UNIT CORPORATION

IPAA Oil & Gas Investment Symposium

April 20, 2015

Forward Looking Statement

This presentation contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, included in this presentation that address activities, events or developments that the Company expects, believes or anticipates will or may occur in the future are forward-looking statements. The words "believe," "expect," "anticipate," "plan," "intend," "foresee," "should," "would," "could," or other similar expressions are intended to identify forward-looking statements, which are generally not historical in nature. However, the absence of these words does not mean that the statements are not forward-looking. Without limiting the generality of the foregoing, forward-looking statements contained in this presentation specifically include the expectations of plans, strategies, objectives and anticipated financial and operating results of the Company, including as to the Company's drilling program, production, hedging activities, capital expenditure levels and other guidance included in this presentation. These statements are based on certain assumptions made by the Company based on management's expectations and perception of historical trends, current conditions, anticipated future developments and other factors believed to be appropriate. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. These include risks relating to financial performance and results, current economic conditions and resulting capital restraints, prices and demand for oil and natural gas, availability of drilling equipment and personnel, availability of sufficient capital to execute the Company's business plan, the Company's ability to replace reserves and efficiently develop and exploit its current reserves and other important factors that could cause actual results to differ materially from those projected. Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law. The SEC generally permits oil and gas companies, in filings made with the SEC, to disclose only proved reserves, which are reserve estimates that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. In this communication, the Company uses the term "unproved reserves" which the SEC guidelines prohibit from being included in filings with the SEC. "Unproved reserves" refers to the Company's internal estimates of hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques. Unproved reserves may not constitute reserves within the meaning of the Society of Petroleum Engineer's Petroleum Resource Management System or proposed SEC rules and does not include any proved reserves. Actual quantities that may be ultimately recovered from the Company's interests will differ substantially. Factors affecting ultimate recovery include the scope of the Company's ongoing drilling program, which will be directly affected by the availability of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals and other factors; and actual drilling results, including geological and mechanical factors affecting recovery rates. Estimates of unproved reserves may change significantly as development of the Company's core assets provide additional data. In addition, our production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases.

This presentation contains financial measures that have not been prepared in accordance with U.S. Generally Accepted Accounting Principles ("non-GAAP financial measures") including LTM EBITDA and certain debt ratios. The non-GAAP financial measures should not be considered a substitute for financial measures prepared in accordance with U.S. Generally Accepted Accounting Principles ("GAAP"). We urge you to review the reconciliations of the non-GAAP financial measures to GAAP financial measures in the appendix.

Overview of Operations

– Tulsa based diversified energy company incorporated in 1963
– Integrated approach to business allows Unit to balance its capital deployment through the various stages of the energy cycle

Key Growth Points

- Exploration & Production
  - 203% average production replacement since 2005
  - Liquids production has grown 258% since the fourth quarter of 2009
  - Proved reserves: 179 MMBoe [1]

- Drilling
  - Six BOSS rigs operating; two contracted to be built
  - 92 drilling rig fleet

- Mid-Stream
  - 145% increase in daily natural gas processing volumes since 2010
  - 170% increase in daily liquids sold volumes since 2010
  - Approximately 1,525 miles of pipeline

- Strong Balance Sheet
  - Remains conservatively financed as the company has grown

[1] As of 12/31/2014.

2014 Accomplishments

- Unit Corporation
  - Revenue increased 16%
  - Adjusted EBITDA increased 17% [1]

- Oil and Natural Gas Segment
  - Production has increased 9%
  - Liquids production (oil and NGLs) have increased 16%

- Contract Drilling Segment
  - Average per day operating margins increased 8% [2]
  - Averaged 75.4 working rigs compared to 65.0, up 16%
  - BOSS drilling rig program is underway
    - First six currently working
    - Two additional BOSS rigs to be built in 2015
    - Ordered long lead time components for two additional BOSS rigs

- Midstream Segment
  - Gas processed volume per day growth of 15%
  - Per day liquids sold growth of 35%
  - Segment operating profit increased 13%

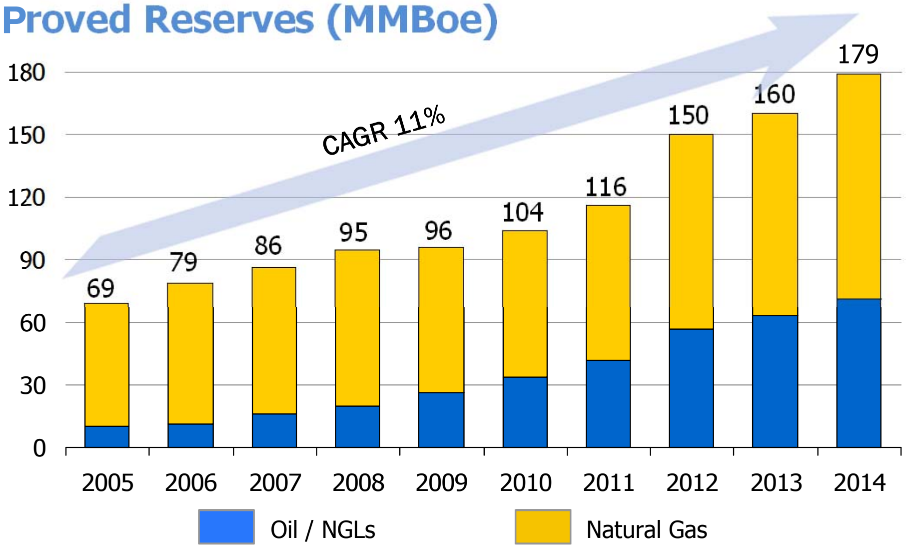
(1) See Non-GAAP Financial Measures – Adjusted EBITDA in Appendix (also available at www.unitcorp.com/investor/reports.html).
(2) See Reconciliation of Average Daily Operating Margin Before Elimination of Intercompany Rig Profit and Bad Debt Expense in Appendix (also available at www.unitcorp.com/investor/reports.html).

Strong Capital Discipline

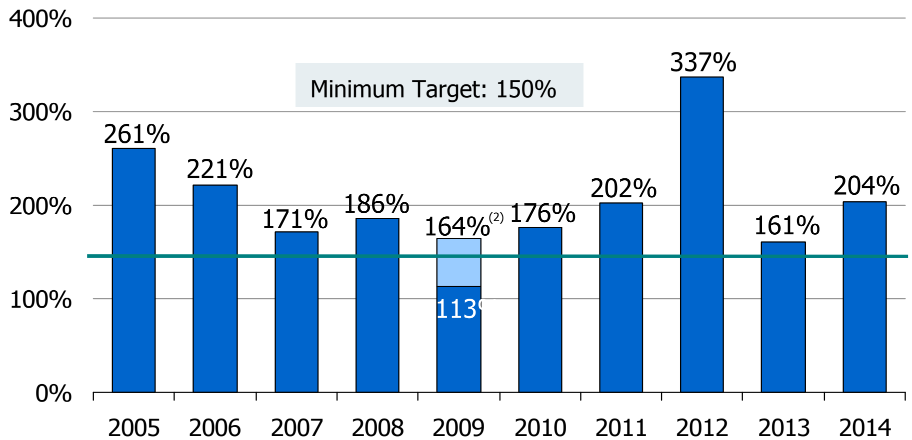
- Debt to market capitalization of 26%
- Strong access to capital
- No near-term maturities
- Consistent growth profile for all segments
- Oil and natural gas exploration not driven by lease expirations

Track Record of Reserve Growth

Proved Reserves (MMBoe)



Annual Reserve Replacement[1]

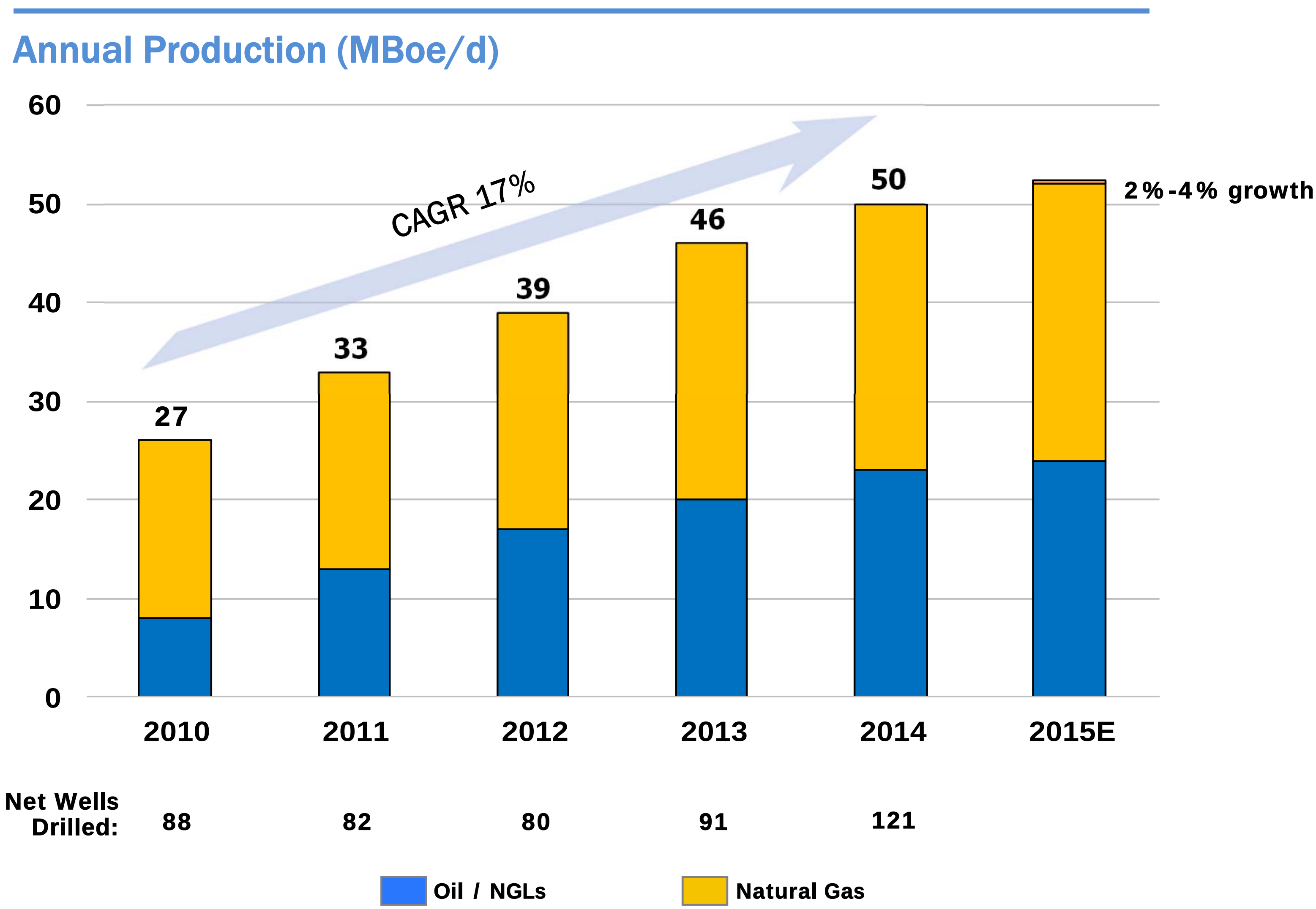


- ✓ Stable and consistent economic growth of oil and natural gas reserves of at least 150% of each year's production
- ✓ 221% average annual production replacement over last 30 years
- ✓ Reserve growth driven by Oklahoma and Texas activity and a shift from vertical to horizontal / liquids-rich drilling

