USA Compression Partners, LP

2016 Baird Industrial Conference

November 10, 2016

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Outlook For Compression and Macro Drivers

Compression Basics and the Need for Compression

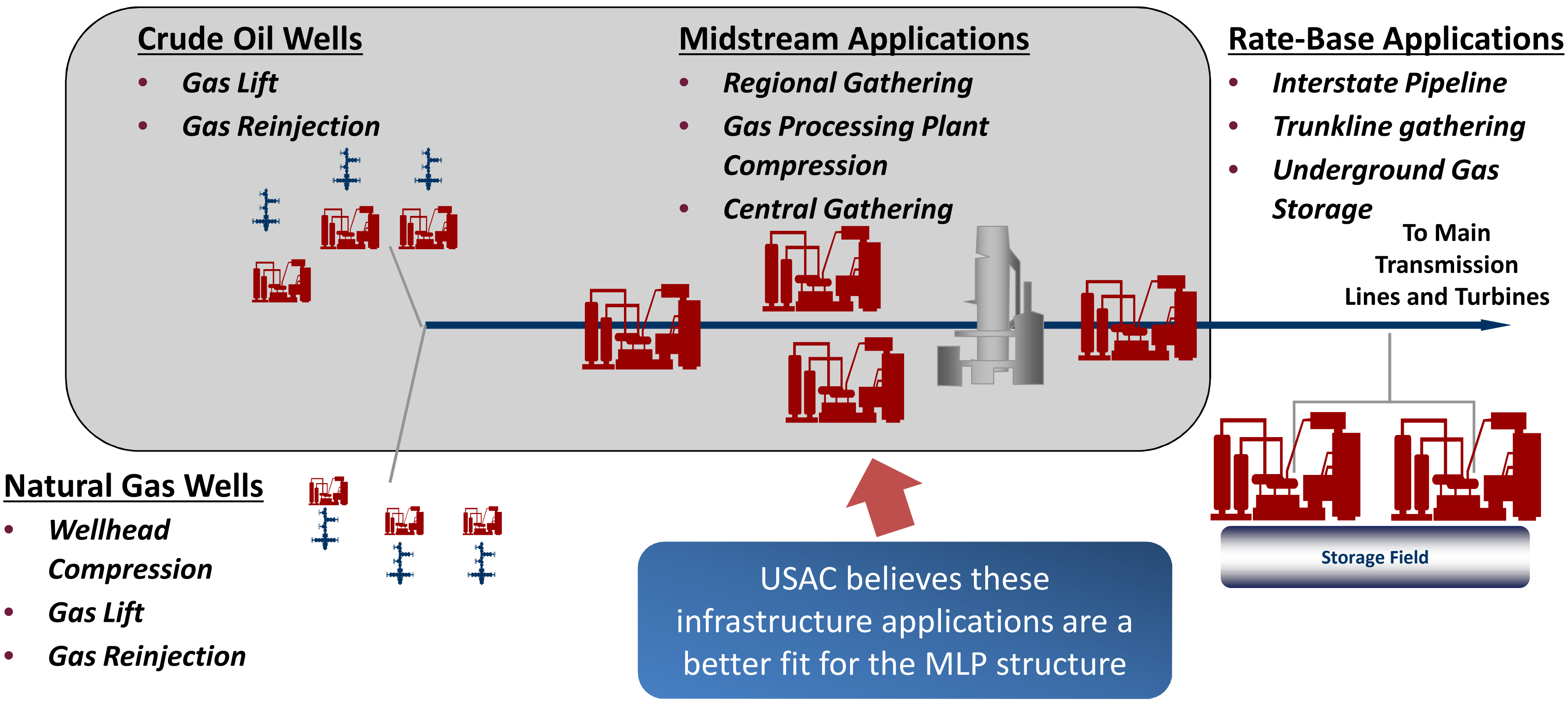
Critical Infrastructure for US Natural Gas

What is Compression?	▪ Compression is a mechanical process where natural gas from a lower pressure is "smashed down" (compressed) to a smaller volume which results in a higher pressure ▪ In a nutshell, compression is used to boost the pressure of a volume of gas from a lower suction pressure to a resulting higher discharge pressure, shrinking the volume
Critical Part of Natural Gas Transportation	▪ The U.S. pipeline system which transports natural gas from producing areas to markets is generally designed to move gas at increasing pressures – Compression is a critical service throughout all stages of the natural gas value chain, including production at the wellhead, gathering, treating & processing, and transportation & storage ▪ Once installed, compression becomes key part of infrastructure, remaining in field for significant lengths of time; however, assets remain "moveable", which allows for redeployment to other regions where and when appropriate
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 ▪ Compression frequently outsourced given increased expertise, safety record and reliability

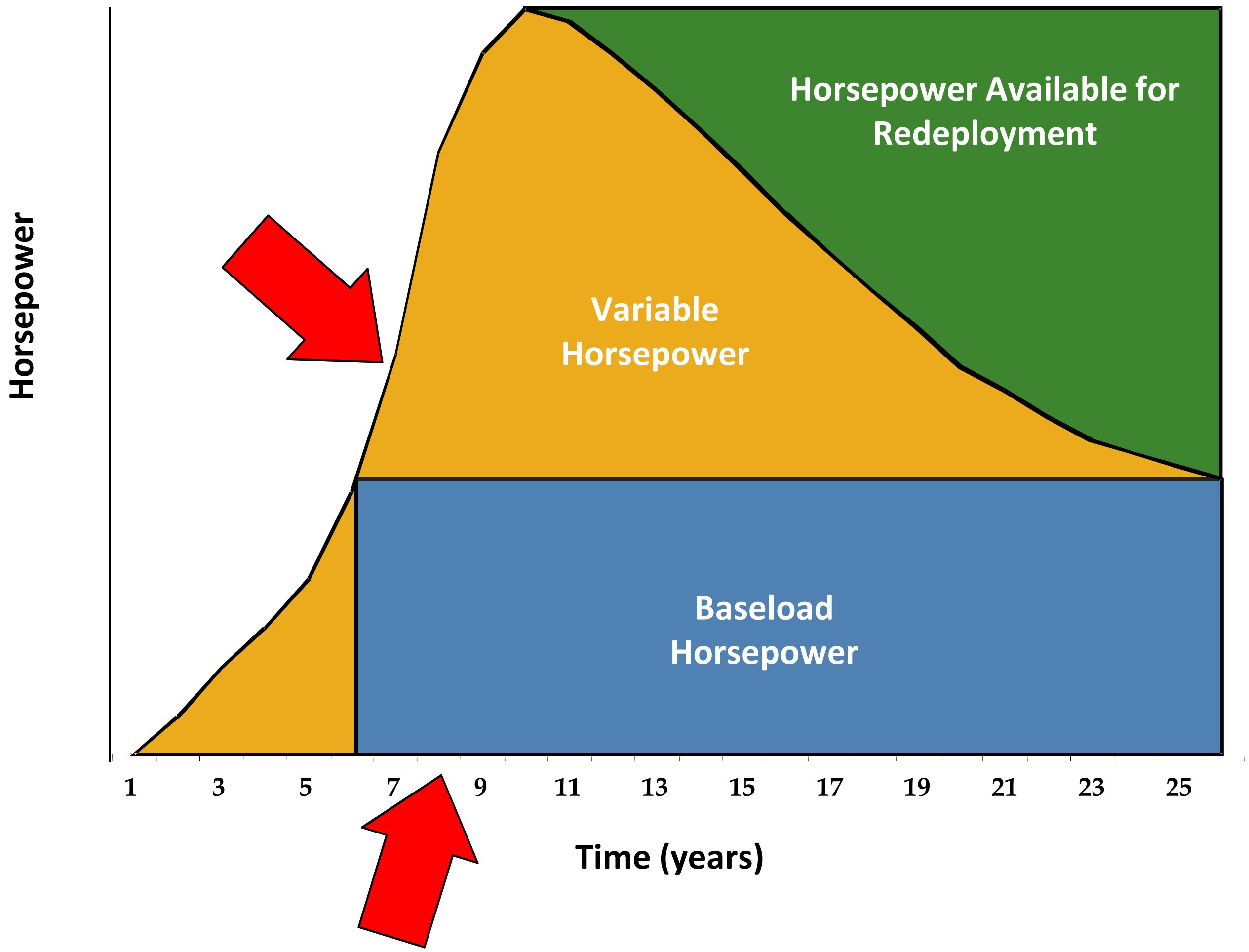
USAC's business is driven by the same attractive fundamentals as the general midstream space: growing domestic hydrocarbon production and demand

Strategic Focus on Infrastructure Applications

- **Compression is a critical service across a range of applications in the production, processing and transportation of oil and natural gas:**
  - Enhances oil and natural gas production
  - Maintains reservoir pressure
  - Transports natural gas through gathering lines and into pipelines
  - Pressurizes natural gas into and out of processing plants
  - Injects and withdraws natural gas into and out of storage
  - Delivers natural gas through pipelines to end users



