ENTERPRISE PRODUCTS PARTNERS L.P.

CITI MLP / MIDSTREAM INFRASTRUCTURE CONFERENCE

August 16–17, 2016

EPD LISTED NYSE

FORWARD–LOOKING STATEMENTS

This presentation contains forward-looking statements based on the beliefs of the company, as well as assumptions made by, and information currently available to our management team. When used in this presentation, words such as “anticipate,” “project,” “expect,” “plan,” “seek,” “goal,” “estimate,” “forecast,” “intend,” “could,” “should,” “will,” “believe,” “may,” “scheduled,” “potential” and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements.

Although management believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will prove to be correct. You should not put undue reliance on any forward-looking statements, which speak only as of their dates. Forward-looking statements are subject to risks and uncertainties that may cause actual results to differ materially from those expected, including insufficient cash from operations, adverse market conditions, governmental regulations, the possibility that tax or other costs or difficulties related thereto will be greater than expected, the impact of competition and other risk factors discussed in our latest filings with the Securities and Exchange Commission.

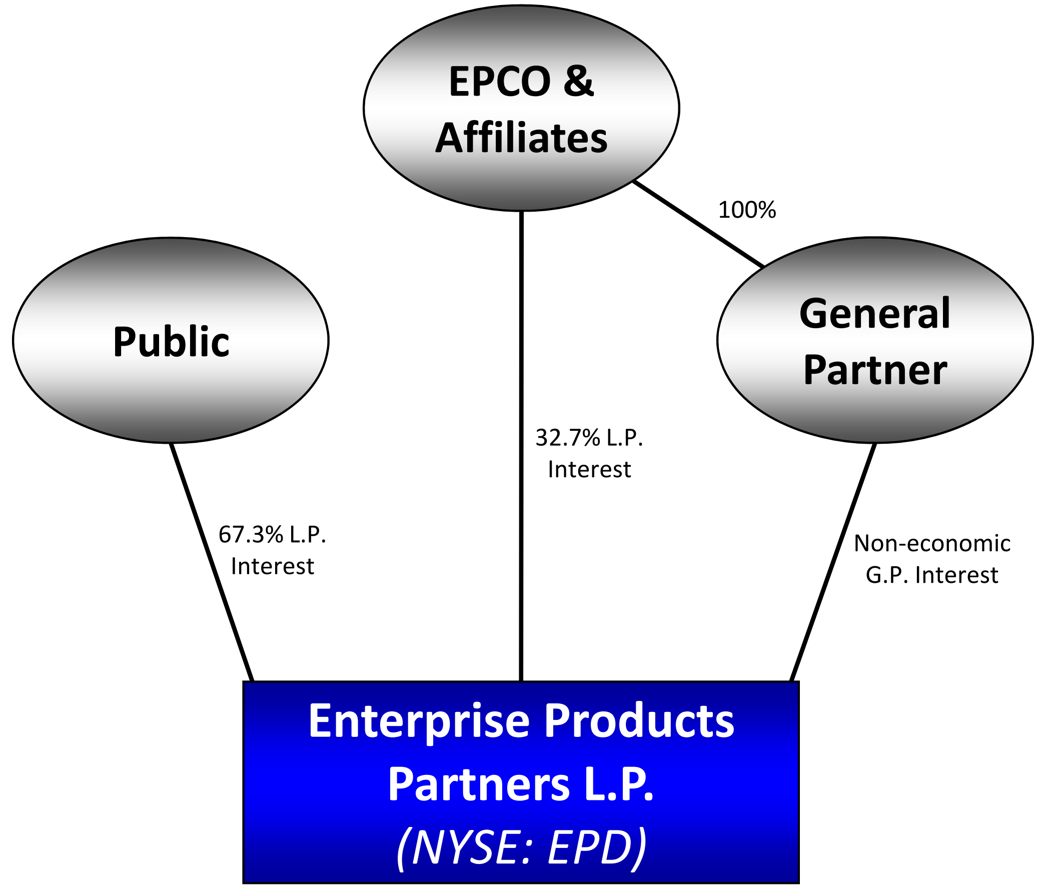
All forward-looking statements attributable to Enterprise or any person acting on our behalf are expressly qualified in their entirety by the cautionary statements contained herein, in such filings and in our future periodic reports filed with the Securities and Exchange Commission. Except as required by law, we do not intend to update or revise our forward-looking statements, whether as a result of new information, future events or otherwise.

KEY INVESTMENT CONSIDERATIONS

- One of the largest integrated midstream energy companies
  - Integrated system enables EPD to reduce impact of cyclical commodity swings
  - Large supply aggregator and access to domestic and international markets provides market optionality to producers and consumers
- History of successful execution of growth projects and M&A
  - ≈$35 billion of organic growth projects and $26 billion of major acquisitions since IPO in 1998
  - ≈$5.6 billion of capital growth projects under construction
  - New projects under development
- Low cost of capital; financial flexibility
  - One of the highest credit ratings among MLPs: Baa1 / BBB+
  - Simplified structure with no GP IDRs for long-term durability and flexibility
  - Margin of safety with average distribution coverage of ≈1.4x and ≈$5.3 billion of retained DCF since 1Q 2011 (excludes non-recurring items)
  - Consistent distribution growth: 48 consecutive quarters
- Financially strong, supportive GP committed for the long-term

SIGNIFICANT INSIDER OWNERSHIP

- Supportive GP with significant ownership
  - EPCO and affiliates own 33% of LP units
  - Facilitated elimination of IDRs in a non-taxable transaction through waiver of ≈$322 million in distributions from 2011 through 2015
  - Supported EPD's capital investments and financial flexibility by purchasing more than $800 million in EPD units since February 2010

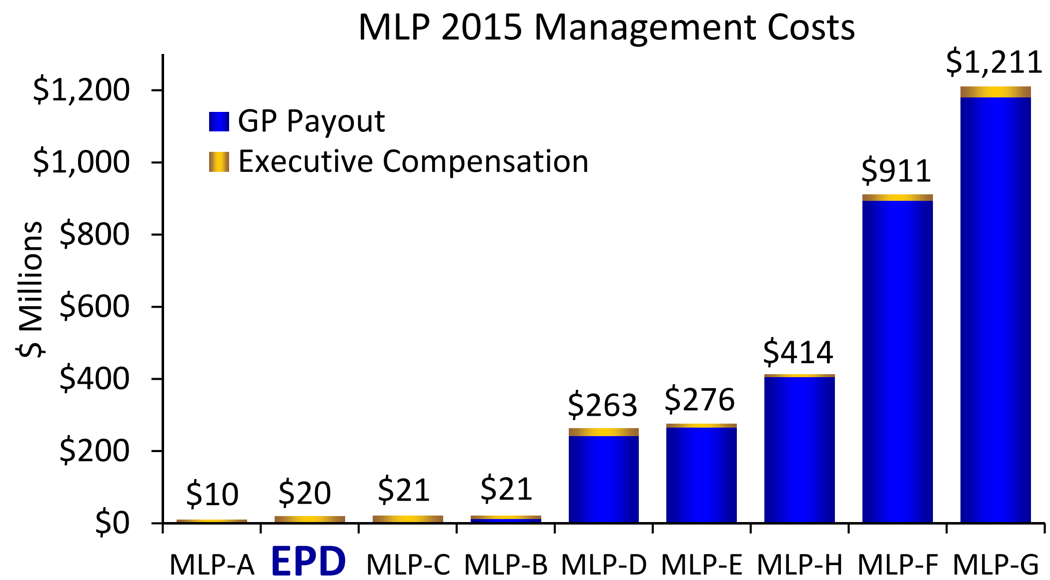


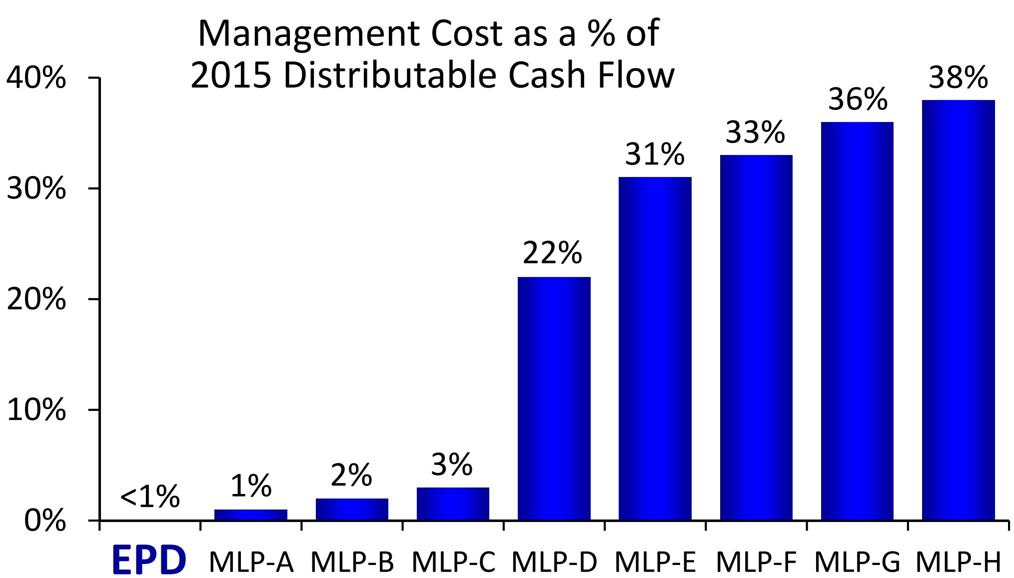
Note: as of July 31, 2016

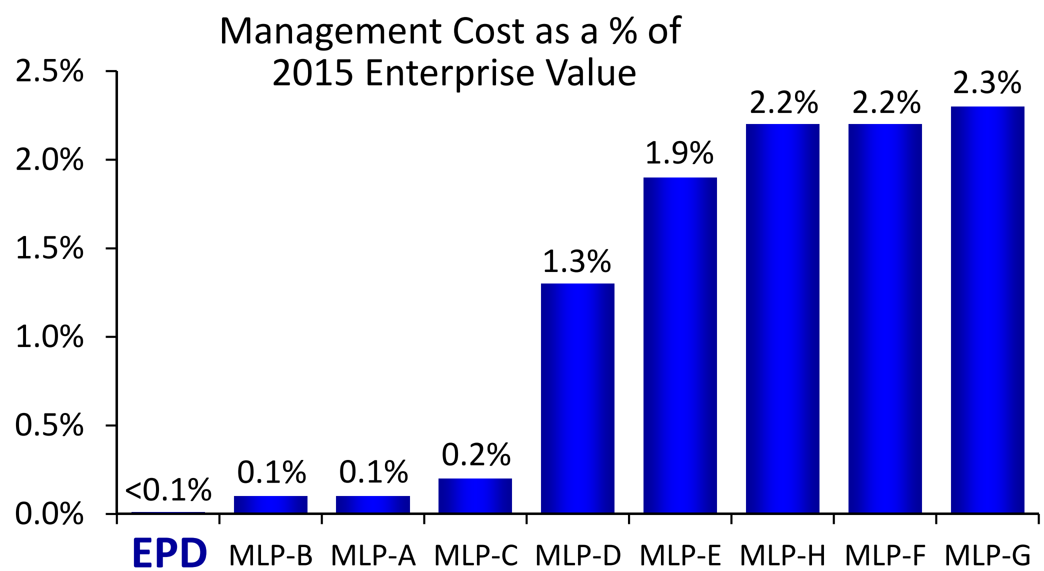
HOW MUCH DOES MLP MANAGEMENT COST?

Are You Getting Your Money's Worth?

- Traditionally and most appropriately, we evaluate GP IDRs as a component of an MLP's cost of capital
- This alternative analysis evaluates IDRs as a management cost similar to how an institutional investor would evaluate carried interest cost for a hedge fund/private equity investment as a % return (i.e. distributable cash flow) and AUM (i.e. enterprise value)
- Management cost defined as the sum of GP IDRs plus total compensation of the 5 named executive officers per SEC filings







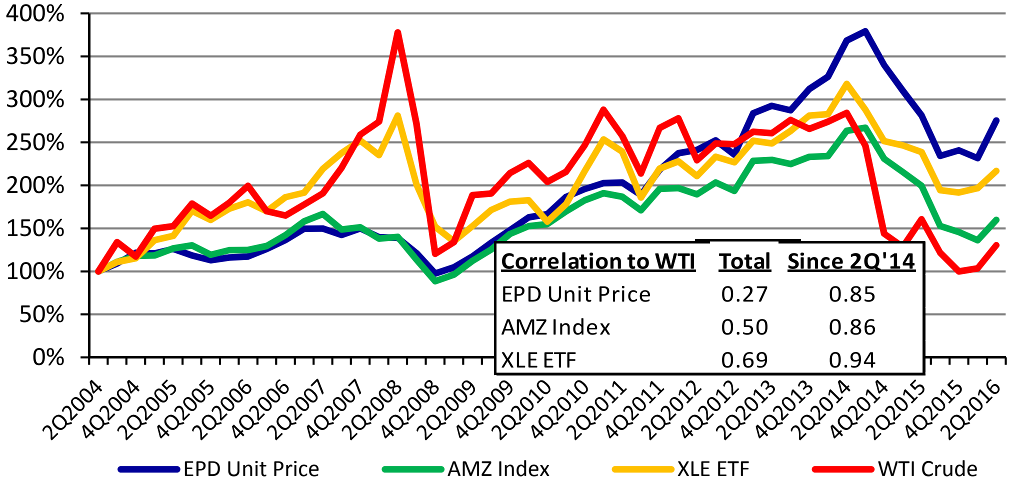
Note: MLPs with market cap >$10 billion, excluding PAA due to pending transaction.

