2014 IPAA Oil & Gas Symposium

April 9, 2014

John A. Weinzierl
Chairman and CEO

Andrew J. Cozby
Vice President and CFO

www.memorialpp.com

Forward-Looking Statements & Other Cautionary Statements

This presentation contains forward-looking statements. All statements, other than statements of historical facts, included in this presentation that address activities, events or developments that MEMP expects, believes or anticipates will or may occur in the future are forward-looking statements. Terminology such as “will,” “expect,” “plan,” “project,” “intend,” “estimate,” “believe,” “target,” “potential,” the negative of such terms or other comparable terminology often identify forward-looking statements. These statements are based on certain assumptions made by MEMP based on its experience and perception of historical trends, current conditions, expected future developments and other factors it believes are appropriate. Such statements are subject to risks and uncertainties. A number of factors, many of which are beyond the control of MEMP, could cause actual results to differ materially from those implied or expressed by the forward-looking statements. These factors include, but are not limited to, the following risks and uncertainties: the uncertainty inherent in the development and production of oil and natural gas and in estimating reserves; potential difficulties in the marketing of, and volatility in the prices for, oil and natural gas; competition in the oil and natural gas industry; risks related to acquisitions, including MEMP’s ability to integrate acquired properties; risks related to MEMP’s ability to generate sufficient cash flow to pay distributions and execute its business plan; and the risk that MEMP’s hedging strategy may be ineffective or may reduce its income. You are cautioned not to place undue reliance on any forward-looking statements, which speak only as of the date of this presentation. All forward-looking statements are qualified in their entirety by this cautionary statement. Please read MEMP’s Annual Report on Form 10-K for the year ended December 31, 2013 and other filings with the SEC, which are available on MEMP’s Investor Relations website at http://investor.memorialpp.com/sec.cfm or on the SEC’s website at www.sec.gov, for a list of certain risk factors that may affect forward-looking statements. MEMP undertakes no obligation and does not intend to update these forward-looking statements to reflect future events or circumstances.

This presentation also includes non-GAAP measures, including Adjusted EBITDA and Distributable Cash Flow. Please see the Appendix for reconciliations of those measures to comparable GAAP measures.

The SEC permits oil and gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserves that meet the SEC’s definition for such terms. This presentation contains estimates of original oil in place (“OOIP”) attributable to MEMP’s offshore California properties. OOIP is merely an indication of the size of a hydrocarbon reservoir and is not an indication of reserves or the quantity of oil that is likely to be produced. You should not assume that estimates of OOIP are comparable to proved or probable reserves or representative of estimates of future production from such properties. It is not possible to measure OOIP in an exact way, and estimating OOIP is inherently uncertain. OOIP has been estimated based on subjective analysis of geological and other relevant data applicable to such properties, including assumptions regarding area, thickness, porosity and saturation. Changes in these factors or inaccuracies in our assumptions could materially alter the estimates of OOIP. In addition, reserve engineering is a complex and subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The estimates of reserves with respect to pending or completed acquisitions in this presentation were prepared by MEMP’s internal reserve engineers and are based on various assumptions, including assumptions related to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. MEMP’s internal estimates of reserves may not be indicative of or may differ materially from the year-end estimates of MEMP’s reserves prepared by a third party as a result of assumptions employed by an independent reserve engineering firm.

Overview of Memorial Production Partners LP

- **Upstream MLP headquartered in Houston**
- **Diverse portfolio of mature, long-lived producing properties**
  - Focus on acquiring, exploiting and developing oil and gas properties
  - Assets in East Texas / North Louisiana, Permian Basin, Eagle Ford, California, Rockies and South Texas
- **Strategy of growing and maintaining production and distributions through acquisitions and low-risk development**
- **Extensive hedge portfolio helps protect production and cash flow through 2019**
- **Since IPO, successfully completed eleven accretive transactions**
- **Relationship with parent and sponsor further drives growth**

Key Statistics[1]

- **Total Proved Reserves: 1,075 Bcfe**
  - 61% proved developed
  - 58% natural gas
- **2014 Estimated Production[2]: 67-69 Bcfe**
  - R/P of 16 years[3]
  - 2,983 gross (1,696 net) wells

(1) Total Proved Reserves reflects estimated proved reserves as of December 31, 2013 per Netherland, Sewell & Associates, Inc. (“NSAI”) audited report. Pro forma for the recently completed East Texas and Eagle Ford acquisitions per MEMP internal estimates
(2) As per MEMP guidance issued on March 25, 2014
(3) Based on MEMP’s current average pro forma net production of 181.9 MMcfe/d

Memorial Production Partners

Acquisitions Update – March & April 2014

- Completed an acquisition of Eagle Ford assets for approximately $173 million, effective January 1, 2014
  - MEMP acquired an interest in 117 producing wells, subject to a seller retained net profits interest, as well as 30% of the seller's leasehold position
  - Acquisition is structured to offset natural production declines and minimize maintenance capital expenditures
    - MEMP's effective working interest ("WI") and net revenue interest ("NRI") in the 117 producing wells will increase to:
      - 2014: 50% of the seller's interest (WI: 6.4% / NRI: 5.2%)
      - 2015: 70% of the seller's interest (WI: 9.0% / NRI: 7.2%)
      - 2016: 85% of the seller's interest (WI: 10.9% / NRI: 8.8%)
      - 2017 and thereafter: 100% of the seller's interest (WI: 12.8% / NRI: 10.3%)
    - Proved reserves of 7.4 MMBoe (63% proved developed and 84% oil)
    - November 2013 net production of approximately 1,650 Boe/d (80% oil)
    - R/P ratio of 12.3 years
    - Primary operator: Murphy Oil Corporation

- Completed the acquisition of oil and natural gas assets in East Texas from Memorial Resource Development LLC ("MRD") for approximately $34 million
  - Proved reserves of 15.4 Bcfe (100% PDP and 54% gas)
  - Current net production of approximately 4.3 MMcfe/d (54% gas)
  - R/P ratio of 9.8 years
  - Properties consist of 80 gross (26 net) producing wells

Memorial Production Partners

Significant Footprint – MEMP Asset Overview

Total Partnership (Pro Forma)	
Proved Reserves (Bcfe)	1,075
% Proved Developed	61%
% Gas Reserves	58%
Production (MMcfe/d)	181.9
Total Proved Reserve Life (R/P)	16.2x
Gross Wells	2,983
Net Wells	1,696
Drilling and Recompletion Opportunities	1,078

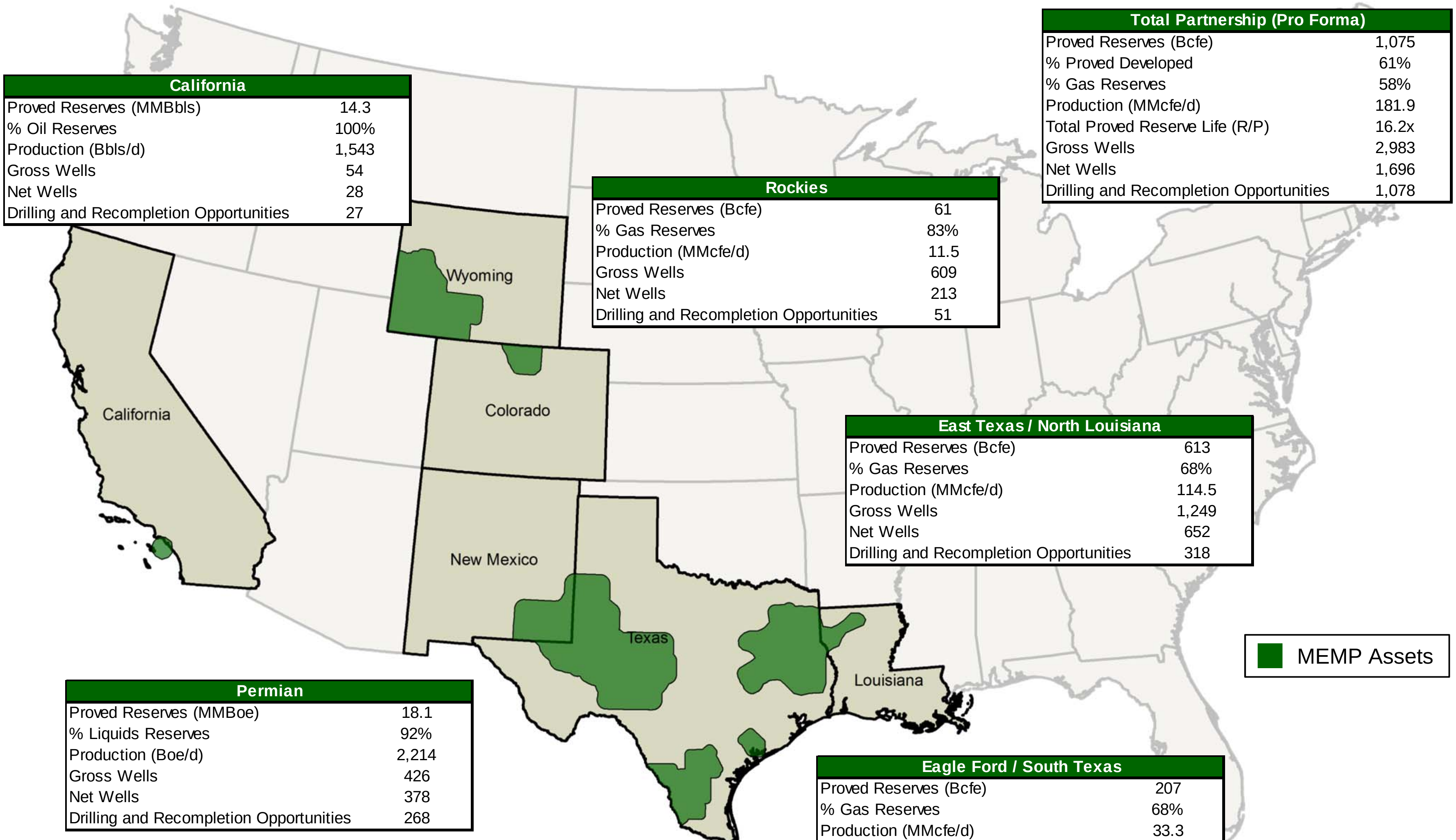
California	
Proved Reserves (MMBbls)	14.3
% Oil Reserves	100%
Production (Bbls/d)	1,543
Gross Wells	54
Net Wells	28
Drilling and Recompletion Opportunities	27

