USA Compression Partners, LP

2018 J.P. Morgan Energy Conference

June 19 – 20, 2018

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Q1 2018 Recap

Strong Start to 2018; Closing of CDM Acquisition

Operational Update

- Q1 2018 fleet HP of 1.85 million and average revenue generating HP of almost 1.7 million
- Average active HP up ~60,000 over Q4
- Average horsepower utilization of 94.9%
- Upward rate movement & continued strong demand for large HP units
- ~140,000 large HP on order for 2018 delivery; 50,000 large HP already ordered for 2019

Financial Update

- Q1 benefitted from ~6% increase in contract compression service revenues (vs. Q4)
  - Adjusted EBITDA of $44.1mm
  - Distributable Cash Flow ("DCF") of $33.7mm
- Q1 gross operating margin of 67.1%, Adjusted EBITDA margin of 56.7%
- LP distribution of $0.525 for Q1; DCF coverage of 1.03x
  - Riverstone elected 0% DRIP participation
- Provided 2018 combined guidance: Adjusted EBITDA of $310.0 – $330.0 million; DCF of $170.0 – $190.0 million
- Added to several Alerian Indexes (AMZ, AMZE & AMMI) on June 15, 2018

CDM Acquisition

- Closed transaction April 2, 2018
- Q2 2018 will be first combined quarter of operations
- Executed senior notes issue in late March (8-year Sr. Notes @ 6 ⅞%: B+/B3/BB- ratings)
- Integration well underway

CDM Acquisition

- On April 2nd, USA Compression completed the previously-announced $1.7bn acquisition of CDM Resource Management
  - Resulted in Energy Transfer Equity acquiring the GP interest and ~48% LP interest in USAC
  - Simplified structure by eliminating the IDRs and economic GP interest

USA COMPRESSION + CDM Resource Management LLC

	USAC [1]
LP Equity Value	~$1.7 billion
Preferred Equity	$0.5 billion
Senior Notes	$0.7 billion
ABL Facility	$0.8 billion
Enterprise Value	**~$3.8 billion**
Active / Total Horsepower	2.9mm / 3.5mm
Utilization	~94% (est)
Employees	~900
Areas of Meaningful Activity	Permian/Delaware; Marcellus/Utica; Mid-Continent/ SCOOP/STACK; S. Texas; E. Texas; Louisiana; Rockies

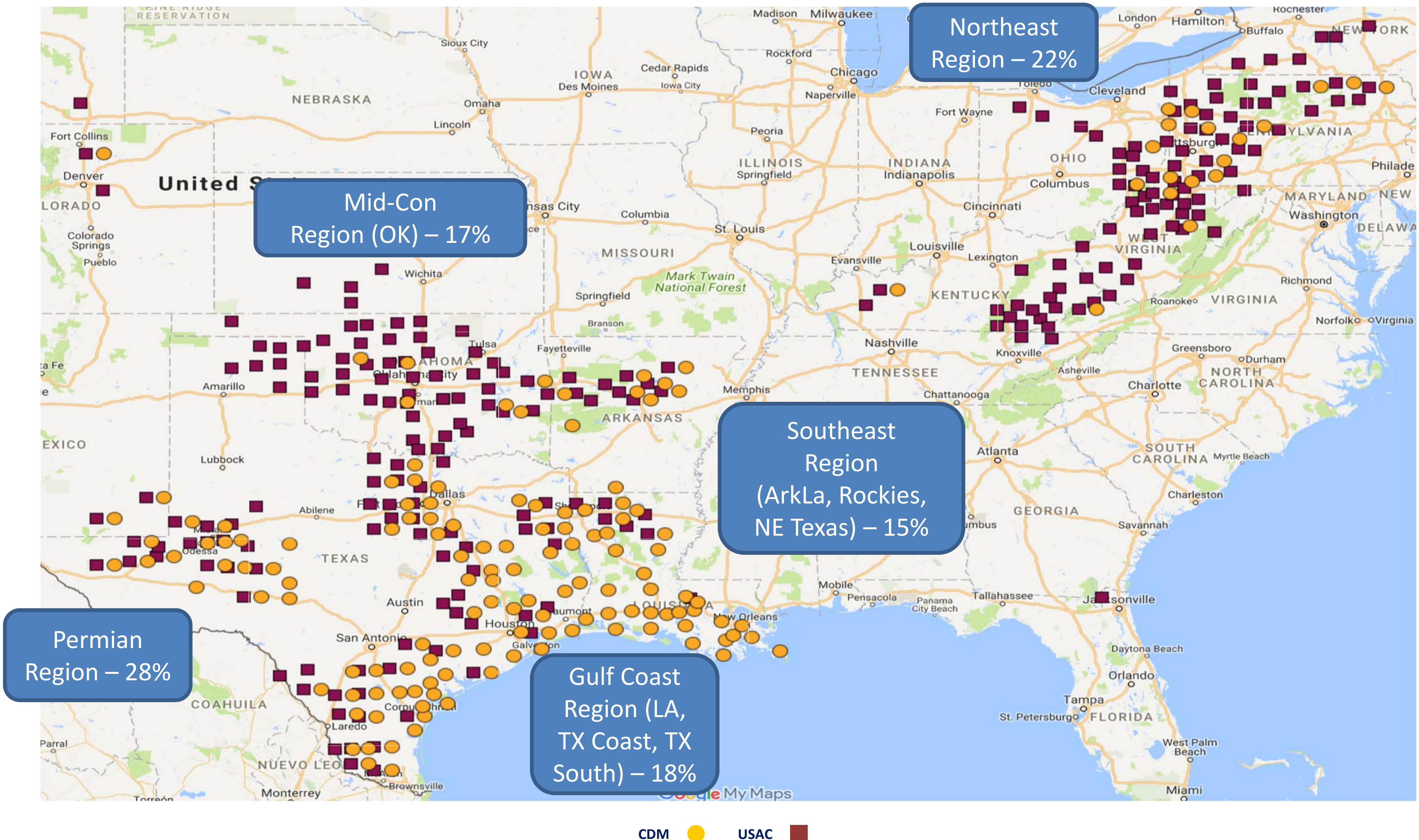
(1) Market data based on USAC closing price of $17.98 on June 12, 2018. LP Equity value includes ~6.4mm Class B units held by ETP.

Compelling Strategic Rationale

Attractive combination of two domestic compression companies	▪ Financially and operationally accretive ▪ Complementary focus on large HP infrastructure applications ▪ Minimal customer and geographic overlap ▪ Brings together experienced field professionals with multi-decade proven track record
Doubles the size of USAC, further strengthening its position in the compression industry	▪ The transaction is intended to achieve the following: – Improved distribution coverage – Ability to leverage increased scale to achieve margin expansion – Further diversity of customer base across upstream and midstream customers – Increase float over time (avg. daily volume up ~2x since announcement) – Access to public debt markets (8-year Sr. Notes @ 6 ⅞% (B+/B3/BB- ratings)
Strong pro forma partnership / governance structure	▪ The Transaction results in a large and supportive corporate group in ETE (BB-/Ba2) and ETP (BBB-/Baa3), elimination of IDR burden, and the conversion of the GP interest to a non-economic GP interest ▪ Governance simplified – elimination of economic GP and IDRs improves long-term cost of capital, further aligns USAC with its public debt and equity holders, and provides potential for publicly elected board in the future

Geographic Presence

Minimal Geographic Overlap



Note: Regional % breakdowns represent active fleet horsepower; excludes non-compression equipment.