Sources: UBS and company filings

SUCCESSFUL EXECUTION THROUGHOUT CYCLES

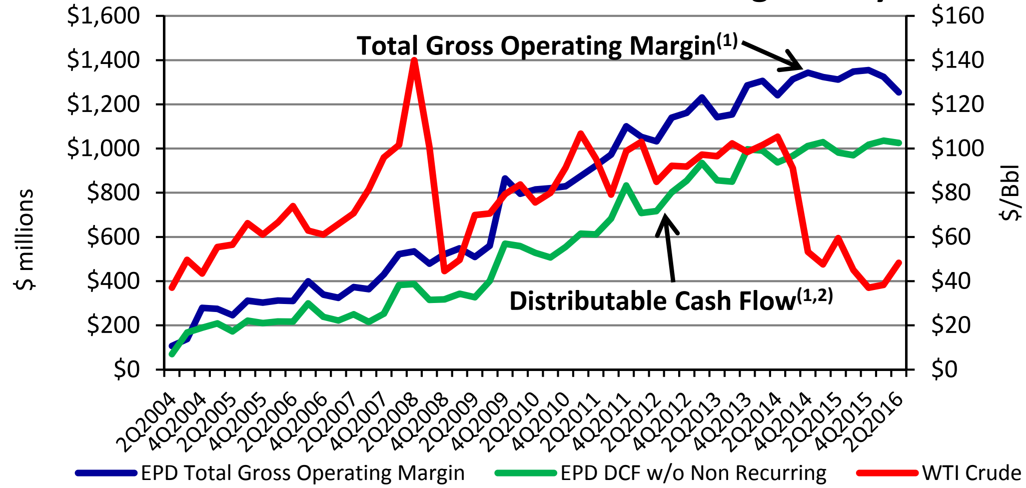
Increased Cash Distributions for 48 Consecutive Quarters

MLP Equities: Higher Correlation to Crude for Last 24 Months

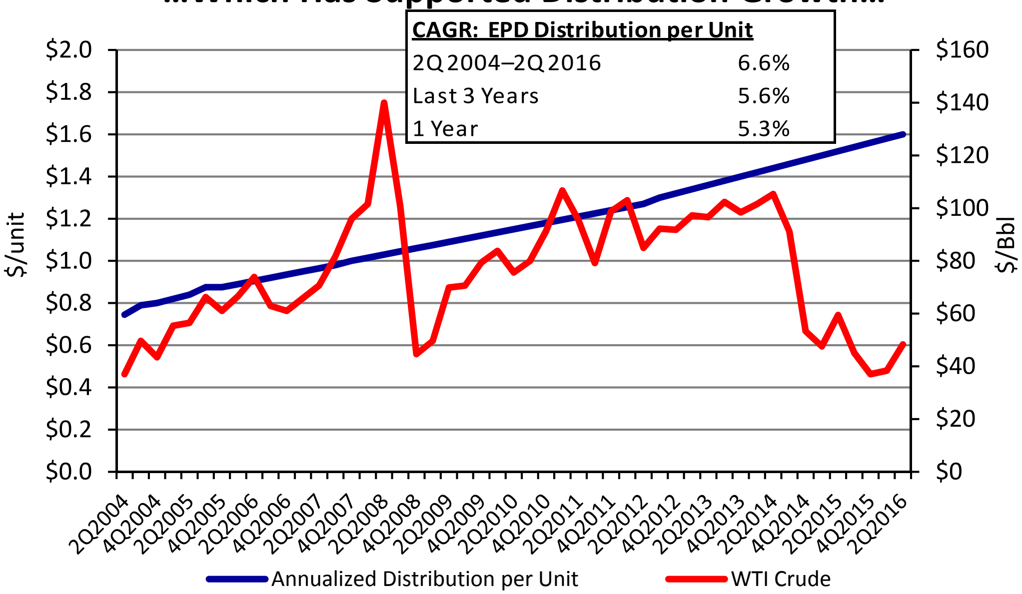


Correlation to WTI	Total	Since 2Q'14
EPD Unit Price	0.27	0.85
AMZ Index	0.50	0.86
XLE ETF	0.69	0.94

EPD Has Delivered Consistent Results Throughout Cycles…

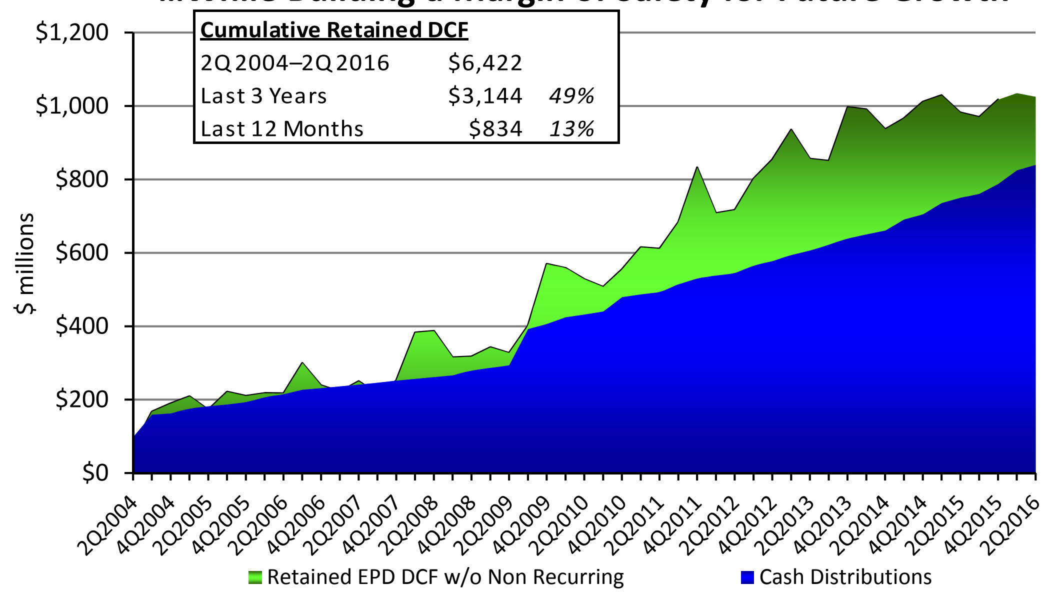


…Which Has Supported Distribution Growth…



CAGR: EPD Distribution per Unit	
2Q2004–2Q2016	6.6%
Last 3 Years	5.6%
1 Year	5.3%

…While Building a Margin of Safety for Future Growth



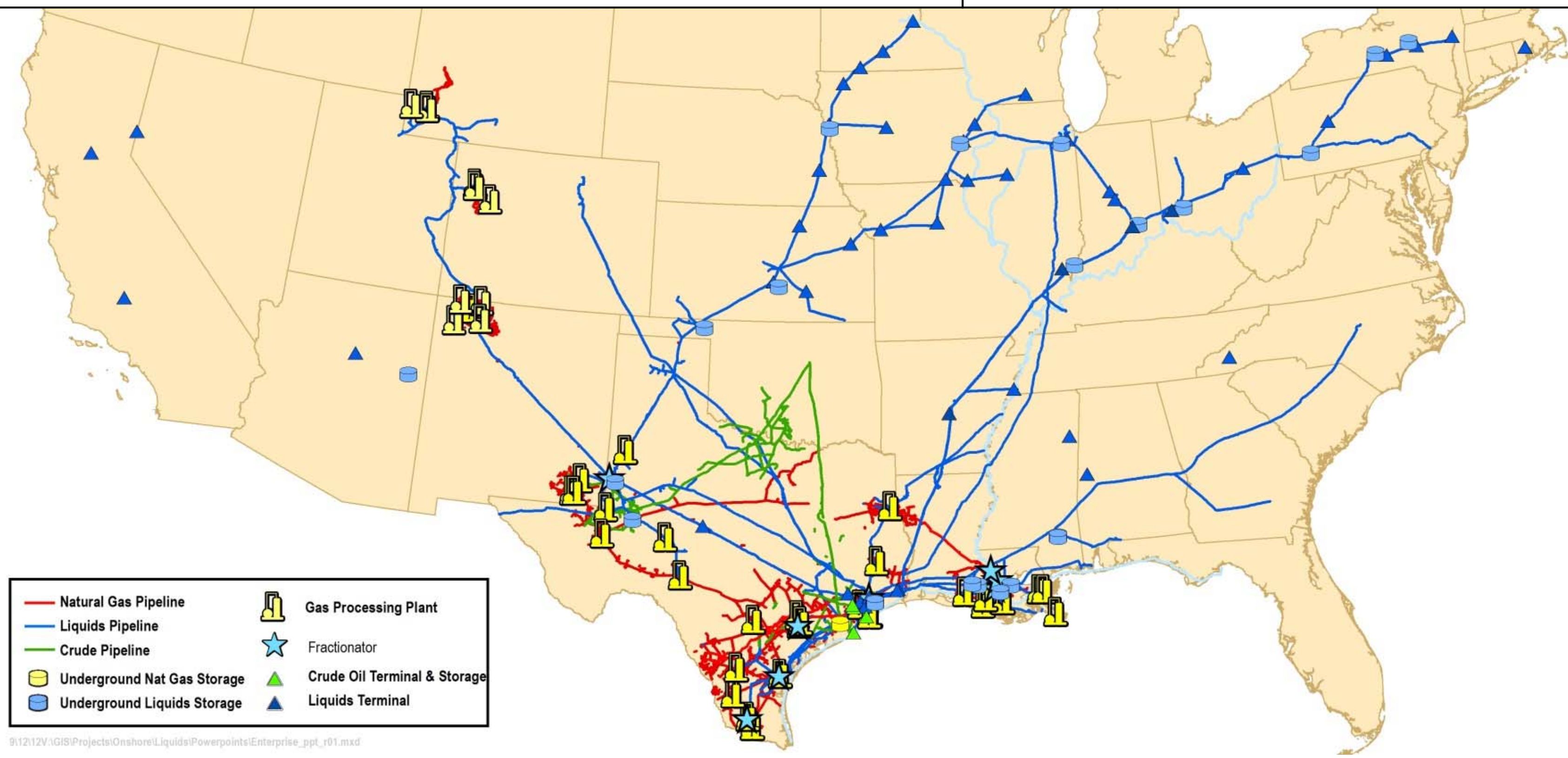
Cumulative Retained DCF		
2Q2004–2Q2016	$6,422	
Last 3 Years	$3,144	*49%*
Last 12 Months	$834	*13%*

(1) Total gross operating margin and distributable cash flow represent reported amounts. For a reconciliation of these amounts to their nearest GAAP counterparts, see "Non-GAAP Financial Measures" on our website.
(2) Excludes non-recurring cash transactions (e.g., proceeds from asset sales and property damage insurance claims and payments to settle interest rate hedges).

Sources: EPD and Bloomberg

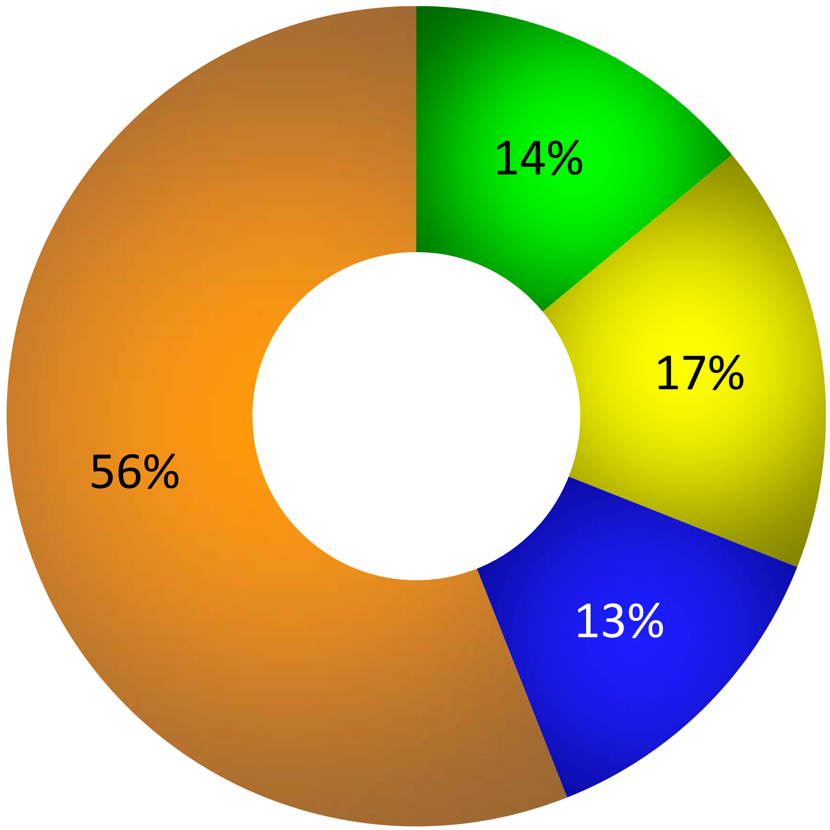
EPD: NATURAL GAS, NGLs, CRUDE OIL, PETROCHEMICALS AND REFINED PRODUCTS

Asset Overview	Connectivity
○ **Pipelines:** ≈49,000 miles of natural gas, NGL, crude oil, petrochemicals and refined products pipelines ○ **Storage:** 250 MMBbls of NGL, petrochemical, refined products, and crude oil, and 14 Bcf of natural gas storage capacity ○ **Processing:** 26 natural gas processing plants; 22 fractionators; 10 condensate distillation facilities ○ **Export Facilities:** LPG, PGP, crude oil and refined products; adding ethane facility in 2016	○ Fully integrated midstream energy company aggregating domestic supply directly connected to domestic and international demand ○ Connected to U.S. major shale basins ○ Connected to every U.S. ethylene cracker ○ Connected to ≈90% of refineries East of Rockies ○ Pipeline connected to 22 Gulf Coast PGP customers

