Fourth Quarter 2016 and 2017 Update

Earnings Call – February 14, 2017

dcp Midstream

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, 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.

Legacy DPM Standalone Q4 and YTD 2016 Results

2016 Highlights… 2017 Path Forward

Legacy DPM Standalone 2016 Highlights

✓ Exceeded $515-525 million 2016 DCF target range	✓ Exceeded $575-585 million 2016 Adjusted EBITDA(1) target range	✓ Executed DCP 2020 strategy, delivered strong results	✓ Held distribution at $0.78/unit quarterly and $3.12/unit annualized	✓ Generated distribution coverage of 1.0x for Q4'16 and 1.11x for full year 2016

New DCP creates the largest U.S. NGL producer and gas processor with an ~$11 billion enterprise value (NYSE: DCP)

DCP 2017 Path Forward

Key Considerations

- Strong track record of execution
- DCP well positioned to take advantage of strengthening industry environment
- Ample liquidity and financial flexibility
- Financial strategy focused on unitholder value creation while managing commodity exposure
- Clear pathway to distribution growth

Announced New Growth Projects

- DJ Basin expansion (~$395 million)
  - 200 MMcf/d plant & gathering
- Sand Hills pipeline increasing capacity to 365,000 BPD (~$70 million)
- Line of sight to incremental organic growth opportunities

(1) 2016 and prior period Adjusted EBITDA excludes distributions in excess of equity earning

Delivered strong 2016 results – DCP well positioned for 2017 and beyond

Q4 and YTD 2016 DPM Standalone Results

Results ($MM)	Q4 2015	Q4 2016	YTD 2015	YTD 2016
Natural Gas Services Adjusted EBITDA(1)	$135	$120	$515	$453
NGL Logistics Adjusted EBITDA(1)	$52	$50	$182	$203
Wholesale Propane Adjusted EBITDA(1)	$11	$7	$44	$27
Adjusted EBITDA(1)	$176	$151	$656	$594
Distributable Cash Flow	$145	$120	$572	$537
Bank Leverage Ratio(2)			3.3x	3.5x
Distribution Coverage Ratio (Paid)	1.21x	1.00x	1.19x	1.11x

Performance drivers for Q4 2016 vs Q4 2015:

Natural Gas Services

- Decreased primarily due to:
  - Lower hedge settlement gains
  - Volume declines in Eagle Ford, East Texas and Southeast Texas
  - Sale of North Louisiana
- Partially offset by:
  - DJ Basin growth – Lucerne 2 plant and Grand Parkway
  - Natural gas storage commercial activities and lower operating costs

NGL Logistics & Wholesale Propane

- Decreased primarily due to:
  - Lower unit margins on Wholesale Propane
  - Higher maintenance costs on NGL Logistics
- Partially offset by:
  - Higher NGL pipeline throughput volumes and earnings

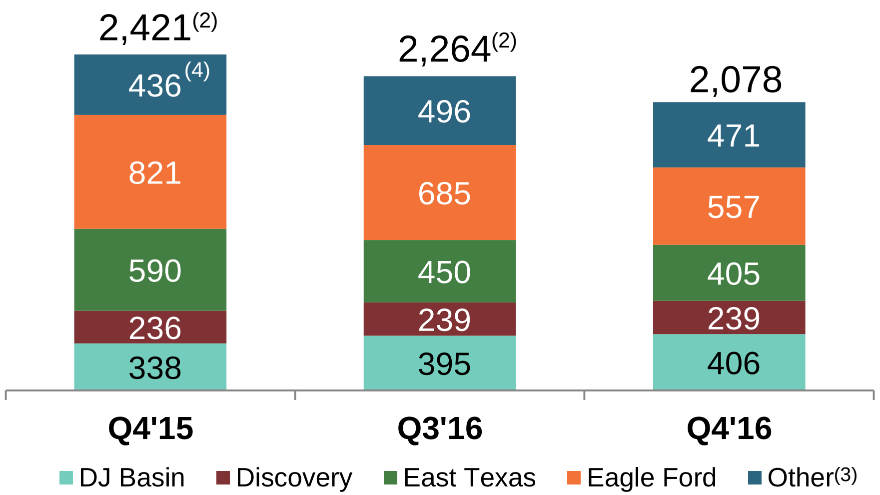
(1) Adjusted EBITDA excludes distributions from unconsolidated affiliates. See Non GAAP reconciliation in the appendix section
(2) As defined in Revolving Credit Facility – includes EBITDA Project Credits and other adjustments

Proactive execution… exceeded 2016 target ranges

DPM Standalone Volume Update

Natural gas volumes decreased ~14% from Q4 2015 primarily due to declines in the South (Eagle Ford, East Texas & Southeast Texas)

Natural Gas Throughput (MMcf/d)(1)

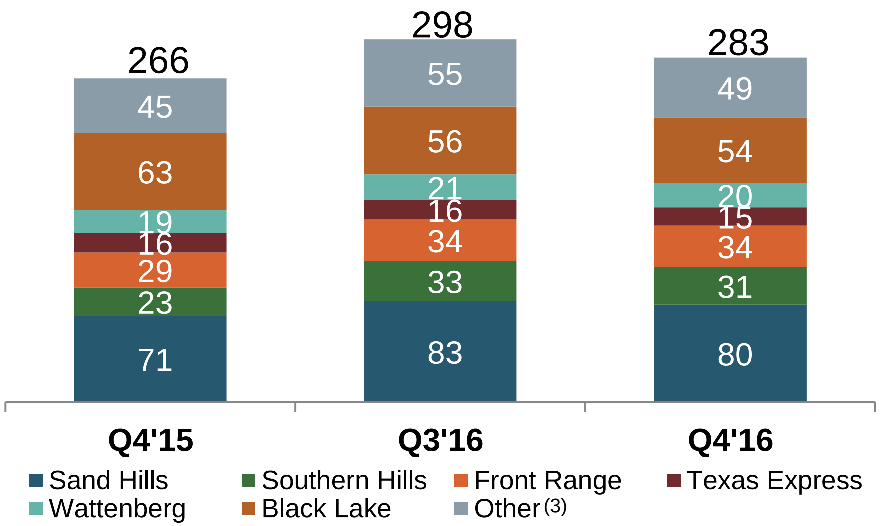


Average Plant Utilization

Region	Net Processing Capacity (Bcf/d)(4)	Q4'16 Utilization %
DJ Basin	0.4	103%
Discovery	0.2	100%
Eagle Ford	0.9	62%
East Texas	0.8	52%

NGL pipeline throughput increased 6% from Q4 2015 primarily due to growth in NGL production from DCP and third party plants

NGL Pipeline Throughput (MBbls/d)(1)



Average Pipeline Utilization

Region	Gross Throughput Capacity (MBbls/d)	Q4'16 Utilization %
Sand Hills	280	~85%
Southern Hills	175	~55%
Front Range	150	~70%
Texas Express	280	~55%

(1) Represents total throughput allocated to our proportionate ownership share

(2) Q4'15 was adjusted to remove throughput volumes associated with the North Louisiana system. All periods shown have been adjusted to remove throughput volumes associated with a small gathering line in the Eagle Ford that was sold in Q4'16

(3) Natural Gas Other includes the following systems: SE Texas, Michigan, Southern Oklahoma, Wyoming & Piceance / NGL Pipeline. NGL Pipeline Other includes Panola, Seabreeze and Wilbreeze NGL pipelines

(4) Net Processing Capacity excludes idled plants

Asset optimization, cost savings and strong reliability offsetting volume declines

2017 Financial Overview

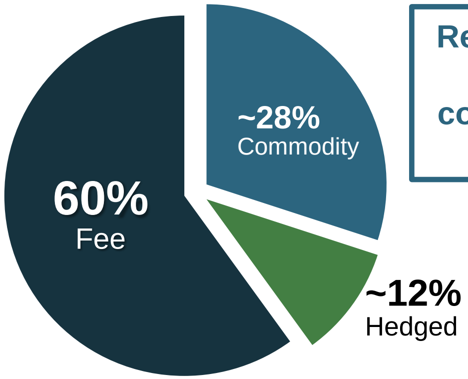
DCP 2017e Guidance

($ in Millions, except per unit amounts) Key Metrics	2017e DCP Guidance
Previous Adjusted EBITDA Range	$865-1,025
Distributions in excess of equity earnings	$75-85
2017 Adjusted EBITDA[(1)]	$940-1,110
Distributable Cash Flow (DCF)	$545-670
Total GP/LP Distributions	$618
Distribution Coverage Ratio (TTM)[(2)]	≥1.0x
Bank Leverage Ratio[(3)]	<4.5x
Distribution per Unit	$3.12
Maintenance Capital	$100-145
Growth Capital	$325-375

