THE UNCONVENTIONAL RESOURCE COMPANY

MAGNUM HUNTER RESOURCES CORPORATION

Investor Presentation

December 2013

Forward-Looking Statements

The statements and information contained in this presentation that are not statements of historical fact, including any estimates and assumptions contained herein, are "forward looking statements" as defined in Section 27A of the Securities Act of 1933, as amended, referred to as the Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, referred to as the Exchange Act. These forward-looking statements include, among others, statements, estimates and assumptions relating to our business and growth strategies, our oil and gas reserve estimates, estimates of oil and natural gas resource potential, our ability to successfully and economically explore for and develop oil and gas resources, our exploration and development prospects, future inventories, projects and programs, expectations relating to availability and costs of drilling rigs and field services, anticipated trends in our business or industry, our future results of operations, our liquidity and ability to finance our exploration and development activities and our midstream activities, market conditions in the oil and gas industry and the impact of environmental and other governmental regulation. In addition, with respect to any pending transactions described herein, forward-looking statements include, but are not limited to, statements regarding the expected timing of the completion of proposed transactions; the ability to complete proposed transactions considering various closing conditions; the benefits of any such transactions and their impact on the Company's business; and any statements of assumptions underlying any of the foregoing. In addition, if and when any proposed transaction is consummated, there will be risks and uncertainties related to the Company's ability to successfully integrate the operations and employees of the Company and the acquired business. Forward-looking statements generally can be identified by the use of forward-looking terminology such as "may," "will," "could," "should," "expect," "intend," "estimate," "anticipate," "believe," "project," "pursue," "plan" or "continue" or the negative thereof or variations thereon or similar terminology.

These forward-looking statements are subject to numerous assumptions, risks, and uncertainties. Factors that may cause our actual results, performance, or achievements to be materially different from those anticipated in forward-looking statements include, among others, the following: adverse economic conditions in the United States, Canada and globally; difficult and adverse conditions in the domestic and global capital and credit markets; changes in domestic and global demand for oil and natural gas; volatility in the prices we receive for our oil, natural gas and natural gas liquids; the effects of government regulation, permitting and other legal requirements; future developments with respect to the quality of our properties, including, among other things, the existence of reserves in economic quantities; uncertainties about the estimates of our oil and natural gas reserves; our ability to increase our production and therefore our oil and natural gas income through exploration and development; our ability to successfully apply horizontal drilling techniques; the effects of increased federal and state regulation, including regulation of the environmental aspects, of hydraulic fracturing; the number of well locations to be drilled, the cost to drill and the time frame within which they will be drilled; drilling and operating risks; the availability of equipment, such as drilling rigs and transportation pipelines; changes in our drilling plans and related budgets; regulatory, environmental and land management issues, and demand for gas gathering services, relating to our midstream operations; and the adequacy of our capital resources and liquidity including, but not limited to, access to additional borrowing capacity.

These factors are in addition to the risks described in the "Risk Factors" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" sections of the Company's 2012 annual report on Form 10-K, as amended, filed with the Securities and Exchange Commission, which we refer to as the SEC. Most of these factors are difficult to anticipate and beyond our control. Because forward-looking statements are subject to risks and uncertainties, actual results may differ materially from those expressed or implied by such statements. You are cautioned not to place undue reliance on forward-looking statements contained herein, which speak only as of the date of this document. Other unknown or unpredictable factors may cause actual results to differ materially from those projected by the forward-looking statements. Unless otherwise required by law, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. We urge readers to review and consider disclosures we make in our reports that discuss factors germane to our business. See in particular our reports on Forms 10-K, 10-Q and 8-K subsequently filed from time to time with the SEC. All forward-looking statements attributable to us are expressly qualified in their entirety by these cautionary statements.

The U.S. Securities and Exchange Commission, which we refer to as the SEC, requires oil and natural gas companies, in filings made with the SEC, to disclose proved reserves, which are those quantities of oil and natural gas that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations.

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates. Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir. Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates. Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project. Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves. Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the Company believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir. Where direct observation has defined a highest known oil (“HKO”) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

The term “contingent resources” is a broader description of potentially recoverable volumes than probable and possible reserves, as defined by SEC regulations. In this presentation disclosure of “contingent resources” represents a high estimate scenario, rather than a middle or low estimate scenario. Estimates of contingent resources are by their nature more speculative than estimates of proved, probable, or possible reserves and accordingly are subject to substantially greater risk of actually being realized by the Company. We believe our estimates of contingent resources and future drill sites are reasonable, but such estimates have not been reviewed by independent engineers. Estimates of contingent resources may change significantly as development provides additional data, and actual quantities that are ultimately recovered may differ substantially from prior estimates.

Who We Are

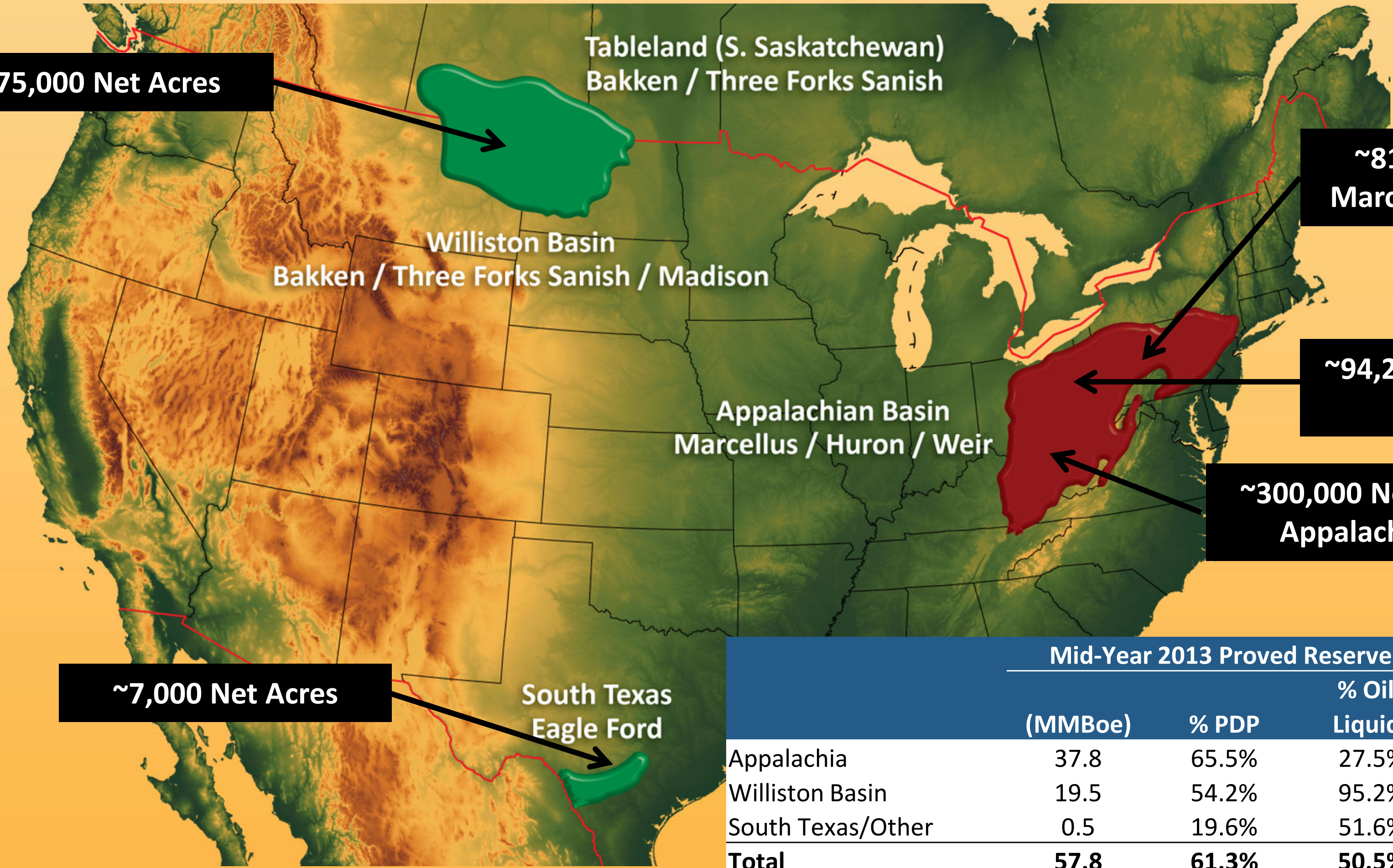
- Magnum Hunter Resources is an exploration and production company focused in three of the most prolific unconventional shale resource plays in North America, namely the Marcellus, Utica and Williston/Bakken Shale
- Current management team assumed leadership of the Company in May 2009 and has decades of combined energy industry experience
- Diversified asset base provides the Company with the flexibility to allocate capital to the highest growth properties within the portfolio
- Achieved "Shale Scale" with significant acreage positions in the Bakken, Marcellus and Utica Plays that total ~350,000 net acres
- Significant insider ownership aligns shareholder and management interests

Key Metrics	
Current Market Capitalization	~$1,250 MM
Current Enterprise Value	~$2,300 MM
Current Production (est.)	15.0 MBoepd
Target Year-End Production	23.0-25.0 MBoepd
Proved Reserves(1)	57.8 MMBoe
3P Reserves(1)(2)	119.3 MMBoe
Contingent Resources(3)	728.9 MMBoe

(1) Reserves as of June 30, 2013
(2) 3P Reserves consist of proved, probable and possible reserves
(3) The contingent resource estimate is an internal estimate prepared by Magnum Hunter that includes the Company's Utica Shale potential on its vast lease acreage holdings

Where We Operate

- A well-balanced and concentrated asset base in large shale plays
- Secure footholds in West Virginia, Ohio, Kentucky, and North Dakota

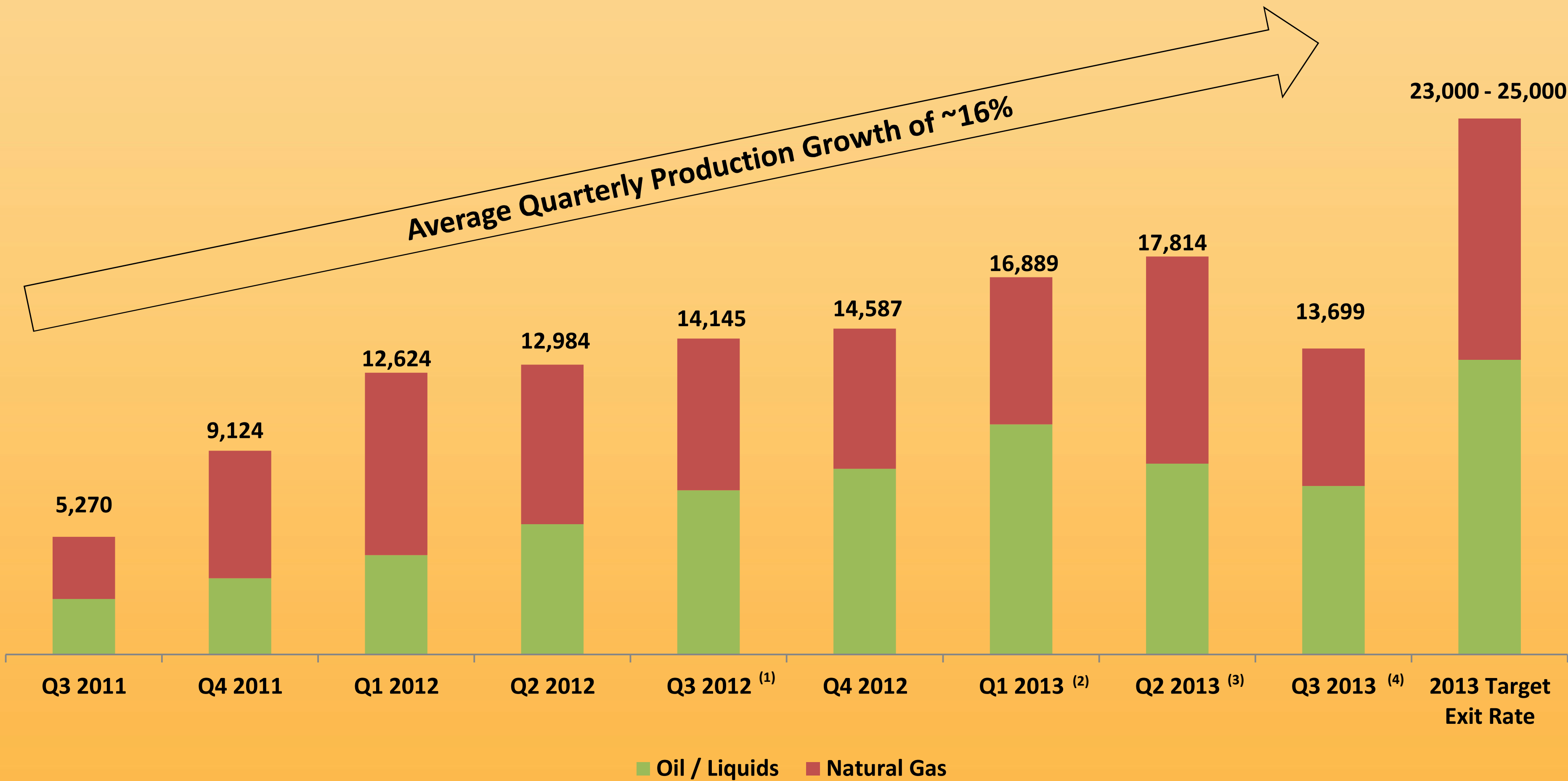


	Mid-Year 2013 Proved Reserves			
	(MMBoe)	% PDP	% Oil/ Liquids	Gross Drilling Locations[1]
Appalachia	37.8	65.5%	27.5%	1,252
Williston Basin	19.5	54.2%	95.2%	1,462
South Texas/Other	0.5	19.6%	51.6%	2
Total	**57.8**	**61.3%**	**50.5%**	**2,716**

(1) Represents total potential drilling locations reflecting current acreage position and reserve report as of June 30, 2013

Production Growth

- 2012 production increased 139% to 13,152 Boepd compared to 5,510 Boepd in 2011
- Year-end 2013 exit rate guidance reaffirmed at 23,000 – 25,000 Boepd

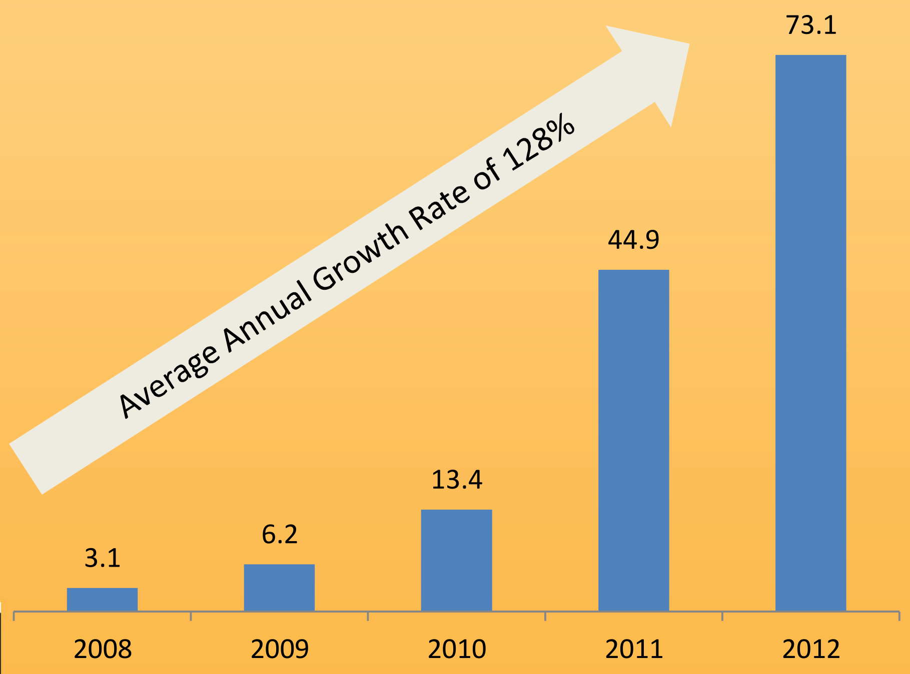


(1) Includes estimated shut-in and curtailed production volumes; actual reported third quarter 2012 production was 12,480 barrels of oil equivalent per day
(2) Includes estimated shut-in and curtailed production volumes; actual reported first quarter 2013 production was 13,769 barrels of oil equivalent per day
(3) Includes, on a pro forma basis, 816 Boe/d of actual production from Eagle Ford Hunter, Inc. operations sold in April 2013, and estimated shut-in production volumes of 1,873 BOEPD
(4) Includes, on a pro forma basis, 1,875 Boe/d of actual production from discontinued operations, and estimated shut-in production volumes of 1,775 BOEPD