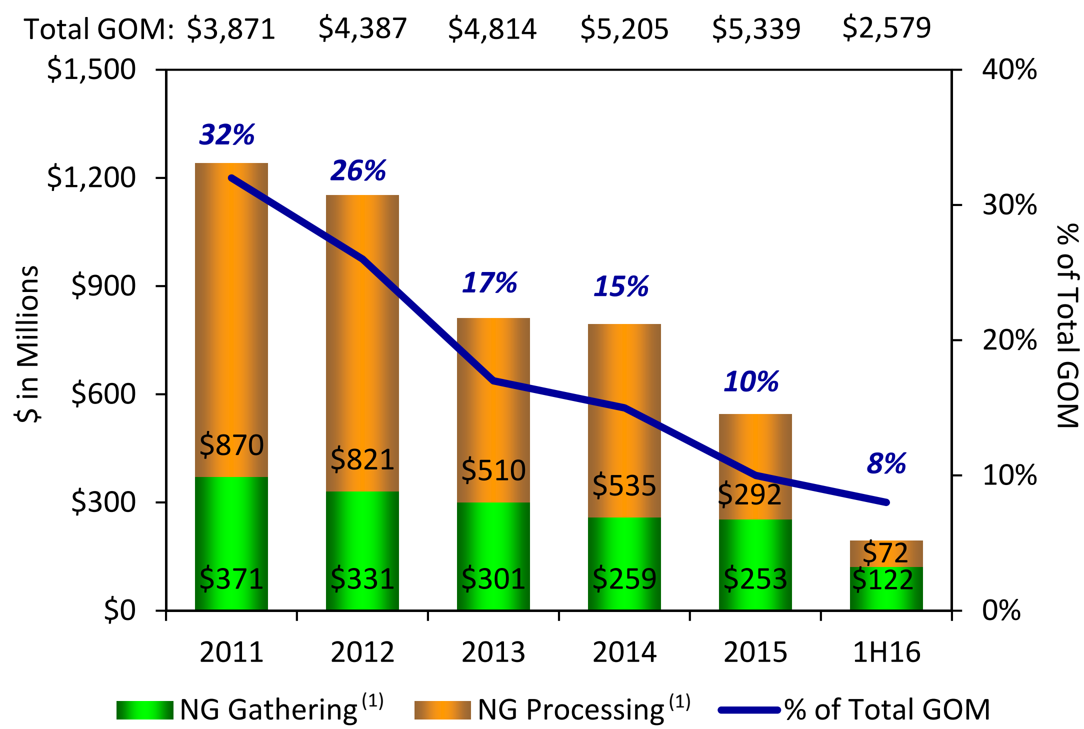


DIVERSIFIED SOURCES OF CASH FLOW BACKED BY FEE–BASED BUSINESS MODEL

$5.3 Billion Total Gross Operating Margin for 12 months ended June 30, 2016



Natural Gas Gathering & Processing Contribution to Total Gross Operating Margin



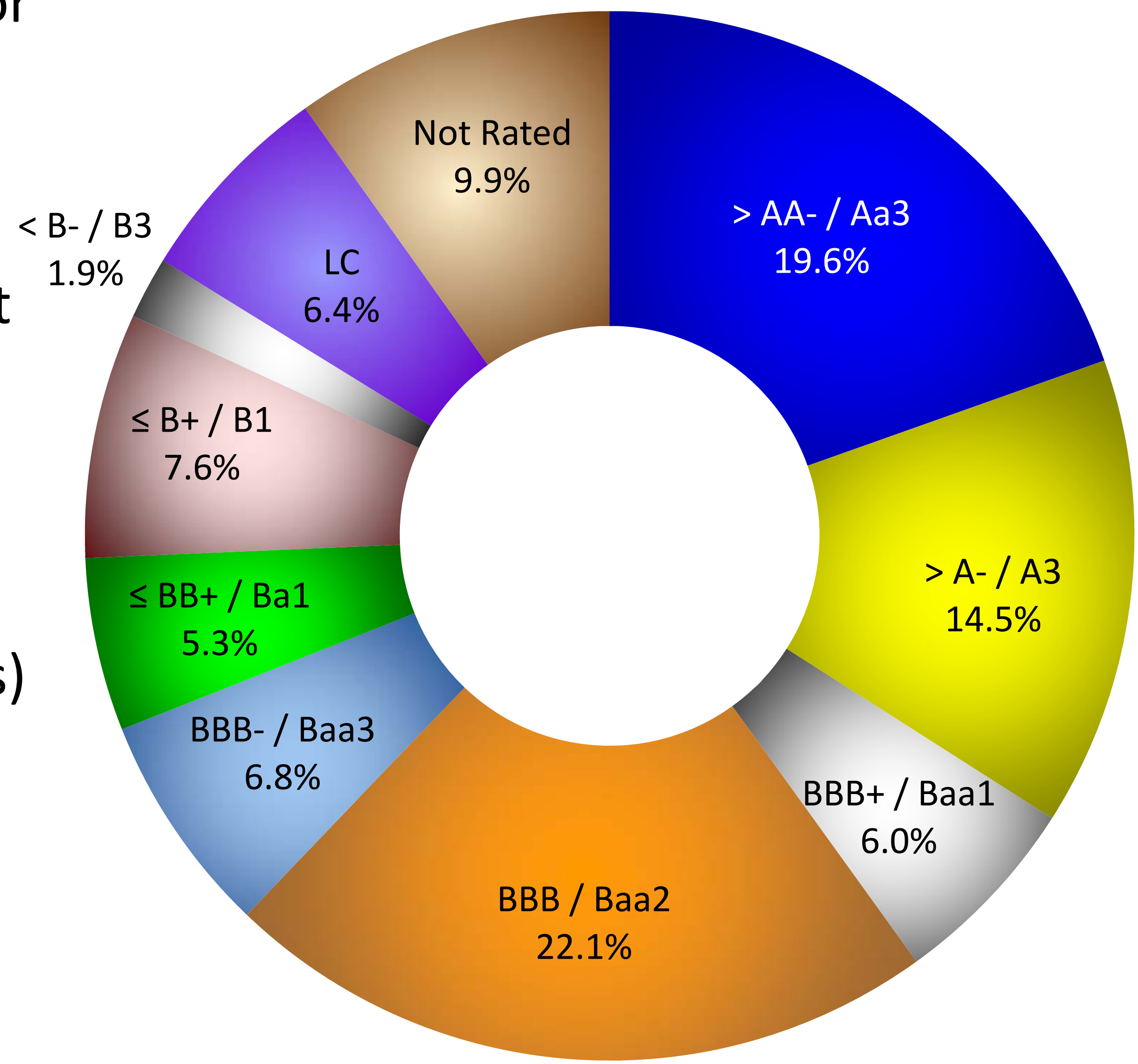
- % contribution from G&P businesses has decreased with investments in fee-based pipelines, fractionators and export facilities and lower commodity prices / volumes

(1) Total gross operating margin amounts presented for NG Gathering and NG Processing are components of the total gross operating margin amounts historically reported for our Natural Gas Pipelines & Services and NGL Pipelines & Services segments, respectively.

COMPOSITE OF TOP 200 CUSTOMERS

- Top 200 customers account for 95.7% of EPD's 2015 revenue
- 75.3% of revenue from our Top 200 customers is from customers with an investment grade credit rating or secured by a letter of credit or prepay
- Only 3.1% of revenue from non-rated or sub-investment grade independent E&P's (4Bs)
  - 19 counterparties

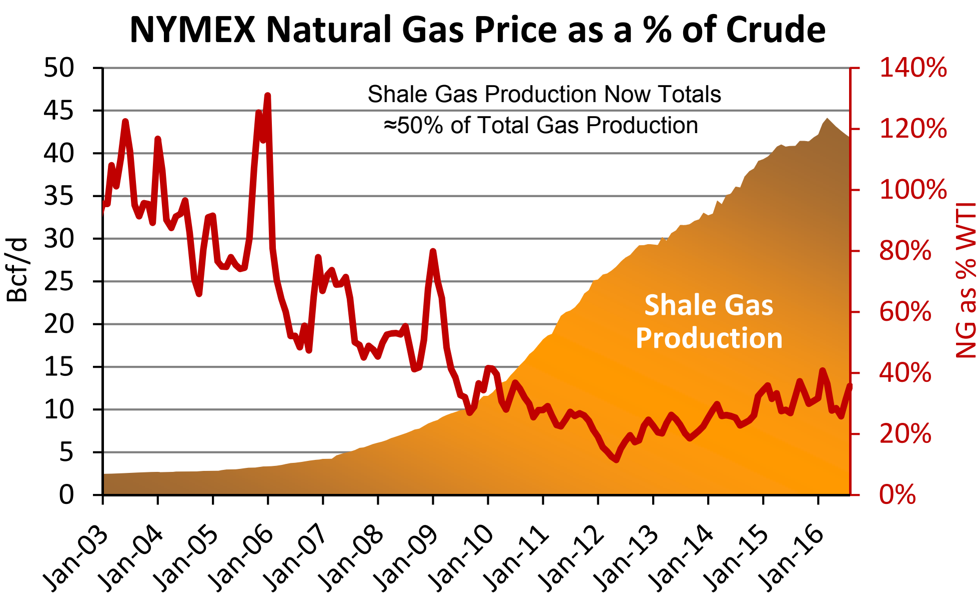
Revenue from Top 200 Customers by Rating[1]

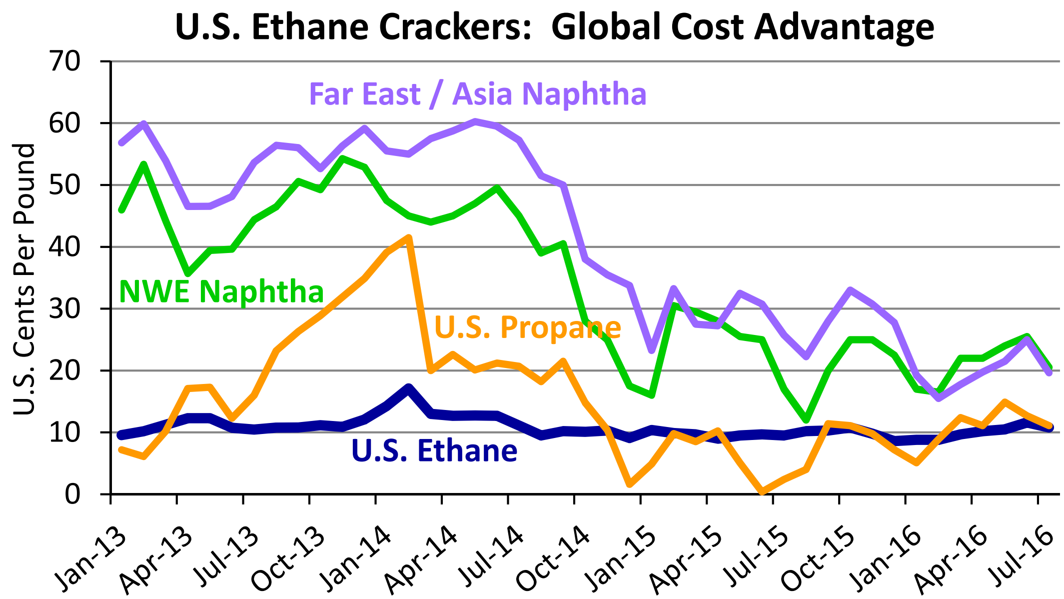


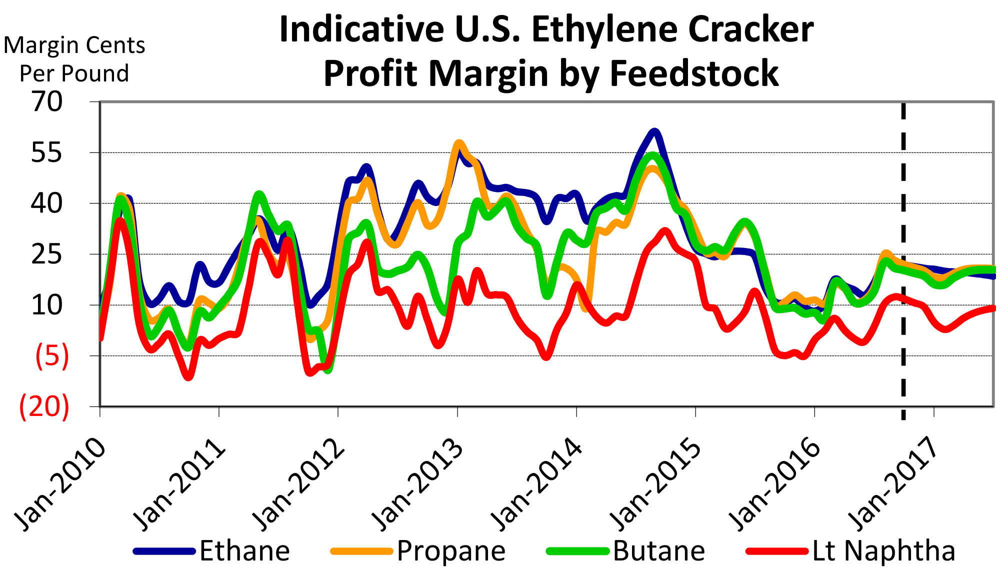
(1) *As of August 3, 2016*

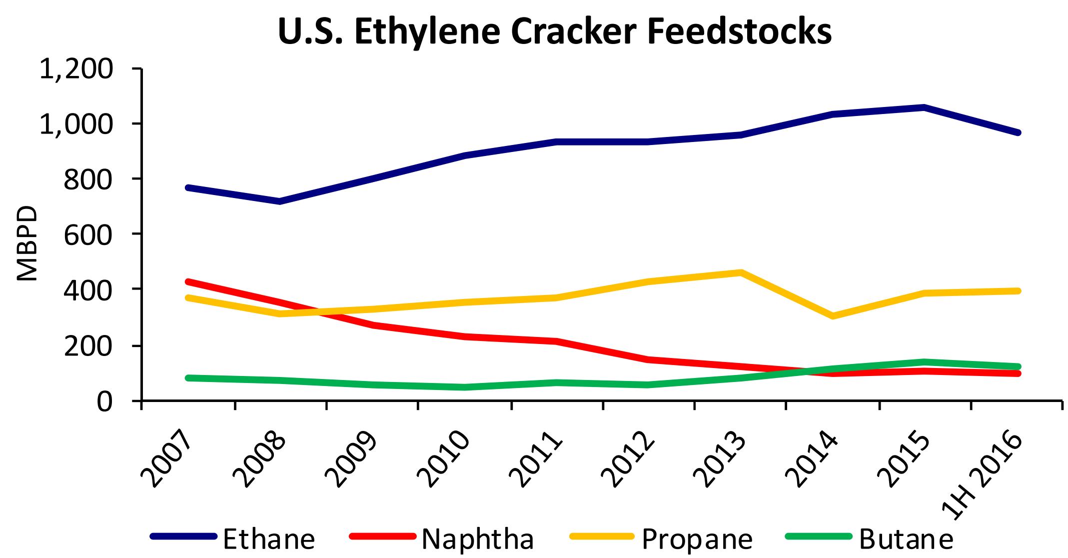
SUPPLY / DEMAND FUNDAMENTALS

LOW GAS TO CRUDE SPREAD CONTINUING TO DRIVE U.S. NGL ADVANTAGE









Sources: EPD Fundamentals, NYMEX, EIA and CMAI

"THE SUPPLY TREADMILL": ≈1/3 OF GLOBAL OIL PRODUCTION MUST BE REPLACED BY 2020

*Oil and Gas Industry Needs to Replace Declines **and** Satisfy Demand Growth*

MMBPD of Oil	**2016**	**2017**	**2018**	**2019**	**2020**
Declines of Existing Fields	5.0	5.0	5.0	5.0	5.0
Annual Demand Growth	1.4	1.4	1.4	1.4	1.4
Annual Additions to Supply	6.4	6.4	6.4	6.4	6.4
Cumulative Additions to Supply	**6.4**	**12.8**	**19.2**	**25.6**	**32**