2017 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

2017e Margin:
72% fee-based & hedged



Retaining upside in a rising commodity price environment

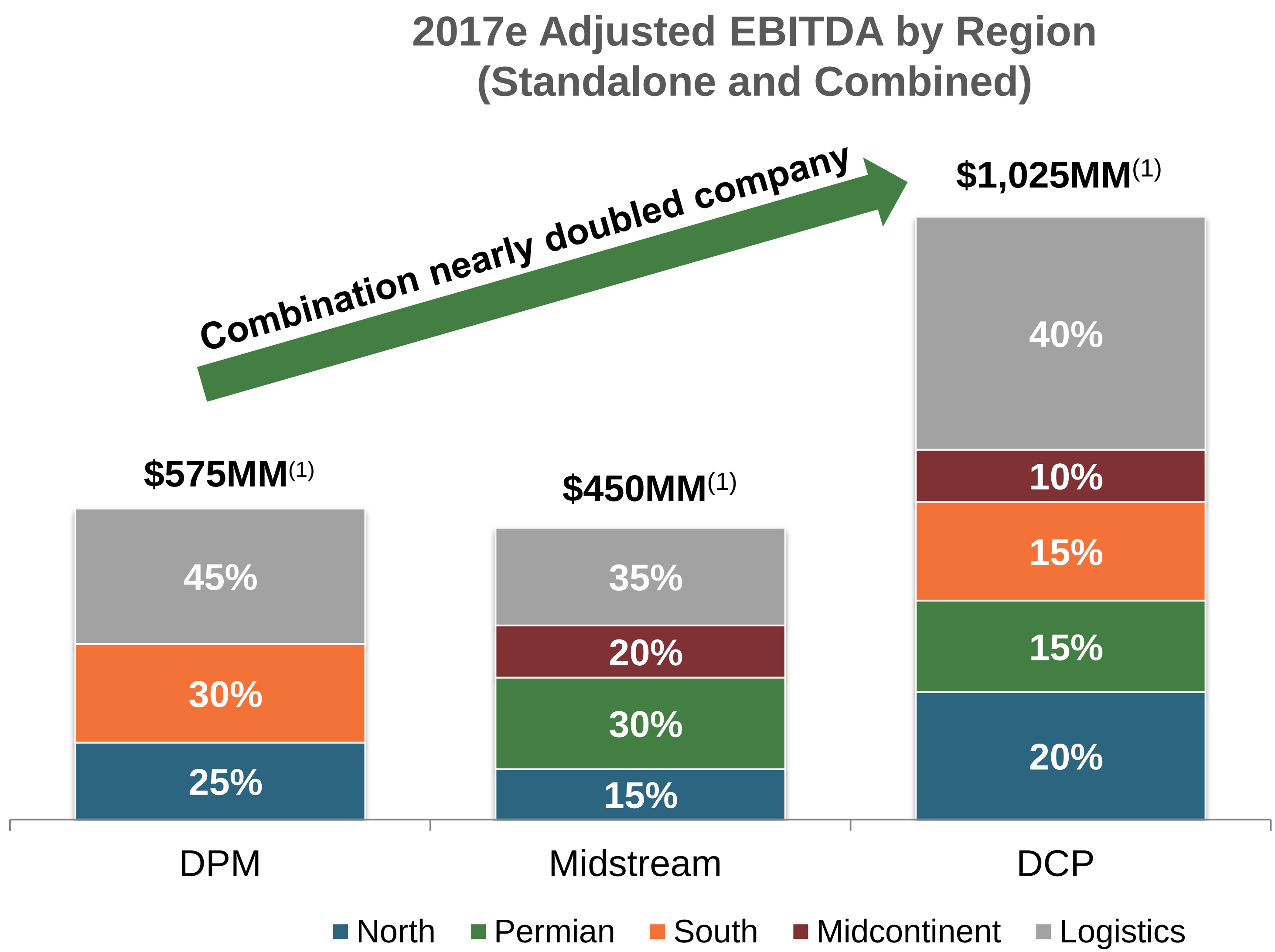
2017… Year of Transition

- Strong line of sight to growth opportunities
  - Sand Hills expansion
  - DJ Basin continued infrastructure expansion
  - Opportunities in Permian, SCOOP/STACK
- Industry environment is strengthening
- DCP well positioned to take advantage of industry and ethane recovery

(1) 2017 Adjusted EBITDA definition has been updated to include distributions from unconsolidated affiliates, consistent with bank definition. See Non GAAP reconciliation in the appendix section
(2) Includes IDR giveback, if needed, to target a 1.0x distribution coverage ratio
(3) 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 which are treated as equity)

DCP 2020 strategy execution positions DCP for significant upside in recovery

2017e Adjusted EBITDA Breakdown



Contributed to DCP's portfolio

- One third interest in Sand Hills & Southern Hills
- Midcontinent, including SCOOP/STACK
- Midstream's strong position in the Permian
- DJ Basin contracts and Midstream's infrastructure

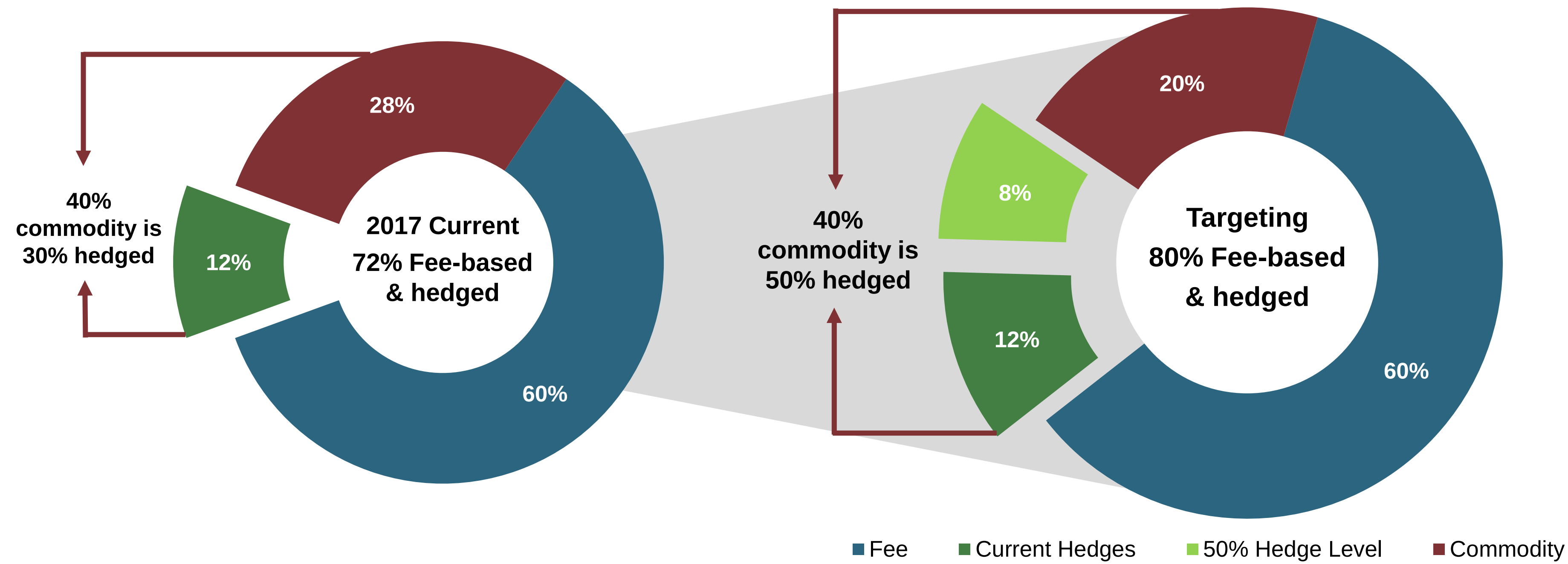
(1) *Assumes midpoint of 2017e adjusted EBITDA guidance range*

DCP combination significantly expands footprint and Adjusted EBITDA in growth basins

Current Hedge Position and Margin Profile

Current Hedge Position	Volume	Price	Hedged %
NGL Hedges[(1)]	16,249 Bbls/d	$0.55 /gal	40%
Gas Hedges	64,375 MMBtu/d	$3.42 /MMBtu	23%
Crude Hedges	3,123 Bbls/d	$52.23 /Bbl	22%

Targeting 80%+ fee based & hedged margin to protect downside while retaining upside in a rising commodity price environment



Note: Fee includes NGL, propane and gas marketing which depend on price spreads rather than nominal price level
(1) Direct commodity hedges for ethane, propane, normal butane and natural gasoline equity length at Mt Belvieu prices

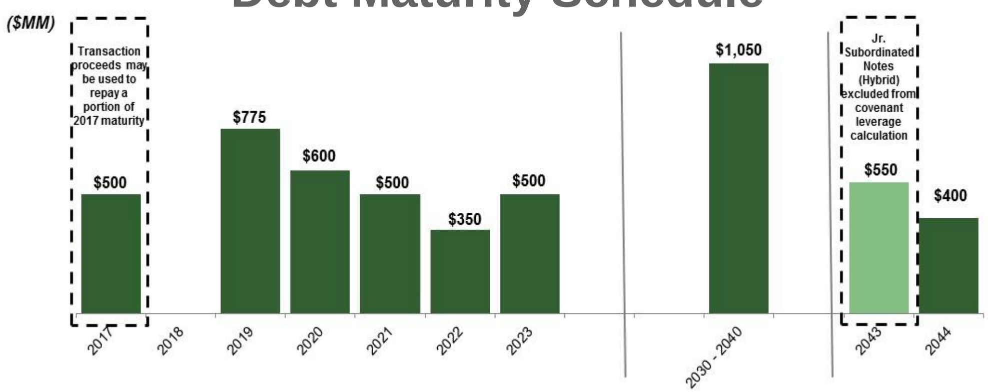
Growth in fee based margins coupled with multi-year hedging program provides downside protection on commodity exposed margin

2017e Liquidity and Credit Metrics

Liquidity and Credit Ratings

- $1.25 billion credit facility
- ~$350 million available under ATM
- Credit Ratings(1): Ba2 / BB / BB+
- Portion of $424 million proceeds from January transaction used to repay $195MM of credit facility borrowings
  - Remaining proceeds available to prefund growth and/or repay a portion of $500 million December 2017 debt maturity

Debt Maturity Schedule



2017 Pro Forma

2017e Bank Leverage Calculation(2)	($MM)
Midstream Debt (12/31/16)	$3,150
Jr. Subordinated Debt (Hybrid)	(550)
DPM Debt (12/31/16)	2,075
Transaction Cash Received	(424)
Outstanding credit facility borrowings (12/31/16)	195
2017e Bank Debt	**$4,446**
DPM 2017e Adj EBITDA(3) (midpoint)	$575
Midstream 2017e Adjusted EBITDA(3) (midpoint)	450
Project EBITDA credits	TBD
2017e Adjusted EBITDA (midpoint)	**$1,025**
2017e Debt/ EBITDA	**<4.5x**

(1) Moody's / S&P / Fitch ratings
(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 which are treated as equity)
(3) 2017 Adjusted EBITDA definition has been updated to include distributions from unconsolidated affiliates, consistent with bank definition. See Non GAAP reconciliation in the appendix section

DCP has ample liquidity and financial flexibility

Pathway to Distribution Growth

Commitments Delivered

Contract Realignment
Lowered Cost Base
System Rationalization
Improved Reliability
Strengthened Balance Sheet

