Second Quarter 2017 Update

August 7, 2017 Earnings Call

Forward-Looking Statements

Under the Private Securities Litigation Act of 1995

This document may contain or incorporate by reference forward-looking statements as defined under the federal securities laws regarding DCP Midstream, LP (the "Partnership" or "DCP"), including projections, estimates, forecasts, plans and objectives. Although management believes that expectations reflected in such forward-looking statements are reasonable, no assurance can be given that such expectations will prove to be correct. In addition, these statements are subject to certain risks, uncertainties and other assumptions that are difficult to predict and may be beyond our control. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, the Partnership's actual results may vary materially from what management anticipated, estimated, projected or expected.

The key risk factors that may have a direct bearing on the Partnership's results of operations and financial condition are highlighted in the earnings release to which this presentation relates and are described in detail in the Partnership's periodic reports most recently filed with the Securities and Exchange Commission, including its most recent Form 10-Q and 10-K. Investors are encouraged to consider closely the disclosures and risk factors contained in the Partnership's annual and quarterly reports filed from time to time with the Securities and Exchange Commission. The Partnership undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. Information contained in this document speaks only as of the date hereof, is unaudited, and is subject to change.

Regulation G

This document includes certain non-GAAP financial measures as defined under SEC Regulation G, such as distributable cash flow, adjusted EBITDA, adjusted segment EBITDA, gross margin, segment gross margin forecasted distributable cash flow and forecasted adjusted EBITDA. A reconciliation of these measures to the most directly comparable GAAP measures is included in the Appendix to this presentation.

Q2 2017 Highlights

2017 Results

- Reaffirming guidance… tightening Adjusted EBITDA and DCF range based on commodity outlook
- Lower Q2 in line with our expectations
- DCF of $119 million Q2 and $280 million YTD 2017
- Distribution coverage of 0.89x Q2 and 1.04x YTD 2017 with IDR giveback
- Adjusted EBITDA $216 million Q2 and $461 million YTD 2017

Reaffirming guidance…. on track to meet 2017 targets

2017 Execution

- Strong July 2017 performance setting the pace for 2H
  - Growing G&P and NGL volumes in key areas
- DJ Basin O'Connor bypass in service adding up to 40 MMcf/d
- Closed high multiple Douglas sale for $129 million; proceeds redeployed to lower multiple growth projects
- No equity needs in 2017
  - $251 million cash on hand

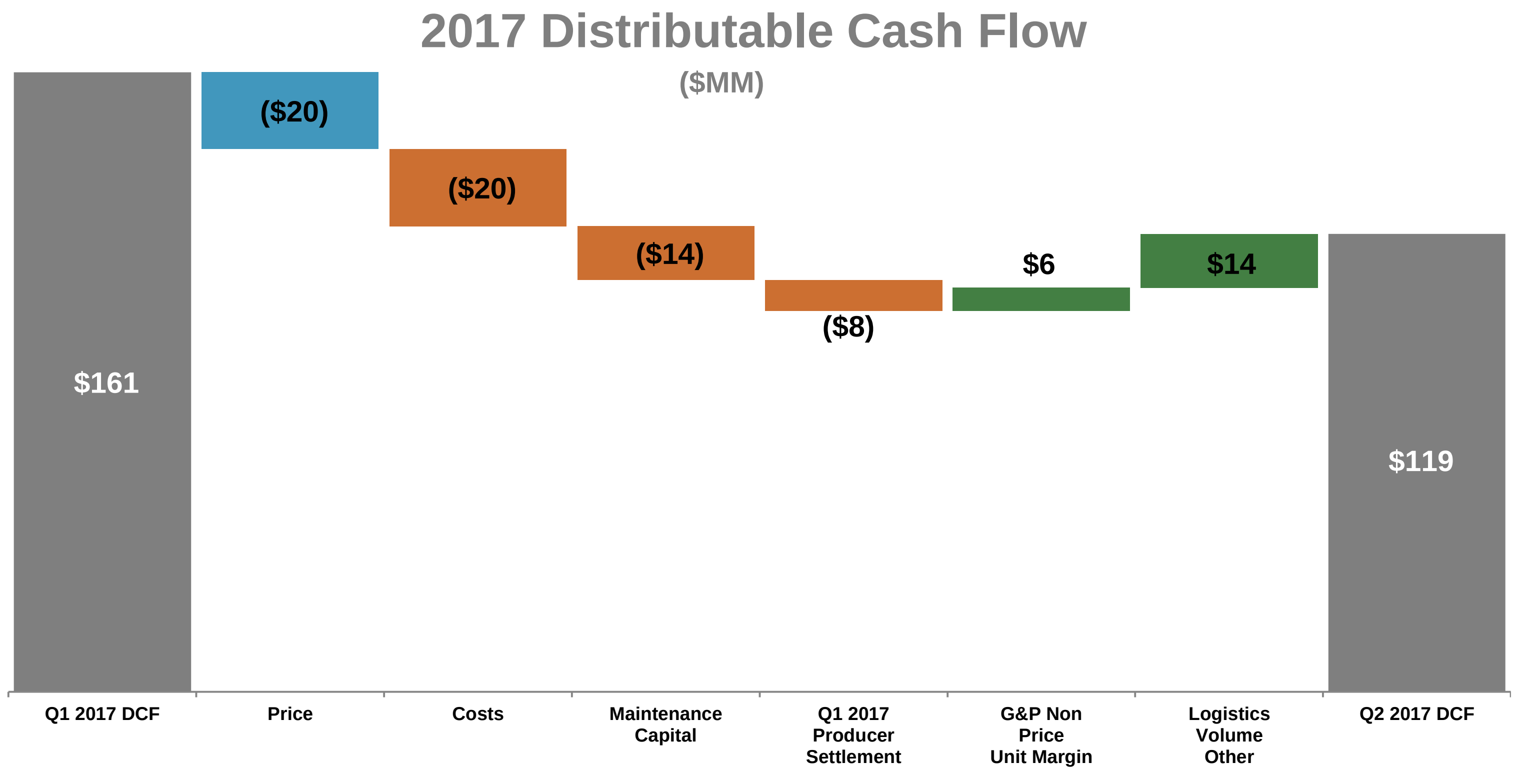
Strong July performance and volumes pointing to improved 2H 2017

Strategic and Disciplined Capital Allocation

- Permian growth
  - Executing 2017-2018 Sand Hills expansions, increasing capacity 60+% to 450 MBpd
  - Advancing Gulf Coast Express natural gas pipeline JV with KMI
- DJ Basin processing capacity increasing 50+% by 2019
  - Approved eleventh plant 200 MMcf/d O'Connor 2
  - 200 MMcf/d Mewbourn 3 plant under construction

Disciplined strategic growth supporting financial targets

Q1 2017 to Q2 2017 DCF Rollforward



Q1 2017 vs Q2 2017 Key Variance Drivers

- (-) Lower commodity prices Q1 vs Q2 2017
- (-) Higher costs and maintenance capital for reliability and planned maintenance, investment in technology and automation and timing
- (-) Q1 2017 producer settlement
- (+) Higher G&P unit margins/mcf in the North, Permian and Midcontinent regions
- (+) Higher distributions received from NGL pipelines

Q2 in line with internal expectations … reaffirming full year guidance

IDR Giveback and Distribution Coverage

Incentive Distribution Right (IDR) giveback provides three year hedge against lower commodity prices and dampened industry environment

Forward thinking IDR structure drives strong GP/LP alignment with unitholders

GP provides up to $100 million IDR giveback annually through 2019, if needed

($MM)	Q1 2017	Q2 2017	YTD 2017
DCF	$ 161	$ 119	$ 280
Quarterly GP and LP distribution declared	$ 155	$ 154	$ 309
IDR giveback declared	$ (20)	$ (20)	$ (40)
Distributions net of IDR giveback	$ 135	$ 134	$ 269
Distribution coverage ratio	**1.19x**	**0.89x**	**1.04x**