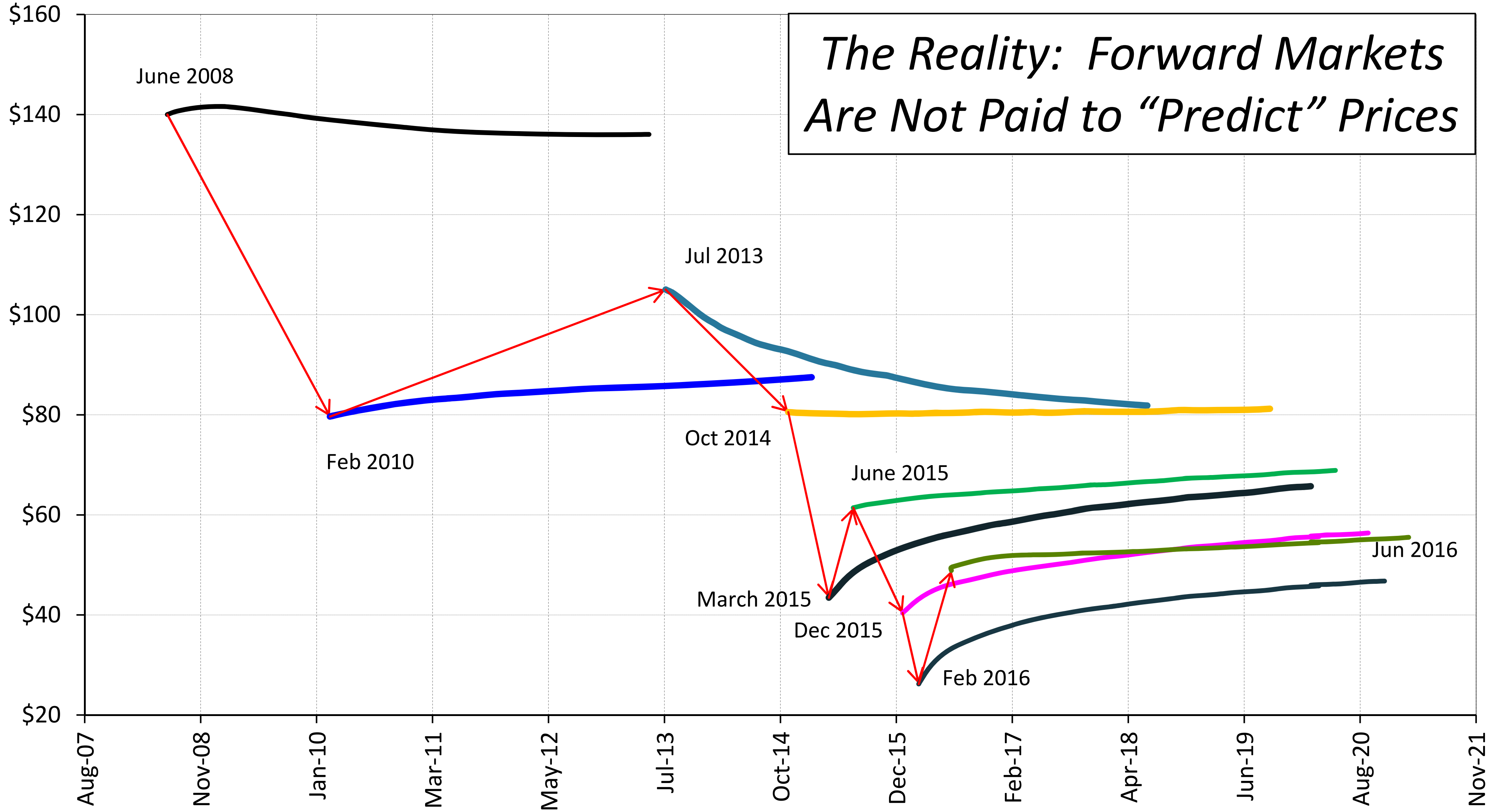
- Industry needs to replace 5–6% decline rates in existing fields ***in addition*** to meeting new demand

  Supply: average annual decline of 5% on 95 MMBPD of production is ≈5 MMBPD of brown field decline

  Demand: just 1.5% annual demand growth requires another 1.4 MMBPD of new production
- Note: the decline rate for shale is much steeper, especially in the early periods
- Billions of CapEx dollars are dedicated yearly to expanding and maintaining existing fields; lesser amounts are dedicated to new fields and exploratory drilling (riskier, longer lead time investments)

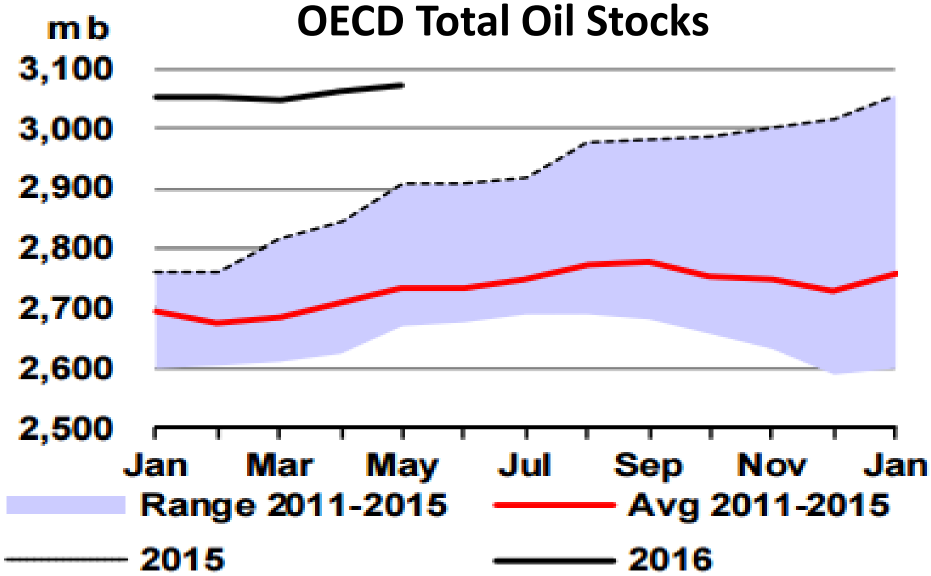
Sources: EPD Fundamentals, IEA, EIA and Various Company Announcements

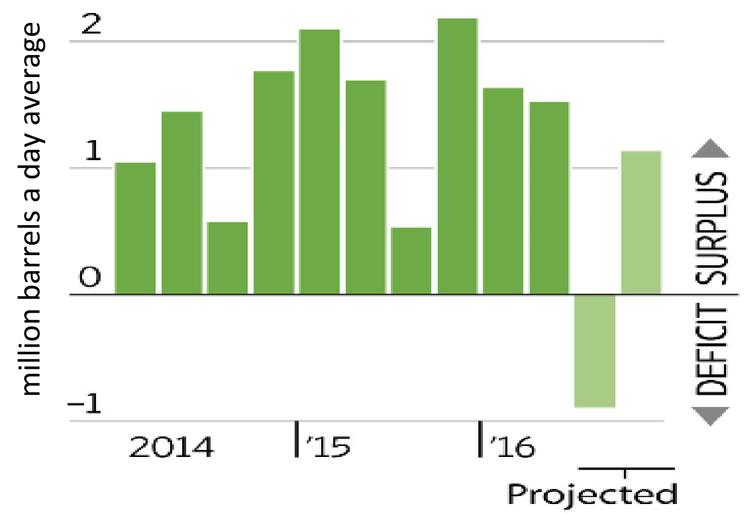
THE WISDOM OF THE MARKETS…***OR***… CAN'T THEY GET ANYTHING RIGHT