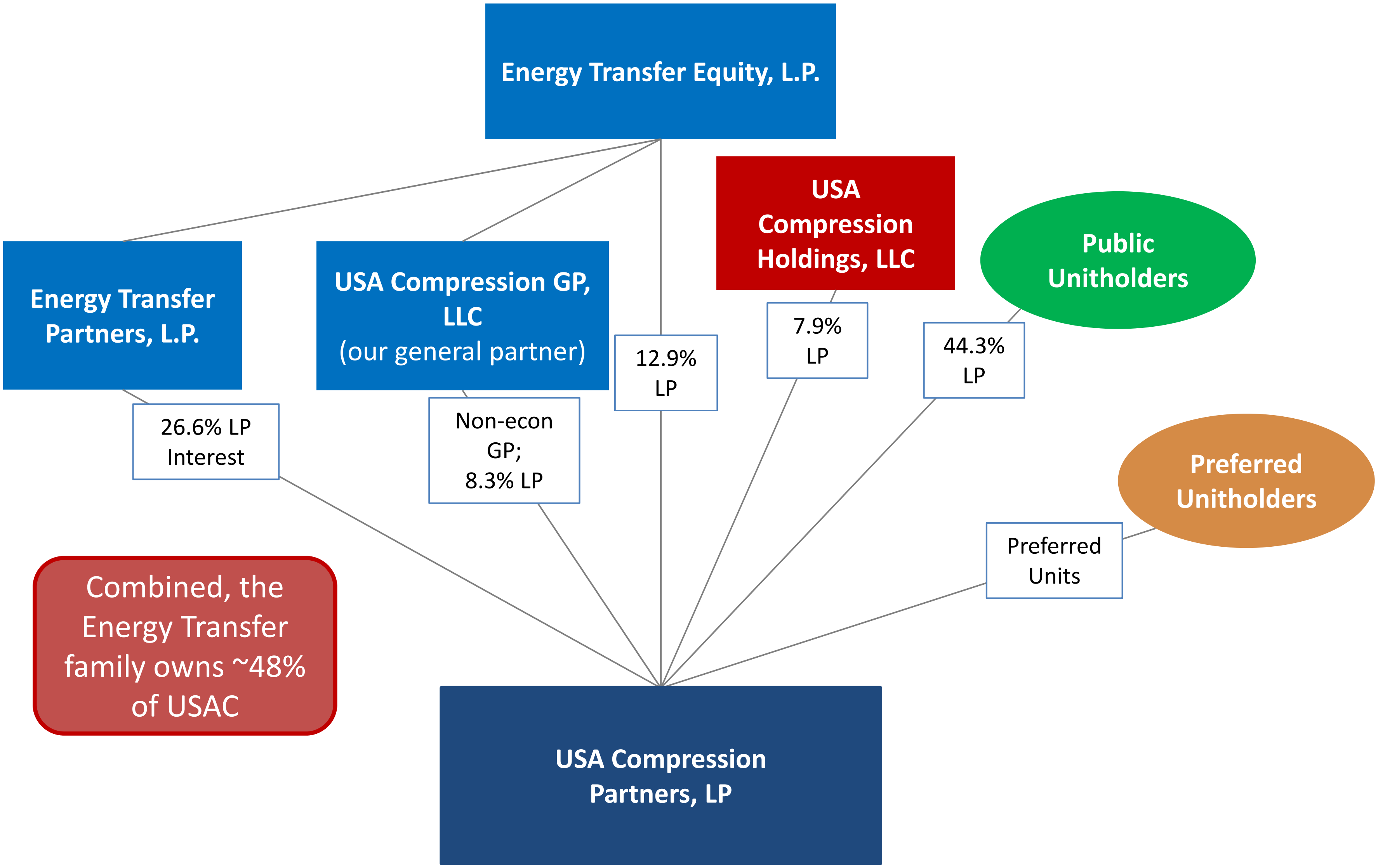
Key Transaction Points

- $1.7 bn total consideration for CDM Resource Management funded through:
  - USAC equity taken back by Energy Transfer family: ~$435mm
  - Preferred Equity: $500mm @ 9.75% coupon (Lead investor: EIG Global)
  - Senior Notes: $725mm 8-year @ 6 ⅞ % coupon (B+ / B3 / BB-)

- Energy Transfer Equity, L.P. (NYSE: ETE) now controls USAC through a non-economic GP interest
  - Exchanged economic GP interest and IDRs for 8.0mm USAC common units at closing
  - Reconstituted Board of Directors

- Enhanced financial flexibility
  - Upsized ABL facility to $1.6bn, reset maturity to 5 years (2023) and provided increased room under covenant levels
  - ~6.4mm Class B LP units taken back by ETP do not pay distributions for four quarters
  - Preferred equity has option to PIK a portion of the quarterly coupon for first 4 quarters following closing

Pro Forma Organizational Chart



Note: Percentages reflect USAC unit count as of June 15, 2018. ETP interest includes ~6.4mm Class B units.

Macro Overview & Demand Drivers

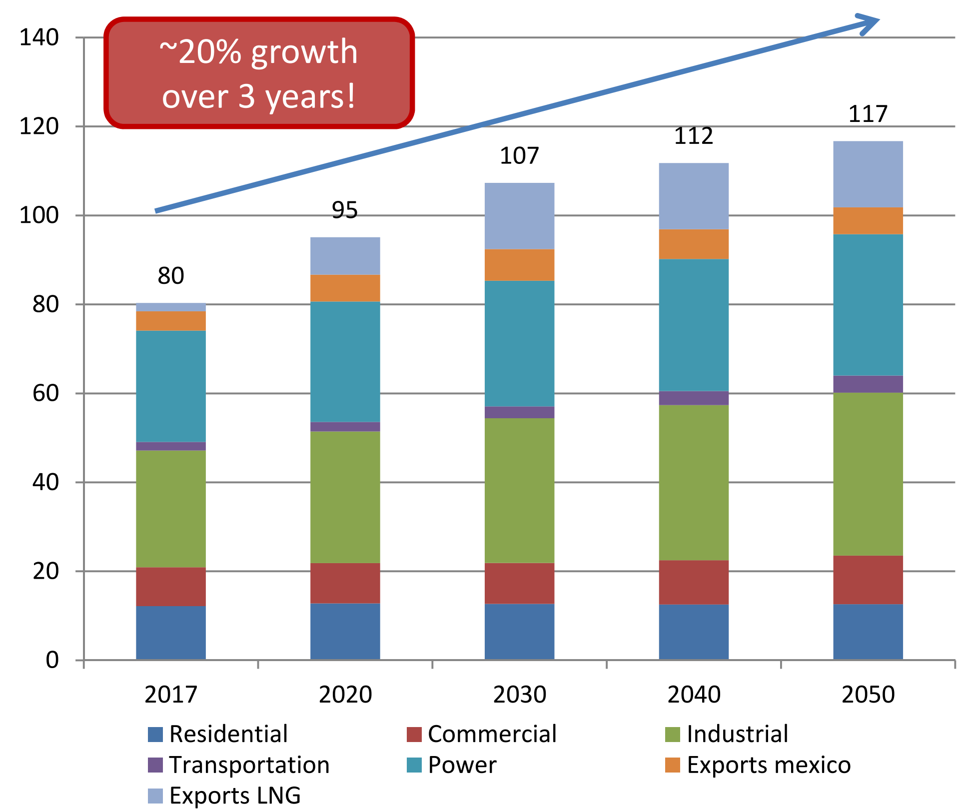
Domestic Natural Gas Supply & Demand Growth