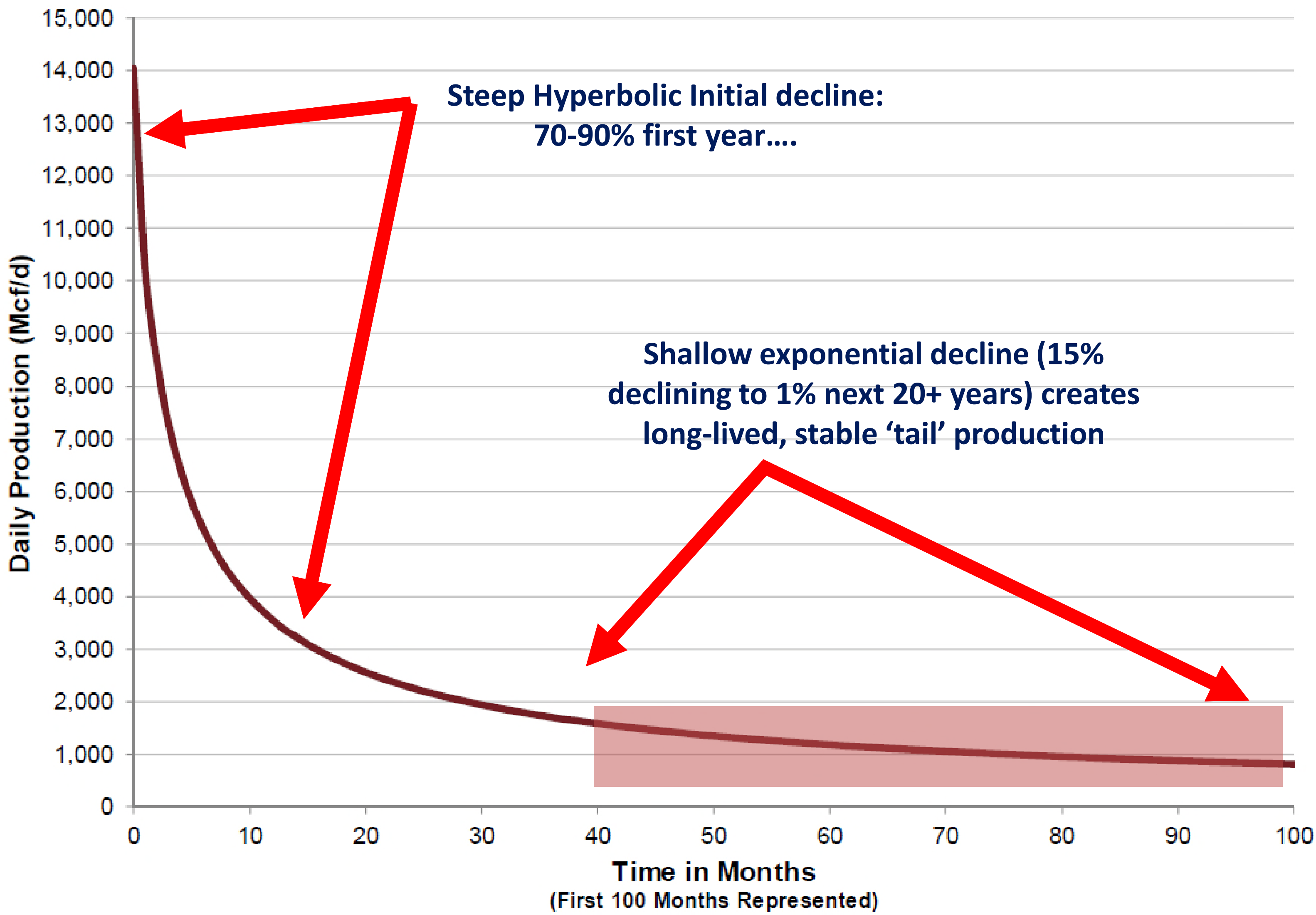
Long-Life Deployment Cycle – "Early to Mid-Innings"



USAC meets changing contract compression requirements during all phases of the life of a developing natural gas play; larger, project-oriented customers provide USAC with a stable, long-life deployment cycle

Production Stabilizes in ~ 3 Years then has a LONG life . . .

Representative Marcellus Shale Type Curve



Source: EQT Corporation.

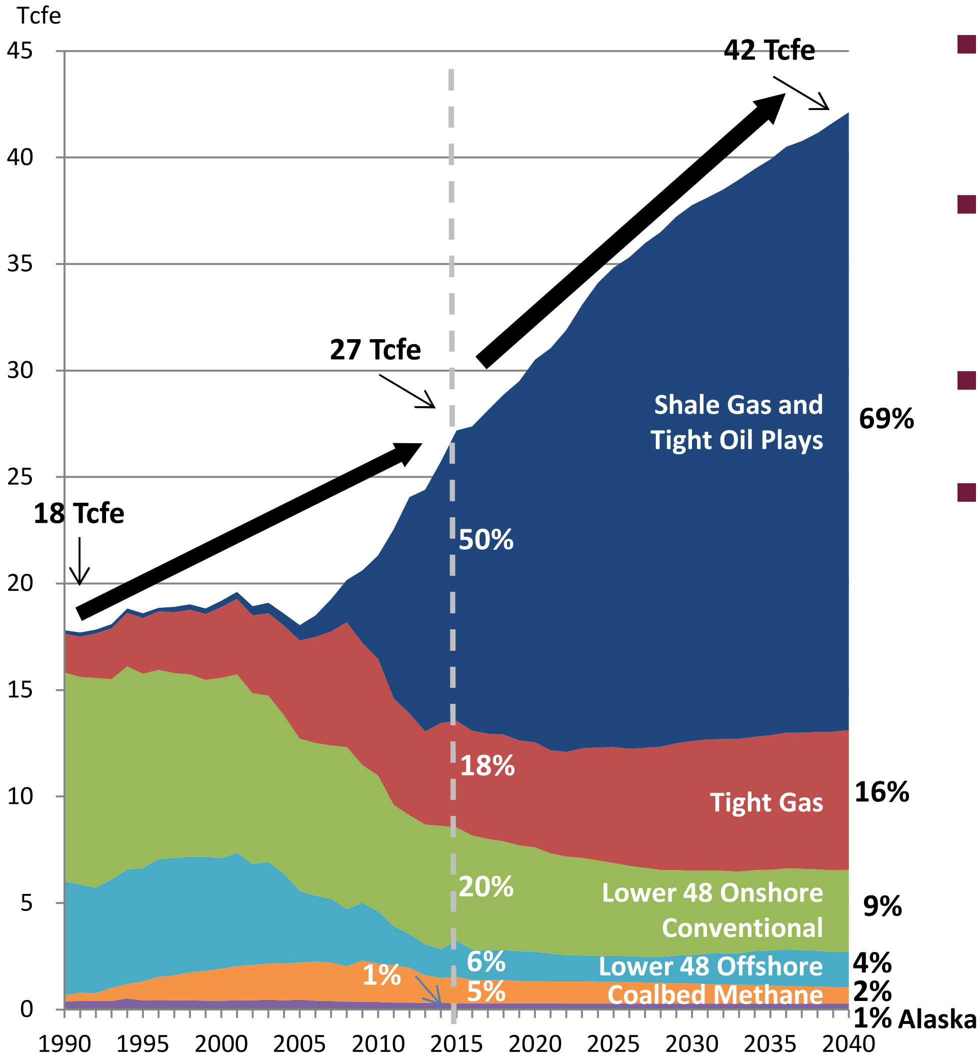
USAC Business Drivers

Compression is Critical Infrastructure for Producing & Transporting Hydrocarbons

Overall Gas Demand & Production	▪ ~85% of USAC's business (by HP) installed in natural gas-based applications ▪ Projected increasing demand / steady production of natural gas ▪ LNG exports, Mexico exports add to the increasing demand 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

Macro Thesis: The "Shift to Shale"

Shale Gas Piece of the Growing Pie Continues to Increase



- Overall natural gas production expected to increase from ~74 Bcf/d in 2015 to ~115 Bcf/d through 2040, an increase of 55%
- Volume projections continue to be revised upwards
  - In 2013, the EIA was projecting ~91 Bcf/d by 2040 – that level of volume now expected by 2023!
- Importantly, total shale gas volumes are projected to grow over 2x over the same projected time period
- Production from Marcellus / Utica Shales and Permian / Delaware Basins represent large portion of future natural gas production growth

USAC has placed almost 75% of its newbuild large-HP fleet additions in these areas of robust production growth since the beginning of 2014

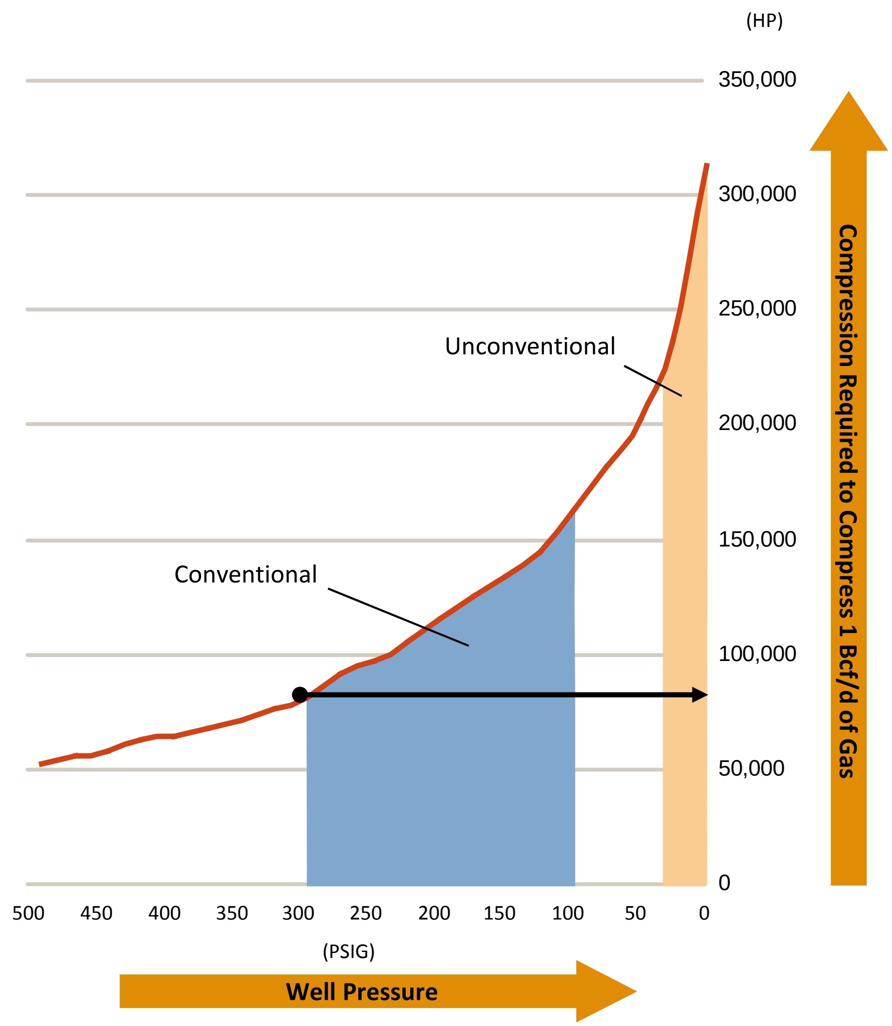
Source: U.S. Energy Information Administration, Annual Energy Outlook 2016, August 2016.