Rockies	
Proved Reserves (Bcfe)	61
% Gas Reserves	83%
Production (MMcfe/d)	11.5
Gross Wells	609
Net Wells	213
Drilling and Recompletion Opportunities	51

East Texas / North Louisiana	
Proved Reserves (Bcfe)	613
% Gas Reserves	68%
Production (MMcfe/d)	114.5
Gross Wells	1,249
Net Wells	652
Drilling and Recompletion Opportunities	318

Permian	
Proved Reserves (MMBoe)	18.1
% Liquids Reserves	92%
Production (Boe/d)	2,214
Gross Wells	426
Net Wells	378
Drilling and Recompletion Opportunities	268

Eagle Ford / South Texas	
Proved Reserves (Bcfe)	207
% Gas Reserves	68%
Production (MMcfe/d)	33.3
Gross Wells	645
Net Wells	425
Drilling and Recompletion Opportunities	414



Note: MEMP base assets reflect estimated proved reserves as of December 31, 2013 per NSAI audited report; Pro forma for the recently completed East Texas and Eagle Ford acquisitions per MEMP internal estimates

Memorial Production Partners

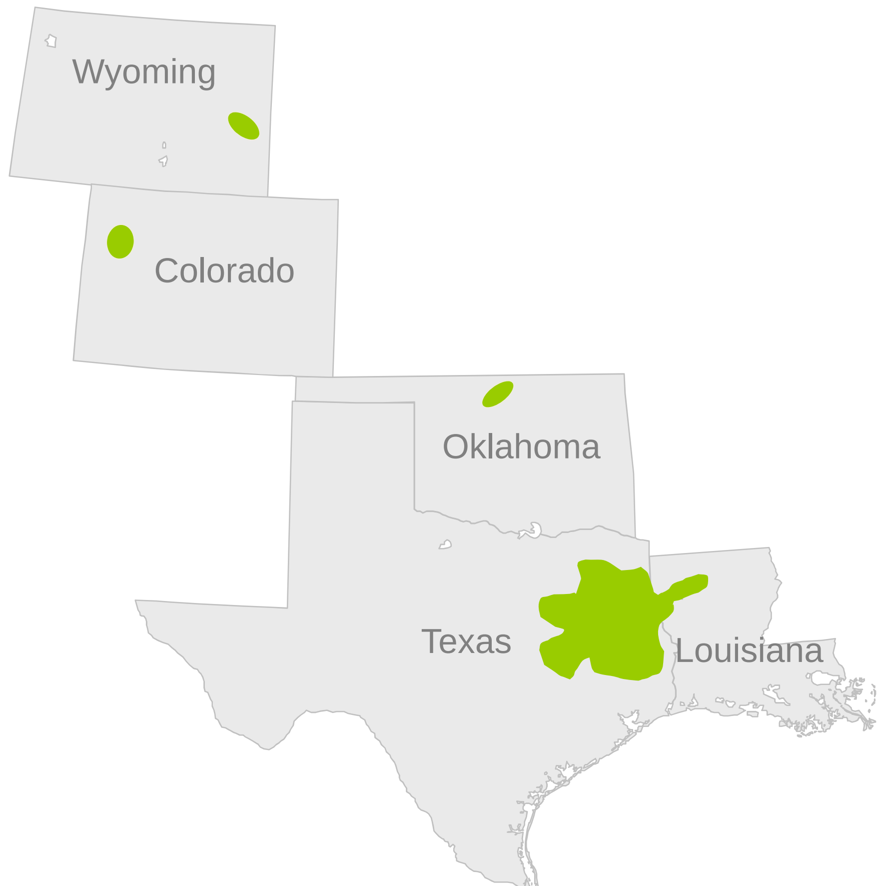
MRD Relationship Provides Exceptional Growth Opportunities

Value Enhancing Relationship with MRD

- Significant and diverse asset base with over 1 Tcfe of proved reserves (1)
  - Maturing assets, substantial drilling inventory provide visibility to drop-down sources
  - Over 700 net horizontal drilling locations in the Terryville Complex with high return profile (over 800 net horizontal total)
- Established as unique private owner
  - Active acquirer with history of completing accretive acquisitions
  - Joint bidding opportunities, strong operational support
- Alignment with MEMP performance provides growth incentives
  - 50% ownership of IDRs
  - Ownership of approximately 5 MM subordinated units
  - ~9% of total outstanding units subordinated until December 2014 (3 years post IPO)
- Employs over 480 full-time employees including over 95 technical staff / engineers

MRD Asset Overview

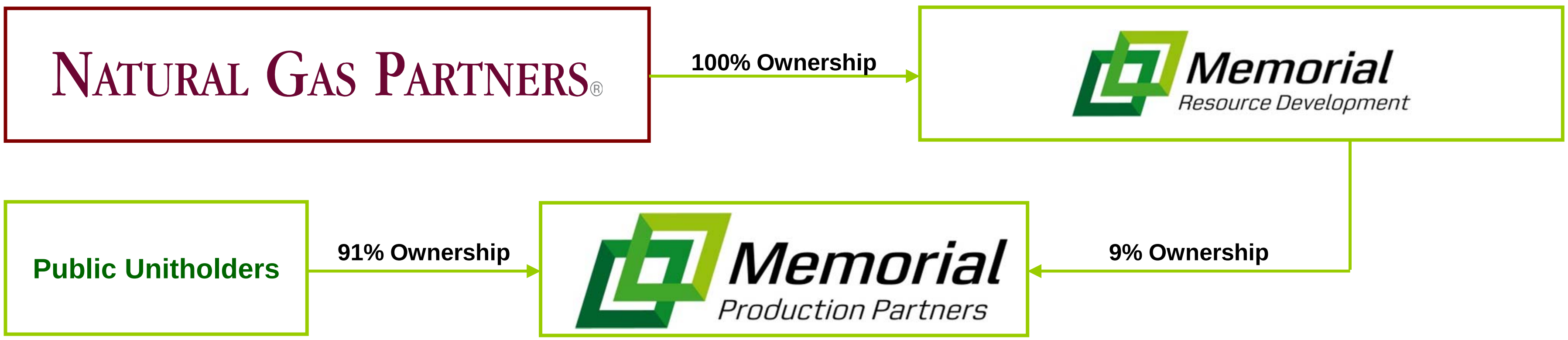
- Over 1 Tcfe of proved reserves (1)
- 4Q 2013 average net production: 137 MMcfe/d
  - R/P of ~23 years
- Over 200,000 net acres



(1) Audited reserves as of December 31, 2013

Memorial Production Partners

MEMP Has Executed on All Acquisition Strategies



Drop Downs from Memorial Resource

- 9% ownership in MEMP
- 50% ownership of IDRs
- Overlapping asset base with over 1 Tcfe of proved reserves
- Over 200,000 net acres
- Experienced operating teams with basin specific M&A and operational expertise

Acquisitions from NGP

- 50% ownership of IDRs (non-voting); incentivized to grow MEMP
- Board representation
- Proprietary deal flow
- Over $10.5 billion of capital commitments under management since inception in 1988
- Family of funds focused on the entire energy spectrum
- 50+ portfolio companies

Third Party Acquisitions

- Industry relationships
- Proven track record
- Industry transition promotes A&D environment for mature assets

Joint Bid with Memorial Resource

- Proper value allocation based on risk profile
- Enhances ability to compete for acquisitions

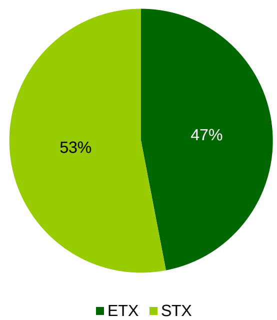
Acquisition Strategy Drives Growth & Diversification

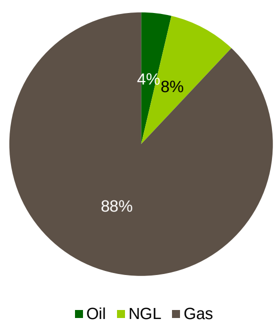
Acquisitions Since IPO

Date	Transaction Structure	Location	Proved Reserves(1) (Bcfe)	Net Production(1) (MMcfe/d)	Purchase Price(1) ($MM)
March 14	Third Party Acquisition	Eagle Ford	44	10	$173
March 14	MRD Drop Dow n	East Texas	15	4	35
September 13	Third Party Acquisitions	East Texas / Rockies	21	5	29
July 13	MRD Drop Dow n / Acquisition from NGP	Permian / East Texas / Rockies	276	45	606
March 13	MRD Drop Dow n	East Texas / North Louisiana	162	21	200
December 12	Acquisition from NGP	California	86	9	271
September 12	Third Party Acquisition	East Texas	139	13	90
May 12	MRD Drop Dow n	East Texas	28	4	27
May 12	Third Party Joint Bid w ith MRD	East Texas / North Louisiana	22	4	37
April 12	MRD Drop Dow n	East Texas	20	2	19
Total			**814**	**118**	**$1,486**