Natural Gas Supply & Demand Continues to Grow…

as does the need for midstream infrastructure to move it through the pipeline system

EIA projects significant increase in natural gas demand by 2050

Projected Natural Gas Demand (Bcf/d)[(1)]



Exports to Mexico:

- Growing power needs to be met by US shale gas
- ~3 Bcf/d to Mexico by 2020

LNG Exports:

- ~8 Bcf/d by 2020; 15 Bcf/d by 2040

Power:

- ~30 Bcf/d by 2040
- Coal plant retirements expected to continue

Industrial Demand:

- ~35 Bcf/d by 2040
- Petrochemical plants (Gulf Coast, NE) driving demand

Source: U.S. Energy Information Administration, Annual Energy Outlook 2018, February 2018

(1) Converted from TCF, on a 360 day/year basis

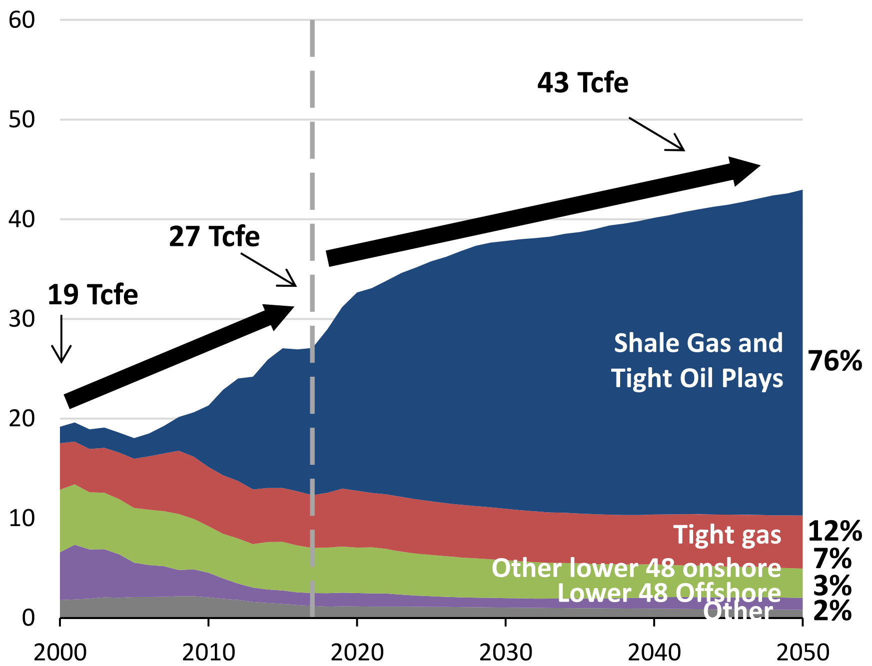
Macro Thesis: The "Shift to Shale"

Shale Gas Expected to be the Primary Source in Future

- **Shale Ramp**: Production from shale has now pulled **<u>even</u>** with all other sources
  - 2017 est. ~ 15 Tcfe of shale production – 55% of total
- **Pie Getting Bigger**: EIA projecting ~117 Bcf/d of total production by 2050 – with shale ~76% of total

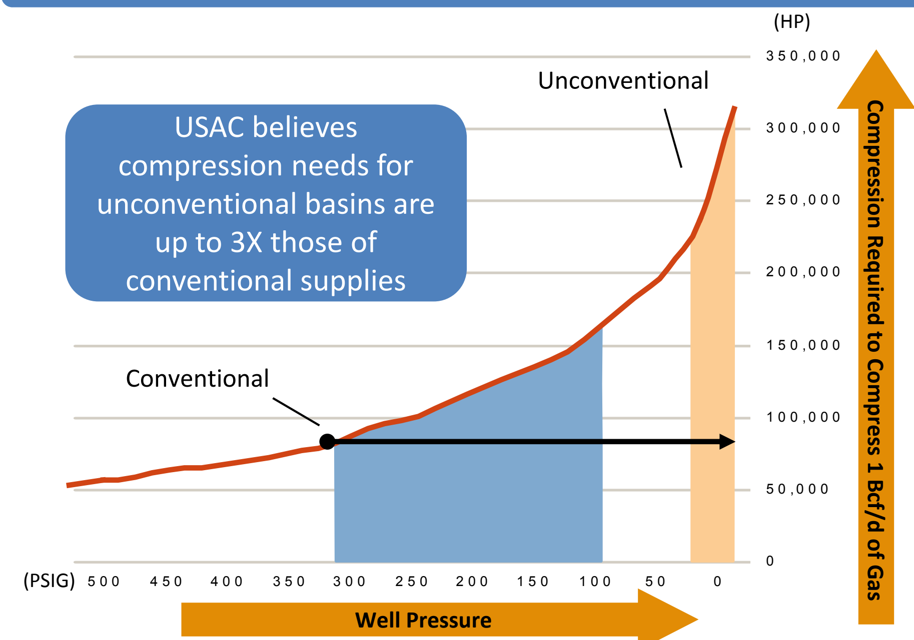
- Shale gas is typically produced at lower wellhead pressures (0-50 PSIG) in contrast to conventional gas wells (100-300 PSIG)
- Pipeline specifications remain constant – requiring gas pressure to be increased significantly to move gas into and through pipelines
- As a result, to move the same amount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

Natural gas production by type
trillion cubic feet



Source: U.S. Energy Information Administration, Annual Energy Outlook 2018, February 2018

Shale Production Drives Increasing Compression Requirements [1]



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

Key Industry Drivers for Compression Services

Compression is Critical Midstream Infrastructure for Producing & Transporting Hydrocarbons

Overall Gas Demand & Production

- ~85% of USAC's business (by HP) is installed in natural gas-based infrastructure applications ("Midstream")
- Projected increasing natural gas demand for the foreseeable future
- LNG and 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
- 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 is still in the early stages; compression follows

Customer Preference to Outsource

- Decision to outsource compression can be due to higher runtimes, lack of internal expertise, alternative capital investment opportunities and other factors
- Many of the largest, most sophisticated energy companies rely on outsourcing
- Mission-critical assets must run
- Guaranteed run time backed up by service and adherence to maintenance intervals
- As capital allocation moves to the forefront, shifting preference to use 3rd party providers

Customer Activity

- E&P Activity
  - Rig count continues strength as E&Ps increase capex
  - Producers showing more discipline; attractive returns driving spending
  - Operators gaining efficiencies in a world of $60/Bbl oil and $2.50/MMBtu gas

Marcellus

Rig Total	% Chg Trough	% Chg Peak
56	115%	(33%)

