USA COMPRESSION

USA Compression Partners, LP
2016 UBS MLP One-on-One Conference
January 12, 2016

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.

Recent Developments: Q3 2015 Review

USAC Continues to Deliver; Achieves Record Revenue, Adjusted EBITDA and Adjusted DCF in Q3 2015

Operational Update

- Q3 2015 fleet HP of 1.7 million and average revenue generating HP of 1.4 million– both are 16% increases over Q3 2014 levels
- Average horsepower utilization of 90.2% for Q3 2015 – effectively flat quarter over quarter
- Total HP orders of ~195K through Q3; 2015 capex program over 90% completed
- Newbuild HP primarily placed in service in Marcellus/Utica and West Texas
  - Continue to add larger units to the fleet – average size of large delivered in Q3 > 2,000 HP

Financial Update

- Record Revenue, Adjusted EBITDA and Adjusted distributable cash flow, or DCF, in Q3 2015
  - Revenue of $70.5mm, up 24% Y-o-Y
  - Adjusted EBITDA of $39.5mm, up 35% Y-o-Y
  - Adjusted DCF of $32.3mm, up 41% Y-o-Y
- LP distribution of $0.525 for Q3 2015; Adjusted DCF coverage of 1.25x
- Successfully executed second follow-on equity offering, raising $74mm in net proceeds – used to repay debt
- Leverage of 4.5x on outstanding borrowings of $712 million
- Upward revision to full-year Adjusted EBITDA and Adjusted DCF guidance (see appendix for full details)
  - Adjusted EBITDA range of $147mm to $152mm; Adjusted DCF range of $113mm to $118mm

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.

Activity and Outlook Remains Positive in USAC's Key Regions

Select Producer Recent Commentary

Southwestern Energy

- Total Appalachia net production of 130 Bcfe in Q3; Northeast Appalachia up 41% year-over-year
- Quarter over quarter, the average time to drill to total depth decreased to 8 days from 9 days in NW Appalachia
- Received permit for first Utica well; expected to be completed during Q4 and placed into production early 2016

Range Resources

- First Utica well in PA estimated to have 15 Bcf EUR; second well projected to be even better; third to be drilled and completed by early 2016
- Unit costs declined 12% year-over-year, allowing 20% production growth on 45% less capital
- Expects improved regional natural gas prices in Appalachia, as Mariner East I becomes fully operational by year-end

Jones Energy

- Jones announced a second increase in production guidance (an increase over 2014 levels), even with reduction in drilling activity in 2015
- Year-over-year capital spend 60% less in 2015
- Expect to develop a cash flow neutral program for 2016

Pioneer Natural Resources

- Recently increased its Q4 production guidance above the previously announced range, driven by strong Spraberry / Wolfcamp drilling program; as a result, also increased its year-over-year production growth guidance to 12%
- Expects to continue operating 18 horizontal rigs in Spraberry/Wolfcamp through 2016
- Due to capital efficiency and productivity improvements, wells averaging EURs in excess of 1.3 MMBoe with estimated cost of $8mm generate IRR >30% with current prices

Apache

- Raised 2015 guidance for North American onshore production while maintaining capital spend guidance
- Operated 10 rigs in the Permian Basin in Q3; completed 65 wells which is up from 53 in Q2
- Operated 2 rigs in the Midcontinent, targeting the Woodford/SCOOP and Marmaton plays
- Plan to live within 2016 cash flow and maintain flexibility

Continental Resources

- Based on continued strong well performance, increased 2015 production growth guidance to midpoint of 25% from midpoint of 21%; drilling and completion costs down 25% since end of 2014
- Achieving record efficiency gains in the SCOOP play; reduced drilling time by 30-50% on recent wells
- 15 rigs running in Oklahoma (SCOOP and STACK plays); two new completion crews added in OK, bringing total to 3

Per Company press releases, earnings call transcripts and presentations

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

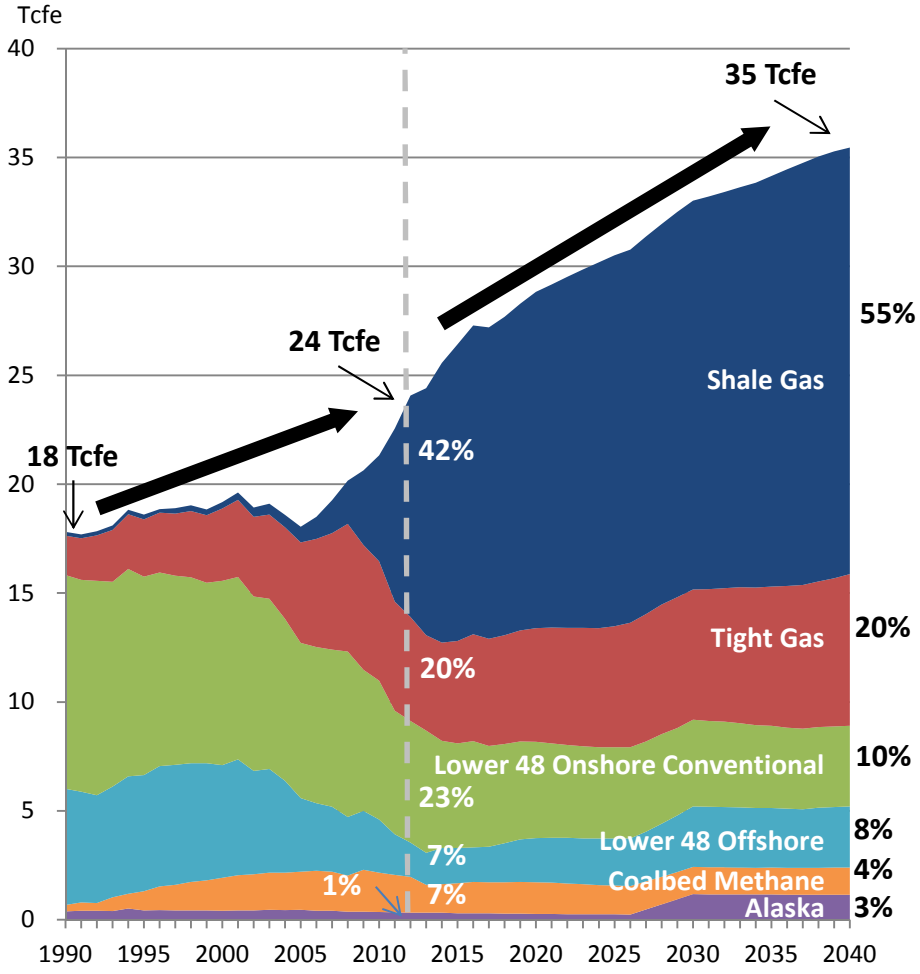
"Core" Crude Oil Production

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

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

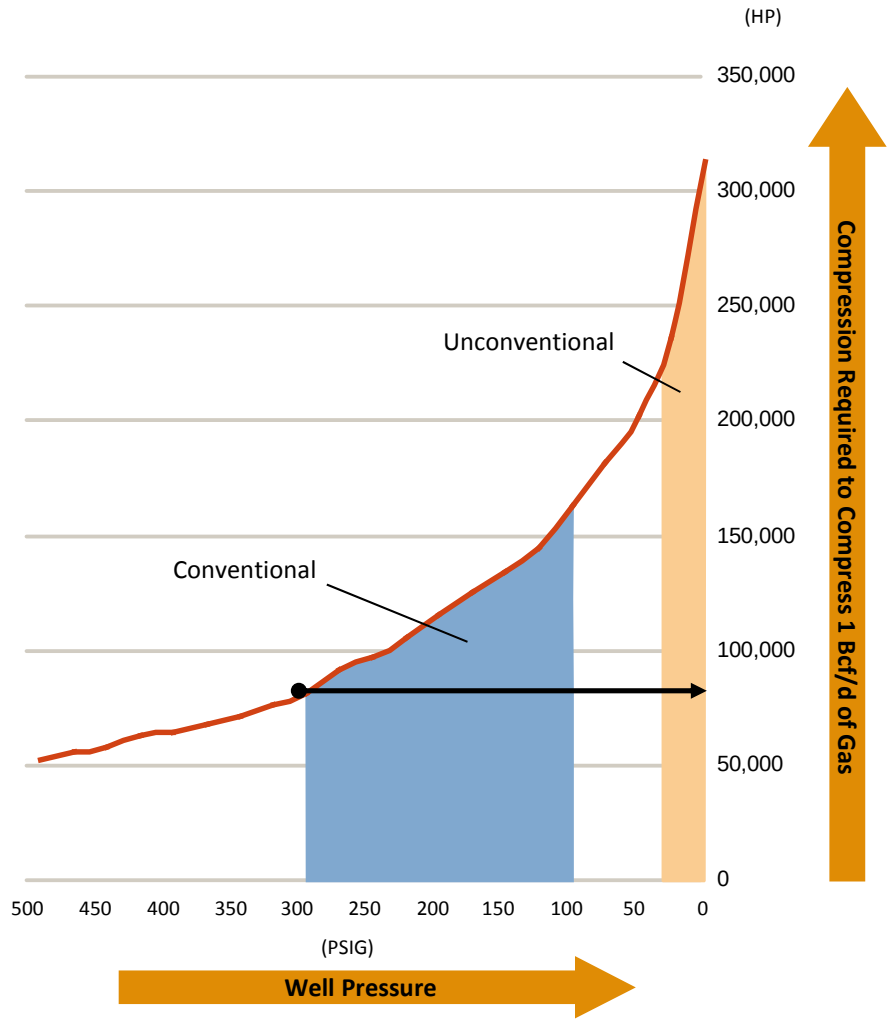
Source: U.S. Energy Information Administration, Annual Energy Outlook 2015.