IDR giveback providing protection against downside risk

- Up to $100 million annually of IDR givebacks for three years (2017-2019)
- IDR giveback targets ~1.0 times annual distribution coverage ratio
- Distribution giveback defaults to $20 million reduction each quarter… trued up annually to target ~1.0x distribution coverage
    - $20 million held back in both Q1 and Q2 2017

IDR giveback hedges impact of lower commodity prices

2H 2017 Outlook

Reaffirming 2017 guidance… tightening ranges to reflect commodity outlook

Key Metrics	2017 DCP Guidance	Updates
2017 Adjusted EBITDA[1]	$940-1,110	Between low & midpoint
Distributable Cash Flow (DCF)	$545-670	Between low & midpoint
Distribution Coverage Ratio (TTM)[2]	≥1.0x	No change
Maintenance Capital	$100-145	Low end
Growth Capital	$325-375	High end

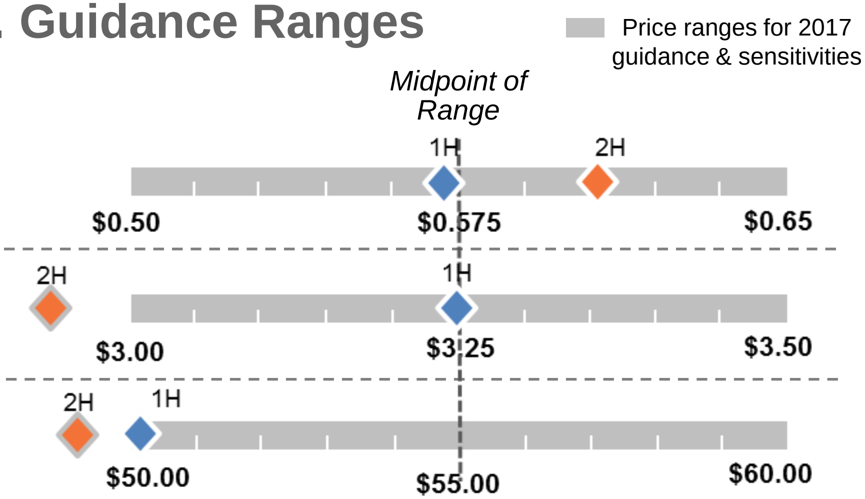
(1) 2017 Adjusted EBITDA includes distributions from unconsolidated affiliates, consistent with bank definition. See Non GAAP reconciliation in the appendix section
(2) Includes IDR giveback, if needed, to target ~1.0x distribution coverage ratio
(3) Volumes do not assume ethane recovery

2H 2017 Guidance Outlook

- ⬆ Higher G&P volumes across key regions
- ⬆ Higher Sand Hills volumes[3]
- ⬆ Lower costs
- ⬇ Lower natural gas and crude outlook
- ⬇ Lower earnings and distributions from Discovery equity investment
- Higher maintenance capital (DCF)

Commodity Outlook vs. Guidance Ranges

	1H 2017	2H 2017*	2017e*
NGL ($/gal)	$0.57	$0.61	**$0.59**
Natural Gas ($/MMBtu)	$3.25	$2.94	**$3.10**
Crude Oil ($/Bbl)	$50.10	$49.33	**$49.71**



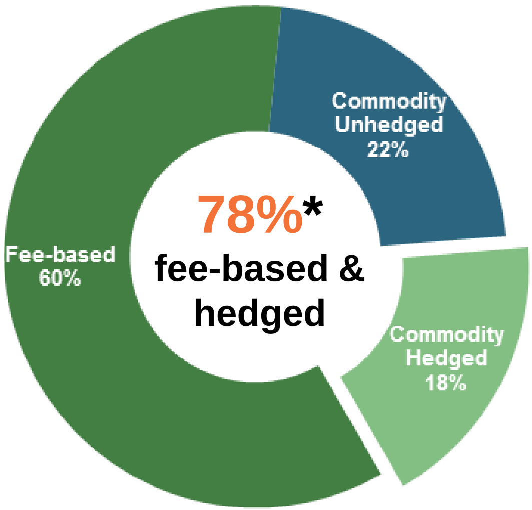
* Assumes August 1, 2017 commodity strip

Strong July performance setting pace for improved 2H 2017

Hedging, Financing and Liquidity

Opportunistically Adding Hedges

2H 2017e Gross Margin



Fee includes NGL, propane and gas marketing which depend on price spreads rather than nominal price level

** As of July 31, 2017*

- Layered on additional natural gas, propane and butane hedges since Q1 2017
- Fee-based margin growth coupled with multi-year hedging program provides downside protection on commodity exposed margin

Ample Liquidity & Flexibility

- ***4.5x Leverage ratio***[(1)] as of June 30, 2017
  - Maximum 2017 bank leverage covenant is 5.75x
- ***Ample Liquidity*** as of June 30, 2017
  - ~$1.4B available on credit facility
  - $251 million cash on hand
    - $129 million proceeds from high multiple divestiture of non-core Douglas gathering being redeployed into low multiple, lower risk, accretive fee-based projects
- ***Flexible financing options… no 2017 equity needs***
  - $500 million December bond maturity options
    - Repay utilizing credit facility and/or cash on hand
    - Refinance all, or a portion of this maturity
  - Targeting ~50/50 debt/equity capital structure

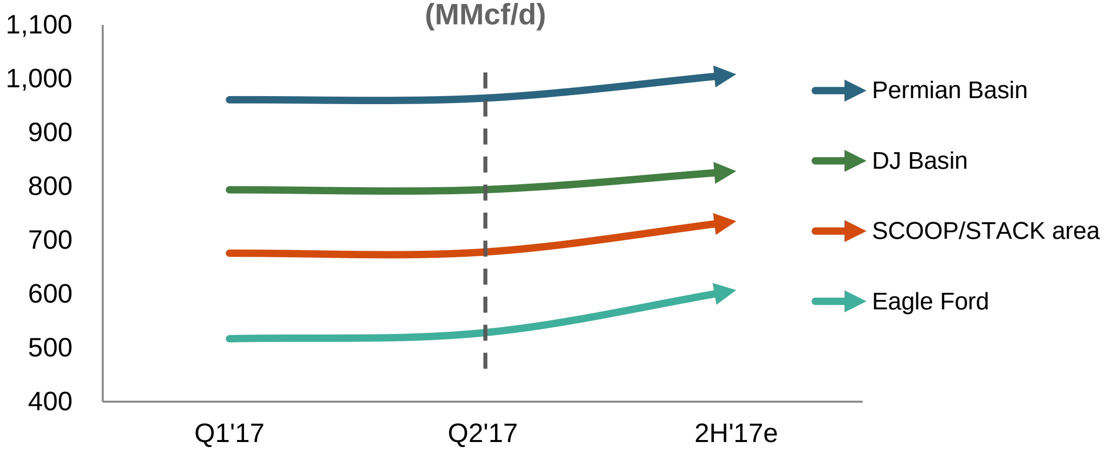
(1) Bank leverage ratio calculation = Adjusted EBITDA, plus certain project EBITDA credits from projects under construction, divided by bank debt (excludes $550 million 2043 Junior Subordinated debt) less cash