DJ Basin

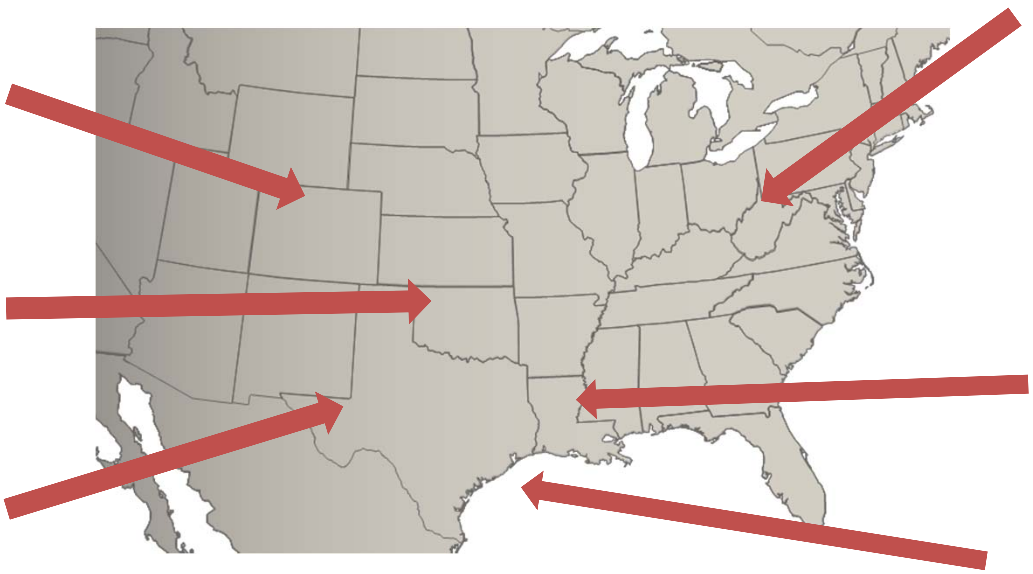
Rig Total	% Chg Trough	% Chg Peak
24	100%	(59%)

Utica

Rig Total	% Chg Trough	% Chg Peak
24	118%	(45%)

SCOOP/Stack/Mid-Con

Rig Total	% Chg Trough	% Chg Peak
123	151%	(9%)



Haynesville

Rig Total	% Chg Trough	% Chg Peak
60	233%	28%

Permian

Rig Total	% Chg Trough	% Chg Peak
480	250%	(15%)

Eagle Ford

Rig Total	% Chg Trough	% Chg Peak
90	200%	(63%)

Source: Baker Hughes, Bloomberg, and B. Riley FBR Research dated June 8, 2018.

USAC Overview

Key Strategic Priorities

Successful CDM Integration

- Near-term focus on integrating all aspects of CDM into USAC
- Alignment of strategy / policies / procedures is critical; build a single culture
- Extract synergies as integration takes place

Consistent Business Model

- Further strengthen the USAC “Southwest Airlines” standardized business model
- Continue focus on large HP class units
- Implement best practices across the combined business

Prudent Capital Spending

- With capital more scarce and more expensive, putting emphasis on highest-return opportunities
- Stringent capital allocation across the business
- Continuous evaluation of 2019 orders

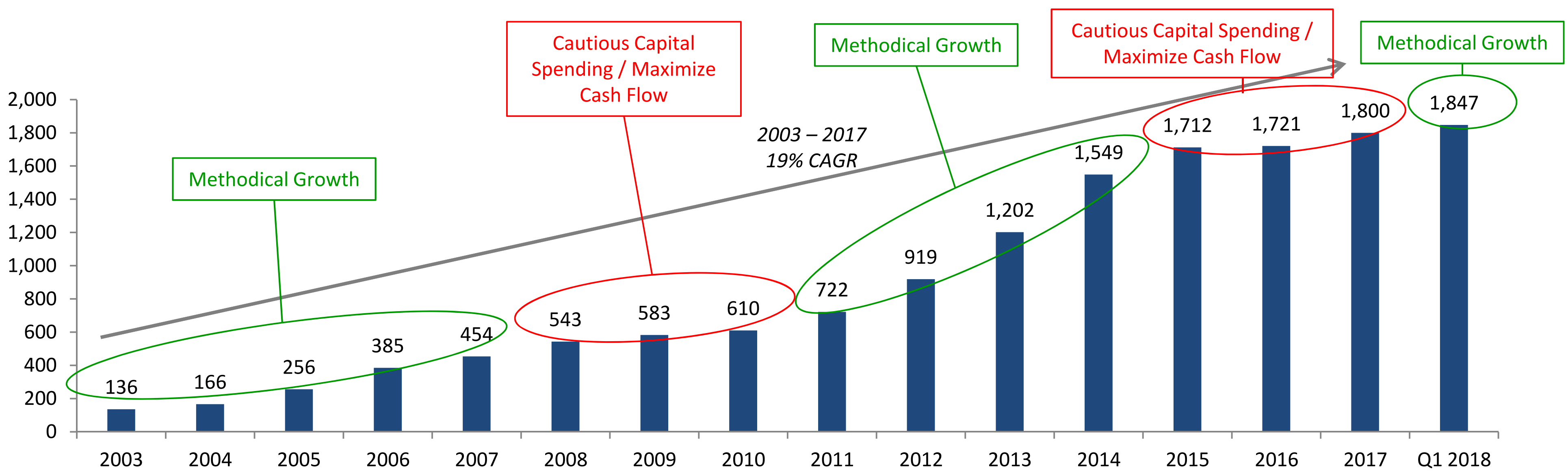
Sound Financial Management

- Continue to improve leverage & coverage metrics
- Optimize fleet pricing and contracts
- Facilitate Riverstone / Energy Transfer LP monetizations

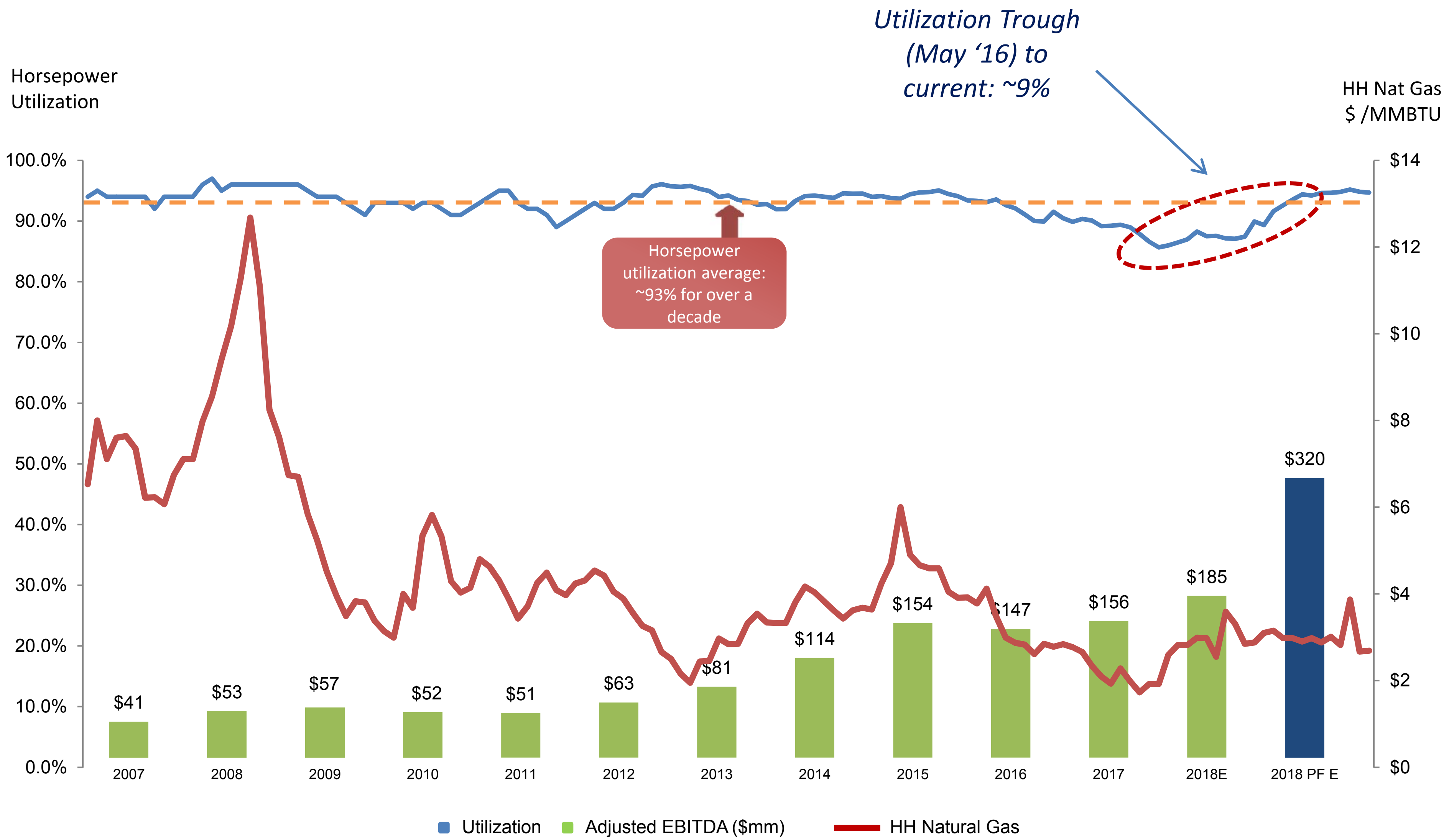
Business Model Allows for Prudent Capital Spending…..