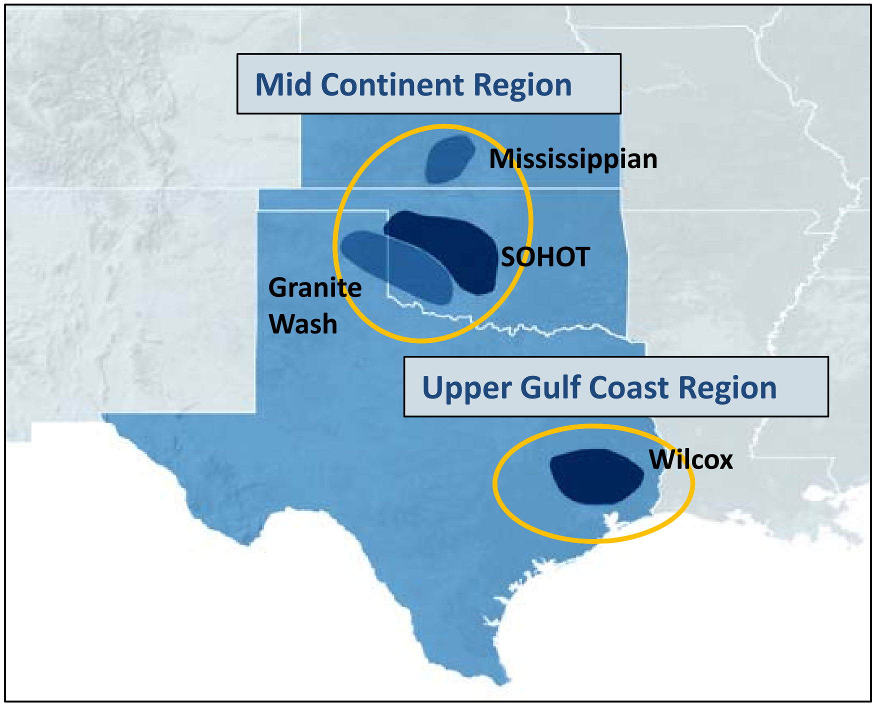
[1] The Company uses the reserve replacement ratio as an indicator of the Company's ability to replenish annual production volumes and grow its proved reserves, including by acquisition, thereby providing some information on the sources of future production. It should be noted that the reserve replacement ratio is a statistical indicator that has limitations. The ratio is limited because it typically varies widely based on the extent and timing of discoveries and property acquisitions. Its predictive and comparative value is also limited for the same reasons. In addition, since the ratio does not imbed the cost or timing of future production of new reserves, it cannot be used as a measure of value creation.

[2] 164% based on previous SEC reporting standards.

Increasing Production While Improving Commodity Mix



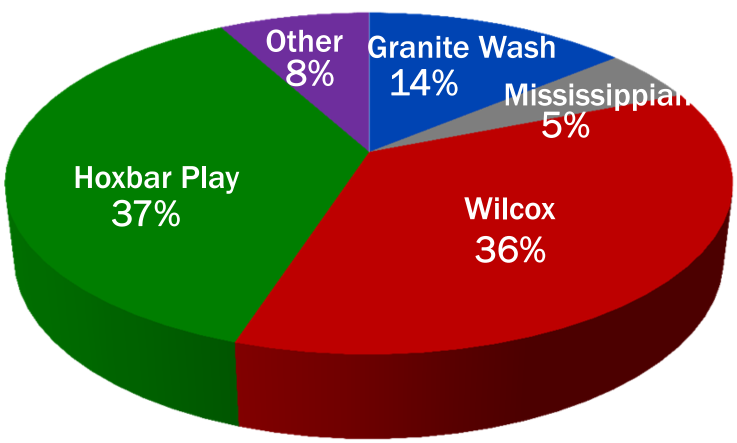
Core Upstream Producing Areas



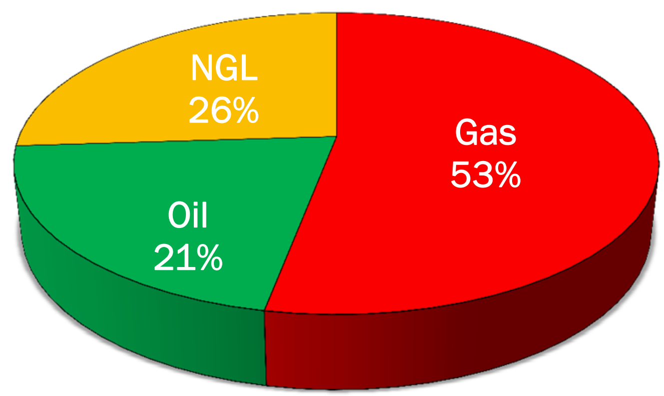
- ✓ **Key focus areas include:**
  - **Gulf Coast**:
    - Wilcox (Southeast Texas)
  - **Mid-Continent:**
    - Hoxbar (Western Oklahoma)
    - Granite Wash (Texas Panhandle)
    - Mississippian (Kansas)

- ✓ **Upside resource potential:**
  - 1,400 – 1,800 gross wells
  - 75% average working interest
  - 760 – 960 gross MMBoe
  - 47% liquids (16% oil, 31% NGLs)

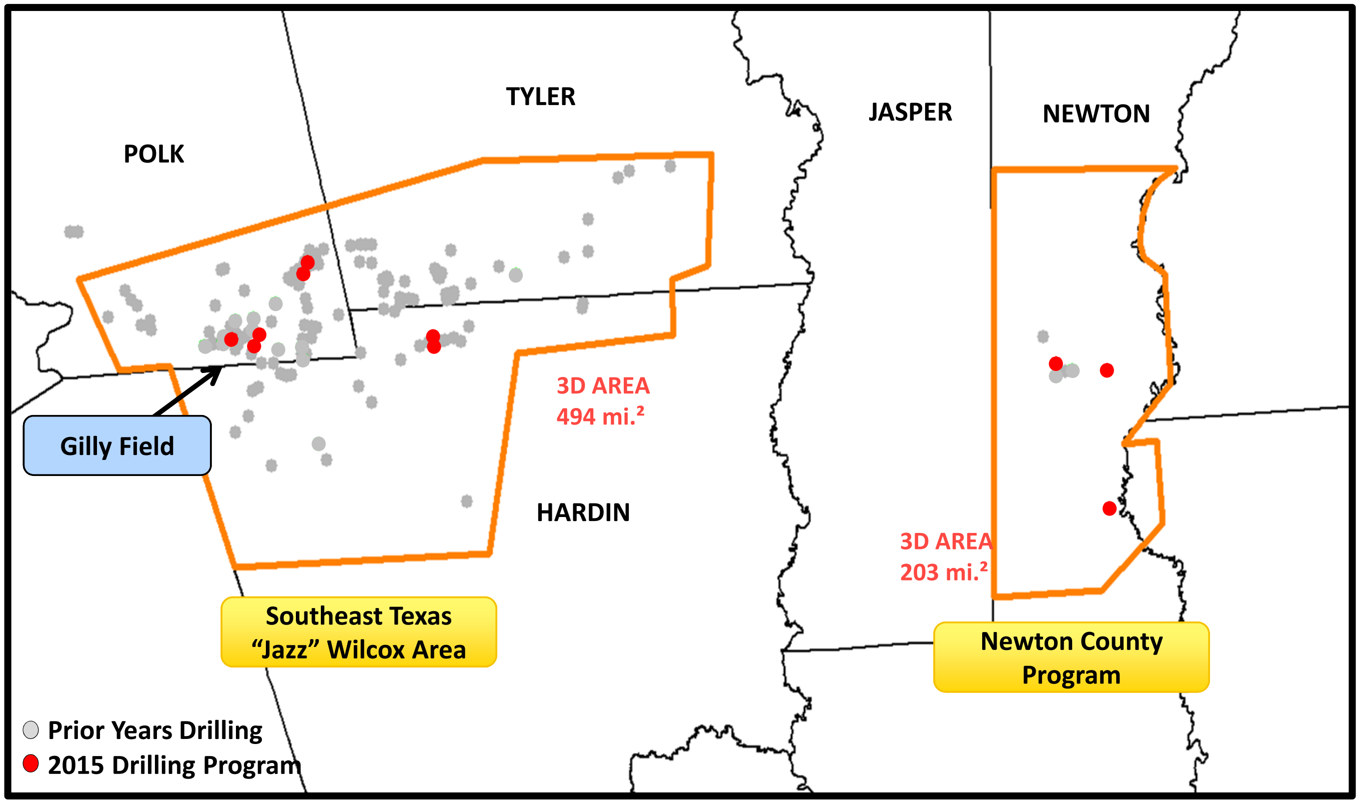
2015 CapEx Breakdown: $309 Million Budget



Q4 2014 Daily Production: 52.9 MBoe/d



Wilcox (Liquids)



Overall Highlights:

- Drilled 133 operated vertical wells since 2003 (12 years)
- 92% average WI
- Q4 '14 avg. production: 70 MMcfe/d
- 43% liquids (11% oil)
- Historical ROR: 112%
- CAGR: 22% (5 years)

Gilly Field Highlights:

- 14 producing wells; 1 PUD
- Increased field resource potential by 37% to 418 gross Bcfe
- Gilly Blackwood zone:
  - CWC: 4.8 MM; EUR: 9.3 Bcfe
  - ROR: ≥100%*

*Price Deck: $50.00 oil; $14.11 NGLs; $3.00 Natural Gas held flat for 2 years followed by strip