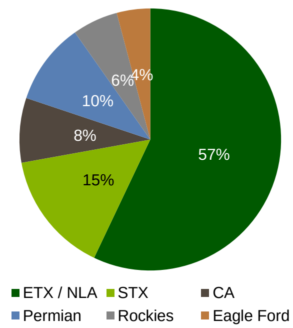
Evolution of Reserve Base

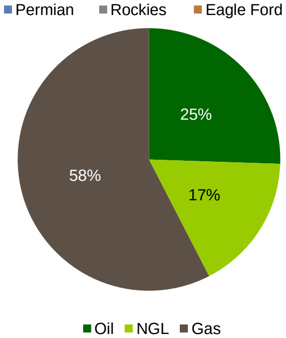
MEMP at IPO (2)
325 Bcfe – R/P of 17 Years





MEMP PF 2013 (3)
1,075 Bcfe – R/P of 16 Years





(1) Reflects proved reserves, average production and purchase price as announced at the time of each acquisition
(2) Reflects estimated proved reserves as of December 2011 IPO
(3) MEMP base assets reflect estimated proved reserves as of December 31, 2013 per NSAI audited report; Pro forma for the recently completed East Texas and Eagle Ford acquisitions per MEMP internal estimates

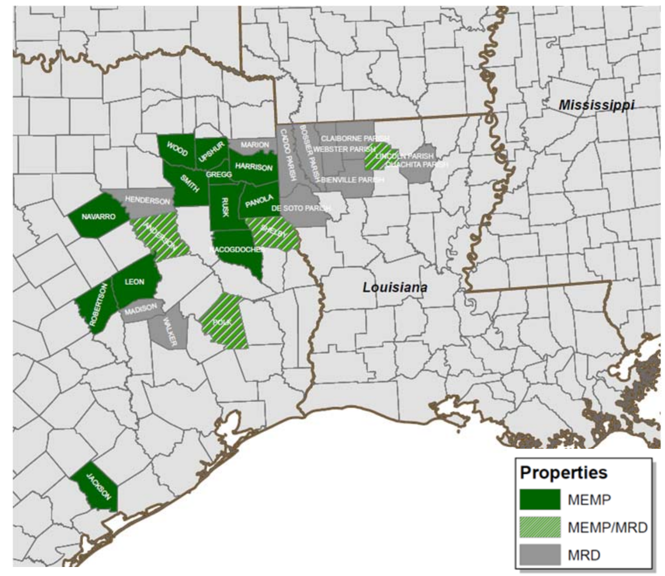
East Texas / North Louisiana Asset Summary

Asset Overview

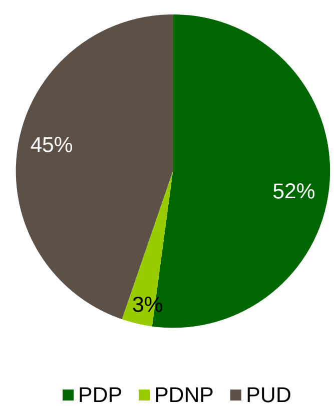
- Key Fields: Joaquin, Carthage, Willow Springs, East Henderson and the Terryville fields
- Primary Formations: Cotton Valley, Travis Peak
- Field Characteristics:
  - Fields discovered as early as 1936
  - Production depth ranges between 6,000 – 10,000 feet
  - Produced over 13.7 Tcfe since initial discoveries
- Estimated Net Proved Reserves: 613 Bcfe [(1)]
  - 68% gas
  - 55% proved developed
- Production: 114.5 MMcfe/d [(2)]
  - R/P of 15 years
- Producing Wells: 1,249 gross (652 net)
  - 788 operated wells [(3)]
  - Average working interest: 52%
- Drilling and Recompletion Opportunities: 118 PDNPs and 200 PUDs[(1)]
- Attractive rates of returns due to high liquids yields

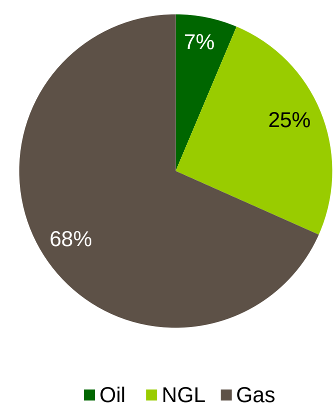
(1) Reflects estimated proved reserves as of December 31, 2013 per NSAI audited report; Pro forma for the recently completed East Texas acquisition per MEMP internal estimates
(2) Average current pro forma net production; Pro forma for the recently completed East Texas acquisition per MEMP internal estimates
(3) Represents wells operated by MEMP and MRD

Asset Location



East TX / North LA Proved Reserves Overview





Memorial Production Partners

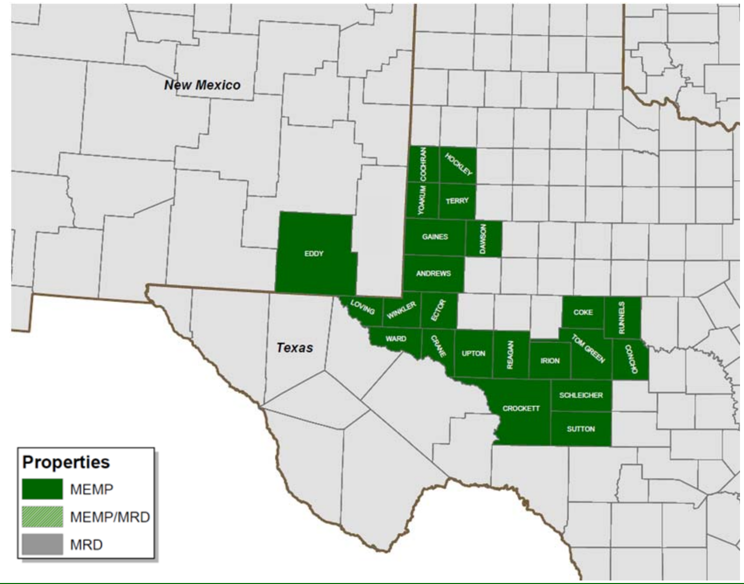
Permian Basin Asset Summary

Asset Overview

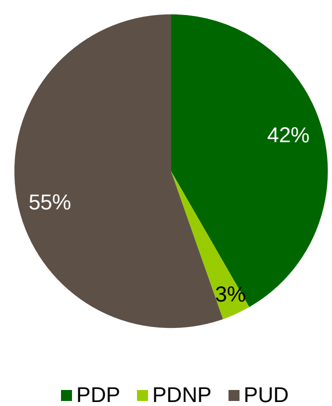
- Key Fields: Anita, Atoka, Dimmitt, Elkhorn, Kingdom Abo and North Square Lake
- Primary Formations: Abo Reef, Cherry Canyon, Clearfork and Palo Pinto
- Field Characteristics:
  - Fields discovered as early as 1920
  - One of the largest structural basins in North America with a surface area of over 75,000 square miles
  - Produced over 42 Billion Boe since initial discoveries
- Estimated Net Proved Reserves: 18.1 MMBoe (1)
  - 92% liquids
  - 45% proved developed
- Production: 2,214 Boe/d (2)
  - R/P of 22 years
- Producing Wells: 426 gross (378 net)
  - 389 operated wells (3)
  - Average working interest: 89%
- Drilling and Recompletion Opportunities: 15 PDNPs and 253 PUDs (1)

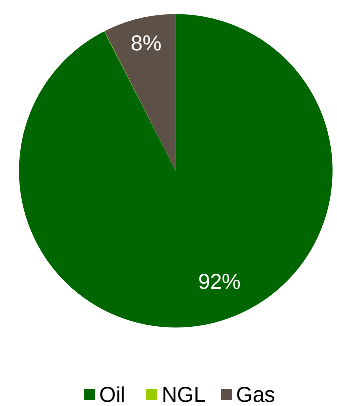
(1) Reflects estimated proved reserves as of December 31, 2013 per NSAI audited report
(2) Average net production is estimated for the three months ended December 31, 2013
(3) Represents wells operated by MEMP and MRD