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



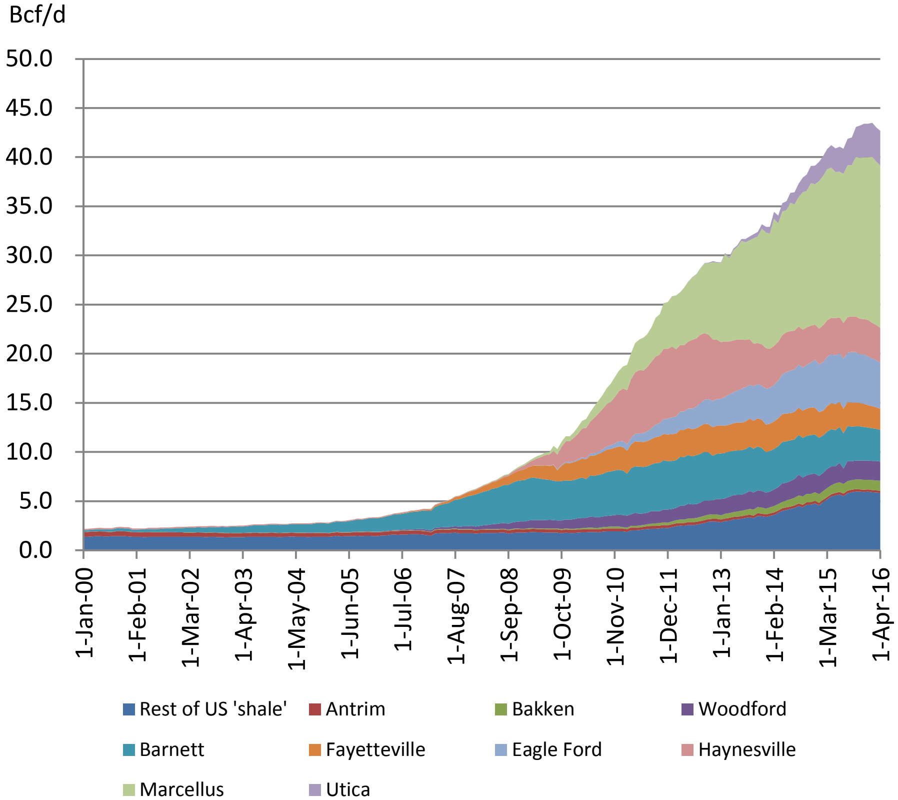
Source: Ariel Corporation: compressor sizing protocol.
(1) Assumes Discharge Pressure = 1,200 PSIG.

Changing, But Still Growing, Natural Gas Market

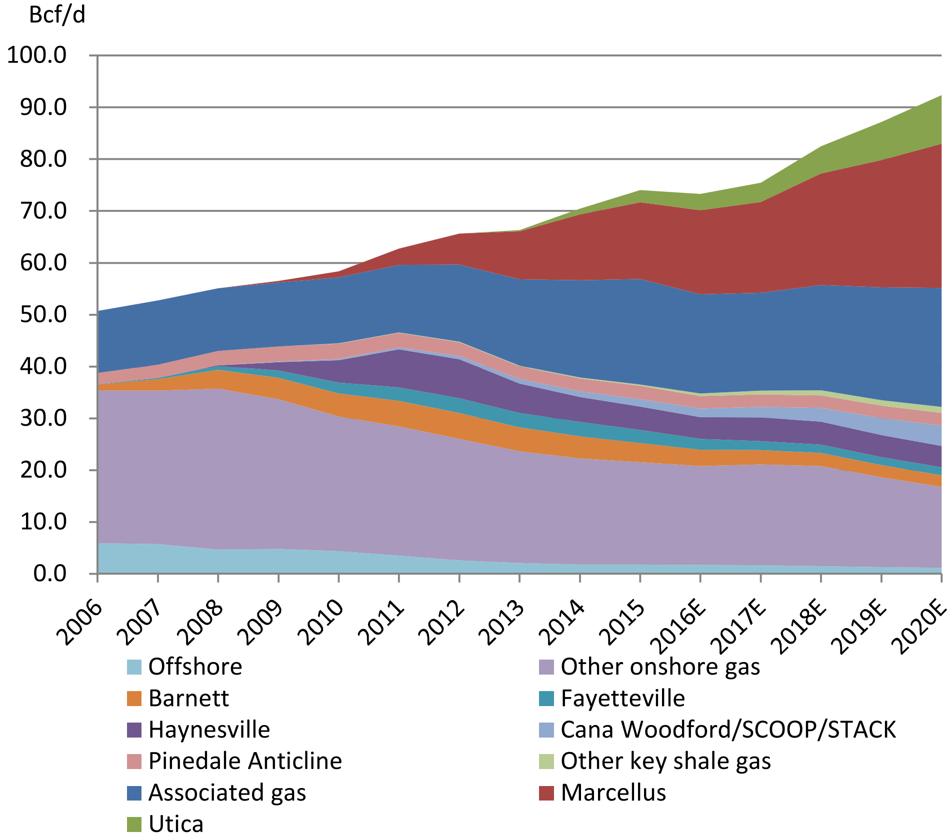
Marcellus/Utica Production Continues to Drive Growth; Expected to Offset 2016 Associated Gas Decline

- Due to lowered liquids-focused activity since the decline in crude prices in late 2014, 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 and enhanced completions in 'mature' gas plays

Historical Shale Gas Production by Play



Projected Dry Gas Production Growth by Region



Per EIA, August 2016 and Goldman Sachs Research, June 2016.

Natural Gas Demand Poised to Surge

"Big Four" Demand Sources Driving Majority of Expected 38 Bcf/d of New Natural Gas Demand Thru 2040

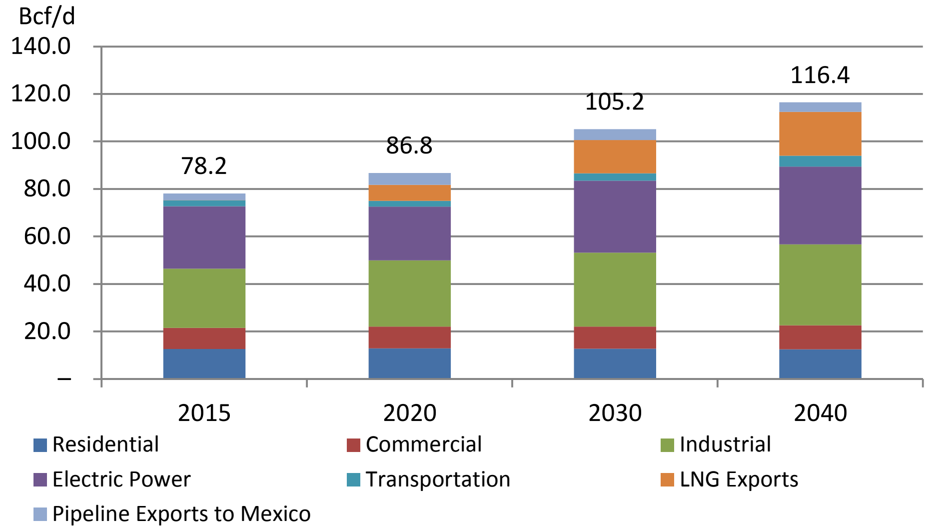
Coal Plant Retirements and Gas-Fired Power Demand	■ EIA expects 40 – 45 gigawatts (GW) of coal-plant retirements in 2016 alone, with 55 GW of expected retirements beyond 2016 ■ >6 Bcf/d of demand growth expected by the EIA by 2040 from total gas-fired power demand, a majority of which is expected coal plant retirements. Assumes 150% increase from current levels of generation capacity from renewables
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 ■ EIA suggests ~5 Bcf/d of gas pipeline exports to Mexico by 2020; increase of ~3 Bcf/d from 2014 ■ Recently announced 2.6 Bcf/d capacity pipeline system project to be built separately in two parts by Spectra Energy and Transcanada; Spectra's leg to be built from Nueces to Brownsville, TX which will connect with TransCanada's Sur de Texas-Tuxpan pipeline in Mexico
LNG Exports	■ EIA suggests almost 7 Bcf/d of US LNG exports by 2020, almost 13 Bcf/d by 2025, and upwards of 18 Bcf/d of export demand expected on a longer-term basis thru 2040 (based on contracts signed by consumers and other LNG projects in development) ■ Potential for an increased coal-to-gas switching in Europe, which would bolster future US LNG export demand ■ First LNG export cargo from Cheniere's Sabine Pass terminal shipped February 2016
Industrial Demand	■ Expect over 3 Bcf/d and 9 Bcf/d of incremental industrial demand growth by 2020 and 2040, respectively ■ Growth driven by increases in both base industrial demand (including fuel for LNG export facilities) as well as new petrochemical plant projects / expansions (ethylene, ammonia and propylene)

Source: U.S. Energy Information Administration, Annual Energy Outlook 2016, August 2016.