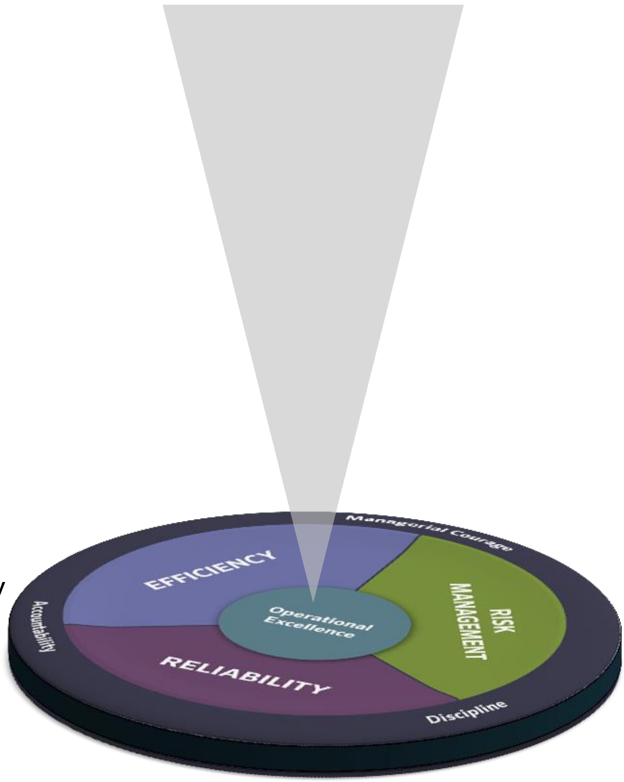
Increased and stabilizing cash flow
- Contract realignment ~$235 million since inception
- Growth in fee based assets to 60%
- Multi-year hedging program… currently 72% fee and hedged

Efficiencies
- Total base cost reductions ~$200 million
- Reduced headcount from ~3,500 to ~2,700
  - Running ~$7 billion larger asset base with same cost structure as 2011

System rationalization
- Sale of non-core assets (~$330 million cash proceeds)
- Consolidation of operations reduced costs (4 plants idled)
- Increased compressor utilization (320+ units idled)

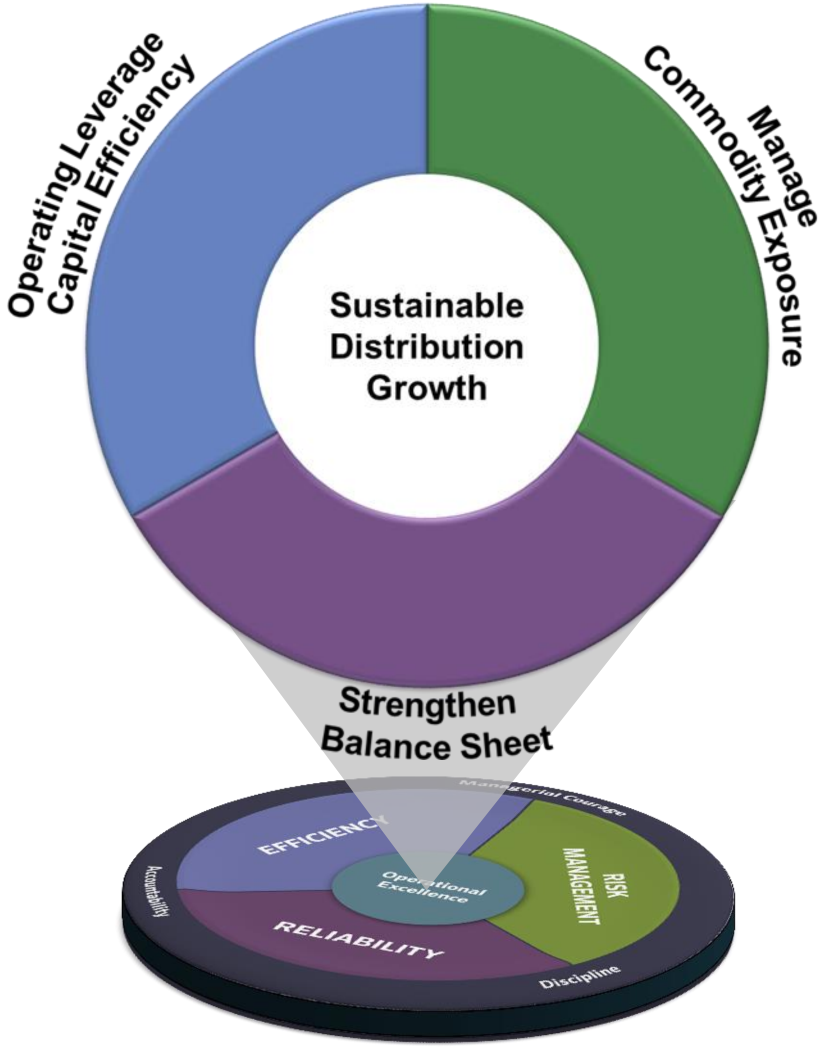
Improved Reliability
- Preventative maintenance process improvement
- Assets achieving best run time and reliability in recent history

Strengthened balance sheet
- $3 billion owner contribution
- ~$2 billion debt reduction since mid 2015
- DCP 2020 execution added incremental EBITDA



Aligned organization, delivering results, set up for 2017 and beyond

Financial Strategy



2018+ Financial Targets

Distribution coverage 1.2x+

Fee and hedged margin 80%+

Bank leverage 3.0-4.0x

Accretive growth projects 5-7x EBITDA

Distribution growth target 4-5%

Capital structure debt/equity 50:50

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

Growth Opportunities and Operating Leverage

Visibility to $1.5-2.0B capital efficient growth opportunities

DJ Basin

- $395 million plant and gathering system expansion (Q4'18)
- Capital efficient offloads and bypass to bridge to new capacity
- Additional 200MMcfd plant in 2019

Permian

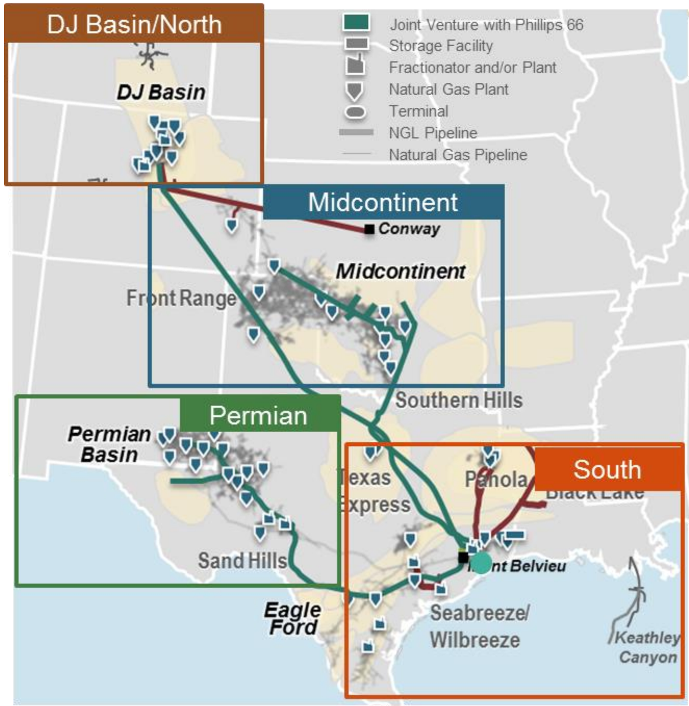
- Utilize existing capacity to capture new growth
- Leverage Sand Hills pipeline

Midcontinent

- Use excess capacity to capture SCOOP/STACK growth
- Strong customer dedication in SCOOP lowers volume growth risk

South

- Operating leverage via idled plants



Announced Growth Projects	Status	Est. Capex ($MM)	Target in Service
Sand Hills expansion	In progress	~$70	Q4 2017
DJ 200 MMcf/d Mewbourn 3	In progress	~$395	Q4 2018
DJ Basin bypass	In progress	~$25	Mid 2017
DJ 200 MMcf/d Plant 11	In development	~$350-400	Mid 2019

~$900 million

NGL Logistics

- Sand Hills expanding due to Permian growth
  - $70 million expansion to full capacity (365MBpd) by Q4'17
  - Opportunity to further expand
- Southern Hills growth via SCOOP/ STACK and ethane recovery
- Front Range/Texas Express driven by DJ Basin growth

Ethane Recovery

- Industry rejecting 600Mbd+ of ethane
- DCP well positioned for upside from new ethane demand
  - NGL transportation growth
  - Improved processing economics

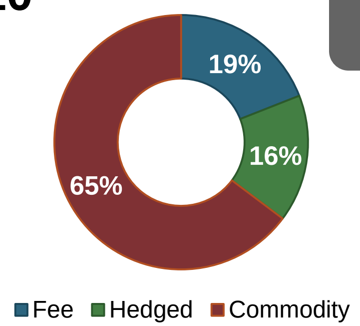
Existing asset portfolio has significant upside potential via prudent growth projects, maximizing operating leverage and capital efficiency

Managing Commodity Exposure

Combined DCP contract mix

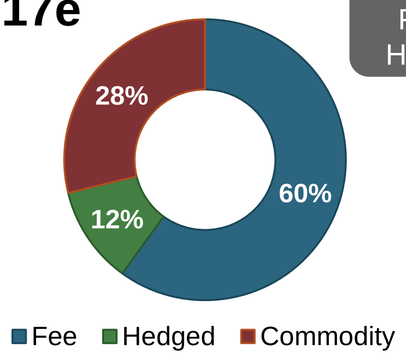
2010

35% Fee & Hedged



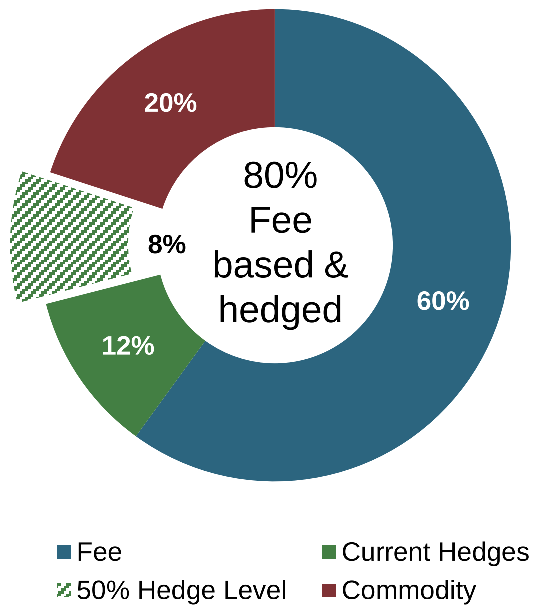
2017e

72% Fee & Hedged



Hedging strategy

- Targeting 80%+ fee based and hedged margin
- Targeting accretive hedges that stabilize cash flows providing downside protection