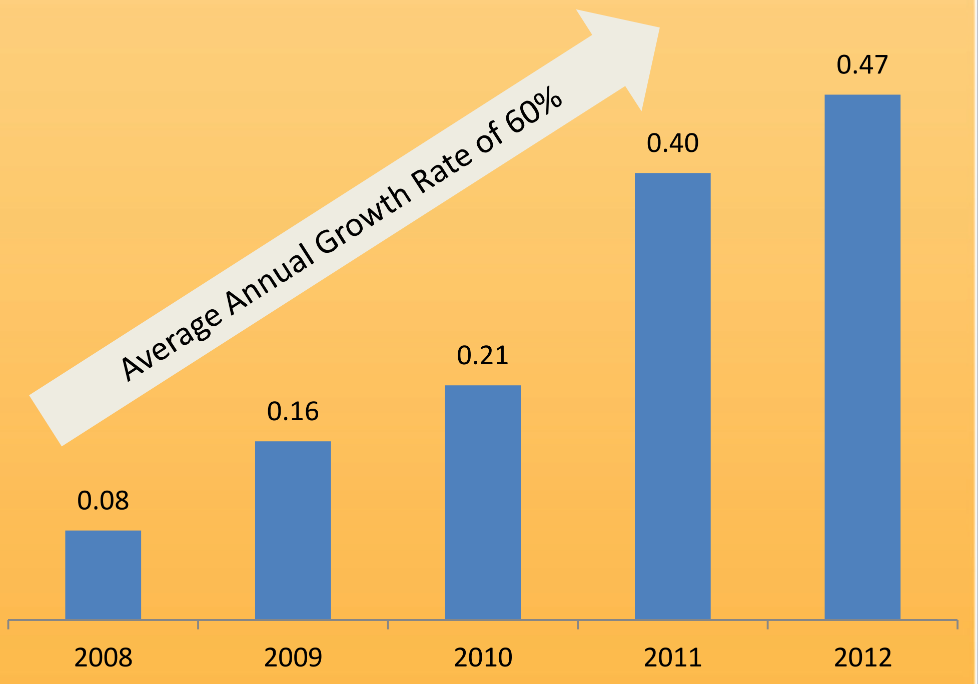
Proved Reserve Growth Consistency

- **Track record of proved reserve growth since inception**
  - Approximately 57.8 MMBoe of proved reserves and 119.3 MMBoe of 3P reserves at June 30, 2013 (50.5% oil/liquids)
  - Anticipate continuing to consistently add proven reserves with an equal mix of oil/liquids and natural gas

Proved Reserves (MMBoe)(1)



Annual Proved Reserves (Boe) / Share(2)

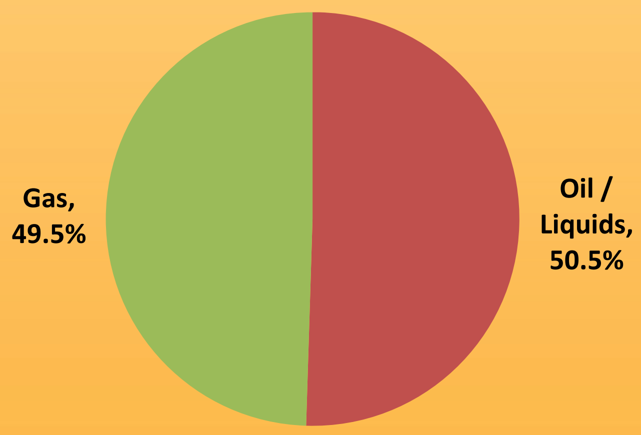


Note: No proved reserves have been booked in the Utica Shale as of June 30, 2013
(1) Pro forma for the Eagle Ford sale, total proved reserves as of December 31, 2012 were 61.6 MMBoe
(2) Calculation based on weighted average of common shares outstanding on annual basis

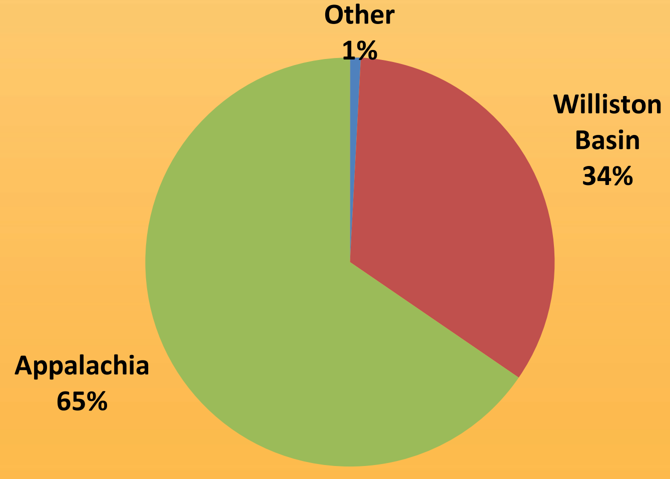
Proved Reserves Summary

Proved Reserves Summary				
	Net Proved Reserves as of Mid-Year 2013 (SEC PRICING)			
Category	Liquids (MMBbls)	Gas (Bcf)	Total (MMBoe)	%
PDP	16.8	111.6	35.4	61.3%
PDNP	0.6	3.8	1.2	2.1%
PUD	11.8	56.4	21.2	36.6%
Total Proved Reserves	**29.2**	**171.8**	**57.8**	**100.0%**

Proved Reserve Allocation



Proved Reserves by Region



Note: No proved reserves have been booked yet in the Utica Shale and minimal reserves have been booked in the Middle Bakken

3P Reserves & Contingent Resources Summary

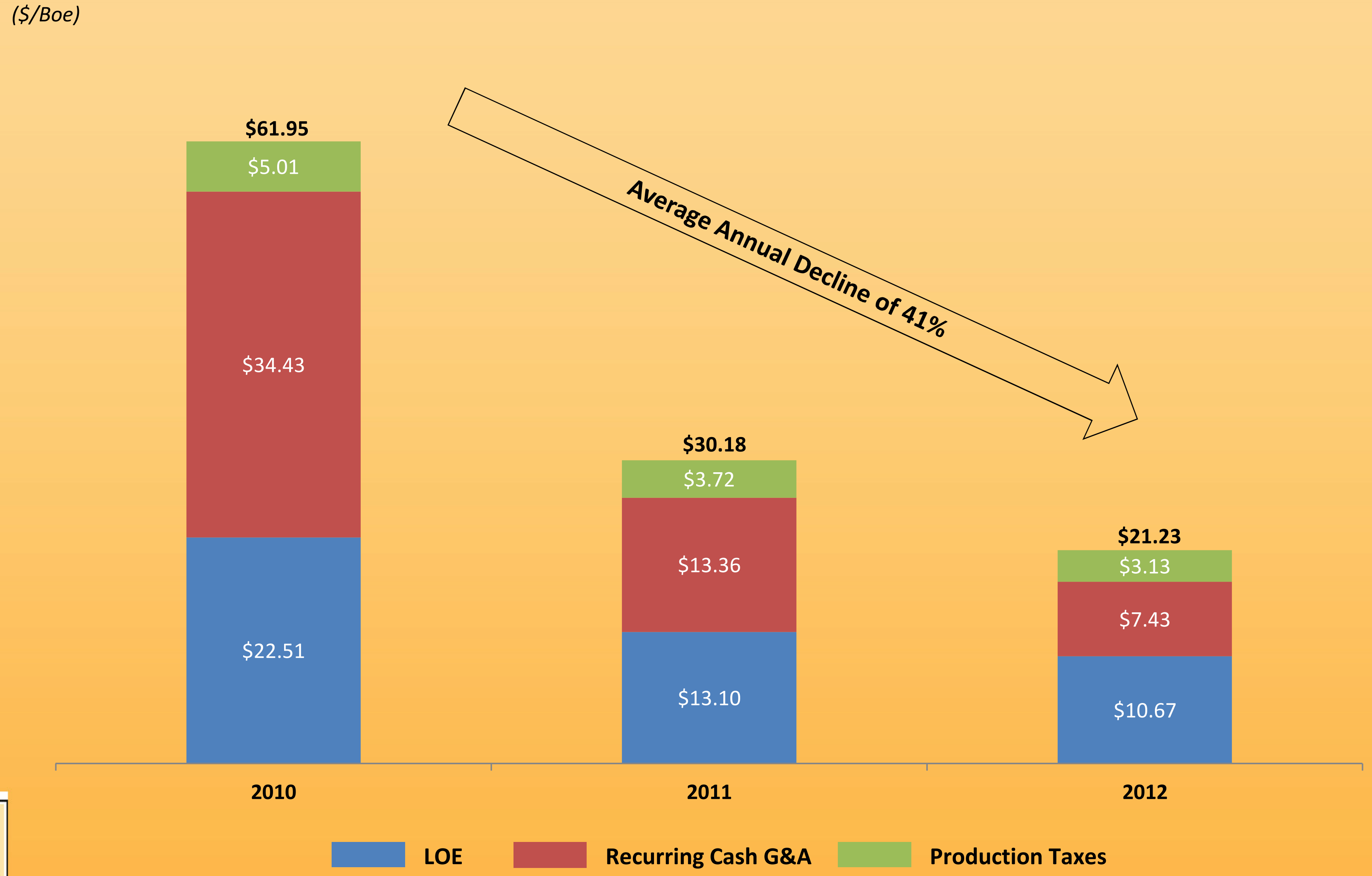
- **3P reserves and contingent resource potential of 848 MMBoe**
- **Extensive inventory of low-risk development drilling locations in the Williston Basin and Marcellus Shale**
- **Significant exploration potential in the wet/dry gas window of the Utica Shale in Ohio and West Virginia**

June 30, 2013 3P Reserves and Contingent Resource Summary[1]

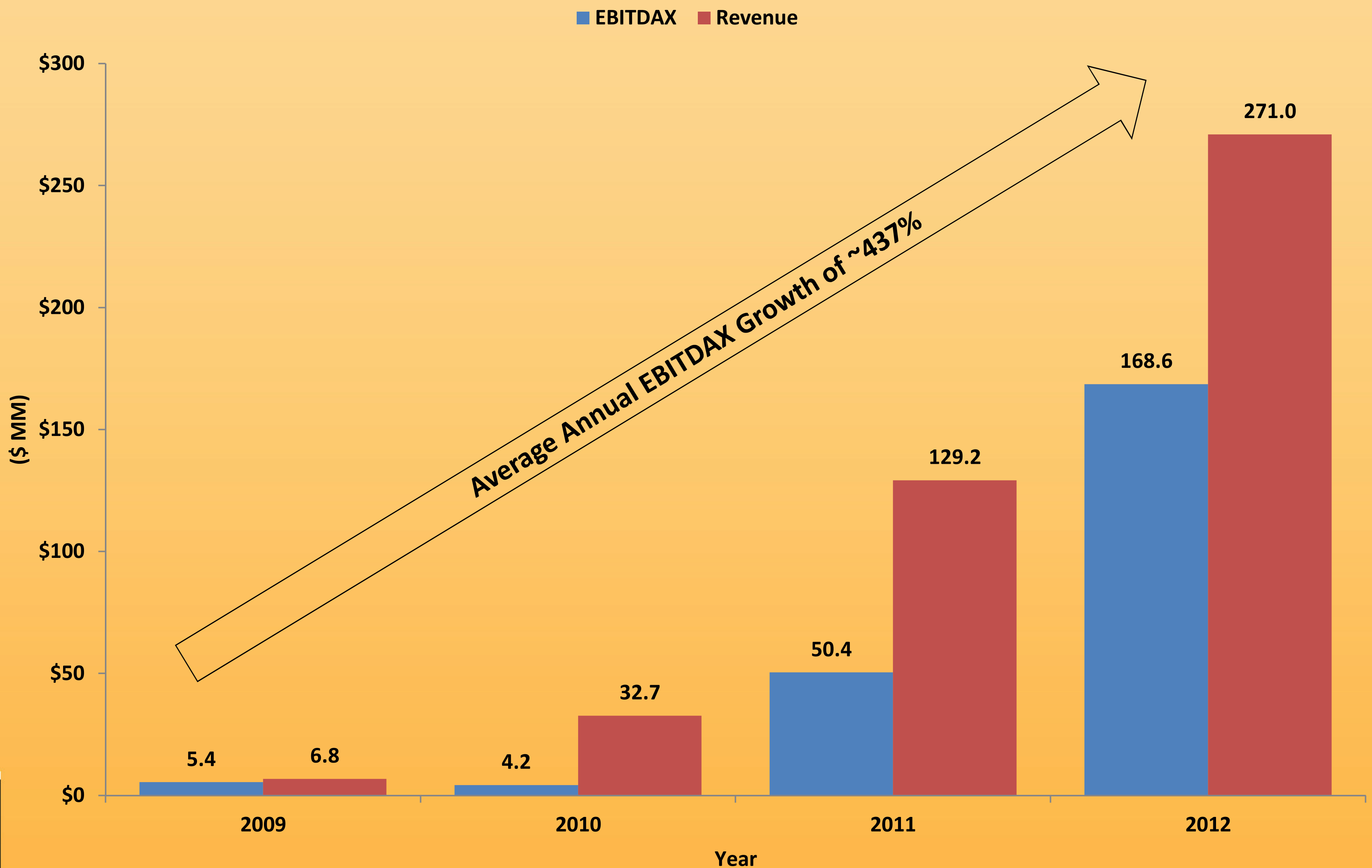
Area	Reservoir	Total Proved (MMVoe)	Total Prob/Poss (MMBoe)	Contingent Resources (MMBoe)	Unrisked 3P Reserves/Contingent Resources (MMBoe)
Williston Hunter	Bakken / Sanish				
USA		17.2	47.5	44.4	109.1
Canada		2.3	2.3	-	4.6
Triad Hunter	Marcellus/Other	30.6	11.7	142.9	185.2
	Utica	-	-	496.2	496.2
Shale Hunter	Eagle Ford/Wilcox	0.5	-	-	0.5
MH Production	Devonian Shale/Other	7.2	-	45.4	52.6
Total		**57.8**	**61.5**	**728.9**	**848.2**

(1) The contingent resource estimate is an internal estimate prepared by Magnum Hunter that includes the Company's Utica Shale potential on its vast lease acreage holdings

Operational Efficiency Improvements



Growth Plan Continues



* Please see page 40 of this presentation for a non-GAAP reconciliation table

Note: Current management team started in May 2009

Substantial Leasehold Inventory

As of September 1, 2013	Developed Acreage [1]		Undeveloped Acreage [2]		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Appalachian Basin [3]						
Marcellus Shale	63,199	62,492	24,336	19,224	87,535	81,716
Utica Shale	65,861	62,334	33,374	28,552	99,235	90,886
Magnum Hunter Production	119,271	100,860	240,686	204,060	359,957	304,920
Other	24,952	24,952	123	13	25,075	24,965
Total	**273,283**	**250,638**	**298,519**	**251,849**	**571,802**	**502,487**
South Texas						
Eagle Ford Shale	1,248	766	11,394	6,034	12,642	6,799
Other[4]	1,504	795	-	-	1,504	795
Total	**2,752**	**1,561**	**11,394**	**6,034**	**14,146**	**7,595**
Williston Basin - USA						
North Dakota	150,517	49,477	169,039	75,388	319,556	124,865
Madison Waterflood	17,500	15,000	-	-	17,500	15,000
Total	**168,017**	**64,477**	**169,039**	**75,388**	**337,056**	**139,865**
Williston Basin - Canada						
Bakken / Three Forks / Sanish - Tableland, SK	12,840	11,296	42,665	42,166	55,505	53,462
Alberta	24,790	19,689	20,640	16,499	45,430	36,188
Total	**37,630**	**30,985**	**63,305**	**58,665**	**100,935**	**89,650**
MHR TOTAL	**481,682**	**347,661**	**542,257**	**391,936**	**1,023,939**	**739,597**

(1) Developed acreage is the number of acres allocated or assignable to producing wells or wells capable of production
(2) Undeveloped acreage is lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether such acreage includes proved reserves
(3) Approximately 40,110 Gross Acres and 34,649 Net Acres overlap in our Utica Shale and Marcellus Shale
(4) Pertains to certain miscellaneous properties in Texas and Louisiana

Future Growth and Profitability Drivers

To achieve consistent growth, we are committed to the following:

- **Focus on developing and growing core assets in areas with the highest rate of return using our proven development expertise**

- **Maintain a more conservative balance sheet with significant liquidity to provide operational flexibility**

- **Target in excess of $250 million of additional non-core asset sales (completed $447 million YTD) allowing us to reallocate resources to higher growth properties, increase proved reserves and further reduce debt**

- **Maintain an active commodity hedging program to support economic returns and ensure strong coverage metrics**