Asset Location



Permian Basin Proved Reserves Overview





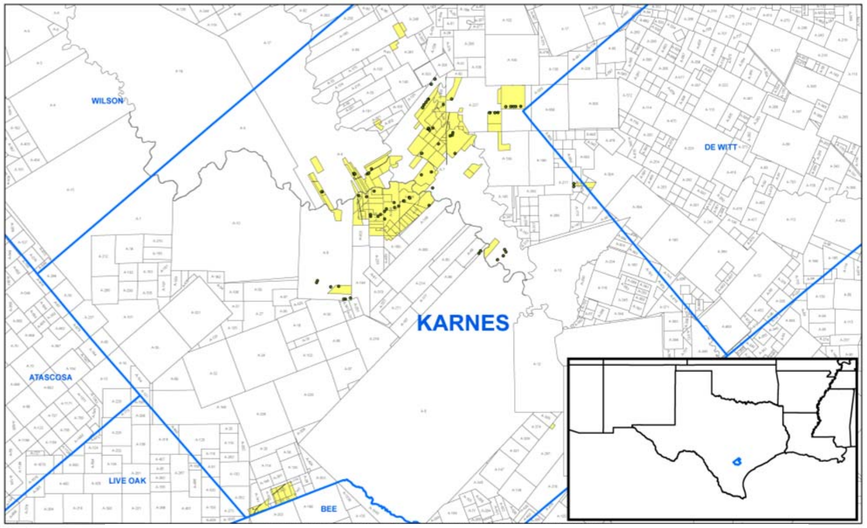
Eagle Ford Asset Summary

Asset Overview

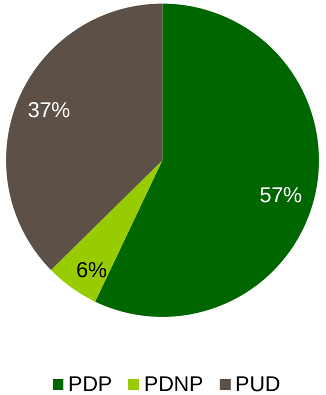
- Acreage position in the core of the Eagle Ford in Karnes County
  – Area recognized as the volatile oil window
- Eagle Ford Shale Trend History and Size:
  – Petrohawk drilled the first of the Eagle Ford wells in 2008
  – Roughly 50 miles wide and 400 miles long with an average thickness of 250 feet
- Estimated Net Proved Reserves: 7.4 MMBoe (1)
  – 92% liquids
  – 63% proved developed
- Production: 1,650 Boe/d (2)
  – R/P of 12 years
- Producing Wells: 117 gross (7.5 net in 2014)
  – 2015: 10.5 net
  – 2016: 12.7 net
  – 2017 and thereafter: 15.0 net
  – Producing wells are 100% non-op with primary operator, Murphy Oil Corporation
- Drilling and Recompletion Opportunities: 20 PDNPs and 168 PUDs
  – MEMP has 30% interest in AMH's net leasehold interest

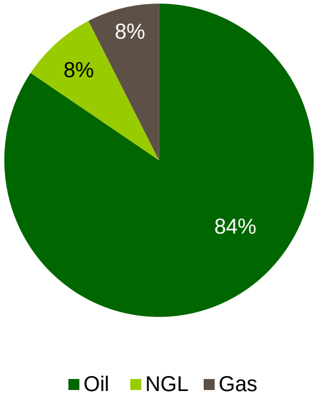
(1) Reflects estimated proved reserves as of December 31, 2013 per MEMP internal estimates
(2) Estimated net production as of November 2013

Asset Location



Eagle Ford Proved Reserves Overview





California Asset Summary

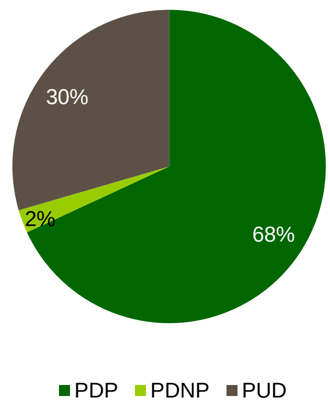
Asset Overview

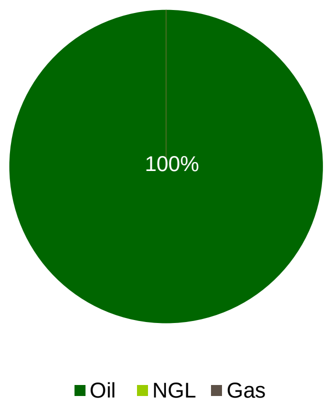
- Located ~11 miles offshore Port of Long Beach, California
  - 2 wellhead platforms each with a permanent drilling rig; 1 processing platform; associated pipelines and onshore facilities
- Field Characteristics:
  - Key field: Beta Field
  - Estimated OOIP of 940 MMBbls with 9% recovered to date (1)
- Estimated Net Proved Reserves: 14.3 MMBbls (2)
  - 100% oil
  - 70% proved developed
- Production: 1,543 Bbls/d (3)
  - R/P of 25 years
- Producing Wells: 54 gross (28 net)
  - 54 operated wells
  - Average working Interest: 52%
- Drilling and Recompletion Opportunities: 4 PDNPs and 23 PUDs (2)
- High operating margins and modest maintenance capex requirements

(1) OOIP estimate as per third-party reservoir consultant; recovery factor based on cumulative production of 88 MMBbls
(2) Reflects estimated proved reserves as of December 31, 2013 per NSAI audited report
(3) Average net production is estimated for the three months ended December 31, 2013

Asset Location

California Proved Reserves Overview





Significant Remaining Original Oil in Place

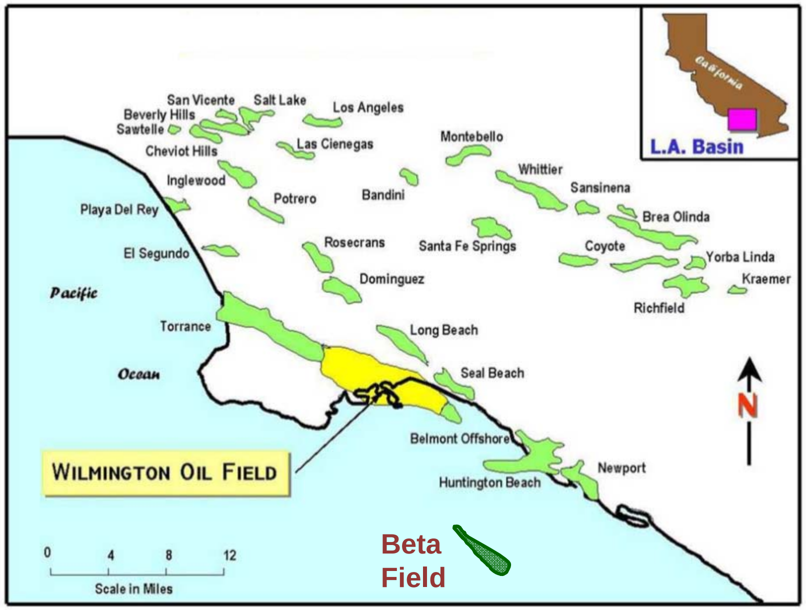
Overview

- An independent third party reservoir consultant prepared an extensive reservoir model that estimates OOIP in the Beta Field
- Cumulative production to date is 88 MMBbls, equating to a 9% current recovery in the Beta Field
- Per NSAI's reserve report, the Beta properties have gross proved reserves of 37.2 MMBbls [2], equating to a 13% total recovery
- Neighboring analog fields currently exhibit recoveries of 30% - 40%; conservative recoveries ranging from 20% - 30% yield additional reserve upside of ~3 - 5x of the NSAI proved reserves

	Original Oil	Recovery @	
(In MMBbls)	In Place	20%	30%
Total Field OIP	940	188	282
Cum. Production to Date		88	88
Remaining		100	194
Upside Factor Assuming 1P Gross Reserve Forecast of 36.1 MMBbls [2]		**2.8x**	**5.4x**

Comparison to an Analogous Field [1]

Category	Wilmington Field	Beta Field
Original Oil in Place	~9 Billion Barrels	~1 Billion Barrels
% Recovered	30% - 40%	~9%
Acre Development	4	40
Water-cut	97%	75%



(1) Estimate based on available data from THUMS; Beta Field located ~11 miles south of Port of Long Beach, California
(2) Reserve forecast grossed up based on 2013 YE NSAI's proved reserve forecast of 14.3 MMBbls and net revenue interest of 39.6%

Memorial Production Partners

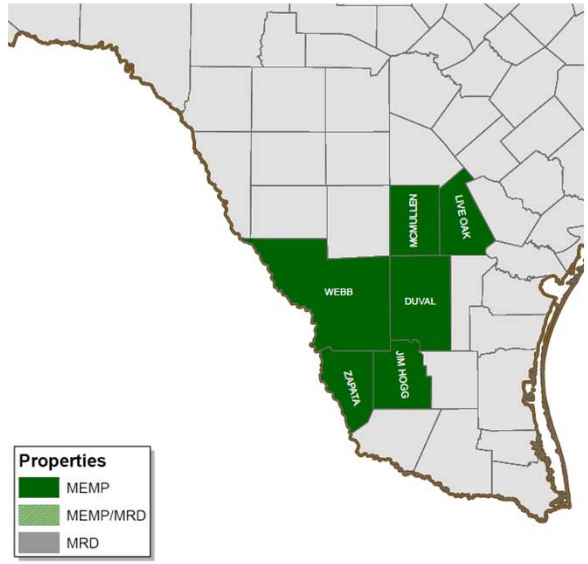
South Texas Asset Summary

Asset Overview

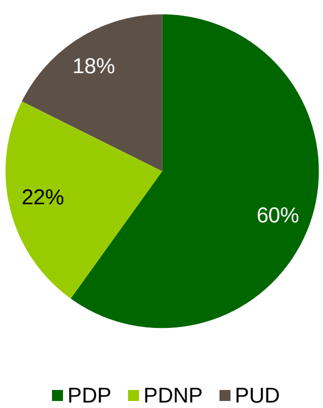
- Key Fields: NE Thompsonville, Laredo and East Seven Sisters
- Primary Formations: Lobo, Wilcox
- Field Characteristics:
  - Fields discovered as early as 1959
  - Production depth ranges between 6,500 – 15,000 feet
  - Produced over 1.5 Tcfe since discoveries
- Estimated Net Proved Reserves: 162 Bcfe (1)
  - 85% gas
  - 82% proved developed
- Production: 23.4 MMcfe/d (2)
  - R/P of 19 years
- Producing Wells: 528 gross (418 net)
  - 502 operated wells (3)
  - Average working interest: 79%
- Drilling and Recompletion Opportunities: 200 PDNPs and 26 PUDs (1)