Ample liquidity and financial flexibility… no equity needs in 2017

Volume Outlook

G&P 2H 2017 Volume Outlook in Key Basins

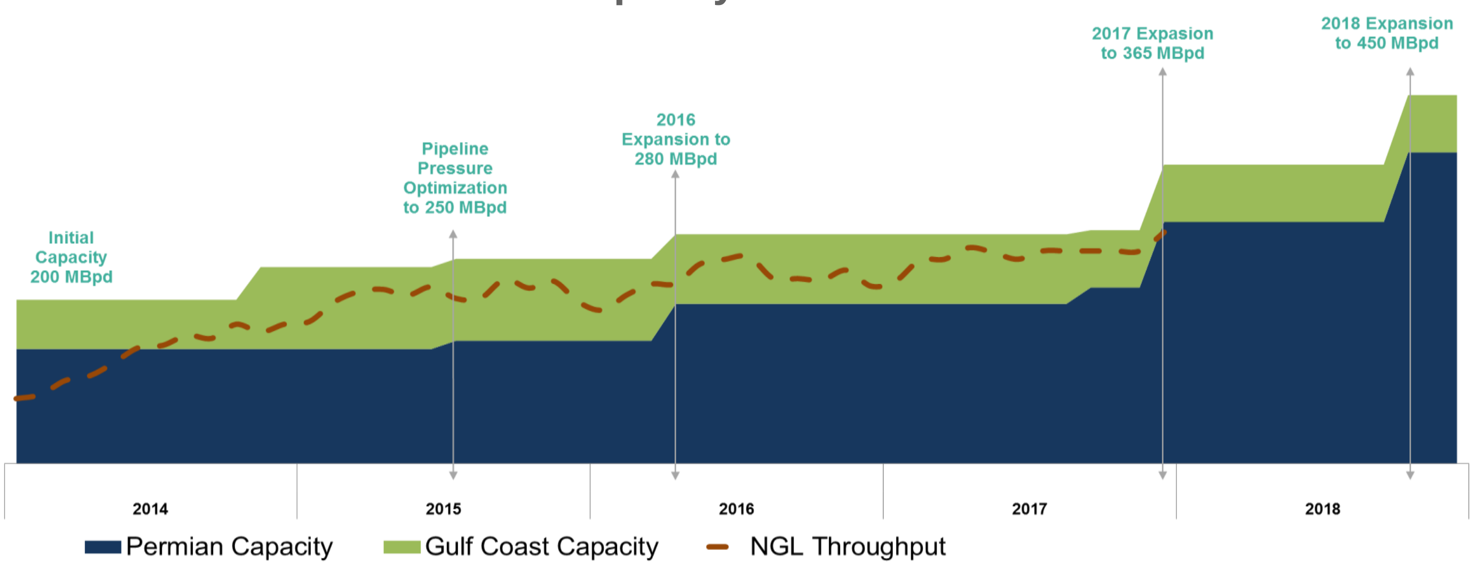
(MMcf/d)



G&P volumes have stabilized… *increased rig count resulting in strong July volumes in key areas*

- **Permian** drilling translating to higher volumes in 2H 2017
- **DJ Basin** hitting volume records - O'Connor bypass added up to 40MMcf/d additional capacity in Q2 2017
- **SCOOP** strong producer volume forecasts
- **Eagle Ford** volumes up over 15% since March 2017

Sand Hills Volume and Capacity Growth



Sand Hills volumes trending up… *high utilization supporting current and potential future expansion… driving increased fee-based cash flows*

Volume growth outlook setting the foundation for stronger results from key basins

Permian Strategy

DCP Midstream

Deliberate focus on higher margin Logistics growth given risk of G&P overbuild and tighter margins

1 G&P: Permian Basin

Permian G&P assets provide connectivity to downstream Logistics assets

- Significant rig count growth… leading indicator for volumes
- Millions of acres dedicated in the Delaware under long-term contracts
- Will build additional plants with large established producers focused on full value chain solutions

2 Logistics: Sand Hills NGL Pipeline

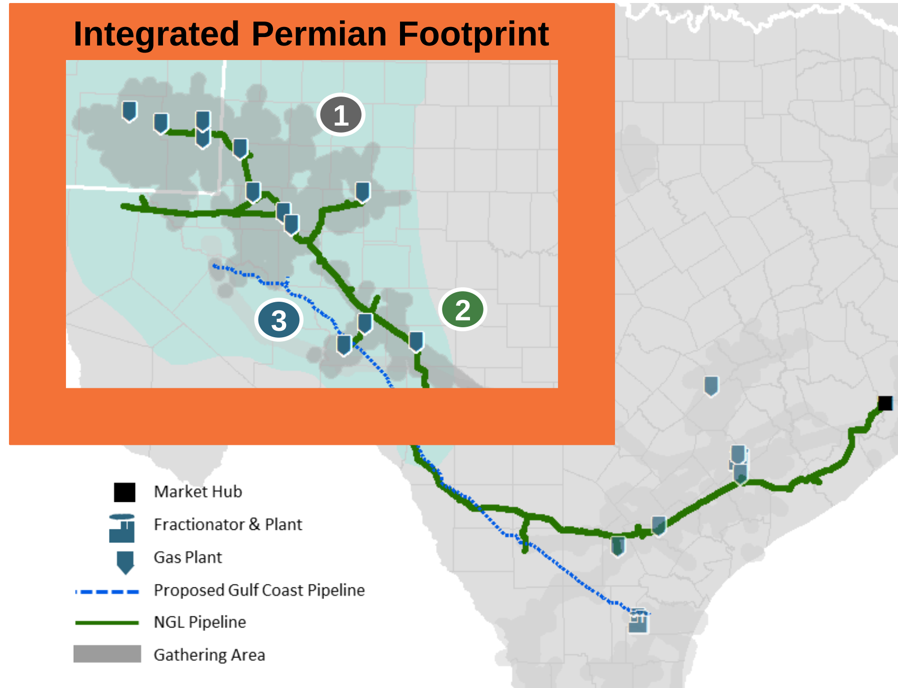
Sand Hills leverages the entire Permian with lower risk and higher returns

- Profitable contract portfolio with 10-20 year commitments
- Vehicle for continued capital disciplined growth in phases

3 Logistics: Gulf Coast Express Gas Pipeline

Advancing Permian Natural Gas Pipeline JV with KMI

- Non-binding open season completed with strong interest expressed; converting interested parties to contracts
- Supply push from Permian growth where DCP's G&P position provides significant connectivity



Permian G&P	Sand Hills	Gulf Coast Express
Processing capacity 1,315 MMcf/d	100% Capacity 280 MBpd	Capacity 1.8 BCF
Active plants 12[1]	Utilization 96%	Miles of pipe 430
Miles of pipe 16,300	30% DCP / 70% third party volumes	Pipe diameter 42"

(1) *Active plant capacity, excludes idled plant capacity*

Executing Permian strategy via disciplined capital allocation focused on maximizing unitholder value

Sand Hills NGL Pipeline Expansions

Executing large scale demand driven expansions of Sand Hills, increasing fee-based earnings and leveraging significant integrated Permian footprint