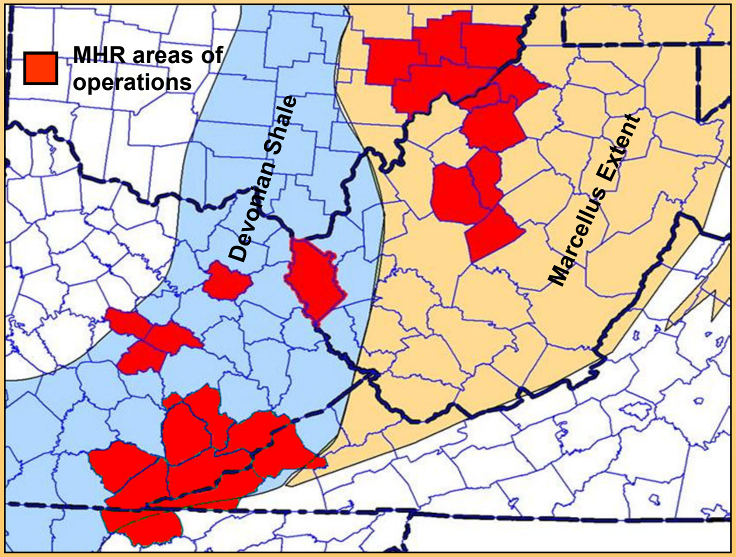
Appalachian Division

Appalachian Division Overview

Overview

- **Proved Reserves**
  - Total proved reserves of **37.8** MMBoe as of 6/30/13
  - Proved producing reserves of **24.8** MMBoe as of 6/30/13
- **Acreage Position**
  - **~500,000** net acres in the Appalachian Basin
    - **81,000** net acres located in the Marcellus Shale
    - **94,200** net acres prospective for the Utica Shale

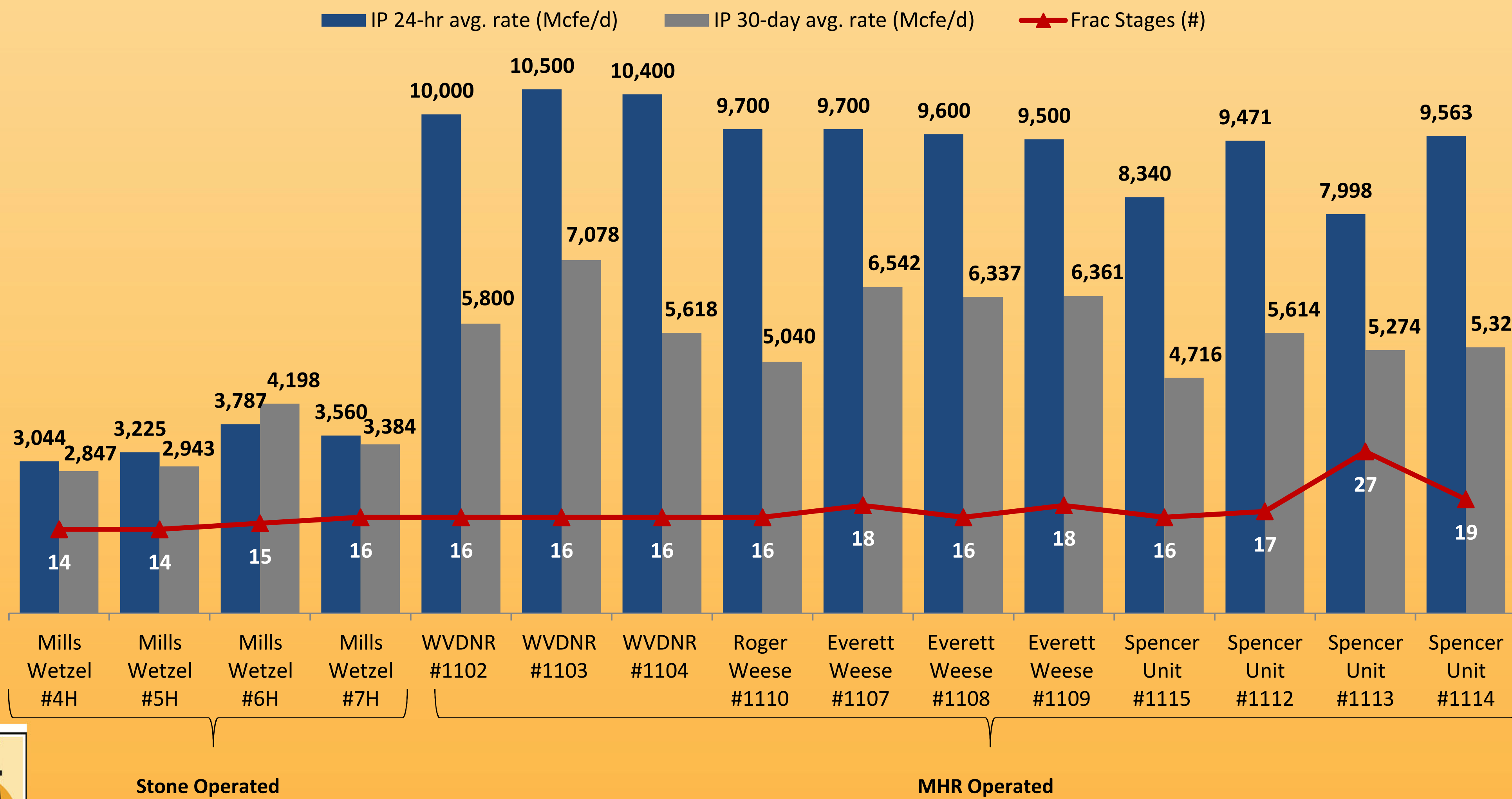
Areas of Operation



- **Utica and Marcellus Shale Overview**
  - 29 wells have been drilled and placed on production to-date with 3 gross (2.9 net) waiting on sales
    - 10 wells in Tyler County, WV
    - 16 wells in Wetzel County, WV
    - 3 well in Monroe County, OH
  - Current Completion Operations
    - 12 (8 net) wells drilled, completing
    - 4 (3.5 net) wells drilled, awaiting completion
  - Current Drilling Operations
    - 2 (0.7 net) wells drilling

Marcellus Operations

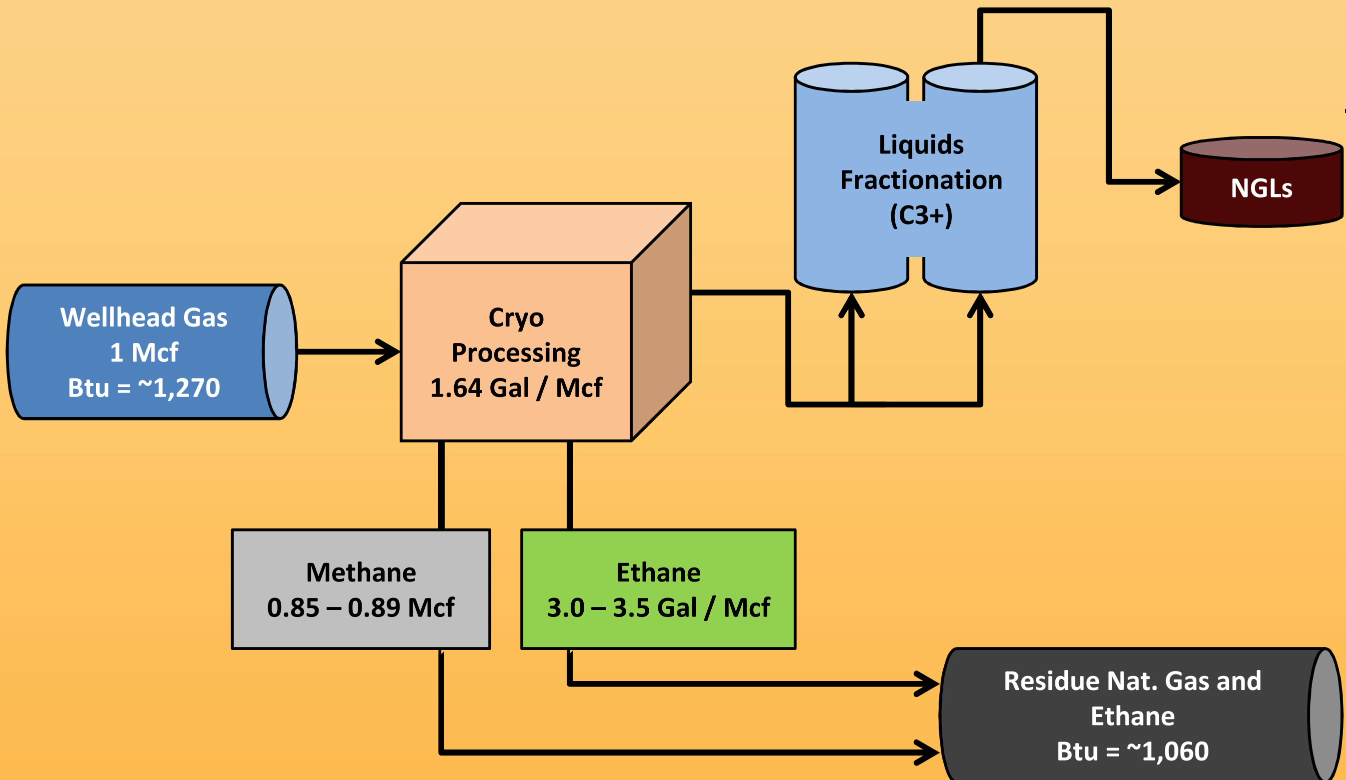
Marcellus Well Results



Note: Well data does not include Natural Gas Liquids

NGL Uplift in Appalachia

- Following the startup of the Mobley Processing Plant in December 2012, Magnum Hunter has realized an uplift in NGLs on a per wellhead Mcf basis between $0.75 - $1.25
- The Company has 200 MMcf/d of dedicated processing capacity at the Mobley Plant



Per Wellhead Mcf (1)

$0.75 - $1.25

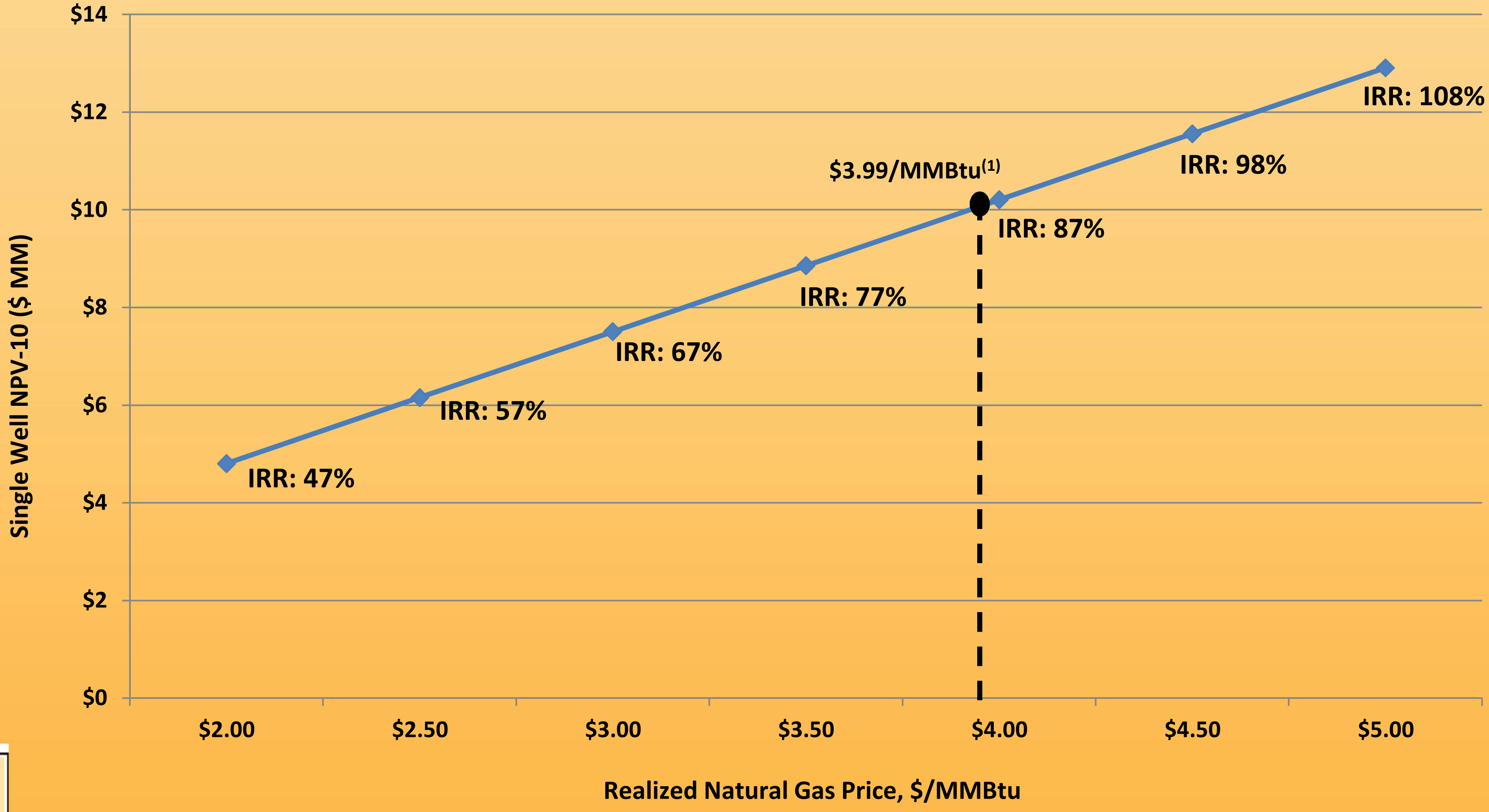
+ $3.50 - $4.00

$4.25 - $5.25

(1) All values shown are versus wellhead production in Mcf.

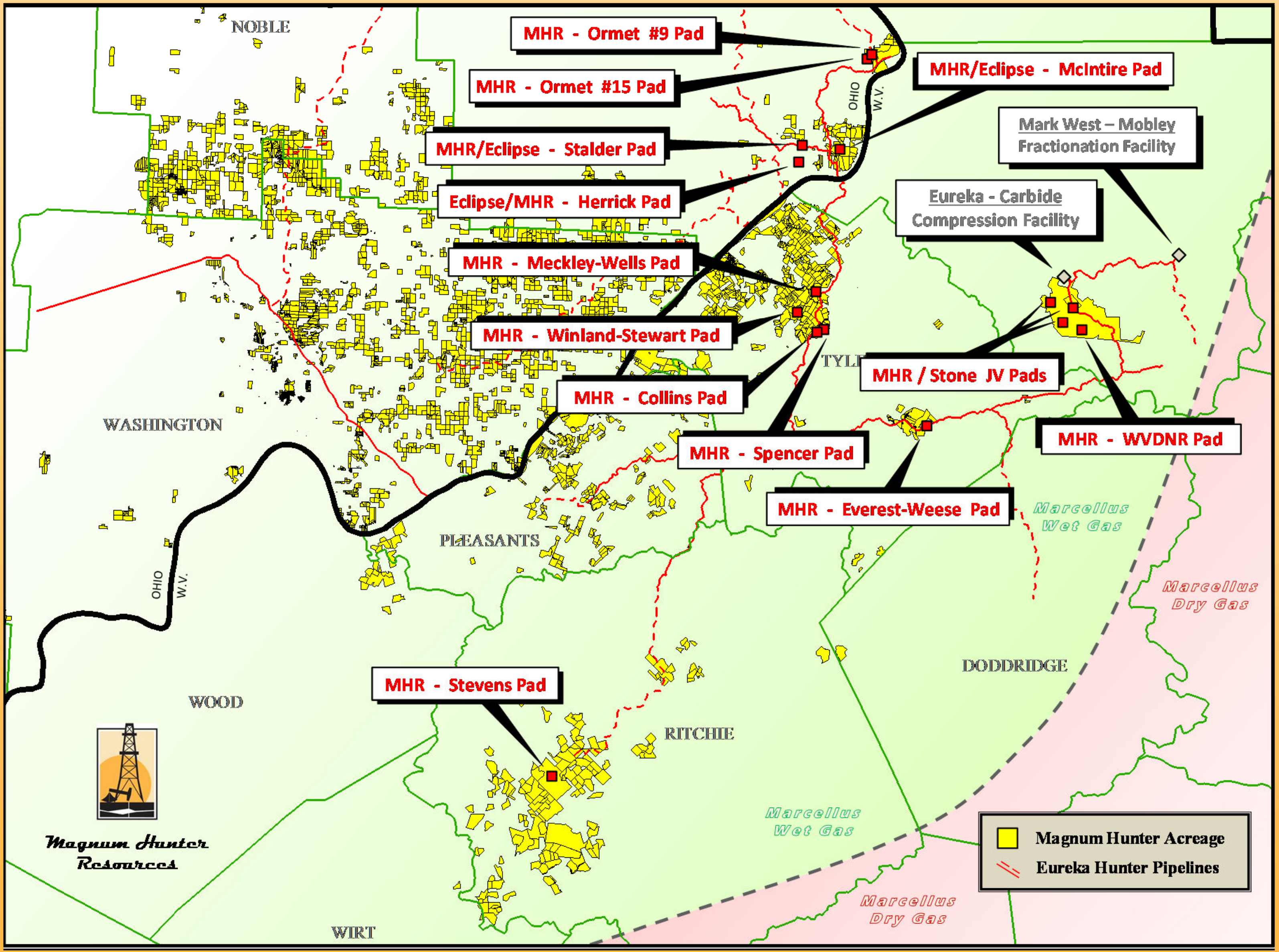
Economic Sensitivity of Marcellus

CAPEX: $6.5 million per well
EUR: 7.8 Bcfe (includes natural gas liquids)



Note: Assumes realized oil price of $90.00/Bbl and realized NGL price of $47.70/Bbl (53% of realized oil price)
(1) Reflects NYMEX natural gas (Henry Hub) spot pricing as of 12/2/2013

Marcellus Shale

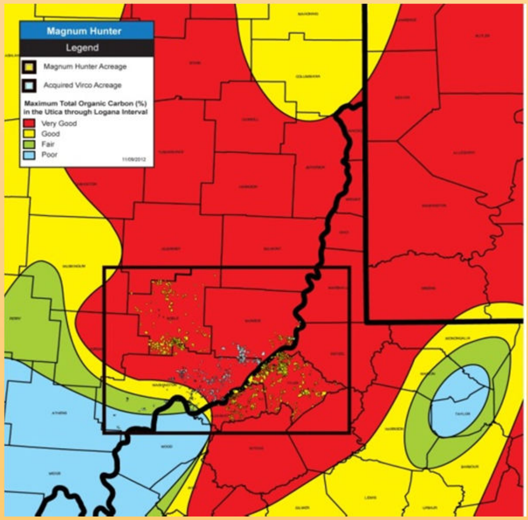


Note: MHR owns approximately 81,000 net acres in the Marcellus Shale.

