USA Compression Partners, LP
2015 NAPTP MLP Investor Conference
May 20 – 22

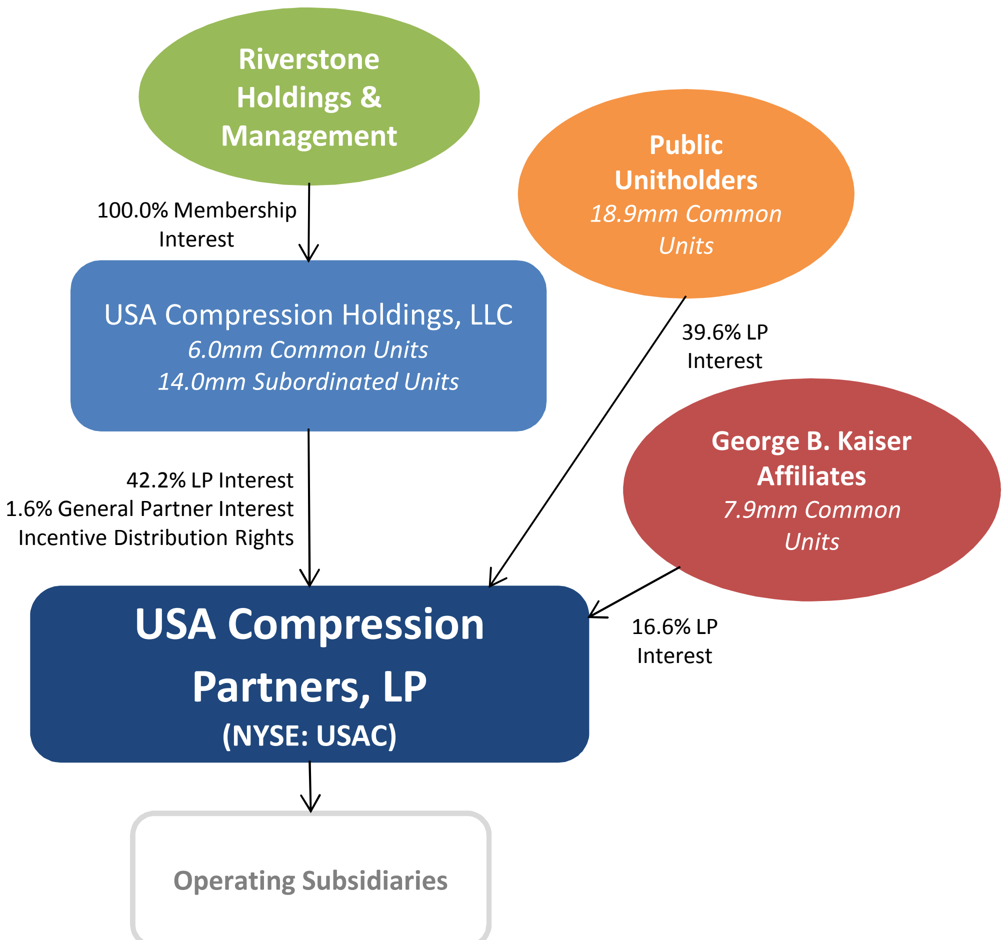
Disclaimers

This presentation contains forward-looking statements relating to the Partnership's operations that are based on management's current expectations, estimates and projections about its operations. You can identify many of these forward-looking statements by words such as "believe", "expect", "intend", "project", "anticipate", "estimate", "continue", or similar words, or the negative thereof. You should consider these statements carefully because they discuss our plans, targets, strategies, prospects and expectations concerning our business, operating results, financial condition, our ability to make distributions and other similar matters. These statements are not guarantees of future performance and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and are difficult to predict. These include risks relating to changes in the long-term supply of and demand for natural gas and crude oil, actions taken by our customers, competitors and third-party operators, competitive conditions in our industry, and the factors set forth under the heading "Risk Factors" or included elsewhere that are incorporated by reference herein from our Annual Report on Form 10-K for the year ended December 31, 2014 filed with the Securities and Exchange Commission, and if applicable, our Quarterly Reports on Form 10-Q and our Current Reports on Form 8-K. As a result of such risks and others, our business, financial condition and results of operations could differ materially from what is expressed or forecasted in such forward-looking statements. Before you invest in our common units, you should be aware of such risks, and you should not place undue reliance on these forward–looking statements. Any forward-looking statement made by us in this presentation speaks only as of the date of this presentation. Unpredictable or unknown factors not discussed herein could also have material adverse effects on forward-looking statements. We undertake no obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Who is USA Compression?

Pure-play Compression MLP Backed by Experienced Energy Investors

Ownership Structure (1)



Market Data

Unit Price (as of 05/15/15)	$22.67
Units O/S (mm) (1)	46.8
LP Equity Value	$1,060.4
GP Equity Value (2)	17.6
Debt (as of 3/31/15)	711.7
Enterprise Value	$1,789.8
Q1 Annualized Distribution	$2.06
Current LP Yield	9.1%

Q1 2015 Fleet Snapshot

	3/31/2015
Fleet HP	1,640,323
Total Units	3,280
HP / Unit - Total Units	500
Revenue-Generating HP	1,397,709
Revenue-Generating Units	2,686
HP / Unit - Revenue-Generating Units	520
Average Horsepower Utilization (3)	91.9%

(1) As of May 15, 2015.
(2) Based on GP's 1.64% LP ownership interest.
(3) See "Basis of Presentation; Explanation of Non-GAAP Financial Measures" for additional information on utilization.

Recent Developments: Q1 2015 Review

USAC Continues to Excel Operationally; Achieves Record Revenue, EBITDA and DCF in Q1 2015

Operational Update

- Q1 2015 fleet HP of 1.6 million and average revenue-generating HP of 1.4 million– a 29% and 27% increase over Q1 2014 levels
- Average horsepower utilization of 92% for Q1 2015
- Total HP orders of ~240K in 2015; ~91K HP delivered in Q1 2015
- Increased the percentage of our existing gas-lift fleet under term contracts to ~60% from ~40% from Q4 2014 to Q1 2015
- Contracting update for fleet additions:
  - Virtually all of the ~350K of 2014 HP deliveries currently revenue-generating
  - Approximately 45% of ~210,000 midstream-oriented HP for delivery in 2015 already committed to customers on long-term basis (89% of Q1 2015 deliveries and 50% of Q2 2015 deliveries)

Financial Update

- Records levels of Revenue, Adjusted EBITDA and Adjusted DCF in Q1 2015
  - Revenue of $65.0mm, up 29% Y-o-Y
  - Adjusted EBITDA of $37.5mm, up 49% Y-o-Y
  - Adjusted DCF of $29.5mm, up 75% Y-o-Y
- Increased LP distribution to $0.515 for Q1 2015 (8th consecutive increase); adjusted DCF coverage of 1.22x
- Leverage of 4.8x on outstanding borrowings of $712 million
- Confirmation of full-year guidance (see slide 28 for further details)

Note: See "Basis of Presentation; Explanation of Non-GAAP Financial Measures" for additional information on calculation of Adjusted EBITDA, Adjusted DCF, Adjusted DCF coverage and average horsepower utilization.

Outlook For Compression

USAC Business Drivers

Compression is Critical Infrastructure for Producing & Transporting Hydrocarbons

Overall Gas Demand & Production

- Approximately 85% of USAC's business (by HP) installed in natural gas-based applications
- Expect to see continued steady demand / production of natural gas
- LNG exports, Mexico exports add to the macro picture
- Largely gas price agnostic; activity driven by production volumes and the need to move the gas

Shale Activity

- Expect majority of gas production growth to be satisfied by shale production
- Less crude drilling results in lower associated gas, thus driving increased dry gas production
- Typically lower pressures (vs. conventional) require significantly more compression to move gas (~3x HP)
- Changing operating conditions over time require flexible assets
- Infrastructure build out in early innings; compression follows

Customer Preference to Outsource

- Decision to outsource compression can be due to safety, lack of expertise, labor scarcity, alternative capital investment opportunities and other factors
  - Expect more opportunities in current commodity price environment
- Mission-critical assets must run
- Guaranteed run time backed up by exemplary service and adherence to maintenance intervals

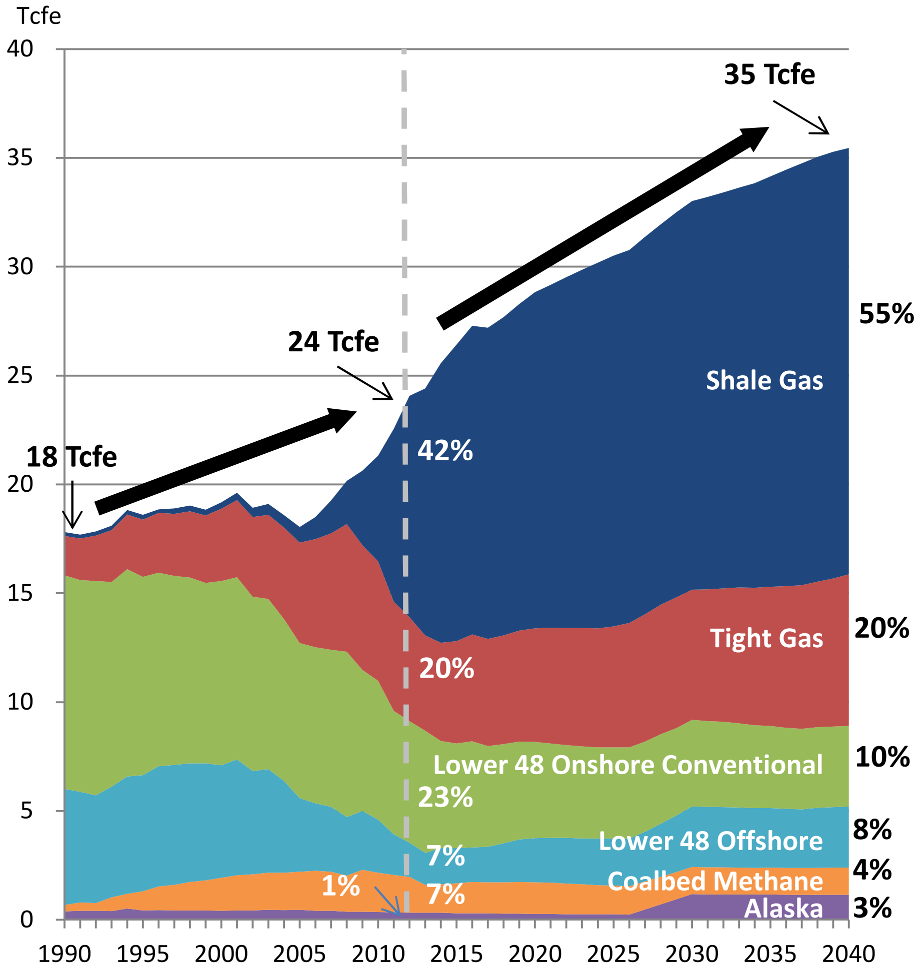
"Core" Crude Oil Production

- Economical crude oil production continuing in core areas
- Already-drilled horizontal wells require gas lift to extract crude oil
- USAC's assets stay utilized for long periods of time (mid-90% utilization over history)

Note: See "Basis of Presentation; Explanation of Non-GAAP Financial Measures" for additional information on calculation of utilization.

