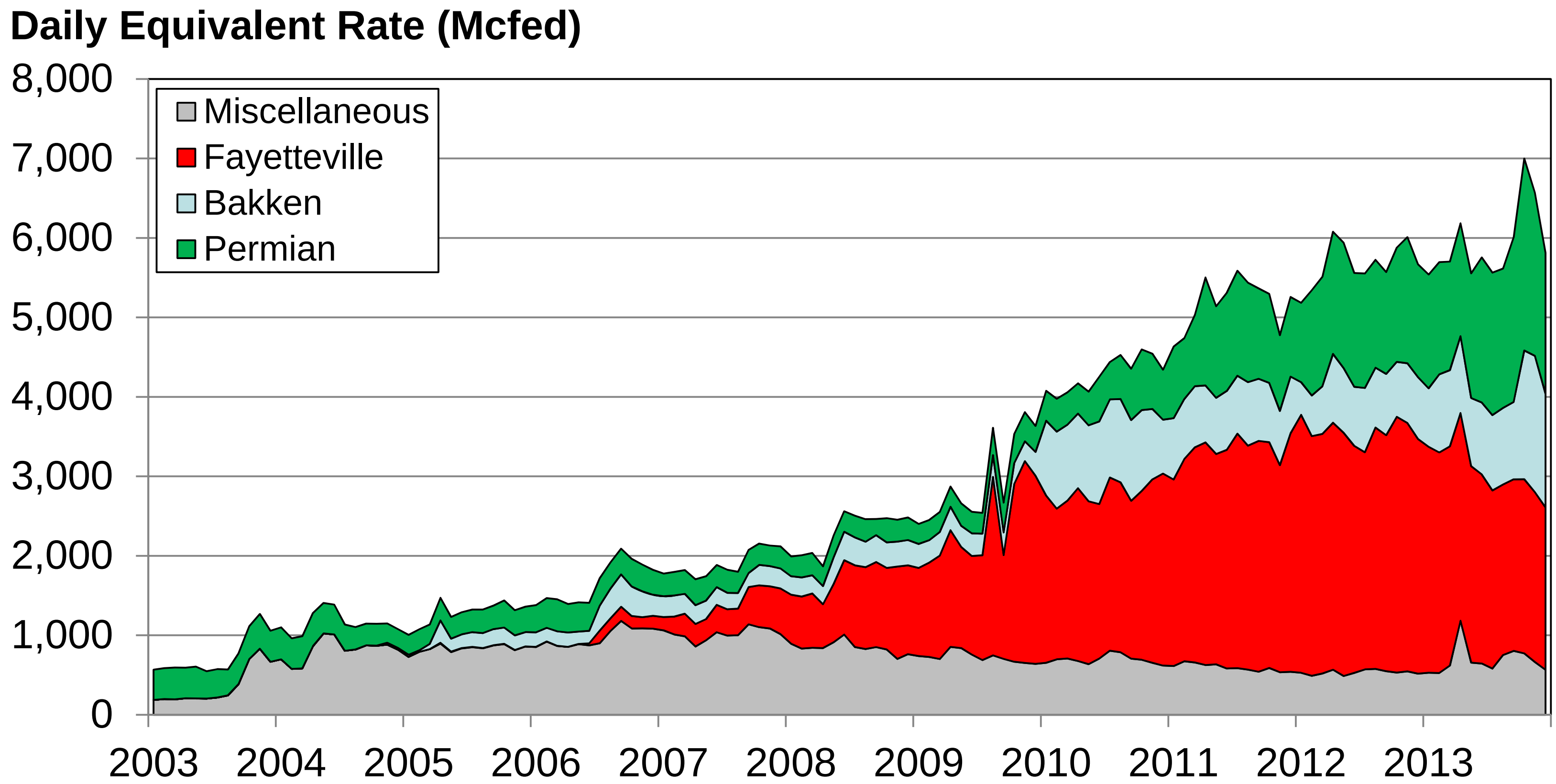
Net Profits Interests Production

- Relative contribution of NPI's has shifted over time
  - Hugoton accounted for 96% of NPI production at inception → 53% in Q4 2013
  - Minerals NPI volumes prior to Q3 2011 were not included in DMLP results



Net Profits Interests Production

- Non-Hugoton NPI Production
  - New Areas: MT Bakken (2005), Fayetteville (2006), ND Bakken (2008), Permian (2010)
  - Additional participation opportunities in West Texas and Bakken