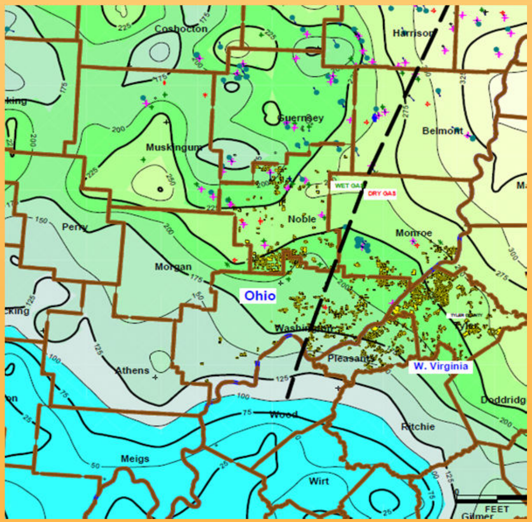
Utica Shale Overview

- The Utica Shale extends approximately 170,000 square miles throughout the Appalachia Basin in the United States and Canada
  - Ordovician-aged organic rich black shale with interbedded limestone with target intervals ~150 feet thick at depths between 7,500 feet and 9,500 feet
  - Similar to the Eagle Ford Shale with three distinct windows: oil, wet gas/condensate, and dry gas with the majority of the activity focused on the wet gas and condensate window
- The “Sweet Spot” for liquids-rich gas occurs in eastern Ohio along a narrow band which generally follows geologic structure
  - Optimum thermal history
  - Depth, pressure and hydrocarbon composition result in excellent recoveries
- Total Organic Carbon (“TOC”) is a measure of organic content and is indicative of the quantity of kerogen in the rock, which is the source material for oil and gas
  - TOC is derived from core analysis; however, it can also be inferred from open hole log resistivity measurements where sufficient data exists for a good correlation
  - There is a general correlation between higher gross interval thickness and larger TOC values
  - East of the Ohio River, the Utica/Point Pleasant is sufficiently deep for the formations to produce dry gas; these areas of high TOC also correspond to high R_o values
- Acreage owned by the Company exhibits good thickness and is highly prospective with a large portion of the acreage in the wet gas and condensate window

Total Organic Carbon



Isopach Map of Utica/Point Pleasant



Potentially Best Shale Play in US

Shale Play Comparison Chart

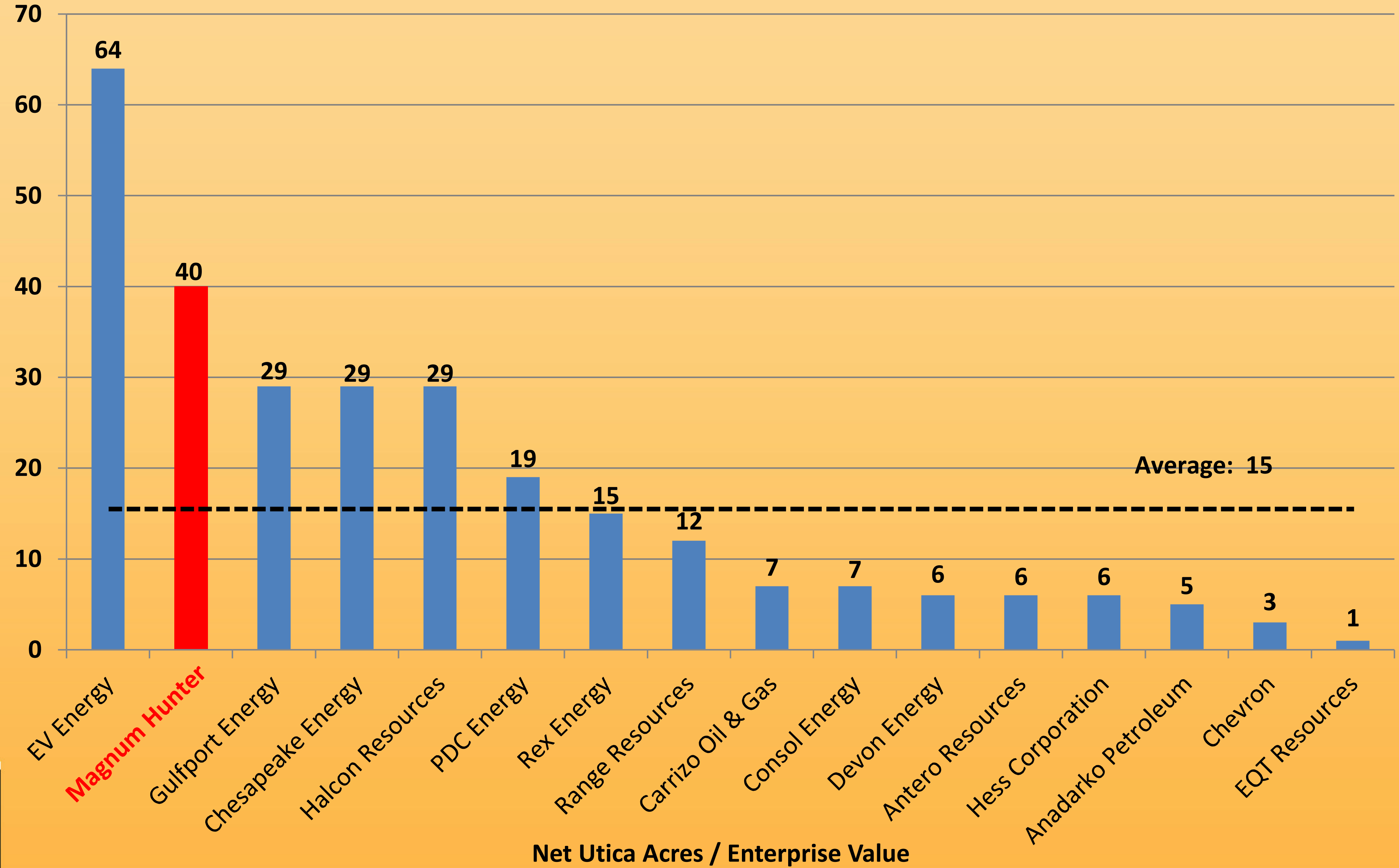
Parameter	Ohio / West Va. / Penn. Utica Shale / Point Pleasant	Wyoming/Colorado DJ Basin Niobrara	Texas Eagle Ford	N. Dakota Bakken
Lithology	**Calcareous Shale**	Chalk/marl	Calcareous Shale	Silty Dolomite
Lithology Descriptor	**Shale with carbonate stringers**	Like Limestone	Like Limestone	More Dolomitic
Storage Capacity				
Formation Thickness	**150-300'**	150-300'	75-300'	<150'
Porosity	**3-10%**	6-10%	4-15%	8-12%
Water Saturation (Sw)	**10-25%**	35-90%	15-45%	15-25%
OOIP per section (MMBOE)	**20-30**	30+	30-50	10-15
Productive Capacity				
Clay Content	**~10-20%**	10-40%	8-11%	5-10%
Total Organic Carbon (TOC)	**2%-4%**	2-6%	5%	9%
Ability to Fracture Stimulate	**na**	Brittleness varies, 250' frac length	Brittle, fracs easy, 500' frac length	Brittle, fracs easy, 500+' frac length
Permeability	**< 0.1 mD**	< 0.1 mD	< 0.1 mD	< 0.1 mD
Reservoir Pressure (psi/ft)	**~0.5-0.8**	0.4-0.6	0.5-0.8	0.5-0.7
Gas-Oil-Ratio (GOR)	**~3,000**	0-10,000+	500-2,000	500-1,000
Development Parameters				
Depth	**7,000'-11,000'**	6,000-8,000'	6,000-8,000'	7,000-11,000'
Well Cost ($MM)	**8.0-10.0**	4.0-6.0	9.0	10.0
Spacing (acres/well)	**80-160**	~160	80-160	100-200
EUR (MBOE/well)	**600+**	175-350	450-700	300-1,000

Major Players in the Utica: Who They Are

Company	Ticker	Net Acres	EV ($MM)	Acres/EV
Chesapeake Energy	CHK	1,000,000	34,063	29
Chevron	CVX	600,000	233,468	3
Anadarko Petroleum	APC	267,000	57,360	5
Devon Energy	DVN	195,000	30,153	6
Range Resources	RRC	190,000	15,451	12
Hess Corporation	HES	185,000	33,068	6
EV Energy	EVEP	177,000	2,746	64
Gulfport Energy	GPOR	147,350	4,996	29
Halcon Resources	HK	142,000	4,953	29
Antero Resources	AR	104,000	17,013	6
Magnum Hunter	**MHR**	**94,200**	**2,343**	**40**
BP	BP	84,000	164,525	1
Consol Energy	CNX	80,000	11,590	7
ExxonMobil	XOM	75,000	427,308	0
PDC Energy	PDCE	48,000	2,496	19
Carrizo Oil & Gas	CRZO	21,700	2,922	7
Rex Energy	REXX	21,000	1,369	15
EQT Resources	EQT	13,600	15,469	1

Source: Company presentations, Bloomberg, state data, Baird

Most Leveraged to the Utica



Source: Company presentations, Bloomberg, state data, Baird

Utica Asset Transactions

Announced Date	Buyer(s)	Seller(s)	Total Transaction Value ($MM)	Acreage	Implied $ / Acre
08/09/13	Undisclosed company(ies)	EnerVest, Ltd.	$228	18,190	$12,551
08/09/13	Undisclosed company(ies)	EV Energy Parnters, L.P.	56	4,345	12,888
02/11/13	Gulfport Energy Corporation	Wexford Capital LP	220	22,000	10,000
01/15/13	Carrizo Oil & Gas Incorporated	Avista Capital Partners LLC	63	11,200	5,634
12/17/12	Gulfport Energy Corporation	Wexford Capital LLC	372	37,000	10,054
09/12/12	Undisclosed	Chesapeake	600	NA	NA
06/25/12	Halcon Resources	Undisclosed	194	31,809	6,099
02/17/12	**Magnum Hunter Resources; Triad Hunter**	**Undisclosed**	**25**	**12,186**	**2,035**
02/11/12	Antero Resources	Undisclosed	112	19,000	5,895
09/08/11	Hess Corporation	Marquette Exploration	750	85,000	8,800
09/07/11	Hess Corporation	CONSOL Energy	593	100,000	6,000

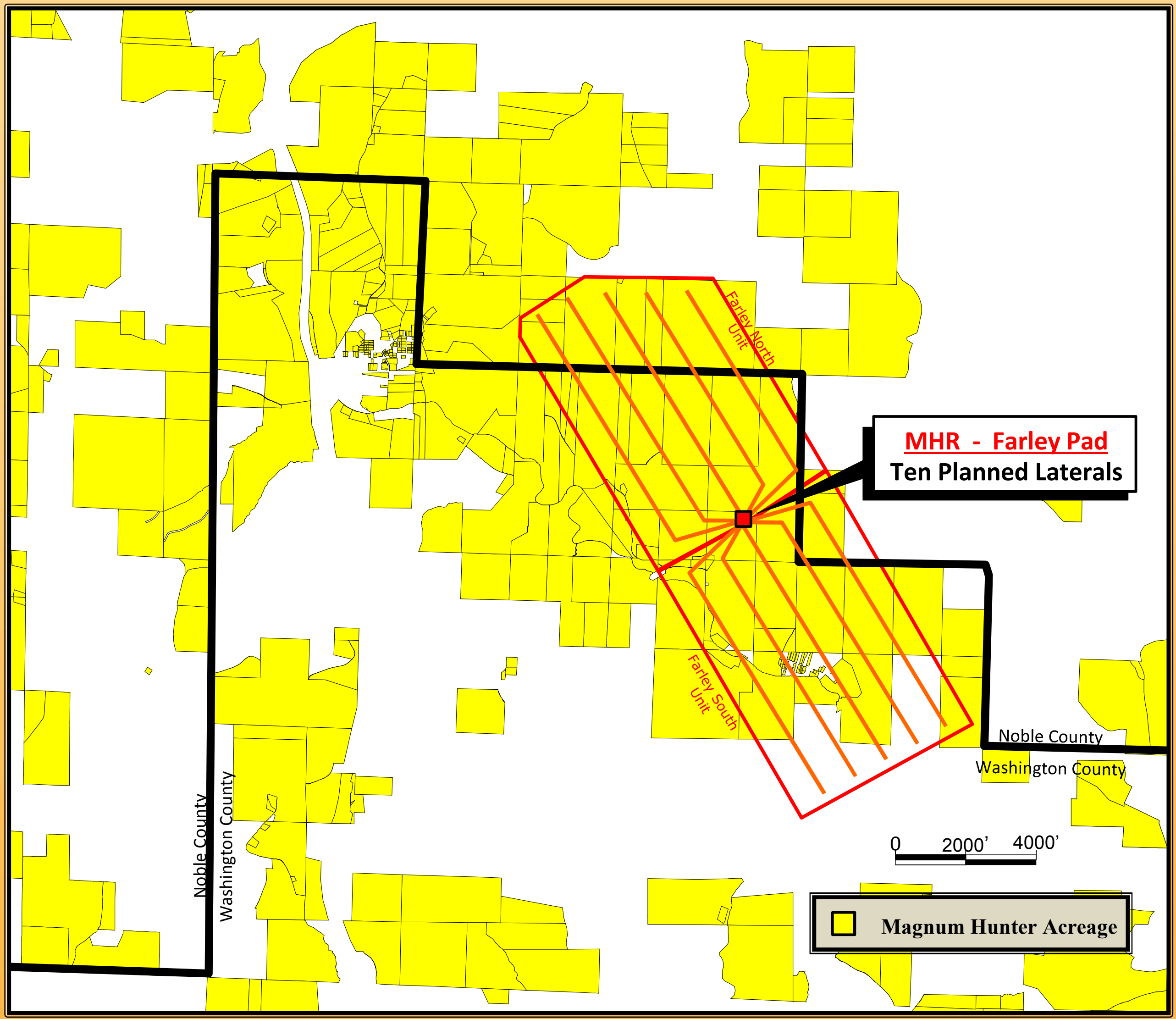
Mean	**$292**	**34,073**	**$7,996**
Median	**$220**	**20,500**	**$7,449**