Macro Thesis: The "Shift to Shale"

Shale Gas Piece of the Growing Pie Continues to Increase



- Overall natural gas production expected to increase from ~66 Bcf/d in 2012 to ~97 Bcf/d through 2040, an increase of 47%
- Importantly, shale gas volumes are projected to grow ~2x the rate of total natural gas volumes over the projected period
- Production from Marcellus / Utica Shales and Permian / Delaware Basins represent large portion of future natural gas production growth

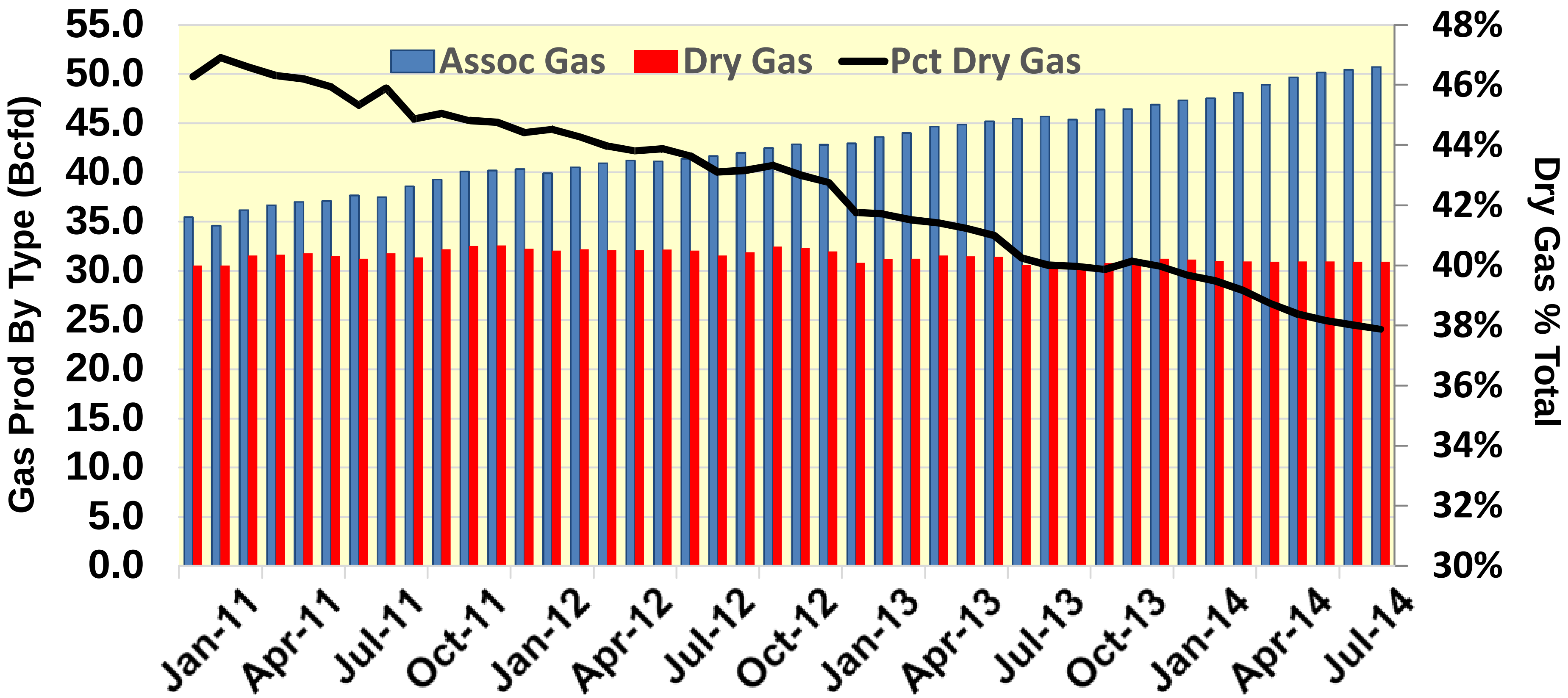
USAC has placed over 70% of its newbuild large-HP fleet additions in these areas of robust production growth since the beginning of 2014

Source: U.S. Energy Information Administration, Annual Energy Outlook 2014.

Dry Gas is Starting to Play a Bigger Role

Decline in Liquids/Associated Gas Production Presents Opportunity

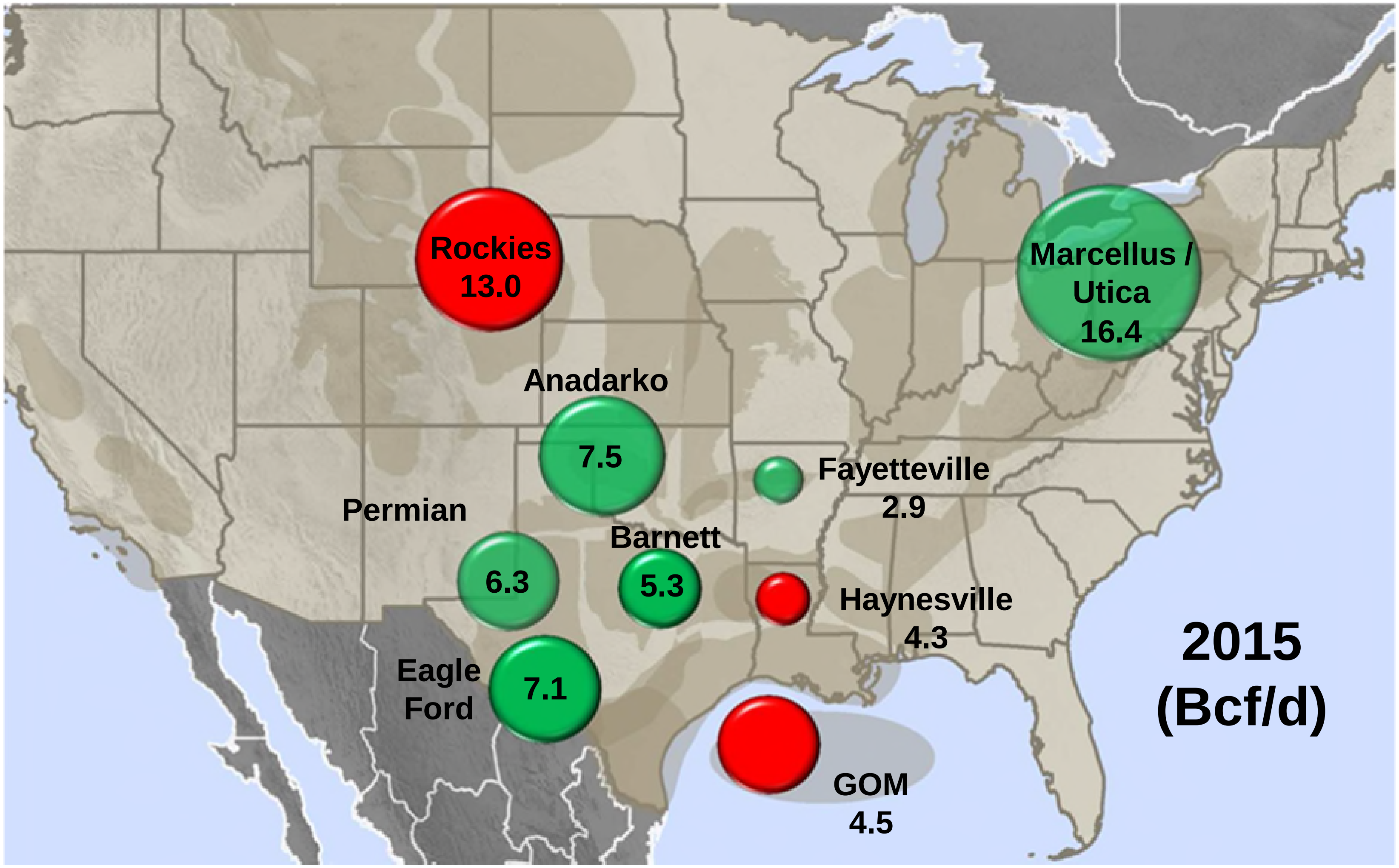
- Dry gas volumes remained relatively constant from 2011 through 2014
- For the past few years, associated gas (accompanying the strong crude oil / NGL market) has accounted for the majority of growth in overall natural gas production
  - Recent pullback in associated gas volumes (due to lower crude oil activity levels) will need to be made up to meet domestic demand – large volume dry gas wells to fill the void



Source: Ponderosa Advisors LLC, December 2014.