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



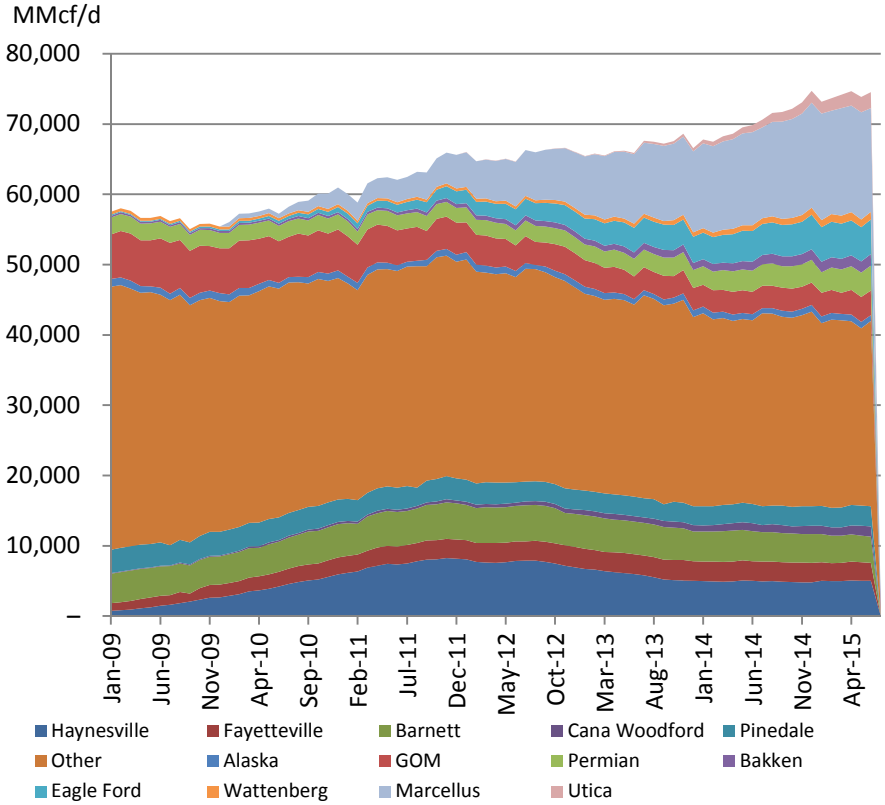
Source: Ariel Corporation: compressor sizing protocol.
(1) Assumes Discharge Pressure = 1,200 PSIG.

Changing, But Still Growing, Natural Gas Market

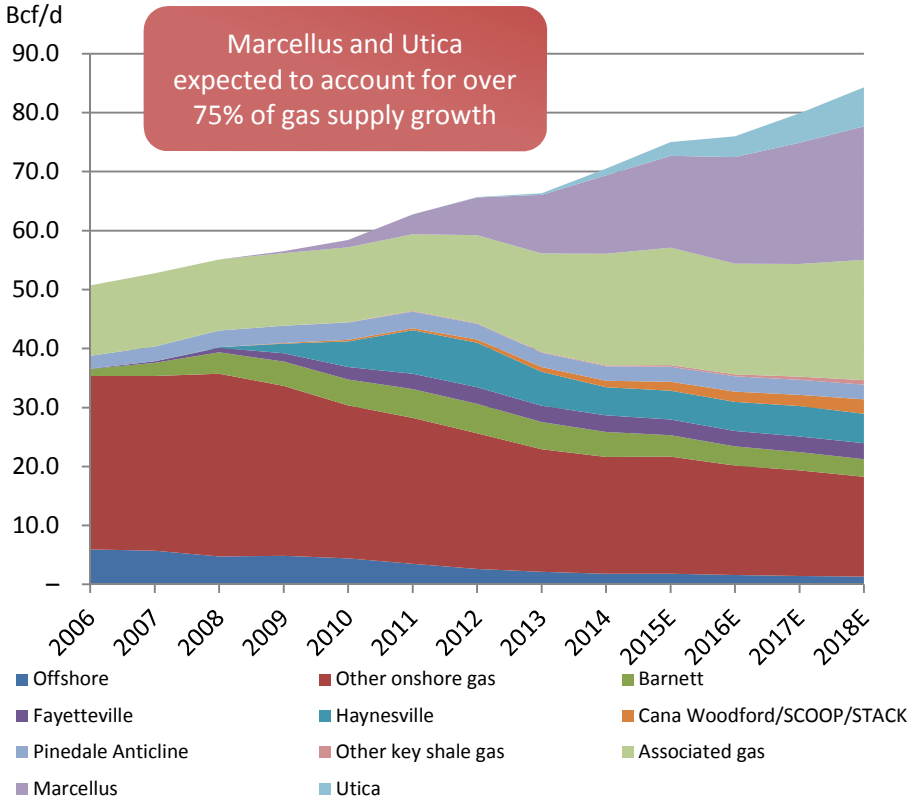
Marcellus/Utica Production Continues to Drive Growth; Expected to Offset 2016 Associated Gas Decline

- Due to lowered liquids-focused activity in 2015, associated gas production projected to decrease in 2016
- However, total natural gas supply is expected to continue to grow through 2020 – driven by:
  1) Productivity gains across key gas plays (specifically Marcellus and Utica)
  2) Lower production decline rates (as well as enhanced completions and longer laterals) in 'mature' gas plays such as Haynesville and Pinedale Anticline

Historical Dry Gas Production by Play



Projected Dry Gas Production Growth by Play



Per Goldman Sachs research, October 2015.

Natural Gas Demand Poised to Surge

"Big Four" Demand Sources Driving Majority of Expected 22 Bcf/d of New Natural Gas Demand Thru 2020

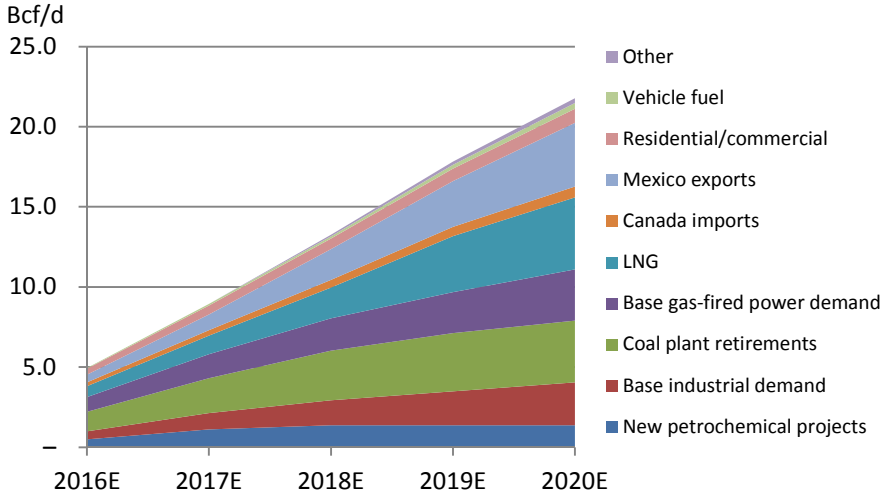
Coal Plant Retirements and Gas-Fired Power Demand	■ Roughly 33 gigawatts of coal plant capacity already announced to be retired through 2020; research suggests more retirements to come – for total expected retirements of almost 50 GW ■ Vast majority of announced retirements occurring by end of 2017 ■ Expected ~7 Bcf/d of demand growth by 2020 from total gas-fired power demand (~4 Bcf/d of which is from expected coal plant retirements)
Mexico Exports	■ Shale gas NOT expected to be near-term focus in Mexico; will continue to rely on imports of US natural gas to meet its growing demand ■ Research suggests an incremental ~4 Bcf/d of US natural gas exports to Mexico by 2020 ■ Includes announced and in-progress projects from midstream operators such as Howard Energy, Energy Transfer, Kinder Morgan, etc.
LNG Exports	■ Research suggests ~5 Bcf/d of US LNG exports by 2020, with upwards of 12 Bcf/d of export demand expected on a longer-term basis (based on contracts signed by consumers) ■ Potential for an increased coal-to-gas switching in Europe, which would bolster future US LNG export demand ■ First LNG train in US (Cheniere's Sabine Pass terminal) began production on December 30, 2015 ■ FERC recently approved 7th LNG export facility (operated by Energy Transfer)
Industrial Demand	■ Expected ~4 Bcf/d of incremental industrial demand growth by 2020 ■ Growth driven by increases in both base industrial demand as well as ~1.7 Bcf/d of new petrochemical plant projects / expansions (ethylene, ammonia and propylene)

Per Goldman Sachs research, November 2015.