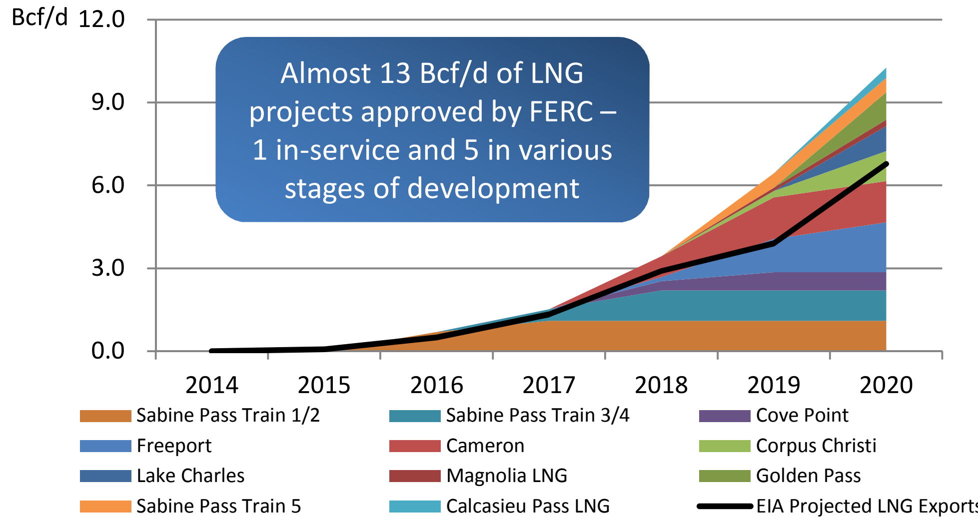
Natural Gas Demand Poised to Surge, Cont'd.

Industrial Sector, LNG and Pipeline Exports to Mexico Drive Demand Growth

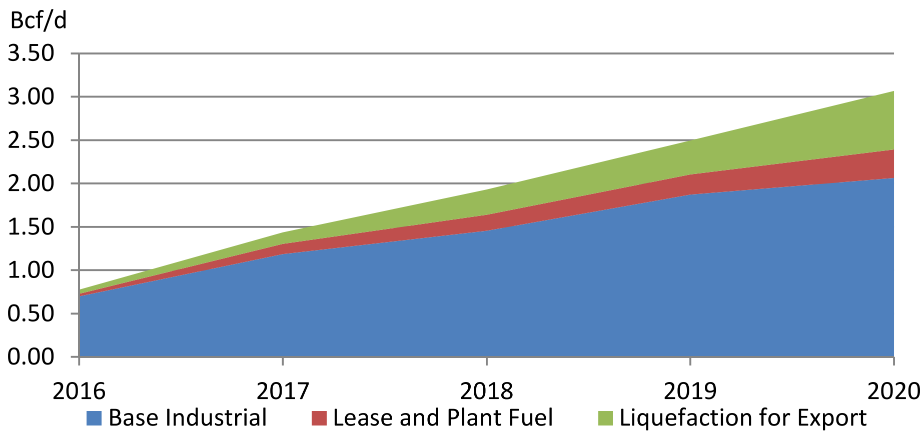
Projected Natural Gas Demand



LNG Export Capacity Thru 2020

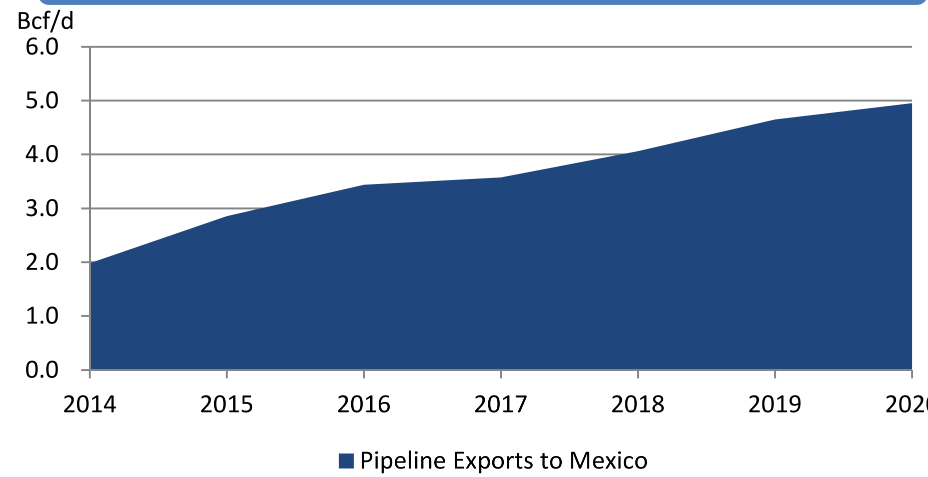


Cumulative Incremental Industrial Demand



Source: EIA Annual Energy Outlook 2016, August 2016 and Goldman Sachs Research.

Pipeline Exports to Mexico



USAC: Story of Stability and Growth

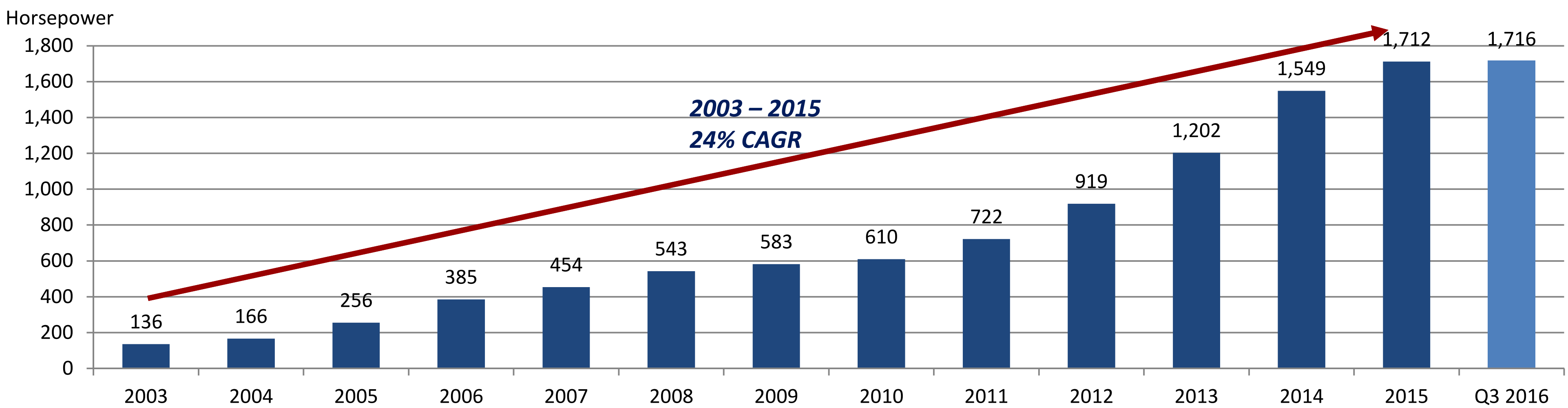
USAC History

18-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 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 — 2016