Fee based asset growth

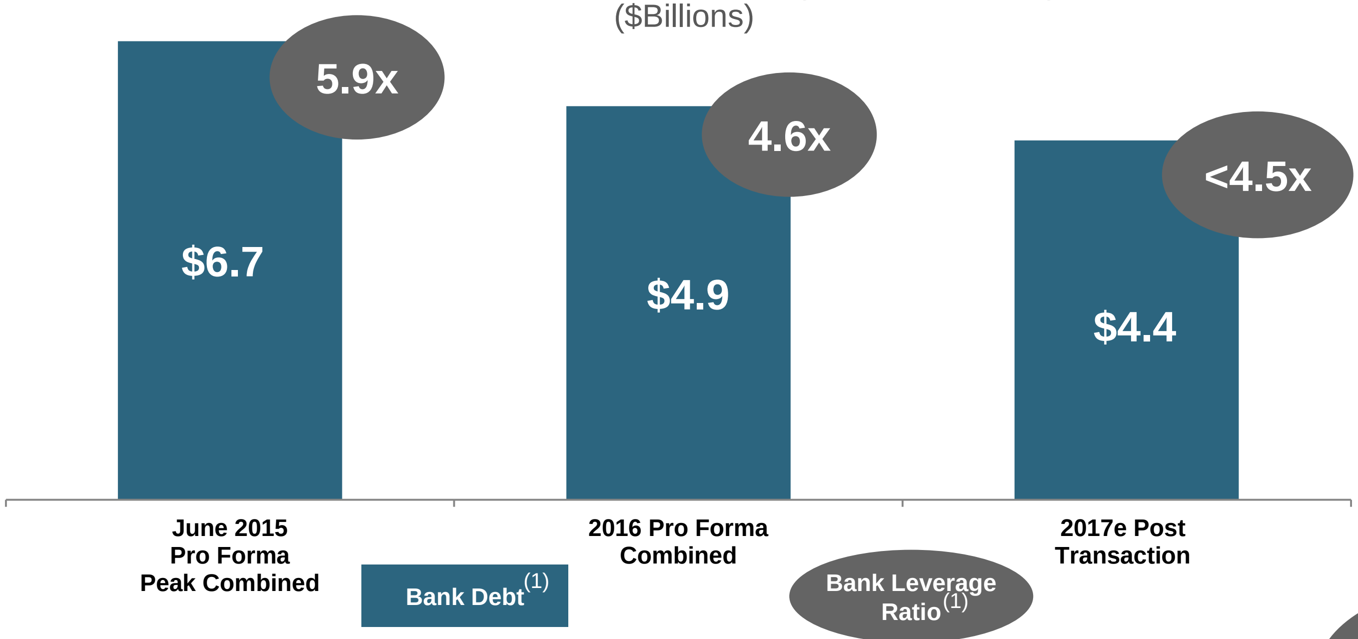
- Sand Hills capacity expansion servicing Permian growth
- DJ Basin O’Connor bypass capacity expansion bridges gap to Mewbourn 3
- Contract realignment (Permian and Midcontinent) provides incremental fee based revenues
- Ethane recovery increases capacity utilization of NGL pipelines

Create cash flow stability through fee based asset growth and strategic hedging

Strengthening the Balance Sheet

Pro Forma Combined Leverage Trending Down

($Billions)



Targeting 3.0-4.0x Leverage

Achieved to date

- Capital prioritization
- Base cost reduction
- Contract realignment
- Over $2 billion of debt reduction

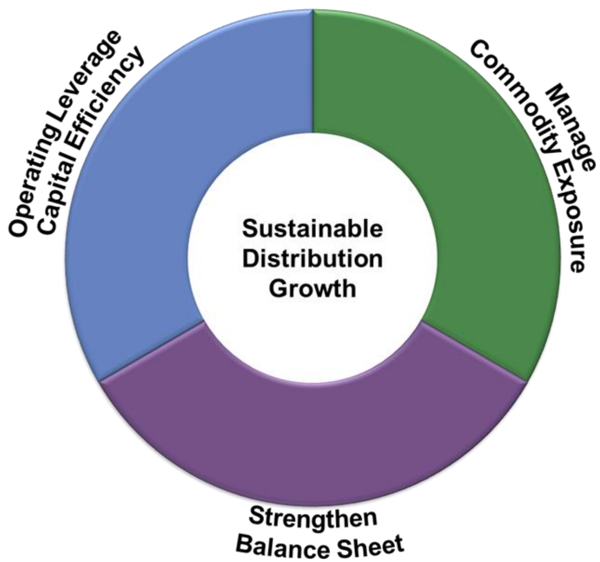
Continued focus

- Accretive growth
- Capital efficiency
- Operating leverage
- Sustained industry improvement
- Targeting 3.0-4.0x bank leverage
- Grow fee based and hedged margin

(1) 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 which are treated as equity)

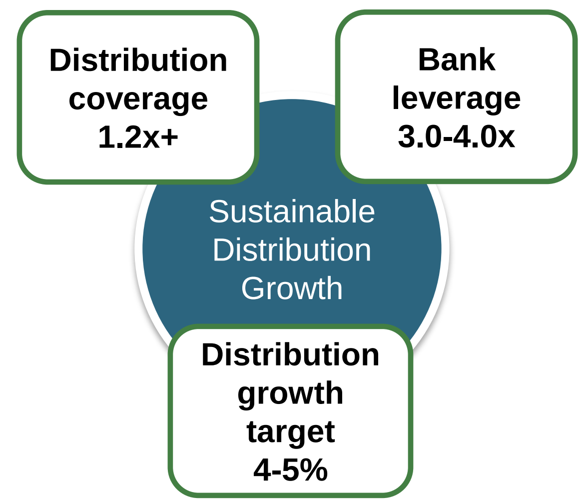
Strengthening balance sheet through value creation and risk management

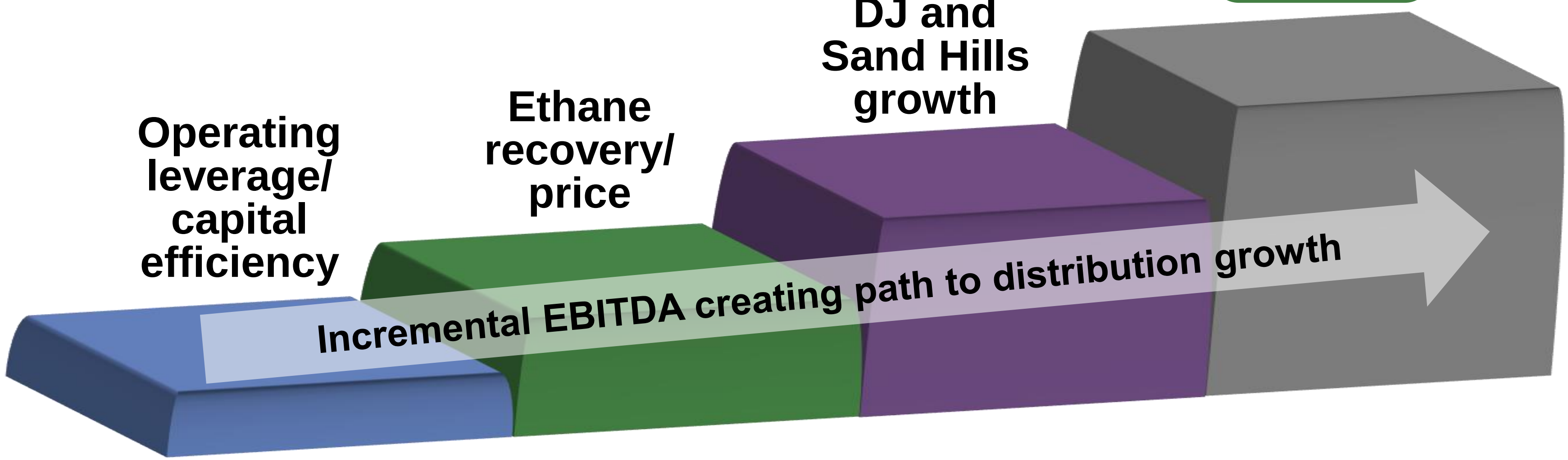
Path Forward



DCP is well positioned to benefit from industry recovery via volume growth, operating leverage and commodity price recovery