Source: IHS Herold and Raymond James

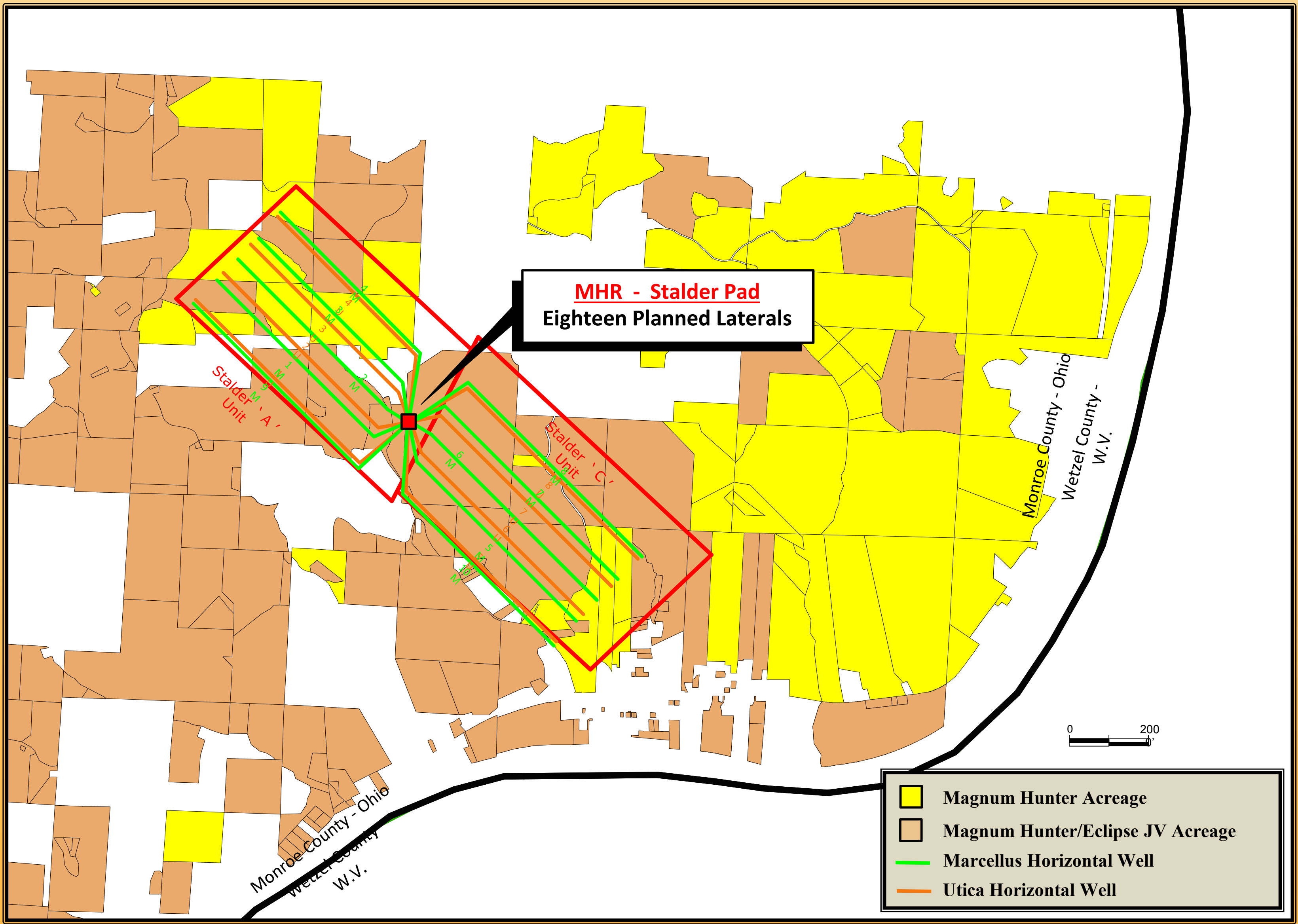
First Utica Pad "Farley"

- **First Utica horizontal well in Washington County spud April 10, 2013**
  - **Farley Pad is designed to handle 10 horizontal wells**
  - **A vertical pilot, and subsequent horizontal well was drilled, logged, cored, and cased**
  - **Due to complications during the drilling of the 6,500' lateral that resulted in poor integrity with the cement bond behind the 5 ½" casing, only ten stages (about 1/3rd) have been fracture stimulated**
  - **Flowback and testing are currently ongoing**
  - **A second horizontal well has been spud with expected completion in mid to late February**

Farley Pad Drilling Locations



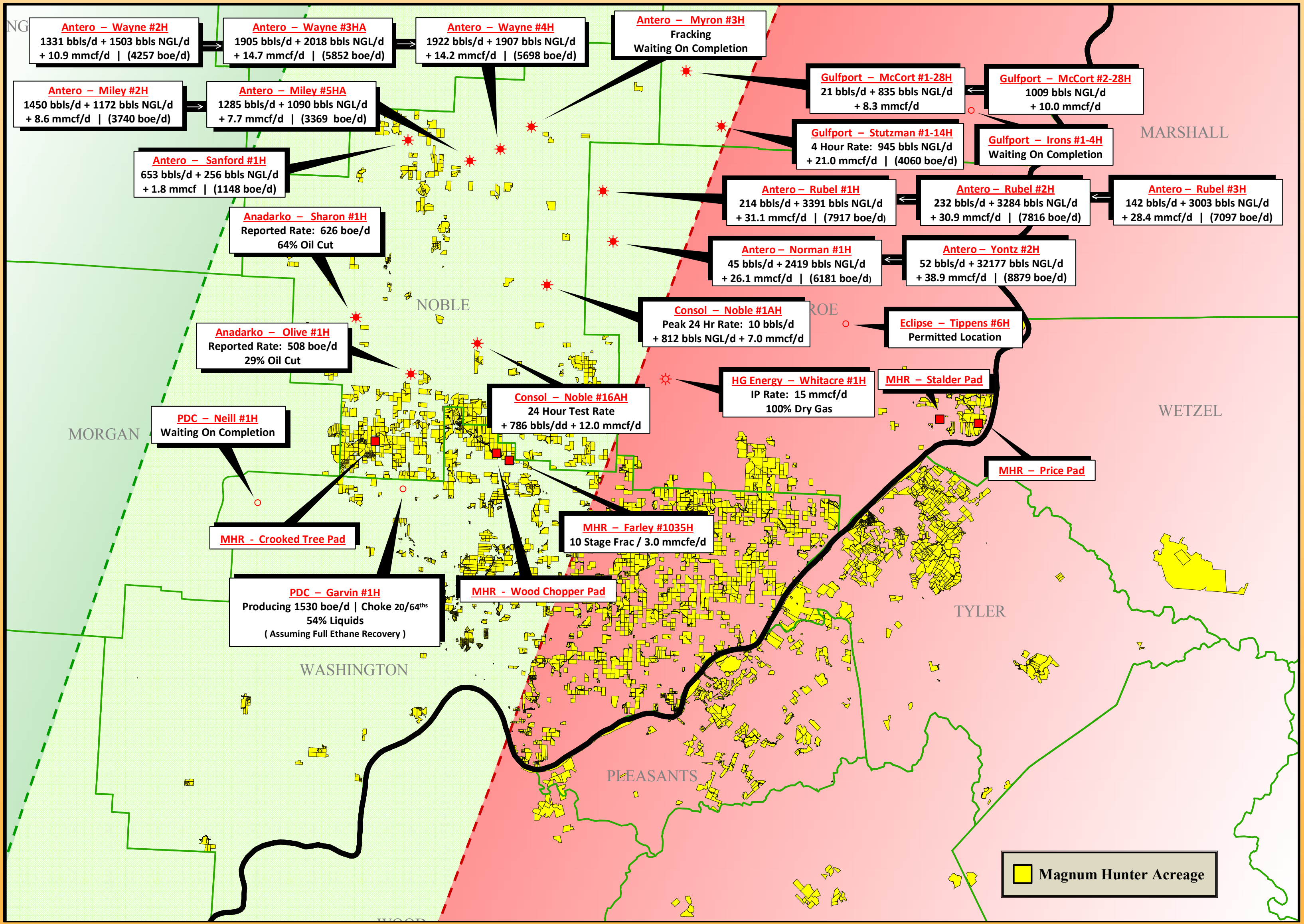
Stalder Pad Drilling Locations



Alpha Hunter T500XD Rig

- **On May 7, 2013 Alpha Hunter took possession of a new state of the art robotic drilling rig**
  - Will be used to drill 16 - 18 wells on the Stalder Pad over the next 18 months
  - First well spud July 1, 2013 (Marcellus test) – Drilling second well on Stalder Pad now (Utica test)

Utica Shale – Recent Well Results



Note: MHR currently owns approximately 94,200 net acres in the Utica Shale; following the MNW acquisition, MHR's acreage position will be in excess of 123,000 net acres.

Eureka Hunter Midstream

Eureka Hunter Midstream Overview

Assets and Business Strategy	***Strategically Positioned Assets*** ➢ **In the heart of "Wet Marcellus" – WV and "Dry Utica" of eastern Ohio** ➢ **~90 miles of primarily 20" – 1135 MAOP gathering system currently in the ground** ➢ **350+ MMcf per day current design capacity with unlimited expansion possibilities** ***Highly Visible Business Model*** ➢ **Stable cash flow through reservation/commodity fee structure** ➢ **Long-term contracts – 10 year minimum** ➢ **Large area reserve potential for continued pipeline expansion and long-life throughput**
Operational and Growth Trajectory	➢ **Building pipeline more efficiently than competition** ➢ **New processing plants in region to realize NGL uplift to wellhead gas price** ➢ **Building pipe into Utica of eastern Ohio – Wet Marcellus / Dry Utica stacked region**
Financial Developments	➢ **Completed partial monetization of Eureka Hunter** • ArcLight Capital Partners, a leading energy-focused investment firm, agreed to invest up to $200 million in the form of convertible preferred units in Eureka Hunter (1) • ArcLight currently owns ~40% of Eureka Hunter ➢ **Completed acquisition of TransTex, a leading private gas treating company with a significant Eagle Ford presence and the potential for Marcellus / Utica expansion (2)**

(1) Initial investment of $106.8 million; ~$60 million to MHR, and the remaining $46.8 million to fund the cash portion of the TransTex acquisition.
(2) TransTex acquisition was completed for $58.5 million. $46.8 million cash portion was funded via the ArcLight Capital Partners investment.

Eureka Hunter Pipeline

Three pipe solution at Carbide

Challenging West Virginia Terrain
(McCormick & Evans)

Ohio River Bore into Ohio

Historical Gathering Volumes

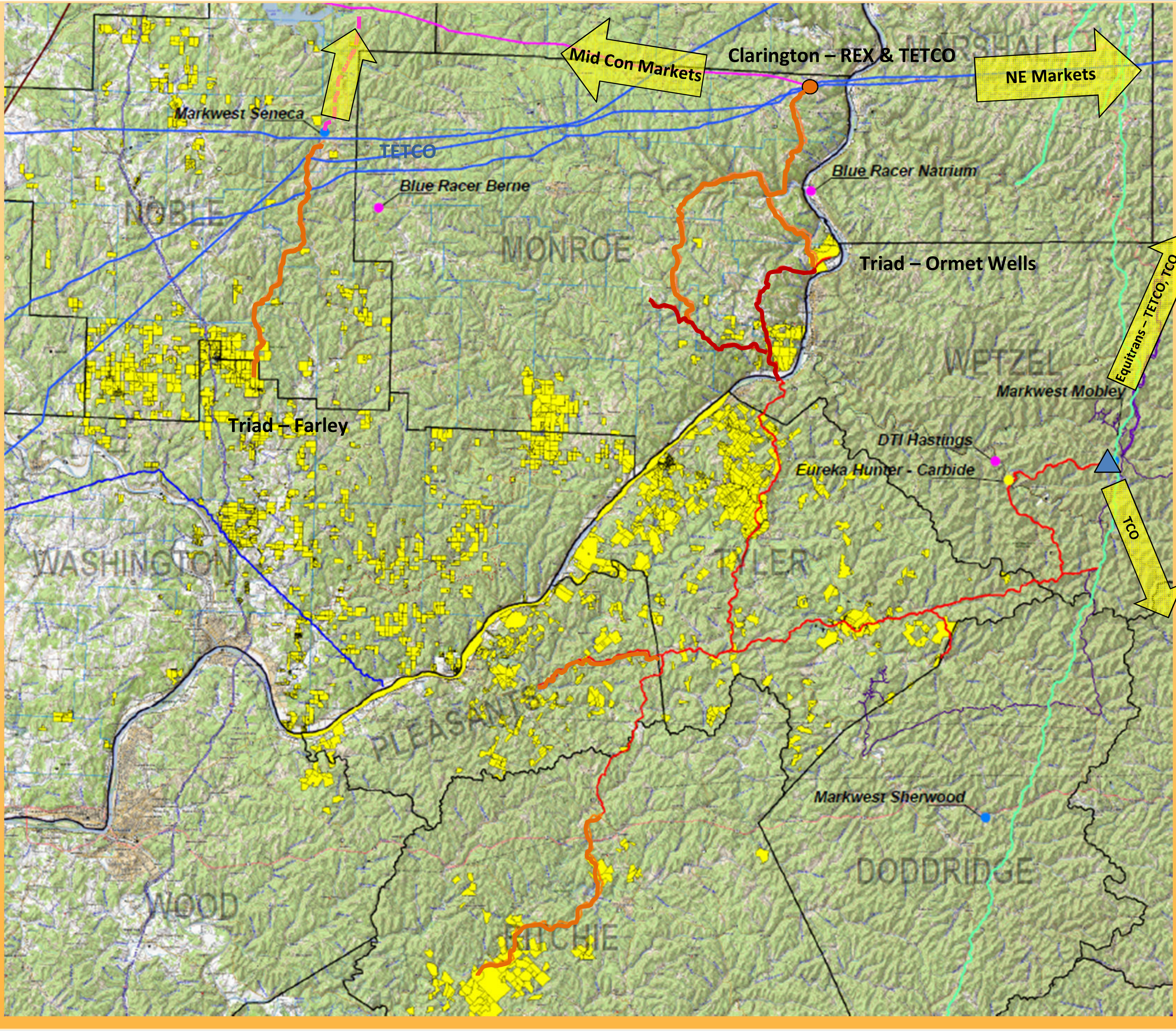
Eureka Hunter Pipeline	2012 Avg.	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13
High Pressure Reservation Volume (MMBtu/d)										
Magnum Hunter	40,000	87,950	87,950	87,950	91,117	92,950	92,950	75,000	75,000	75,000
Third-Parties	6,667	35,000	35,000	35,000	47,000	47,000	47,000	88,000	88,000	88,000
Total	**46,667**	**122,950**	**122,950**	**122,950**	**138,117**	**139,950**	**139,950**	**163,000**	**163,000**	**163,000**
High Pressure Throughput Volume (MMBtu/d)										
Magnum Hunter	23,291	16,055	20,137	29,448	27,876	49,201	59,461	53,984	37,601	26,677
Third-Parties	-	23,688	29,194	35,167	35,180	37,161	38,691	54,426	51,147	26,787
Total	**23,291**	**39,743**	**49,331**	**64,615**	**63,056**	**86,362**	**98,152**	**108,410**	**88,748***	**53,464***

Current throughput of 126,000 MMBtu/d

Year-End 2013 throughput target of 200,000 MMBtu/d (55% third-party)

* Throughput drop is due to Markwest Mobley Plant shut-in

Residue Gas Takeaway



Eureka Hunter Near-Term Organic Expansion

West Virginia

In Process / Under Construction

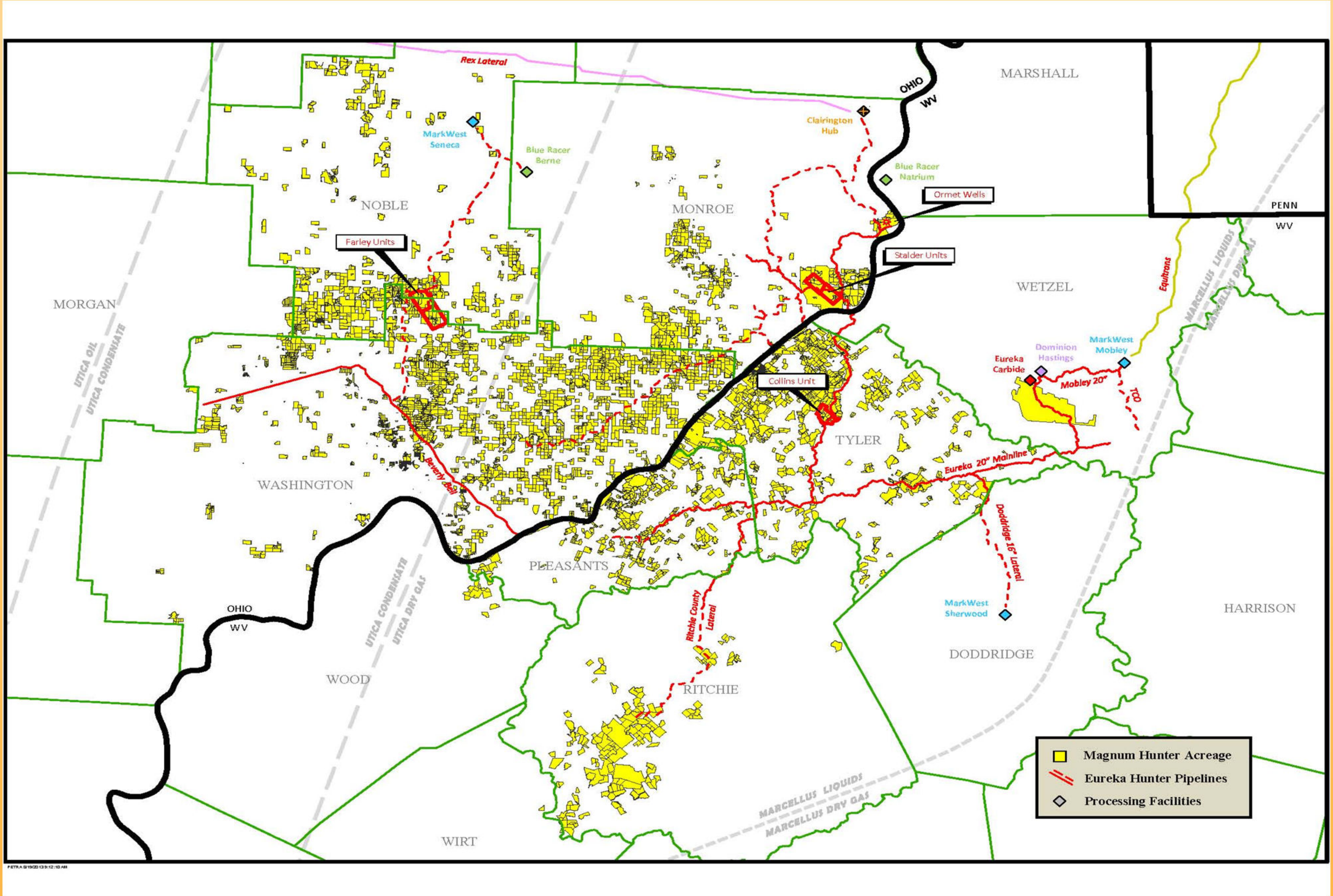
- **Ritchie County Lateral**
  - Southern expansion off mainline to Ritchie County
  - Total project - 23 miles of 16’’ pipeline
  - 13 miles completed
  - Targeting our large contiguous acreage block in Ritchie County
- **Mobley Residue Lateral**
  - Deliver residue gas from Mobley to Columbia Gas Transmission
  - Allows for multiple outlets off of Mobley
  - 90% of ROW acquired
- **Other Mainline Extensions**
  - 5 miles of extensions off Pursley lateral to pick up third-party gas
  - ROW acquired, awaiting permits
  - Expect to be in service by year-end