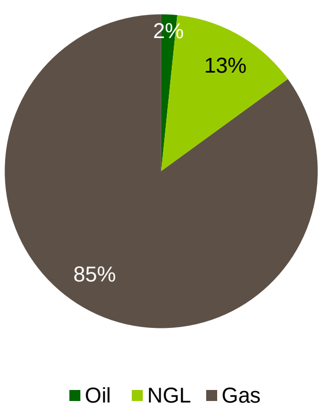
(1) Reflects estimated proved reserves as of December 31, 2013 per NSAI audited report
(2) Average net production is estimated for the three months ended December 31, 2013
(3) Represents wells operated by MEMP and MRD

Asset Location



South Texas Proved Reserves Overview





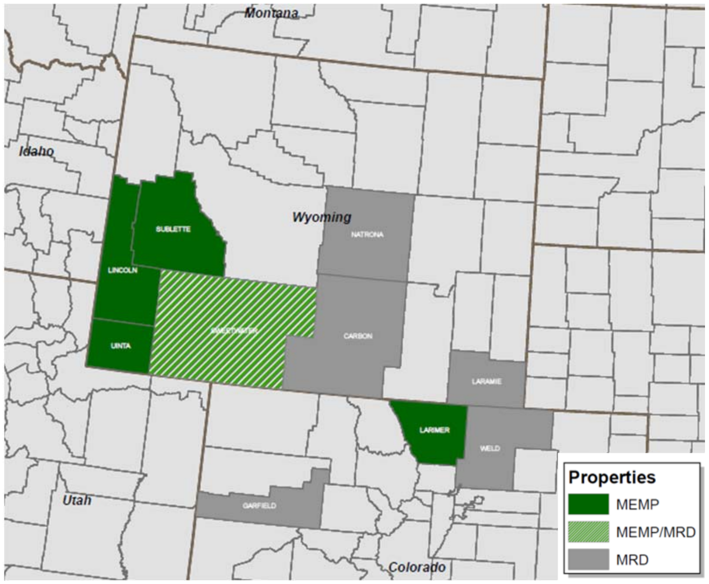
Rockies Asset Summary

Asset Overview

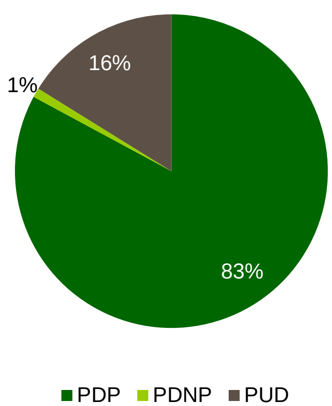
- Key Fields: Fort Collins and Moxa Arch
- Primary Formations: Muddy, Frontier and Dakota
- Field Characteristics:
  - Fort Collins: Muddy Sandstone production with waterflood operations
  - Moxa Arch: Majority of the production from the Frontier and Dakota reservoirs
- Estimated Net Proved Reserves: 61 Bcfe [1]
  - 83% gas
  - 84% proved developed
- Production: 11.5 MMcfe/d [2]
  - R/P of 14 years
- Producing Wells: 609 gross (213 net)
  - 188 operated wells [3]
  - Average working interest: 35%
- Drilling and Recompletion Opportunities: 11 PDNPs and 40 PUDs [1]

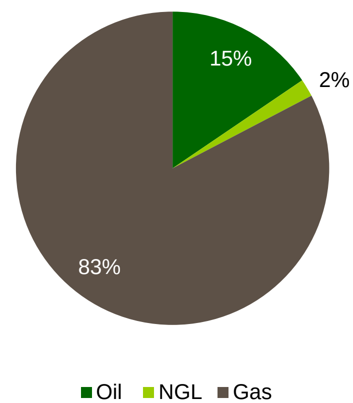
(1) Reflects estimated proved reserves as of December 31, 2013 per NSAI audited report
(2) Average net production is estimated for the three months ended December 31, 2013
(3) Represents wells operated by MEMP and MRD

Asset Location



Rockies Proved Reserves Overview





Financial Strategy – Safety, Growth and Cash Flows

Preserve Financial Flexibility	• Liquidity provided by $845 MM borrowing base (before redetermination) • 4Q 2013 trailing 12-month DCF coverage ratio of 1.03x • Expect to fund acquisitions on a conservative debt / equity basis over the long term
Hedge to Secure Cash Flows	• Target 65-85% of targeted production hedged on a rolling 3-6 year basis • Execute additional hedges with acquisitions to lock-in accretion • 100% hedged to the appropriate basis differential for gas through 2014 and oil basis exposure to Eagle Ford and California to 2014 and 2015, respectively
Re-Investment Strategy	• Ability to fund maintenance requirements from existing cash flow • Conservative capex profile with multiple organic growth opportunities • Capital projects characterized by low-risk development activities • Maintenance capex forecasted at ~26% of mid-point EBITDA guidance

MEMP Hedging Overview: 2014 through 2019

- MEMP's commodity risk management policy provides for hedging approximately 65-85% of estimated production from total proved reserves on a rolling three to six year period
  - Policy reduces MEMP's exposure to movements in commodity prices and provides stability to distributable cash flow
  - All of MEMP's trading counterparties have credit ratings of A- (S&P) or A3 (Moody's) or higher
  - All of MEMP's current hedges are costless, fixed price swaps and collars
- MEMP's targeted average net production estimate represents the production required to reach the lower boundary of the annual production range in the current 2014 full year guidance of 67 Bcfe

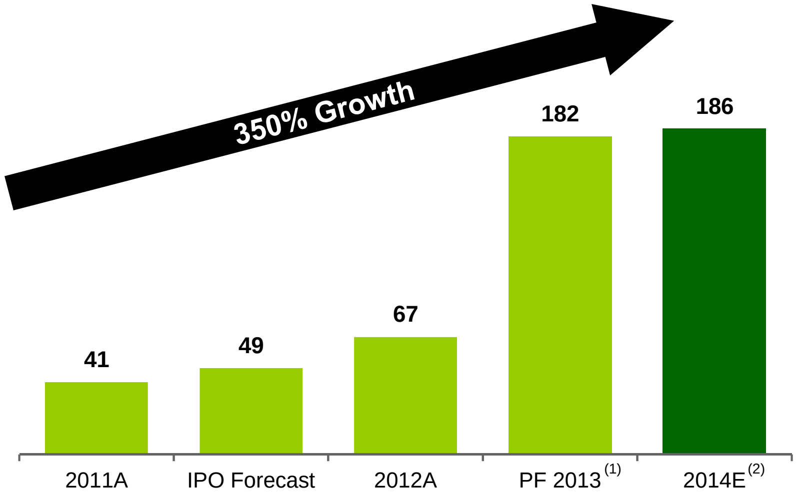
Hedge Summary

	Year Ending December 31,					
	2014	2015	2016	2017	2018	2019
Natural Gas Derivative Contracts:						
Total weighted-average fixed/floor price	$4.41	$4.33	$4.41	$4.31	$4.52	$4.77
Percent of 2014 production hedged	87%	82%	74%	69%	61%	54%
Crude Oil Derivative Contracts:						
Total weighted-average fixed/floor price	$94.24	$91.60	$86.05	$84.74	$84.59	$85.00
Percent of 2014 production hedged	90%	97%	88%	81%	74%	20%
Natural Gas Liquids Derivative Contracts:						
Total weighted-average fixed/floor price	$36.39	$35.04	–	–	–	–
Percent of 2014 production hedged	78%	68%	–	–	–	–
Total Derivative Contracts:						
Total weighted-average fixed/floor price	$7.29	$7.37	$7.42	$7.28	$7.46	$5.87
Percent of 2014 production hedged	86%	83%	64%	59%	53%	37%

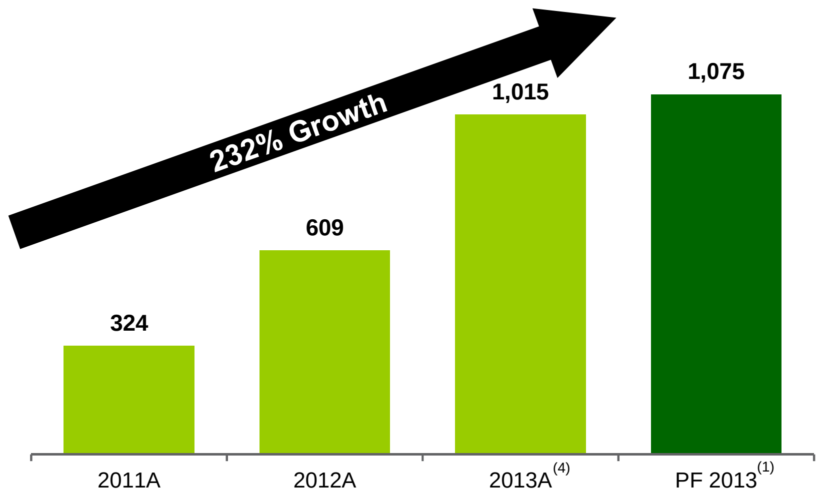
Memorial Production Partners

Steady Growth Since IPO

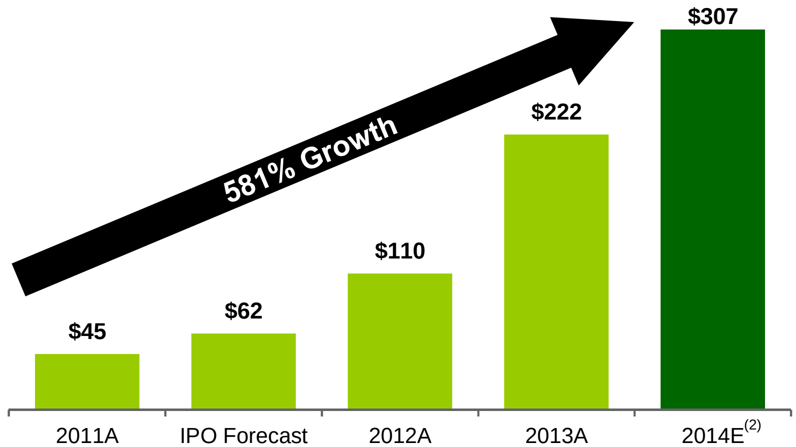
Daily Production (MMcfe/d)