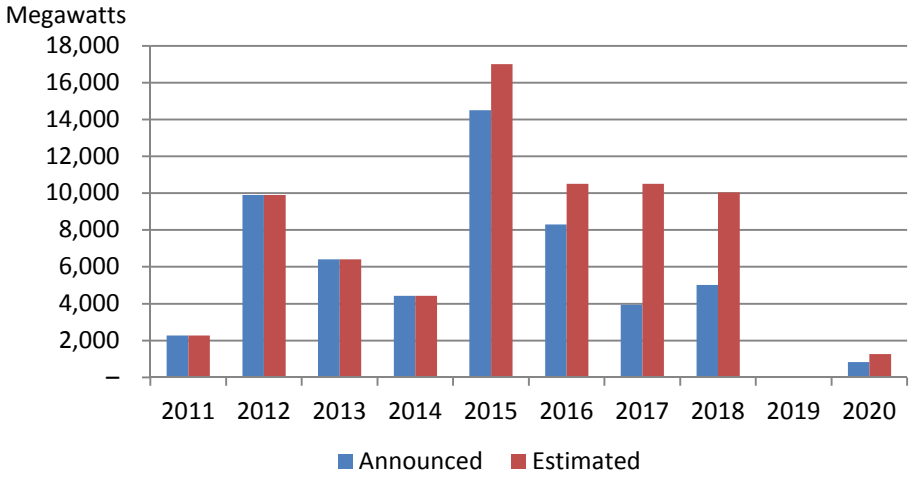
Natural Gas Demand Poised to Surge, Cont'd.

Demand Drivers Expected to Increase Total Natural Gas Demand ~30% by 2020

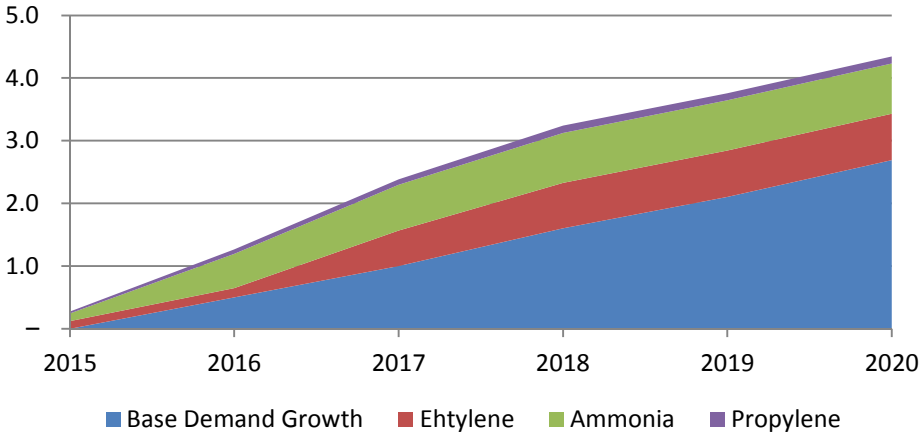
Cumulative New Sources of Natural Gas Demand



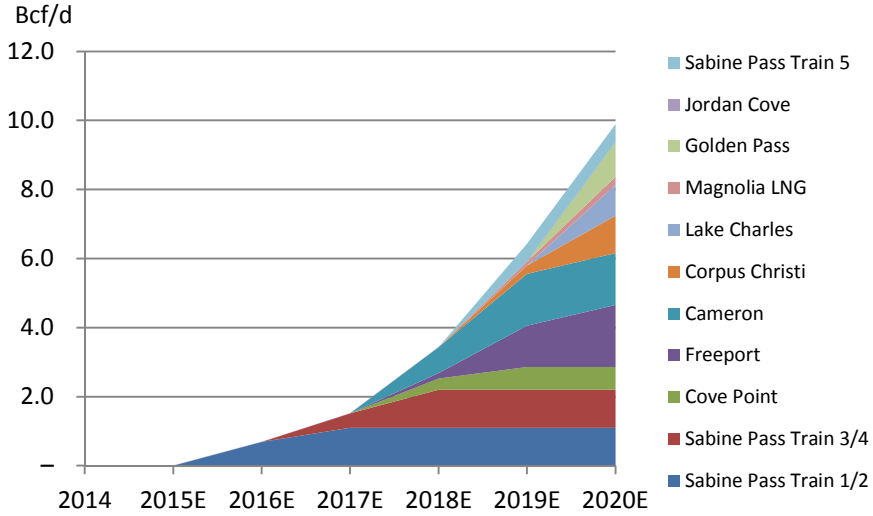
Coal Plant Retirements



Industrial Demand



Expected Schedule of Contracted LNG Exports



Per Goldman Sachs research, November 2015.

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

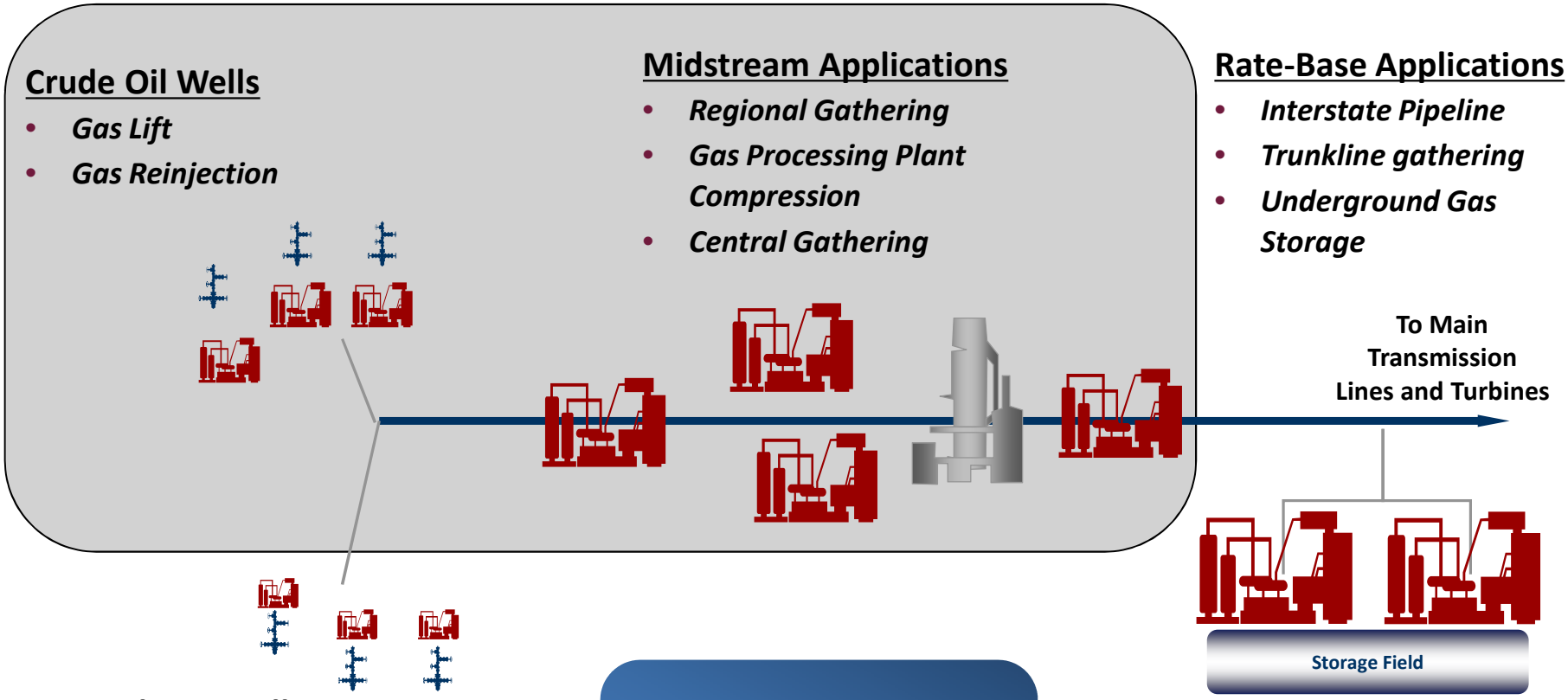
Attractive Fundamentals Driving Growth

- Gas production increasing primarily in shale plays, which require both more overall 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