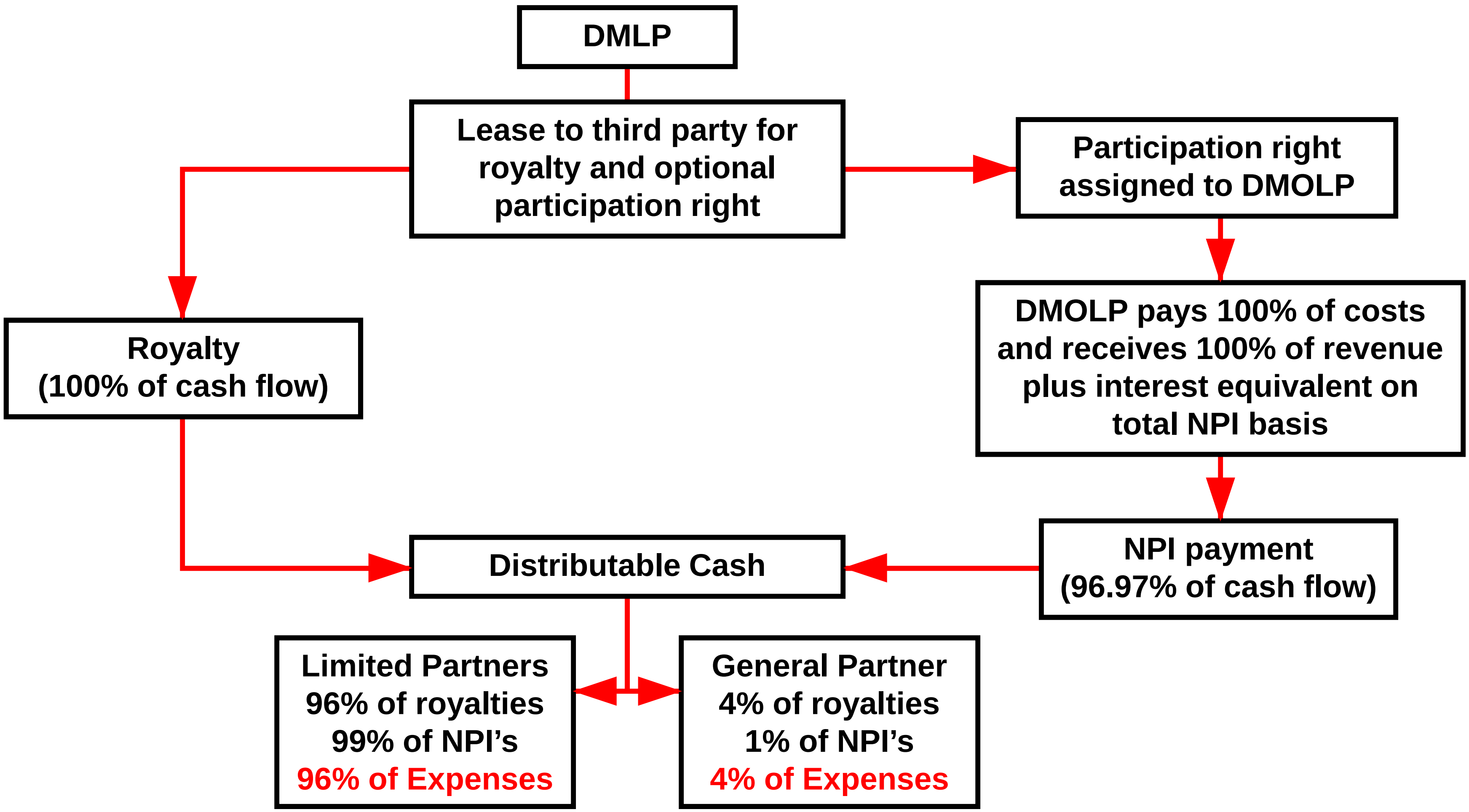
Note: Includes pre-payout Minerals NPI production volumes

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?

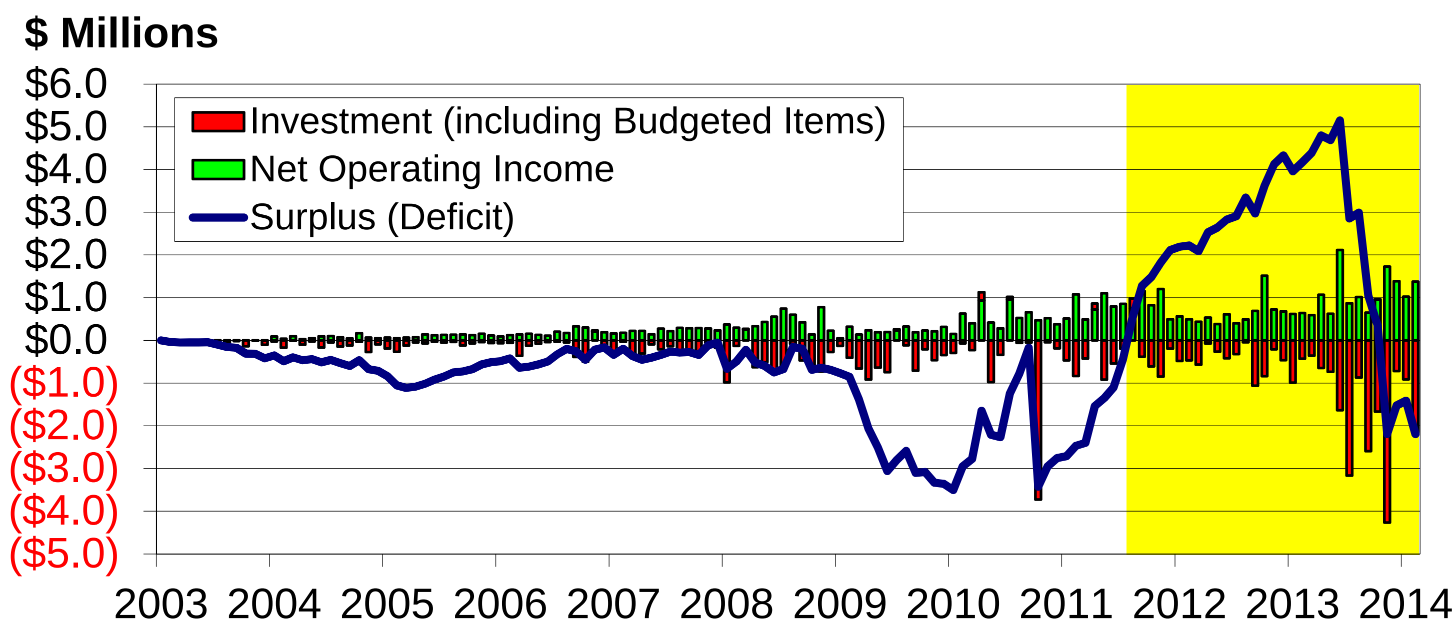


Minerals NPI

- Minerals NPI Cash Flow – Inception through Q1 2014

Cumulative Revenue	$67.5 MM
Cumulative Expense (LOE, taxes, etc)	($14.0 MM)
Cumulative Operating Income	$53.5 MM
Cumulative Investment/Commitments	($55.4 MM)
Cumulative Surplus (Deficit)	($1.9 MM)