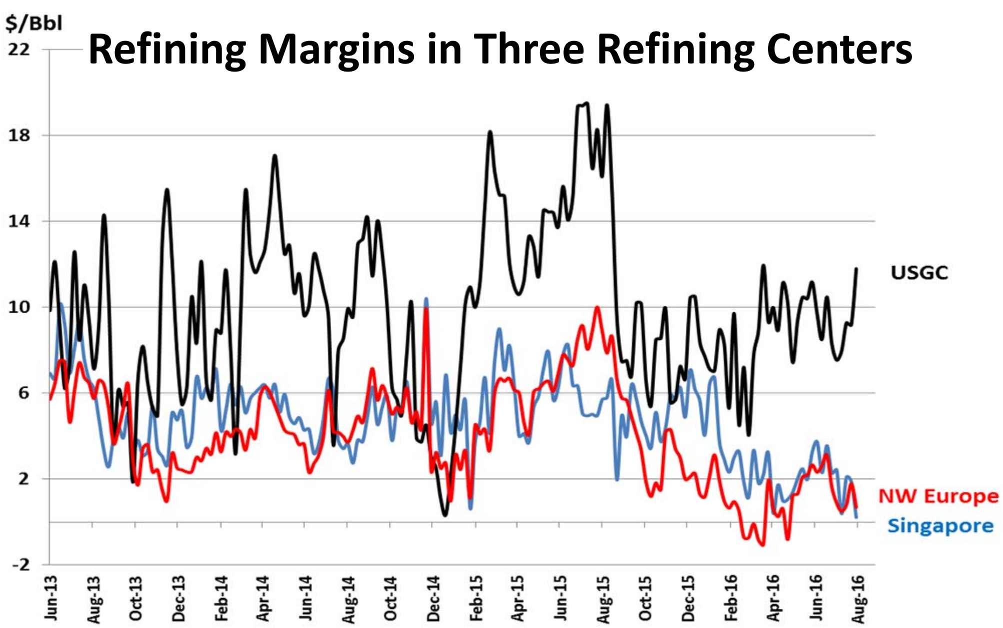


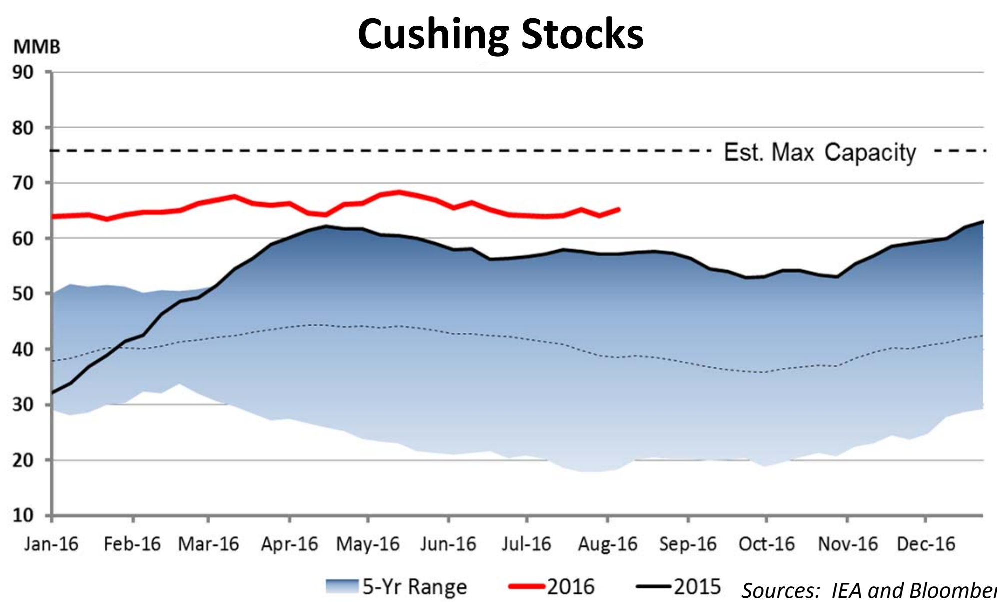
Source: NYMEX

GLOBAL OIL INVENTORIES REMAIN VERY HIGH BY HISTORICAL STANDARDS



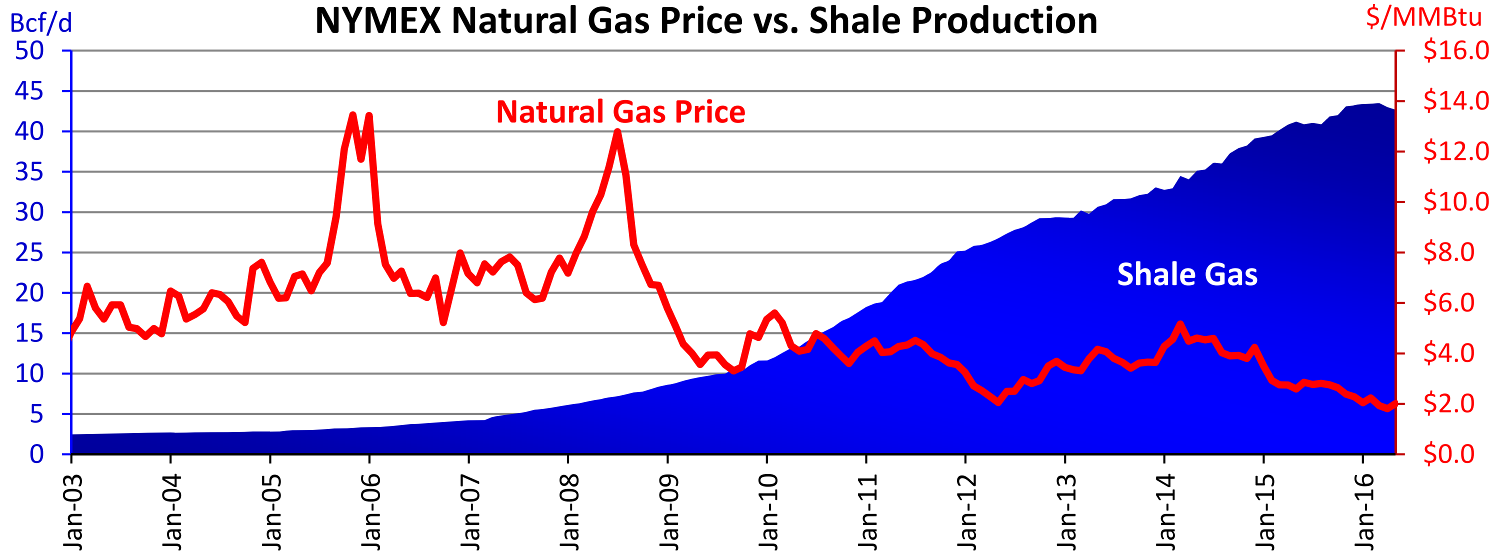


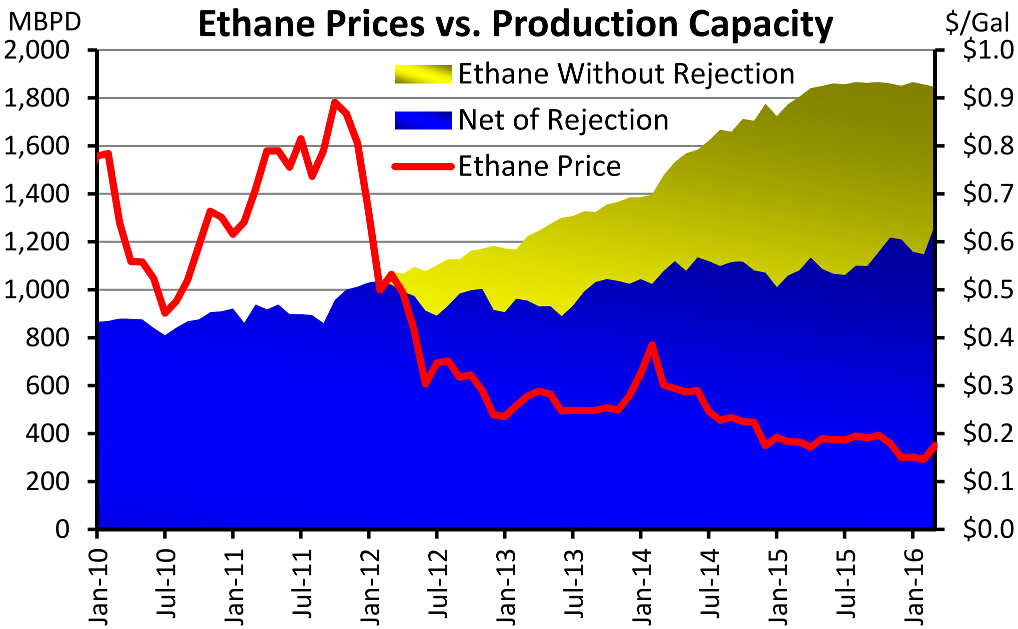


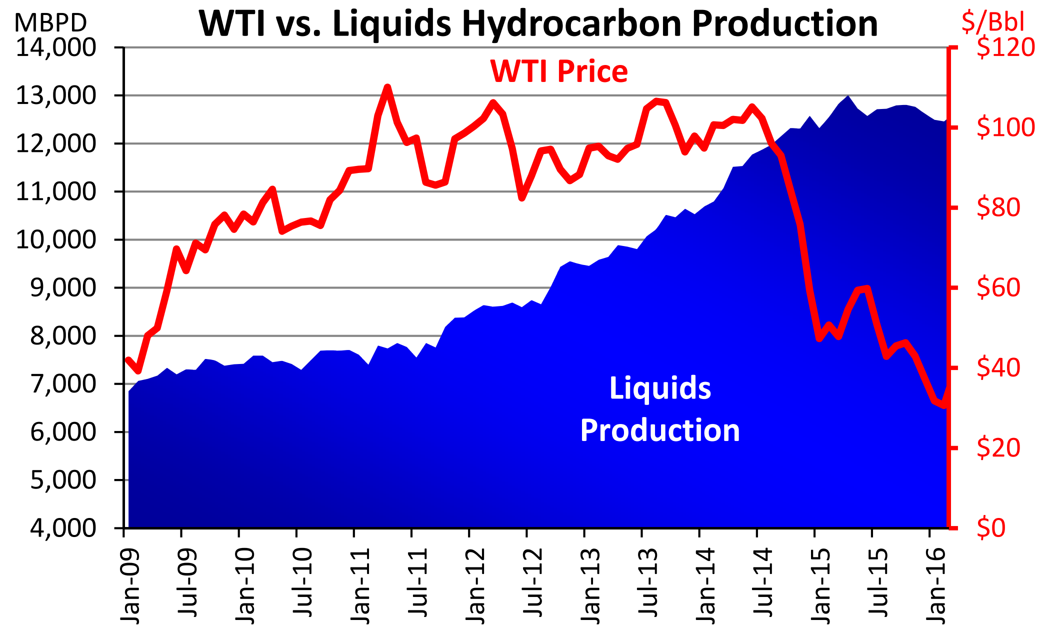


Sources: IEA and Bloomberg

THE SHALE "REVOLUTION"
Rapidly Growing Production and Falling Prices

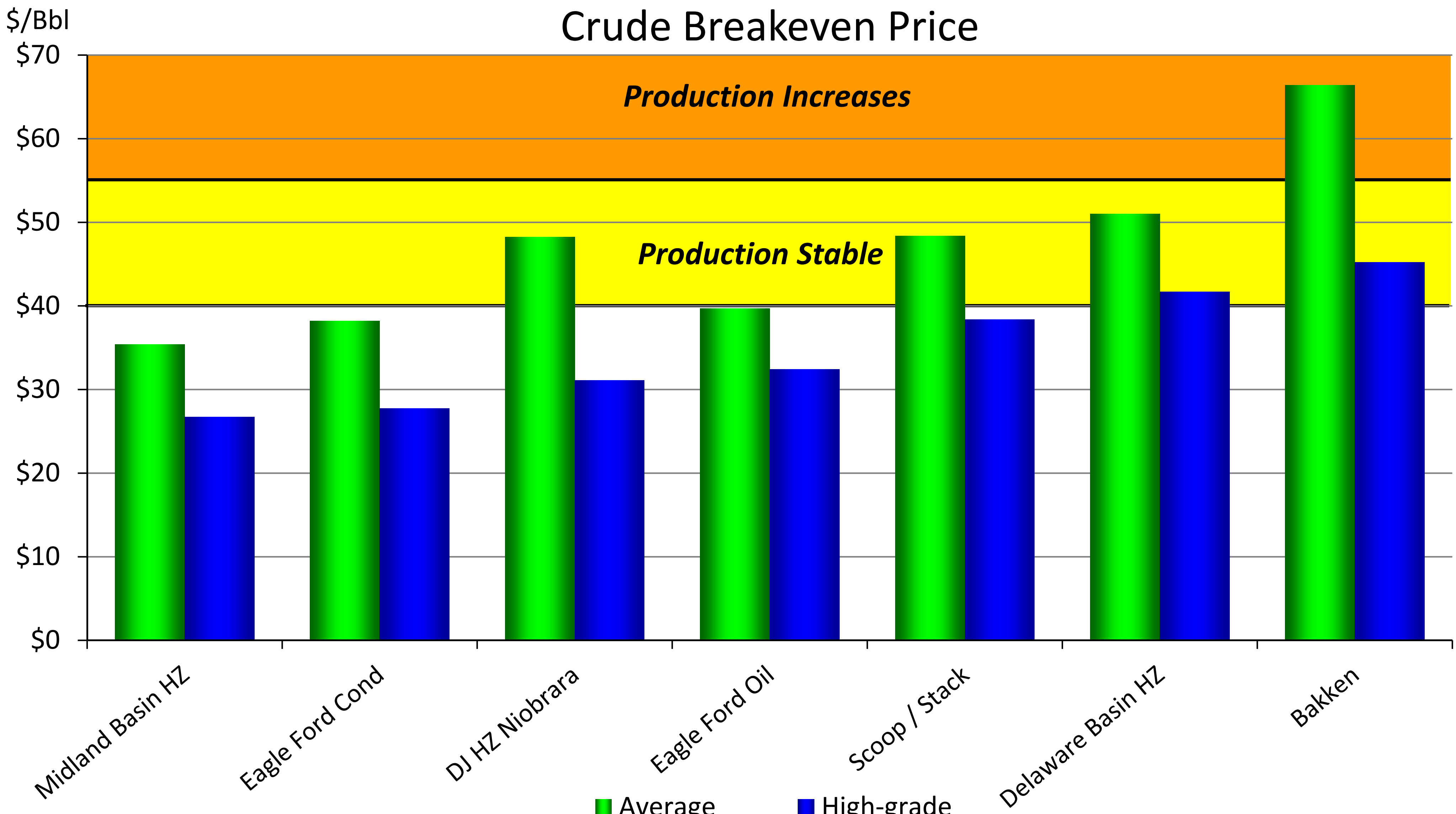






Sources: NYMEX and EPD Fundamentals

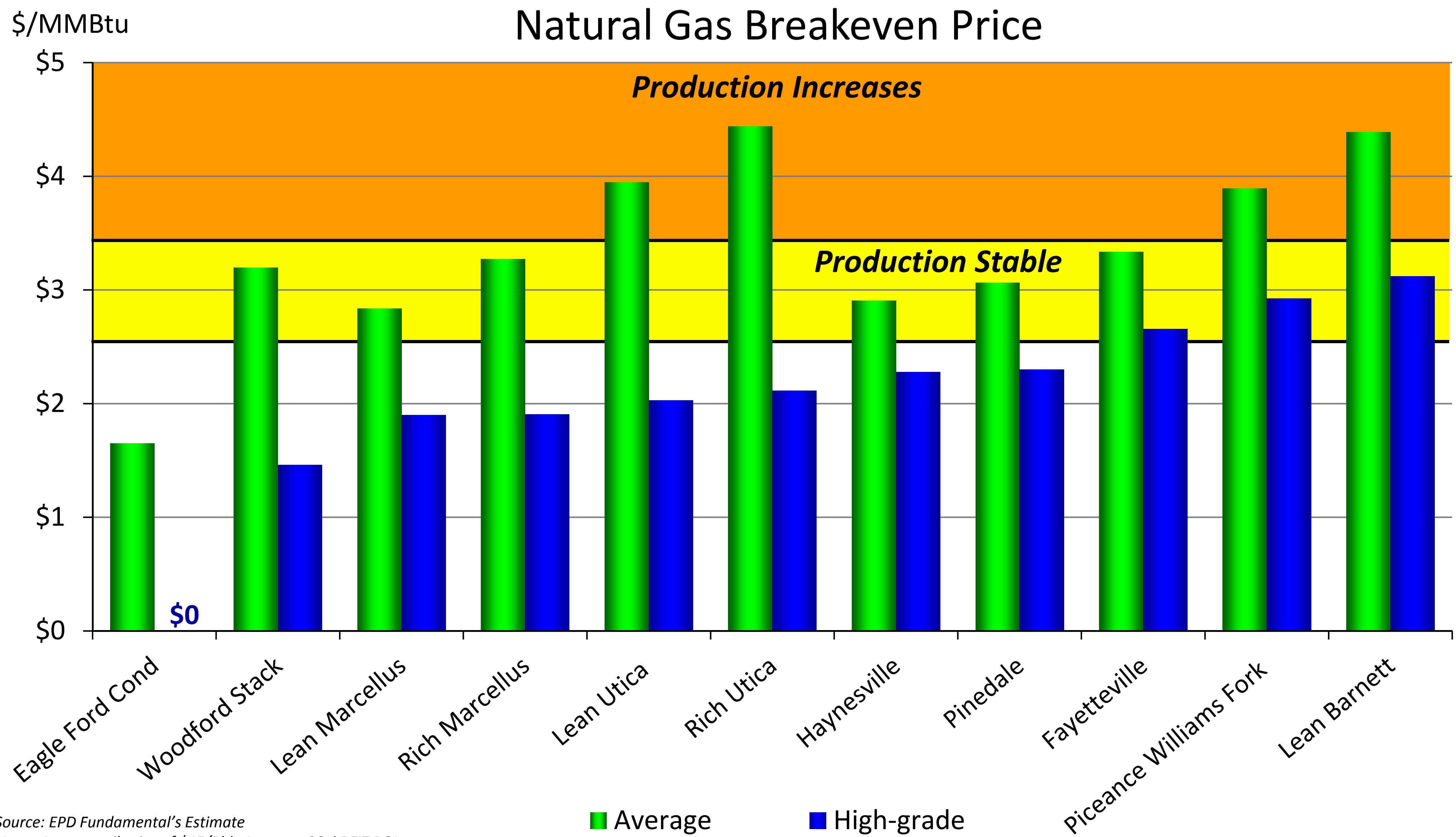
U.S. OFFERS WORLD CLASS RESOURCES AT COMPETITIVE PRICES