Horsepower Growth

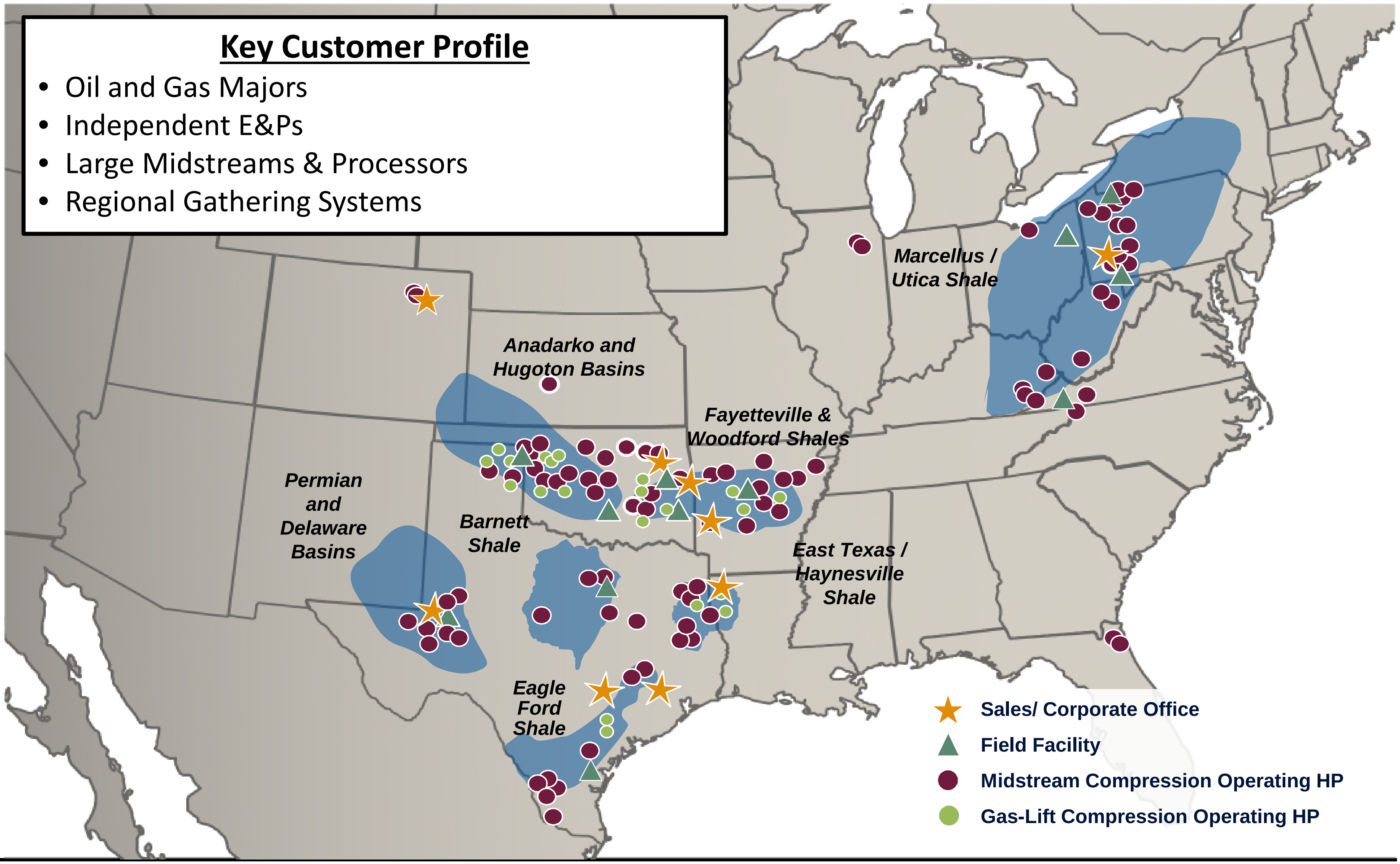


Geographical Presence

Diversified Presence in Key Geographical Regions

Key Customer Profile

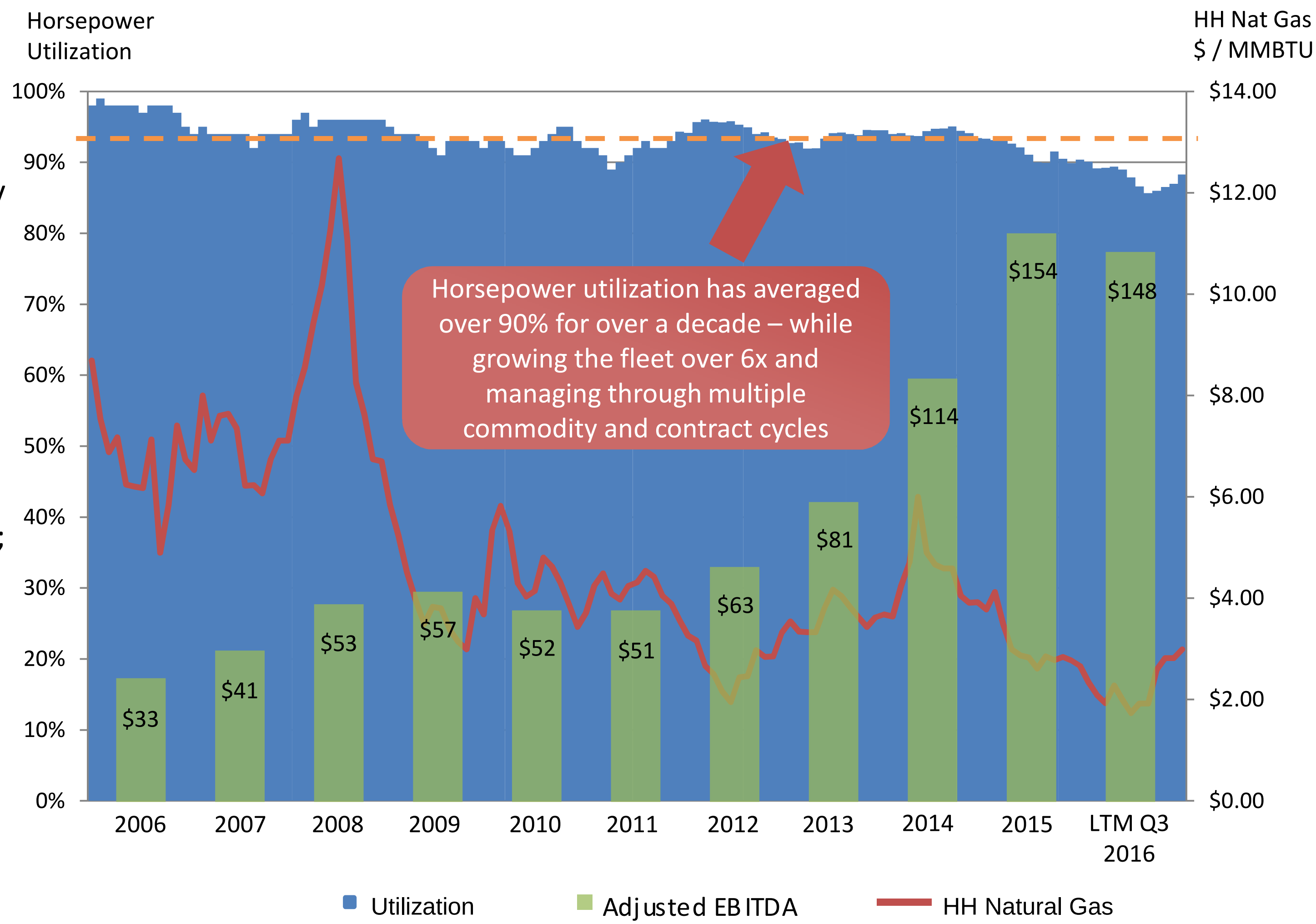
- Oil and Gas Majors
- Independent E&Ps
- Large Midstreams & Processors
- Regional Gathering Systems



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 calculations of horsepower utilization, Adjusted EBITDA, and LTM Adjusted EBITDA.

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Large Horsepower Gas Applications Drives Stability

Gas Compression Industry Varies By Size of Compression Unit

Gas Compression Industry: Key Characteristics by Size					
	Small	Medium	Large	Extra Large	Commentary
Compression Unit HP Range	0 – 400 HP	400 – 1,000 HP	1,000 – 1,500 HP	1,500+ HP	**More horsepower required to move larger volumes → <u>critical gas infrastructure</u>**
Gas Volumes Moved (mmcf/d)	0.90	3.20	6.50	13.00+	
Size (L x W x H, ft.)	21 x 12 x 11	33 x 19 x 16	38 x 27 x 20	77 x 17 x 27	**Increasing size & demobilization costs create <u>significant 'barriers to exit'</u>**
Weight (lbs.)	~40,000	~85,000	~150,000	~250,000+	
De-mobilization Costs (typically borne by customer)	< $10K	~$25K	~$50K	$100K+	
Typical Contract Length in Industry	1 – 12 months	6 months – 2 years	2 – 5 years	2 – 5 years	**Larger units = longer deployment cycles**

Note: Used CAT 3306TA ,CAT 3508TALE, CAT 3516BLE, and CAT 3608TALE as representative units for small, medium, large and extra large horsepower categories, respectively. Gas volumes based off of 50 psi suction pressure and 1200 psi discharge pressure.

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Nature of USA Compression's Contracts

Compression Services Contract Profile

Contract Service Rate Structure is 100% Fixed-Fee	■ USA Compression's service contract rates are billed monthly (typically 30 days in advance) and are 100% fixed fee (i.e. contract stipulates a specific $ / month) ► Structured similar to take-or-pay contracts commonly seen with midstream companies who operate long-haul, interstate pipelines and large-scale storage assets ■ USAC contracts are not tied to either volumetric throughput or any direct commodity price exposure
Critical Nature of Contracts in Distressed Situations	■ In the case of customer credit issues, the critical nature of our services is generally recognized by our customers as well as the courts ■ We also tend to get paid on an ongoing basis for our services following a customer's bankruptcy petition ► Without compression, gas is not able to flow and therefore there are no cash flows for our customers to service debt and pay bills ► Unlike drilling services providers, USAC is as a long-term provider of mission critical compression services under long-term fee based contracts
Unit Level Contracts Limit Large-Scale Returns	■ Each of our 2,500+ active units has its own separate and discrete contract with its own original start date and primary term ■ Over 60% of our active fleet is under contract with remaining primary term ► Little risk of large portion of our fleet being returned

Strong, Large-Cap Customer Base Able to Weather the Storm

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

Rank	Top Customers	Length of Relationship
1	Pipeline Subsidiary of Utility	3 years
2	Large Public Independent E&P	10+ years
3	Large Public Independent E&P	10+ years (1)
4	Large Public MLP	3 years
5	Large Private Midstream	3 years
6	Large Public Independent E&P	9 years
7	Oil and Gas Major	9 years
8	Large Diversified Oil and Gas and MLP Sub	8 years
9	Pipeline Subsidiary of Diversified Oil and Gas	8 years
10	Public Independent E&P	2 years

Top 10 customers represent over 42% of total revenue, have a weighted average market cap and enterprise value of ~$31 billion and ~$42 billion(2), respectively, and a weighted average credit rating of investment grade(3)

- USAC has historically had very little bad debt write-offs; in fact, over the **last 11 years, USAC has written off only ~$1 million in bad debts**
  - Equates to 0.1% of total billings (>$1.0 billion) over same period

Note: Rankings and %'s of revenue reflect YTD Q3 2016 revenue.
(1) Includes prior relationship with S&R Compression, which USAC acquired in August 2013.
(2) Per ThomsonOne as of 11/1/16.
(3) Per Moody's and S&P, as of November 2016.