$5.4 MM Distributed
$39.0 MM Invested
$16.4 MM Committed

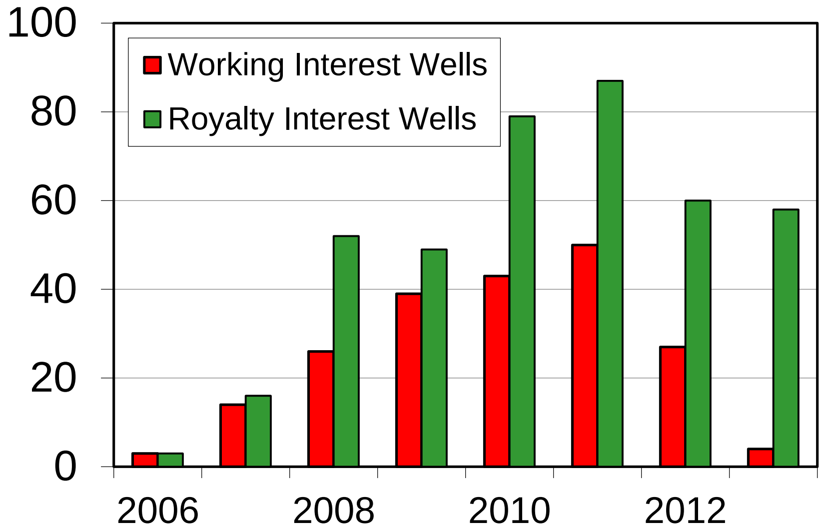


Note: Figures provide on a cash basis. Includes Maecenas NPI which was combined with Minerals NPI effective 01/01/2013.

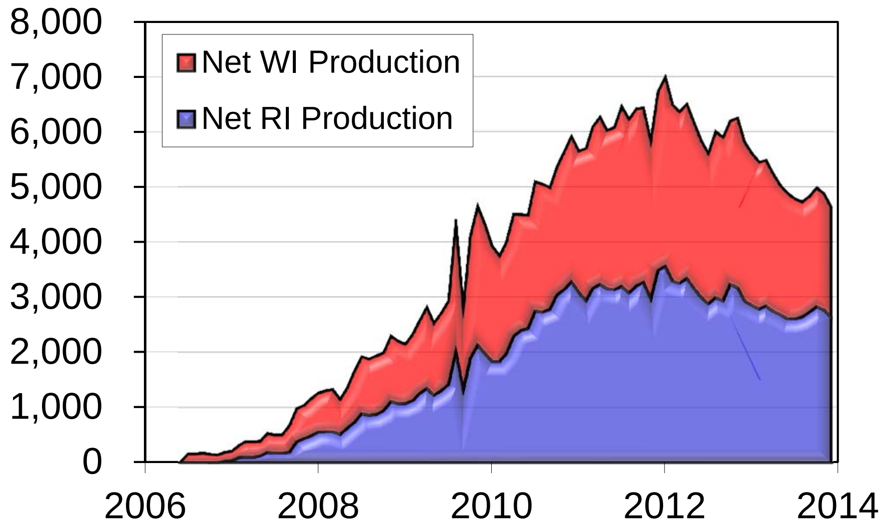
Fayetteville Shale

- Eastern Arkoma Basin – Northern Arkansas
  - DMLP owns 23,336 gross/11,464 net acres in 196 sections
  - 403 wells producing 4.6 MMcfd at year-end 2013 → 45% from Working Interests
  - Production has decreased as a result of decreased activity
  - 136 total wells permitted in field in Q1 2014 → Seeco (125), XTO (10), BHP (1)

Well Count



Net Daily Production (Mcfd)

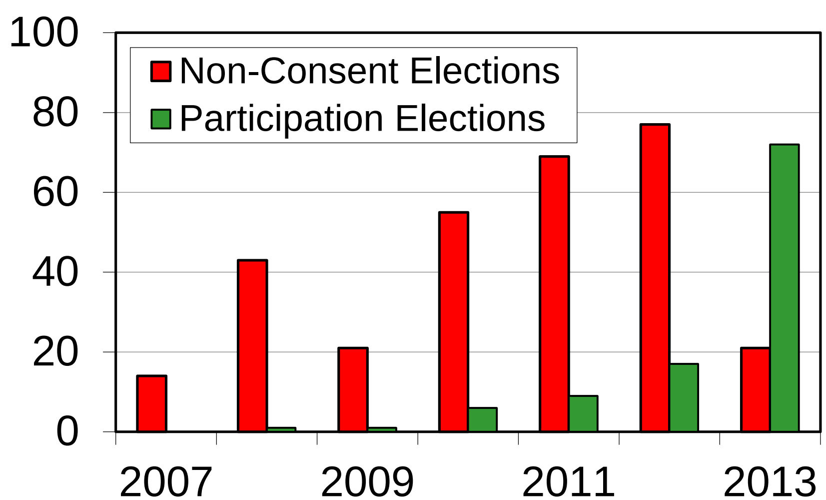


Note: Volumes from AOGC, 1st point on DMLP normalize curve based on estimates from partial month data