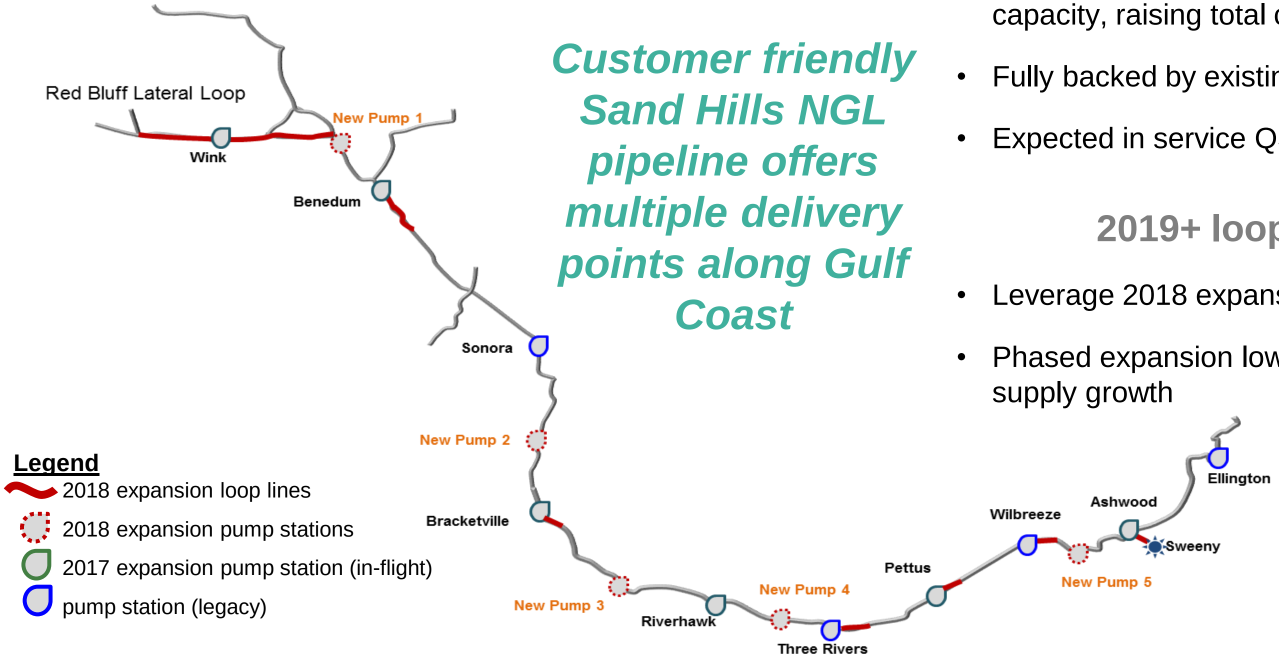
2017 Sand Hills expansion

- **85 MBpd pump expansion to 365 MBpd in progress**
- **Expected in service Q4 2017**

2018 and future Sand Hills expansions

- **450 MBpd by Q3 2018 in progress**
- **550+ MBpd timing TBD**

- $70 million, ~2x EBITDA Multiple
- Lateral and three pump stations increasing Permian capacity
- Backed by long term, 10-20 year third party dedications



Customer friendly Sand Hills NGL pipeline offers multiple delivery points along Gulf Coast

2018 expansion to 450MBpd is underway

- ~$300 million, 5-7x EBITDA multiple
- Partial looping and new pump stations adding 85 MBpd of Permian capacity, raising total capacity to 450 MBpd
- Fully backed by existing customer commitments
- Expected in service Q3 2018

2019+ loop expansion to 550+ MBpd

- Leverage 2018 expansion to complete full loop, adding 100+ MBpd
- Phased expansion lowers risk by matching capital outlay with supply growth

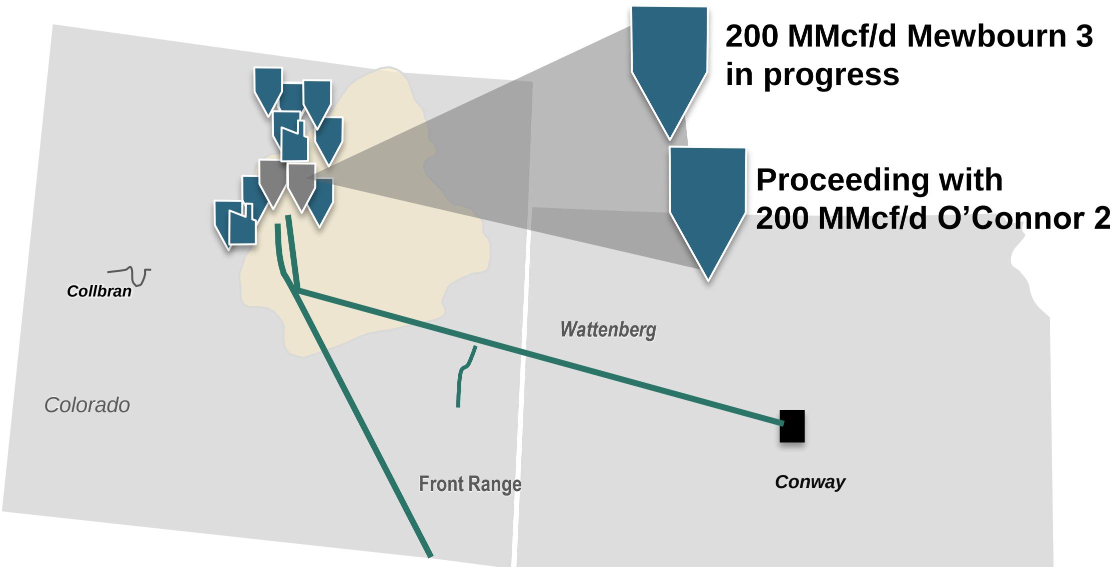
$'s noted are net to DCP's 67% interest

2017 and 2018 expansions to 450 MBpd fully backed by existing customer commitments

DJ Basin Strategy

Premier integrated midstream position in the DJ Basin… life-of-lease contracts with minimum volume commitments and margin requirements underpinning investments

Continued strong partnership with producers to execute current and future growth



- Approved 200 MMcf/d O'Connor 2 plant… eleventh plant in the DJ Basin
  - ~$350-400 million
  - Expected in service mid 2019
- 200 MMcf/d Mewbourn 3 under construction
  - ~$395 million
  - Expected in service Q4 2018
- Placed up to 40 MMcf/d of bypass capacity in service in Q2 2017
- Continued strong capacity utilization driving future expansion beyond 2019

DJ Basin G&P

Active plants 9

Total processing plus bypass capacity ~850 MMcf/d

Miles of pipe 3,510

Adding DJ Capacity

200 MMcf/d Mewbourn 3 in Q4 2018

200 MMcf/d O'Connor 2 in 2019

Front Range

NGL miles of pipe 450

DCP ownership 33%

Connected to DCP DJ Basin and third party plants

Increasing processing capacity 50+% to 1.2 Bcf/d by 2019 via Mewbourn 3 and O'Connor 2 plants

Summary

Key Takeaways

- Reaffirming guidance… tightening ranges to reflect commodity outlook
- Strong July performance and volumes
- YTD distribution coverage of 1.04x, with ~1.0x for 2017
  - IDR giveback provides hedge against lower commodity prices
- Ample liquidity and financial flexibility
  - No equity needs in 2017

Path Forward

- Strategic capital allocation to top producing basins… Permian and DJ
  - Sand Hills: 2017 and 2018 expansions to 450 MBpd underway
  - 200 MMcf/d Mewbourn 3 under construction
  - 200 MMcf/d O'Connor 2 plant approved