2018+ Targets

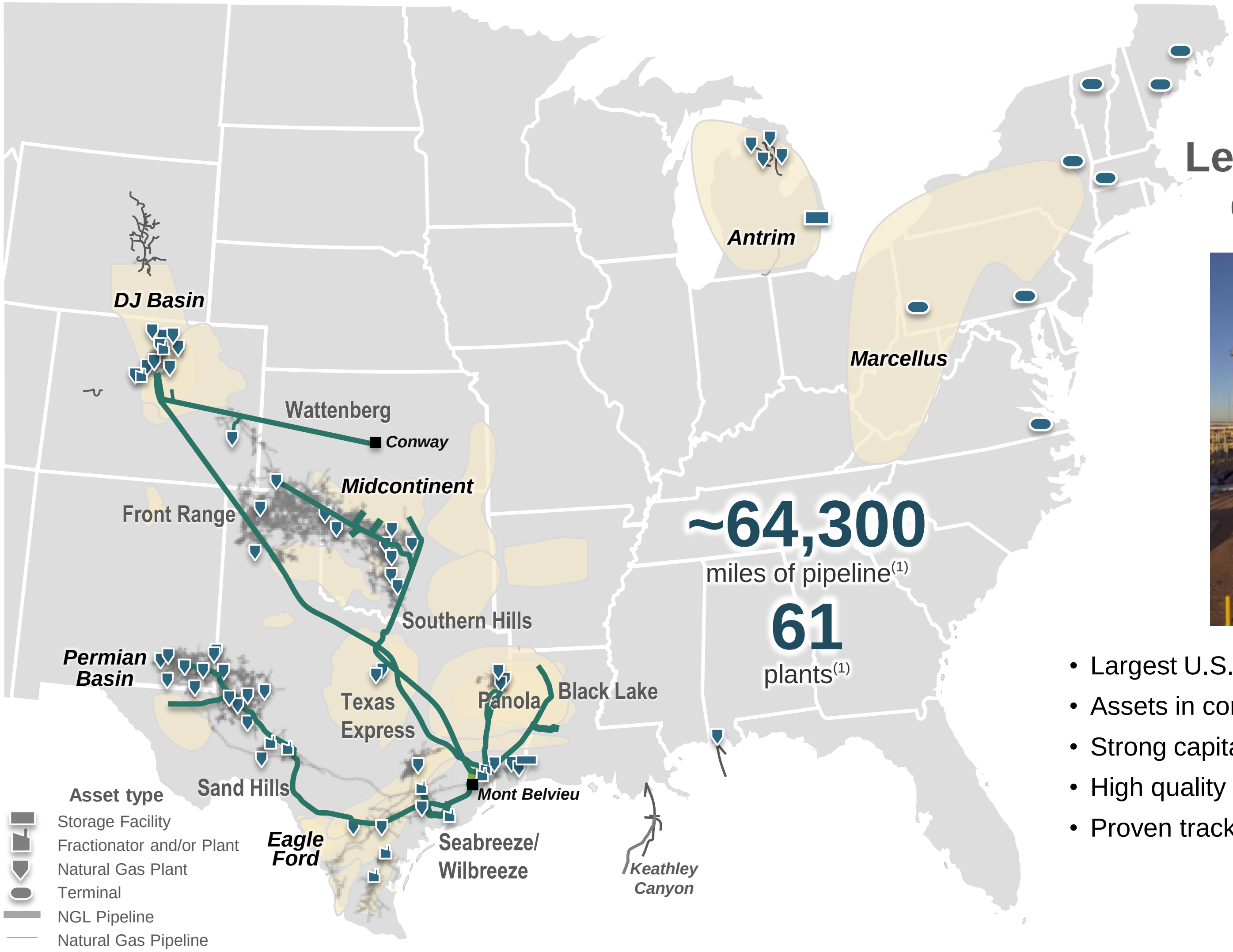




Deliver distribution growth through operating leverage and capital efficiency

DCP Midstream – Appendix

Industry Leading Position



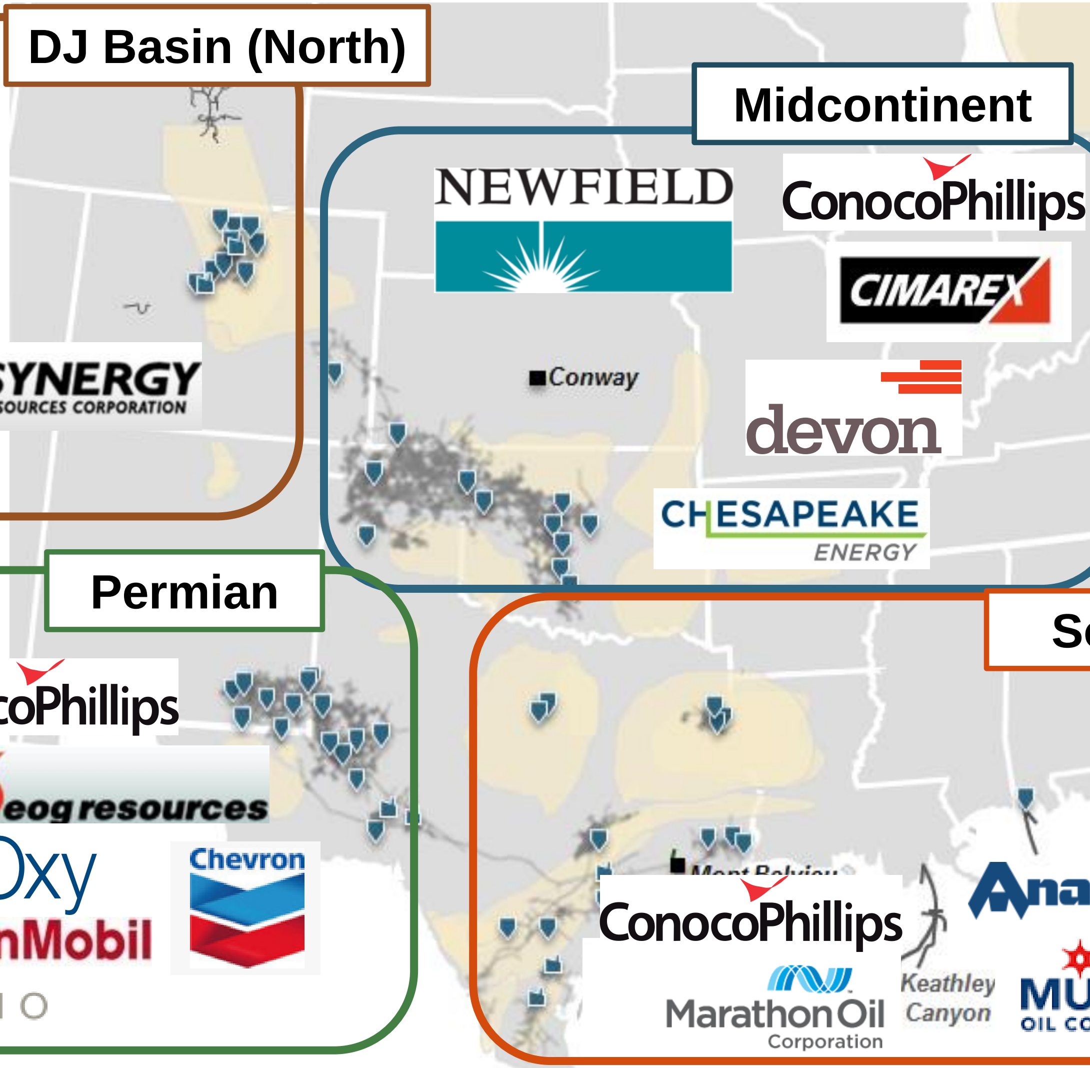
Leading integrated G&P company

- Largest U.S. NGL producer and gas processor
- Assets in core areas
- Strong capital efficiency and asset utilization
- High quality customers and producers
- Proven track record of strategy execution

(1) Statistics as of December 31, 2016

Must-run business with competitive footprint and geographic diversity

Strong Producers in Key Basins



DJ Basin (North)

- noble energy
- PDC ENERGY
- EXTRACTION Oil & Gas
- Anadarko
- SYNERGY RESOURCES CORPORATION
- Bill Barrett Corporation

Midcontinent

- NEWFIELD
- ConocoPhillips
- CIMAREX
- devon
- CHESAPEAKE ENERGY

Permian

- devon
- Apache
- ConocoPhillips
- Anadarko
- eog resources
- CIMAREX
- Oxy
- Chevron
- ExxonMobil
- CONCHO

South

- ConocoPhillips
- Anadarko
- Marathon Oil Corporation
- MURPHY OIL CORPORATION

DCP's volume and margin portfolio is supported by long term agreements with a diverse number of high quality producers in key producing regions

Logistics and Marketing Overview

DCP Logistics Assets

Other Regional Stats

NGL Storage Capacity	8 MMBls
Gas Storage Capacity	12 Bcf

Key Attributes

- 100% fee based margin
- NGL pipeline margin represents majority of the total margin
- Increased pipeline throughput driving strong fee based margin growth

Pipeline	% Owned	Approx. System Length (Miles)	Approx. Gross Throughput Capacity (MBbls/d)	YTD 2016 Gross Pipeline Throughput (MBbls/d)	YTD 2016 Net Pipeline Throughput (MBbls/d)(1)	2016 Pipeline Utilization
Sand Hills	66.7%	1,160	280(2)	236	158	85%
Southern Hills	66.7%	940	175	97	65	55%
Front Range	33.3%	450	150	101	34	67%
Texas Express	10%	595	280	149	15	55%
Black Lake	100%	315	80	55	55	70%
Other(3)		970	135	116	75	85%
NGL Pipelines		**4,480**	**1,100**		**402**	

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

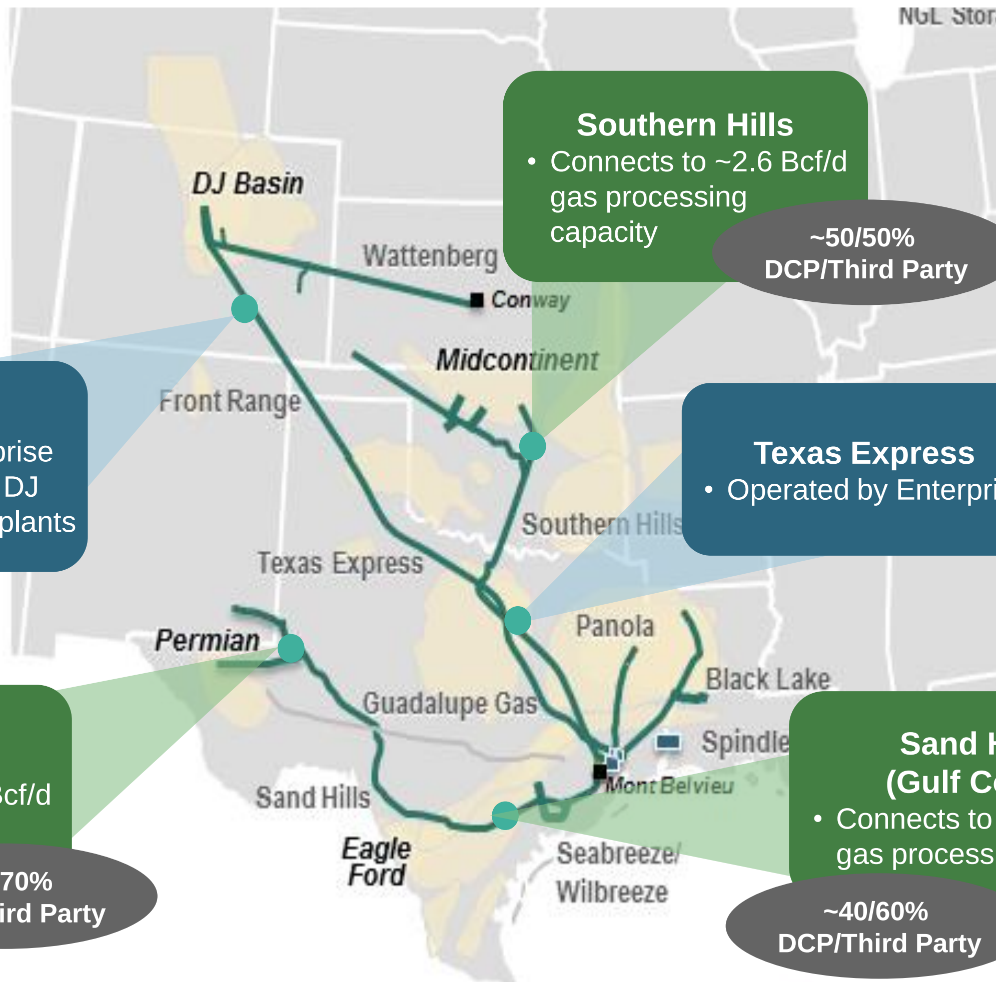
NGL volume growth driven by production in the DJ, Permian and SCOOP/STACK plays