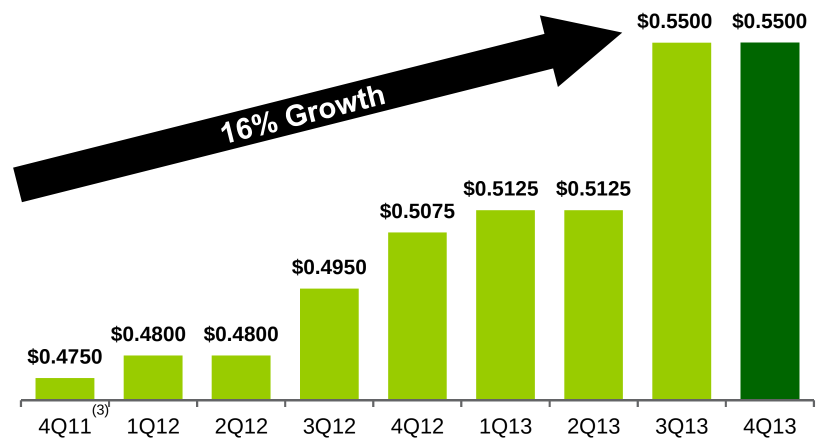
Reserves (Bcfe)



Adjusted EBITDA ($ millions)



Quarterly Distribution per LP Unit ($ / Unit)

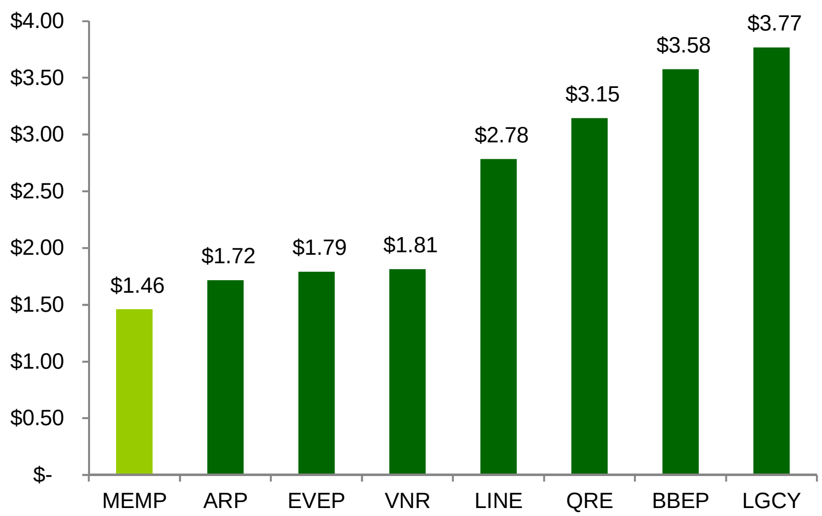


(1) Reflects estimated operating information and proved reserves as of December 31, 2013; Pro forma for the recently completed East Texas and Eagle Ford acquisitions per MEMP internal estimates
(2) As per MEMP guidance issued on March 25, 2014
(3) Reflects annualized distribution of $0.0929 / unit which is the prorated distribution from IPO closing to December 31, 2011
(4) For the period ended December 31, 2013 per MEMP's 2013 Form 10-K

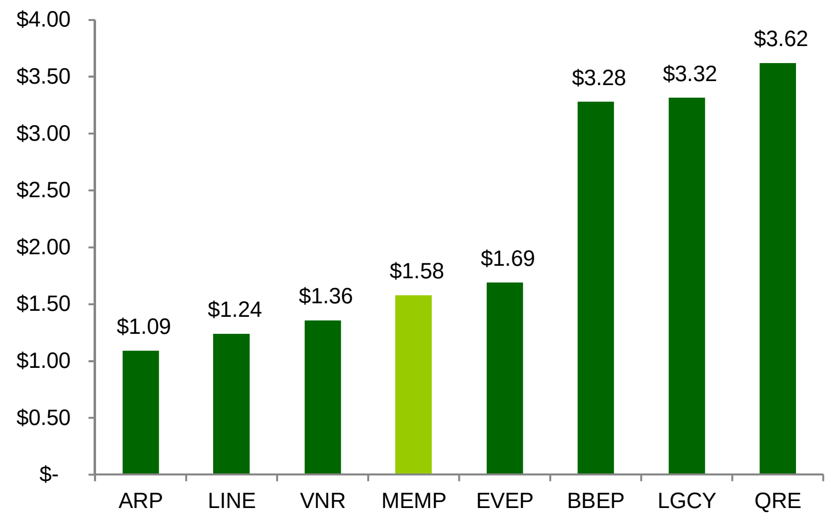
Memorial Production Partners

Industry Leading Cost Structure

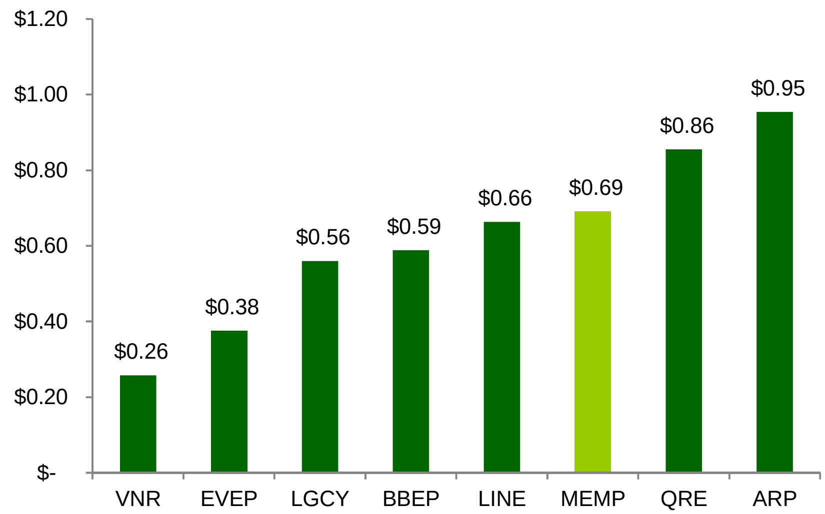
F&D / Mcfe



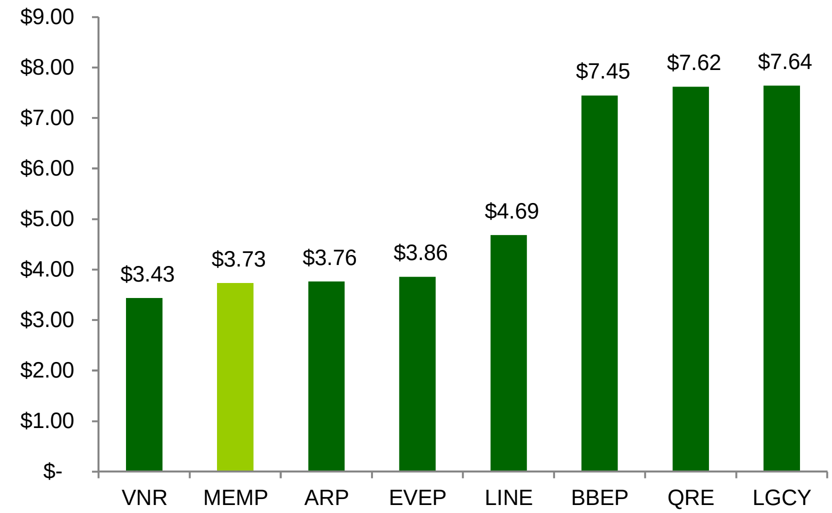
LOE / Mcfe (1)



G&A / Mcfe



Total Cost / Mcfe



Source: Public filings
Note: Peers' F&D cost data as of FY 2013, MEMP F&D cost calculated as PDNP & PUD capex divided by PDNP and PUD reserves per Netherland, Sewell & Associates, Inc. audited report; LOE and G&A costs as of FY 2013 public filings
(1) LOE includes production and ad valorem taxes

Memorial Production Partners

Full Year 2014 Guidance

Full Year 2014 Guidance		
	Low For Year Ending December 31, 2014	**High For Year Ending December 31, 2014**
Annual Production (Bcfe)	67	69
Adjusted EBITDA ($MM)	$303	$311
Distributable Cash Flow ($MM)	$158	$166
DCF Coverage	1.15x	1.25x
Maintenance Capex ($MM)	$81	$81
Growth Capex ($MM)	$50	$80

Note: As per MEMP guidance issued on March 25, 2014

Safety, Growth and Returns

- High quality assets ☑
- MLP appropriate asset profile ☑
- Strong sponsorship with aligned interests ☑
- Supportable and clear growth strategy ☑
- Seasoned management team ☑
- Cash flow visibility and security ☑
- Attractive yield ☑