Changing Natural Gas Market

Marcellus / Utica to Transform Market in Near Term

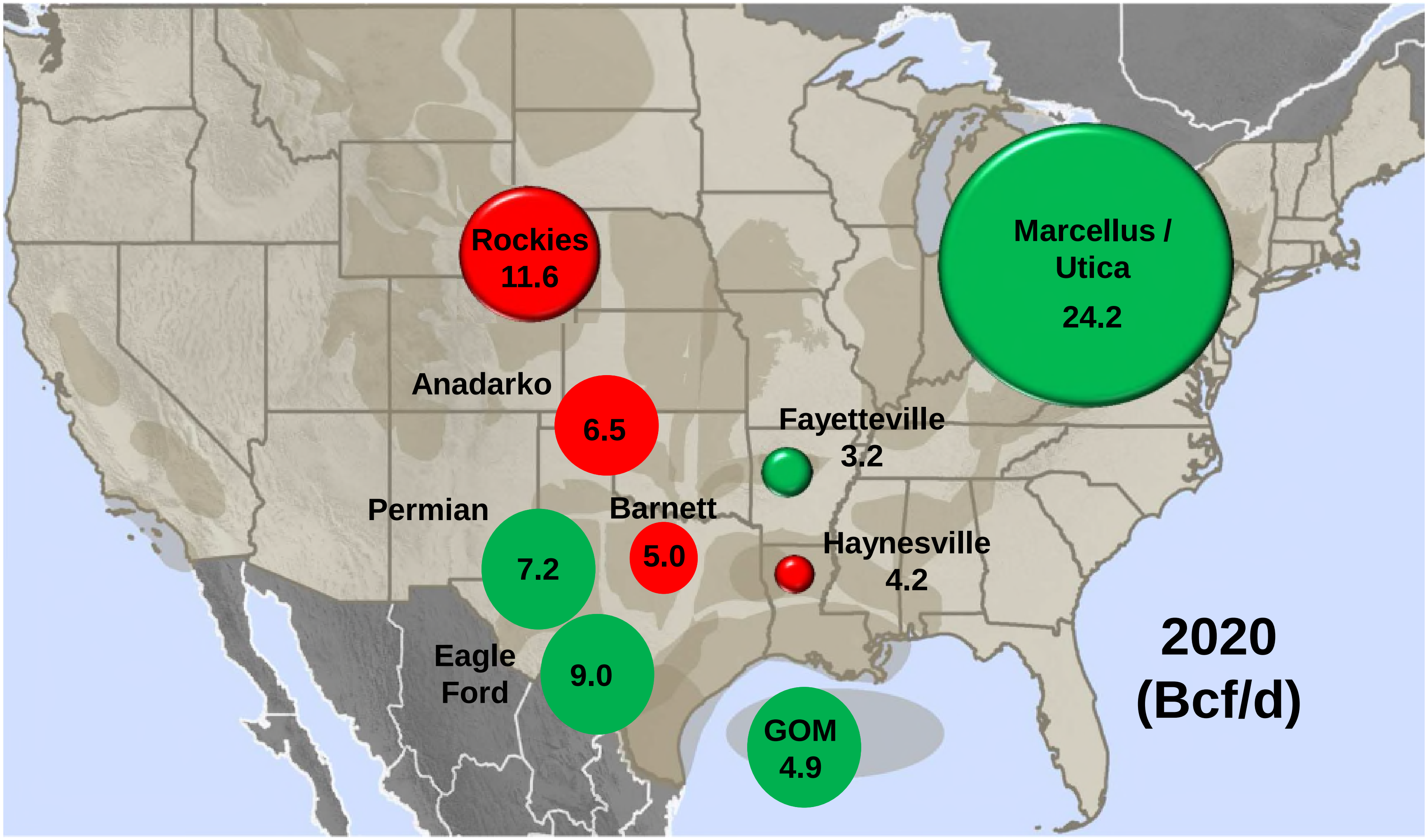


Note: Green/red circles indicate whether projected natural gas production expands/contracts post 2010; number represents projected total production.

Source: Ponderosa Advisors LLC, December 2014.

Changing Natural Gas Market, Continued

Northeast Continues Growth; West / South Texas Adding



Note: Green/red circles indicate whether projected natural gas production expands/contracts post 2015; number represents projected total production.
Source: Ponderosa Advisors LLC, December 2014.

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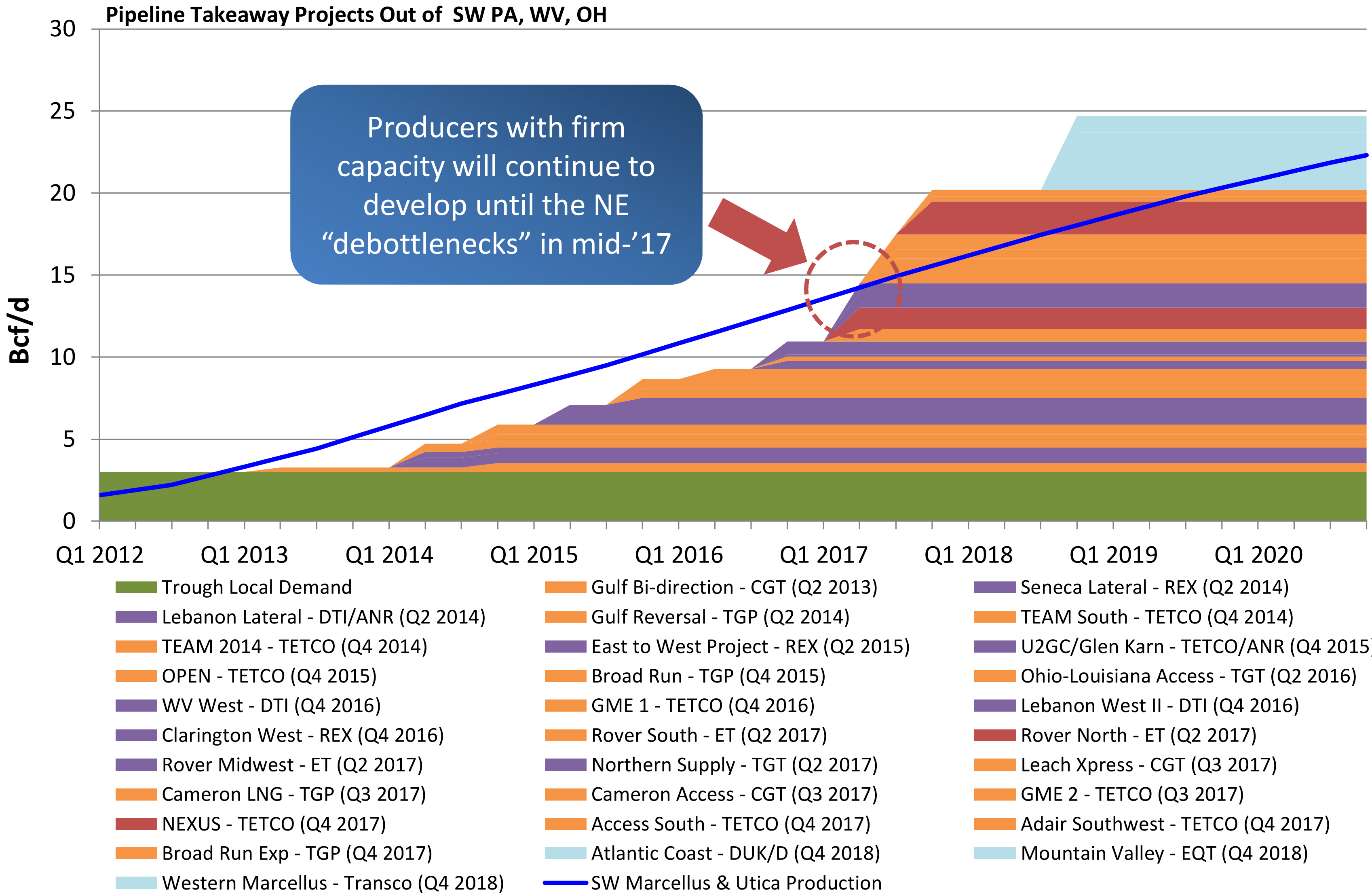
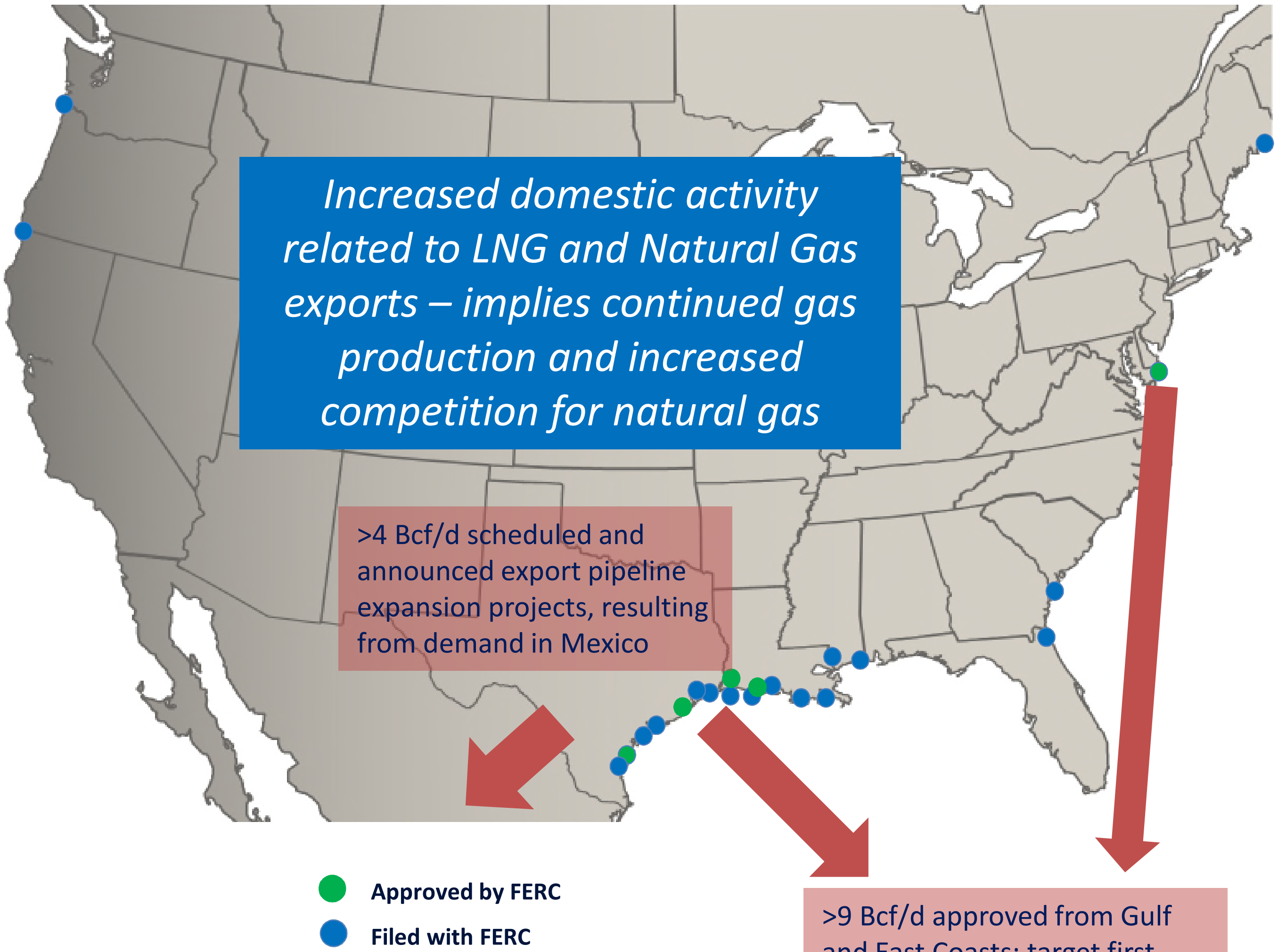
Continued Northeast Infrastructure Build-Out



Source: Company Presentations, Public Filings, TPH Estimates, EIA.

LNG and Pipeline Exports Drive Growing U.S. Gas Demand

Approved LNG Projects and Incremental Natural Gas Export Capacity Total ~27 Bcf/d; Supports the Need for Midstream Compression



Filings and approvals as of April 14, 2015.