- Large HP focus ideally suited for growth and stability
- Advent of shale production has changed the industry: demand for larger, more flexible assets
- Assets provide growth when marketplace demands (and willing to pay)
- Ability to rein in spending and operate for cash flow when market softens
- Largely agnostic to commodity prices; tied more to the overall domestic production of (and demand for) natural gas

Total Fleet Horsepower (000s)



…..Leading to Cash Flow and Asset Stability Through Cycles



Source: EIA and Partnership historical financials.

Note: 2018E reflects midpoint of previous USAC standalone guidance; 2018 PF E represents midpoint of guidance for combined company.

Fleet Overview – Horsepower Mix Fits Like a Glove

Pro Forma, Large Horsepower Focus Remains Paramount

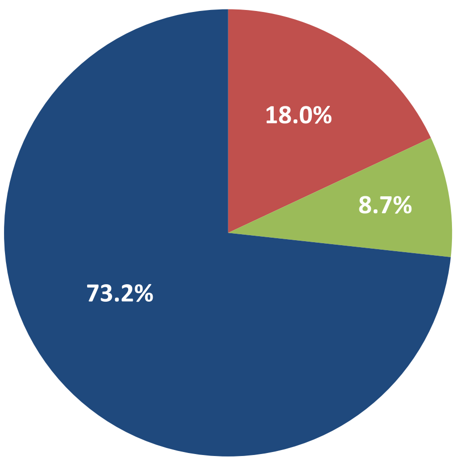
USAC Standalone

	Fleet Horsepower	% Total
Less than 400 HP	333,004	18.0%
400 - 999 HP	161,612	8.7%
1,000 HP and Greater	1,352,800	73.2%
Total	1,847,416	

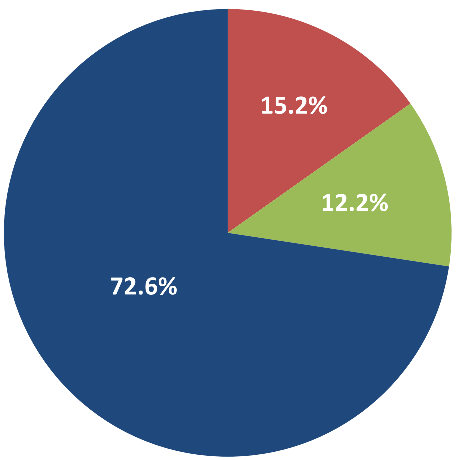
Pro forma, USAC will continue its large HP focus – over 70% of fleet with HP >1,000HP

USAC Pro Forma

	Fleet Horsepower	% Total
Less than 400 HP	529,400	15.2%
400 - 999 HP	425,602	12.2%
1,000 HP and Greater	2,527,345	72.6%
Total	3,482,347	



Less than 400 HP
400 – 999 HP
1,000 HP and Greater



Combined Customer Overview

Top 20 Customers: Diverse Counterparties & Long-Term Relationships

Customer	% of Rev[1]	Length of relationship	Total HP		Customer	% of Rev[1]	Length of relationship	Total HP[2]
Independent Public E&P	10%	17 Years	303K		Midstream C-corp	2%	11 Years	69K
Large Private E&P	5%	20 Years	126K		Private E&P	2%	4 Years	48K
Public Utility	4%	5 Years	138K		Independent Public E&P	2%	4 Years	47K
Independent Public E&P	4%	13 Years	108K		Large MLP	2%	6 Years	66K
Large MLP	3%	4 Years	111K		Private Midstream	2%	5 Years	57K
Independent Public E&P	3%	6 Years	81K		Independent Public E&P	2%	6 Years	50K
Independent Public E&P	3%	10 Years	79K		Independent Public E&P	2%	5 Years	51K
Private Midstream	2%	6 Years	80K		Independent Public E&P	2%	5 Years	56K
Major O&G	2%	4 Years	71K		Independent Public E&P	2%	15 Years	55K
Midstream Sub of Large Public E&P	2%	12 Years	68K		Independent Public E&P	1%	3 Years	27K
USAC #1-10	**39%**		**1,165K**		**USAC #11-20**	**18%**		**526K**

- USAC has historically had very little bad debt write-offs; in fact, over the last 13+ years, USAC has written off only ~$1.2 million in bad debts
  - Equates to 0.06% of total billings (>$1.9 billion) over same period [2]

USAC & CDM customer

USAC customer

CDM customer

(1) Represents recurring revenues for the quarter ended March 31, 2018.
(2) Historical data refers to USAC on a standalone basis.

Large Horsepower Gas Applications Drives Stability

Compression Unit Size Matters

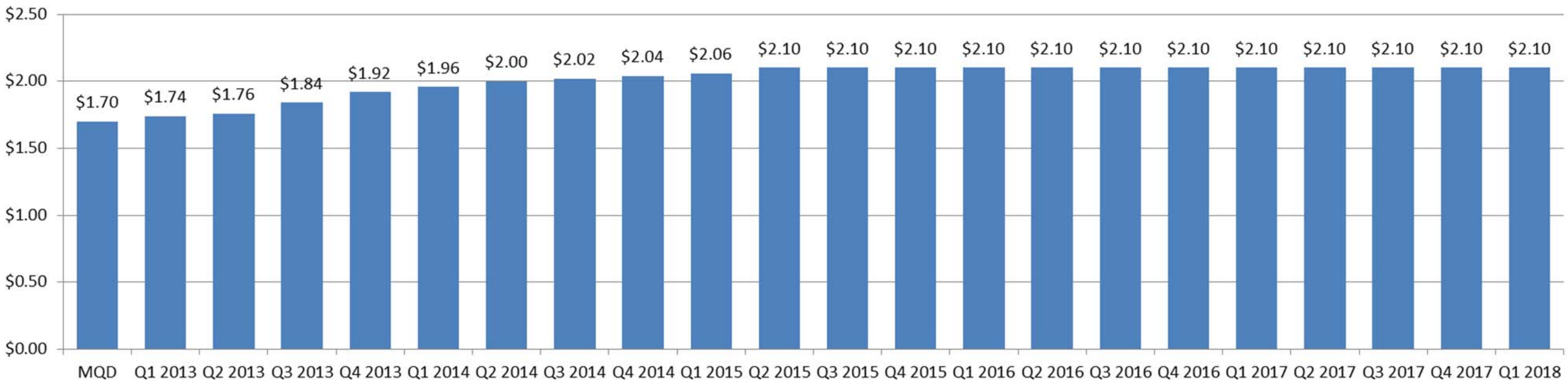
USAC Focus:

Gas Compression Industry: Key Characteristics by Size						
	Small	Medium	Large	Ex. Large	XX Large	Commentary
Compression Unit HP Range	0 – 400 HP	400 – 1,000 HP	1,000 – 1,500 HP	1,500 – 2,300 HP	2,300 – 2,600 HP	**More horsepower needed to move larger gas volumes**
Gas Vol (MMcf/d)	0.90	3.20	5.0	8.0	13.0	
Size (L x W x H, ft.)	21 x 12 x 11	33 x 19 x 16	38 x 27 x 20	43 x 34 x 20	80 x 17x 28	**Increasing size, transportation & demobilization costs create significant 'barriers to exit'**
Weight (lbs.)	~40,000	~85,000	~185,000	~250,000+	~400,000+	
Transportation Requirements	1 F350	2 x 18-wheelers	3 x 18-wheelers	5 x 18-wheelers	8 x 18-wheelers	
De-mobilization Costs (cust pays)	< $10K	~$25K	~$60K	$100K+	$200K+	
Typical Contract Length	1 – 12 mos	6 months – 2 years	2 – 5 years	2 – 5 years	2 – 5 years +	**Larger units = longer deployment**

Note: Used CAT 3306TA ,CAT 3508TALE, CAT 3516BLE, CAT 3606TALE and CAT 3608TALE as representative units for small, medium, large, extra large and XX large horsepower categories, respectively. Gas volumes based on 50 psi suction pressure and 1,200 psi discharge pressure.

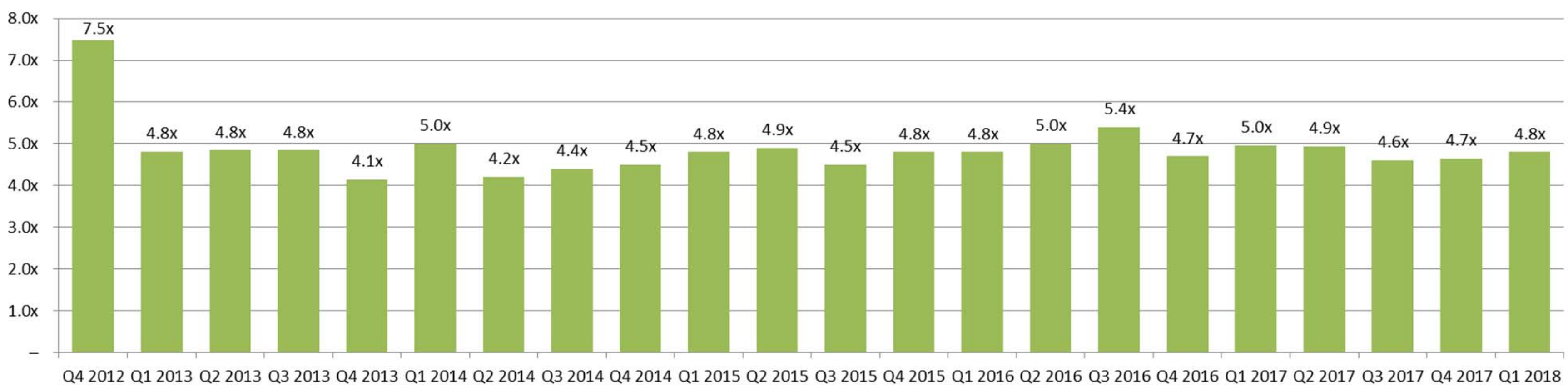
Balancing Distribution Stability and Leverage

Annualized Distributions per LP Unit



- DCF (and Cash) coverage (1) for Q1 2018 was 1.03x
- Riverstone did not participate in DRIP

USAC Historical Leverage(2)

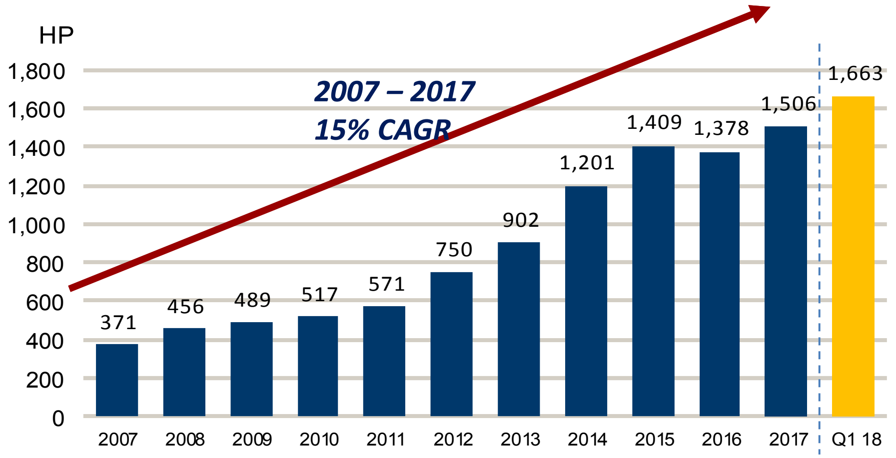


- Managed leverage through market softness
- 4.78x vs covenant of 5.75x in Q1 2018

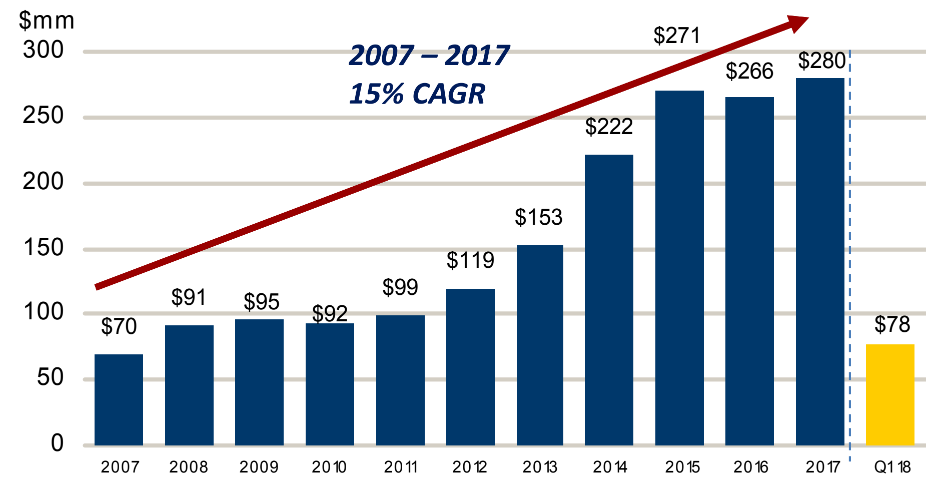
(1) See "Basis of Presentation; Explanation of Non-GAAP Financial Measures" for additional information on calculation of DCF coverage and Cash Coverage Ratios.
(2) Historical leverage calculated as total debt divided by annualized quarterly Adjusted EBITDA for the applicable quarter, in accordance with our current Credit Agreement. Actual historical leverage may differ based on certain adjustments, and prior to Q4 2013 was calculated using LTM Adjusted EBITDA.