Reaffirming Guidance/ Financial Flexibility

Positive Volume Outlook in Key Basins

Executing Disciplined Capital Growth

Continuing DCP 2020 strategy execution focused on long term value creation

DCP Midstream – Appendix

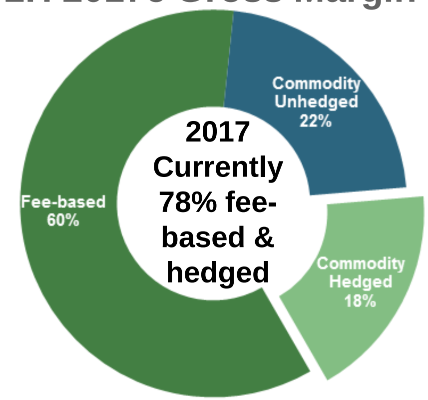
Margin by Segment

$MM, except per unit measures		Q2 2017		Q1 2017		Q2 2016		Q1 2016
Gathering & Processing (G&P) Segment								
Natural gas wellhead - Bcf/d		4.48		4.58		5.25		5.43
Segment gross margin including equity earnings before hedging [1]	$	352	$	374	$	324	$	279
Net realized cash hedge settlements received (paid)	$	(2)	$	(9)	$	10	$	44
Non-cash unrealized gains (losses)	$	16	$	31	$	(29)	$	(39)
G&P Segment gross margin including equity earnings	**$**	**366**	**$**	**396**	**$**	**305**	**$**	**284**
G&P Margin including equity earnings before hedging/wellhead mcf	$	0.86	$	0.91	$	0.68	$	0.57
G&P Margin including equity earnings and realized hedges/wellhead mcf	$	0.86	$	0.89	$	0.70	$	0.65
G&P Segment Fee as % of G&P margin including equity earnings before hedging [2]		46%		42%		47%		53%
Logistics & Marketing Segment gross margin including equity earnings [3]	**$**	**112**	**$**	**112**	**$**	**97**	**$**	**111**
Total gross margin including equity earnings	**$**	**478**	**$**	**508**	**$**	**402**	**$**	**395**
Direct Operating and G&A Expense	$	(249)	$	(229)	$	(235)	$	(241)
DD&A		(94)		(94)		(95)		(95)
Other Income (Loss) [4]		29		(10)		(11)		87
Interest Expense, net		(73)		(73)		(79)		(79)
Income Tax Expense		(2)		(1)		(3)		(2)
Noncontrolling interest		(1)		(0)		(1)		(0)
Net Income (loss) - DCP Midstream, LP	**$**	**88**	**$**	**101**	**$**	**(22)**	**$**	**65**
Industry average NGL $/gallon	$	0.55	$	0.60	$	0.46	$	0.37
NYMEX Henry Hub $/mmbtu	$	3.18	$	3.32	$	1.95	$	2.09
NYMEX Crude $/bbl	$	48.28	$	51.91	$	45.64	$	33.45
Other data:								
NGL pipelines throughput (MBbl/d) [5]		451		427		430		399
NGL Production (MBbl/d)		366		352		415		396
Total Fee margin as % of Total gross margin including equity earnings before G&P hedging [6]		59%		56%		59%		66%

2017e Hedged Commodity Sensitivities

Commodity	Price range	Per unit Δ	2017 ($MM)
NGL ($/gallon)	$0.50-0.65	$0.01	$5
Natural Gas ($/MMBtu)	$3.00-3.50	$0.10	$7
Crude Oil ($/Barrel)	$50-60	$1.00	$4

2H 2017e Gross Margin



Fee includes NGL, propane and gas marketing which depend on price spreads rather than nominal price level

FOOTNOTES:
(1) Represents Gathering and Processing (G&P) Segment gross margin plus Earnings from unconsolidated affiliates, excluding Trading and marketing (losses) gains, net
(2) G&P segment fee margin includes Transportation, processing and other revenue, plus approximately 90% of Earnings from unconsolidated affiliates
(3) Represents Logistics and Marketing Segment gross margin plus Earnings from unconsolidated affiliates
(4) "Other Income" includes gain/(loss) on asset sales, asset write-offs and other miscellaneous items, including a producer settlement in Q1 2016
(5) This volume represents equity and third party volumes transported on DCP's NGL pipeline assets
(6) Total Fee margin includes G&P segment fee margin (refer to (2) above), plus the Logistics and Marketing segment which includes fees for NGL transportation and fractionation, and NGL, propane and gas marketing which depend on price spreads rather than nominal price level

*** Segment gross margin is viewed as a non-Generally Accepted Accounting Principles ("GAAP") measure under the rules of the Securities and Exchange Commission ("SEC"), and is reconciled to its most directly comparable GAAP financial measures under "Reconciliation of Non-GAAP Financial Measures" in schedules at the end of this presentation.*

Hedging Update

Opportunistically Adding Hedges in 2017 and 2018
2H 2017 is 78% fee and hedged

***Percent hedged** by commodity as of 7/31/17*

Hedge position	Q3 2017	Q4 2017	Q1 2018
NGLs hedged [1] **(Bbls/d)**	**27,500**	**29,348**	**10,500**
Average price **($/gal)**	**$0.59**	**$0.59**	**$0.61**
Percent hedged	**83%**	**88%**	**35%**
Natural Gas hedged **(MMBtu/d)**	**62,500**	**60,000**	**27,500**
Average price **($/MMBtu)**	**$3.57**	**$3.61**	**$3.59**
Percent hedged	**25%**	**24%**	**12%**
Condensate hedged **(Bbls/d)**	**3,123**	**3,123**	**n/a**
Average price **($/Bbl)**	**$52.23**	**$52.23**	
Percent hedged	**22%**	**22%**	

- Balance of 2017 is 40% commodity margin x 44% hedged equity length = 18% total hedged margin
- Fee-based margin growth coupled with multi-year hedging program provides downside protection on commodity exposed margin

(1) Direct commodity hedges for ethane, propane, normal butane and natural gasoline equity length at Mt Belvieu prices

2H 2017 margin is 78% fee + hedged

Growth Focus

Clear line of sight to $1.5-2B of strategic growth projects around our footprint

1 Logistics & Marketing: Sand Hills

Sand Hills NGL Pipeline expansion
- Expansion from 280 MBpd to 365 MBpd in Q4 2017
- Multiple new supply connectors in flight throughout 2017
- Executing 2018 expansion of Sand Hills to 450 MBpd

2 Logistics & Marketing: Gulf Coast Express

Potential Permian Natural Gas Pipeline JV with KMI
- 430 mile 42” intrastate pipeline connecting Permian to Gulf Coast; 1.8 Bcf/d capacity; in service the second half 2019
- Supply push from Permian growth where DCP’s G&P position provides significant connectivity

3 G&P: DJ Basin

DJ Basin expansion
- 200 MMcf/d Mewbourn 3 Plant and Grand Parkway gathering in Q4 2018 under construction
- Up to 40 MMcf/d O’Connor bypass in service Q2 2017
- Approved 200 MMcf/d O’Connor 2 plant in service Mid 2019

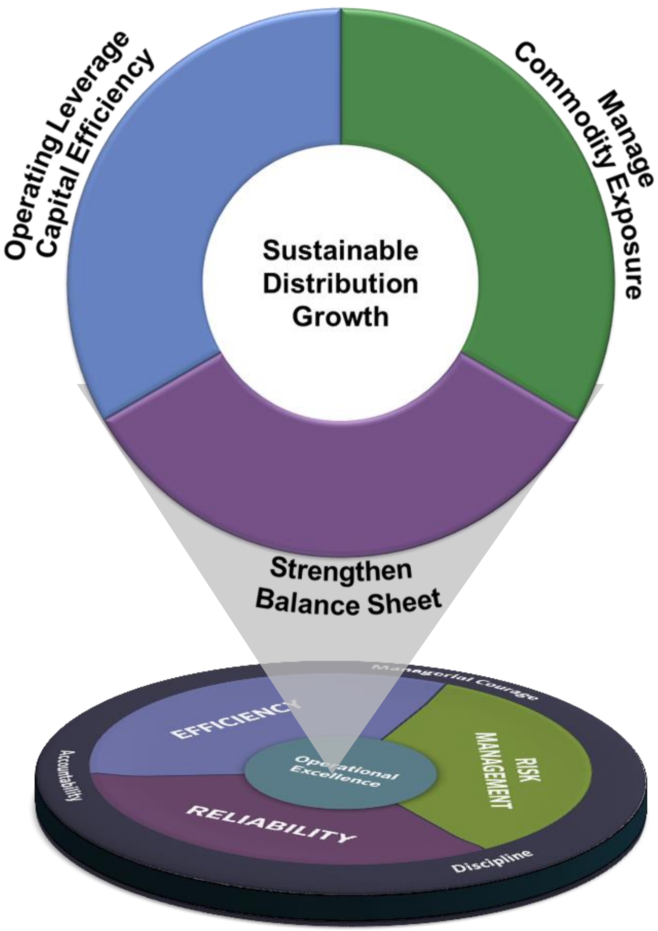
Current and Potential Growth Projects	Status	Est Capex $MM net to DCP’s interest	Target in Service
Logistics & Marketing Growth			
Sand Hills expansion to 365 MBpd	In progress	~$70	Q4 2017
Sand Hills supply connectors	In progress	~$70	2017
Sand Hills 2018 expansion to 450 MBpd	In progress	~$300	Q3 2018
Sand Hills 2019+ expansion to 550+ MBpd	TBD	$550-600	TBD
Gulf Coast Express w/KMI	In development	TBD	2H 2019
G&P Growth			
DJ 200 MMcf/d Mewbourn 3 plant & Grand Parkway gathering	In progress	~$395	Q4 2018
DJ Basin bypass	**In service**	~$25	Q2 2017
DJ 200 MMcf/d O’Connor 2 plant & gathering	**Approved**	~$350-400	Mid 2019
Growth Opportunities		**$1,500-2,000**	