NGL Pipeline Customers

Customer centric NGL pipeline takeaway… providing open access to premier demand markets along the Gulf Coast and at Mont Belvieu

Legend:

- DCP operated
- Third party operated



Southern Hills
- Connects to ~2.6 Bcf/d gas processing capacity

~50/50% DCP/Third Party

Front Range
- Operated by Enterprise
- Connected to DCP DJ Basin & third party plants

Texas Express
- Operated by Enterprise

Sand Hills (Permian)
- Connects to ~4.4 Bcf/d gas processing capacity

~30/70% DCP/Third Party

Sand Hills (Gulf Coast)
- Connects to ~1.2 Bcf/d gas processing capacity

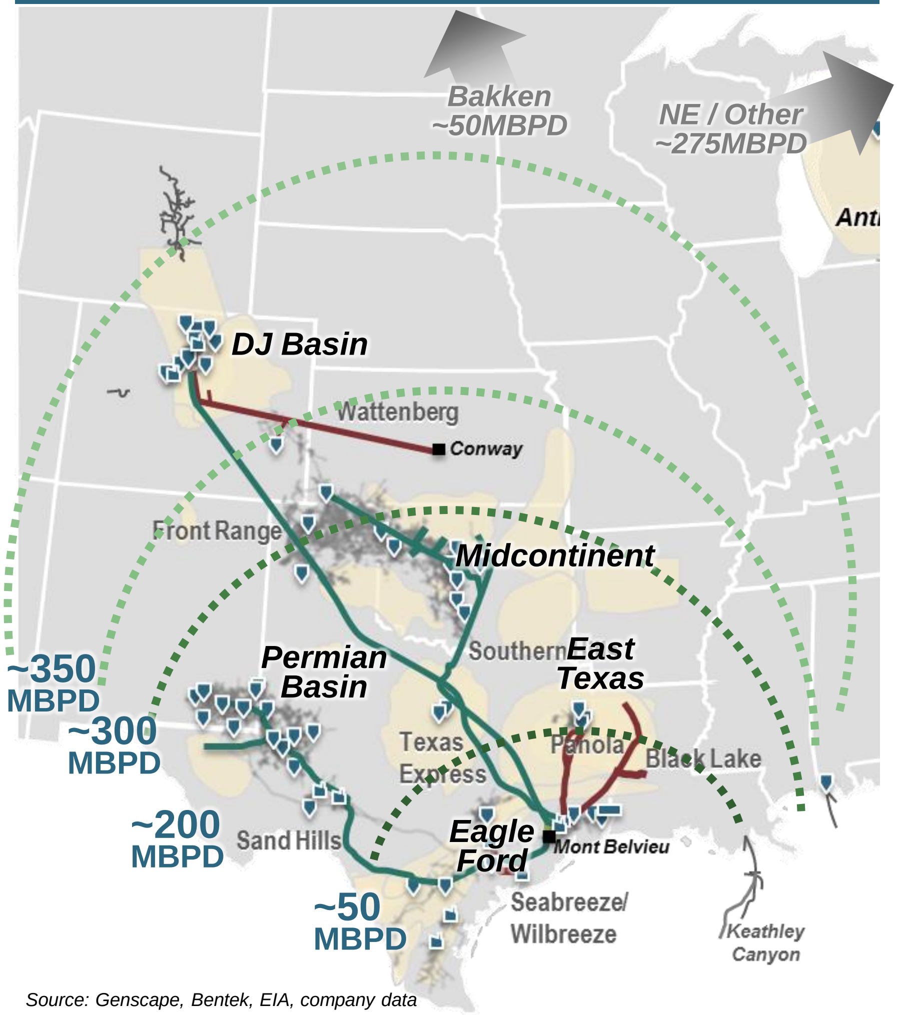
~40/60% DCP/Third Party

NGL pipelines backed by plant dedications from DCP and third parties with strong growth outlooks

Ethane Recovery Opportunity

- DCP is well positioned for upside from ethane recovery
  - **NGL pipelines poised for ~$75-100 million volume/margin uplift[(1)]**
    - About half is ethane uplift on NGL pipelines utilizing current capacity
    - Remainder would require capital investment
- Demand should drive ethane prices higher in its relationship to gas incentivizing midstream companies to extract ethane
  - G&P contracts to further benefit from ethane price uplift
  - Ethane price must cover cost to transport and fractionate (T&F) to make recovery economic
  - T&F is higher further away from Mont Belvieu
- Markets around DCP's footprint are closer to Mont Belvieu and should see benefits first
- ~ 350,000 Bpd of industry ethane being rejected around DCP's footprint
- Industry is rejecting >600,000 Bpd of ethane

DCP plants rejecting ~60,000 – 65,000 bpd



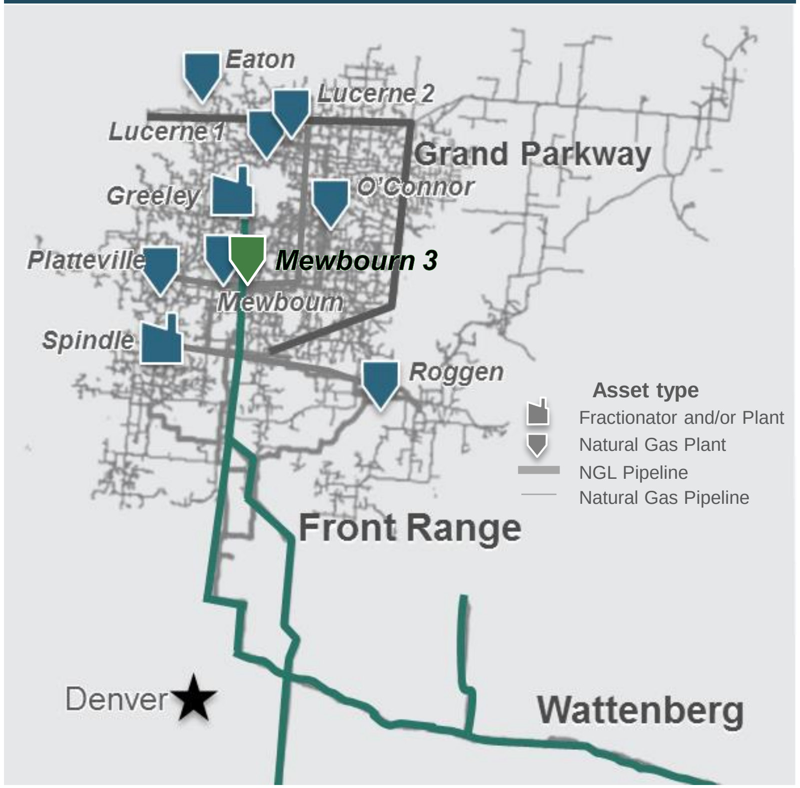
Source: Genscape, Bentek, EIA, company data

(1) Represents DCP's ownership interest

DCP positioned to benefit from both commodity uplift as well as product flow

North Region Overview

DCP DJ Basin Assets



DJ Basin Expansion

- $395 million DJ Expansion (in service Q4'18)
  - Mewbourn 3: 200MMcf/d new processing plant
  - Grand Parkway expansion
- Utilize capital efficient offloads and bypass to bridge to new capacity
- 200MMcf/d Plant 11 expansion in 2019

North Operating Data YTD December 31, 2016

	Gas & NGL Gathering Systems (Miles)	Active Plant / Treater Count	Available Plant Capacity (Bcf/d) (1)	Total Wellhead Volumes (Bcf/d)	NGL Production (MBbls/d)	Plant Utilization (1)
DJ Basin	3,510	9	0.8	0.8	78	100%
WY/MI/Collbran	1,940	3	0.4	0.3	4	~75%
North	**5,450**	**12**	**1.2**	**1.1**	**82**	**~90%**

North Plant Listing

Region	Sub-Region	Location (County)	Plant Name	Ownership %	Gross Nameplate Capacity (MMcf/d)
North	DJ Basin	Weld, CO	Lucerne 1 (2)	100%	35
North	DJ Basin	Weld, CO	O'Connor (2)	100%	160
North	DJ Basin	Weld, CO	Lucerne 2 (2)	100%	200
North	DJ Basin	Weld, CO	Eaton	100%	10
North	DJ Basin	Weld, CO	Greeley	100%	30
North	DJ Basin	Weld, CO	Mewbourn	100%	160
North	DJ Basin	Weld, CO	Platteville	100%	65
North	DJ Basin	Weld, CO	Roggen	100%	70
North	DJ Basin	Weld, CO	Spindle	100%	40
North	**DJ Basin**		**Active Plants: 9**		**770 ***
North	Michigan	Otsego, MI	Antrim	100%	350
North	Michigan	Otsego, MI	Turtle Lake	100%	30
North	Michigan	Antrim, MI	Warner	100%	40
North	**Michigan**		**Active Treaters: 3**		**420**