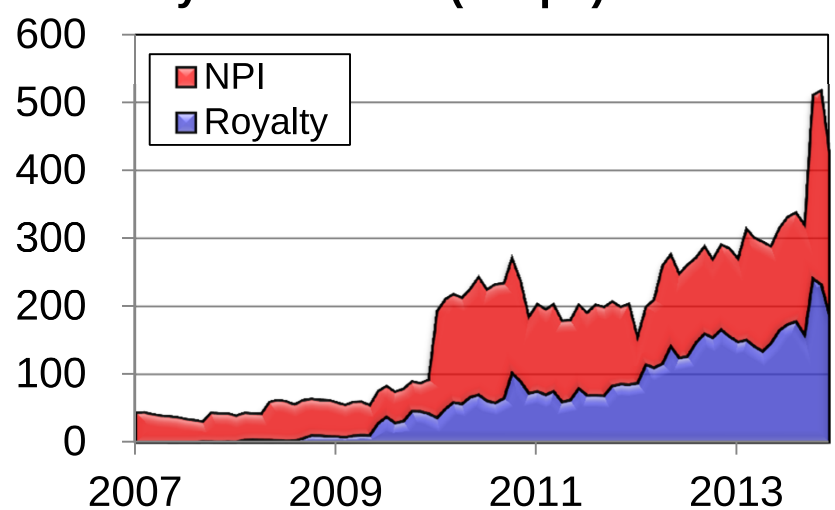
Bakken/Three Forks

- Williston Basin – Northwestern North Dakota
  - Diversified acreage position
    - 70,390 gross acres/8,905 net acres
  - Operators: Continental, COP, EOG, Hess, Marathon, Oasis
  - Elected non-consent option in 312 wells to date
    - Average royalty of all leases in unit (~16% royalty)
    - Back-in for full working interest after 150% payout
    - Working interest subject to Minerals NPI

Well Count



Net Daily Production (boepd)

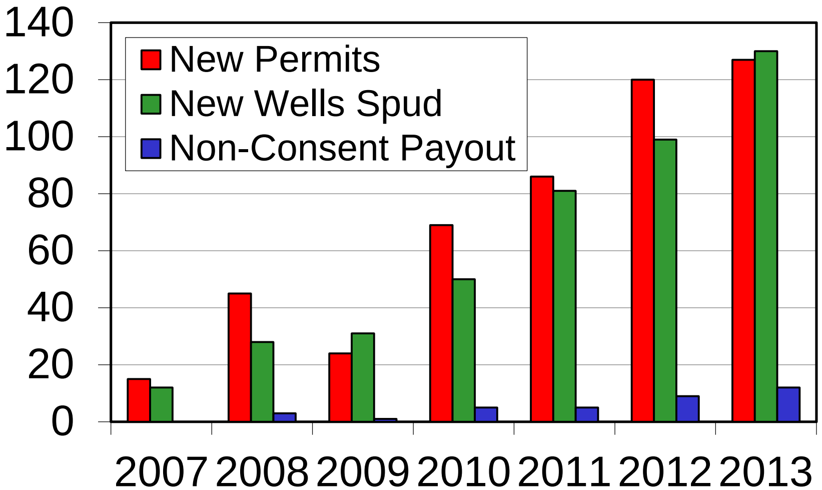


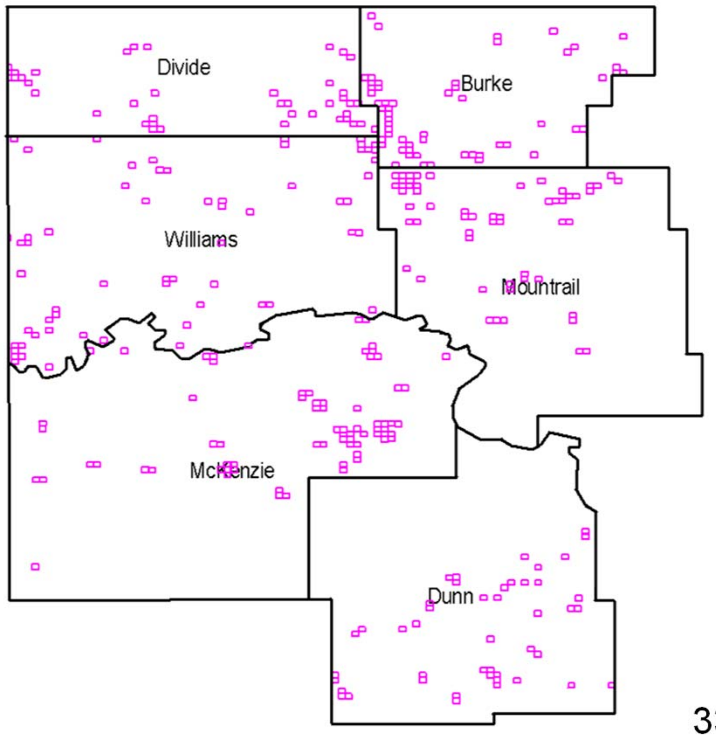
Bakken/Three Forks

- Six County Core Area
  - Current development activity on DMLP acreage
    - 379 wells completed as producers
    - 88 wells in various stages of drilling or completion (or confidential)
    - 59 wells permitted and/or proposed by operator