Source: LNG projects per FERC. Natural gas export projects to Mexico per EIA study.

LNG Opportunity

- ~23 Bcf/d of LNG export projects filed/approved by FERC; 5 approved for total capacity of over 9 Bcf/d
- EIA expects LNG exports to reach 7 Bcf/d by 2022

Natural Gas Exports

- Rate of pipeline exports to Mexico has doubled since 2010; export capacity growth driven by strong increase in demand from power generation in Mexico
- Phase 1 of Mexico's Los Ramones project came on line in Q4 2014 - 2.1 Bcf/d by Q4 2015 (connected to NET Midstream's domestic pipeline); KMI's 200 Mmcf/d Sierrita Pipeline also on line in Q4 2014
- ETP and Howard Energy both in various stages of additional pipeline export expansions; could increase total capacity by another 2.0 Bcf/d

The Need for Compression

Critical Infrastructure for US Natural Gas

Critical Part of Natural Gas Transportation	▪ Compression is required to transport natural gas throughout the pipeline system ▪ Once installed, becomes part of midstream infrastructure, remaining in field for significant lengths of time ▪ However, assets remain "moveable", which allows for redeployment to other regions where appropriate ▪ Service frequently outsourced given increased expertise, safety record and reliability
Strong Fundamentals Driving Growth	▪ Gas production increasing primarily in shale plays, which require both overall more compression horsepower and flexible / convertible compressor packages ▪ Midstream build-out still in "early innings" in many shale plays; compression grows alongside gathering and processing ("G&P") expansions ▪ Crude oil economics support unconventional production techniques made possible with compression

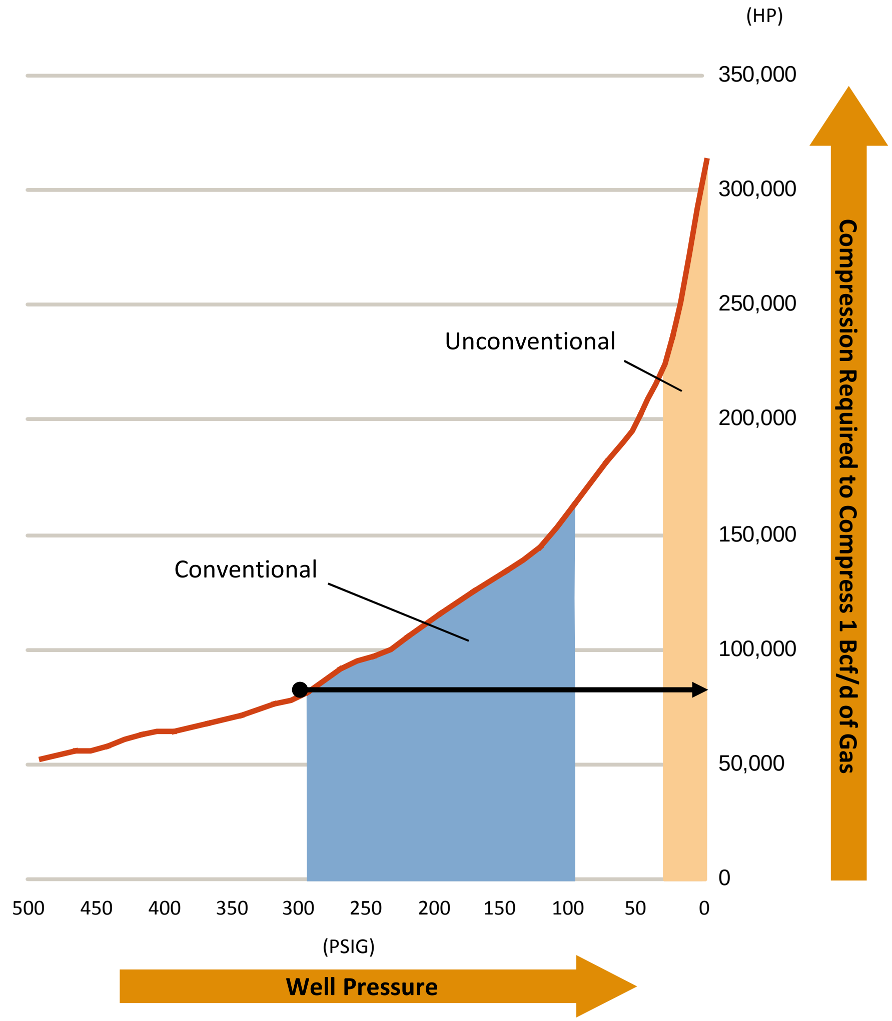
USAC's business is driven by the same attractive fundamentals as the G&P and more general midstream space: growing domestic hydrocarbon production

Growing Shale Compression Requirements

Shale Production Drives Increasing Compression Requirements (1)

- Shale gas is typically produced at lower wellhead pressures (0-50 PSIG) in contrast to conventional gas wells (100-300 PSIG)
- Pipeline specifications remain constant – requiring gas pressure to be increased significantly to move gas into and through pipelines
- As a result, to move the same amount of gas requires significantly more compression

USAC believes compression needs for unconventional basins are up to 3X those of conventional supplies



Source: Ariel Corporation: compressor sizing protocol.

(1) Assumes Discharge Pressure = 1,200 PSIG.

Strategic Focus on Infrastructure Applications

Midstream and Crude-Oriented Gas Lift Compression Offer Cash Flow Stability

Crude Oil Wells

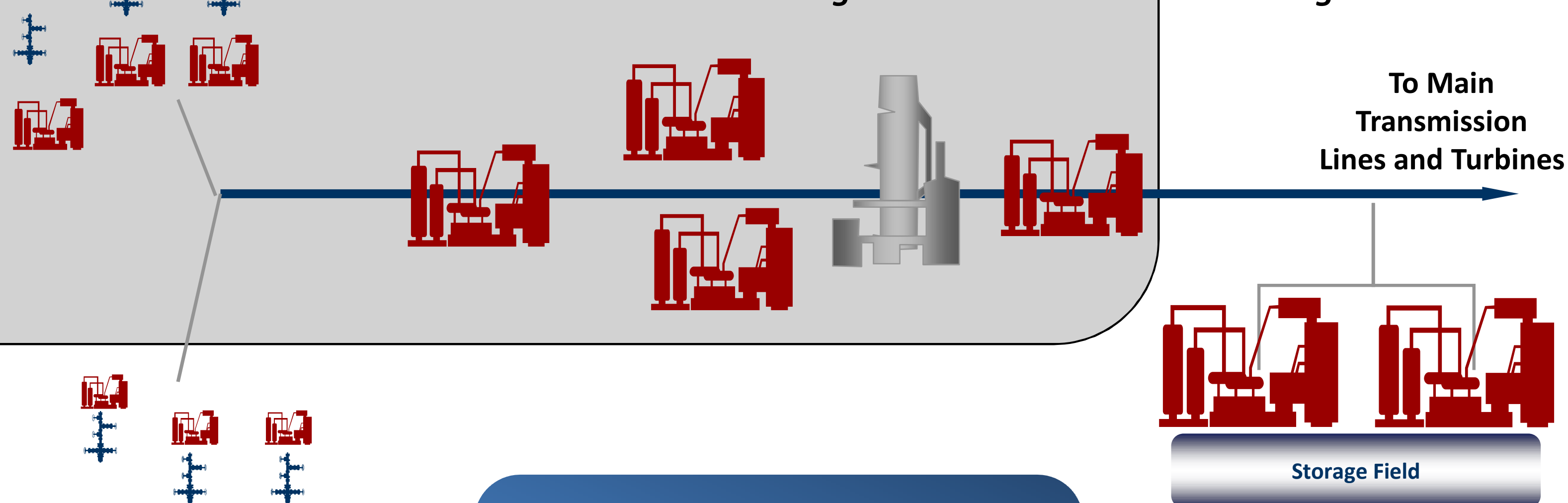
- *Gas Lift*
- *Gas Reinjection*

Midstream Applications

- *Regional Gathering*
- *Gas Processing Plant Compression*
- *Central Gathering*

Rate-Base Applications

- *Interstate Pipeline*
- *Trunkline gathering*
- *Underground Gas Storage*



Natural Gas Wells

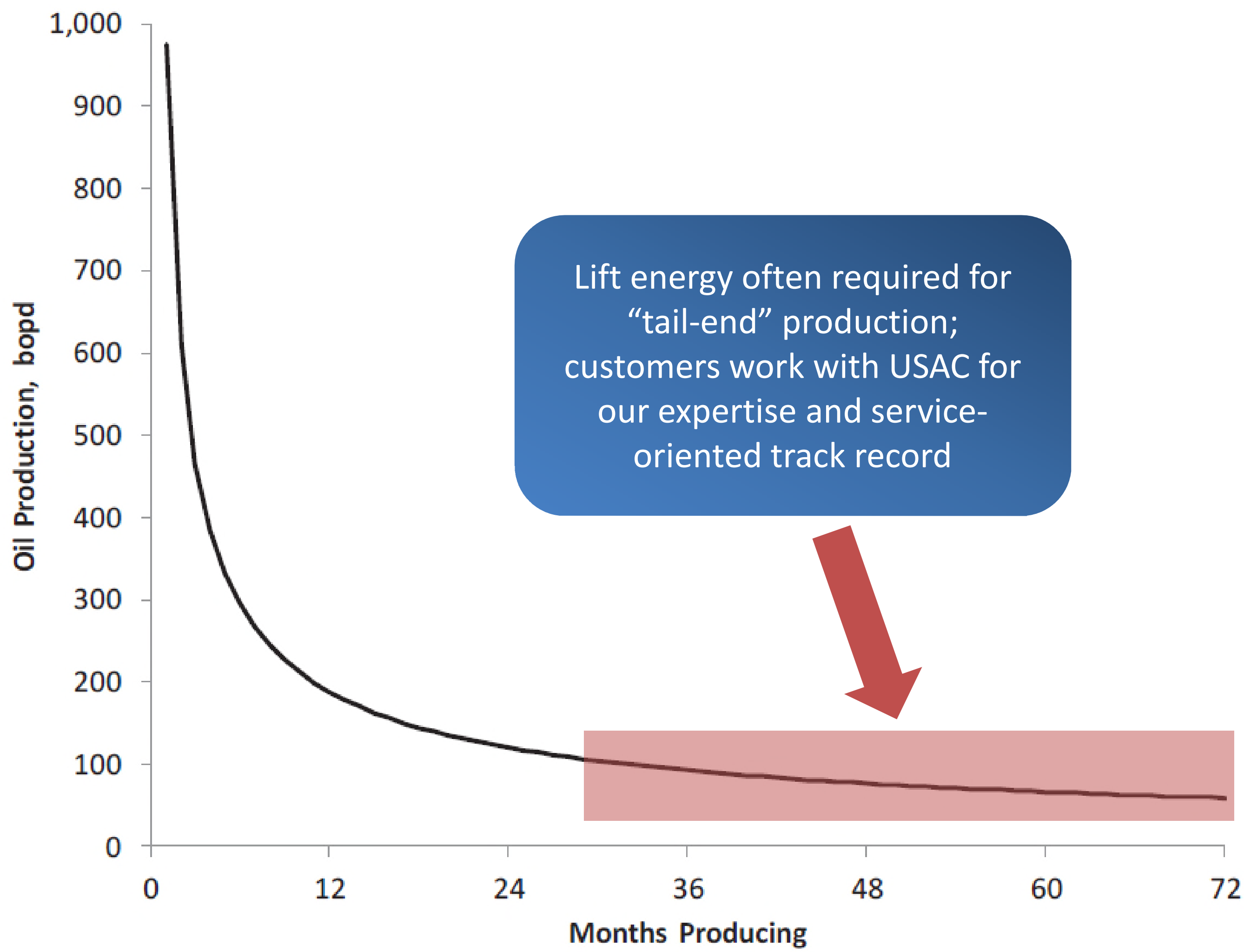
- *Wellhead Compression*
- *Gas Lift / Gas Reinjection*