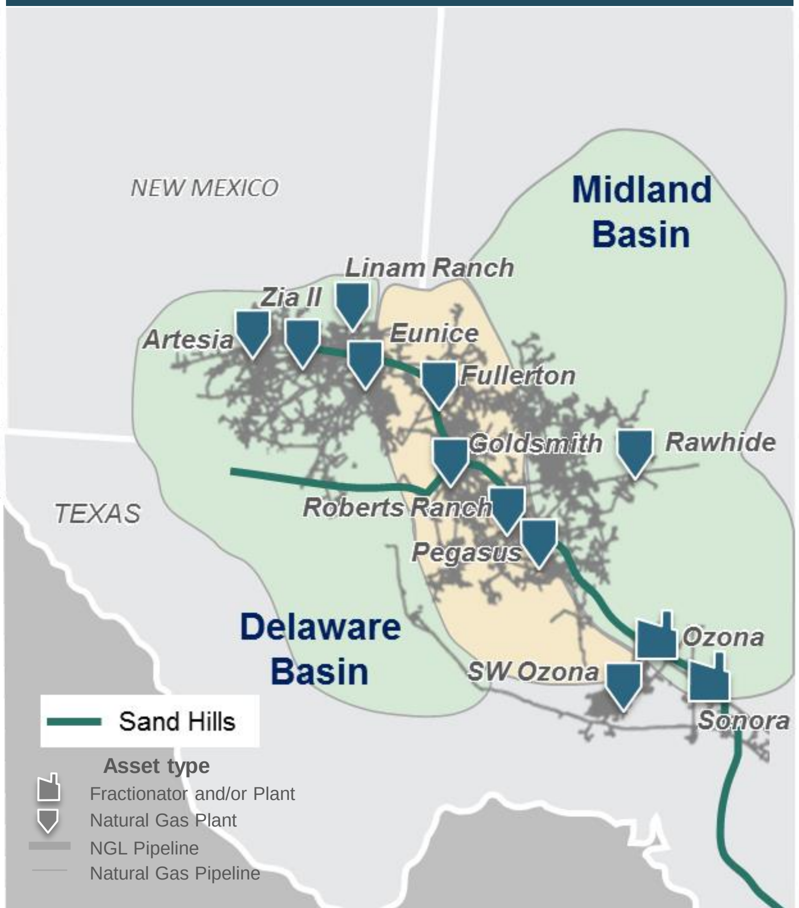
*Excludes ~30MMcf/d of bypass capacity

(1) Plant utilization divides gas throughput by available plant capacity, excludes idled plant capacity
(2) Legacy DPM Plant

High capacity utilization with the strongest G&P contracts in the DCP portfolio

Permian Region Overview

DCP Permian Assets



Recent Expansion

- 200MMcf/d Zia II Sour Gas Processing Plant – Q3'15

Permian Operating Data YTD December 31, 2016

	Gas & NGL Gathering Systems (Miles)	Active Plant Count	Available Plant Capacity (Bcf/d)(1)	Total Wellhead Volumes (Bcf/d)	NGL Production (MBbls/d)	Plant Utilization(1)
Permian	16,300	12	1.3	1.1	107	~80%

Permian Plant Listing

Region	Sub-Region	County	Name	Ownership %	Net Processing Capacity (MMcf/d)
Permian	Central	Andrews	Fullerton	100%	70
Permian	Central	Ector	Goldsmith	100%	160
Permian	Midland	Crockett	Ozona	63%	75
Permian	Midland	Sutton	Sonora	100%	71
Permian	Midland	Crockett	SW Ozona	100%	95
Permian	Midland	Midland	Pegasus	90%	90
Permian	Midland	Glasscock	Rawhide	100%	75
Permian	Midland	Midland	Roberts Ranch	100%	75
Permian	Delaware	Eddy	Artesia	100%	90
Permian	Delaware	Lea	Eunice - DCP	100%	105
Permian	Delaware	Lea	Linam Ranch	100%	225
Permian	Delaware	Lea	Zia II	100%	200
Permian			**Active Plants: 12**		**1,331**

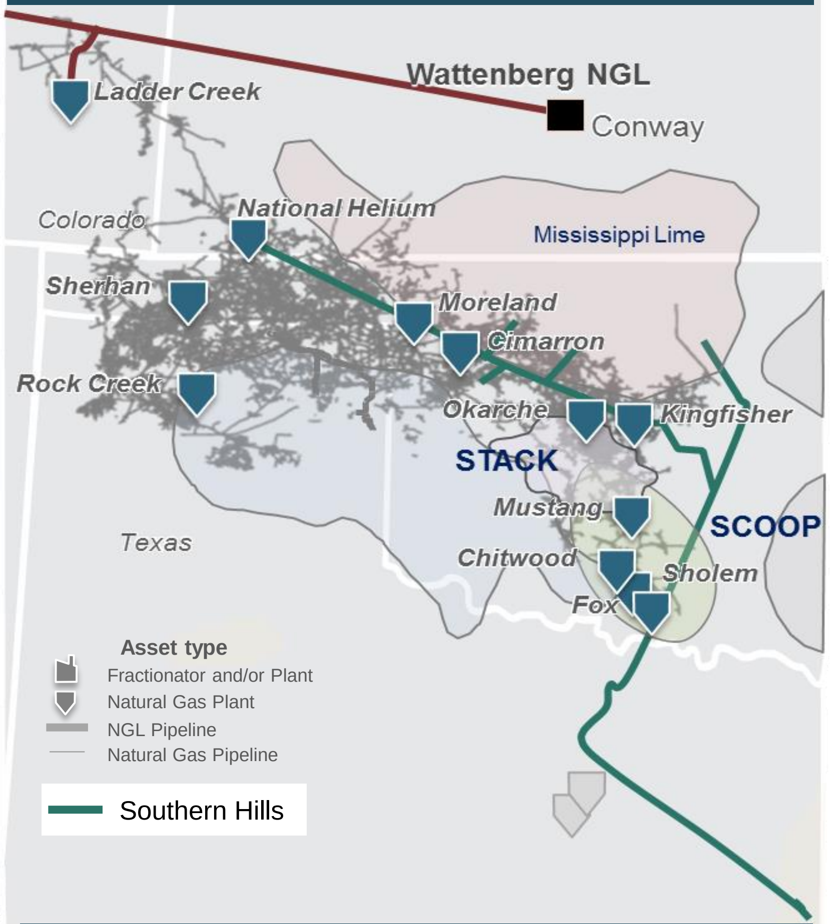
(1) Plant utilization divides gas throughput by available plant capacity, excludes idled plant capacity

Recently added Zia II to our Northern Delaware position

Leveraging improved reliability and customer focus to attract growth opportunities

Midcontinent Region Overview

DCP Midcontinent Assets



Recent Expansion

- National Helium upgrade in Q4 '15 increased NGL production capabilities & efficiencies

Midcontinent Operating Data YTD December 31, 2016

	Gas & NGL Gathering Systems (Miles)	Active Plant Count	Available Plant Capacity (Bcf/d)(1)	Total Wellhead Volumes (Bcf/d)	NGL Production (MBbls/d)	Plant Utilization(1)
SCOOP/STACK	8,100	8	0.7	0.7	60	~90%
Liberal/Panhandle	21,300	4	1.0	0.6	34	~60%
Midcontinent	**29,400**	**12**	**1.7**	**1.3**	**94**	**~65%**

Midcontinent Plant Listing

Region	Sub-Region	County	Name	Ownership %	Net Processing Capacity (MMcf/d)
MidCon	SCOOP/STACK	Grady	Chitwood	100%	90
MidCon	SCOOP/STACK	Carter	Fox	100%	25
MidCon	SCOOP/STACK	Grady	Mustang	100%	38
MidCon	SCOOP/STACK	Stephens	Sholem	100%	60
MidCon	SCOOP/STACK	Woodward	Cimarron	100%	60
MidCon	SCOOP/STACK	Kingfisher	Kingfisher	100%	180
MidCon	SCOOP/STACK	Woodward	Mooreland	98%	117
MidCon	SCOOP/STACK	Kingfisher	Okarche	100%	165
	SCOOP/STACK		**Active Plants: 8**		**735**
MidCon	Liberal	Cheyenne	Ladder Creek	100%	40
MidCon	Liberal	Seward	National Helium	100%	550
MidCon	Panhandle	Hutchinson	Rock Creek	100%	170
MidCon	Panhandle	Hansford	Sherhan	100%	270
	Liberal/Panhandle		**Active Plants: 4**		**1,030**

(1) Plant utilization divides gas throughput by available plant capacity, excludes idled plant capacity

Well positioned to capture SCOOP/STACK growth and maximize operating leverage

South Overview

DCP South Assets

(1) Plant utilization: gas throughput divided by active plant capacity, excludes idled plant capacity

South Operating Data YTD December 31, 2016

	Gas & NGL Gathering Systems (Miles)	Active Plant Count	Available Plant Capacity (Bcf/d)(1)	Total Wellhead Volumes (Bcf/d)	NGL Production (MBbls/d)	Plant Utilization(1)
Eagle Ford	6,100	6	0.9	0.7	66	~75%
E Texas	875	2	0.8	0.5	23	~60%
Gulf Coast/North LA(3)	1,500	5	0.9	0.5	18	~60%
South	**8,475**	**13**	**2.6**	**1.7**	**107**	**~65%**

South Plant Listing

Region	Sub-Region	County	Name	Ownership %	Net Processing Capacity (MMcf/d)
South	Eagle Ford	Jackson	Eagle (2)	100%	200
South	Eagle Ford	Fayette	Giddings (2)	100%	85
South	Eagle Ford	Nueces	Gulf Plains(2)	100%	160
South	Eagle Ford	Lavaca	Wilcox (2)	100%	200
South	Eagle Ford	Goliad	Goliad (2)	100%	200
South	Eagle Ford	Live Oak	Three Rivers(2)	100%	90
	Eagle Ford		**Active Plants: 6**		**935**
South	East TX	Panola	East Texas Complex(2)	100%	660
South	East TX	Panola	George Gray(2)	100%	120
	East TX		**Active Plants: 2**		**780**
South	Gulf Coast	St Charles	Discovery-LaRose(2)	40%	240
South	Gulf Coast	Jefferson	Port Arthur	100%	230
South	Gulf Coast	Mobile	Mobile Bay	100%	300
South	Gulf Coast	Terrebonne	N. Terrebonne	8%	114
South	Gulf Coast	St Bernard	Toca	1%	8
	Gulf Coast		**Active Plants: 5**		**892**