Strategic Focus on Infrastructure Applications

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

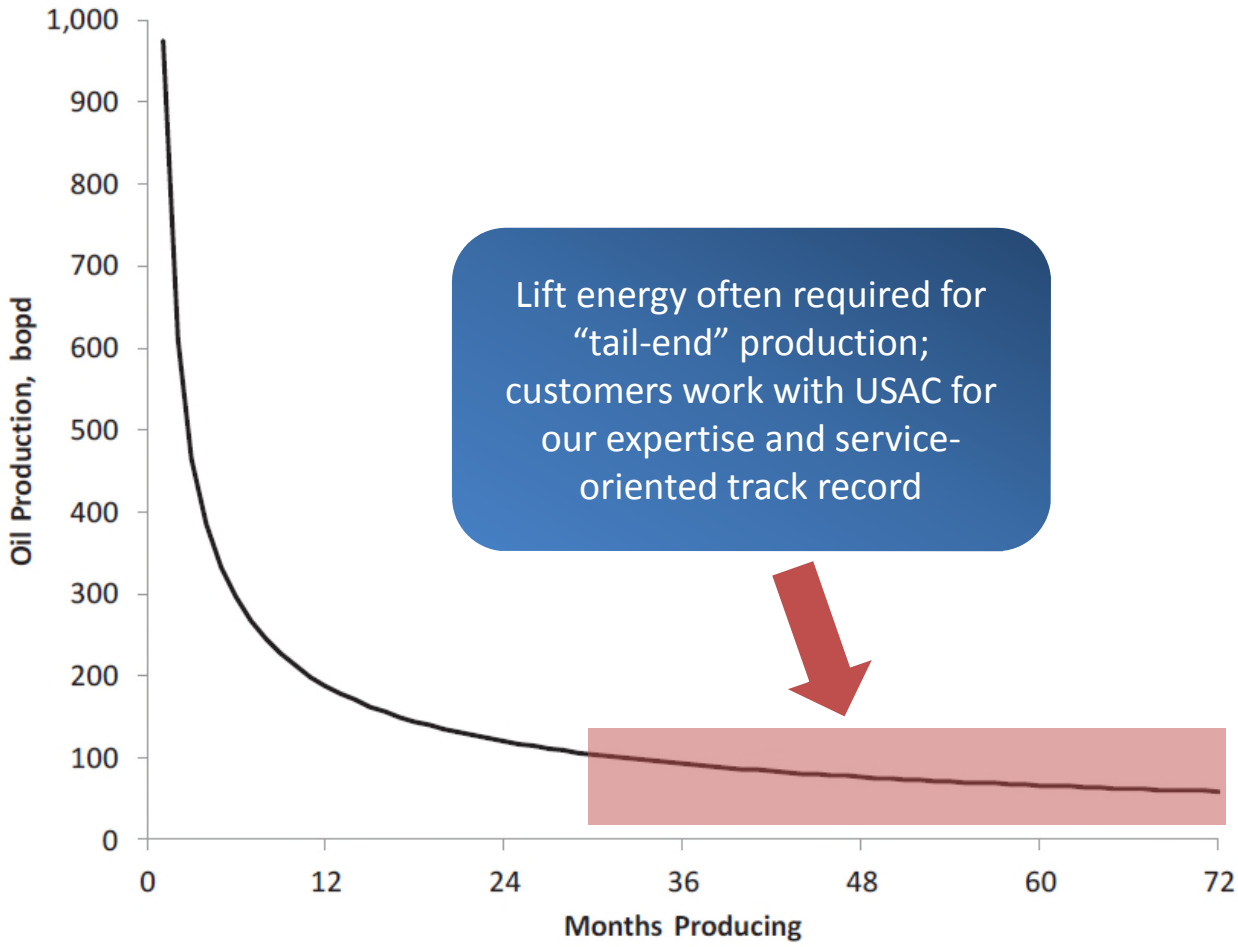


USAC believes these infrastructure applications are a better fit for the MLP structure

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
- Even in current commodity price environment, production from existing wells remains economic due to management of upstream operating costs
  - Many producers have seen lower LOE costs in 2015, from increased operational efficiencies and service cost reductions



Source: TPH & Co.

USAC: Story of Stability and Growth

USA COMPRESSION

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 HP

Dec 2010: Riverstone completes acquisition of USAC

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

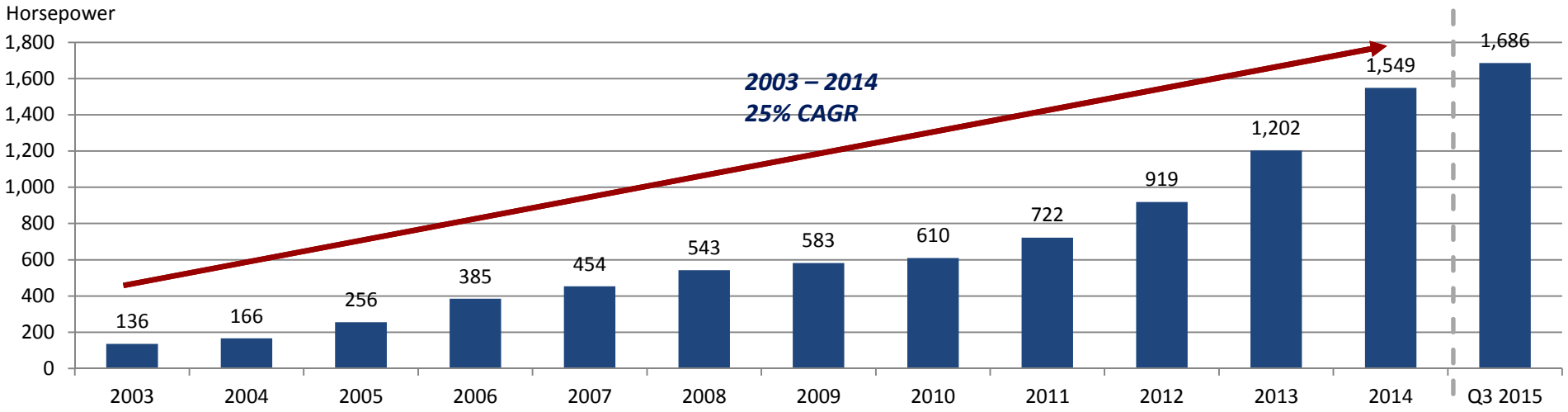
Aug 2013: USAC completes $182mm S&R Acquisition, 100% equity funded

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

September 2015: USAC completes $74mm equity offering; net proceeds used to repay debt