USAC has made a strategic decision not to pursue more volatile, higher beta gas wellhead equipment

Stable, Long-Lived "Tail" Oil Production Supports Gas-Lift Operations

Illustrative Shale Oil Well Production Profile

- 1,000 Bpd initial production can decline to ~100 Bpd by year 3
- Gas-lift compression utilized during this long "tail" of production
  - Provides lift energy required to maintain production on horizontal shale oil wells
  - Compression assets remain highly utilized, even in low commodity price cycles, given relative favorable economics of low lifting costs of existing production vs. full F&D costs for newly drilled wells



Source: TPH & Co.

USAC: Story of Stability and Growth

USAC History

17-year History of Growth and Differentiated Business Model

1998: USAC founded by CEO Eric Long with private financial backing

1998 – 2010: USAC grows through organic development – focused primarily on large horsepower

Dec 2010: Riverstone completes acquisition of USAC

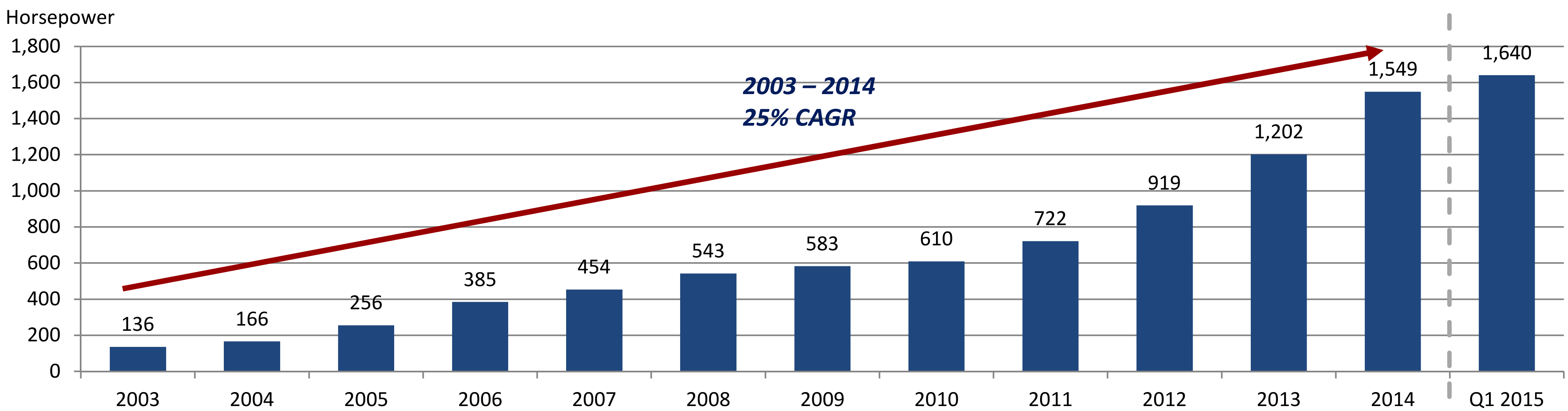
Jan 2013: USAC $198mm IPO, used for debt reduction

Aug 2013: USAC completes $182mm S&R Acquisition, 100% equity funded

May 2014: USAC completes $169mm primary and secondary equity offering; primary net proceeds of $138mm used to repay debt

1998 **2010** **2013** **2015**

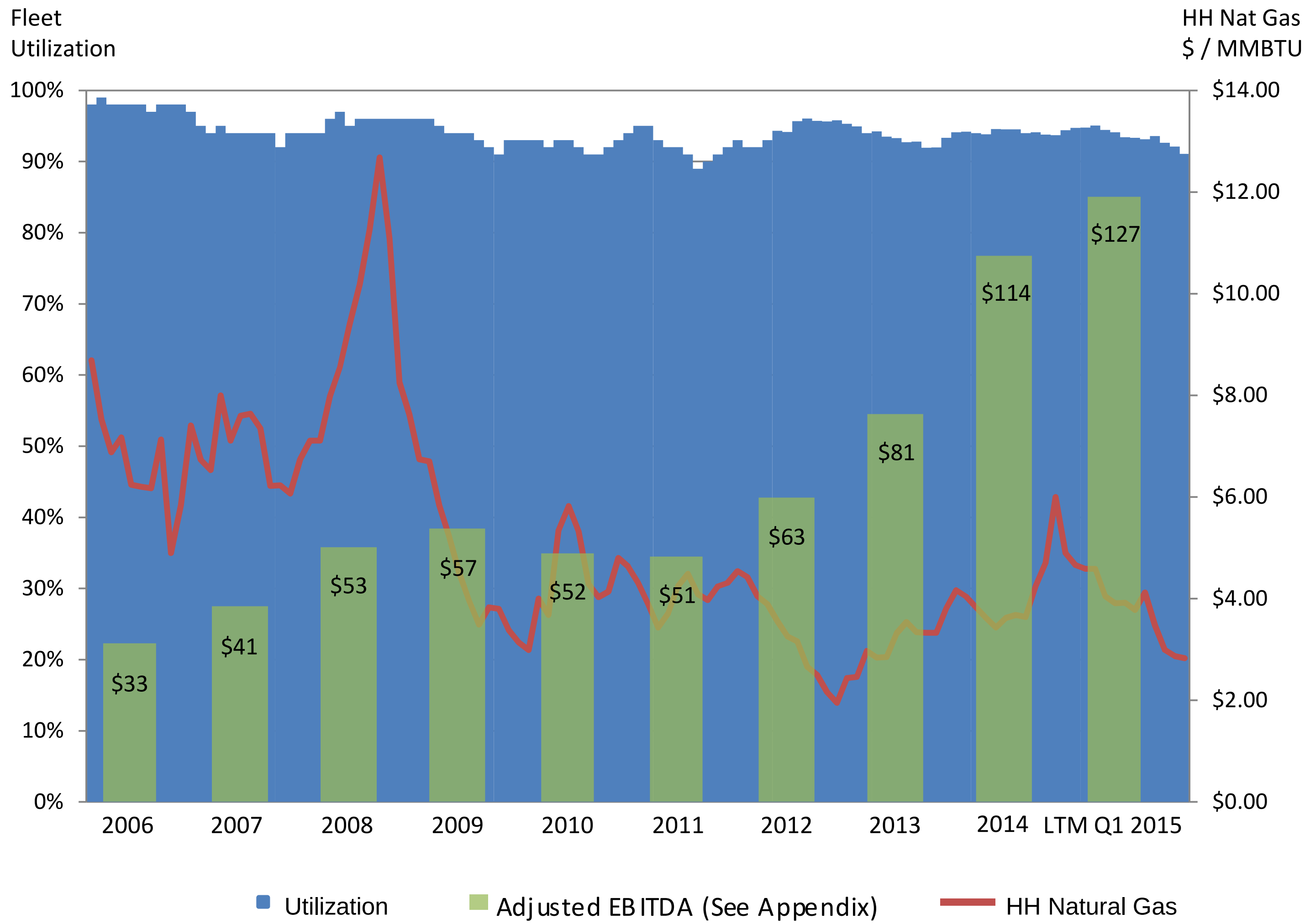
Horsepower Growth



Business Model Underpinned by Stability

Stability Through Multiple Commodity Price Cycles

- Commodity price levels do not directly affect USAC's business prospects
- Rather, natural gas compression is impacted by the level of natural gas <u>Demand</u> and <u>Production</u>
- Throughout both the recent and longer-term commodity price cycle, USAC has demonstrated its ability to:
  - i) Grow the Partnership;
  - ii) Maintain high utilization; and
  - iii) Manage for the impact, if any, of commodity prices on our customers



Source: EIA and Partnership historical financials.

Note: See "Basis of Presentation; Explanation of Non-GAAP Financial Measures" for additional information on calculation of utilization and Adjusted EBITDA.