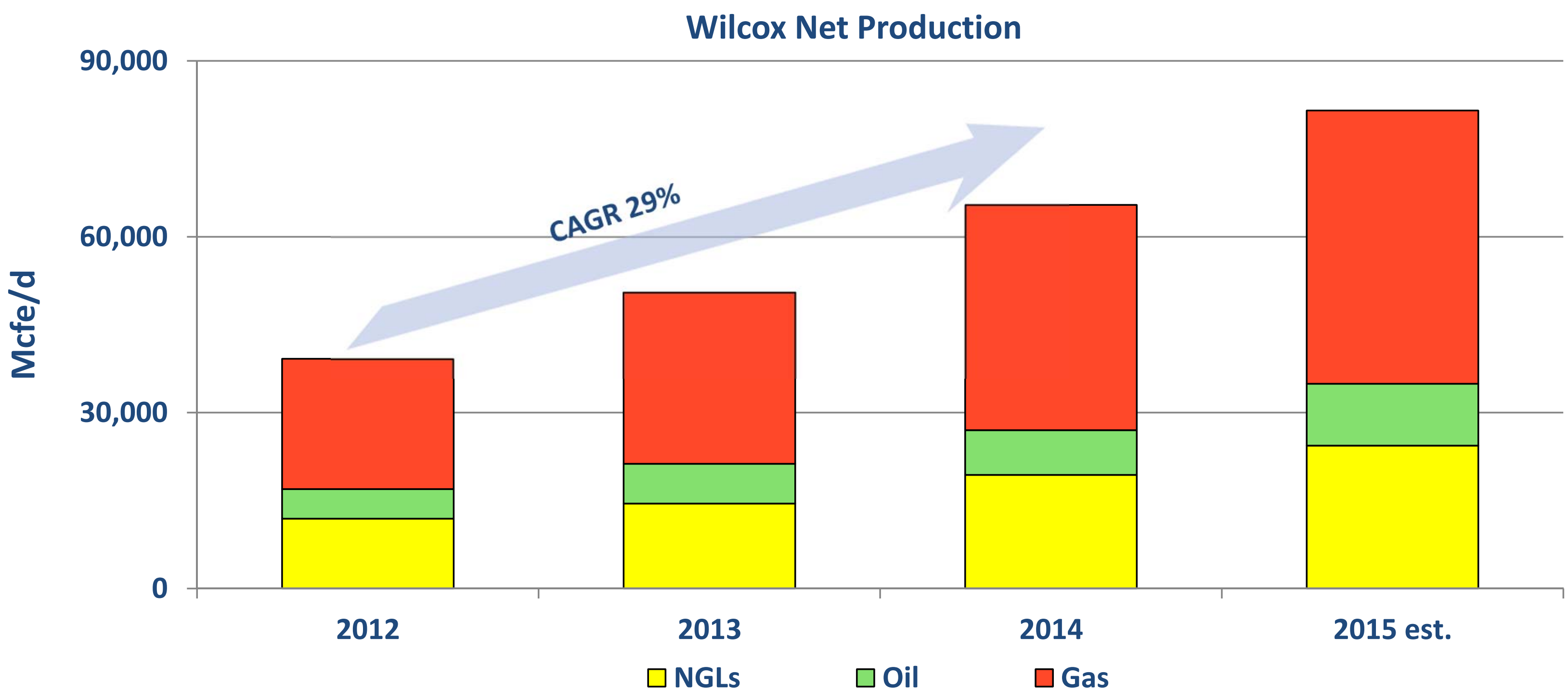
Wilcox (Southeast Texas)

2015 Activity:

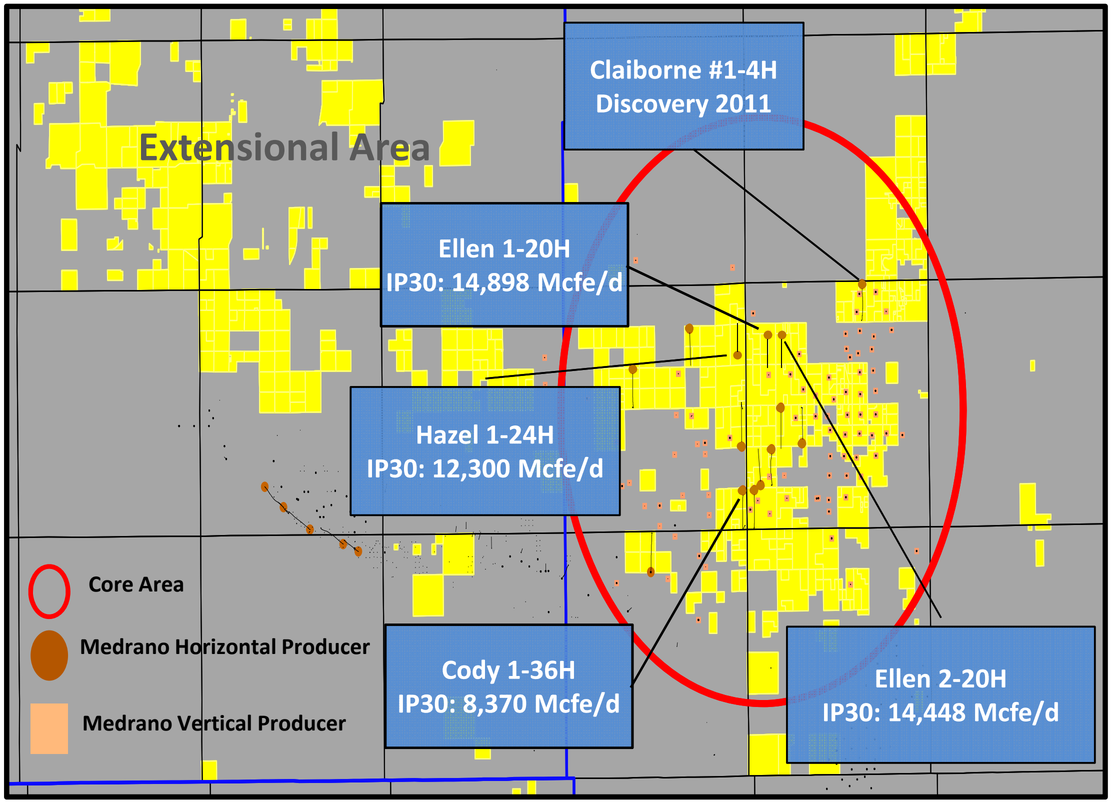
- 1-2 rigs
- 12-14 gross wells (6 horizontal)
- 2015 projected 18% growth

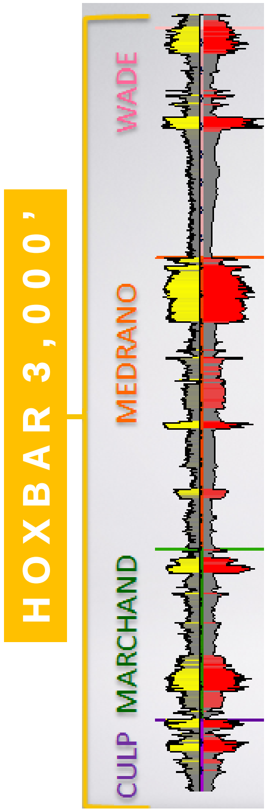
Upside Resource Potential:

- 135 wells (110 horizontal)
- 870 Bcfe
- 95% average WI
- 43% Liquids (11% oil, 32% NGLs)



Hoxbar (Liquids)
SOHOT – Medrano Sand





Medrano Single Well Parameters:

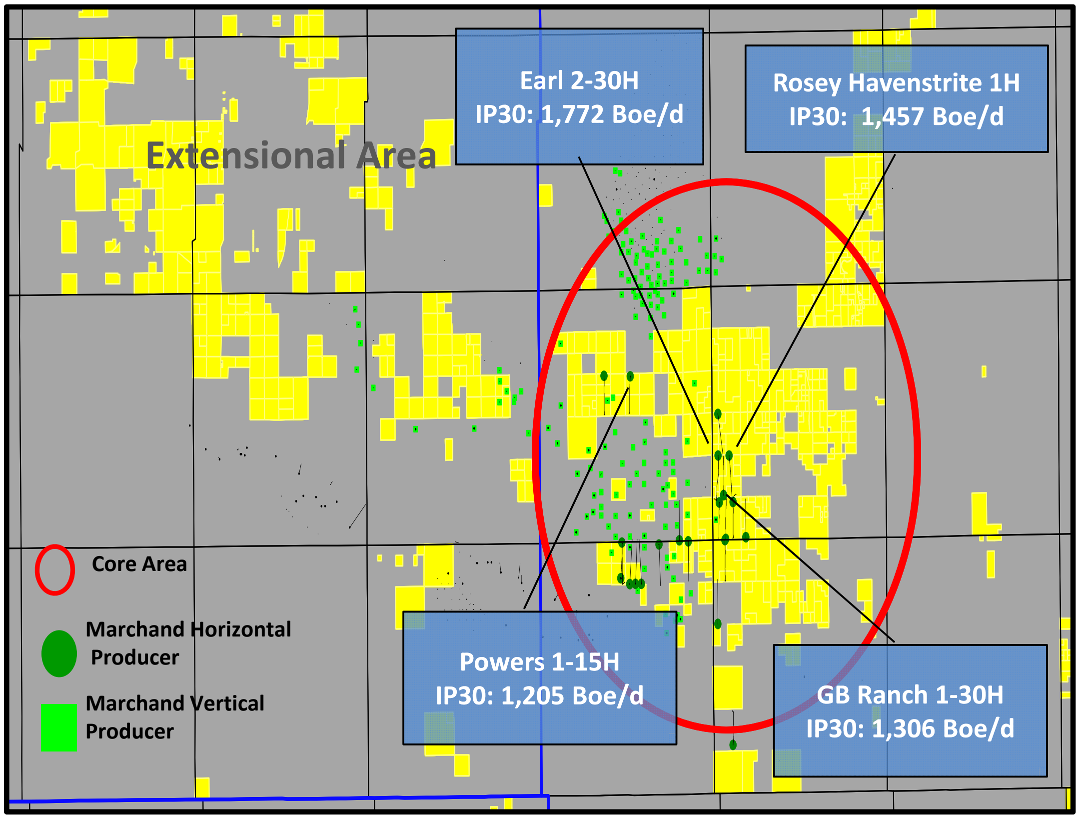
- EUR: 5.8 Bcfe (larger frac)
- Well cost: $4.8 million
- ROR: 44%*
- 33% liquids (8% oil)
- 150-200 core locations
- 60% avg. working interest

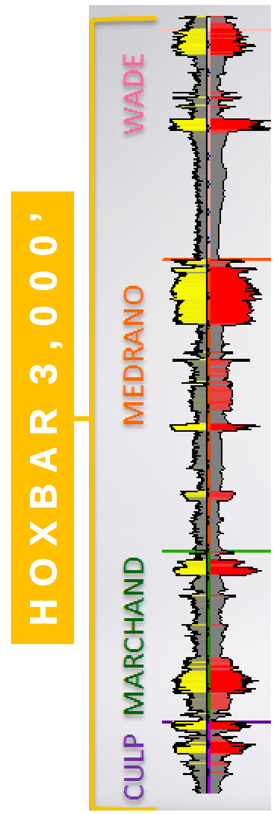
2015 Hoxbar Activity:

- 1-2 rigs
- 8-10 wells

*Price Deck: $50.00 oil; $14.11 NGLs; $3.00 Natural Gas held flat for 2 years followed by strip

Hoxbar (Oil)
SOHOT – Marchand Sand





Marchand Single Well Parameters:

- EUR: 447 MBoe
- Well cost: $6.0 million
- ROR: 92%*
- 89% liquids (80% oil)
- 50 core locations
- 60% avg. working interest

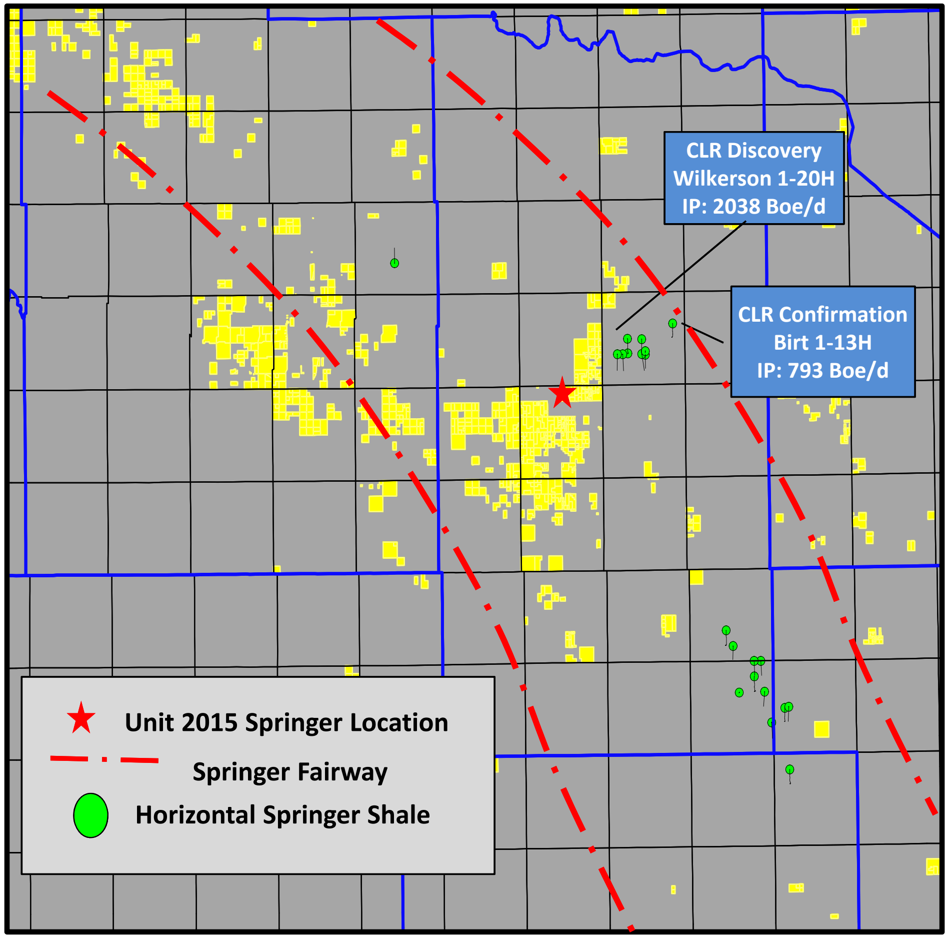
2015 Hoxbar Activity:

- 0-1 rigs
- 2-4 wells

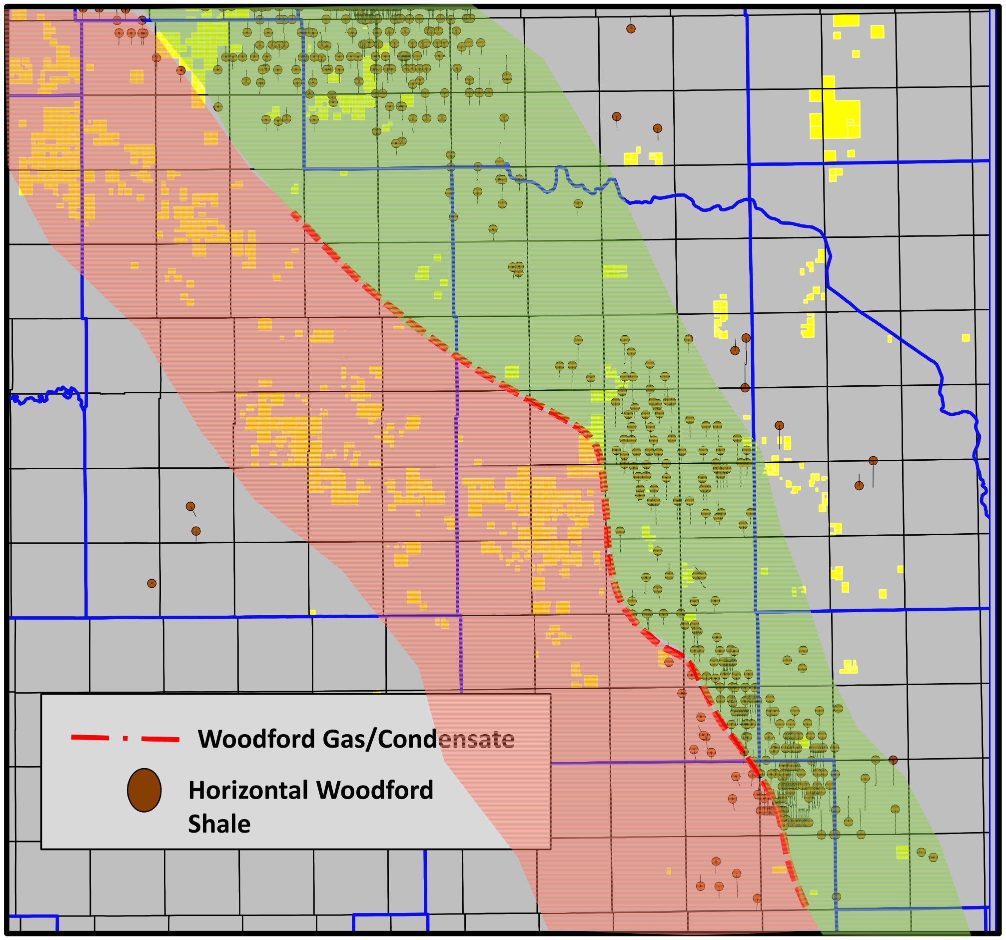
*Price Deck: $50.00 oil; $14.11 NGLs; $3.00 Natural Gas held flat for 2 years followed by strip

SOHOT Upside

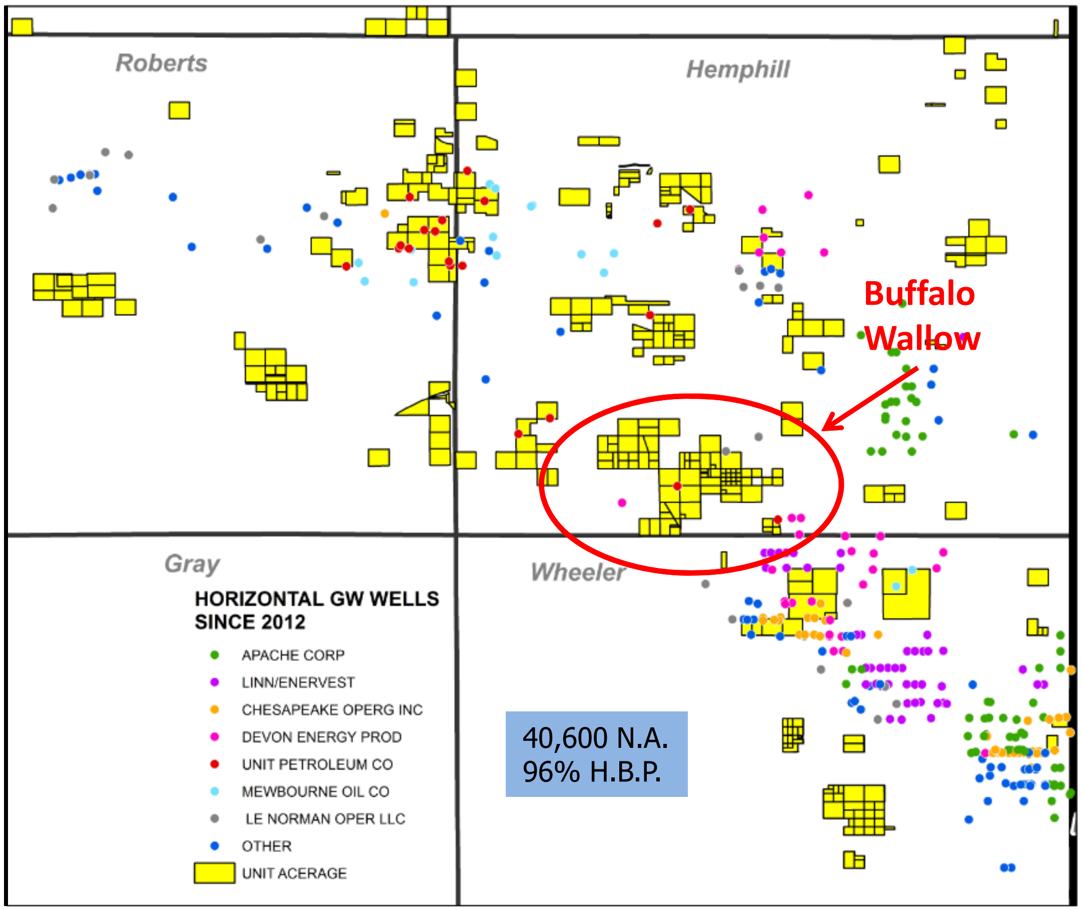
Springer Shale



Woodford Shale



Granite Wash (Liquids)



Historical Highlights:

- Completed 93 operated horizontal wells since 2008
- Average WI: 80%
- Q4 '14 avg. production: 122 MMcfe/d
- Average IP30: 5.3 MMcfe/d
- 52% liquids (12% oil)
- CAGR: 37% (5 years)