    526 wells/permits
  - 12 rigs currently drilling on DMLP acreage

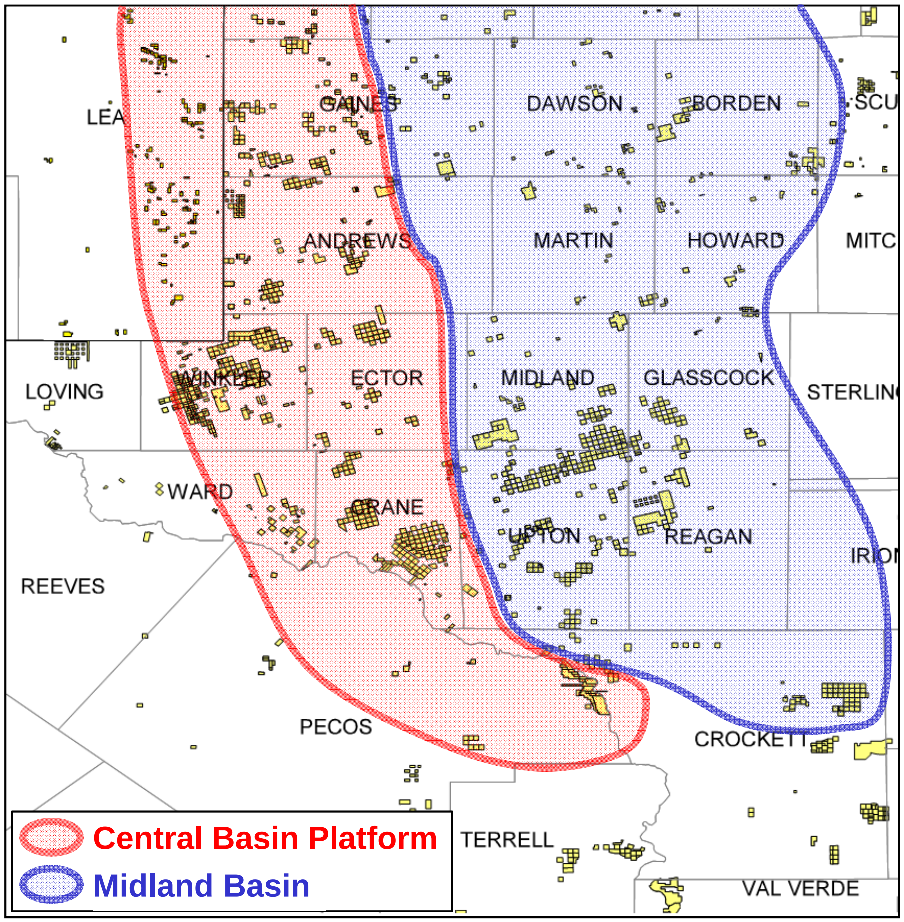
Well Count





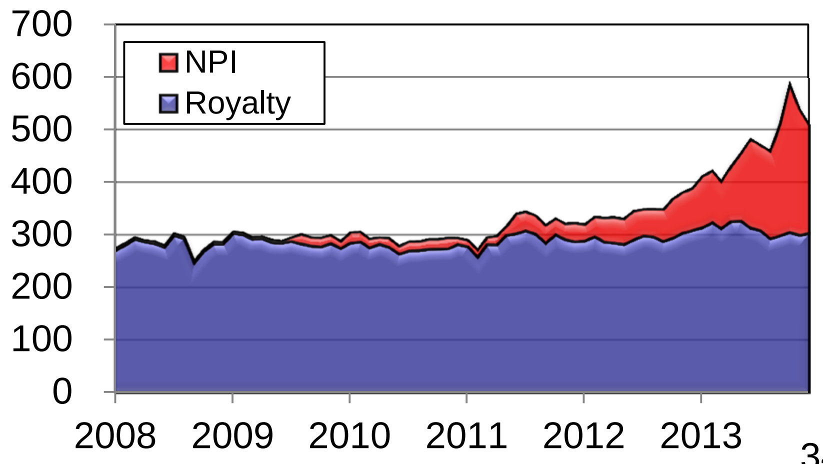
Permian Basin

- Legacy Permian and emerging Wolfcamp
  - Unleased at some depth in numerous tracts



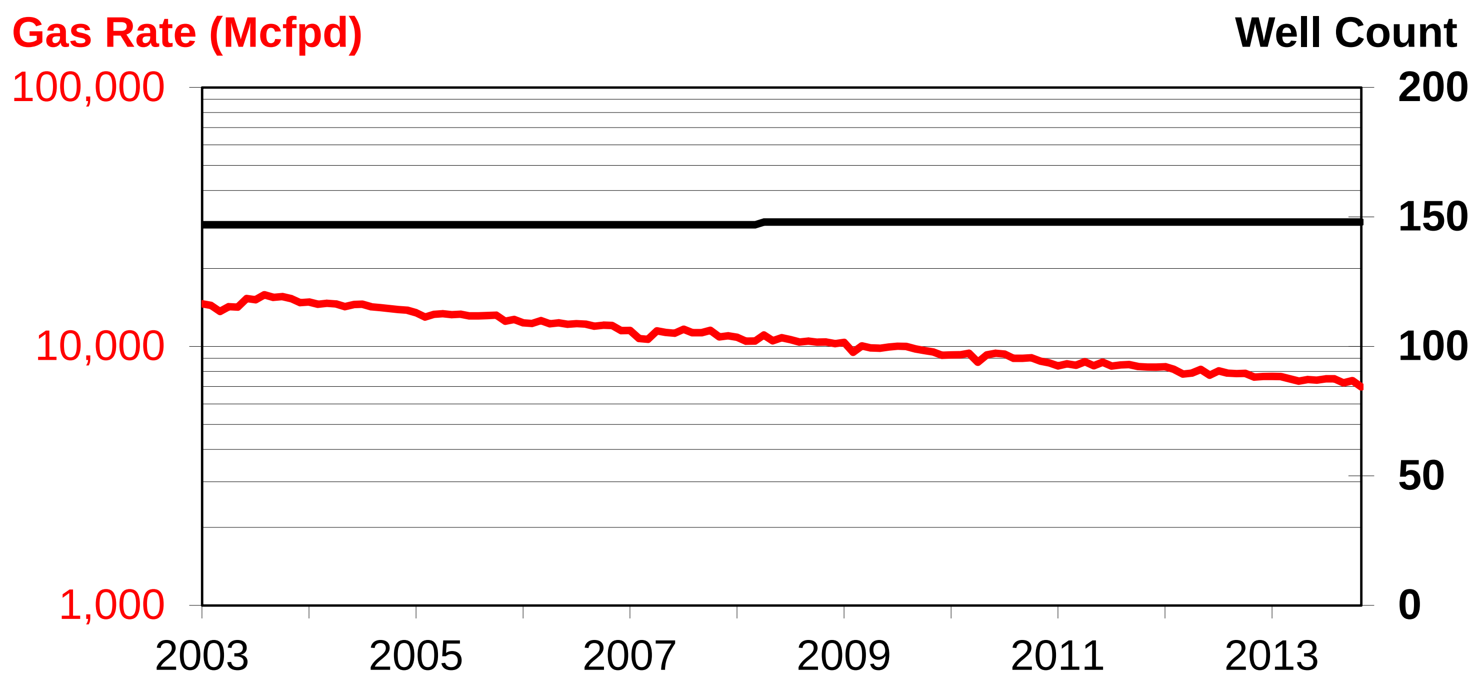
Region	Gross Mineral Acres	Net Mineral Acres	Gross NPRI/ORRI Acres
Midland Basin	263,750	22,207	155,469
Central Basin Platform	334,979	35,603	143,585
Other Permian Basin	124,971	17,917	40,394
Total	**723,700**	**75,727**	**339,448**