Ohio

In Process / Under Construction

- **Monroe County System**
  - **Wet and dry gas gathering system expanding throughout eastern Monroe County**
  - **100% of ROW acquired**
  - **Approximately 15 miles of pipe in ground to-date**
  - **Connected to 20” Pursley Lateral in West Virginia**
  - **Unlimited expansion capabilities for both wet gas, dry gas and condensate gathering**
- **Washington / Noble County Lateral**
  - Optioning ROW for lateral from Triad’s Farley pad north to Markwest Seneca / Blue Racer Berne
  - Pipeline will go through the heart of the very rich eastern side of Noble County
  - Initial line will be over 15 miles of 20’’ pipe

Eureka Hunter Utica Exposure



TransTex Hunter Overview

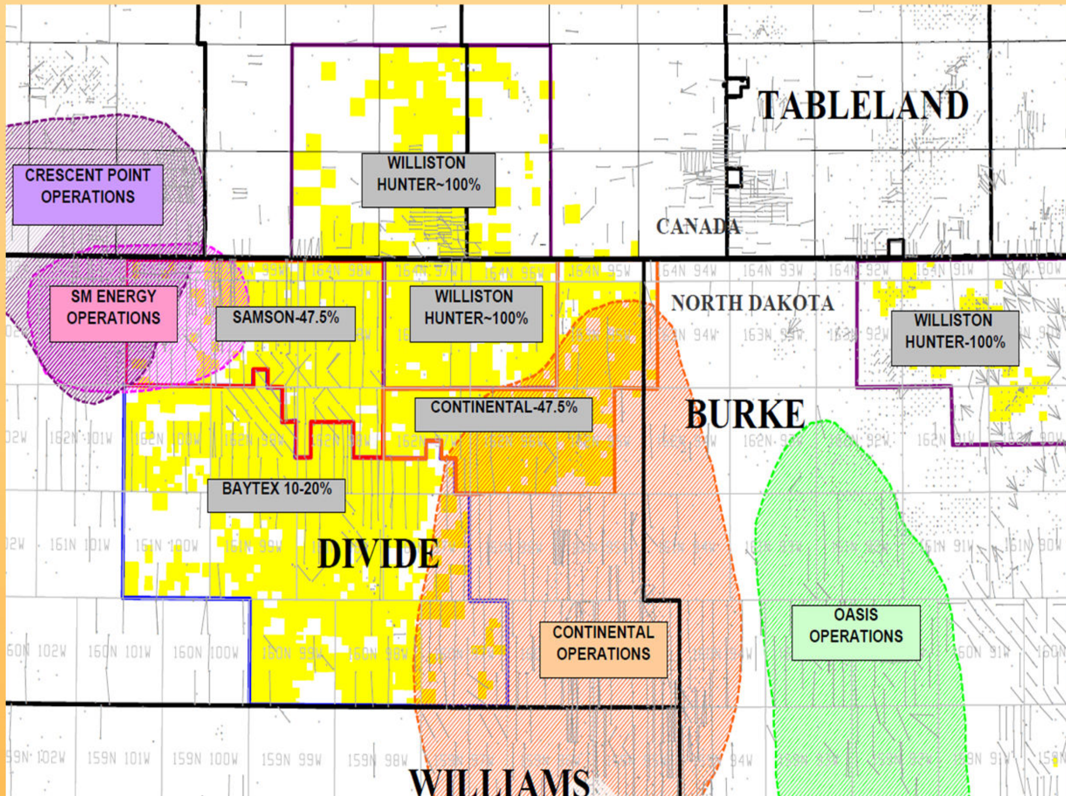
- TransTex Hunter, LLC ("TransTex") founded in 2006; acquired by Eureka Hunter in April 2012
- Provides gas treating services for natural gas producers
- Assets for gas treating, processing, dehydration, and separation equipment
  - Significant market position in treating plants 60 GPM and smaller
  - 38 units currently on location and in operation with 19 customers
  - Majority of the plants located in Texas – in both conventional and unconventional oil / gas fields
  - **Building new units in Hallettsville fabrication shop to meet increased demand**
- Operations team - Design, build, install and operate all sizes of gas treating plants
- Over 90% of revenue from operating lease agreements; 24 - 36 months
- YTD recurring revenues have increased 35% primarily due to increased utilization of TransTex's core assets
- Majority of plants remain in place beyond the term of original agreement

TransTex Hunter Amine Plants

Williston Basin Division

Williston Basin Overview

Areas of Operation

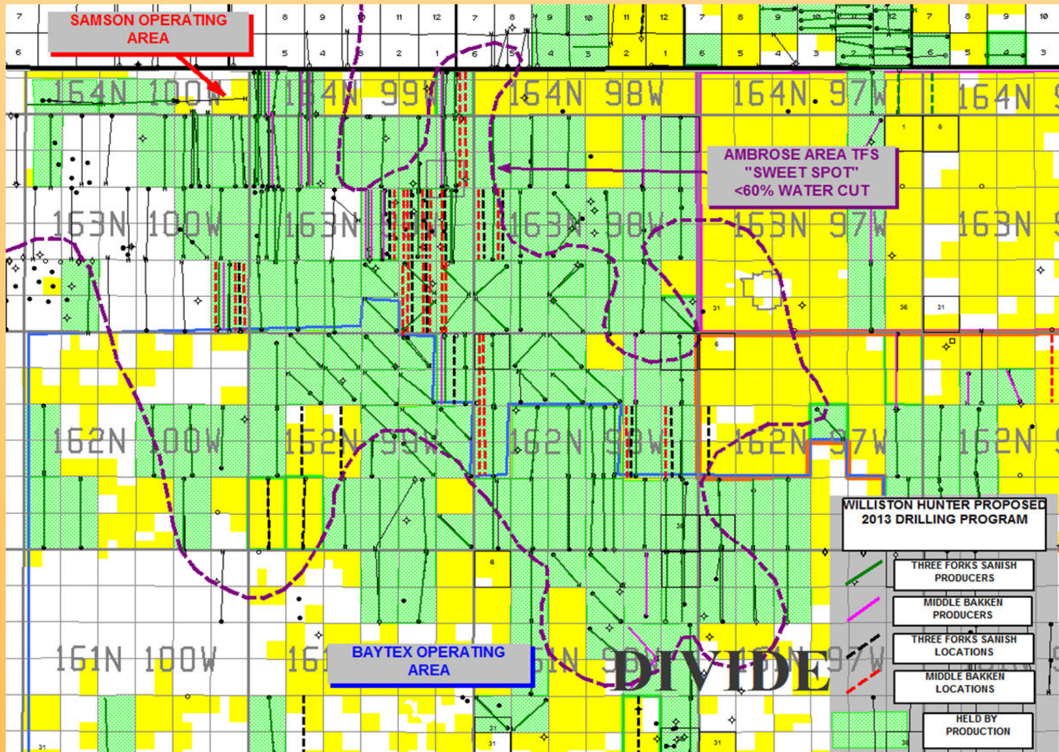


Overview

- **Proved Reserves**
  - Total proved reserves of **19.5** MMBoe as of 6/30/13
  - Proved producing reserves of **10.6** MMBoe as of 6/30/13
- **Acreage**
  - **~175,000** net acres in the Williston Basin
    - **~125,000** net acres in North Dakota, with **~ 90,000** net acres in Divide County
    - **~53,000** net acres in Tableland
- **Drilling Opportunities**
  - Drilling locations target the Middle Bakken/Three Forks Sanish
- **2 Drilling Rigs Active**
  - Our operated rig is currently drilling in Divide County, North Dakota
- **5,500 – 6,000 Boepd of Current Production**
  - 4,500 - 5,000 Boepd in North Dakota
  - 1,000 Boepd in Canada
  - 272 gross producing wells in Divide County, North Dakota and Tableland

Ambrose/Divide County 2013 Activity

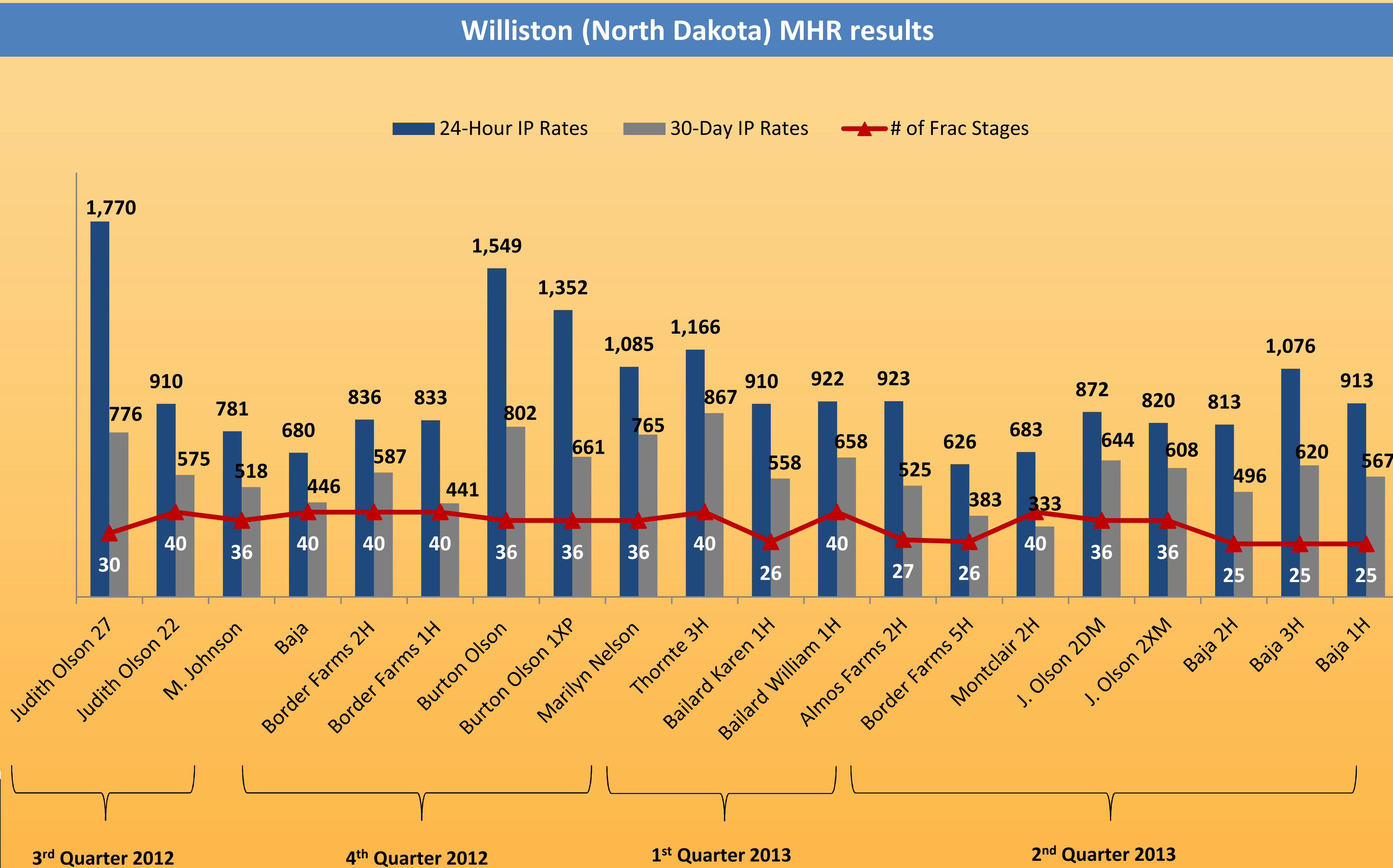
Areas of Operation



Overview

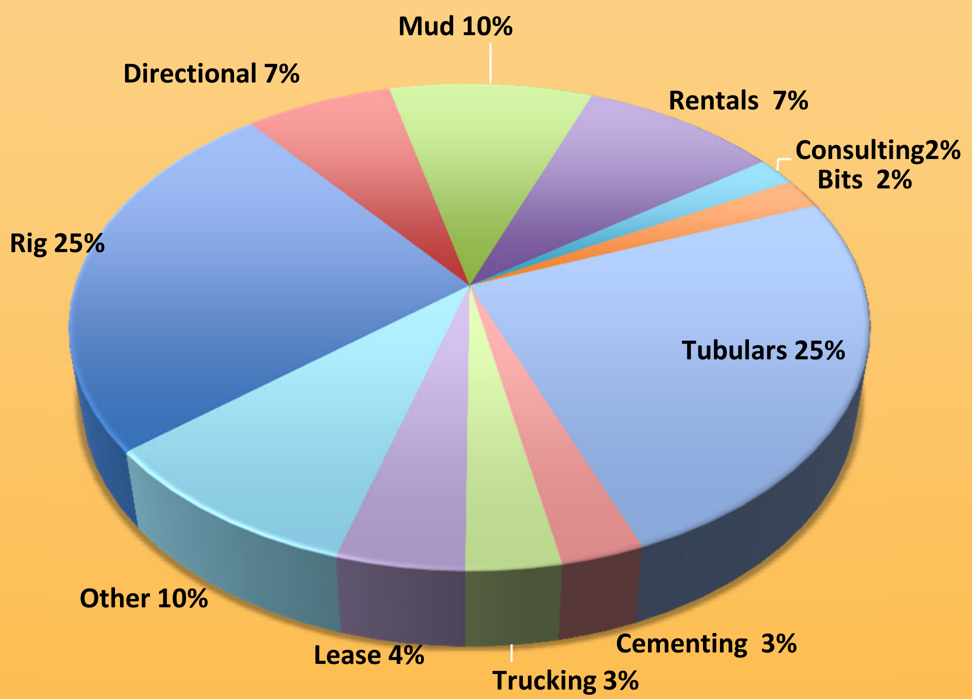
- **2013 Ambrose Field Drilling Program**
  - 30 gross, 10 net wells
  - Targeting Three Forks Sanish and Middle Bakken
- **Prolific Two-mile Lateral Wells**
  - IP 24-hour rates up to 1,200 Boepd
  - IP 30-day rates - 500 – 800 Boepd
- **Reserve Growth Compounding**
  - EUR 350 – 550 Mboe
  - ~500 gross locations in Ambrose sweet spot
- **IRR Increasing Significantly**
  - Low-cost eco-pad drilling reduces per well capital costs
  - Finding costs forecast range $10 - $17/Bbl MBOE
  - ONEOK gas gathering expected to generate reserve bookings, cash flow and production