2015 Activity:

- 0-1 rigs total
- 5 net wells

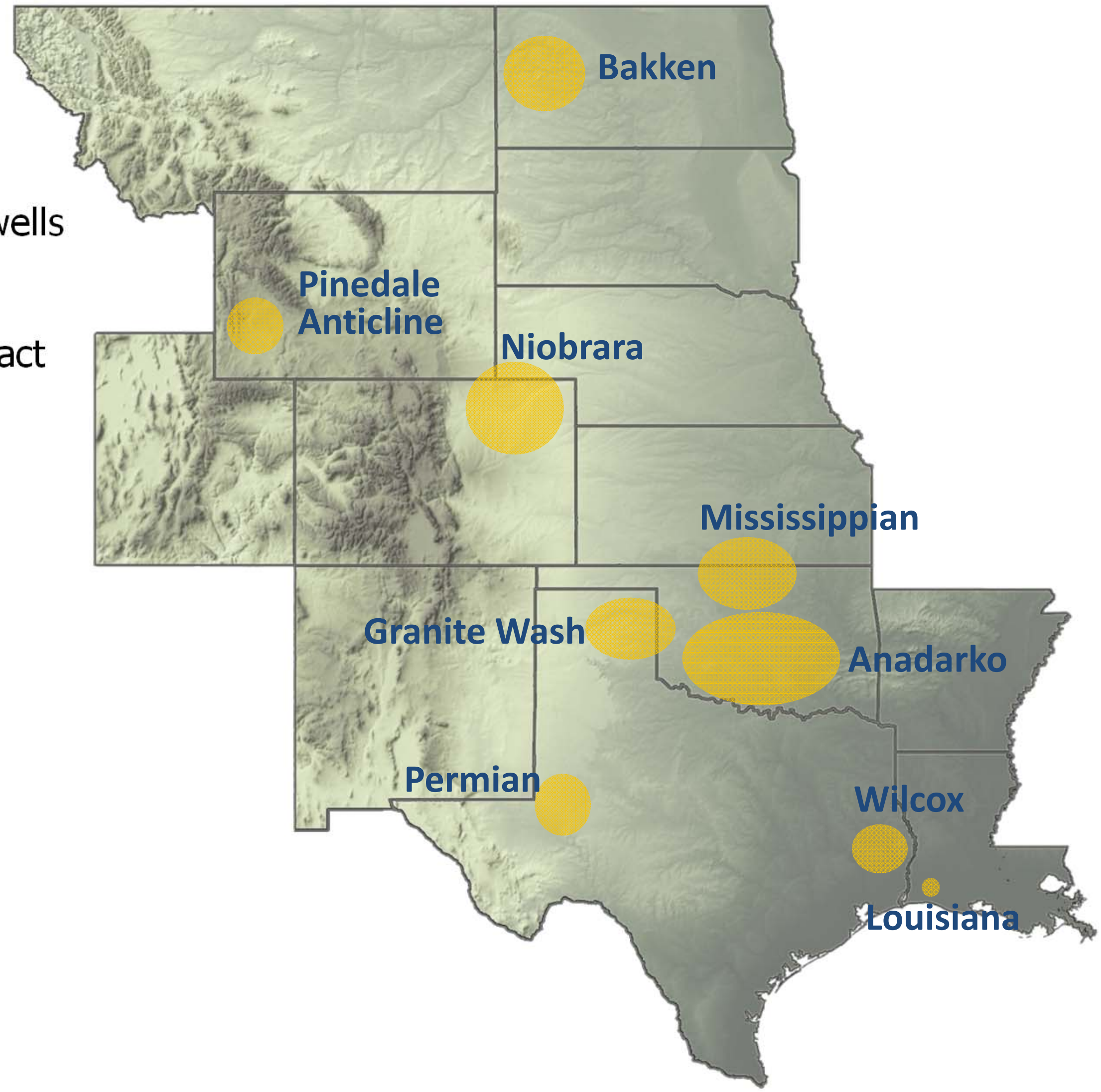
Buffalo Wallow Highlights:

- Completed 9 "H" wells GW [B, C(3), D, E(3), F] zones
- Average WI: 100%
- Average IP30: 4.2 MMcfe/d
- 45% liquids (7% oil)
- Focus GW "B" & "C" zones
  - IP30: 5.5 MMcfe/d
  - 49% liquids (12% oil)
- Six new horizontal wells GW [B(2), C(2), A, G] zones
  - Upsized frac

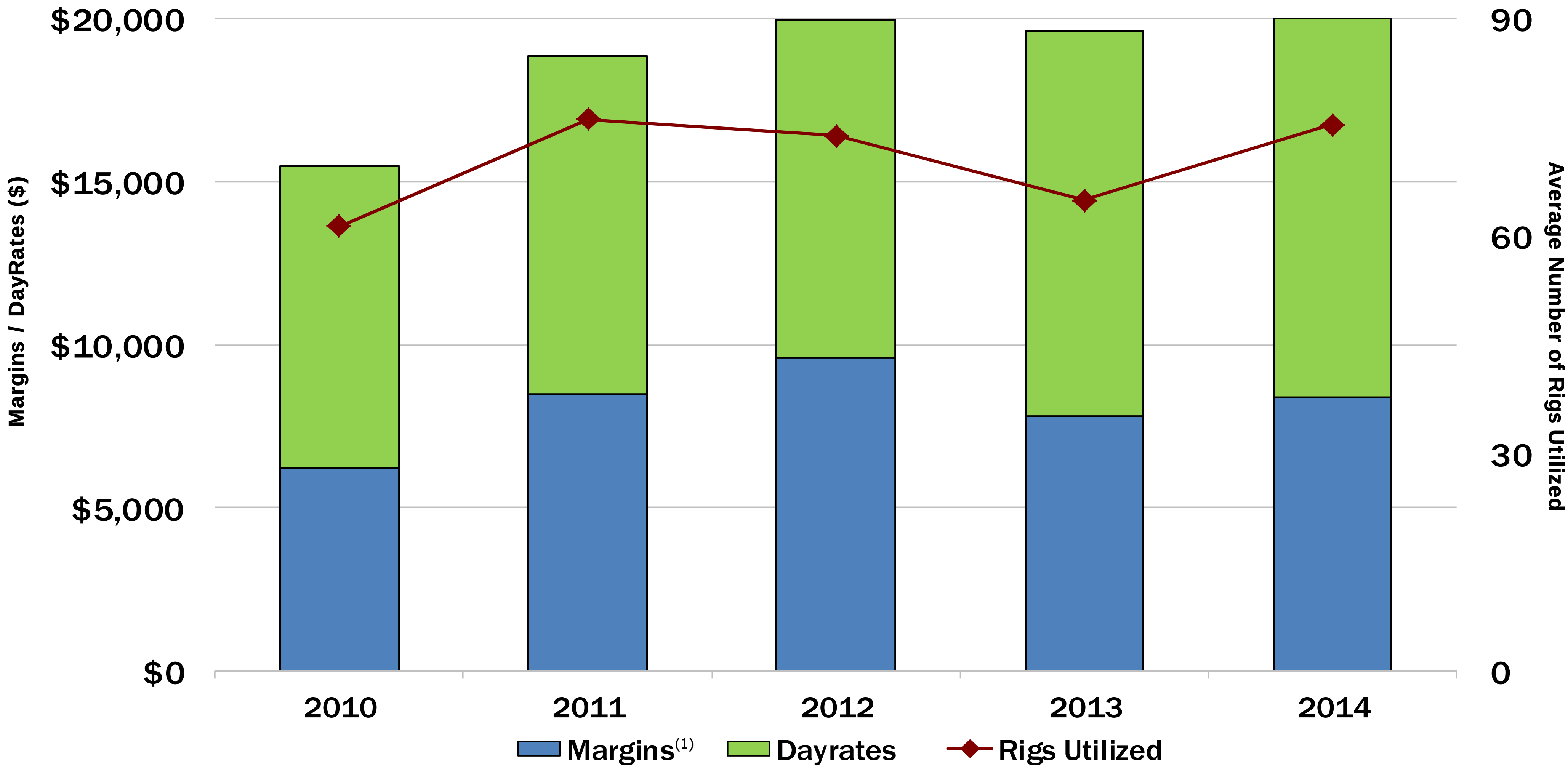
Significant Drilling Presence in Attractive Producing Regions

- ✓ **92 rig fleet**
  - Fleet average ~1,250 HP rating;
  - Almost all of contracted rigs drilling horizontal wells
- ✓ **68% utilization rate for Q4 2014**
  - 43% of the 47 1,200-1,700 HP rigs under contract
- ✓ **Refurbished 48 rigs since 2009**
- ✓ **Eight BOSS rigs contracted**

Area	# of Rigs
Anadarko Basin	9
Bakken	5
Granite Wash	4
Louisiana	1
Mississippi	4
Permian	3
Pinedale Anticline	2
Niobrara	1
Wilcox	2
Total	31

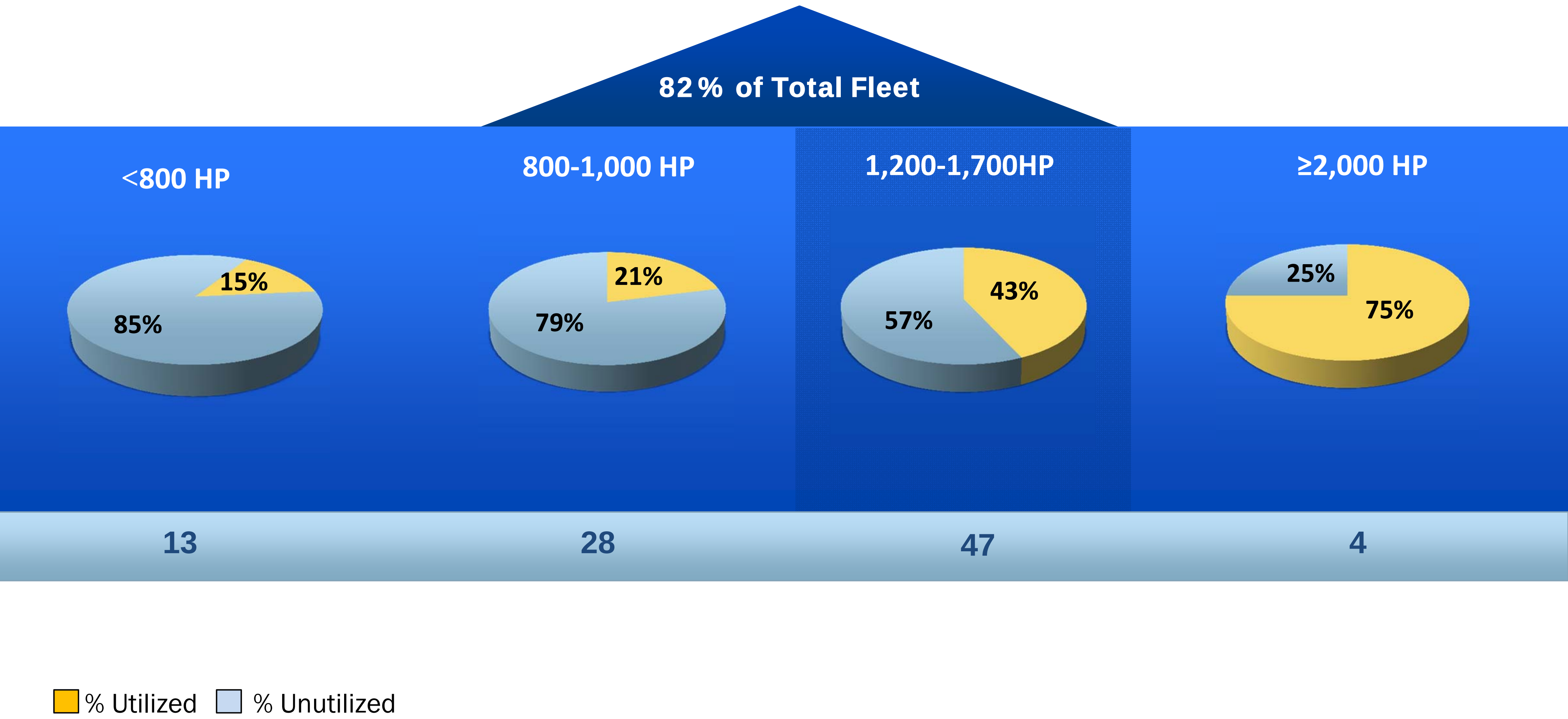


Average Dayrates and Margins (1)