1998 — 2010 — 2013 — 2014 — 2015

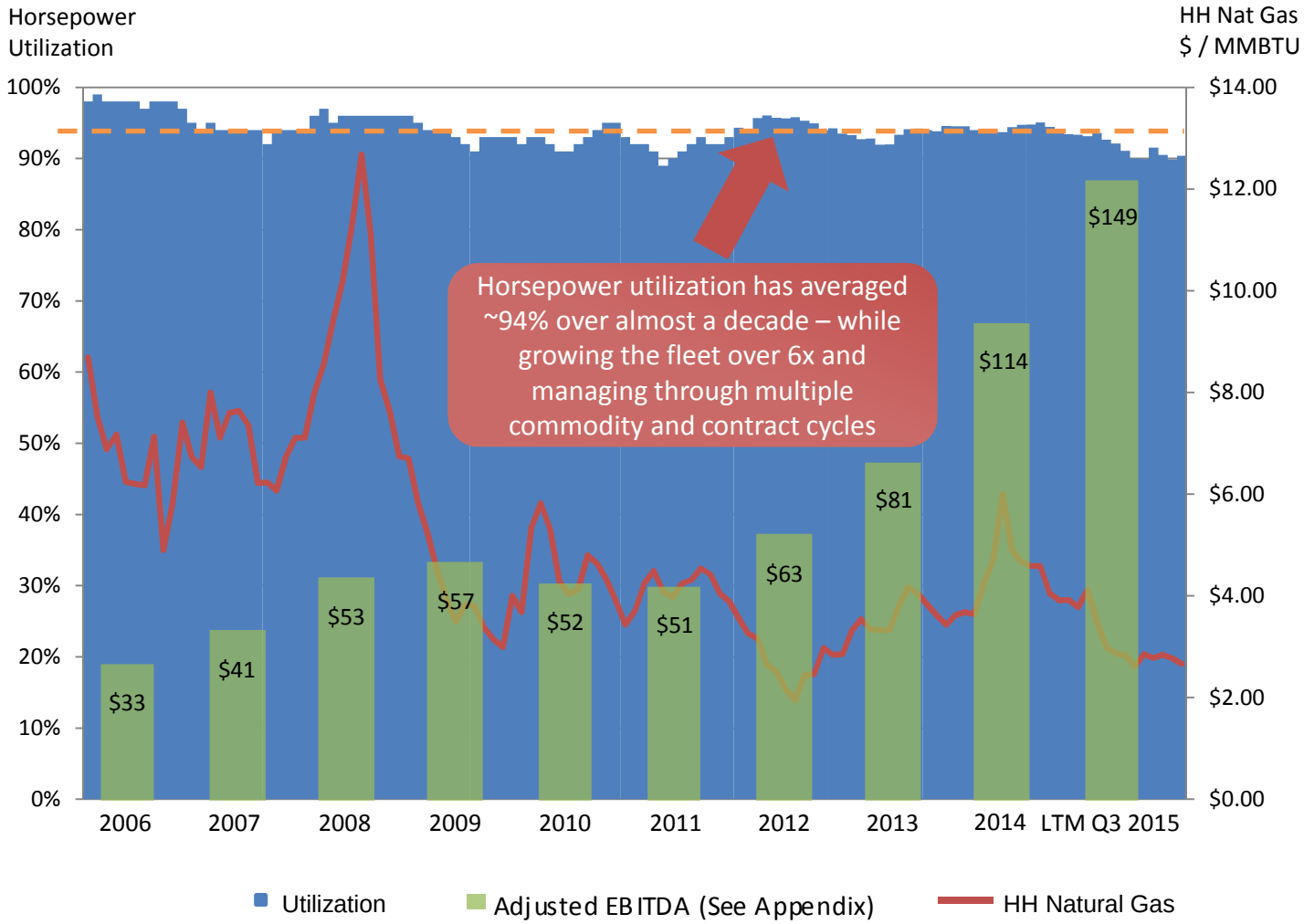
Horsepower Growth



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 Demand and Production
- 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 horsepower 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 under 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 generally will not flow into and through pipeline systems without compression
- Production matters more than drilling activity
- Lagging development following G&P build-out

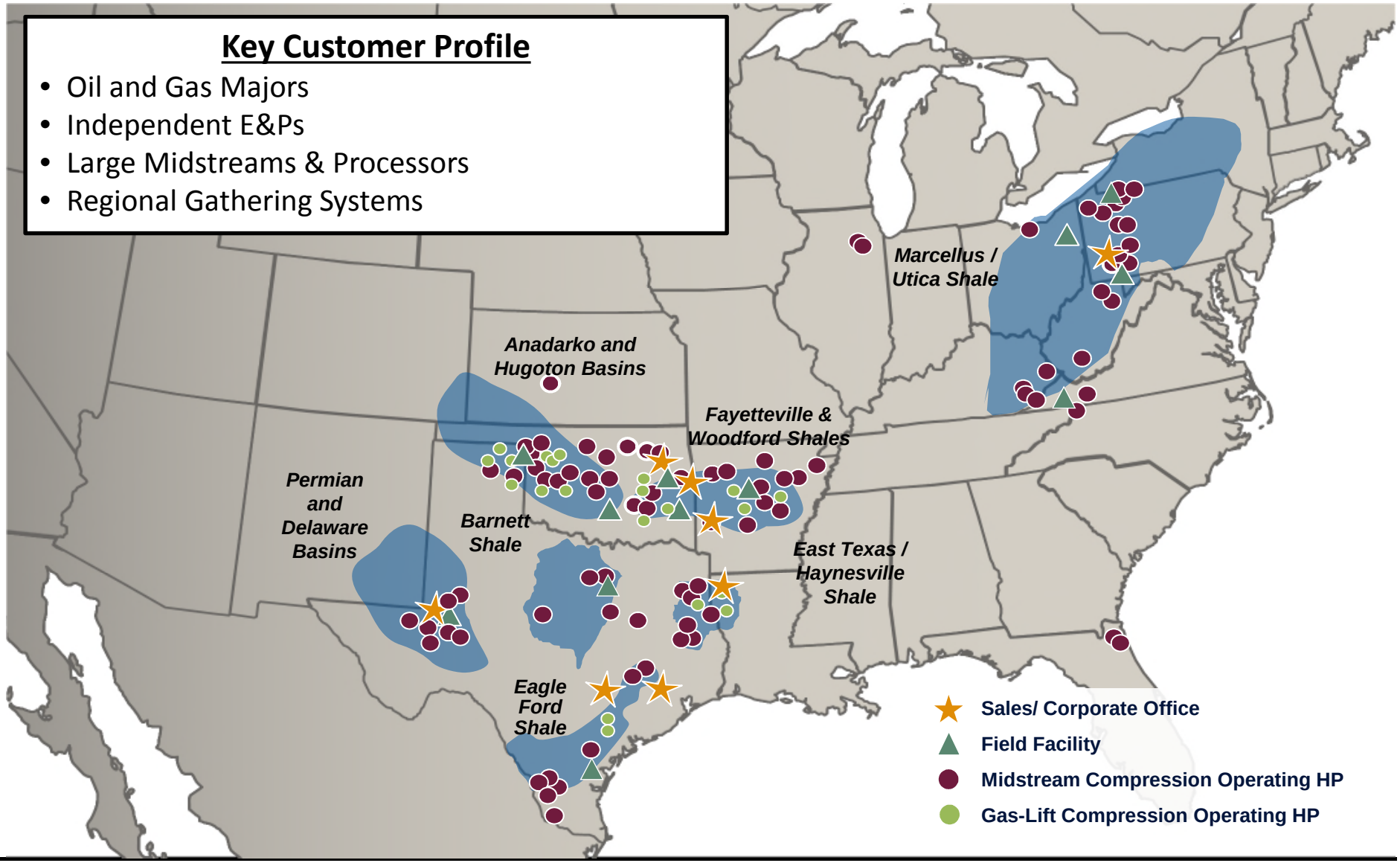
Loyal Customer Base

- 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 <u>Not</u> Directly Dependent on Commodity Prices