Williston Basin Recent North Dakota Well Results

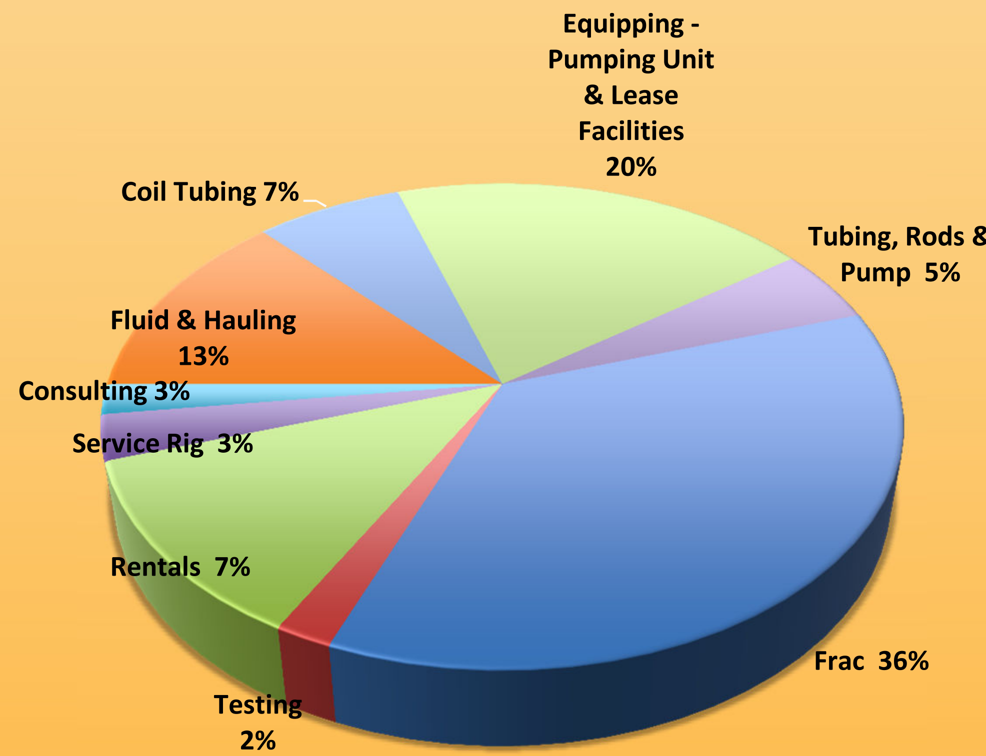


Williston Basin: Drilling Costs: 2 mile lateral

- **Total drill, complete and equipment costs are $6.0 million**
  - **1280 acre DSU – 2 mile lateral**
  - **22 to 28 stage Frac – ~33,000 lb per stage**

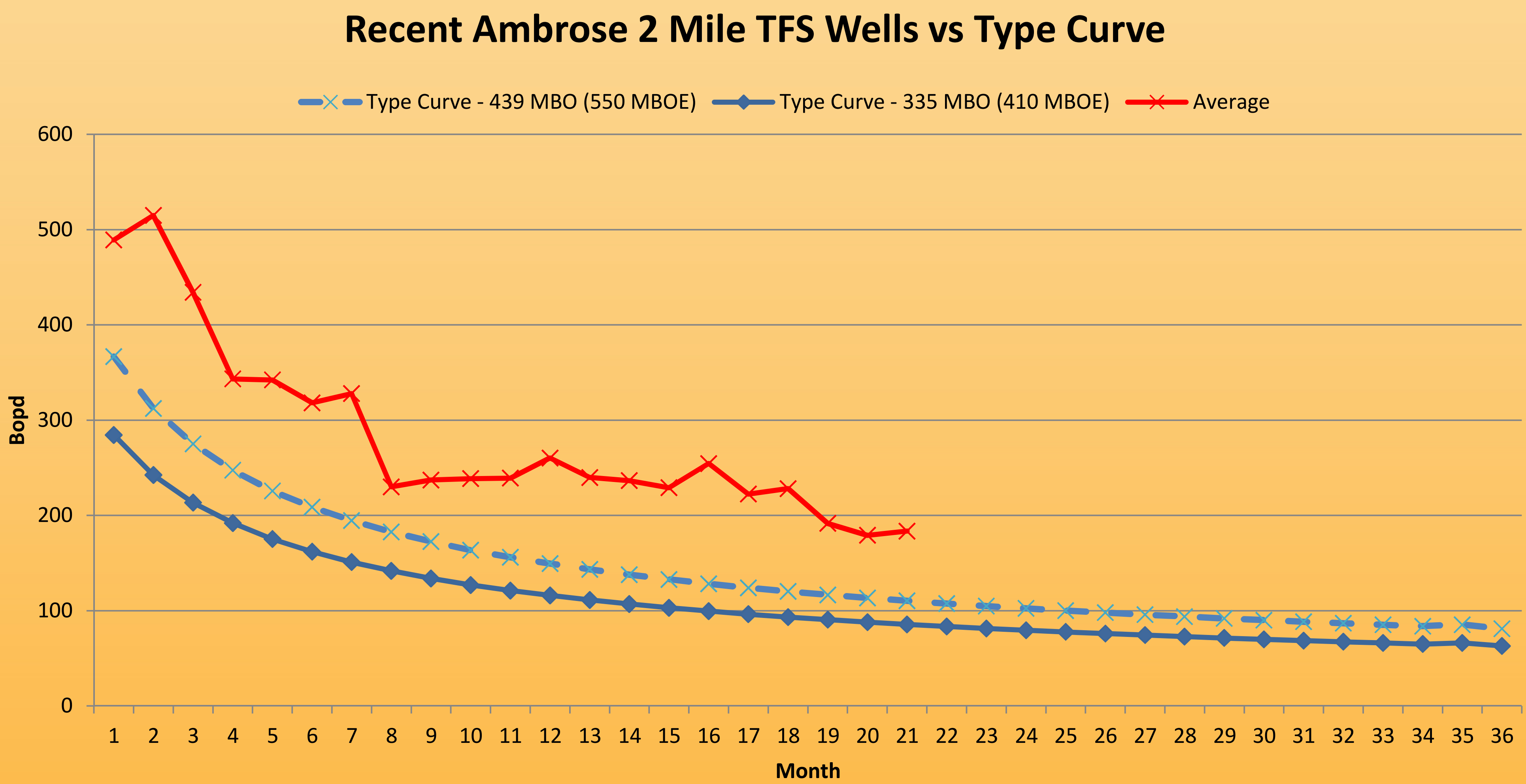


Drilling: $3.2 million



Completion: $2.8 million

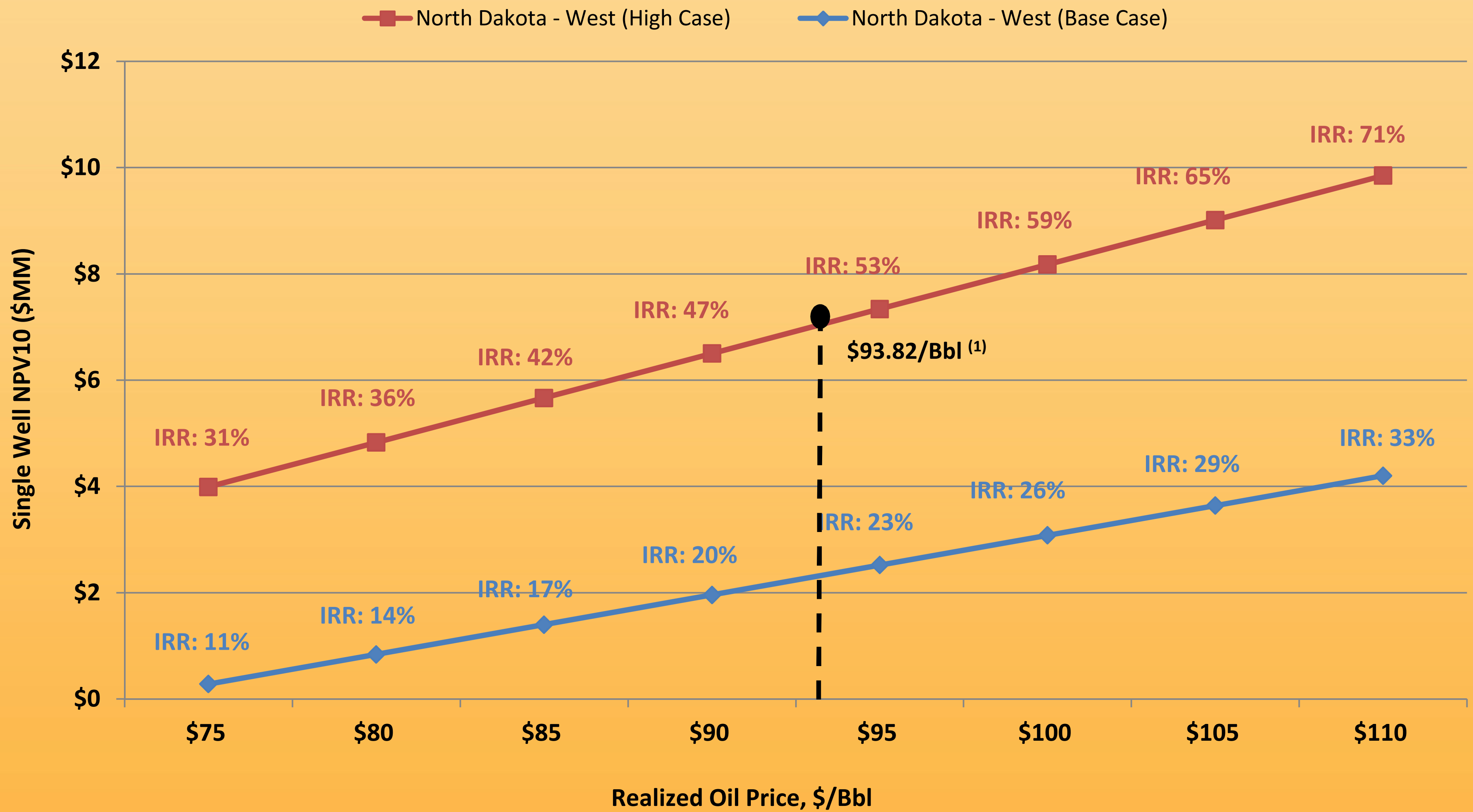
Ambrose 2 Mile TFS Wells vs Type Curve



Williston Basin Economics – Sensitivity

North Dakota – West (High Case)
CAPEX: $6.4 million per well
EUR: 550 MBOE
Differential: $(8)

North Dakota – West (Base Case)
CAPEX: $6.4 million per well
EUR: 350 MBOE
Differential: $(8)



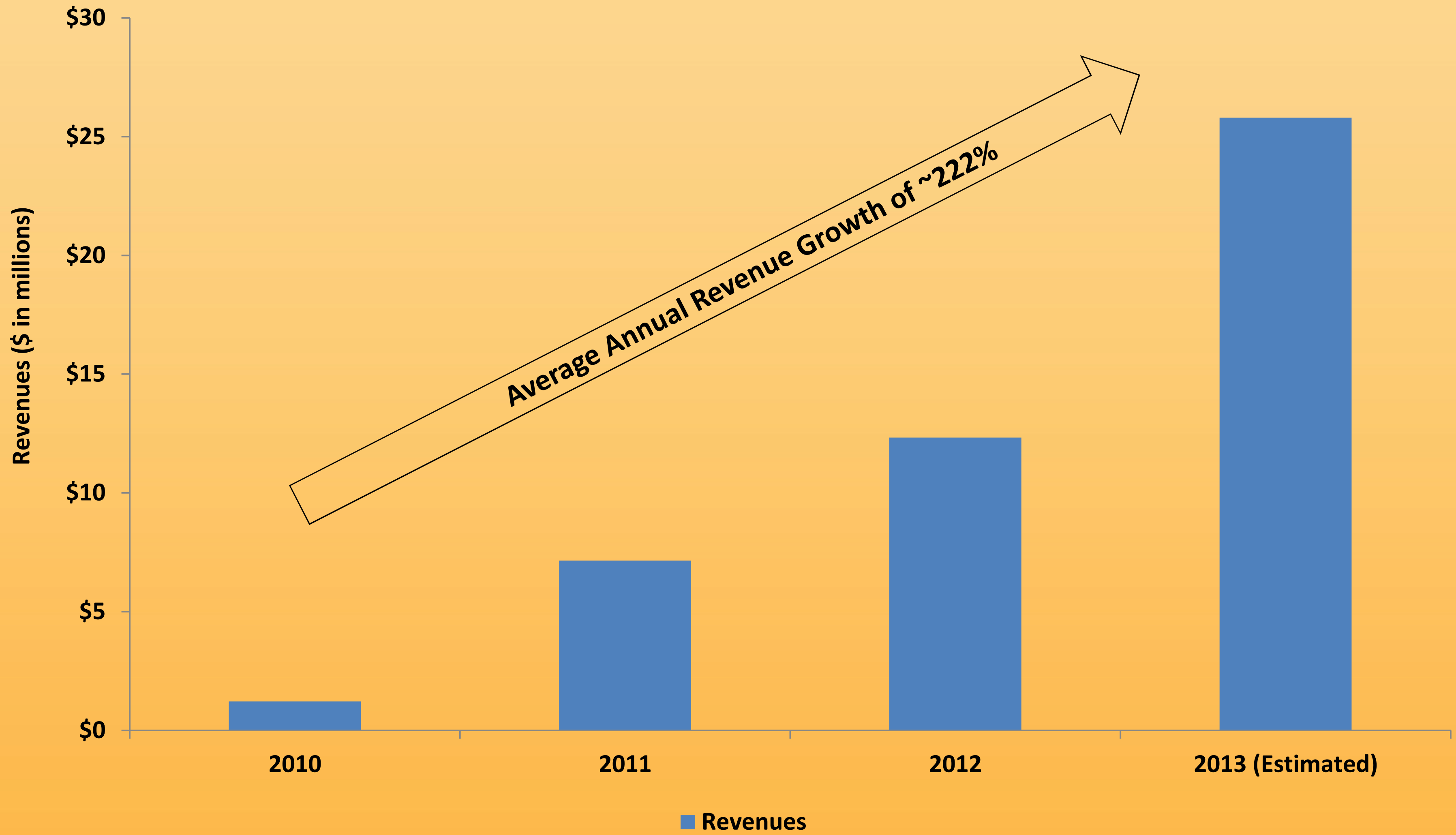
(1) Reflects NYMEX crude oil (WTI) spot pricing as of 12/2/2013

Alpha Hunter Drilling

Drilling Company Overview

- Wholly-owned subsidiary of Magnum Hunter Resources Corporation
- Current fleet of six (6) drilling rigs consisting of:
  - One (1) – Schramm TXD 500
    - Rig #7
      - Spud first well (Stalder Pad) on July 1, 2013
      - Contract Rate of $21,500/day
      - Two (2) year term with Triad Hunter
  - Five (5) – Schramm TXD 200
    - Rig #4
      - Contracted with EQT through December 2013
      - Contract Rate of $12,500/day
    - Rig #5
      - Contracted with EQT through December 2013
      - Contract Rate of $12,500/day
    - Rig #6
      - Contracted with EQT through December 2013
      - Contract Rate of $12,500/day
    - Rig #8
      - Contracted with EQT through December 2013
      - Contract Rate of $12,500/day
    - Rig #9
      - Contracted with Eclipse through May 2014
      - Contract Rate of $12,500/day

Alpha Hunter Growth Plan Continues



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Alpha Hunter Experience

Company	# of Wells Drilled
Bretagne	1
CNX Gas	8
Consol	3
Central WV Oil & Gas	1
Dominion	34
Eagle Ford Hunter	15
Eclipse	3
EQT	136
EXCO Resources	57
Green Hunter Water	4
Hildreth	7
PetroEdge	1
Rex Energy	2
Rogers & Son	1
Rouzer Oil	5
Triad Hunter	14
Virco	1
TOTAL WELLS DRILLED	**293**

Year	# of Wells Drilled
2010	51
2011	64
2012	69
2013	109
TOTAL	**293**

Financial Overview

Capitalization

($ in millions)	December 31, 2012	March 31, 2013	June 30, 2013	September 30, 2013
Cash	$57.6	$91.2	$32.7	$55.3
Debt:				
Revolving Credit Facility due 2016 [1]	$225.0	$325.0	$0.0	$90.0
Senior Unsecured Notes due 2020	$600.0	$600.0	$600.0	$600.0
Equipment and Real Estate Notes Payable	$18.5	$18.9	$22.5	$16.1
Total Debt	$843.5	$943.9	$622.5	$706.1
Redeemable Preferred Stock				
Series C Cumulative Perpetual Preferred Stock (Non-Convertible)	$100.0	$100.0	$100.0	$100.0
Shareholders' Equity				
Series D Cumulative Perpetual Preferred Stock (Non-Convertible)	$210.4	$221.2	$221.2	$221.2
Series E Cumulative Convertible Preferred Stock	$94.4	$95.1	$95.1	$95.1
Common Stock	$406.8	$348.5	$498.1	$192.8
Total Capitalization	**$1,655.2**	**$1,708.8**	**$1,536.9**	**$1,315.2**

Note: Capitalization excludes Series A Convertible Preferred Units of Eureka Hunter Holdings, LLC and a $50 million term loan at Eureka Hunter Pipeline, LLC.
(1) Current borrowing base of $265 million.