Midland Basin Production (boepd)



Hugoton Operated Properties

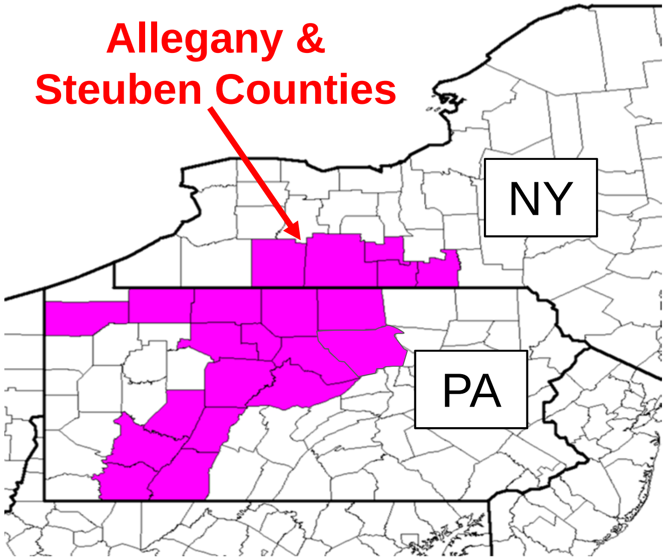
- Hugoton Field – Oklahoma Panhandle & SW Kansas
  - 2013 production within 2.7% of projection
  - Year-over-year production decline of 7.0% with a 0.4% increase in net reserves
  - World-class asset but limited upside potential
  - Ongoing well optimization and cost-saving initiatives



Note: Gas rate based on sales volumes

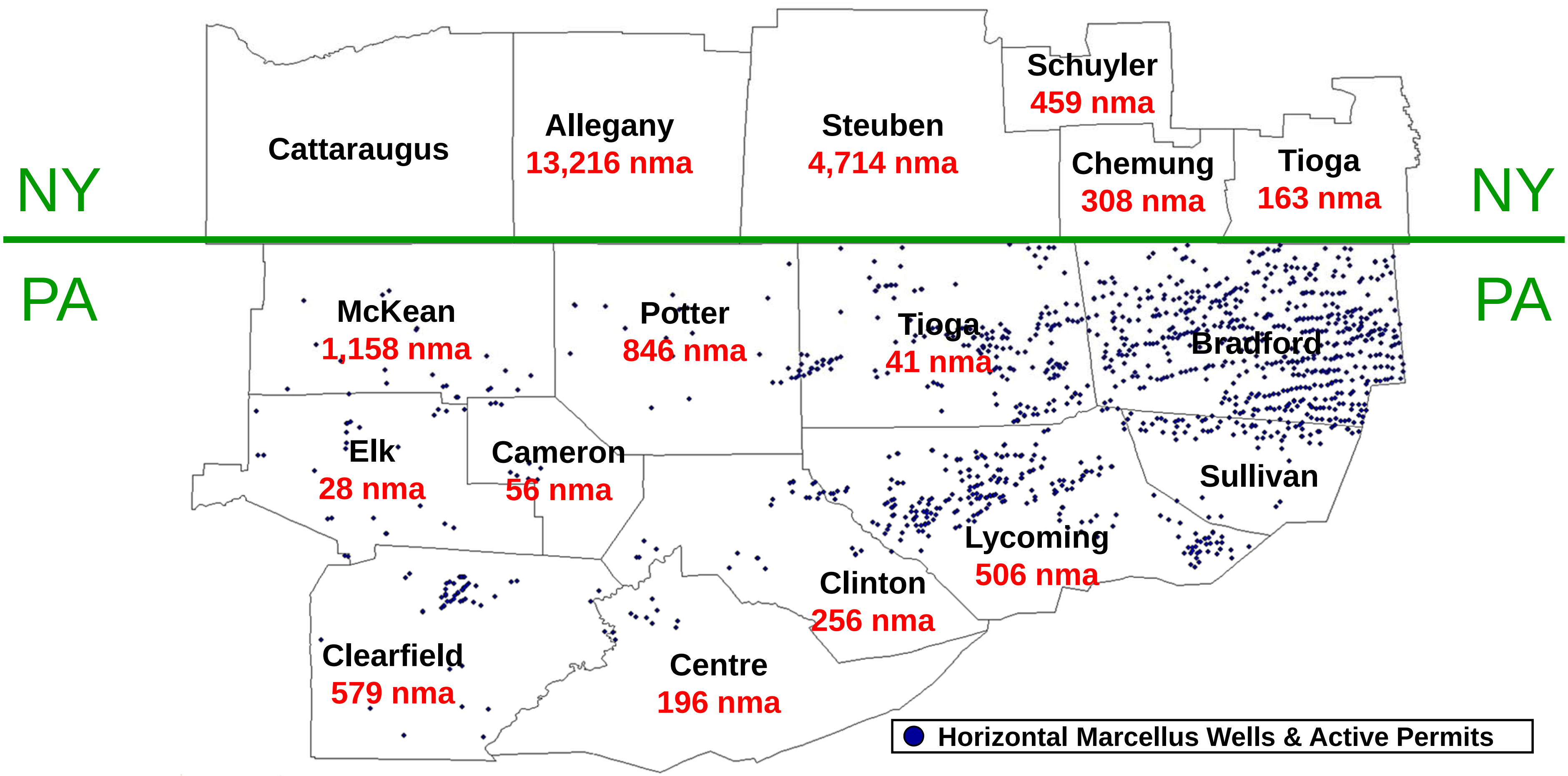
Appalachia

- Marcellus Shale – New York and Pennsylvania
  - Concentrated acreage position
    - 32,395 gross acres/24,494 net acres
    - 70% in Allegany and Steuben Counties, NY
  - Challenging political environment in New York has limited activity relative to Pennsylvania
  - Operators: Anadarko, Chesapeake, EOG, Range, Seneca, Shell, Talisman
  - Leased 1,086 gross acres/ 506 net acres in Lycoming County, PA to Anadarko E&P in 2012
    - Commenced production in May 2013
    - 400 Mcfpd (net) from 11 wells at year-end