USAC Standalone Operational and Financial Performance

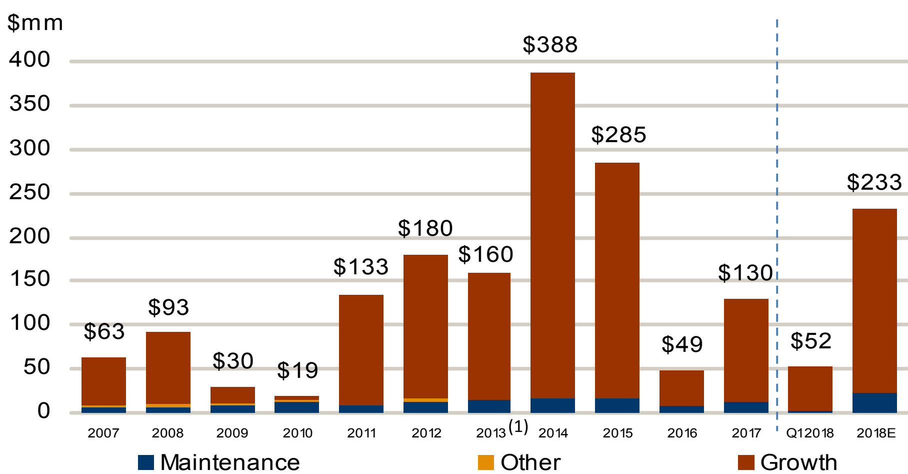
Avg. Revenue Generating HP (000s)



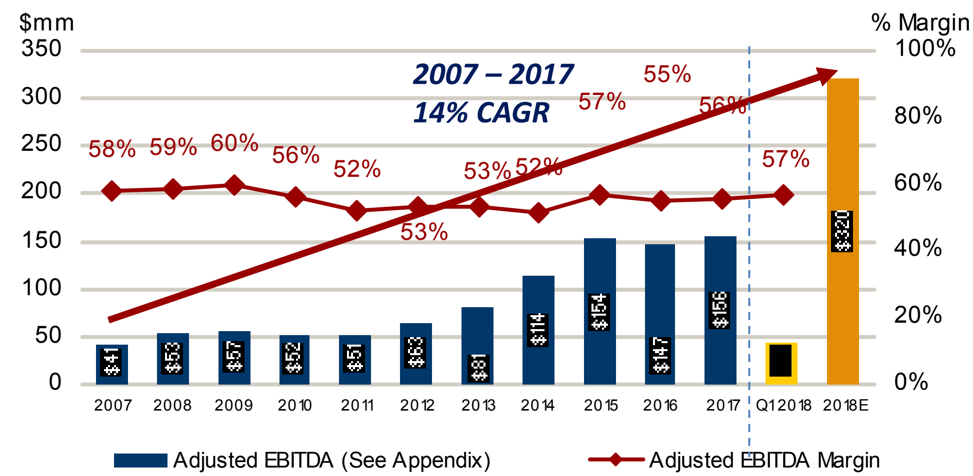
Revenue ($MM)



Total Capex ($MM)(2)



Adjusted EBITDA ($MM) & Margin Percentage(2)(3)



(1) *Does not include $182mm acquisition of S&R Compression, financed with 7.4mm Common Units ($178mm net of cash acquired).*
(2) *2018E data reflects midpoint of guidance provided on May 9, 2018 in earnings release and 10-Q.*
(3) *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; CDM Acquisition further expands presence in areas where USAC was historically under-represented ■ 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
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 ■ CDM brings new customers / opportunities to USAC

Appendix

Compression Throughout the Value Chain

Midstream Compression Offers Cash Flow & Customer Stability

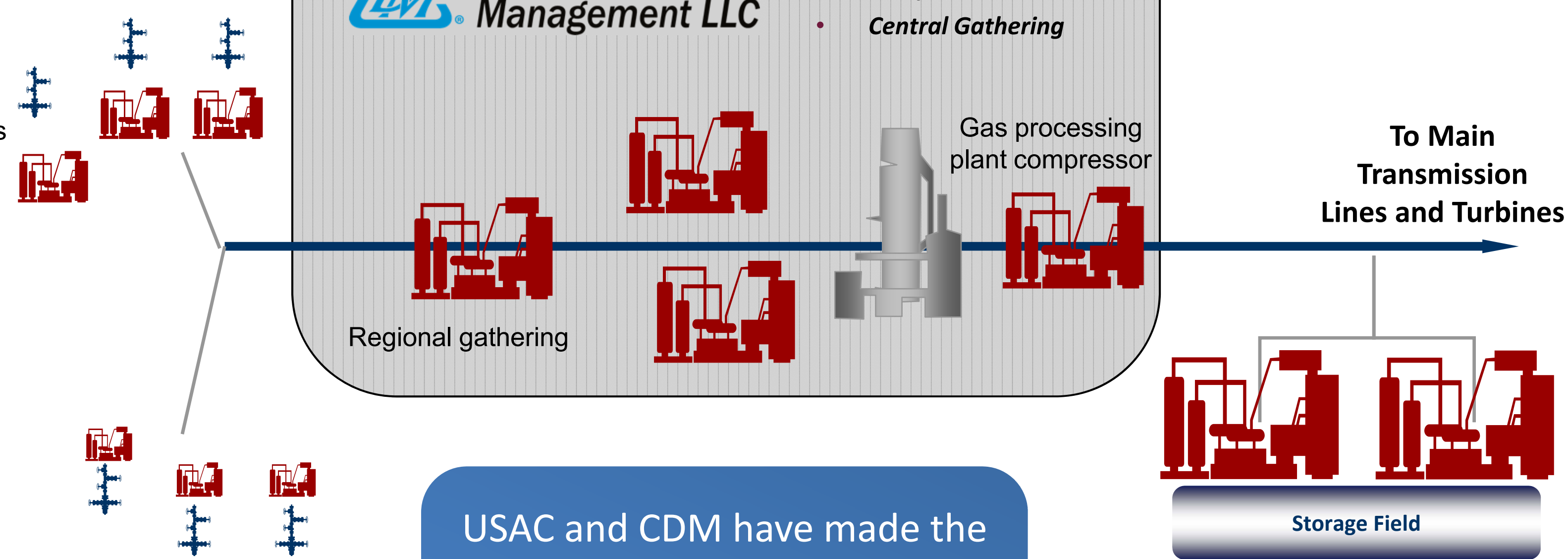
Lower (Sm. Volumes) **Pressure Regime** *Higher (Lg. Volumes)*

Crude Oil Wells
- ***Gas Lift***
- ***Gas Reinjection***

Limited exposure for both USAC & CDM

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 and CDM have made the strategic decision not to pursue more volatile gas wellhead equipment

Non-GAAP Reconciliations

($ in 000's)	Three Months Ended March 31,		Years Ended December 31,		
	2018	2017	2017	2016	2015
Net income (loss)	$ (15,370)	$ 1,552	$ 11,440	$ 12,935	$ (154,273)
Interest expense, net	9,219	5,674	25,129	21,087	17,605
Depreciation and amortization	25,112	24,151	98,603	92,337	85,238
Income tax expense	70	149	538	421	1,085
EBITDA	$ 19,031	$ 31,526	$ 135,710	$ 126,780	$ (50,345)
Impairment of compression equipment	—	1,112	4,972	5,760	27,274
Impairment of goodwill	—	—	—	—	172,189
Interest income on capital lease	351	431	1,610	1,492	1,631
Unit-based compensation expense	2,239	2,945	11,708	10,373	3,863
Transaction expenses for acquisitions	21,731	—	1,406	894	—
Severance charges	1,041	62	314	577	—
Other	—	171	—	—	—
Loss (gain) on disposition of assets	(324)	(244)	(17)	772	(1,040)
Adjusted EBITDA	$ 44,069	$ 36,003	$ 155,703	$ 146,648	$ 153,572
Interest expense, net	(9,219)	(5,674)	(25,129)	(21,087)	(17,605)
Income tax expense	(70)	(149)	(538)	(421)	(1,085)
Interest income on capital lease	(351)	(431)	(1,610)	(1,492)	(1,631)
Non-cash interest expense and other	704	547	2,186	2,108	1,702
Transaction expenses for acquisitions	(21,731)	—	(1,406)	(894)	—
Severance charges	(1,041)	(62)	(314)	(577)	—
Other	—	(171)	(490)	—	—
Changes in operating assets and liabilities	24,033	(11,777)	(3,758)	(20,588)	(17,552)
Net cash provided by operating activities	$ 36,394	$ 18,286	$ 124,644	$ 103,697	$ 117,401

Non-GAAP Reconciliations, cont'd.