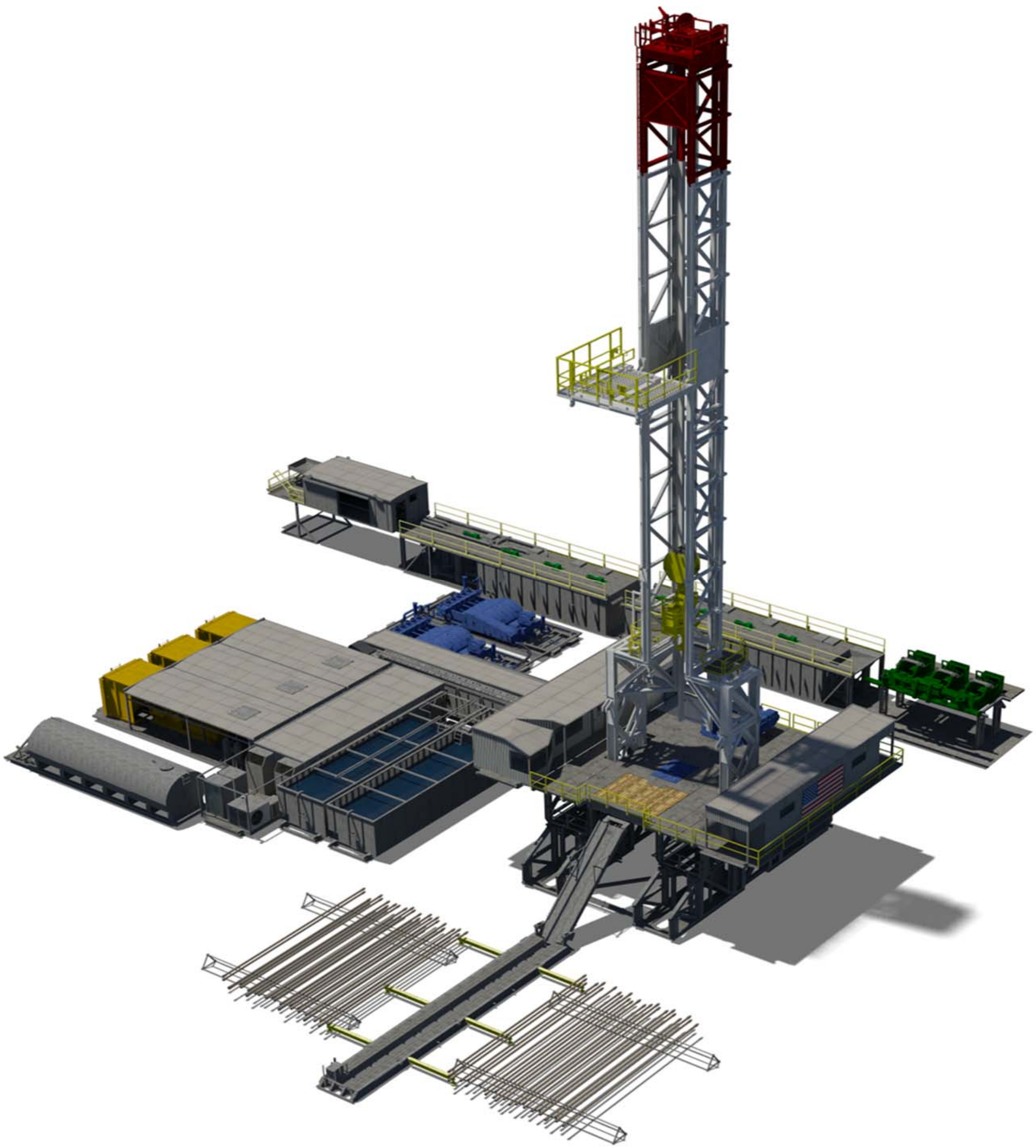


(1) See Reconciliation of Average Daily Operating Margin Before Elimination of Intercompany Rig Profit and Bad Debt Expense in Appendix (also available at www.unitcorp.com/investor/reports.html).

Rig Fleet Snap Shot



Introducing the New BOSS Drilling Rig



Optimized for Pad Drilling

- Multi-direction walking system

Faster Between Locations

- Quick assembly substructure
- 32-34 truck loads

More Hydraulic Horsepower

- (2) 2,200 horsepower mud pumps
- 1,500 gpm available with one pump

Environmentally Conscious

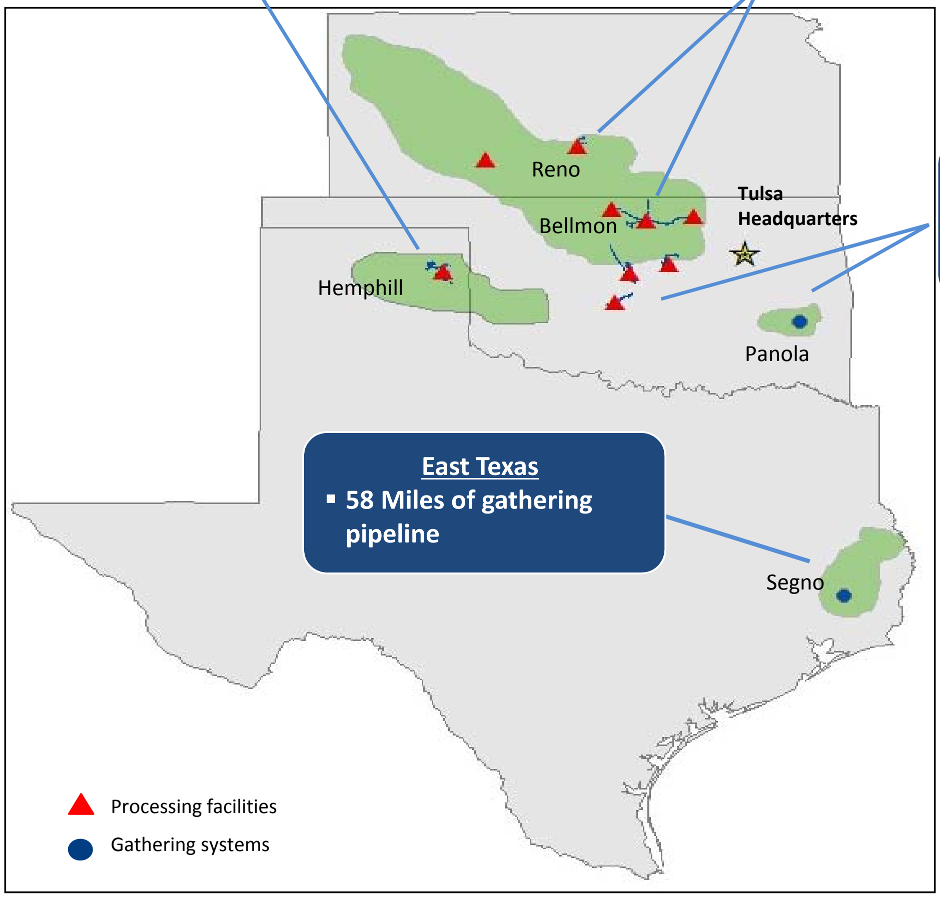
- Dual-fuel capable engines
- Compact location footprint

Eight BOSS Rigs Currently Contracted

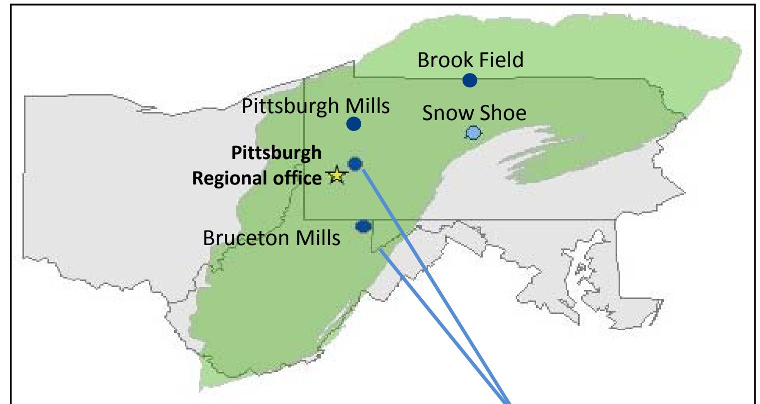
Midstream Core Operations

<u>Texas Panhandle</u>
- 35,000 dedicated acres
- 135 MMcf/d processing capacity
- 340 miles of gathering pipeline

<u>Northern Oklahoma and Kansas</u>
- 1,800,000+ dedicated acres
- 197 MMcf/d processing capacity
- 555 miles of gathering pipeline



<u>East Texas</u>
- 58 Miles of gathering pipeline



<u>Central & Eastern OK</u>
- 52,000+ dedicated acres
- 12 MMcf/d processing capacity
- 520 miles of gathering pipeline

<u>Appalachia</u>
- 60,000+ dedicated acres
- 33 miles of gathering pipeline

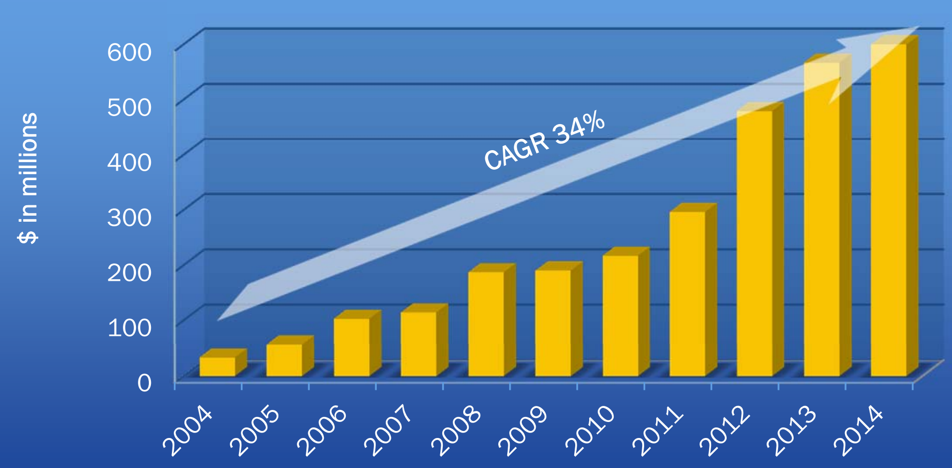
Key Metrics

- 29 Active Systems
- Three Natural Gas Treatment Plants
- 335 MMcf/d Processing Capacity
- Approx. 1,525 miles of Pipeline