Source: EPD Fundamentals Estimate

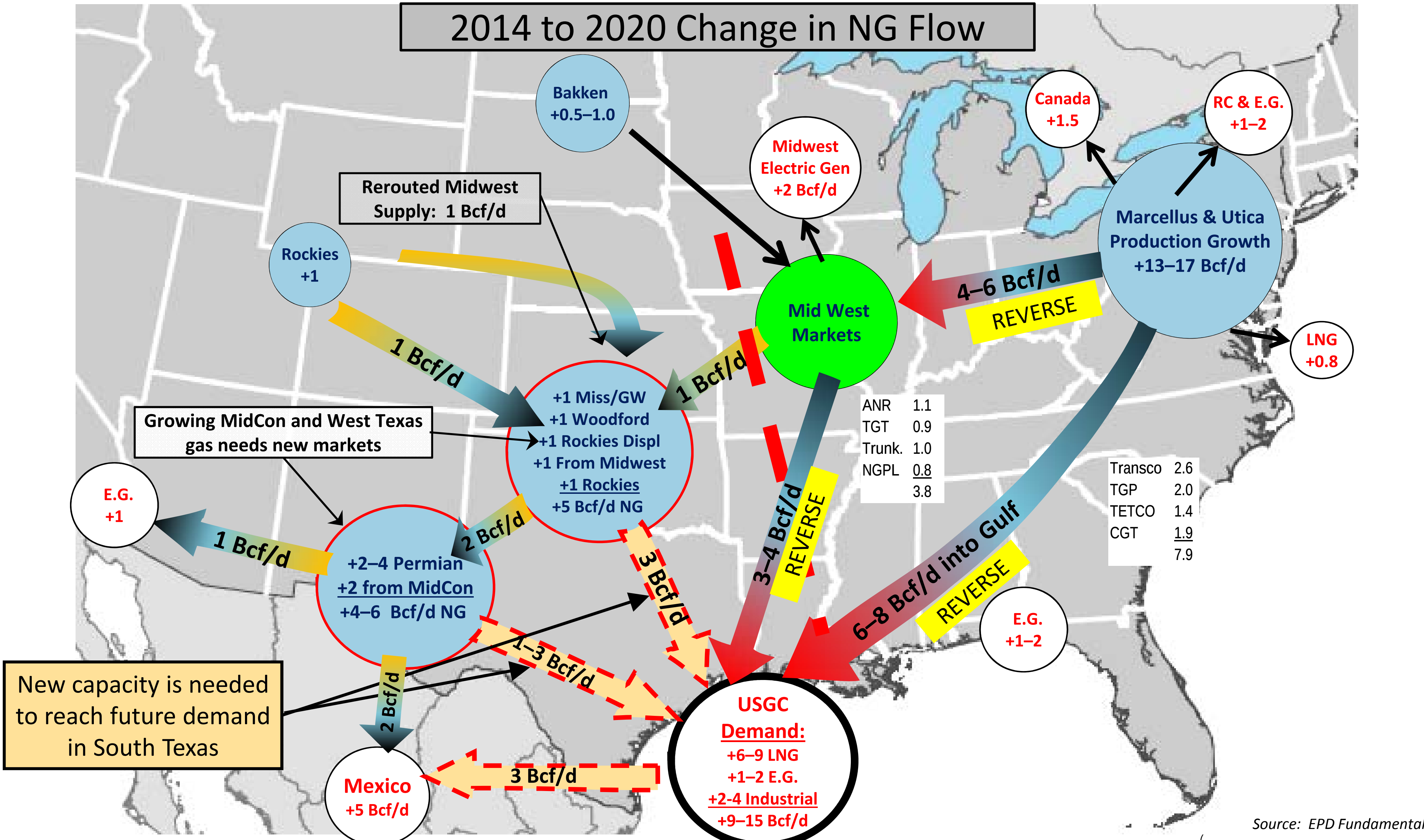
Note: Assumes gas price of $2.75/MMBtu. Assumes 20% BFIT ROI

U.S. HAS PLENTIFUL NATURAL GAS BELOW $3.50



Source: EPD Fundamental's Estimate
Note: Assumes oil price of $45/Bbl,. Assumes 20% BFIT ROI

NATURAL GAS: SUPPLIES VS. U.S. GULF COAST–CENTRIC DEMAND & FORECASTED FLOW PATTERNS



Source: EPD Fundamentals

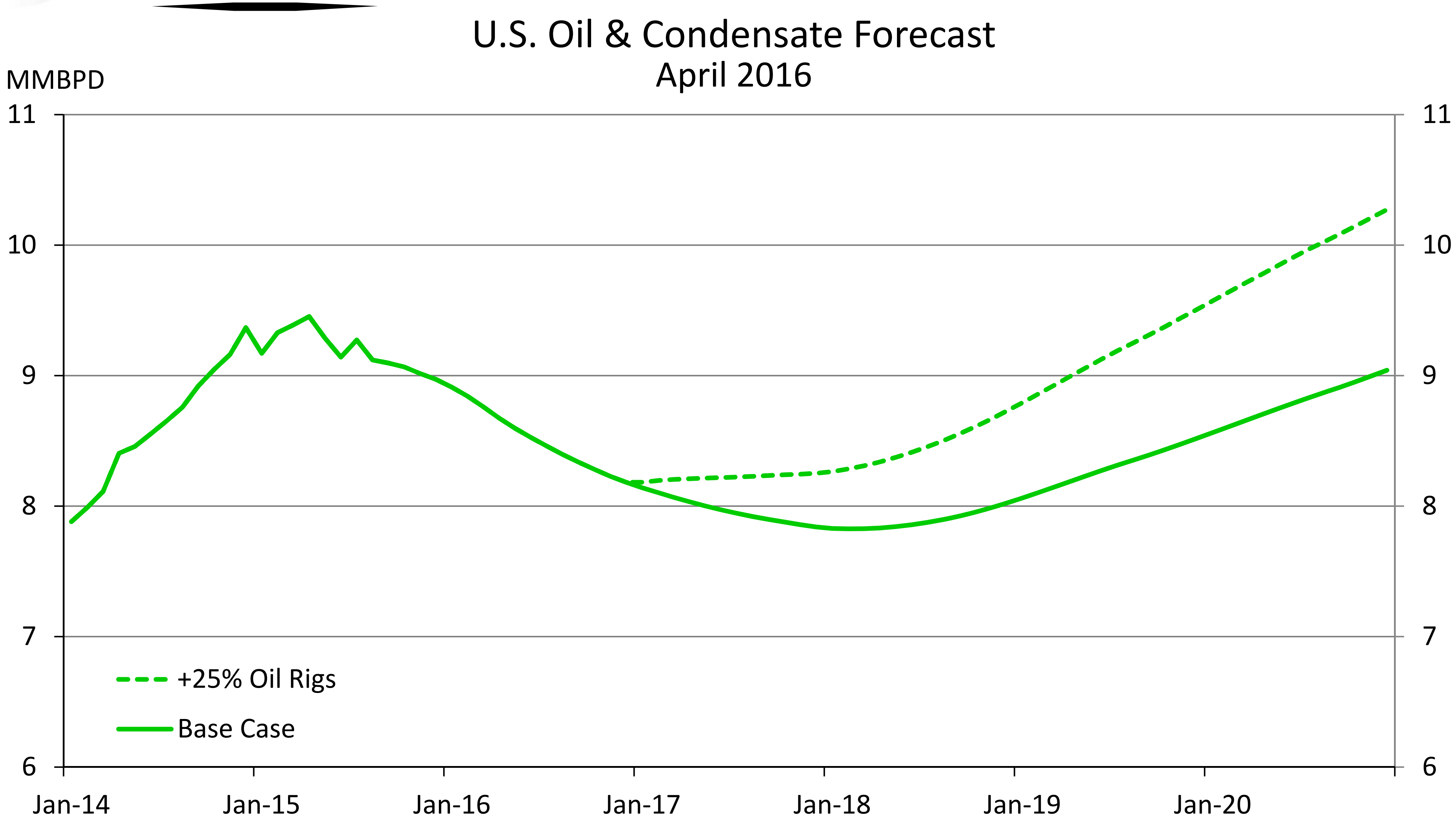
U.S. GULF COAST LNG PROJECTS

Company	Owners	Natural Gas Loading Capacity (MMcf/d)	Location	Est Completion Date
Sabine Pass LNG	Cheniere Energy	3,500	Sabine Pass, LA	2016–2019
Freeport LNG	Freeport LNG	2,000	Freeport, TX	2018–2019
Corpus Christi LNG	Cheniere Energy	3,200	Ingleside, TX	2018
Lake Charles LNG Company LLC	Energy Transfer	2,300	Lake Charles, LA	2019–2020
Cameron LNG	Sempra, ENGIE, Mitsui, Mitsubishi, Nippon	2,100	Hackberry, LA	2019
Golden Pass LNG	Exxon, Qatar Petroleum	2,250	Sabine Pass, TX	2020–2021
TOTAL		**15,350**		

Sources: EPD Fundamentals and respective company websites – assumes all capacity gets built