Logistics & Marketing

Gathering & Processing

Integrated G&P and Logistics asset portfolio driving fee-based growth opportunities

2018+ Financial Targets



Key financial metric priorities and targets

1	2	3
Bank leverage 3.0-4.0x	**Distribution coverage 1.2x+**	**Distribution growth target 4-5%**

Key targets supporting financial metrics

Accretive growth projects 5-7x EBITDA	**Fee and hedged margin 80%+**	**Capital structure debt/equity 50:50**

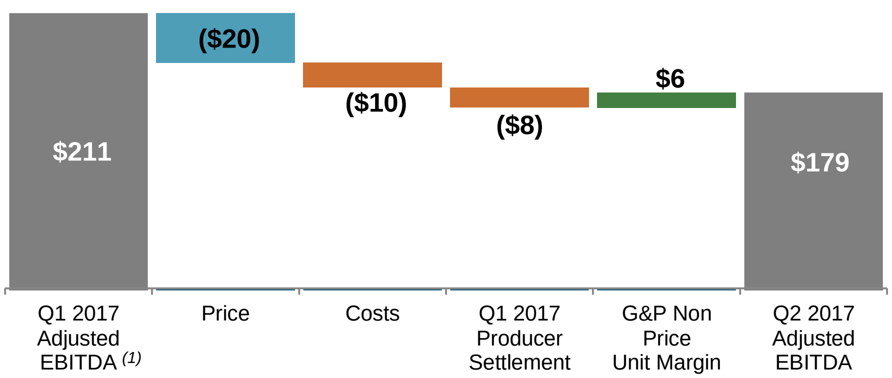
Maximize operating leverage and capital efficiency, manage commodity exposure and strengthen balance sheet to achieve sustainable distribution growth

Financial Schedules & Non GAAP Reconciliations

Q1 2017 vs. Q2 2017 Segment Results

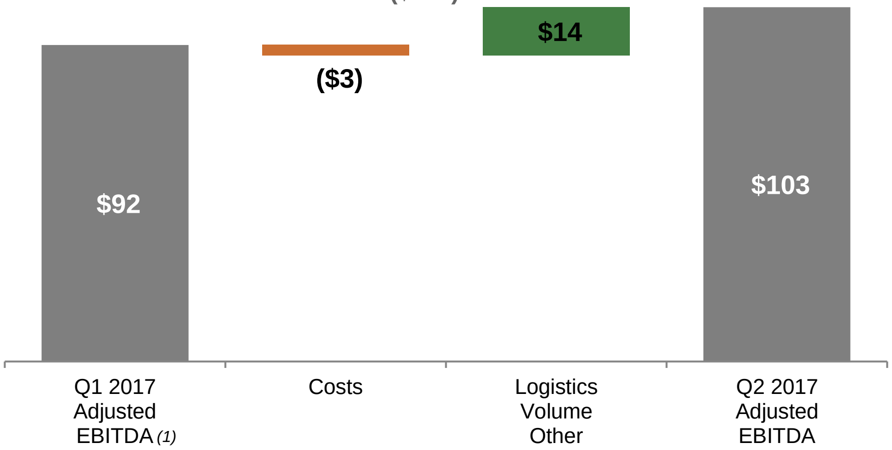
G&P Adjusted EBITDA Q1'17 vs. Q2'17

($MM)



Logistics and Marketing Adjusted EBITDA Q1'17 vs. Q2'17

($MM)



Q1 2017 vs Q2 2017 G&P Key Variance Drivers

- Results were lower due to:
  - Lower commodity prices, net of hedges
  - Higher costs associated with asset reliability and planned maintenance, investment in technology and automation to drive greater productivity, reliability and efficiency, and timing
  - Producer settlement in Q1 2017
- Partially offset by:
  - Higher G&P margins in the DJ Basin, Permian and Midcontinent

Q1 2017 vs Q2 2017 L&M Key Variance Drivers

- Results were higher due to:
  - Higher cash distributions from NGL pipeline joint ventures, driven by higher distributions from Sand Hills, Front Range and Texas Express
- Partially offset by
  - Higher costs due to reliability and planned maintenance spend

(1) Amount has been adjusted to retrospectively include the historical results of the DCP Midstream Business, acquired in January 2017, similar to the pooling method

Q2 2017 Volume trend and update

G&P Volume Trend, Utilization and Rig Activity

System	Q2'17 Net Plant/ Treater Capacity (MMcf/d)(1)	Q2'16 Average Wellhead Volumes (MMcf/d)	Q1'17 Average Wellhead Volumes (MMcf/d)	Q2'17 Average Wellhead Volumes (MMcf/d)	Q2'17 Average NGL Production (MBbls/d)	Plant Utilization(1)	Q2'16 Average Rig Count in DCP's Area	Q2'17 Average Rig Count in DCP's Area	% Increase YoY
North(2)	1,258	1,092	1,106	1,048	86	83%	12	18	50%
Permian	1,315	1,072	961	964	105	73%	135	306	127%
Midcontinent	1,685	1,253	1,199	1,194	87	71%	61	119	95%
South(3)(4)	2,265	1,699	1,279	1,252	88	55%	39	77	97%
Total	**6,523**	**5,116**	**4,545**	**4,458**	**366**	**68%**	**247**	**521**	**111%**

(1) Plant utilization: Average wellhead volumes divided by active plant capacity, excludes idled plant capacity
(2) Q2'16, Q1'17 and Q2'17 wellhead volumes exclude 38MMcf/d, 35MMcf/d and 25MMcf/d, respectively, associated with the sale of Douglas, Wyoming in June 2017
(3) 90MMcf/d Three Rivers Plant in the Eagle Ford was idled effective March 2017
(4) Q2'16 wellhead volumes exclude 101 MMcf/d associated with the sale of North Louisiana in June 2016 and 38 MMcf/d

Rig count increased 111% in DCP areas… leading indicator for future volume growth

Volume Outlook

Permian: slight growth

North: flat to slight growth
- Driven by DJ Basin – at full capacity

Midcontinent: slight growth
- Driven by SCOOP

South: flat to slight growth
- Driven by Eagle Ford

Logistics NGL Pipeline Volume Trends and Utilization

Pipeline	Average Gross Capacity (MBbls/d)	% Owned	Net Capacity	Q2'16 Average NGL Throughput (MBbls/d)(5)	Q1'17 Average NGL Throughput (MBbls/d)(5)	Q2'17 Average NGL Throughput (MBbls/d)(5)	Q2'17 Pipeline Utilization
Sand Hills	280(6)	66.7%	186	165	169	180	96%
Southern Hills	175	66.7%	117	66	67	68	58%
Front Range	150	33.3%	50	34	34	37	74%
Texas Express	280	10.0%	28	14	14	16	57%
Other(7)	215	Various	172	152	143	150	87%
Total	**1,100**			**431**	**427**	**451**	

(5) Represents total throughput allocated to our proportionate ownership share
(6) Sand Hills capacity is in process of being expanded to 365 MBbls/d
(7) Other includes the Black Lake, Panola, Seabreeze, Wilbreeze and other NGL pipelines