(1) Plant utilization divides gas throughput by available plant capacity, excludes idled plant capacity
(2) Legacy DPM Plant
(3) North LA was sold June 1, 2016

Aggressively managing utilization and controlling costs in the Eagle Ford and East Texas where there is excess capacity

Growth Projects in Execution or Development

New plants in the DJ Basin and Sand Hills capacity expansion

G&P: DJ Basin Expansion

- Cooperative development plan with key producers
- $395 million DJ Basin expansion
  - 200 MMcf/d processing plant (Mewbourn 3)
  - Grand Parkway Phase 2 low pressure gathering system and related compression
  - 5-7x multiple
  - Expected in service YE'18
- Currently constructing additional field compression and plant bypass infrastructure
  - ~40 MMcf/d of incremental capacity
  - Expected in service mid'17
- 200MMcf/d plant 11 by 2019 (in development)
  - ~$350-400 million capital investment

Logistics & Marketing: Sand Hills Expansion

- Visible growth expected from Delaware Basin and ethane recovery
- $70 million expansion of Sand Hills (DCP to fund two-thirds)
  - Install three additional pump stations and a lateral
- Increases capacity to ~365 MBbls/d from 280 MBbls/d
  - Backed by long term, 10-20 year 3rd party plant dedications
  - ~2x multiple
- Expected in service YE'17

Strategic low-risk/low-multiple organic growth projects create upside in 2018 and beyond

Financial Schedules & Non GAAP Reconciliations

Consolidated Financial Results

($ in millions, except per unit amounts)	Three Months Ended December 31, 2016	Three Months Ended December 31, 2015	Twelve Months Ended December 31, 2016	Twelve Months Ended December 31, 2015
Sales, transportation, processing and other revenues	$413	$407	$1,517	$1,813
(Losses) gains from commodity derivative activity, net	(15)	28	(20)	85
Total operating revenues	**398**	**435**	**1,497**	**1,898**
Purchases of natural gas, propane and NGLs	(254)	(257)	(946)	(1,246)
Operating and maintenance expense	(42)	(58)	(183)	(214)
Depreciation and amortization expense	(31)	(32)	(122)	(120)
General and administrative expense	(24)	(21)	(88)	(85)
Goodwill impairment	—	—	—	(82)
Gain on sale of assets	—	—	47	—
Other expense	—	(4)	(7)	(4)
Total operating costs and expenses	**(351)**	**(372)**	**(1,299)**	**(1,751)**
Operating income	**47**	**63**	**198**	**147**
Interest expense	(23)	(23)	(94)	(92)
Earnings from unconsolidated affiliates	55	52	214	173
Income tax benefit	1	2	—	5
Net income attributable to noncontrolling interests	(5)	(4)	(6)	(5)
Net income attributable to partners	**$75**	**$90**	**$312**	**$228**
Adjusted EBITDA	**$151**	**$176**	**$594**	**$656**
Distributable cash flow	**$120**	**$145**	**$537**	**$572**
Distribution coverage ratio – declared	**0.99x**	**1.20x**	**1.11x**	**1.18x**
Distribution coverage ratio – paid	**1.00x**	**1.21x**	**1.11x**	**1.19x**

Commodity Derivative Activity

($ in millions)	Three Months Ended December 31, 2016	Three Months Ended December 31, 2015	Twelve Months Ended December 31, 2016	Twelve Months Ended December 31, 2015
Non-cash losses – commodity derivative	$(25)	$(25)	$(108)	$(130)
Other net cash hedge settlements received	10	53	88	215
(Losses) gains from commodity derivative activity, net	$(15)	$ 28	$(20)	$ 85

Balance Sheet

	December 31, 2016	December 31, 2015
	(Millions)	
Cash and cash equivalents	$ 1	$ 2
Other current assets	226	304
Property, plant and equipment, net	3,272	3,476
Other long-term assets	1,662	1,695
Total assets	$ 5,161	$ 5,477
Current liabilities	$ 234	$ 200
Current portion of long-term debt	500	—
Long-term debt	1,750	2,424
Other long-term liabilities	44	48
Partners' equity	2,601	2,772
Noncontrolling interests	32	33
Total liabilities and equity	$ 5,161	$ 5,477

Non GAAP Reconciliation

	Three Months Ended December 31,		Year Ended December 31,	
	2016	2015	2016	2015
	(Millions, except per unit amounts)			
Reconciliation of Non-GAAP Financial Measures:				
Net income attributable to partners	$ 75	$ 90	$ 312	$ 228
Interest expense	23	23	94	92
Depreciation, amortization and income tax expense, net of noncontrolling interests	28	29	120	114
Goodwill impairment	—	—	—	82
Discontinued construction projects	—	9	—	10
Other charges	—	—	7	—
Gain on sale of assets	—	—	(47)	—
Non-cash commodity derivative mark-to-market	25	25	108	130
Adjusted EBITDA	151	176	594	656
Interest expense	(23)	(23)	(94)	(92)
Maintenance capital expenditures, net of noncontrolling interest portion and reimbursable projects	(4)	(5)	(10)	(25)
Distributions from unconsolidated affiliates, net of earnings	6	5	44	28
Impact of minimum volume receipt for throughput commitment	(10)	(10)	—	(1)
Other, net	—	2	3	6
Distributable cash flow	$ 120	$ 145	$ 537	$ 572
Net cash provided by operating activities	$ 120	$ 157	$ 575	$ 650
Interest expense	23	23	94	92
Distributions from unconsolidated affiliates, net of earnings	(6)	(5)	(44)	(28)
Net changes in operating assets and liabilities	(4)	(17)	(126)	(174)
Net income attributable to noncontrolling interests, net of depreciation and income tax	(5)	(4)	(7)	(6)
Non-cash commodity derivative mark-to-market	25	25	108	130
Other, net	(2)	(3)	(6)	(8)
Adjusted EBITDA	$ 151	$ 176	$ 594	$ 656
Interest expense	(23)	(23)	(94)	(92)
Maintenance capital expenditures, net of noncontrolling interest portion and reimbursable projects	(4)	(5)	(10)	(25)
Distributions from unconsolidated affiliates, net of earnings	6	5	44	28
Other, net	(10)	(8)	3	5
Distributable cash flow	$ 120	$ 145	$ 537	$ 572

Non GAAP Reconciliation

	Three Months Ended December 31, 2016	Three Months Ended December 31, 2015	Year Ended December 31, 2016	Year Ended December 31, 2015
	(Millions, except as indicated)			
Natural Gas Services Segment:				
Financial results:				
Segment net income attributable to partners	$ 66	$ 72	$ 275	$ 182
Non-cash commodity derivative mark-to-market	26	25	108	133
Depreciation and amortization expense	28	29	111	109
Goodwill impairment	—	—	—	82
Gain on sale of assets	—	—	(47)	—
Noncontrolling interest portion of depreciation and income tax	—	—	(1)	(1)
Other charges	—	9	7	10
Adjusted segment EBITDA	$ 120	$ 135	$ 453	$ 515
Operating and financial data:				
Natural gas throughput (MMcf/d)	2,098	2,705	2,449	2,714
NGL gross production (Bbls/d)	138,141	165,030	154,959	161,007
Operating and maintenance expense	$ 35	$ 50	$ 153	$ 184
NGL Logistics Segment:				
Financial results:				
Segment net income attributable to partners	$ 48	$ 50	$ 195	$ 174
Depreciation and amortization expense	2	2	8	8
Adjusted segment EBITDA	$ 50	$ 52	$ 203	$ 182
Operating and financial data:				
NGL pipelines throughput (Bbls/d)	283,014	266,009	289,395	261,659
NGL fractionator throughput (Bbls/d)	60,315	61,206	60,296	56,927
Operating and maintenance expense	$ 5	$ 5	$ 22	$ 20
Wholesale Propane Logistics Segment:				
Financial results:				
Segment net income attributable to partners	$ 7	$ 10	$ 24	$ 44
Non-cash commodity derivative mark-to-market	(1)	—	—	(3)
Depreciation and amortization expense	1	1	3	3
Adjusted segment EBITDA	$ 7	$ 11	$ 27	$ 44
Operating and financial data:				
Propane sales volume (Bbls/d)	15,607	13,749	13,309	15,685
Operating and maintenance expense	$ 2	$ 3	$ 8	$ 10

Non GAAP Reconciliation

	Three Months Ended December 31, 2016	Three Months Ended December 31, 2015	Year Ended December 31, 2016	Year Ended December 31, 2015
	(Millions, except as indicated)			
Reconciliation of Non-GAAP Financial Measures:				
Distributable cash flow	$ 120	$ 145	$ 537	$ 572
Distributions declared	$ 121	$ 121	$ 483	$ 483
Distribution coverage ratio - declared	0.99 x	1.20 x	1.11 x	1.18 x
Distributable cash flow	$ 120	$ 145	$ 537	$ 572
Distributions paid	$ 120	$ 120	$ 483	$ 482
Distribution coverage ratio - paid	1.00 x	1.21 x	1.11 x	1.19 x

	Q116	Q216	Q316	Q416	Twelve months ended December 31, 2016
	(Millions, except as indicated)				
Reconciliation of Non-GAAP Financial Measures:					
Net income attributable to partners	$ 72	$ 45	$ 120	$ 75	$ 312
Maintenance capital expenditures, net of noncontrolling interest portion and reimbursable projects	(2)	(1)	(3)	(4)	(10)
Depreciation, amortization and income tax expense, net of noncontrolling interests	32	29	31	28	120
Non-cash commodity derivative mark-to-market	45	37	1	25	108
Distributions from unconsolidated affiliates, net of earnings	14	11	13	6	44
Impact of minimum volume receipt for throughput commitment	3	4	3	(10)	—
Gain on sale of assets	—	—	(47)	—	(47)
Other, net	1	3	6	—	10
Distributable cash flow	$ 165	$ 128	$ 124	$ 120	$ 537
Distributions declared	$ 121	$ 121	$ 120	$ 121	$ 483
Distribution coverage ratio - declared	1.36x	1.06x	1.03x	0.99x	1.11x
Distributable cash flow	$ 165	$ 128	$ 124	$ 120	$ 537
Distributions paid	$ 121	$ 121	$ 121	$ 120	$ 483
Distribution coverage ratio - paid	1.36x	1.06x	1.02x	1.00x	1.11x

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