OIL PRODUCTION FORECAST

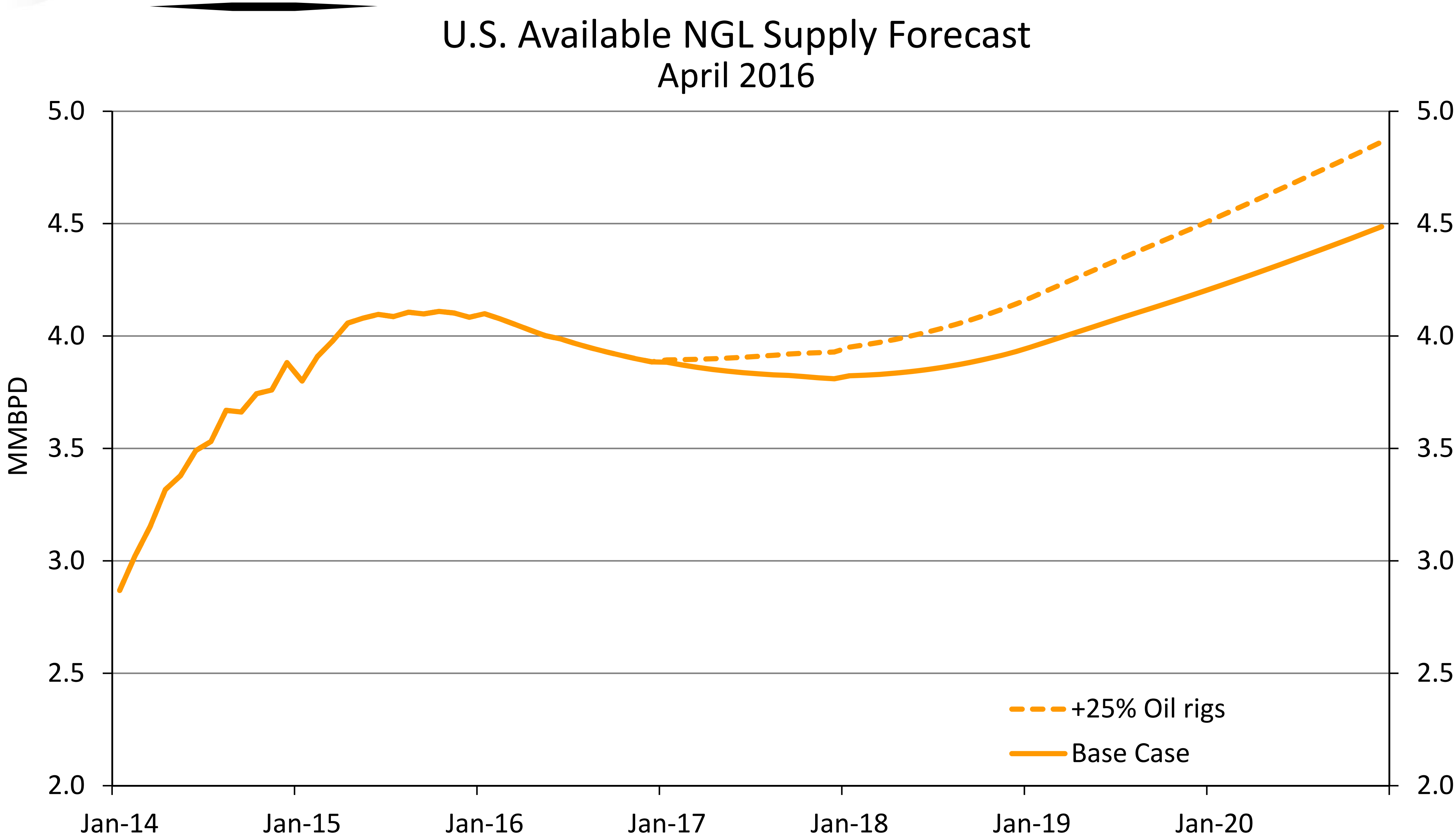
Sensitivity to +25% Oil Rig Count Swing



Note: assumes rig count rebound 1/1/2017

Source: EPD Fundamentals' Estimates

NGL PRODUCTION FORECAST
Sensitivity to +25% Oil Rig Count Swing

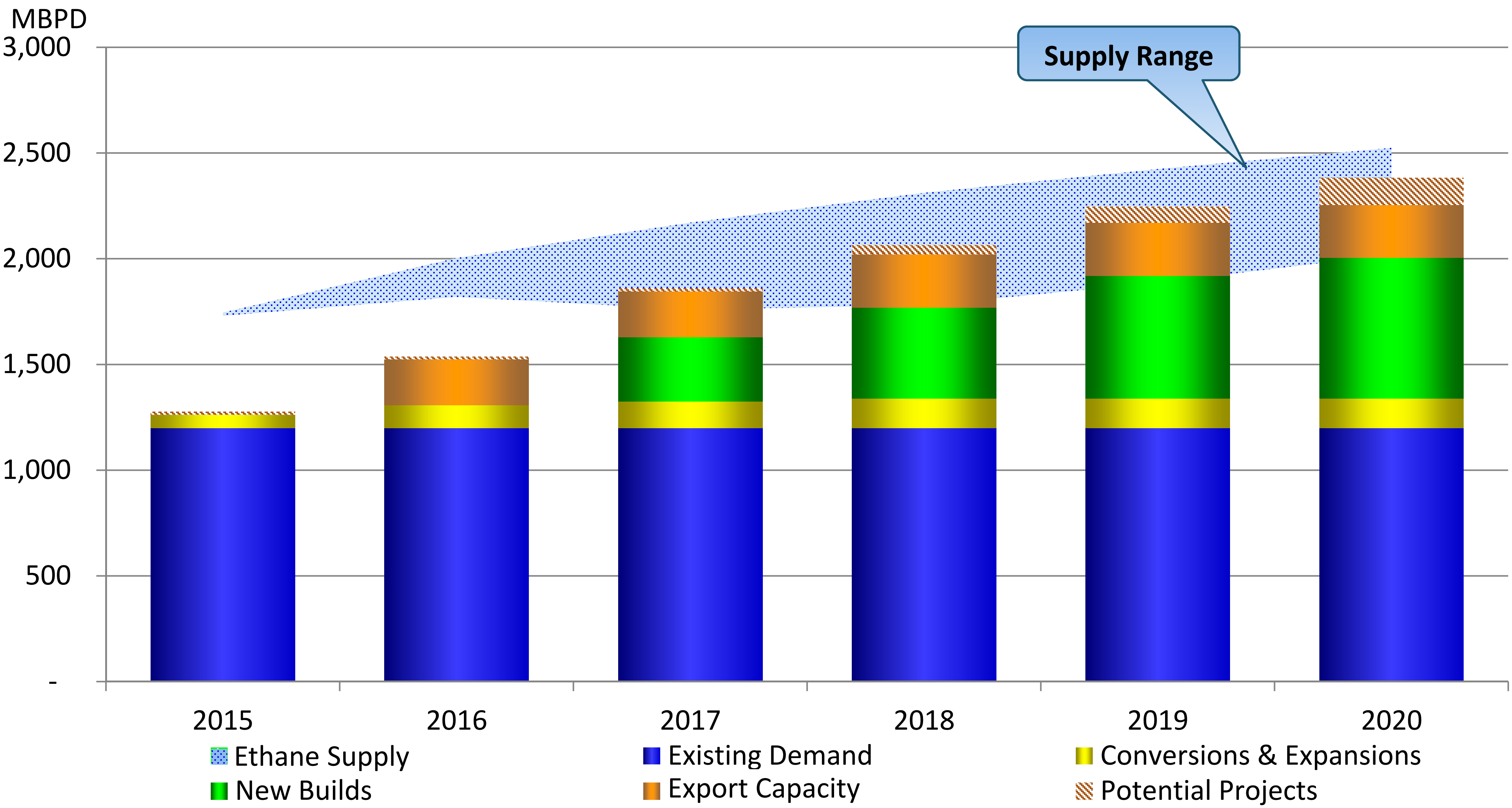


Note: assumes rig count rebound 1/1/2017

Source: EPD Fundamentals' Estimates

U.S. ETHANE SUPPLY / DEMAND OUTLOOK

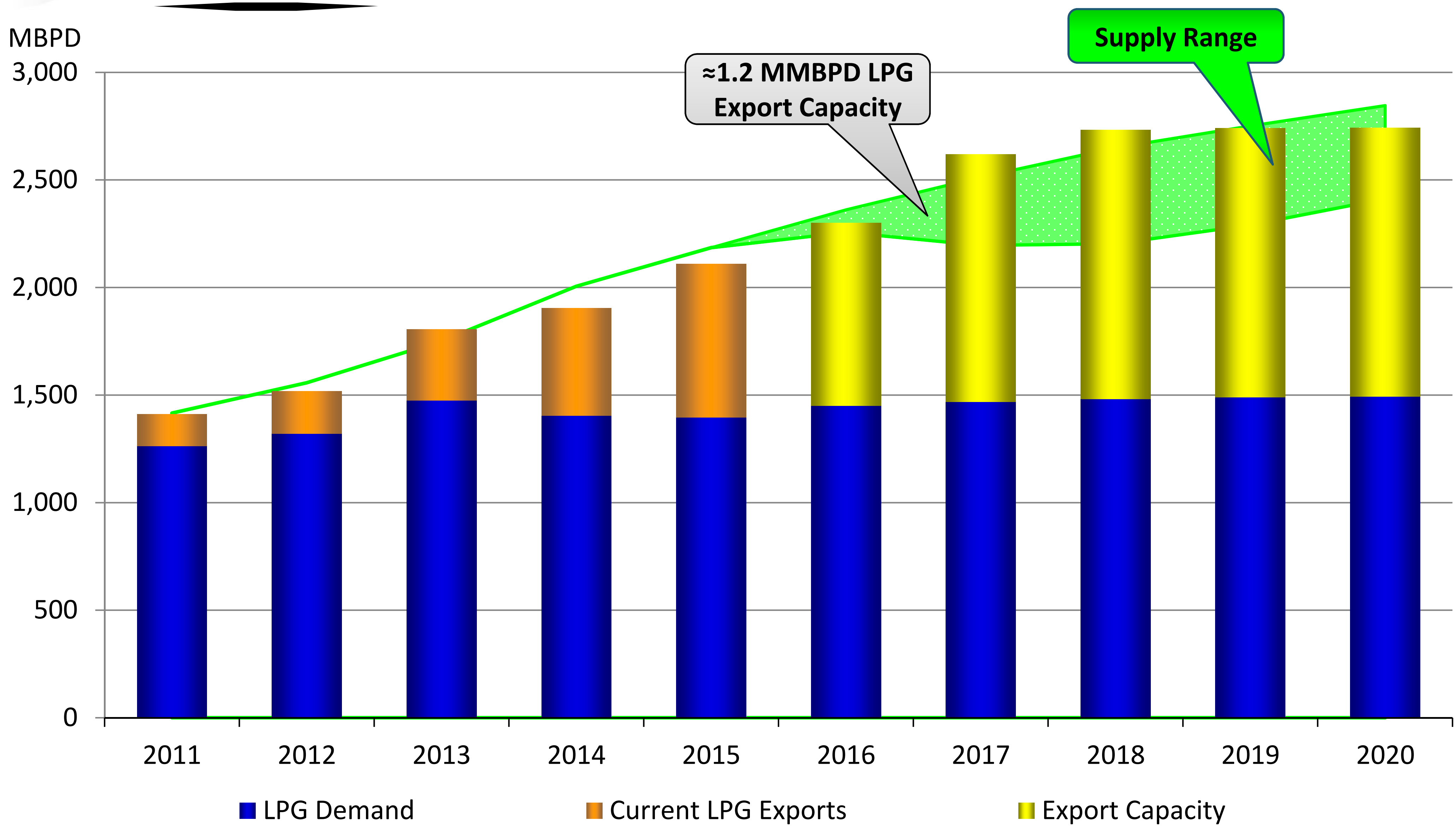
Demand Increases by ≈800 MBPD



Source: EPD Fundamentals

Note: Assumes 90% operating rate for Petchems, 70% for Exports. Potential projects are viewed as <80% likely to occur.

U.S. LPG…BALANCES WILL BE DRIVEN BY EXPORTS



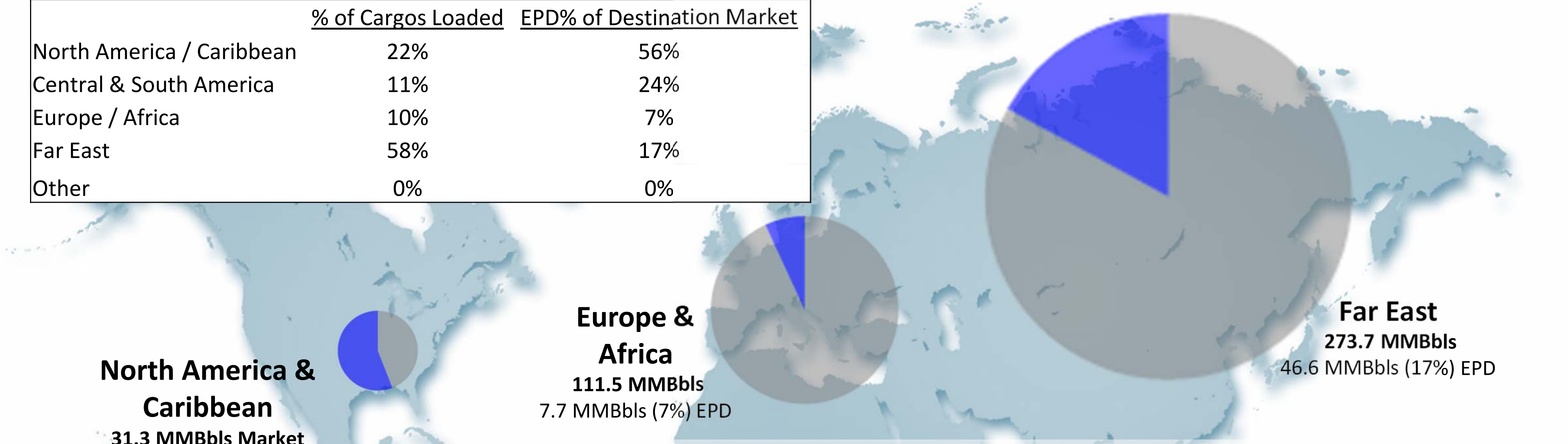
Source: EPD Fundamentals

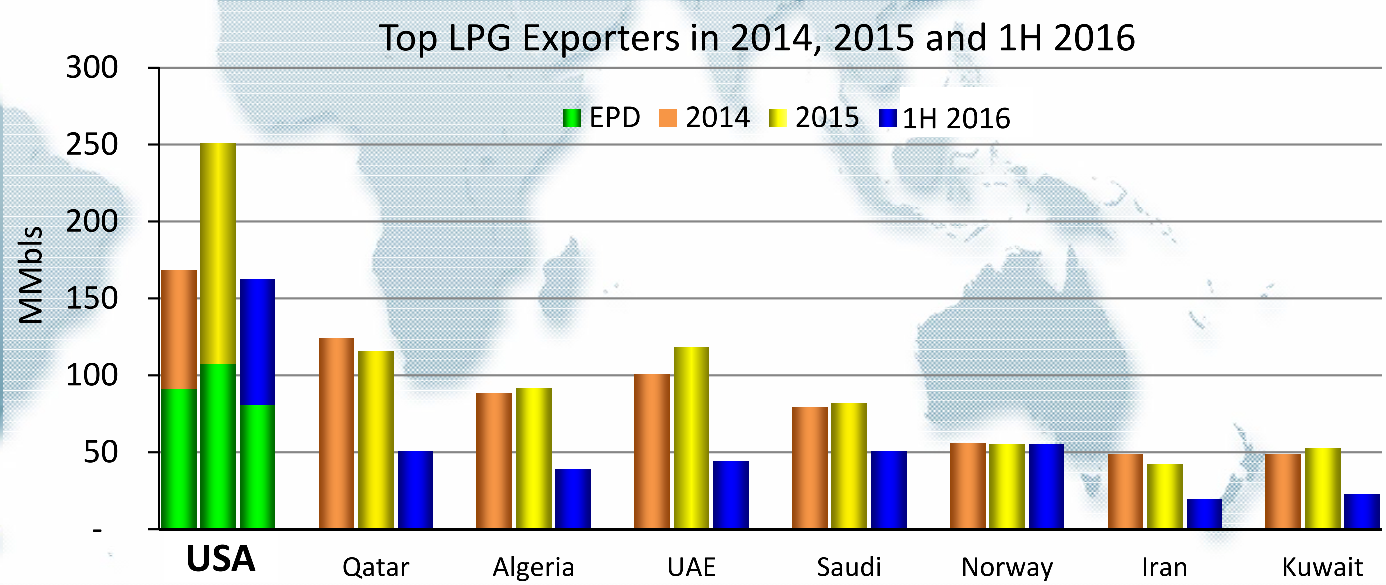
Note: LPG is Propane and Butane

U.S. THE LARGEST EXPORTER OF LPG

LPG Exports by Destination through 1H 2016

2016 EPD LPG Exports by Destination Region: 80.7 MMBbls	% of Cargos Loaded	EPD% of Destination Market
North America / Caribbean	22%	56%
Central & South America	11%	24%
Europe / Africa	10%	7%
Far East	58%	17%
Other	0%	0%