Business Fundamentals Result in Cash Flow Stability

"Infrastructure-Nature" of USAC Assets Provide Cash Flow Stability

Long-lived Asset Base

- Long asset life complements gathering systems and processing facilities served
- Compression units typically last for 40+ years, when properly maintained
- 60% of the capital cost of a unit never wears out
- Young, standardized large HP fleet (avg. age ~4 years): fuel and emissions-efficient

Contract Profile

- Initial contracts for midstream applications are typically 2-5 years
- Assets tend to stay in field much longer
  - Average 24 months active in-place past original contract term
- USAC will work with customers to optimize their compression needs

Compression Needs Follow G&P Development

- USAC's services are essential for the transportation of natural gas and crude oil
  - Gas will not flow into and through pipeline systems without compression
- Production matters more than drilling activity
- Lagging development following G&P build-out

Loyal Customer Base

- Long-standing customer base values relationships and reliability
- USAC has followed its customers to provide compression across multiple basins
- Strategically focused primarily on midstream applications where our customers remain active

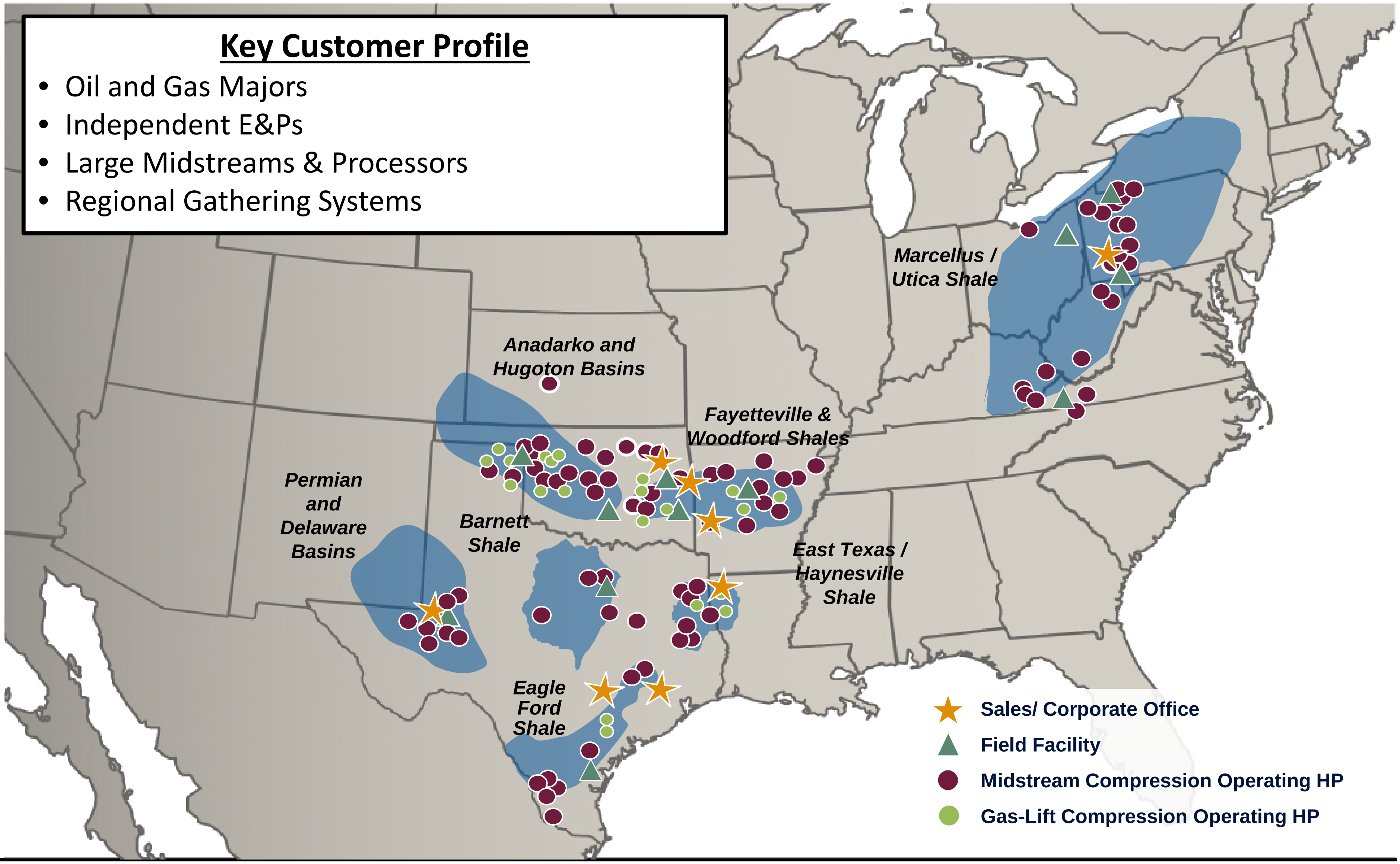
USAC's Activity Level is Not Directly Dependent on Commodity Prices

Geographical Presence

Presence in Key Geographical Regions

Key Customer Profile

- Oil and Gas Majors
- Independent E&Ps
- Large Midstreams & Processors
- Regional Gathering Systems



Well-Capitalized Customer Base with Strong Credit Ratings

Diverse Customer Base Includes O&G Majors, Independent E&Ps, Large Midstream Operators and Regional Gatherers

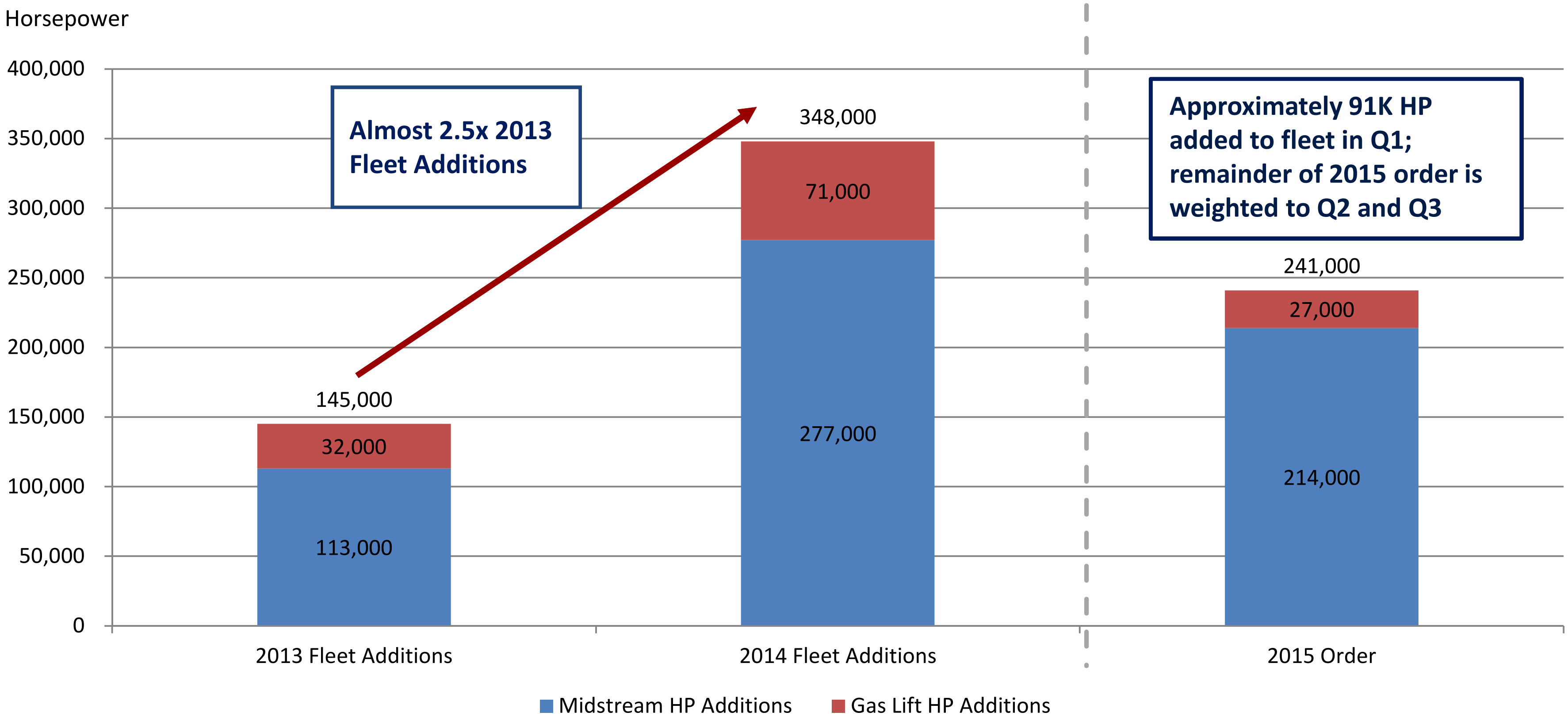
Rank	Top Customers	Length of Relationship	Credit Rating [1]
1	Large Public Independent E&P	9 years	Baa3 / BBB-
2	Large Public Independent E&P	7 years [2]	Baa1 / BBB+
3	Large Public MLP	2 years	Baa3 / BBB-
4	Large Private Midstream	2 years	N/A
5	Pipeline Subsidiary of Utility	1 year	A3 / BBB+
6	Oil and Gas Major	10+ years	Aa1 / AA
7	Pipeline Subsidiary of Large E&P	9 years	Ba3 / BB-
8	Large Public Independent E&P	10+ years	A3 / A-
9	Large Diversified Oil and Gas	10+ years	Ba3 / BB
10	Oil and Gas Major	10+ years	Aaa / AAA

Our largest customer, Southwestern Energy, continues to account for >10% of total revenues
Top 10 customers represent over 45% of total revenue; average credit rating of BBB+ / Baa1

Note: Rankings and %'s of revenue reflect YTD Q1 2015 revenue.
(1) Per Bloomberg and company filings.
(2) Includes prior relationship with S&R Compression, which USAC acquired in August 2013.

2015 Capital Program

Continued Build-Out of the High-Growth Shale Plays Drives Robust Capital Program



- Due to lack of clarity regarding customer activity levels in the back half of 2015, USAC has decreased its fleet additions from 2014 record levels and will take delivery of the compression units primarily over the first three quarters of the year
- Currently no gas-lift fleet additions planned beyond Q2 2015
- Lead times from order to receipt of compressor packages have shortened significantly from those USAC experienced in 2014; potential to add incremental midstream units in 2H 2015 to meet any customer demand

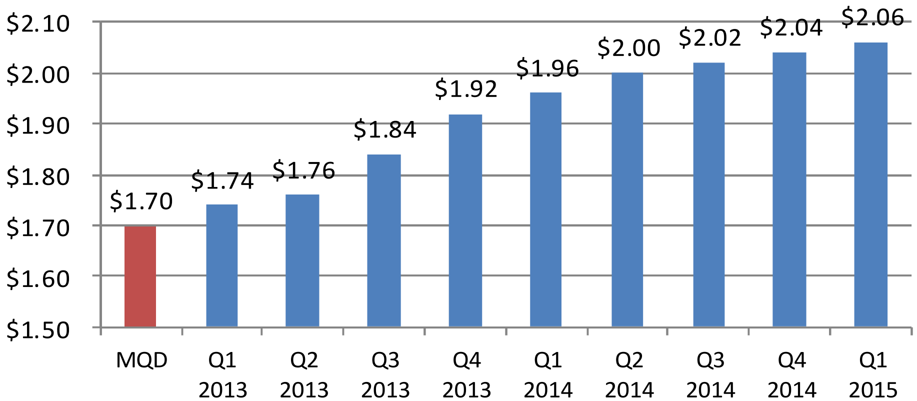
Note: 2013 fleet additions excludes the initial S&R acquisition of ~138,000HP; includes subsequent gas lift fleet additions.