Geographical Presence

Presence in Key Geographical Regions



Well-Capitalized Customer Base with Strong Credit Ratings

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

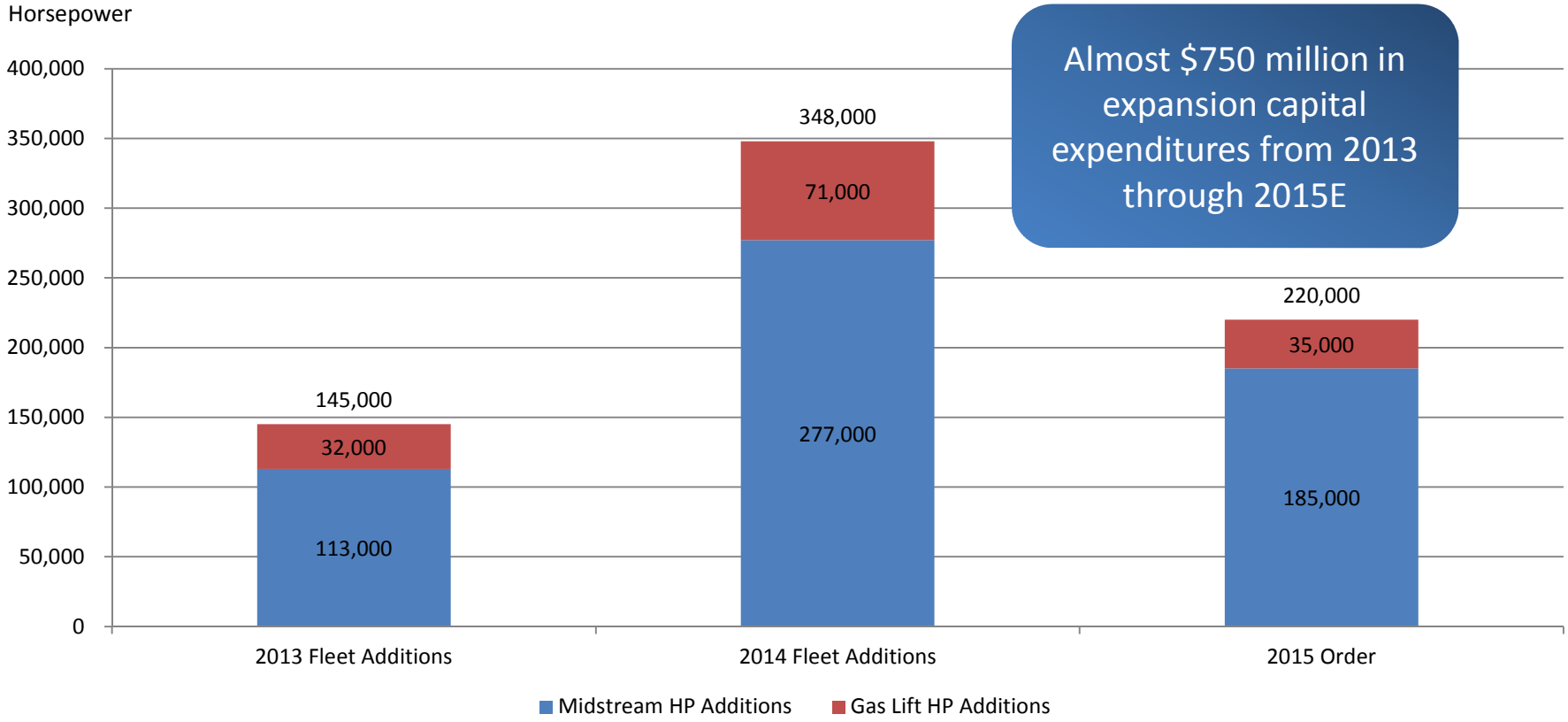
Rank	Top Customers	Length of Relationship	Credit Rating [1]
1	Large Public Independent E&P	10+ years	Baa3 / BBB-
2	Large Public Independent E&P	7 years [2]	Baa1 / BBB+
3	Large Public MLP	2 years	Baa3 / BBB-
4	Pipeline Subsidiary of Utility	2 years	A3 / BBB+
5	Large Private Midstream	2 years	N/A
6	Oil and Gas Major	10+ years	Aa1 / AA-
7	Pipeline Subsidiary of Large E&P	9 years	Ba3 / BB-
8	Large Diversified Oil and Gas	10+ years	B1 / BB
9	Large Public Independent E&P	10+ years	A3 / A-
10	Public Independent E&P	4 years [2]	B2 / NR

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 / Baa3

Note: Rankings and %'s of revenue reflect YTD Q3 2015 revenue.
(1) Per Bloomberg and company filings, as of November 2015.
(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



Almost $750 million in expansion capital expenditures from 2013 through 2015E

- Following record levels of capital spending in 2014, USAC has spent over 90% of its planned growth capital for the year through Q3 2015
- Approximately 30,000 HP on order so far for delivery in 2016
- Lead times from order to receipt of compressor packages continue to be significantly shorter than those USAC experienced in 2014; potential to quickly add incremental units throughout 2016 to meet customer demand

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

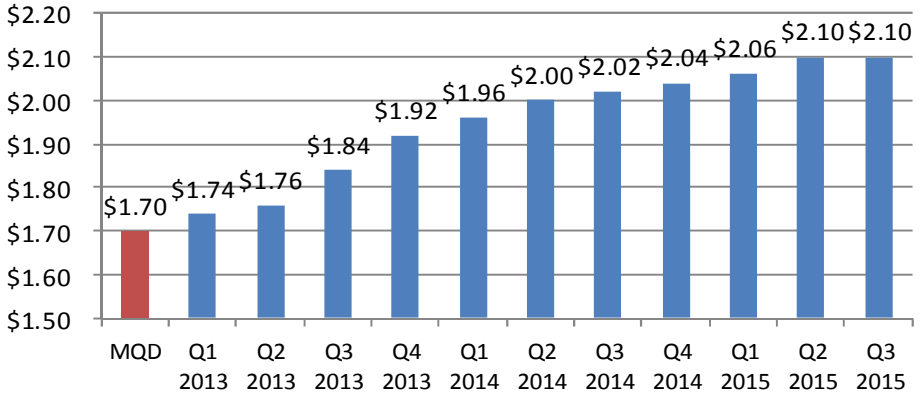
Financial Overview and Investment Highlights

USA COMPRESSION

USAC Distributions and Leverage Since IPO

Prudent Balance Between Distribution Growth, Coverage and Leverage

Annualized Distributions per LP Unit

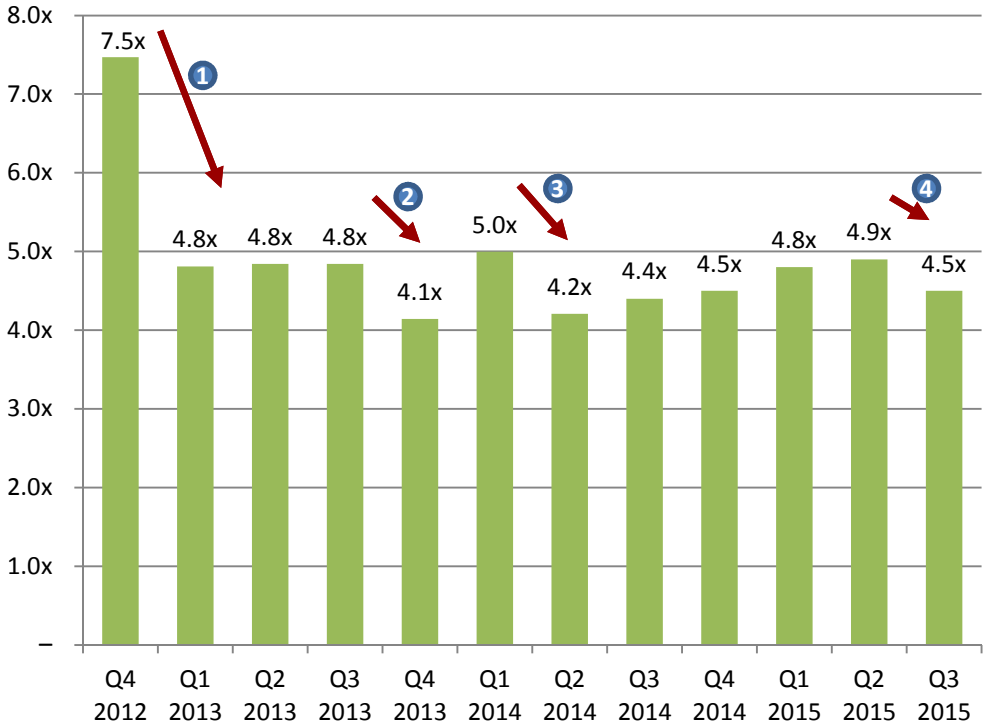


- USAC has increased the distribution to 24% above the MQD since IPO in January 2013
- Adjusted DCF coverage for Q3 2015 is 1.25x and cash coverage ratio [1], as a result of USAC's Distribution Reinvestment Plan ("DRIP"), is 3.12x

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]

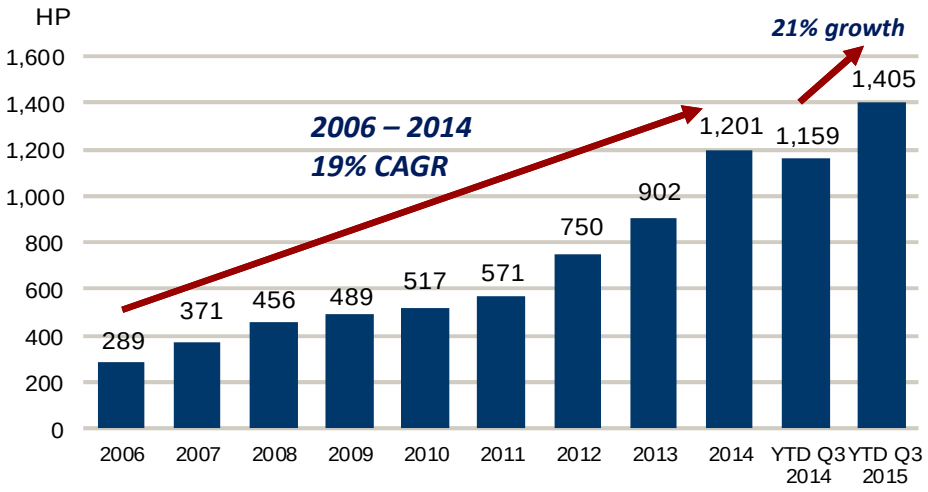


- 1) $198mm IPO proceeds; used to repay debt
- 2) $182mm acquisition of S&R gas lift fleet; 100% equity
- 3) $138mm follow-on offering; proceeds used to repay debt
- 4) $74mm follow-on offering; proceeds used to repay debt