Sand Hills volumes trending up… driving increased cash flow

Q2 2017 Consolidated Results

Consolidated Results ($MM)	Q2 2016[1]	Q2 2017	YTD June 2016[1]	YTD June 2017
Gathering & Processing Adjusted EBITDA	$183	$179	$436	$390
Logistics & Marketing Adjusted EBITDA	$106	$103	$223	$195
Other	($63)	($66)	($126)	($124)
Adjusted EBITDA	**$226**	**$216**	**$533**	**$461**
Distributable Cash Flow	**	**$119**	**	**$280**
Distributions declared (Adj. for IDR giveback)	**	**$134**	**	**$269**
Distribution Coverage Ratio (Declared)	**	**0.89x**	**	**1.04x**
Bank Leverage Ratio[2]	**	**4.5x**	**	**4.5x**

Q2 2016 vs Q2 2017 Key Variance Drivers

Results were lower due to:

- Lower volumes in the South, Midcontinent and Permian partially driven by reduced drilling in 2016
- Disposition of Northern Louisiana system in June 2016
- Higher costs associated with asset reliability and planned maintenance, investment in technology and automation to drive greater productivity, reliability and efficiency, and timing

Partially offset by:

- Higher commodity prices, net of hedges
- Higher distributions primarily due to the expansion and volume ramp on Sand Hills
- Higher G&P margins in the DJ Basin, Permian and Midcontinent

(1) Amount has been adjusted to retrospectively include the historical results of the DCP Midstream Business, acquired in January 2017, similar to the pooling method
(2) Bank leverage ratio calculation = Adjusted EBITDA, plus certain project EBITDA credits from projects under construction, divided by bank debt (excludes $550 million Jr. Subordinated notes)
*** Amount/ratio has not been calculated under the pooling method*

Solid leverage and coverage metrics in Q2 2017 and YTD

Consolidated Financial Results

($ in millions, except per unit amounts)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016(1)	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016(1)
Sales, transportation, processing and other revenues	$1,927	$1,646	$4,017	$3,092
Trading and marketing gains (losses), net	22	(23)	53	(5)
Total operating revenues	**1,949**	**1,623**	**4,070**	**3,087**
Purchases of natural gas and NGLs	(1,557)	(1,294)	(3,244)	(2,429)
Operating and maintenance expense	(178)	(166)	(345)	(345)
Depreciation and amortization expense	(94)	(95)	(188)	(190)
General and administrative expense	(71)	(61)	(133)	(123)
Gain/(loss) on sale of assets, net	34	(6)	34	(6)
Restructuring costs	–	(8)	–	(8)
Other (expense) income	(5)	(5)	(15)	82
Total operating costs and expenses	**(1,871)**	**(1,635)**	**(3,891)**	**(3,019)**
Operating income (loss)	**78**	**(12)**	**179**	**68**
Interest expense	(73)	(79)	(146)	(158)
Earnings from unconsolidated affiliates	86	73	160	139
Income tax expense	(2)	(3)	(3)	(5)
Net income attributable to noncontrolling interest	(1)	(1)	(1)	(1)
Net income (loss) attributable to partners	**$88**	**$(22)**	**$189**	**$ 43**
Adjusted EBITDA	**$216**	**$226**	**$461**	**$533**
Distributable cash flow	**$119**	**	**$280**	**
Distribution coverage ratio – declared(2)	**0.89x**	**	**1.04x**	**
Distribution coverage ratio – paid(3)	**0.88x**	**	**1.09x**	**

(1) Includes the DCP Midstream Business, which the Partnership acquired in January 2017, retrospectively adjusted. Transfers of net assets between entities under common control are accounted for as if the transactions had occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.
(2) Distributions declared reflect $20 million and $40 million of IDR givebacks for the three and six months ended June 30, 2017, respectively.
(3) Distributions paid reflect $20 million of IDR givebacks for the three months ended June 30, 2017
*** Distributable cash flow and distribution coverage have not been calculated under the pooling method.*

Non GAAP Reconciliation

($ in millions)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016[1]	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016[1]
Gathering and Processing (G&P) Segment				
Segment net income attributable to partners	$ 141	$ 56	$ 293	$ 176
Operating and maintenance expense	162	151	315	312
Depreciation and amortization expense	86	87	171	173
General and administrative expense	7	4	13	8
Other expense (income), net	3	–	3	(87)
Earnings from unconsolidated affiliates	(24)	(17)	(44)	(32)
(Gain) loss on sale of assets, net	(34)	6	(34)	6
Net income attributable to noncontrolling interests	1	1	1	1
Segment gross margin	**$ 342**	**$ 288**	**$ 718**	**$ 557**
Earnings from unconsolidated affiliates	24	17	44	32
Segment gross margin including equity earnings	**$ 366**	**$ 305**	**$ 762**	**$ 589**

Logistics and Marketing Segment				
Segment net income attributable to partners	$ 92	$ 76	$ 179	$ 170
Operating and maintenance expense	13	10	22	20
Depreciation and amortization expense	3	4	7	8
Other expense	2	5	11	5
General and administrative expense	2	2	5	5
Earnings from unconsolidated affiliates	(62)	(56)	(116)	(107)
Segment gross margin	**$ 50**	**$ 41**	**$ 108**	**$ 101**
Earnings from unconsolidated affiliates	62	56	116	107
Segment gross margin including equity earnings	**$ 112**	**$ 97**	**$ 224**	**$ 208**

*** We define gross margin as total operating revenues, less purchases of natural gas and NGLs, and we define segment gross margin for each segment as total operating revenues for that segment less commodity purchases for that segment. Segment gross margin is included as a supplemental disclosure because it is a primary performance measure used by management as it represents the results of product sales versus product purchases. As an indicator of our operating performance, margin should not be considered an alternative to, or more meaningful than, net income or cash flow as determined in accordance with GAAP. Our gross margin may not be comparable to a similarly titled measure of another company because other entities may not calculate gross margin in the same manner.*

(1) Includes the DCP Midstream Business, which the Partnership acquired in January 2017, retrospectively adjusted. Transfers of net assets between entities under common control are accounted for as if the transactions had occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

Commodity Derivative Activity

($ in millions)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016[1]	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016[1]
Gathering & Processing Segment: Non-cash unrealized gains (losses)	$16	$(29)	$47	$(68)
Logistics & Marketing Segment: Non-cash unrealized gains (losses)	8	(15)	13	(21)
Non-cash unrealized gains (losses) – commodity derivative	**$24**	**$(44)**	**$60**	**$(89)**
Gathering & Processing Segment: Net realized cash hedge settlements (paid) received	$(2)	$10	$(11)	$54
Logistics & Marketing Segment: Net realized cash hedge settlements received	–	11	4	30
Net realized cash hedge settlements (paid) received	**$(2)**	**$21**	**$(7)**	**$84**
Trading and marketing gains (losses), net	**$22**	**$(23)**	**$53**	**$(5)**

(1) *Includes the DCP Midstream Business, which the Partnership acquired in January 2017, retrospectively adjusted. Transfers of net assets between entities under common control are accounted for as if the transactions had occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.*

Balance Sheet

	June 30, 2017	December 31, 2016 (1)
	(Millions)	
Cash and cash equivalents	$ 251	$ 1
Other current assets	814	993
Property, plant and equipment, net	8,950	9,069
Other long-term assets	3,555	3,548
Total assets	$ 13,570	$ 13,611
Current liabilities	$ 935	$ 1,123
Current portion of long-term debt	500	500
Long-term debt	4,710	4,907
Other long-term liabilities	226	228
Partners' equity	7,170	6,821
Noncontrolling interests	29	32
Total liabilities and equity	$ 13,570	$ 13,611

(1) Includes the DCP Midstream Business, which the Partnership acquired in January 2017, retrospectively adjusted. Transfers of net assets between entities under common control are accounted for as if the transactions had occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