($ in 000's)	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007
	Years Ended December 31,										
Net income (loss)	$ 11,440	$ 12,935	$ (154,273)	$ 24,946	$ 11,071	$ 4,503	$ 69	$ 10,479	$ 21,228	$ 20,911	$ 7,122
Interest expense, net	25,129	21,087	17,605	12,529	12,488	15,905	12,970	12,279	10,043	14,003	16,468
Depreciation and amortization	98,603	92,337	85,238	71,156	52,917	41,880	32,738	24,569	22,957	18,016	13,437
Income tax expense	538	421	1,085	103	280	196	155	155	190	119	155
EBITDA	$ 135,710	$ 126,780	$ (50,345)	$ 108,734	$ 76,756	$ 62,484	$ 45,932	$ 47,482	$ 54,418	$ 53,049	$ 37,182
Impairment of compression equipment	4,972	5,760	27,274	2,266	203	—	—	—	1,677	—	1,028
Impairment of goodwill	—	—	172,189	—	—	—	—	—	—	—	—
Interest income on capital lease	1,610	1,492	1,631	1,274	—	—	—	—	—	—	—
Unit-based compensation expense	11,708	10,373	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 charges	—	—	—	—	—	—	300	—	—	—	—
Fees and expenses related to the Holdings Acquisition	—	—	—	—	—	—	—	1,838	—	—	—
Transaction expenses for acquisitions	1,406	894	—	1,299	2,142	—	—	—	—	—	—
Severance charges	314	577	—	—	—	—	—	—	—	—	—
Loss (gain) on sale of assets and other	(17)	772	(1,040)	(2,198)	637	—	—	—	—	—	—
Adjusted EBITDA	$ 155,703	$ 146,648	$ 153,572	$ 114,409	$ 81,130	$ 63,484	$ 51,285	$ 51,987	$ 56,917	$ 53,274	$ 40,562
Interest expense, net	(25,129)	(21,087)	(17,605)	(12,529)	(12,488)	(15,905)	(12,970)	(12,279)	(10,043)	(14,003)	(16,468)
Income tax expense	(538)	(421)	(1,085)	(103)	(280)	(196)	(155)	(155)	(190)	(119)	(155)
Interest income on capital lease	(1,610)	(1,492)	(1,631)	(1,274)	—	—	—	—	—	—	—
Equipment operating lease expense	—	—	—	—	—	—	(4,053)	(2,285)	(553)	—	—
Riverstone management fee	—	—	—	—	(49)	(1,000)	(1,000)	—	—	—	—
Restructuring charges	—	—	—	—	—	—	(300)	—	—	—	—
Non-cash interest expense and other	2,186	2,108	1,702	1,189	1,839	(58)	(920)	3,362	288	201	1,666
Fees and expenses related to the Holdings Acquisition	—	—	—	—	—	—	—	(1,838)	—	—	—
Transaction expenses for acquisitions	(1,406)	(894)	—	(1,299)	(2,142)	—	—	—	—	—	—
Severance charges	(314)	(577)	—	—	—	—	—	—	—	—	—
Other	(490)	—	—	—	—	—	—	—	—	—	—
Changes in operating assets and liabilities	(3,758)	(20,588)	(17,552)	1,498	180	(4,351)	1,895	(220)	(3,474)	1,346	836
Net cash provided by operating activities	$ 124,644	$ 103,697	$ 117,401	$ 101,891	$ 68,190	$ 41,974	$ 33,782	$ 38,572	$ 42,945	$ 40,699	$ 26,441

Non-GAAP Reconciliations, cont'd.

($ in 000's)	Three Months Ended March 31, 2018	Three Months Ended December 31, 2017	Three Months Ended March 31, 2017
Net income (loss)	$ (15,370)	$ 4,546	$ 1,552
Plus: Non-cash interest expense	704	545	547
Plus: Non-cash income tax expense	20	90	109
Plus: Depreciation and amortization	25,112	25,110	24,151
Plus: Unit-based compensation expense	2,239	3,548	2,945
Plus: Impairment of compression equipment	-	163	1,112
Plus: Transaction expenses for acquisitions	21,731	1,406	—
Plus: Severance charges	1,041	22	62
Plus: Other	613	258	171
Less: Loss (gain) on disposition of assets	(324)	(300)	(244)
Less: Maintenance capital expenditures	(2,041)	(2,165)	(3,182)
Distributable Cash Flow	$ 33,725	$ 33,223	$ 27,223
Plus: Maintenance capital expenditures	2,041	2,165	3,182
Plus: Change in working capital	24,033	5,731	(11,777)
Less: Other	(23,405)	(1,776)	(342)
Net cash provided by operating activities	$ 36,394	$ 39,343	$ 18,286
Distributable Cash Flow	33,725	33,223	27,223
Cash distributions to general partner and IDRs	-	754	749
Distributable Cash Flow attributable to limited partner interest	$ 33,725	$ 32,469	$ 26,474
Distributions for Distributable Cash Flow Coverage Ratio	$ 32,783	$ 32,652	$ 32,119
Distributions reinvested in the DRIP	$ 175	$ 304	$ 6,635
Distributions for Cash Coverage Ratio	$ 32,608	$ 32,348	$ 25,484
Distributable Cash Flow Coverage Ratio	1.03	0.99	0.82
Cash Coverage Ratio	1.03	1.00	1.04

Non-GAAP Reconciliations, cont'd.

($ in 000's)	Guidance
Net loss	$(50.0) million to $(30.0) million
Plus: Interest expense, net	$84.5 million
Plus: Depreciation and amortization	$235.0 million
Plus: Income tax expense	$0.5 million
EBITDA	$270.0 million to $290.0 million
Plus: Interest income on capital lease	$1.0 million
Plus: Unit-based compensation expense (1)	$14.0 million
Plus: Transaction expenses and severance charges	$25.0 million
Adjusted EBITDA	$310.0 million to $330.0 million
Less: Cash interest expense	$80.0 million
Less; Preferred unit distribution	$36.5 million
Less: Current income tax expense	$0.5 million
Less: Maintenance capital expenditures	$23.0 million
Distributable Cash Flow	$170.0 million to $190.0 million

(1) Based on the Partnership's unit closing price as of March 31, 2018.

Basis of Presentation; Explanation of Non-GAAP Financial Measures

This presentation includes the non-GAAP financial measures of 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, impairment of goodwill, interest income on capital lease, 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 2018 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 and Distributable Cash Flow.

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.