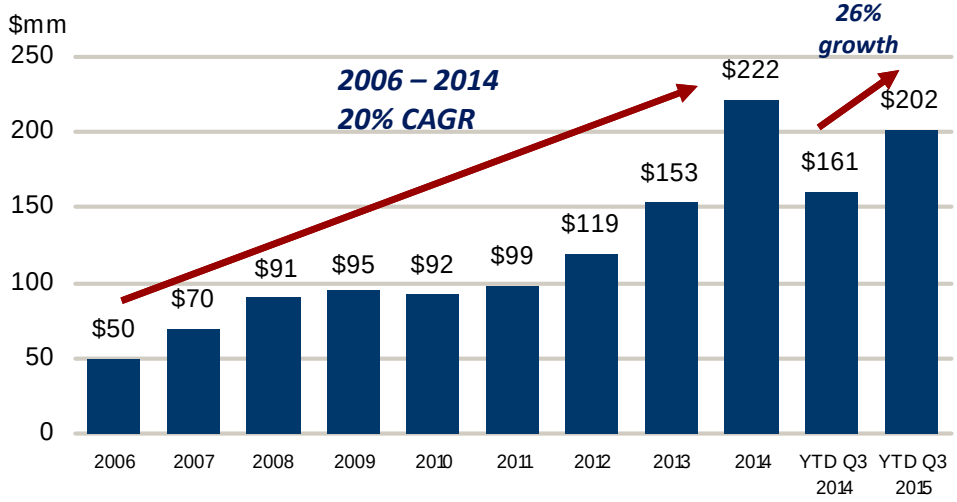
(1) See "Basis of Presentation; Explanation of Non-GAAP Financial Measures" for additional information on calculation of Adjusted DCF coverage and cash coverage ratios.
(2) Historical Pro Forma Leverage calculated as total debt divided by annualized quarterly Adjusted EBITDA for the applicable quarter, 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

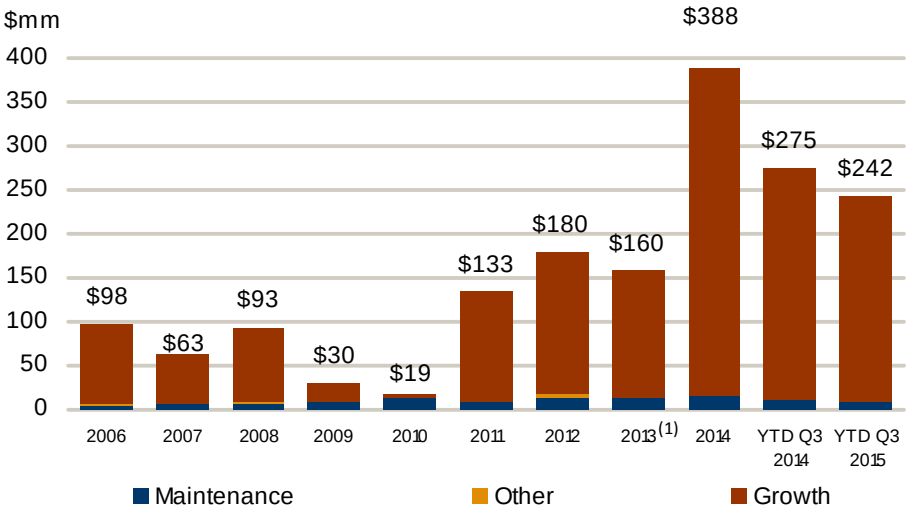
Avg. Revenue Generating HP (000s)



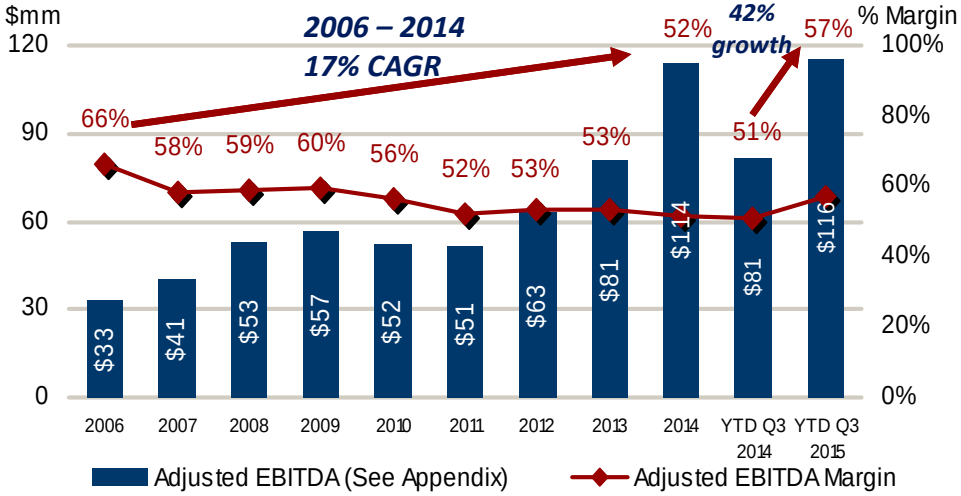
Revenue ($MM)



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.

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
- 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