Financial Overview and Investment Highlights

USAC Distributions and Leverage Since IPO

Partnership Has Delivered Strong Distribution Growth, While Taking Steps to Methodically De-Lever the Balance Sheet

Annualized Distributions per LP Unit

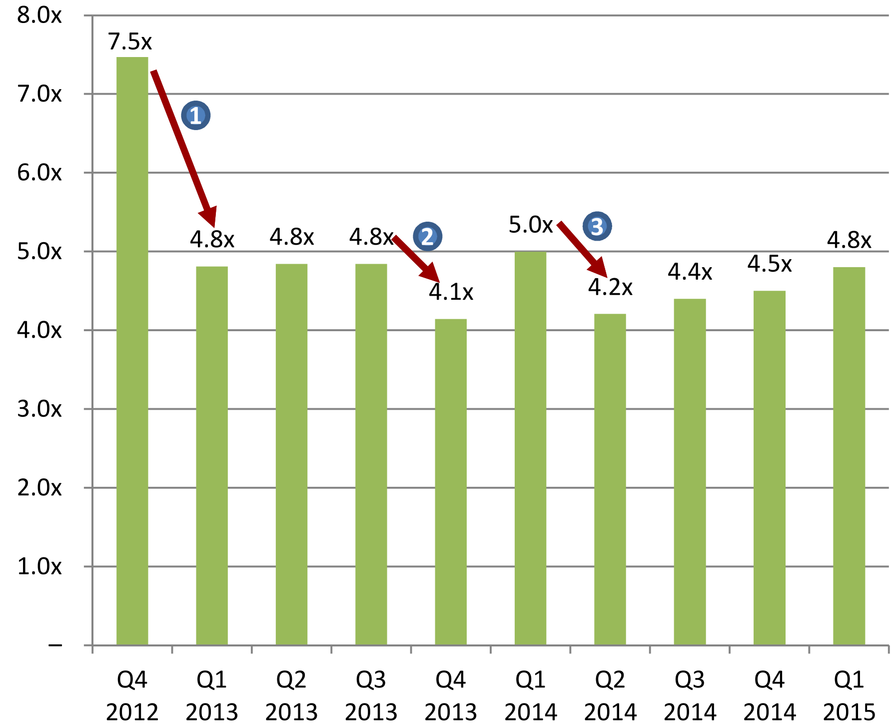


- USAC has increased the distribution to 21% above the MQD since IPO in January 2013
- Adjusted DCF coverage for Q1 2015 is 1.22x and adjusted cash coverage [(1)], as a result of USAC's Distribution Reinvestment Plan ("DRIP") , is 2.99x

DRIP Program

- The DRIP has given all investors the option to reinvest distributions on their units into newly issued common units
- The participation by affiliates of USAC in the DRIP has allowed USAC to retain over half of its quarterly cash distributions, providing an additional cash coverage cushion for our public investors and utilizing the retained cash to fund continued organic growth

USAC Historical Pro Forma Leverage[(2)]



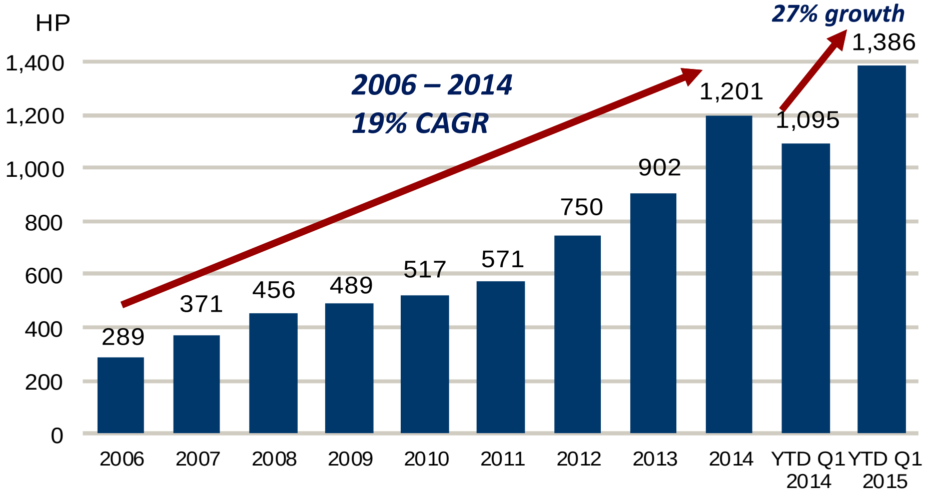
- 1) $198mm IPO proceeds; used to repay debt
- 2) $182mm acquisition of S&R gas lift fleet; 100% equity
- 3) $138mm follow-on primary offering; proceeds used to repay debt
- Covenant level of 5.95x in Q1/Q2 2015; 5.50x from Q3 2015 to Q2 2016; 5.00x thereafter

(1) See "Basis of Presentation; Explanation of Non-GAAP Financial Measures" for additional information on calculation of Adjusted DCF and cash coverage.

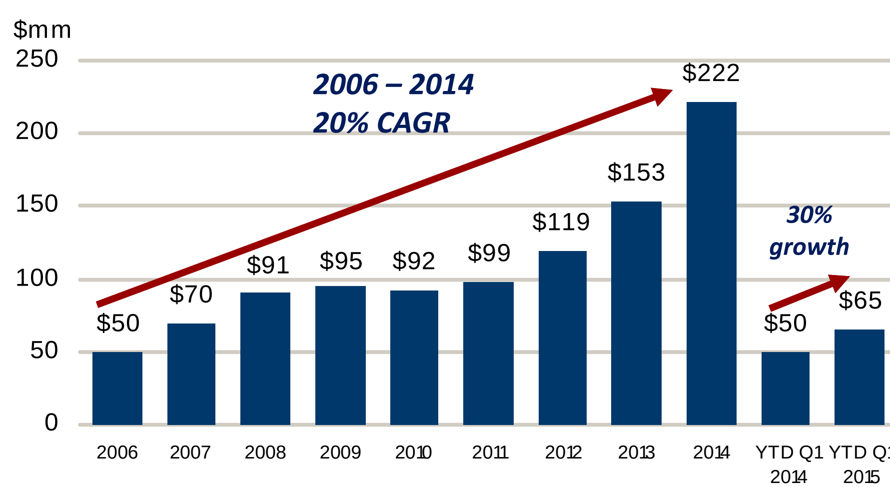
(2) Historical Pro Forma Leverage calculated as total debt divided by annualized quarterly Adjusted EBITDA for the applicable quarter, in accordance with our current Credit Agreement. Actual historical leverage may differ based on certain adjustments, and prior to Q4 2013 was calculated using LTM Adjusted EBITDA.

Operational and Financial Performance

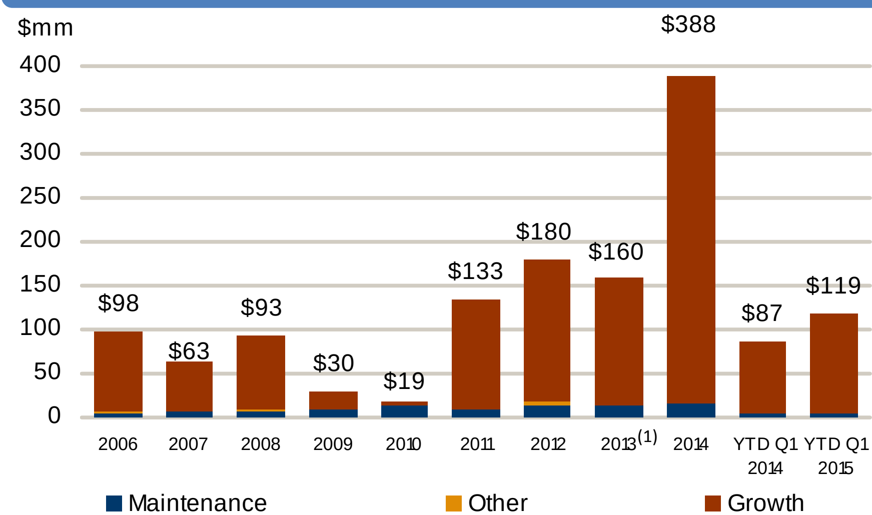
Avg. Revenue Generating HP (000s)



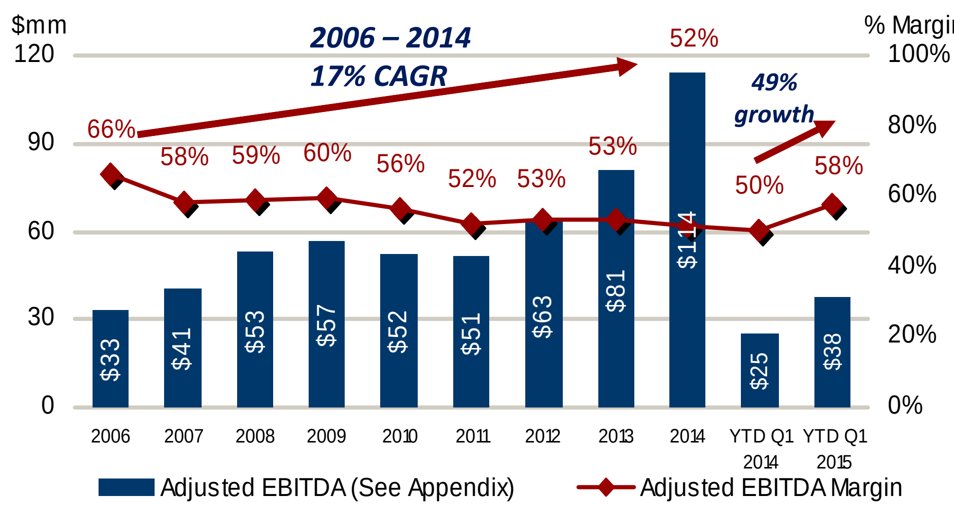
Revenue ($MM)



Total Capex ($MM)



Adjusted EBITDA(2) ($MM) & Margin



(1) Does not include $182mm acquisition of S&R Compression, financed with 7.4mm Common Units ($178mm net of cash acquired).

(2) See "Basis of Presentation; Explanation of Non-GAAP Financial Measures" for additional information on calculation of Adjusted EBITDA.