Non GAAP Reconciliation

	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016 (1)	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016 (1)
	(Millions)			
Reconciliation of Non-GAAP Financial Measures:				
Net income (loss) attributable to partners	$ 88	$ (22)	$ 189	$ 43
Interest expense	73	79	146	158
Depreciation, amortization and income tax expense, net of noncontrolling interests	96	98	191	195
Distributions from unconsolidated affiliates, net of earnings	15	16	17	37
Other non-cash charges	2	5	12	5
(Gain) loss on sale of assets	(34)	6	(34)	6
Non-cash commodity derivative mark-to-market	(24)	44	(60)	89
Adjusted EBITDA	216	$ 226	461	$ 533
Interest expense	(73)		(146)	
Maintenance capital expenditures, net of noncontrolling interest portion and reimbursable projects	(29)		(44)	
Other, net	5		9	
Distributable cash flow	$ 119	**	$ 280	**
Net cash provided by operating activities	$ 216	$ 153	$ 360	$ 304
Interest expense	73	79	146	158
Net changes in operating assets and liabilities	(44)	(50)	22	(14)
Non-cash commodity derivative mark-to-market	(24)	44	(60)	89
Other, net	(5)	—	(7)	(4)
Adjusted EBITDA	216	$ 226	461	$ 533
Interest expense	(73)		(146)	
Maintenance capital expenditures, net of noncontrolling interest portion and reimbursable projects	(29)		(44)	
Other, net	5		9	
Distributable cash flow	$ 119	**	$ 280	**

(1) *Includes the DCP Midstream Business, which the Partnership acquired in January 2017, retrospectively adjusted. Transfers of net assets between entities under common control are accounted for as if the transactions had occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.*

** *Distributable cash flow and distribution coverage have not been calculated under the pooling method.*

Non GAAP Reconciliation

	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016 (1)	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016 (1)
	(Millions, except as indicated)		(Millions, except as indicated)	
Gathering and Processing Segment:				
Financial results:				
Segment net income attributable to partners	$ 141	$ 56	$ 293	$ 176
Non-cash commodity derivative mark-to-market	(16)	29	(47)	68
Depreciation and amortization expense, net of noncontrolling interest	86	87	171	173
(Gain) loss on sale of assets, net	(34)	6	(34)	6
Distributions from unconsolidated affiliates, net of earnings	(1)	5	4	13
Other charges	3	—	3	—
Adjusted segment EBITDA	$ 179	$ 183	$ 390	$ 436
Operating and financial data:				
Natural gas wellhead (MMcf/d)	4,483	5,255	4,532	5,343
NGL gross production (MBpd)	366	415	359	405
Operating and maintenance expense	$ 162	$ 151	$ 315	$ 312
Logistics and Marketing Segment:				
Financial results:				
Segment net income attributable to partners	$ 92	$ 76	$ 179	$ 170
Depreciation and amortization expense	3	4	7	8
Distributions from unconsolidated affiliates, net of earnings	16	11	13	24
Other charges	—	—	9	—
Non-cash commodity derivative mark-to-market	(8)	15	(13)	21
Adjusted segment EBITDA	$ 103	$ 106	$ 195	$ 223
Operating and financial data:				
NGL pipelines throughput (MBpd)	451	430	439	415
Operating and maintenance expense	$ 13	$ 10	$ 22	$ 20

(1) *Includes the DCP Midstream Business, which the Partnership acquired in January 2017, retrospectively adjusted. Transfers of net assets between entities under common control are accounted for as if the transactions had occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.*

Non GAAP Reconciliation

	Three Months Ended June 30, 2017	Six Months Ended June 30, 2017
	(Millions, except as indicated)	
Reconciliation of Non-GAAP Financial Measures:		
Distributable cash flow	$ 119	$ 280
Distributions declared **	$ 134	$ 269
Distribution coverage ratio - declared	0.89 x	1.04 x
Distributable cash flow	$ 119	$ 280
Distributions paid ***	$ 135	$ 256
Distribution coverage ratio - paid	0.88 x	1.09 x

** Distributions declared reflect $20 million and $40 million of IDR givebacks for the three and six months ended June 30, 2017, respectively.

*** Distributions paid reflect $20 million of IDR givebacks for the three months ended June 30, 2017.

Note: Distributable cash flow and distribution coverage have not been calculated under the pooling method for prior periods.

Non GAAP Reconciliation

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016 (1)
	(Millions)	
Reconciliation of Non-GAAP Financial Measures:		
Net income attributable to partners	$ 101	$ 65
Interest expense	73	79
Depreciation, amortization and income tax expense, net of noncontrolling interests	95	97
Distributions from unconsolidated affiliates, net of earnings	2	21
Other non-cash charges	10	—
Non-cash commodity derivative mark-to-market	(36)	45
Adjusted EBITDA	245	$ 307
Interest expense	(73)	
Maintenance capital expenditures, net of noncontrolling interest portion and reimbursable projects	(15)	
Other, net	4	
Distributable cash flow	$ 161	**
Net cash provided by operating activities	$ 144	$ 151
Interest expense	73	79
Net changes in operating assets and liabilities	66	36
Non-cash commodity derivative mark-to-market	(36)	45
Other, net	(2)	(4)
Adjusted EBITDA	245	$ 307
Interest expense	(73)	
Maintenance capital expenditures, net of noncontrolling interest portion and reimbursable projects	(15)	
Other, net	4	
Distributable cash flow	$ 161	**

(1) Includes the DCP Midstream Business, which the Partnership acquired in January 2017, retrospectively adjusted. Transfers of net assets between entities under common control are accounted for as if the transactions had occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

*** Distributable cash flow and distribution coverage have not been calculated under the pooling method.*

Non GAAP Reconciliation

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016 (1)
	(Millions, except as indicated)	
Gathering and Processing Segment:		
Financial results:		
Segment net income attributable to partners	$ 152	$ 120
Non-cash commodity derivative mark-to-market	(31)	39
Depreciation and amortization expense	85	86
Distributions from unconsolidated affiliates, net of earnings	5	8
Adjusted segment EBITDA	$ 211	$ 253
Operating and financial data:		
Natural gas wellhead (MMcf/d)	4,580	5,431
NGL gross production (MBbls/d)	352	396
Operating and maintenance expense	$ 153	$ 161
Logistics and Marketing Segment:		
Financial results:		
Segment net income attributable to partners	$ 87	$ 94
Depreciation and amortization expense	4	4
Distributions from unconsolidated affiliates, net of earnings	(3)	13
Other charges	9	—
Non-cash commodity derivative mark-to-market	(5)	6
Adjusted segment EBITDA	$ 92	$ 117
Operating and financial data:		
NGL pipelines throughput (MBbls/d)	427	399
Operating and maintenance expense	$ 9	$ 10

(1) Includes the DCP Midstream Business, which the Partnership acquired in January 2017, retrospectively adjusted. Transfers of net assets between entities under common control are accounted for as if the transactions had occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information similar to the pooling method.

2017e DCP Guidance Non GAAP Reconciliation

	Twelve Months Ended December 31, 2017	
	Low Forecast	High Forecast
	(Millions)	
Reconciliation of Non-GAAP Measures:		
Forecasted net income attributable to partners	$ 165	$ 324
Distributions from unconsolidated affiliates, net of earnings	75	85
Interest expense, net of interest income	288	288
Income taxes	7	7
Depreciation and amortization, net of noncontrolling interests	398	398
Non-cash commodity derivative mark-to-market	7	8
Forecasted adjusted EBITDA	940	1,110
Interest expense, net of interest income	(288)	(288)
Maintenance capital expenditures, net of reimbursable projects	(100)	(145)
Income taxes and other	(7)	(7)
Forecasted distributable cash flow	$ 545	$ 670