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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 less than 5 years): fuel and emissions-efficient

Contract Profile

- Initial contracts for midstream applications are typically 2-5 years
- Assets tend to stay in field significantly longer than original contract term
- Midstream application customers have high "barriers to exit" resulting in stability in utilization and pricing

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 Not Directly Dependent on Commodity Prices

USA COMPRESSION

Financial Overview and Investment Highlights

Recent Developments: Q3 2016 Review

USAC Delivers Strong Q3 2016 Results in a Tough Market; Updates 2016 Guidance

Operational Update

- Q3 2016 fleet HP of 1.7 million and average revenue generating HP of 1.4 million
- Average horsepower utilization of 87.3% for Q3 2016 – up from 86.1% in sequential quarters
  - Utilization increase driven by material increase in signed contracts for new projects at quarter-end: at highest level since end of 2014 and ~6x our lowest levels seen earlier this year
- Average pricing holding in at $15.35/HP/month, driven by stability in rates on large HP units
- Increased fleet orders this year by ~7K HP for our very large horsepower class; also expect initial deliveries of 20K HP for 2017

Financial Update

- Softer activity levels experienced earlier in 2016 impacted Q3 results:
  - Adjusted EBITDA of $34.6mm
  - Distributable Cash Flow ("DCF") of $27.2mm
- Q3 gross operating margin % of 69% and Adjusted EBITDA margin % of 57%
- LP distribution of $0.525 for Q3 2016; DCF coverage of 0.91x
  - Cash coverage of 1.06x; Riverstone decreased DRIP participation to 30%
- Leverage of 5.36x (vs. covenant of 5.95x) on borrowings of $744 million as of quarter-end
- Updated 2016 Adjusted EBITDA and DCF guidance (see appendix for full details)
  - Adjusted EBITDA range of $142.5mm to $147.5mm; DCF range of $114.0mm to $119.0mm

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

Addressing the Market Backdrop: USAC's Strategy

USA Compression has pulled multiple levers to help navigate this difficult environment

Market Backdrop and the Effect on the Compression Industry

- Lower drilling activity during the downturn has resulted in less production growth; however existing production requires increasing compression to move the same gas volumes through the pipeline system as pressures decline
- Recently hearing more upbeat commentary about activity levels from our customers – assuming commodity prices stabilize at recent levels
- Most customers have completed right-sizing of their compression needs

USA Compression's Strategy

Significantly Reduce Capital Spending

- 2016 budget reduced by ~80% vs. 2015 levels; currently expect $40 to $50 million of growth capital
- Relative to many pipeline companies with long, multi-year lead-time projects and large financing needs, USAC is able to quickly ratchet back its capital spending

Focus on Utilization

- Reallocating resources, people, capital and equipment from regions of softness to areas of continued strength and demand
- Flexible unit design allows our compression units to be utilized in a broader range of applications and geographies
- Proactively work with customers to help them optimize their compression requirements

Expense Control

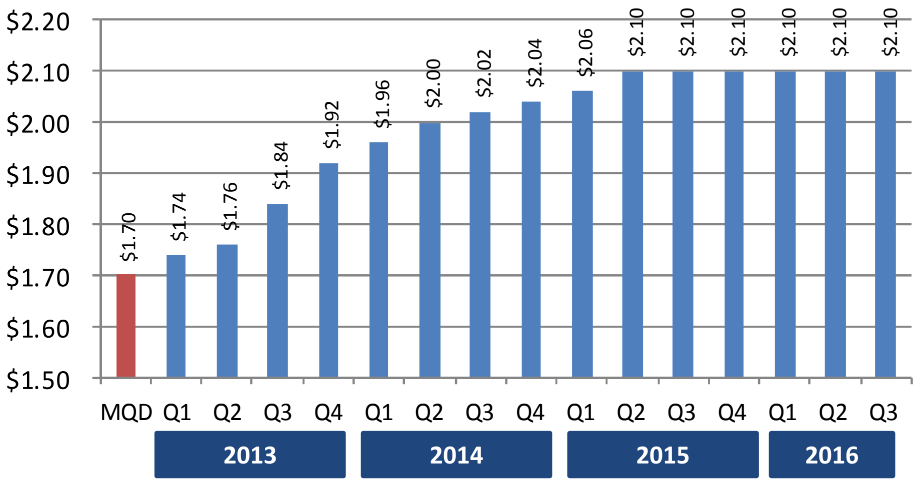
- Continue to wring out operational and corporate efficiencies, as well as savings related to maintenance activities
- Our operations team continues to be proactive in finding creative cost-control solutions
- Margins remain near all-time highs

Our compression services business model is characterized by both stability and growth; our strategy in this down cycle has resulted in relatively stable cash flows

USAC Distributions and Leverage Since IPO

Prudent Balance Between Distribution Growth, Coverage and Leverage

Annualized Distributions per LP Unit

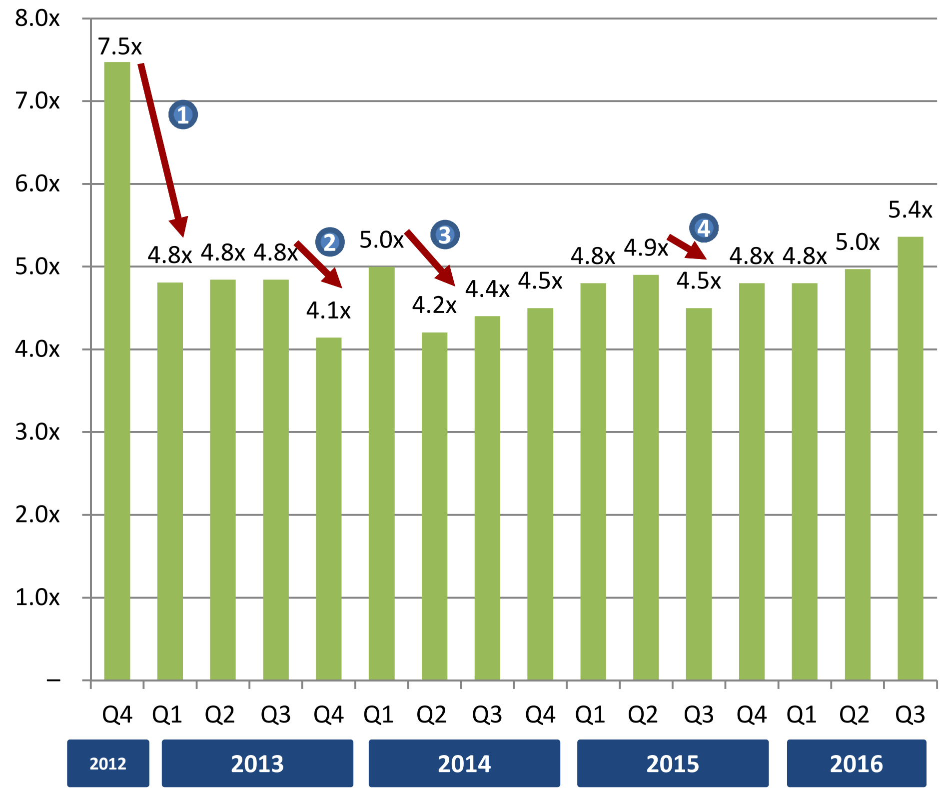


- DCF coverage for Q3 2016 is 0.91x and Cash Coverage Ratio [1], as a result of USAC's Distribution Reinvestment Plan ("DRIP"), is 1.06x

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 a significant portion of its quarterly cash distributions, providing an additional cash coverage cushion and permit us to utilize the retained cash to fund continued organic growth or to help de-lever the balance sheet

USAC Historical Leverage[2]



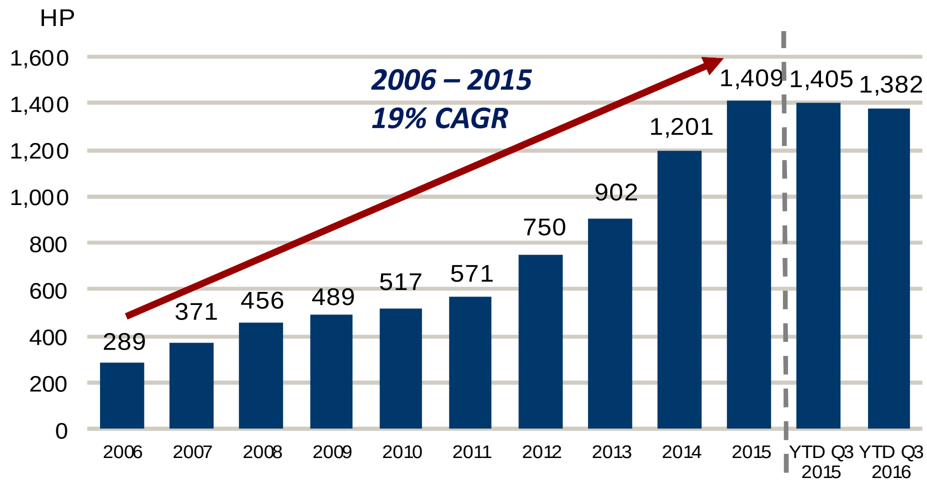
- 1) $198mm IPO proceeds; used to repay debt
- 2) $182mm acquisition of S&R gas lift fleet; 100% equity
- 3) $138mm follow-on offering; proceeds used to repay debt
- 4) $74mm follow-on offering; proceeds used to repay debt