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USAC Investment Highlights

USAC's Business Prospects Driven By Positive Macro Drivers in the Midstream Industry

Critical Midstream Infrastructure	■ Continued focus on infrastructure-oriented compression applications; compression is critical to transporting hydrocarbons to end markets ■ Shale gas continues to reward flexible compression providers ■ Gas lift operations continue in our core areas; well economics (lifting vs. finding costs) still favorable
Exposure to Strategic Producing Regions	■ USAC owns and operates assets in prolific oil and gas shale basins benefitting from ongoing midstream build-out ■ Well-positioned in previously neglected dry gas basins – able to capitalize on recent shift from 'associated gas' growth to dry gas production growth ■ Continued organic development through presence in areas of natural gas processing ■ Gas-lift compression exposed to favorable trends / markets in crude oil production
Stable Cash Flows with Visible Growth	■ Infrastructure nature of assets results in compression units typically remaining in the field well beyond initial contract term ■ Order backlog and demand indications provide visible growth ■ Continued strong utilization history drives return on capital employed
Strategic Customer Relationships	■ Services provided to large, high-quality midstream and upstream customers ■ Continued outsourcing of service providers creates strategic opportunities for USAC ■ Long-standing customer relationships in all operating regions creates a significant barrier to entry

Appendix

2015 Guidance

	Guidance ($ in millions)
Net income	$13.1 to $24.1
Plus: Interest expense	$17.6 to $18.6
Plus: Depreciation and amortization	$92.0
Plus: Income taxes	$0.2
EBITDA	**$123.9 to $133.9**
Plus: Interest income on capital lease	$1.6
Plus: Unit-based compensation expense (1)	$4.5
Adjusted EBITDA	**$130.0 to $140.0**
Less: Cash interest expense	$17.5 to $18.5
Less: Income tax provision	$0.2
Less: Maintenance capital expenditures	$20.0
Distributable cash flow	**$91.3 to $102.3**

(1) Based on the Partnership's common unit closing price as of December 31, 2014.

Non-GAAP Reconciliations

($ in thousands)	Three Months Ended March 31,		Years Ended December 31,			
	2015	2014	2014	2013	2012	2011
Net income	$ 11,456	$ 3,915	$ 24,946	$ 11,071	$ 4,503	$ 69
Interest expense	3,994	3,549	12,529	12,488	15,905	12,970
Depreciation and amortization	20,731	16,220	71,156	52,917	41,880	32,738
Income taxes	79	103	103	280	196	155
Impairment of compression equipment	-	-	2,266	203	-	-
Interest income on capital lease	427	-	1,274	-	-	-
Unit-based compensation expense	1,026	1,096	3,034	1,343	-	-
Equipment operating lease expense	-	-	-	-	-	4,053
Riverstone management fee	-	-	-	49	1,000	1,000
Restructuring charges	-	-	-	-	-	300
Transaction expenses	-	46	1,299	2,142	-	-
Loss (gain) on sale of assets and other	(195)	263	(2,198)	637	-	-
Adjusted EBITDA	$ 37,518	$ 25,192	$ 114,409	$ 81,130	$ 63,484	$ 51,285
Interest expense	(3,994)	(3,549)	(12,529)	(12,488)	(15,905)	(12,970)
Income tax expense	(79)	(103)	(103)	(280)	(196)	(155)
Equipment operating lease expense	-	-	-	-	-	(4,053)
Interest income on capital lease	(427)	-	(1,274)			
Riverstone management fee	-	-	-	(49)	(1,000)	(1,000)
Restructuring charge	-	-	-	-	-	(300)
Transaction expenses	-	(46)	(1,299)	(2,142)	-	-
Other	455	548	1,189	1,840	(58)	(920)
Changes in operating assets and liabilities	(18,960)	(11,973)	1,498	180	(4,351)	1,895
Net cash provided by operating activities	$ 14,513	$ 10,069	$ 101,891	$ 68,190	$ 41,974	$ 33,782

Non-GAAP Reconciliations (cont'd)

	Three Months Ended		
	March 31, 2015	December 31, 2014	March 31, 2014
Net income	$ 11,456	$ 8,501	$ 3,915
Plus: Non-cash interest expense	455	307	582
Plus: Depreciation and amortization	20,731	19,631	16,220
Plus: Unit-based compensation(1)	1,026	77	1,096
Plus: Impairment of compression equipment	-	1,102	-
Less: Maintenance capital expenditures(2)	(4,093)	(3,357)	(5,289)
Distributable cash flow	$ 29,575	$ 26,261	$ 16,524
Transaction expenses for acquisitions(3)	-	18	46
Loss (gain) on sale of equipment and other	(36)	(4)	263
Adjusted distributable cash flow	$ 29,539	$ 26,275	$ 16,833
Plus: Maintenance capital expenditures	4,093	3,357	5,289
Plus: Change in operating assets and liabilities	(18,960)	1,676	(11,973)
Less: Transaction expenses for acquisitions	-	(18)	(46)
Less: Other	(159)	-	(34)
Net cash provided by operating activities	$ 14,513	$ 31,290	$ 10,069
Adjusted distributable cash flow	29,539	26,275	16,833
GP interest in distributions	588	546	389
Adjusted distributable cash flow attributable to LP interest	$ 28,951	$ 25,729	$ 16,444
Distributions for coverage ratio	$ 23,779	$ 23,131	$ 18,691
Distributions reinvested in the DRIP(4)	$ 14,111	$ 13,600	$ 13,122
Distributions for cash coverage ratio(5)	$ 9,668	$ 9,531	$ 5,569
Adjusted distributable cash flow coverage ratio	1.22	1.11	0.88
Cash coverage ratio	2.99	2.70	2.95

(1) For the quarters ended March 31, 2015 and December 31, 2014, unit-based compensation expense included $0.1 million and $0.2 million of cash payments related to quarterly payments of distribution equivalent rights on outstanding phantom unit awards, respectively. For the quarter ended March 31, 2015, unit-based compensation expense included $0.2 million of cash payments related to the cash portion of any settlement of phantom unit awards upon vesting. The remainder of the unit-based compensation expense for 2015 and 2014 is related to non-cash adjustments to the unit-based compensation liability.

(2) Reflects actual maintenance capital expenditures for the period presented. Maintenance capital expenditures are capital expenditures made to replace partially or fully depreciated assets, to maintain the operating capacity of the Partnership's assets and extend their useful lives, or other capital expenditures that are incurred in maintaining the Partnership's existing business and related cash flow.

(3) Represents certain transaction expenses related to acquisitions, potential acquisitions and other items. The Partnership believes it is useful to investors to view its results excluding these fees.

(4) Represents distributions to holders enrolled in the Partnership's DRIP as of the record date for each period. Amount for the three months ended March 31, 2015 is based on an estimate as of the record date.

(5) Represents cash distributions declared for common units not participating in the Partnership's DRIP.

Basis of Presentation; Explanation of Non-GAAP Financial Measures

This presentation includes the non-GAAP financial measures of Adjusted EBITDA ,distributable cash flow and cash coverage, as well as fleet utilization.

EBITDA, a measure not defined under U.S. generally accepted counting principles (“GAAP”), is defined by USAC as net income before net interest expense, income taxes, and depreciation and amortization expense. Adjusted EBITDA, which also is a non-GAAP measure, is defined by USAC as EBITDA plus impairment of compression equipment expense, unit-based compensation expense, restructuring charges, management fees, expenses under our operating lease with Caterpillar, certain fees and expenses related to our acquisition of USA Compression Holdings, (gain)/loss on sale of assets and transaction expenses. The Partnership’s management views Adjusted EBITDA as one of its primary management tools, to assess: (1) the financial performance of the Partnership’s assets without regard to the impact of financing methods, capital structure or historical cost basis of the Partnership’s assets; (2) the viability of capital expenditure projects and the overall rates of return on alternative investment opportunities; (3) the ability of the Partnership’s assets to generate cash sufficient to make debt payments and to make distributions; and (4) the Partnership’s operating performance as compared to those of other companies in its industry without regard to the impact of financing methods and capital structure. The Partnership believes that Adjusted EBITDA provides useful information to investors because, when viewed with GAAP results and the accompanying reconciliations, it provides a more complete understanding of the Partnership’s performance than GAAP results alone.

Distributable cash flow, a non-GAAP measure, is defined as net income (loss) plus non-cash interest expense, depreciation and amortization expense, unit-based compensation expense, impairment of compression equipment, less maintenance capital expenditures. Adjusted distributable cash flow is distributable cash flow plus certain transaction fees and (gain)/loss on sale of equipment. The Partnership’s management believes distributable cash flow and adjusted distributable cash flow are important measures of operating performance because such measures allow management, investors and others to compare basic cash flows the Partnership generates (prior to the establishment of any retained cash reserves by the Partnership’s general partner and the effect of the Partnership’s Distribution Reinvestment Plan) to the cash distributions the Partnership expects to pay its unitholders. The Partnership’s distributable cash flow may not be comparable to a similarly titled measure of another company because other entities may not calculate distributable cash flow in the same manner. See previous slides for Adjusted EBITDA reconciled to net income and net cash provided by operating activities, and net income reconciled to distributable cash flow and adjusted distributable cash flow.

This presentation contains a forward-looking estimate of Adjusted EBITDA and distributable cash flow projected to be generated by the Partnership in its 2015 fiscal year. A reconciliation of Adjusted EBITDA and distributable cash flow to net cash provided by operating activities is not provided because the items necessary to estimate net cash provided by operating activities, in particular the change in operating assets and liabilities amounts, are not accessible or estimable at this time. The Partnership does not anticipate the changes in operating assets and liabilities amounts to be material, but changes in accounts receivable, accounts payable, accrued liabilities and deferred revenue could be significant, such that the amount of net cash provided by operating activities would vary substantially from the amount of projected Adjusted EBITDA.

Adjusted EBITDA and Adjusted DCF should not be considered an alternative to, or more meaningful than, net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP as measures of operating performance and liquidity. Moreover, Adjusted EBITDA and Adjusted DCF as presented may not be comparable to similarly titled measures of other companies.

The Partnership believes that external users of its financial statements benefit from having access to the same financial measures that management uses in evaluating the results of the Partnership’s business. Further, the Partnership believes that these measures are useful to investors because they are one of the bases for comparing the Partnership’s operating performance with that of other companies with similar operations.

Fleet utilization is calculated as (i)(a) revenue generating HP plus (b) HP in the Partnership's fleet that is under contract, but is not yet generating revenue plus (c) HP not yet in the Partnership's fleet that is under contract not yet generating revenue and that is subject to a purchase order, divided by (ii) total available HP less idle HP that is under repair. Average utilization calculated as the average utilization for the months in the period based on utilization at the end of each month in the period.

Adjusted distributable cash flow coverage ratio, a non-GAAP measure, is defined as Adjusted DCF flow less cash distributions to the Partnership’s general partner and incentive distribution rights (“IDRs”), divided by distributions declared to limited partnership unitholders for the period. We define cash coverage ratio as Adjusted DCF less cash distributions to the Partnership’s general partner and IDRs divided by cash distributions paid to limited partnership unitholders, after consideration of the DRIP. We believe adjusted DCF coverage ratio and cash coverage ratio are important measures of operating performance because they allow management, investors and others to gauge our ability to pay cash distributions to limited partner unitholders using the cash flows we generate. Our adjusted DCF coverage ratio and cash coverage ratio as presented may not be comparable to similarly titled measures of other companies.