Adjusted EBITDAX Reconciliation

($ in millions)	Full Year 2009	Full Year 2010	Full Year 2011	Full Year 2012
Net income (loss)	**(15.1)**	**(22.3)**	**(76.7)**	**(139.4)**
Unrealized (gain) loss on derivatives, net	**7.7**	**3.1**	**4.2**	**(10.9)**
Interest expense, net	**2.7**	**3.6**	**12.0**	**51.8**
Income taxes expense (benefit)	**0.0**	**0.0**	**(0.7)**	**(23.0)**
Impairment of oil and gas properties	**0.6**	**0.3**	**22.9**	**4.1**
Depreciation, depletion and amortization	**4.5**	**8.9**	**49.1**	**135.8**
Non-cash stock compensation expense	**3.1**	**6.3**	**25.1**	**15.7**
Non-cash 401K matching expense	**0.0**	**0.0**	**0.0**	**1.4**
Exploration & abandonment expense	**0.6**	**0.9**	**1.5**	**117.2**
Loss (gain) on sale of assets	**0.0**	**(0.1)**	**(0.2)**	**0.6**
Unrealized (gain) loss on investments	**0.0**	**0.0**	**0.0**	**0.0**
Non-recurring transaction and other expense	**1.2**	**3.4**	**13.2**	**15.2**
Adjusted EBITDAX	**$5.4**	**$4.2**	**$50.4**	**$168.6**

Estimated Fourth Quarter Production Expected to Drive 2013 Exit Rate

Well Name[1]	Location	MHR Working Interest	MHR Net Revenue Interest	Estimated Gross Production[2] Bbls/d[3]	Estimated Gross Production[2] Mcfe/d	Estimated Net Production[2] Bbls/d[3]	Estimated Net Production[2] Mcfe/d	Anticipated Timing
Charger 0706-1H	Divide County, North Dakota	48%	38%	350	2,100	133	798	10/1/13
Strom 2536-1H	Divide County, North Dakota	46%	37%	350	2,100	129	774	10/6/13
Coronet 2314-1H	Divide County, North Dakota	46%	37%	350	2,100	128	767	10/30/13
Pulvermacher 1NC	Divide County, North Dakota	34%	27%	250	1,500	67	404	11/1/13
Johnson 3-6HS	Divide County, North Dakota	2%	1%	350	2,100	4	27	11/15/13
Tundra 3130 3TFH	Divide County, North Dakota	90%	72%	200	1,200	145	867	12/7/13
Tundra 3130 4TFH	Divide County, North Dakota	90%	72%	200	1,200	145	867	12/7/13
Points 2-163-97	Divide County, North Dakota	95%	76%	150	900	114	684	12/7/13
Bel Air 2314-2H	Divide County, North Dakota	44%	35%	350	2,100	123	737	12/21/13
Bel Air 2314-3H	Divide County, North Dakota	44%	35%	350	2,100	123	737	12/21/13
Comet 2635-2H	Divide County, North Dakota	44%	35%	350	2,100	123	737	12/21/13
Comet 2635-3H	Divide County, North Dakota	44%	35%	350	2,100	123	737	12/21/13
Bel Air 2314-1H	Divide County, North Dakota	44%	35%	350	2,100	123	737	12/21/13
Comet 2635-1H	Divide County, North Dakota	44%	35%	350	2,100	123	737	12/21/13
Kidd 1-19H1	Divide County, North Dakota	27%	22%	350	2,100	77	461	12/21/13
Meadow Valley 3-1H	Divide County, North Dakota	2%	2%	350	2,100	5	32	12/21/13
Morner 1-23H	Divide County, North Dakota	0%	0%	250	1,500	0	2	12/21/13
BH Issac 6H	Divide County, North Dakota	100%	80%	200	1,200	160	960	12/23/13
BH Pacer 3427 2H	Divide County, North Dakota	100%	80%	200	1,200	160	960	2/1/14
Peter 4-2H	Divide County, North Dakota	1%	1%	350	2,100	4	21	2/1/14
Windfaldet 2-4H	Divide County, North Dakota	2%	2%	350	2,100	6	33	3/1/14
Anker 1-22H	Divide County, North Dakota	2%	2%	250	1,500	4	23	3/1/14
				6,600	**39,600**	**2,017**	**12,103**	

Note: This information constitutes forward-looking statements and is subject to the qualifications on the first page of this investor presentation
(1) Wells are currently in the process of drilling, completing, and /or waiting on sales
(2) Based on estimated IP-30 day rate (average daily amount of production during the first 30 days of production)
(3) Does not include any associated natural gas or NGLs

Estimated Fourth Quarter Production Expected to Drive 2013 Exit Rate

Well Name[1]	Location	MHR Working Interest	MHR Net Revenue Interest	Estimated Gross Production[2]		Estimated Net Production[2]		Anticipated Timing
				Boe/d[3]	Mcfe/d	Boe/d[3]	Mcfe/d	
Collins #1116H	Tyler County, West Virginia	100%	87%	966	5,798	841	5,044	12/6/13
Collins #1117H	Tyler County, West Virginia	100%	87%	966	5,798	841	5,044	12/6/13
Collins #1118H	Tyler County, West Virginia	100%	87%	966	5,798	841	5,044	12/6/13
Collins #1119H	Tyler County, West Virginia	100%	87%	966	5,798	841	5,044	12/6/13
Mills Wetzel 20H	Wetzel County, West Virginia	50%	40%	485	2,910	194	1,164	12/31/13
Mills Wetzel 21H	Wetzel County, West Virginia	50%	40%	485	2,910	194	1,164	12/31/13
Mills Wetzel 22H	Wetzel County, West Virginia	50%	40%	485	2,910	194	1,164	12/31/13
Mills Wetzel 23H	Wetzel County, West Virginia	50%	40%	485	2,910	194	1,164	12/31/13
Stalder #3UH	Monroe County, Ohio	50%	39%	1,689	10,133	664	3,983	12/31/13
Ormet #1-9H	Monroe County, Ohio	100%	87%	755	4,531	657	3,942	12/31/13
Ormet #2-9H	Monroe County, Ohio	100%	88%	755	4,531	661	3,965	12/31/13
Ormet #3-9H	Monroe County, Ohio	90%	70%	755	4,531	531	3,189	12/31/13
WVDRN #1207	Wetzel County, West Virginia	100%	80%	970	5,821	776	4,657	1/31/14
WVDRN #1208	Wetzel County, West Virginia	100%	80%	970	5,821	776	4,657	1/31/14
WVDRN #1209	Wetzel County, West Virginia	100%	80%	970	5,821	776	4,657	1/31/14
Mills Wetzel 16H	Wetzel County, West Virginia	50%	40%	485	2,910	194	1,164	2/28/14
Mills Wetzel 17H	Wetzel County, West Virginia	50%	40%	485	2,910	194	1,164	2/28/14
Mills Wetzel 18H	Wetzel County, West Virginia	50%	40%	485	2,910	194	1,164	2/28/14
Mills Wetzel 19H	Wetzel County, West Virginia	50%	40%	485	2,910	194	1,164	2/28/14
Stalder #2MH	Monroe County, Ohio	47%	39%	755	4,531	297	1,781	3/31/14
				15,366	**92,195**	**10,053**	**60,320**	

New Wells in Appalachia and the Bakken Potentially Add Net Production in Excess of 12,000 BOEPD

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(1) Wells are currently in the process of drilling, completing, and/or waiting on sales
(2) Based on estimated IP-30 day rate (average daily amount of production during the first 30 days of production)
(3) Includes NGLs and condensate

Non-Core Divestiture Summary

- **Aggressively pursuing in excess of $250 million of non-core asset sales to enhance our financial flexibility to focus capital on high return oil/liquids projects**
- **Internal technical team evaluating portfolio for additional non-core property divestitures**

Non-Core Asset Sales	Value ($MM)	
Completed To-Date		
Eagle Ford Sale	$401.0	
Gain on Sale of PVA Stock	$10.6	
Burke County, North Dakota	$32.5	
Red Star Gold	$1.5	
Other	$1.0	
Subtotal	**$446.6**	
In Process		
Pearsall Shale - Atascosa County	$25.0	(Est.)
Waterfloods - North Dakota and West Virginia [1]	$75.0	(Est.)
Combined Canadian Properties	$80.0 - $95.0	(Est.)
Magnum Hunter Production	$70.0 - $85.0	(Est.)
Other [2]	$5.0	(Est.)
Subtotal	**$255.0 - $285.0**	(Est.)
Total Non-Core Assets	**$701.6 - $731.6**	(Est.)

(1) On November 19, 2013, MHR entered into a PSA with Enduro Operating LLC to sell the North Dakota Waterfloods for $45 million
(2) Includes Sentra, a utility in Kentucky, and other miscellaneous assets

Financial Strategy

- **Capital spending driven by rates of return across all operating areas**
  - Focus on development of existing acreage in our core areas
  - 2013 capital budget will focus on high return oil/liquids areas in the Williston and Appalachian Basins
  - Margins and EBITDA projected to substantially increase throughout the next two years
  - Limited overhead expansion required to meet growth objectives
- **Maintain manageable credit ratios and liquidity while managing growth**
  - Continue to increase Senior Credit Facility borrowing base through reserves additions from organic growth to maximize liquidity
  - Raised a total of $600 million of senior unsecured notes in 2012
  - Aggressively pursuing in excess of $250 million of identified non-core asset divestitures
  - Maintain sufficient liquidity to provide operational flexibility
  - Goal is to further simplify balance sheet
- **Maintain an active hedging program to support economic returns and ensure strong coverage metrics**
  - Target rolling 50% hedging program one to two years forward – will hedge further opportunistically
  - Current natural gas hedges in place provide ~$4/MMBtu on ~50% of estimated 2013 production

Crude Oil and Natural Gas Hedges

Crude Oil	2013	2014	2015
NYMEX Average [(1)]	$97.46	$93.00	$88.15
Weighted-Average Hedge Price With Ceilings	$100.38	$100.90	$115.93
Weighted-Average Hedge Price With Floors	$87.33	$85.00	$85.00
Weighted-Average Swap Price	$92.74	-	-
Hedge Volumes [(2)(3)]	7,963	4,663	259

Natural Gas	2013	2014	2015
NYMEX Average [(1)]	$3.66	$3.96	$4.07
Weighted-Average Hedge Price With Ceilings	$5.90	$5.05	-
Weighted-Average Hedge Price With Floors	$4.50	$4.25	-
Weighted-Average Swap Price	$3.62	$4.13	-
Hedge Volumes [(2)(3)]	35,534	20,000	-

(1) NYMEX strip pricing as of 12/2/2013
(2) Includes three-way oil collars: Floors sold (put) by year are as follows: 2013: 4,201 bbls/d at $62.92; 2014: 4,663 bbls/d at $64.95 ; 2015: 259 bbls/d at $70.00
(3) Does not include 10,000 MMBtu/d at $3.75 of sold puts in 2014 and 1,570 bbls/d at $120.00 of sold calls in 2015

MHR Net Asset Value*

($ in thousands)		Assumptions Low	Assumptions High	Valuation Low	Valuation High
Total Proved Reserves PV-10 (6/30/2013) [(1)]				**666,369**	**666,369**
		$/acre Low	$/acre High		
Undeveloped Acreage [(2)]					
Eagle Ford	6,000	$3,000	$5,000	$18,000	$30,000
Williston Basin U.S.	61,725	$3,000	$5,000	$185,175	$308,625
Williston Basin Canada	48,500	$1,000	$2,000	$48,500	$97,000
Marcellus	81,000	$5,000	$7,000	$405,000	$567,000
Utica - Wet	25,000	$10,000	$13,000	$250,000	$325,000
Utica - Dry	69,200	$8,000	$13,000	$553,600	$899,600
Other Appalachia	200,000	$50	$100	$10,000	$20,000
Total				**$1,470,275**	**$2,247,225**
Certain Other Assets (9/30/2013)					
Eureka Hunter Pipeline - MHR Share of Estimated Total Market Value [(3)]				$420,000	$570,000
Alpha Hunter Drilling [(4)]				$20,000	$40,000
Total				**$440,000**	**$610,000**
Total Asset Value				**$2,576,644**	**$3,523,594**
Less (9/30/2013):					
Series C Preferred				$100,000	$100,000
Series D Preferred				$221,244	$221,244
Series E Preferred				$95,069	$95,069
Senior Revolver Outstanding, net of cash				$34,700	$34,700
Senior Notes				$600,000	$600,000
Other Debt				$16,100	$16,100
Total				**$1,067,113**	**$1,067,113**
Net Asset Value				**$1,509,531**	**$2,456,481**
Shares Outstanding [(5)]				171.0	171.0
Net Asset Value per Share				**$8.83**	**$14.37**

* See Appendix for information regarding NAV, PV-10 and Standardized Measure
(1) Includes the proved reserves associated with the Burke County, ND properties (14,500 net acres) the subject of our previously announced sale to Oasis Petroleum for $32.5 million cash, that closed in September 2013
(2) Approximate amount of undeveloped acreage as of November 1, 2013
(3) Based on MHR's estimated total market valuation of Eureka Hunter Pipeline of between $750 million and $1.0 billion and MHR's approximate 60% equity ownership of Eureka Hunter Pipeline
(4) MHR's estimated FMV of Alpha Hunter Drilling
(5) Basic shares outstanding as of November 7, 2013

A Focused Company on the Right Path

- Proven management and technical team in place committed to proper capital allocation for future growth
- Geographically diversified asset base in three of the most prolific shale plays in the US (Utica, Marcellus and Bakken)
- Successful proven track record in all aspects of the development of key resource plays in the US
- Improved balance sheet with significant liquidity to provide operational flexibility in funding capital expenditures for future growth
- Continued focus on operational efficiency and net margin expansion
- Commitment to best practices regarding financial and operational procedures

Equity Research Coverage / Contact Information

Magnum Hunter Resources (NYSE: MHR)

Equity Research Analyst Coverage:

BMO Capital Markets
Canaccord Genuity
Capital One Southcoast
Citigroup Global Markets
Credit Suisse
Deutsche Bank Securities
Goldman Sachs
Imperial Capital
KeyBanc Capital Markets
MLV Partners
RBC Capital Markets
Robert W. Baird & Co.
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Appendix

Net Asset Value

Although Magnum Hunter does not consider "Net Asset Value" and "Net Asset Value Per Share" to be "non-GAAP financial measures," as defined in SEC rules, Magnum Hunter uses Net Asset Value as an estimate of fair value. Net Asset Value and Net Asset Value Per Share should not be considered as alternatives to PV-10, GAAP Stockholders Equity or GAAP per share net income (loss) amounts. Magnum Hunter's NAV calculation is based on numerous assumptions that may change as a result of future activities or circumstances.

PV-10

PV-10 is the present value of the estimated future cash flows from estimated total proved reserves after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates of future income taxes. The estimated future cash flows are discounted at an annual rate of 10% to determine their "present value." We believe PV-10 to be an important measure for evaluating the relative significance of our oil and gas properties and that the presentation of the non-GAAP financial measure of PV-10 provides useful information to investors because it is widely used by professional analysts and investors in evaluating oil and gas companies. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable for evaluating the Company. We believe that PV-10 is a financial measure routinely used and calculated similarly by other companies in the oil and gas industry. However, PV-10 should not be considered as an alternative to the standardized measure as computed under GAAP.

The standardized measure of discounted future net cash flows relating to Magnum Hunter's total proved oil and gas reserves is as follows:

	As of June 30, 2013 (1)
Future cash inflows	$ 2,768,997
Future production costs	(1,199,407)
Future development costs	(285,526)
Future income tax expense	-
Future net cash flows	1,284,064
10% annual discount for estimated timing of cash flows	(617,695)
Standardized measure of discounted future net cash flows related to proved reserves	$ 666,369
Reconciliation of Non-GAAP Measure	
PV-10	$ 666,369
Less: Income taxes	
Undiscounted future income taxes	-
10% discount factor	-
Future discounted income taxes	-
Standardized measure of discounted future net cash	$ 666,369

(1) The PV-10 value and the standardized measure shown in the table above are the same as the Company projects that any potential future net tax expense related to the projected future net cash flows above would be offset by currently existing net operating loss carry forwards and tax basis even after consideration of the tax gain from the sale of the Eagle Ford Properties. The tax gain on the sale is expected to be primarily offset in 2013 by the Company's expensing of intangible drilling costs and a projected tax loss from continuing operations. As a result, the majority of the net operating loss carry forwards available at December 31, 2012 will still be available to offset future net cash flows. Based on the lower projected future net cash flows, no tax expense, after utilization of the net operating loss carry forwards and tax basis, would be recognized.