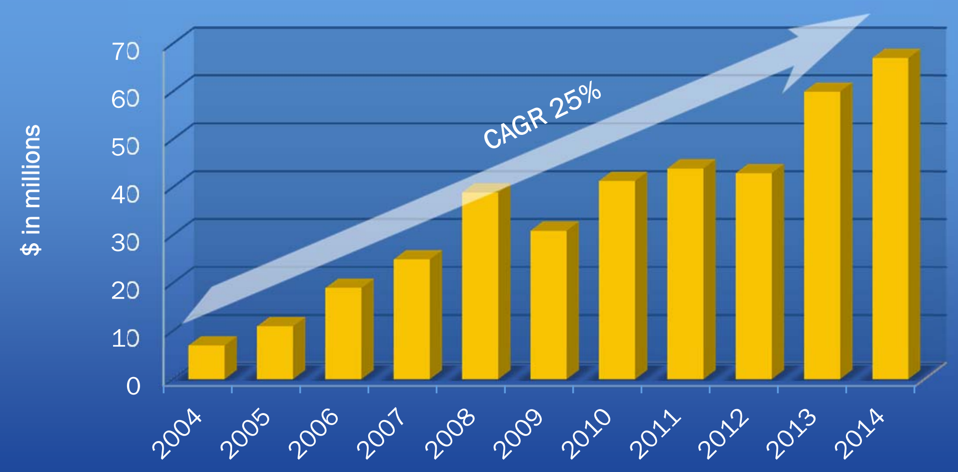
Midstream Segment Historical Performance

- 34% compound growth rate in assets since year-end 2004
- Operating 14 processing plants at eight different locations with combined processing capacity of 335 MMcf per day
- Increased from 12 to over 143 employees since 2004

Cumulative Invested Capital



Segment Operating Margin*



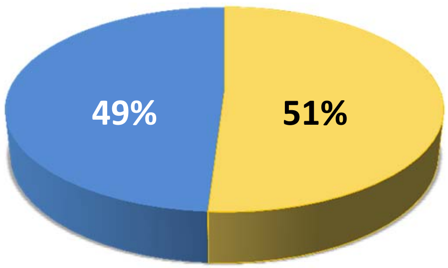
*Before G&A

Midstream Segment Contract Mix

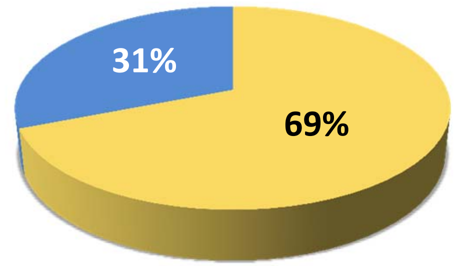
2010

Contract Mix Based on Volume

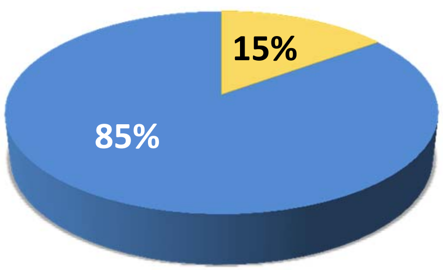
2014



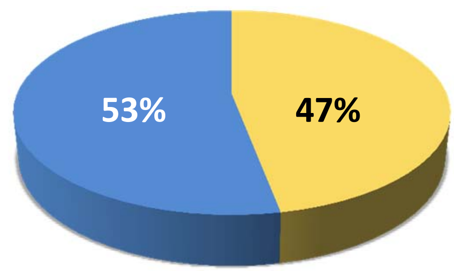
- Fee Based
- Commodity Based



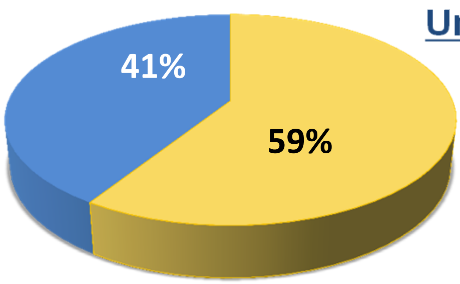
Contract Mix Based on Margin



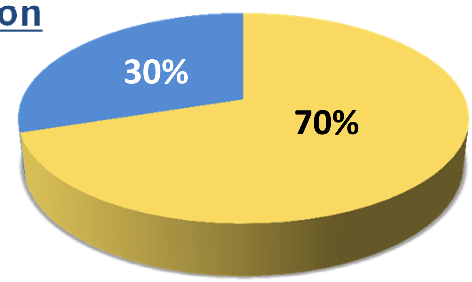
- Fee Based
- Commodity Based



Unit vs. 3rd Party Margin Contribution

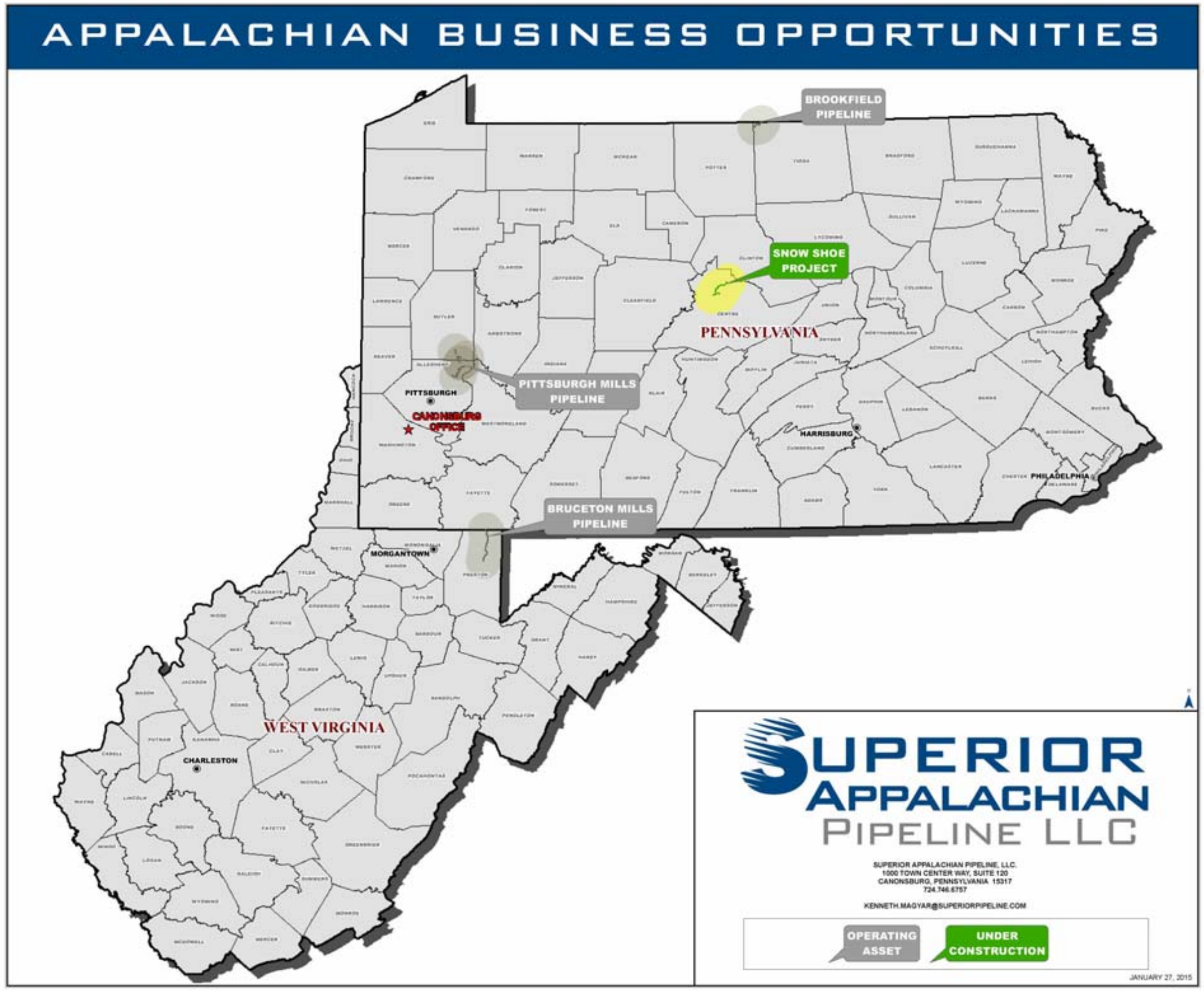


- 3rd Party
- Unit



Appalachian Growth Opportunities

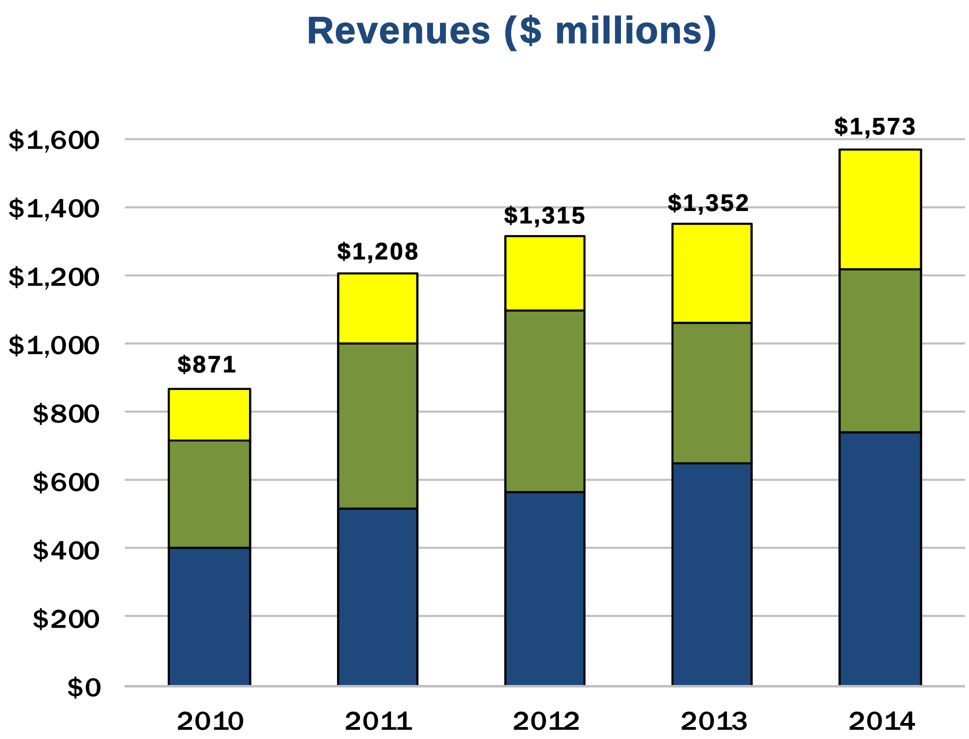
- Constructing Snowshoe Gathering System in Centre County, PA
  - Estimated Total Capital: $97 million
  - Initial 2015 Capital: $42 million
- Expansion of Pittsburgh Mills gathering system into Butler County, PA (operational in 2Q 2015)