Appalachia

- Southern Tier NY & Northern Tier PA



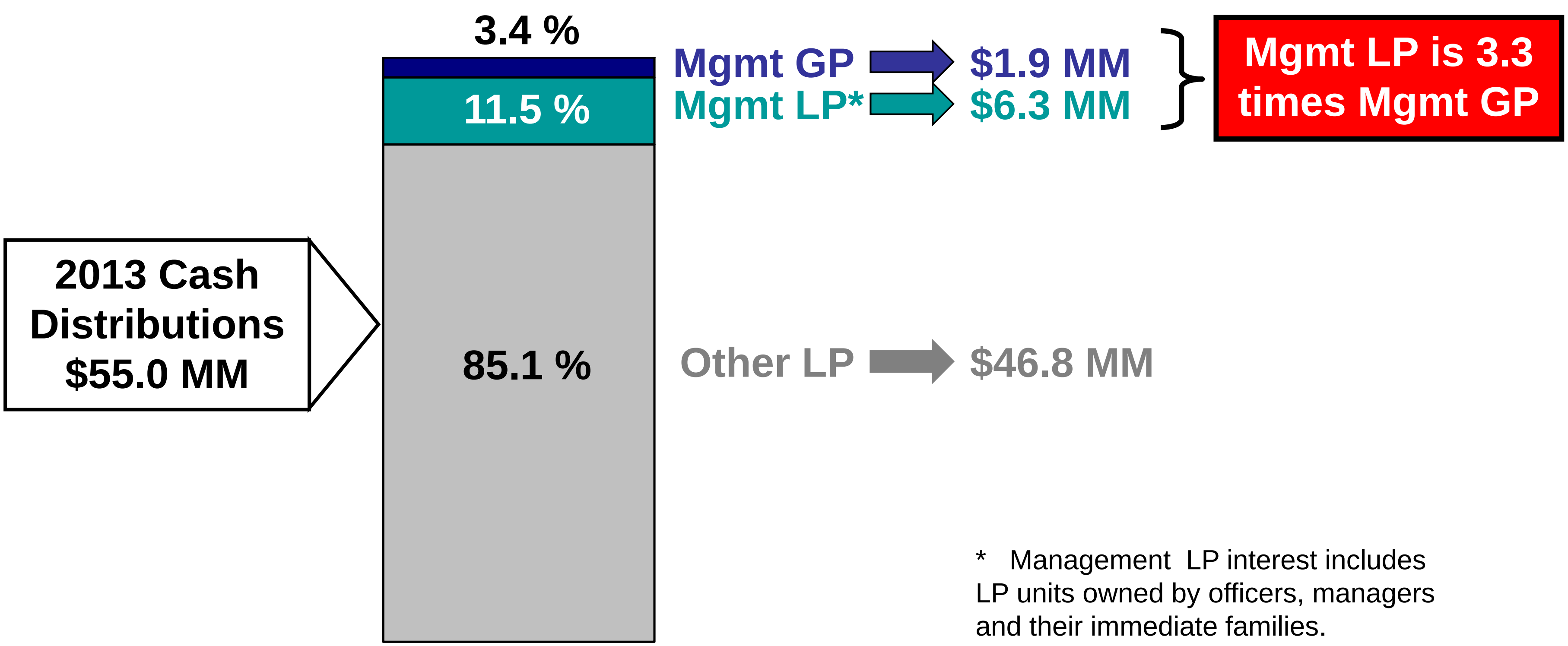
Distributions

- Distribution Determinations
  - Period from October 2012 through September 2013

	($ thousands) Limited Partners	General Partner
4% of Net Cash Receipts from Royalty Properties	$ --------	$1,767
96% of Net Cash Receipts from Royalty Properties	$42,410	$ --------
1% of Net Profits Interests Paid to our Partnership	$ --------	$ 109
99% of Net Profits Interests Paid to our Partnership	$10,729	$ --------
Total Distributions	**$53,139**	$1,876
Operating Partnership Share (3.03% of Net Proceeds)	$ --------	$ 338
Total General Partner Share		**$2,214**
% 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