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

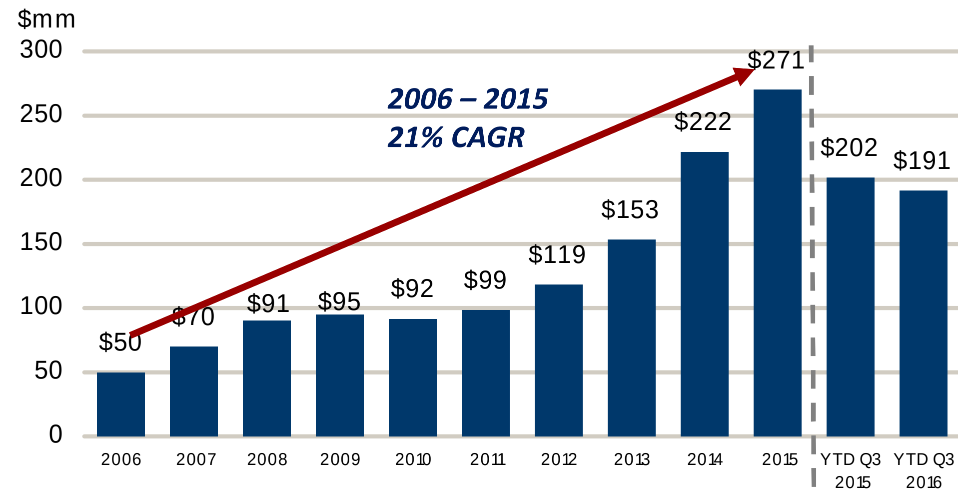
(2) Historical leverage calculated as total debt divided by annualized quarterly Adjusted EBITDA for the applicable quarter, in accordance with our current Credit Agreement. Actual historical leverage may differ based on certain adjustments, and prior to Q4 2013 was calculated using LTM Adjusted EBITDA.

Operational and Financial Performance

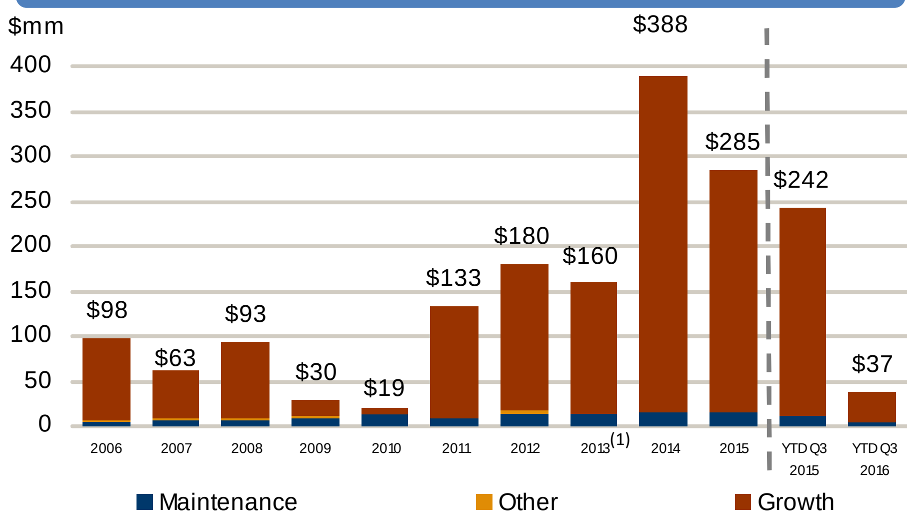
Avg. Revenue Generating HP (000s)



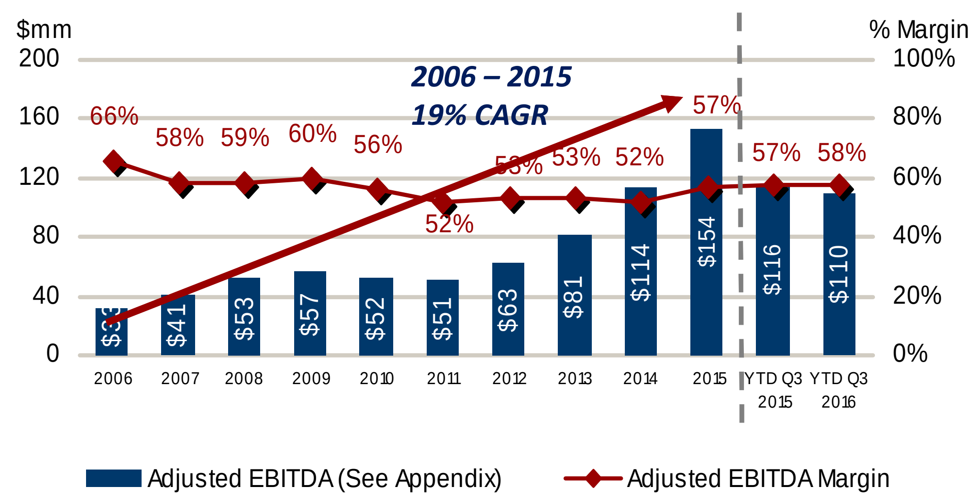
Revenue ($MM)



Total Capex ($MM)



Adjusted EBITDA ($MM) & Margin Percentage(2)



(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 information on calculations of Adjusted EBITDA and Adjusted EBITDA Margin Percentage.

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

Updated 2016 Guidance Ranges

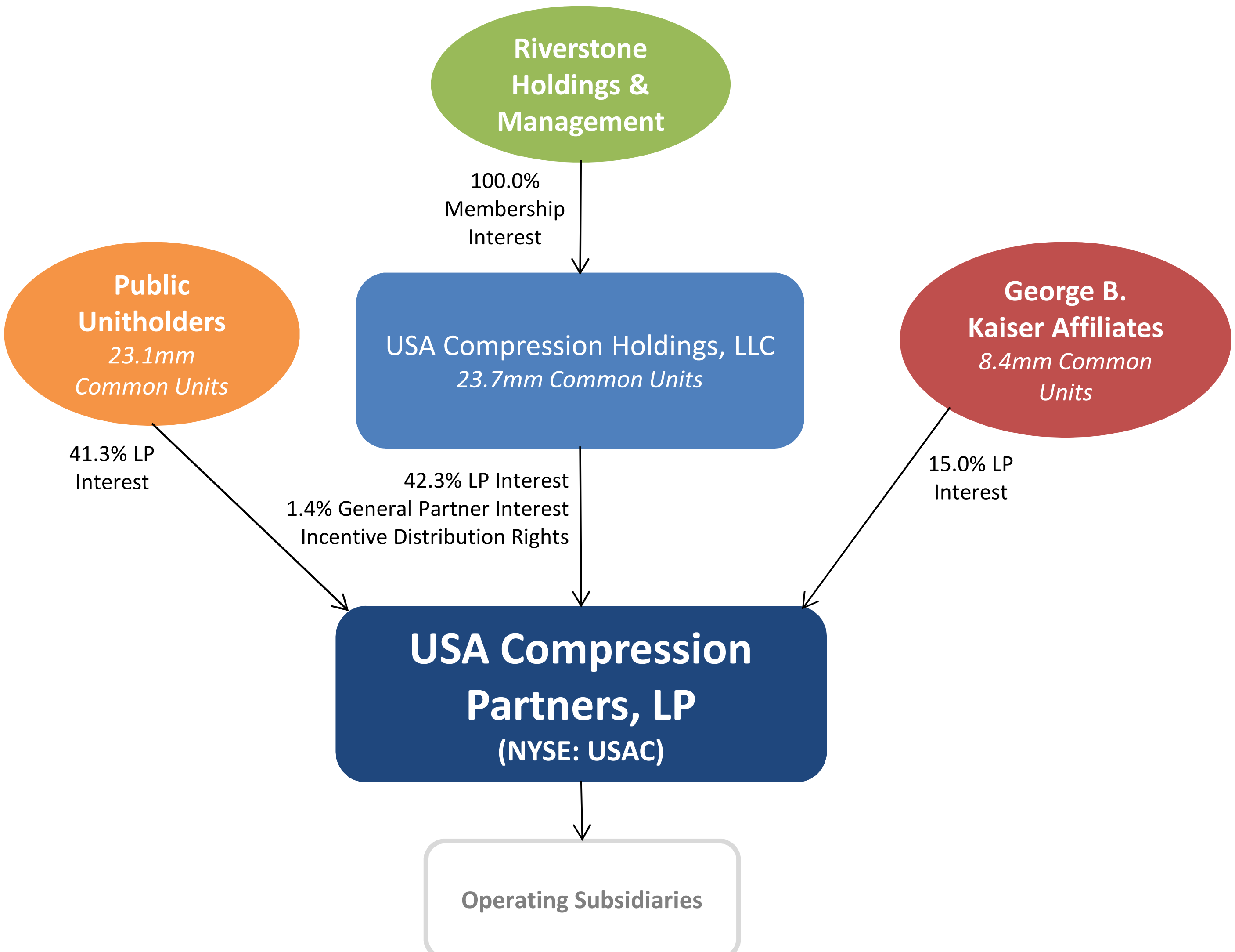
	Guidance
Net income	$9.3 million to $14.3 million
Plus: Interest expense, net	$21.2 million
Plus: Depreciation and amortization	$91.6 million
Plus: Income tax expense	$0.4 million
EBITDA	$122.5 million to $127.5 million
Plus: Interest income on capital lease	$1.5 million
Plus: Unit-based compensation expense (1)	$12.1 million
Plus: Impairment of compression equipment	$4.1 million
Plus: Loss (gain) on sale of assets	$0.8 million
Plus: Transaction expenses	$1.0 million
Plus: Severance charges	$0.5 million
Adjusted EBITDA	$142.5 million to $147.5 million
Less: Cash interest expense	$20.0 million
Less: Current income tax expense	$0.5 million
Less: Maintenance capital expenditures	$8.0 million
Distributable Cash Flow	$114.0 million to $119.0 million

(1) Based on the Partnership's closing unit price as of September 30, 2016.