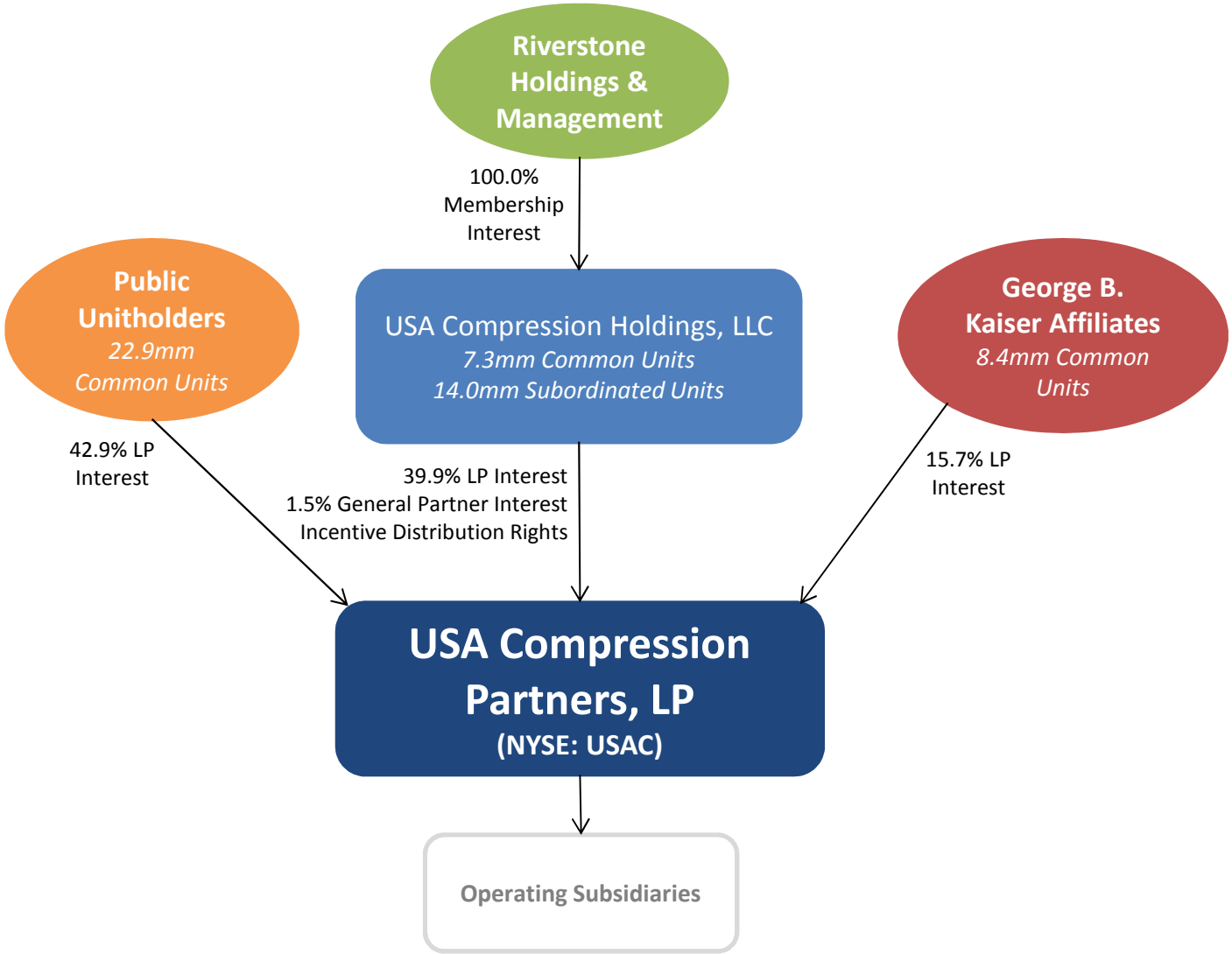
2015 Revised Guidance

	Guidance
Net income	$7.4 million to $12.4 million
Plus: Interest expense	$19.5 million
Plus: Depreciation and amortization	$86.5 million
Plus: Income tax expense	$1.4 million
EBITDA	$114.8 million to $119.8 million
Plus: Interest income on capital lease	$1.6 million
Plus: Unit-based compensation expense(1)	$3.8 million
Plus: Impairment of compression equipment	$26.8 million
Adjusted EBITDA	**$147.0 million to $152.0 million**
Less: Cash interest expense	$17.3 million
Less: Current income tax expense	$0.3 million
Less: Maintenance capital expenditures	$17.0 million
Plus: Loss (gain) on sale of assets	$0.6 million
Adjusted distributable cash flow	**$113.0 million to $118.0 million**

(1) Based on the Partnership's closing unit price as of September 30, 2015.

USA Compression Ownership Structure

USAC is a Pure-play Compression MLP Backed by Experienced Energy Investors



Note: As of November 13, 2015. Reflects effect of Q3 2015 DRIP.

Non-GAAP Reconciliations

($ in thousands)	Three Months Ended September 30,		Nine Months Ended September 30,		Years Ended December 31,			
	2015	2014	2015	2014	2014	2013	2012	2011
Net income	$ 9,805	$ 5,013	$ 5,357	$ 16,446	$ 24,946	$ 11,071	$ 4,503	$ 69
Interest expense	4,665	2,677	13,074	9,269	12,529	12,488	15,905	12,970
Depreciation and amortization	21,360	18,261	63,598	51,525	71,156	52,917	41,880	32,738
Income taxes	1,083	-	1,304	103	103	280	196	155
Impairment of compression equipment	443	1,163	27,272	1,163	2,266	203	-	-
Interest income on capital lease	401	433	1,242	835	1,274	-	-	-
Unit-based compensation expense	804	855	3,068	2,957	3,034	1,343	-	-
Equipment operating lease expense	-	-	-	-	-	-	-	4,053
Riverstone management fee	-	-	-	-	-	49	1,000	1,000
Restructuring charges	-	-	-	-	-	-	-	300
Transaction expenses	-	862	-	1,282	1,299	2,142	-	-
Loss (gain) on sale of assets and other	920	63	702	(2,194)	(2,198)	637	-	-
Adjusted EBITDA	$ 39,481	$ 29,327	$ 115,617	$ 81,386	$ 114,409	$ 81,130	$ 63,484	$ 51,285
Interest expense	(4,665)	(2,677)	(13,074)	(9,269)	(12,529)	(12,488)	(15,905)	(12,970)
Income tax expense	(1,083)	-	(1,304)	(103)	(103)	(280)	(196)	(155)
Equipment operating lease expense	-	-	-	-	-	-	-	(4,053)
Interest income on capital lease	(401)	(433)	(1,242)	(835)	(1,274)			
Riverstone management fee	-	-	-	-	-	(49)	(1,000)	(1,000)
Restructuring charge	-	-	-	-	-	-	-	(300)
Transaction expenses	-	(862)	-	(1,282)	(1,299)	(2,142)	-	-
Other	416	43	1,286	882	1,189	1,840	(58)	(920)
Changes in operating assets and liabilities	445	13,534	(18,540)	(178)	1,498	180	(4,351)	1,895
Net cash provided by operating activities	$ 34,193	$ 38,932	$ 82,743	$ 70,601	$ 101,891	$ 68,190	$ 41,974	$ 33,782

Non-GAAP Reconciliations (cont'd)

	Three months ended		
	September 30, 2015	June 30, 2015	September 30, 2014
Net income (loss)	$ 9,805	$ (15,904)	$ 5,013
Plus: Non-cash interest expense	416	415	43
Plus: Non-cash income tax expense	1,076	-	-
Plus: Depreciation and amortization	21,360	21,507	18,261
Plus: Unit-based compensation expense(1)	804	1,238	855
Plus: Impairment of compression equipment	443	26,829	1,163
Less: Maintenance capital expenditures(2)	(2,959)	(3,061)	(3,305)
Distributable cash flow	$ 30,945	$ 31,024	$ 22,030
Transaction expenses for acquisitions(3)	-	-	862
Loss (gain) on sale of equipment and other	1,324	(23)	63
Adjusted distributable cash flow	$ 32,269	$ 31,001	$ 22,955
Plus: Maintenance capital expenditures	2,959	3,061	3,305
Plus: Changes in operating assets and liabilities	445	(25)	13,534
Less: Transaction expenses for acquisitions	-	-	(862)
Less: Other	(1,480)	-	-
Net cash provided by operating activities	$ 34,193	$ 34,037	$ 38,932
Adjusted distributable cash flow	32,269	31,001	22,955
Cash distributions to GP and IDRs	697	671	506
Adjusted distributable cash flow attributable to LP interest	$ 31,572	$ 30,330	$ 22,449
Distributions for Coverage Ratio (4)	$ 25,290	$ 24,579	$ 22,606
Distributions reinvested in the DRIP(5)	$ 15,179	$ 14,731	$ 13,148
Distributions for Cash Coverage Ratio(6)	$ 10,111	$ 9,848	$ 9,458
Adjusted Distributable Cash Flow Coverage Ratio(7)	1.25	1.23	0.99
Cash Coverage Ratio(8)	3.12	3.08	2.37

(1) For the quarters ended September 30, 2015, June 30, 2015 and September 30, 2014, unit-based compensation expense included $0.2 million for each period of cash payments related to quarterly payments of distribution equivalent rights on outstanding phantom unit awards, respectively. The remainder of the unit-based compensation expense for each period presented in 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 distribution to the weighted average holders of the Partnership's units for the quarter ended September 30, 2015. Represents distribution to units outstanding at the record date for the quarters ended June 30, 2015 and September 30, 2014.

(5) Represents distributions to holders enrolled in the DRIP as of the record date for each period. Amount for the three months ended September 30, 2015 is based on an estimate as of the record date.

(6) Represents cash distributions declared for weighted average common units not participating in the DRIP for the quarter ended September 30, 2015. Represents cash distributions declared for common units not participating in the DRIP at the record date for the quarters ended June 30, 2015 and September 30, 2014.

(7) For the three months ended September 30, 2015, the Adjusted Distributable Cash Flow Coverage Ratio based on units outstanding at the record date is 1.16x. The Adjusted Distributable Cash Flow Coverage Ratio for the quarters ended June 30, 2015 and September 30, 2014 are based on units outstanding at the record date for each respective period.

(8) For the three months ended September 30, 2015, the Cash Coverage Ratio based on units outstanding at the record date is 2.65x. The Cash Coverage Ratio for the quarters ended June 30, 2015 and September 30, 2014 are based on units outstanding at the record date for each respective period.

Basis of Presentation; Explanation of Non-GAAP Financial Measures

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

EBITDA, a measure not defined under U.S. generally accepted counting principles ("GAAP"), is defined by USAC as net income (loss) 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, interest income, 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, non-cash income tax 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 (loss) and net cash provided by operating activities, and net income (loss) reconciled to distributable cash flow and adjusted distributable cash flow.

This presentation contains a forward-looking estimate of Adjusted EBITDA and Adjusted distributable cash flow projected to be generated by the Partnership in its 2015 fiscal year. A reconciliation of the forward-looking estimates of Adjusted EBITDA and Adjusted 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 distributable cash flow should not be considered an alternative to, or more meaningful than, net income (loss), 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 distributable cash flow 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.

Horsepower 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 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 distributable cash 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 distributable cash flow 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 distributable cash flow 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 distributable cash flow coverage ratio and cash coverage ratio as presented may not be comparable to similarly titled measures of other companies.