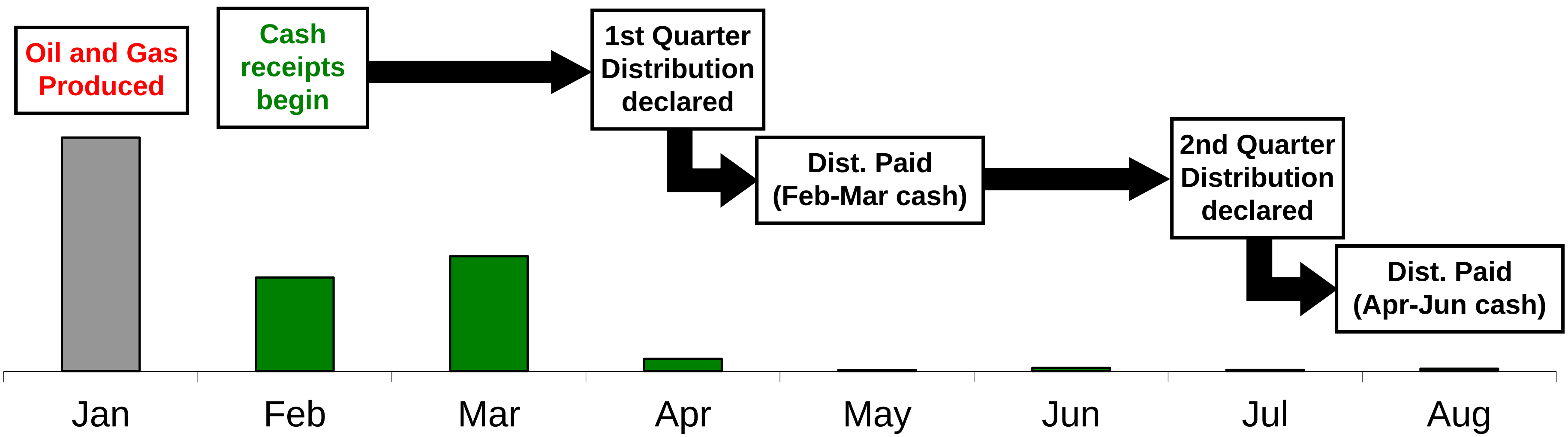
	Royalty Interest	Net Profits Interest
Production Volume	1,000 Mcf	1,000 Mcf
Gas Price	$5.00/Mcf	$5.00/Mcf
Revenue	$5,000	$5,000
Fixed Production Costs	($0)	($1,000)
Operating Income	$5,000	$4,000
Net Interest	25% Royalty	25% NPI
Net Cash Flow	$1,250	$1,000

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 :

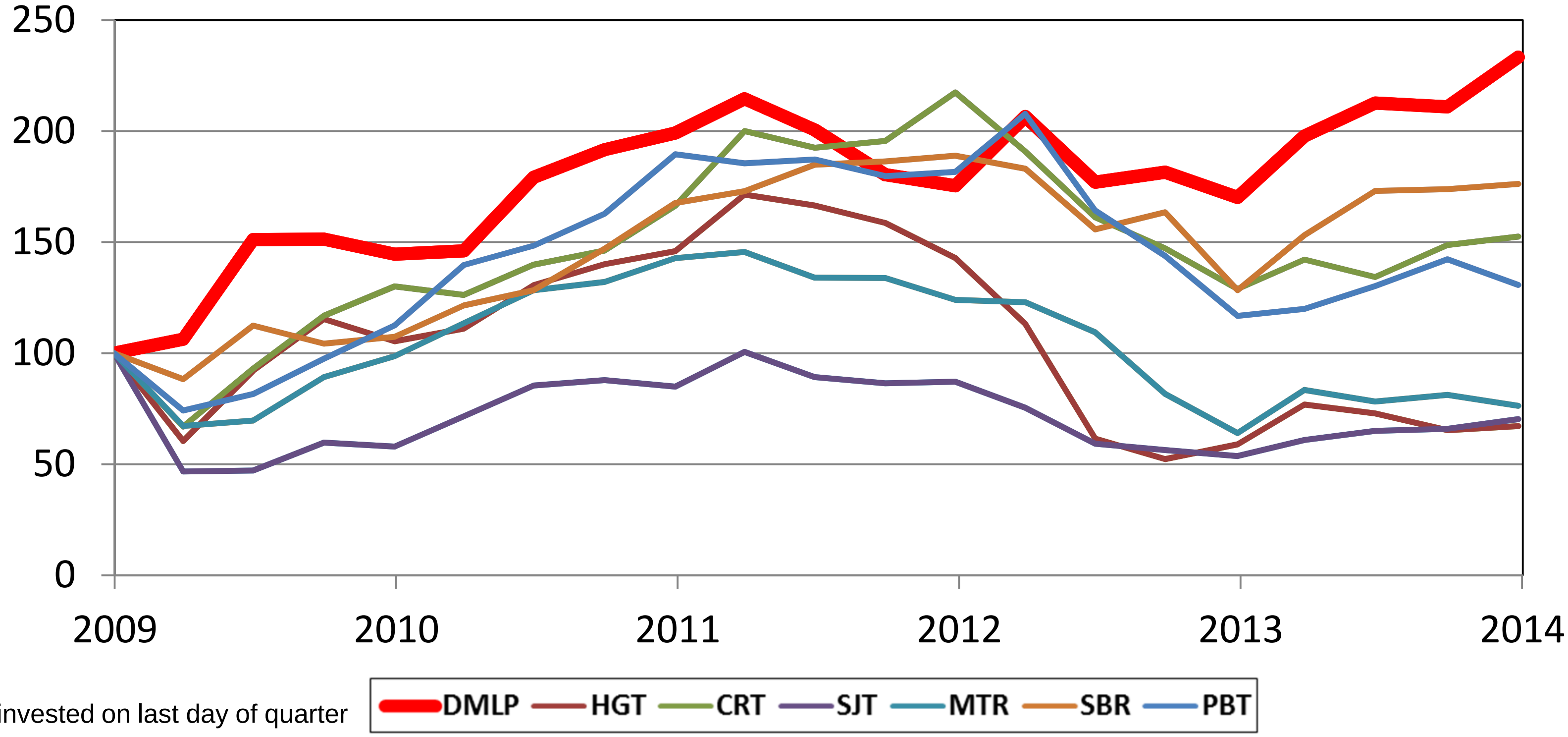


LP distribution of all cash attributable to January production may occur as late as August, a 7-month time lag

Peer Group Comparison

- Market Performance
  - Pure royalties lack operating leverage inherent in net profits interests → Less volatility
  - Outperformance in low price environment (mid-2009) due to lower fixed cost structure

5-Year Normalized Returns (distributions reinvested)



Note: Dist. reinvested on last day of quarter