Memorial Production Partners

Appendix

Cash Margin Per Mcfe

	Three Months Ended 12/31/2013
Net production volumes	
Oil (MBbls)	457
NGLs (MBbls)	485
Natural gas (MMcf)	9,787
Total (MMcfe)	**15,428**
Average net production (MMcfe/d)	*167.7*
Average sales prices before hedges	
Oil (per Bbl)	$95.60
NGLs (per Bbl)	33.10
Natural gas (per Mcf)	3.24
Average sales prices per Mcfe before hedges	**$5.92**
Average sales prices per Mcfe after hedges	**$6.30**
Average cash unit costs per Mcfe:	
Lease operating expenses	$1.55
Production and ad valorem taxes	0.19
General and administrative expenses (excl. non-cash based comp)	0.57
Cash margin before hedges ($/Mcfe) (1)	**$3.61**
% Margin	*61%*
Cash margin after hedges ($/Mcfe) (1)	**$3.99**
% Margin	*63%*

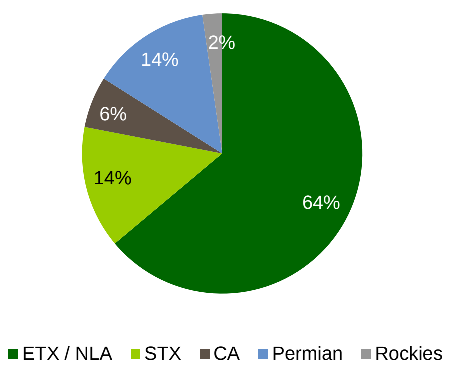
(1) Average sales price less lease operating expenses, production and ad valorem taxes and general and administrative expenses

Low Development Costs Maximize Margins

Identified Production Replacement

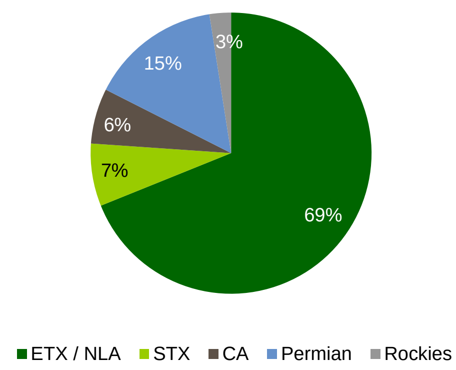
PDNP + PUDs

459.7 Bcfe Total

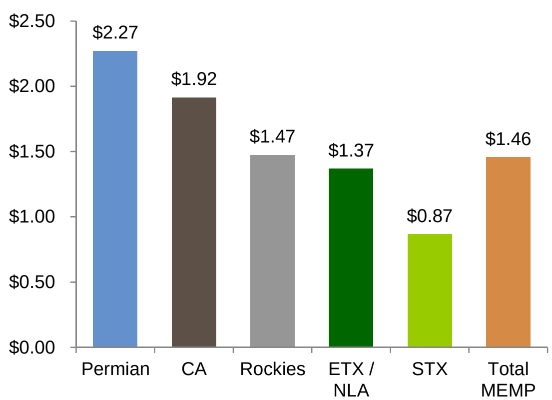


PUDs Only

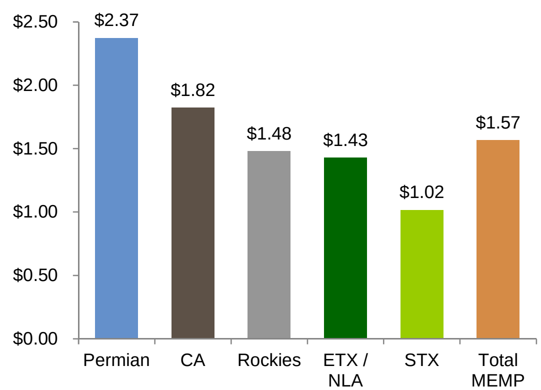
398.2 Bcfe Total



Estimated F&D Costs by Region: PDNP + PUDs (1)



Estimated F&D Costs by Region: PUDs Only (2)



Project Types

- Control and reduce costs through low-risk drilling, recompletions and operational enhancements
- Field exploitation
  - Infill drilling
  - Optimize production
    - Artificial lift methods
    - Gathering system enhancements
    - Recomplete bypassed pay
  - Well reactivations
- Repeatable lifting cost reductions
  - Intense focus on cost analysis
  - Maximize economies of scale
    - Supplies
    - Services
  - Aggregate utility contracts

Note: Does not PF for any acquisition after YE 2013

(1) F&D costs calculated as PDNP & PUD capex divided by PDNP and PUD reserves per NSAI audited reserve reports

(2) F&D costs calculated as PUD capex divided by PUD reserves per NSAI audited reserve reports

Memorial Production Partners

Natural Gas and NGL Hedges: 2014 through 2019

Natural Gas / NGLs Hedge Summary						
	Year Ending December 31,					
	2014	2015	2016	2017	2018	2019
Natural Gas Derivative Contracts:						
Swap contracts:						
Volume (MMBtu)	32,345,500	29,823,340	29,909,300	27,600,800	24,720,000	21,775,000
Volume (MMBtu/d)	88,618	81,708	81,719	75,619	67,726	59,658
Weighted-average fixed price	$4.37	$4.31	$4.41	$4.31	$4.52	$4.77
Collar contracts:						
Volume (MMBtu)	2,640,000	3,240,000	–	–	–	–
Volume (MMBtu/d)	7,233	8,877	–	–	–	–
Weighted-average floor price	$4.84	$4.44	–	–	–	–
Weighted-average ceiling price	$6.02	$5.52	–	–	–	–
Put options:						
Volume (MMBtu)	–	–	–	–	–	–
Volume (MMBtu/d)	–	–	–	–	–	–
Weighted-average floor price	–	–	–	–	–	–
Total Natural Gas Derivative Contracts:						
Total natural gas volumes hedged (MMBtu)	34,985,500	33,063,340	29,909,300	27,600,800	24,720,000	21,775,000
Total natural gas volumes hedged (MMBtu/d)	95,851	90,584	81,719	75,619	67,726	59,658
Total weighted-average fixed/floor price	$4.41	$4.33	$4.41	$4.31	$4.52	$4.77
Percent of target production hedged	87%	82%	74%	69%	61%	54%
Natural Gas Liquids Derivative Contracts:						
Swap contracts:						
Volume (Bbl)	1,567,000	1,353,600	–	–	–	–
Volume (Bbl/d)	4,293	3,708	–	–	–	–
Weighted-average fixed price	$36.39	$35.04	–	–	–	–
Collar contracts:						
Volume (Bbl)	–	–	–	–	–	–
Volume (Bbl/d)	–	–	–	–	–	–
Weighted-average floor price	–	–	–	–	–	–
Weighted-average ceiling price	–	–	–	–	–	–
Total Natural Gas Liquids Derivative Contracts:						
Total natural gas liquids volumes hedged (Bbl)	1,567,000	1,353,600	–	–	–	–
Total NGL volumes hedged (Bbl/d)	4,293	3,708	–	–	–	–
Total weighted-average fixed/floor price	$36.39	$35.04	–	–	–	–
Percent of target production hedged	78%	68%	–	–	–	–

Oil Hedges: 2014 through 2019

Oil Hedge Summary						
	Year Ending December 31,					
	2014	2015	2016	2017	2018	2019
NYMEX Oil Derivative Contracts:						
Swap contracts:						
Volume (Bbl)	1,255,824	1,641,372	1,503,756	1,375,200	1,224,000	180,000
Volume (Bbl/d)	3,441	4,497	4,109	3,768	3,353	493
Weighted-average fixed price	$92.60	$89.04	$82.65	$81.64	$81.16	$80.00
Collar contracts:						
Volume (Bbl)	276,000	60,000	–	–	–	–
Volume (Bbl/d)	756	164	–	–	–	–
Weighted-average floor price	$82.83	$80.00	–	–	–	–
Weighted-average ceiling price	$105.31	$94.00	–	–	–	–
Brent Oil Derivative Contracts:						
Swap contracts:						
Volume (Bbl)	687,500	690,000	660,000	624,000	600,000	300,000
Volume (Bbl/d)	1,884	1,890	1,803	1,710	1,644	822
Weighted-average fixed price	$101.81	$98.69	$93.79	$91.57	$91.60	$88.00
Collar contracts:						
Volume (Bbl)	–	–	–	–	–	–
Volume (Bbl/d)	–	–	–	–	–	–
Weighted-average floor price	–	–	–	–	–	–
Weighted-average ceiling price	–	–	–	–	–	–
Total Crude Oil Derivative Contracts:						
Total Crude Oil Derivative Contracts:						
Total crude oil volumes hedged (Bbl)	2,219,324	2,391,372	2,163,756	1,999,200	1,824,000	480,000
Total crude oil volumes hedged (Bbl/d)	6,080	6,552	5,912	5,477	4,997	1,315
Total weighted-average fixed/floor price	$94.24	$91.60	$86.05	$84.74	$84.59	$85.00
Percent of target production hedged	90%	97%	88%	81%	74%	20%