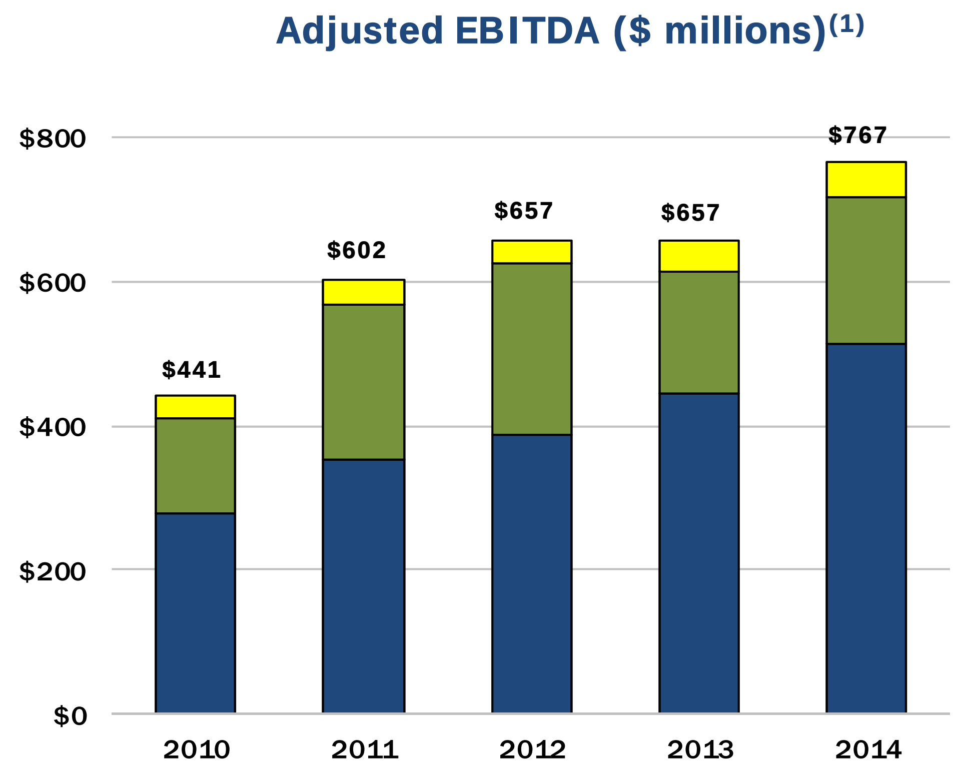


Balance Sheet Summary

	12/31/14	12/31/13
	(In Millions)	
Total Assets	**4,473.7**	**4,022.4**
Long-Term Debt		
Senior Subordinated Notes	646.2	645.7
Bank Facility	166.0	—
Total Long-Term Debt	812.2	645.7
Shareholders' Equity	**2,332.4**	**2,173.4**
Credit Line Undrawn	**334.0**	**500.0**
Long-Term Debt to Total Capitalization	**26%**	**23%**

Segment Contribution

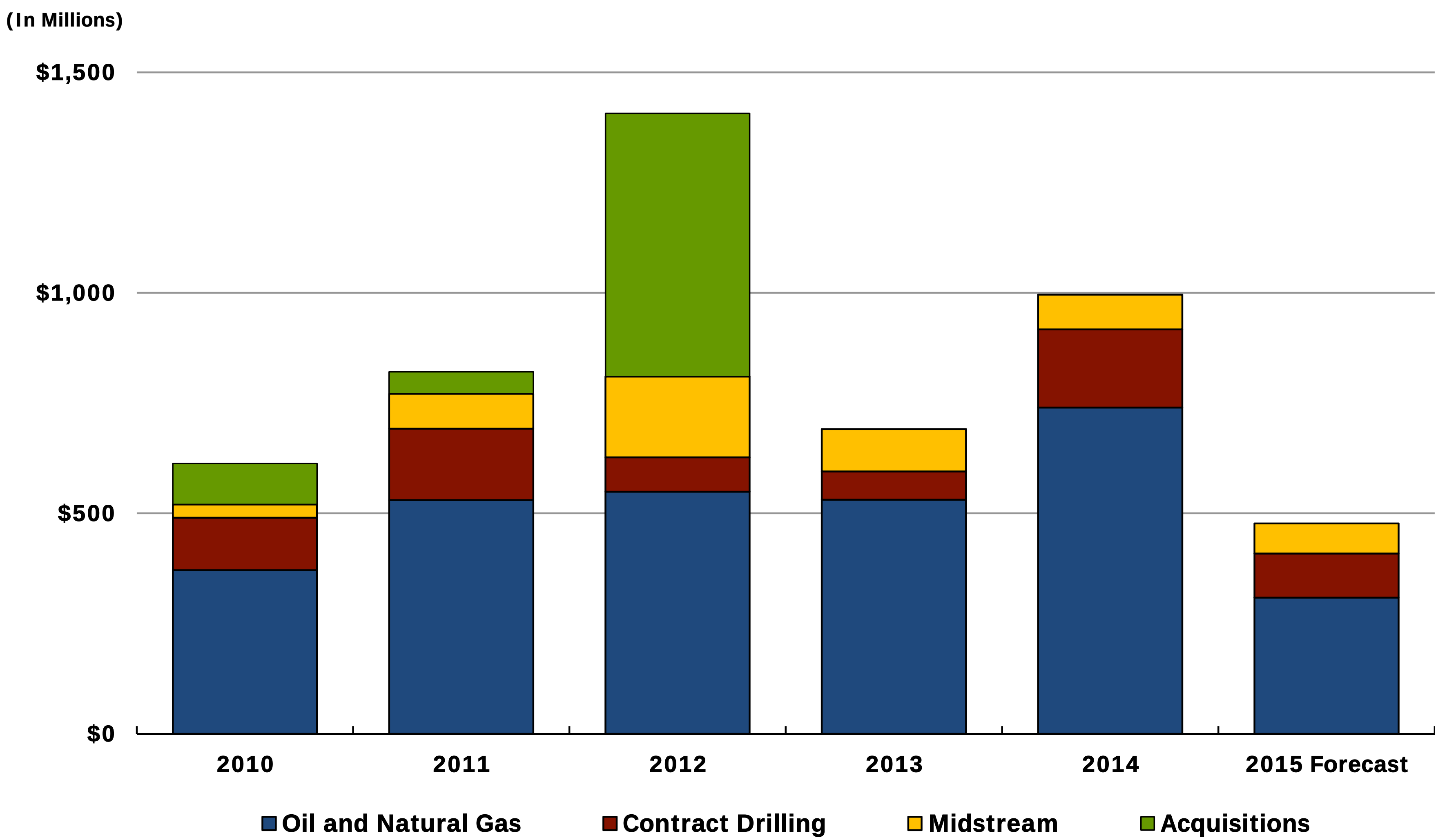




Oil and Natural Gas | Contract Drilling | Midstream

[1] See Non-GAAP Financial Measures in Appendix (also available at www.unitcorp.com/investor/reports.html).

Capital Expenditures



Current Debt Structure

Senior Subordinated Notes

- $650 million, 6.625%
- 10-year, NC5; maturity 2021

Ratings	S&P	Moody's	Fitch
Corporate	BB-	Ba3	BB
Senior Subordinated Notes	BB-	B1	BB-

Unsecured Bank Facility

Current Borrowing Base	$725 million
Elected Commitment	$500 million
Outstanding [1]	$166 million
Maturity	April 2020

(1) As of December 31, 2014

APPENDIX

Non-GAAP Financial Measures

Adjusted EBITDA

($ in Millions)	Years ended December 31, 2010	2011	2012	2013	2014
Net Income	**$146**	**$196**	**$23**	**$185**	**$136**
Income Taxes	91	123	16	117	87
Depreciation, Depletion and Amortization	205	281	319	334	405
Impairments	-	-	284	-	158
Interest Expense	-	4	14	15	17
(Gain) loss on derivatives not designated as hedges and hedge ineffectiveness	(1)	(2)	1	8	(30)
Settlements during the period of matured derivative contracts	-	-	-	(2)	(6)
Adjusted EBITDA	**$441**	**$602**	**$657**	**$657**	**$767**
Unit Petroleum					
Income Before Income Taxes (1)	$176	$200	($77)	$239	$199
Depreciation, Depletion and Amortization	119	183	211	226	276
Impairment of Oil and Natural Gas Properties	-	-	284	-	77
EBITDA	$295	$383	$418	$465	$552
Unit Drilling					
Income Before Income Taxes (1)	$60	$135	$159	$96	$42
Depreciation and Impairment	70	80	81	71	160
EBITDA	$130	$215	$240	$167	$202
Superior Pipeline					
Income Before Income Taxes (1)	$17	$17	$6	$11	$2
Depreciation, Amortization and Impairment	15	16	24	33	48
EBITDA	$32	$33	$30	$44	$50

(1) Does not include allocation of G&A expense.

Non-GAAP Financial Measures

Reconciliation of Average Daily Operating Margin Before Elimination of Intercompany Rig Profit and Bad Debt Expense

(In thousands except for operating days and operating margins)	Years ended December 31, 2010	2011	2012	2013	2014
Contract drilling revenue	$ 316,384	$ 484,651	$ 529,719	$ 414,778	$ 476,517
Contract drilling operating cost	186,813	269,899	289,524	247,280	274,933
Operating profit from contract drilling	129,571	214,752	240,195	167,498	201,584
Add:					
Elimination of intercompany rig profit and bad debt expense	9,158	19,900	15,583	17,416	29,343
Operating profit from contract drilling before elimination of intercompany rig profit and bad debt expense	138,729	234,652	255,778	184,914	230,927
Contract drilling operating days	22,367	27,619	26,704	23,720	27,516
Average daily operating margin before elimination of intercompany rig profit and bad debt expense	$ 6,202	$ 8,496	$ 9,578	$ 7,796	$ 8,392

Hedges

Natural Gas

Period	Swap Volume MMBTU/Day	Collar Volume MMBTU/Day	Average Swap Price	Average Floor Price	Average Ceiling Price
Q1 2015	40,000	30,000	$3.98	$4.20	$5.03
Q2 2015	70,000	30,000	$3.60	$2.92	$3.26
Q3 2015	40,000	30,000	$3.98	$2.58	$3.04
Q4 2015	40,000	0	$3.98		

Crude

Period	Swap Volume Bbl/Day	Collar Volume Bbl/Day	Average Swap Price	Average Floor Price	Average Ceiling Price
Jan - Dec 2015	1,000	0	$95.00		

UNIT CORPORATION

IPAA Oil & Gas Investment Symposium

April 20, 2015