See "Basis of Presentation; Explanation of Non-GAAP Financial Measures" for additional information on forward-looking estimates.

USA Compression Ownership Structure

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



Note: As of November 4, 2016. Does not reflect effect of Q3 2016 DRIP.

Non-GAAP Reconciliations

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Net income (loss)	$ (2,146)	$ 9,805	$ 9,666	$ 5,357
Interest expense, net	5,275	4,665	15,476	13,074
Depreciation and amortization	23,195	21,360	68,701	63,598
Income taxes	74	1,083	402	1,304
EBITDA	$ 26,398	$ 36,913	$ 94,245	$ 83,333
Impairment of compression equipment	3,441	443	4,134	27,272
Impairment of goodwill	-	-	-	-
Interest income on capital lease	348	401	1,085	1,242
Unit-based compensation expense	3,647	804	8,481	3,068
Equipment operating lease expense	-	-	-	-
Riverstone management fee	-	-	-	-
Restructuring / severance charges	5	-	497	-
Fees and expenses related to the Holdings Acquisition	-	-	-	-
Transaction expenses for acquisitions	950	-	950	-
Loss (gain) on sale of assets and other	(155)	920	795	702
Adjusted EBITDA	$ 34,634	$ 39,481	$ 110,187	$ 115,617
Interest expense, net	(5,275)	(4,665)	(15,476)	(13,074)
Income tax expense	(74)	(1,083)	(402)	(1,304)
Interest income on capital lease	(348)	(401)	(1,085)	(1,242)
Equipment operating lease expense	-	-	-	-
Riverstone management fee	-	-	-	-
Restructuring / severance charges	(5)	-	(497)	-
Fees and expenses related to the Holdings Acquisition	-	-	-	-
Transaction expenses for acquisitions	(950)	-	(950)	-
Non-cash interest expense and other	546	416	1,561	1,286
Changes in operating assets and liabilities	7,611	445	1,258	(18,540)
Net cash provided by operating activities	$ 36,139	$ 34,193	$ 94,596	$ 82,743

Non-GAAP Reconciliations, Cont'd.

	Year Ended December 31,									
	2015	2014	2013	2012	2011	2010	2009	2008	2007	2006
Net income (loss)	$ (154,273)	$ 24,946	$ 11,071	$ 4,503	$ 69	$ 10,479	$ 21,228	$ 20,911	$ 7,122	$ 9,829
Interest expense, net	17,605	12,529	12,488	15,905	12,970	12,279	10,043	14,003	16,468	13,209
Depreciation and amortization	85,238	71,156	52,917	41,880	32,738	24,569	22,957	18,016	13,437	9,770
Income taxes	1,085	103	280	196	155	155	190	119	155	-
EBITDA	$ (50,345)	$ 108,734	$ 76,756	$ 62,484	$ 45,932	$ 47,482	$ 54,418	$ 53,049	$ 37,182	$ 32,808
Impairment of compression equipment	27,274	2,266	203	-	-	-	1,677	-	1,028	-
Impairment of goodwill	172,189	-	-	-	-	-	-	-	-	-
Interest income on capital lease	1,631	1,274	-	-	-	-	-	-	-	-
Unit-based compensation expense	3,863	3,034	1,343	-	-	382	269	225	2,352	-
Equipment operating lease expense	-	-	-	-	4,053	2,285	553	-	-	-
Riverstone management fee	-	-	49	1,000	1,000	-	-	-	-	-
Restructuring / severance charges	-	-	-	-	300	-	-	-	-	-
Fees and expenses related to the Holdings Acquisition	-	-	-	-	-	1,838	-	-	-	-
Transaction expenses for acquisitions	-	1,299	2,142	-	-	-	-	-	-	-
Loss (gain) on sale of assets and other	(1,040)	(2,198)	637	-	-	-	-	-	-	-
Adjusted EBITDA	$ 153,572	$ 114,409	$ 81,130	$ 63,484	$ 51,285	$ 51,987	$ 56,917	$ 53,274	$ 40,562	$ 32,808
Interest expense, net	(17,605)	(12,529)	(12,488)	(15,905)	(12,970)	(12,279)	(10,043)	(14,003)	(16,468)	(13,209)
Income tax expense	(1,085)	(103)	(280)	(196)	(155)	(155)	(190)	(119)	(155)	-
Interest income on capital lease	(1,631)	(1,274)	-	-	-	-	-	-	-	-
Equipment operating lease expense	-	-	-	-	(4,053)	(2,285)	(553)	-	-	-
Riverstone management fee	-	-	(49)	(1,000)	(1,000)	-	-	-	-	-
Restructuring / severance charges	-	-	-	-	(300)	-	-	-	-	-
Fees and expenses related to the Holdings Acquisition	-	-	-	-	-	(1,838)	-	-	-	-
Transaction expenses for acquisitions	-	(1,299)	(2,142)	-	-	-	-	-	-	-
Non-cash interest expense and other	1,702	1,189	1,839	(58)	(920)	3,362	288	201	1,666	(1,077)
Changes in operating assets and liabilities	(17,552)	1,498	180	(4,351)	1,895	(220)	(3,474)	1,346	836	1,047
Net cash provided by operating activities	$ 117,401	$ 101,891	$ 68,190	$ 41,974	$ 33,782	$ 38,572	$ 42,945	$ 40,699	$ 26,441	$ 19,569

Non-GAAP Reconciliations, Cont'd.

	Three months ended		
	September 30, 2016	June 30, 2016	September 30, 2015
Net income (loss)	$ (2,146)	$ 3,274	$ 9,805
Plus: Non-cash interest expense	546	548	416
Plus: Non-cash income tax expense	74	32	1,076
Plus: Depreciation and amortization	23,195	23,412	21,360
Plus: Unit-based compensation expense	3,647	3,022	804
Plus: Impairment of compression equipment	3,441	693	443
Plus: Transaction expenses for acquisitions	950	-	-
Plus: Severance charges	5	81	-
Plus: Loss (gain) on sale of assets and other	(82)	1,072	1,324
Less: Maintenance capital expenditures	(2,407)	(1,644)	(2,959)
Distributable cash flow	$ 27,223	$ 30,490	$ 32,269
Plus: Maintenance capital expenditures	2,407	1,644	2,959
Plus: Changes in operating assets and liabilities	7,611	4,476	445
Less: Other	(1,102)	(113)	(1,480)
Net cash provided by operating activities	$ 36,139	$ 36,497	$ 34,193
Distributable Cash Flow	27,223	30,490	32,269
Cash distributions to general partner and IDRs	717	715	697
Distributable Cash Flow attributable to limited partner interest	$ 26,506	$ 29,775	$ 31,572
Distributions for Distributable Cash Flow Coverage Ratio	$ 29,025	$ 28,805	$ 25,290
Distributions reinvested in the DRIP	$ 4,108	$ 6,483	$ 15,179
Distributions for Cash Coverage Ratio	$ 24,917	$ 22,322	$ 10,111
Distributable Cash Flow Coverage Ratio	0.91	1.03	1.25
Cash Coverage Ratio	1.06	1.33	3.12

Basis of Presentation; Explanation of Non-GAAP Financial Measures

This presentation includes the non-GAAP financial measures of Adjusted EBITDA ,LTM Adjusted EBITDA, Adjusted EBITDA Margin Percentage, Distributable Cash Flow, 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, impairment of goodwill, interest income, unit-based compensation expense, restructuring/severance charges, management fees, expenses under our operating lease with Caterpillar, certain transaction fees, (gain)/loss on sale of assets and other. 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. Adjusted EBITDA Margin Percentage is calculated by USAC as Adjusted EBITDA divided by Revenue for the period presented. LTM Adjusted EBITDA is calculated by USAC as the sum of Adjusted EBITDA for the most recently completed fiscal year and the Adjusted EBITDA for the most recent fiscal year-to-date period for which we have provided an income statement, minus the Adjusted EBITDA for the corresponding year-to-date period of the preceding fiscal year.

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, severance charges, impairment of compression equipment, impairment of goodwill, certain transaction fees, and (gain)/loss on sale of assets and other, less maintenance capital expenditures. The definition of Distributable Cash Flow is identical to the definition of Adjusted Distributable Cash Flow previously presented. The Partnership's management believes Distributable Cash Flow is an important measure of operating performance because it allows 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. 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.

This presentation contains a forward-looking estimate of Adjusted EBITDA and Distributable Cash Flow projected to be generated by the Partnership in its 2016 fiscal year. A reconciliation of the forward-looking estimates 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 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 Distributable Cash Flow as presented may not be comparable to similarly titled measures of other companies because other entities may not calculate such measures in the same manner.

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.

Distributable Cash Flow Coverage Ratio, a non-GAAP measure, is defined as 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 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 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 Distributable Cash Flow Coverage Ratio and Cash Coverage Ratio as presented may not be comparable to similarly titled measures of other companies.