Natural Gas & Oil Basis Hedges: 2014 through 2019

Basis Hedge for Natural Gas						
	Year Ending December 31,					
	2014	2015	2016	2017	2018	2019
NGPL Tex/Ok Gas Differential						
Total natural gas volumes hedged (MMBtu)	27,025,000	–	–	–	–	–
Total natural gas volumes hedged (MMBtu/d)	74,041	–	–	–	–	–
Total weighted-average fixed/floor price	($0.09)	–	–	–	–	–
NGPL STX Gas Differential						
Total natural gas volumes hedged (MMBtu)	4,560,000	–	–	–	–	–
Total natural gas volumes hedged (MMBtu/d)	12,493	–	–	–	–	–
Total weighted-average fixed/floor price	($0.11)	–	–	–	–	–
HSC Gas Differential						
Total natural gas volumes hedged (MMBtu)	2,280,000	–	–	–	–	–
Total natural gas volumes hedged (MMBtu/d)	6,247	–	–	–	–	–
Total weighted-average fixed/floor price	($0.07)	–	–	–	–	–
Total Gas Differential						
Total natural gas volumes hedged (MMBtu)	33,865,000	–	–	–	–	–
Total natural gas volumes hedged (MMBtu/d)	92,781	–	–	–	–	–
Total weighted-average fixed/floor price	($0.09)	–	–	–	–	–

Basis Hedge for Crude Oil						
	Year Ending December 31,					
	2014	2015	2016	2017	2018	2019
Midway-Sunset Differential						
Total crude oil volumes hedged (Bbl)	687,500	690,000	–	–	–	–
Total crude oil volumes hedged (Bbl/d)	1,884	1,890	–	–	–	–
Total weighted-average fixed/floor price	($9.21)	($9.73)	–	–	–	–
Louisiana Light Sweet (LLS) Differential						
Total crude oil volumes hedged (Bbl)	306,000	–	–	–	–	–
Total crude oil volumes hedged (Bbl/d)	838	–	–	–	–	–
Total weighted-average fixed/floor price	$3.61	–	–	–	–	–
Total Crude Differential						
Total crude oil volumes hedged (Bbl)	993,500	690,000	–	–	–	–
Total crude oil volumes hedged (Bbl/d)	2,722	1,890	–	–	–	–
Total weighted-average fixed/floor price	($5.26)	($9.73)	–	–	–	–

- Gas is 100% hedged to basis in 2014, 91% through NYMEX to basis trades and 9% direct to basis
- Oil basis to Midway-Sunset and Louisiana Light Sweet (LLS) at this time

2014 Adjusted EBITDA & Distributable Cash Flow Guidance Reconciliation

(In millions)	Low For Year Ended December 31, 2014	High For Year Ended December 31, 2014
Calculation of Adjusted EBITDA:		
Net income	$ 134	$ 142
Interest expense	64	64
Depletion, depreciation and amortization	105	105
Adjusted EBITDA	**$ 303**	**$ 311**
Reconciliation of Net Cash From Operating Activities to Adjusted EBITDA:		
Net cash provided by operating activities	$ 239	$ 247
Changes in working capital	-	-
Interest expense	64	64
Adjusted EBITDA	**$ 303**	**$ 311**
Reconciliation of Adjusted EBITDA to Distributable Cash Flow:		
Adjusted EBITDA	$ 303	$ 311
Cash interest expense	(64)	(64)
Estimated maintenance capital expenditures	(81)	(81)
Distributable Cash Flow	**$ 158**	**$ 166**

Note: As per MEMP guidance issued on March 25, 2014

Memorial Production Partners

Adjusted EBITDA Reconciliation

(In thousands)	Historical For the Year Ended December 31, 2012	2013
Calculation of Adjusted EBITDA:		
Net income [1]	**$ 46,518**	**$ 20,268**
Interest expense, net	20,436	41,901
Income tax expense	285	308
Depletion, depreciation and amortization	76,036	97,269
Impairment	10,532	54,362
Accretion of AROs	4,377	4,853
(Gain) loss on commodity derivative instruments	(21,417)	(26,281)
Cash settlements on commodity derivative instruments	44,111	19,879
Acquisition related costs	4,135	6,729
Unit-based compensation expense	1,423	3,558
Non-cash compensation expense	-	1,057
Gain on sale of properties	(9,759)	(2,848)
Exploration costs	2,463	1,130
Amortization of investment premium	194	-
Adjusted EBITDA	**$ 179,334**	**$ 222,185**
Reconciliation of Net Cash From Operating Activities to Adjusted EBITDA:		
Net cash provided by operating activities	**$ 156,844**	**$ 193,697**
Changes in working capital	(178)	(16,644)
Interest expense	20,436	41,901
Premiums paid for derivatives	411	-
Premiums received for derivatives	-	-
Gain (loss) on interest rate derivative instruments	(4,839)	548
Cash settlements on interest rate derivative instruments	1,804	960
Acquisition related costs	4,135	6,729
Amortization of premium / (discount)	-	(504)
Amortization of deferred financing fees	(1,991)	(5,845)
Income tax expense - current portion	285	308
Exploration costs	2,427	1,035
Adjusted EBITDA	**$ 179,334**	**$ 222,185**

(1) Reflects 2013 acquisitions accounted for as transactions between entities under common control as described in MEMP's 2013 Form 10-K; For additional information regarding the reconciliations, please read MEMP's 2013 Form 10-K and 2012 Form 10-K

Distributable Cash Flow Reconciliation

(In thousands)	Historical For the Year Ended December 31, 2012	 2013
Calculation of Distributable Cash Flow:		
Net income [(1)]	**$ 46,518**	**$ 20,268**
Interest expense, net	20,436	41,901
Income tax expense	285	308
Depletion, depreciation and amortization	76,036	97,269
Impairment	10,532	54,362
Accretion of AROs	4,377	4,853
(Gain) loss on commodity derivative instruments	(21,417)	(26,281)
Cash settlements on commodity derivative instruments	44,111	19,879
Acquisition related costs	4,135	6,729
Unit-based compensation expense	1,423	3,558
Non-cash compensation expense	-	1,057
Gain on sale of properties	(9,759)	(2,848)
Exploration costs	2,463	1,130
Amortization of investment premium	194	-
Adjusted EBITDA	**$ 179,334**	**$ 222,185**
Less: Cash interest expense	6,348	34,744
Less: Estimated maintenance capital expenditures	14,749	43,151
Less: Adjusted EBITDA prior to effective date of common control transactions	99,275	27,396
Total Distributable Cash Flow	**$ 58,962**	**$ 116,894**
Less: Distribution to GP	50	193
Distributable Cash Flow Available to Limited Partners	**$ 58,912**	**$ 116,701**
Cash Distribution to Limited Partners	**$ 49,802**	**$ 112,783**
Distribution Coverage Ratio	**1.18x**	**1.03x**

(1) Reflects 2013 acquisitions accounted for as transactions between entities under common control as described in MEMP's 2013 Form 10-K; For additional information regarding the reconciliations, please read MEMP's 2013 Form 10-K and 2012 Form 10-K

Memorial Production Partners

Non-GAAP Measures

Use of Non-GAAP Financial Measures. This presentation includes the non-GAAP financial measures of Adjusted EBITDA and Distributable Cash Flow. The accompanying schedules provide a reconciliation of these non-GAAP financial measures to their most directly comparable financial measure calculated and presented in accordance with GAAP. MEMP's non-GAAP financial measures should not be considered as alternatives to GAAP measures such as net income, operating income, net cash flows provided by operating activities or any other measure of financial performance calculated and presented in accordance with GAAP. MEMP's non-GAAP financial measures may not be comparable to similarly-titled measures of other companies because they may not calculate such measures in the same manner as MEMP does.

Adjusted EBITDA. MEMP defines Adjusted EBITDA as net income or loss, plus interest expense, including realized and unrealized losses on interest rate derivative contracts; income tax expense; depreciation, depletion and amortization; impairment of goodwill and long-lived assets; accretion of asset retirement obligations; unrealized losses and cash settlements received on commodity derivative contracts; losses on sale of assets; unit-based compensation expenses; exploration costs; acquisition related costs; amortization of investment premium; and other non-routine items, less interest income; income tax benefit; unrealized gains and cash settlements paid on commodity derivative contracts; gains on sale of assets and other non-routine items. Adjusted EBITDA is commonly used as a supplemental financial measure by management and external users of MEMP's financial statements, such as investors, research analysts and rating agencies, to assess: (1) the financial performance of its assets without regard to financing methods, capital structures or historical cost basis; (2) the ability of its assets to generate cash sufficient to pay interest, support MEMP's indebtedness and make distributions on its units; and (3) the viability of projects and the overall rates of return on alternative investment opportunities. Since Adjusted EBITDA excludes some, but not all, items that affect net income or loss and because these measures may vary among other companies, the Adjusted EBITDA data presented in this presentation may not be comparable to similarly titled measures of other companies. The GAAP measure most directly comparable to Adjusted EBITDA is net cash flows provided by operating activities.

Distributable Cash Flow. MEMP defines distributable cash flow as Adjusted EBITDA, less cash income taxes; cash interest expense; and estimated maintenance capital expenditures. Management compares the distributable cash flow MEMP generates to the cash distributions it expects to pay MEMP's partners. Using this metric, management computes MEMP's distribution coverage ratio. Distributable cash flow is an important non-GAAP financial measure for MEMP's limited partners since it serves as an indicator of MEMP's success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not MEMP is generating cash flows at a level that can sustain or support an increase in its quarterly cash distributions. Distributable cash flow is also a quantitative standard used by the investment community with respect to publicly traded partnerships because the value of a partnership unit is, in part, measured by its yield, which is based on the amount of cash distributions a partnership can pay to a unitholder. The GAAP measure most directly comparable to distributable cash flow is net cash flows provided by operating activities.

Memorial

Production Partners