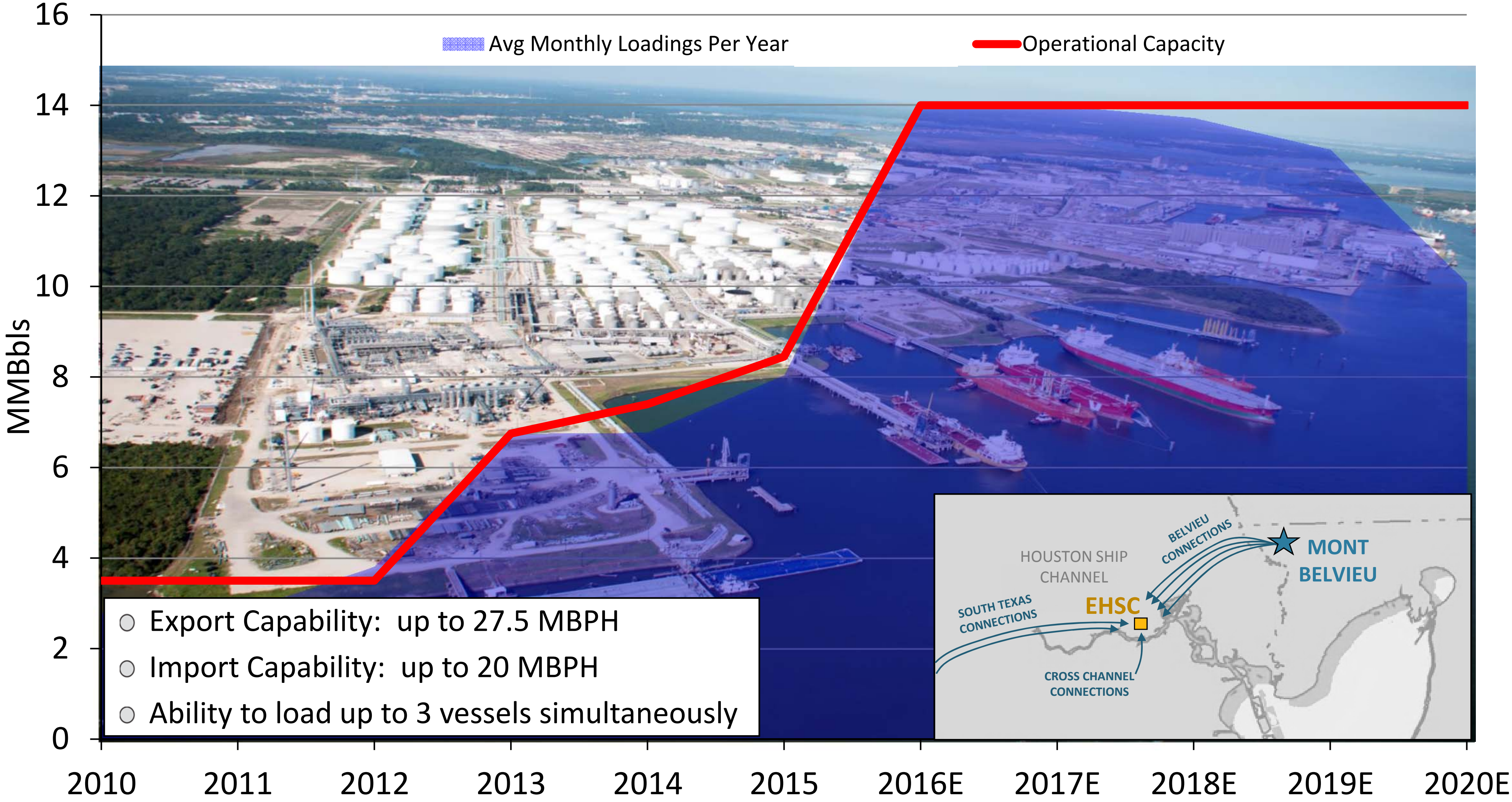




Source: *Waterborne*

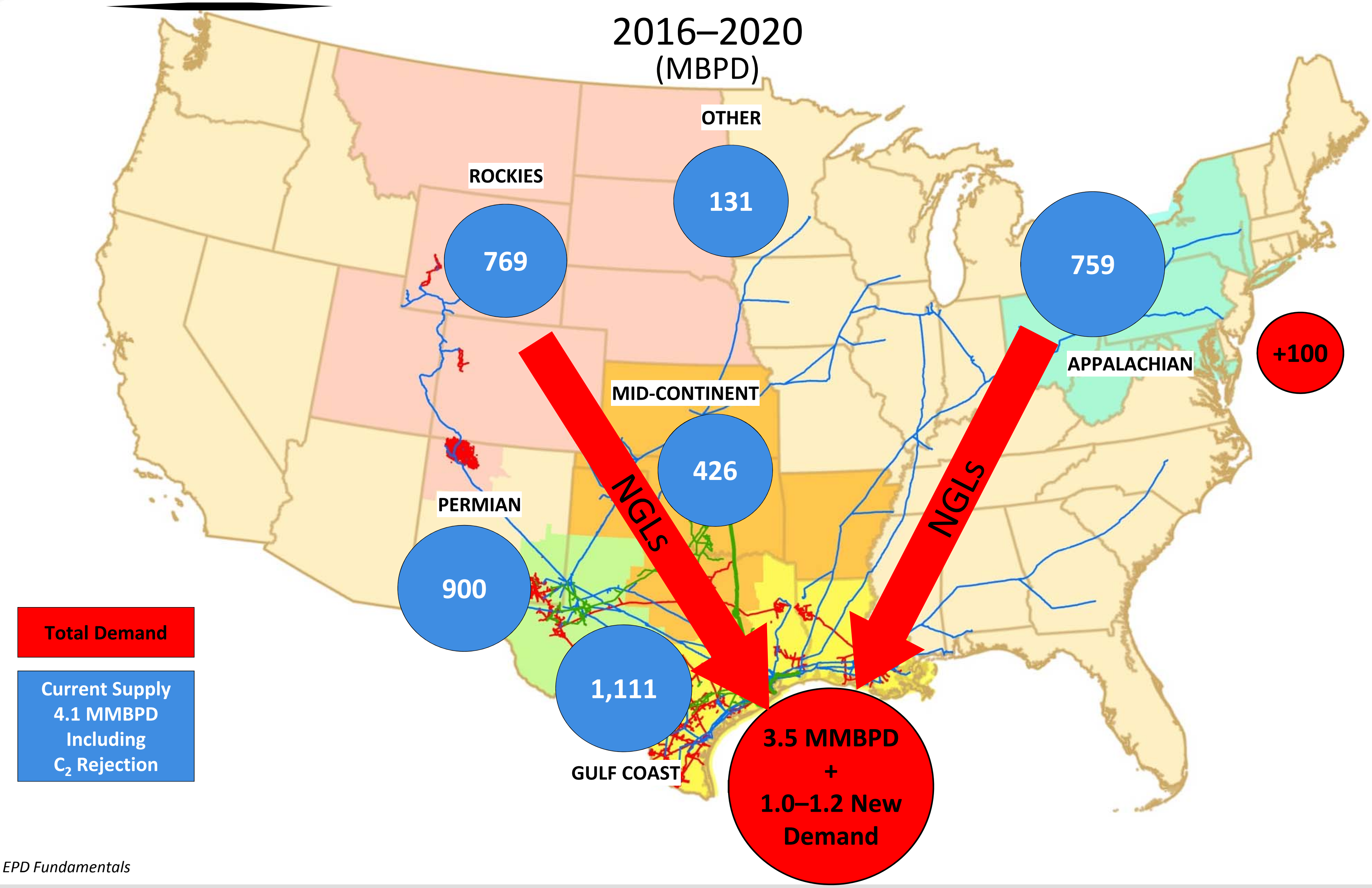
LPG LOADINGS
Committed Loadings vs. Capacity

1,150 Cargos Scheduled from 2015–2020



- Export Capability: up to 27.5 MBPH
- Import Capability: up to 20 MBPH
- Ability to load up to 3 vessels simultaneously

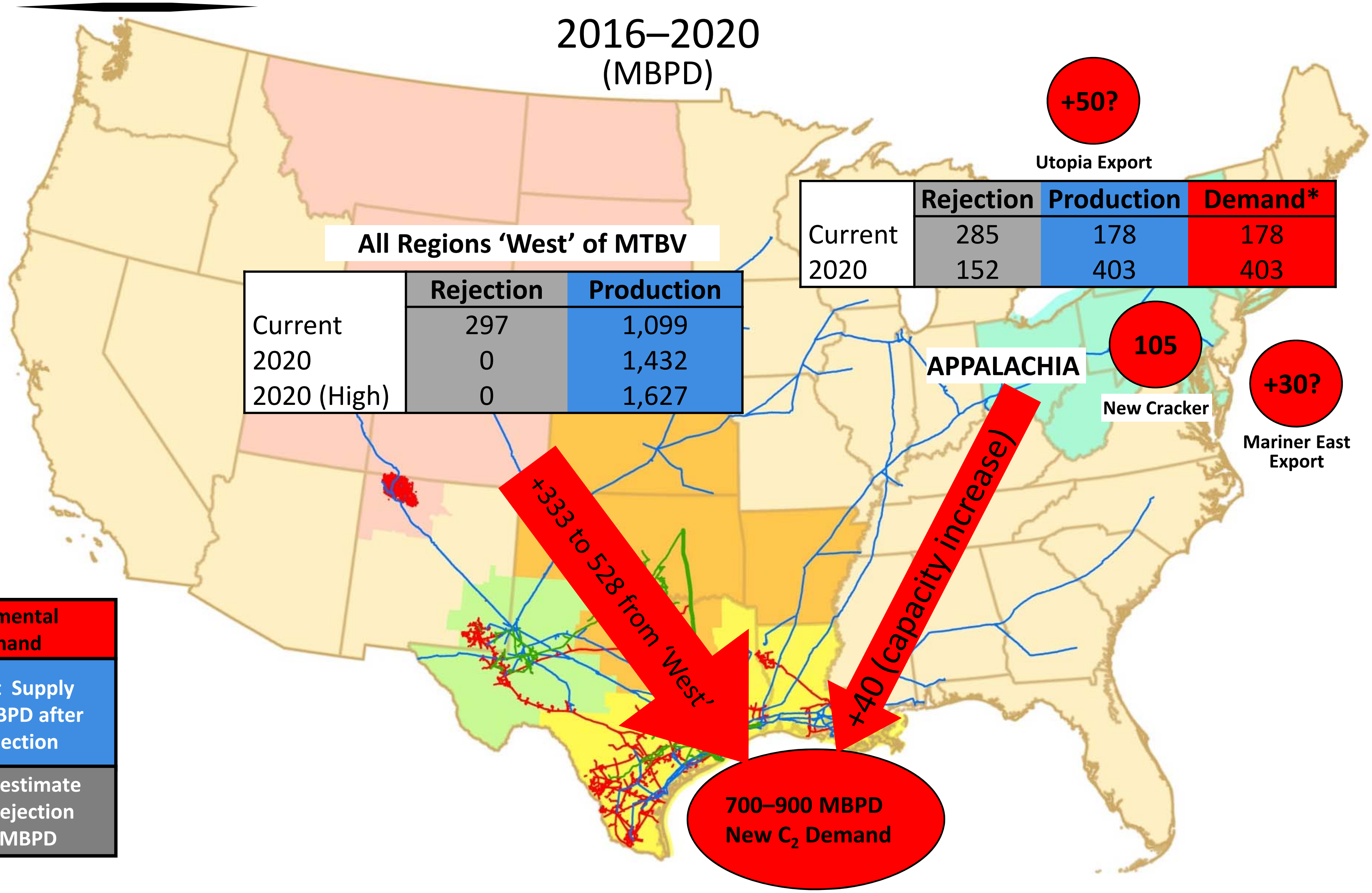
NGLs: U.S. GULF COAST IS SHORT NGLs; PRODUCERS NEED PRICE SIGNAL TO PRODUCE / TRANSPORT



Source: EPD Fundamentals

ETHANE: APPALACHIA ALONE CANNOT MEET U.S. DEMAND

2016–2020
(MBPD)



All Regions 'West' of MTBV

	Rejection	Production
Current	297	1,099
2020	0	1,432
2020 (High)	0	1,627

	Rejection	Production	Demand*
Current	285	178	178
2020	152	403	403

Incremental Demand
Current Supply 1.2 MMBPD after C_2 Rejection
Current estimate for C_2 Rejection ≈600 MBPD

Source: EPD Fundamentals

* Rejection is based on total potential ethane as calculated by EPD Supply Appraisal minus ethane actually produced as reported by EIA
** Demand includes Existing Flows (+): Incremental ATEX, One Cracker, 30 MBPD ME2 and 50 MBPD exports on Utopia East

THE CHEMICALS INDUSTRY IS MAKING LARGE INVESTMENTS BASED ON U.S. SHALES

- American Chemistry Council (ACC) analysis shows ≈$164 billion in capital spending could lead to ≈$105 billion per year in new chemical output
  - Much of new investment geared towards export markets; will help improve U.S. trade balance

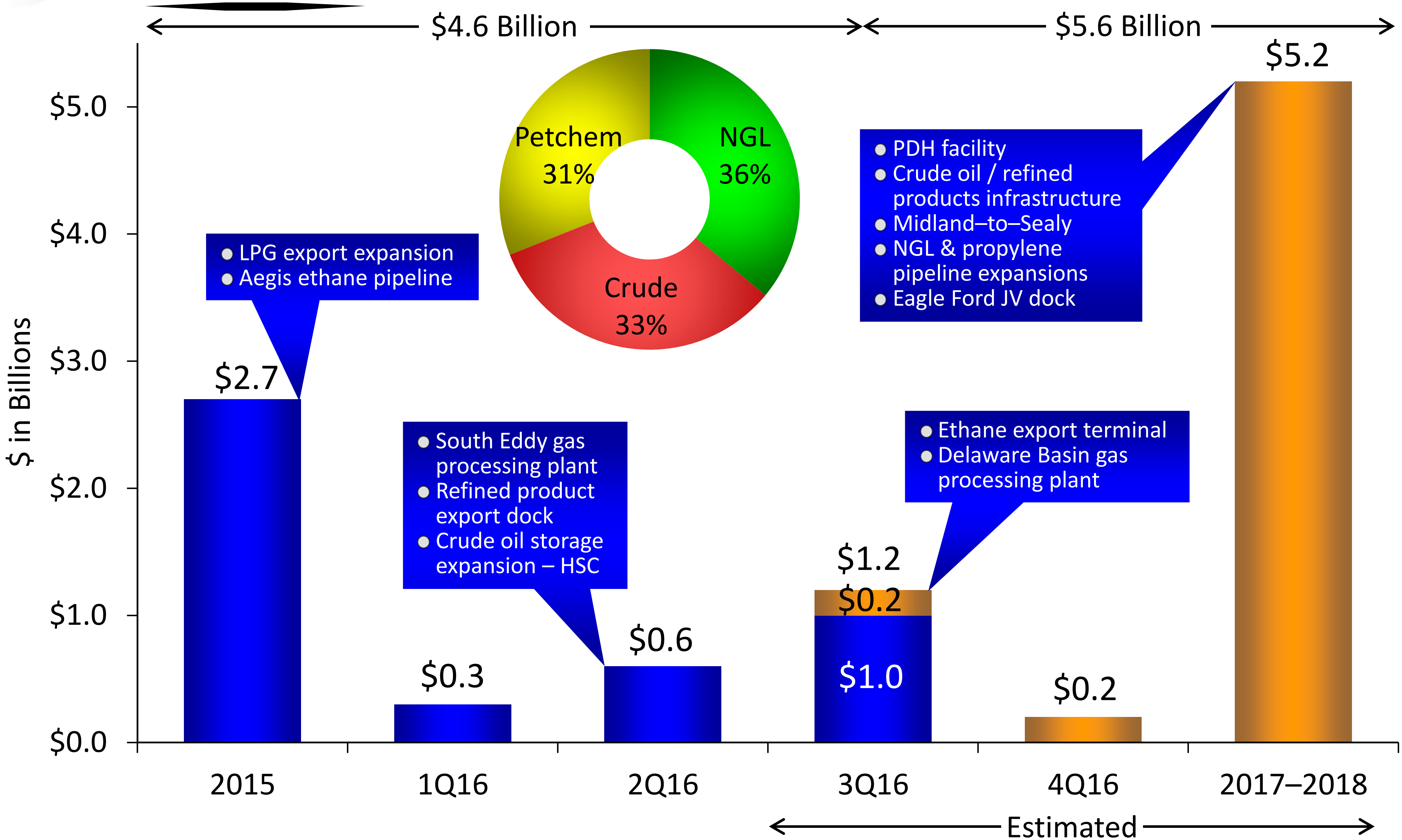
U.S. World Scale Ethylene Plants Under Construction

Company	Capacity MM Metric Tons	Ethane Consumption (MBPD)	Location	Est Completion Date
Chevron Phillips Chemical	1.5	90	Cedar Bayou, TX	2017
ExxonMobil Chemical	1.5	90	Baytown, TX	2017
Dow Chemical	1.5	90	Freeport, TX	2017
Occidental Chemical / Mexichem	0.55	33	Ingleside, TX	2017
Shintech	0.5	32	Plaquemine, LA	2018
Sasol	1.5	90	Lake Charles, LA	Late 2018
Formosa Plastics	1.2	70	Point Comfort, TX	2019
Axiall / Lotte	1.2	70	Lake Charles, LA	2019
Shell	1.5	105	Monaca, PA	Early 2020s
TOTAL	10.65	670		

Sources: American Chemistry Council and EPD Fundamentals

PROJECT UPDATES

VISIBILITY TO GROWTH: $10.2B OF MAJOR CAPITAL PROJECTS BY IN–SERVICE DATE



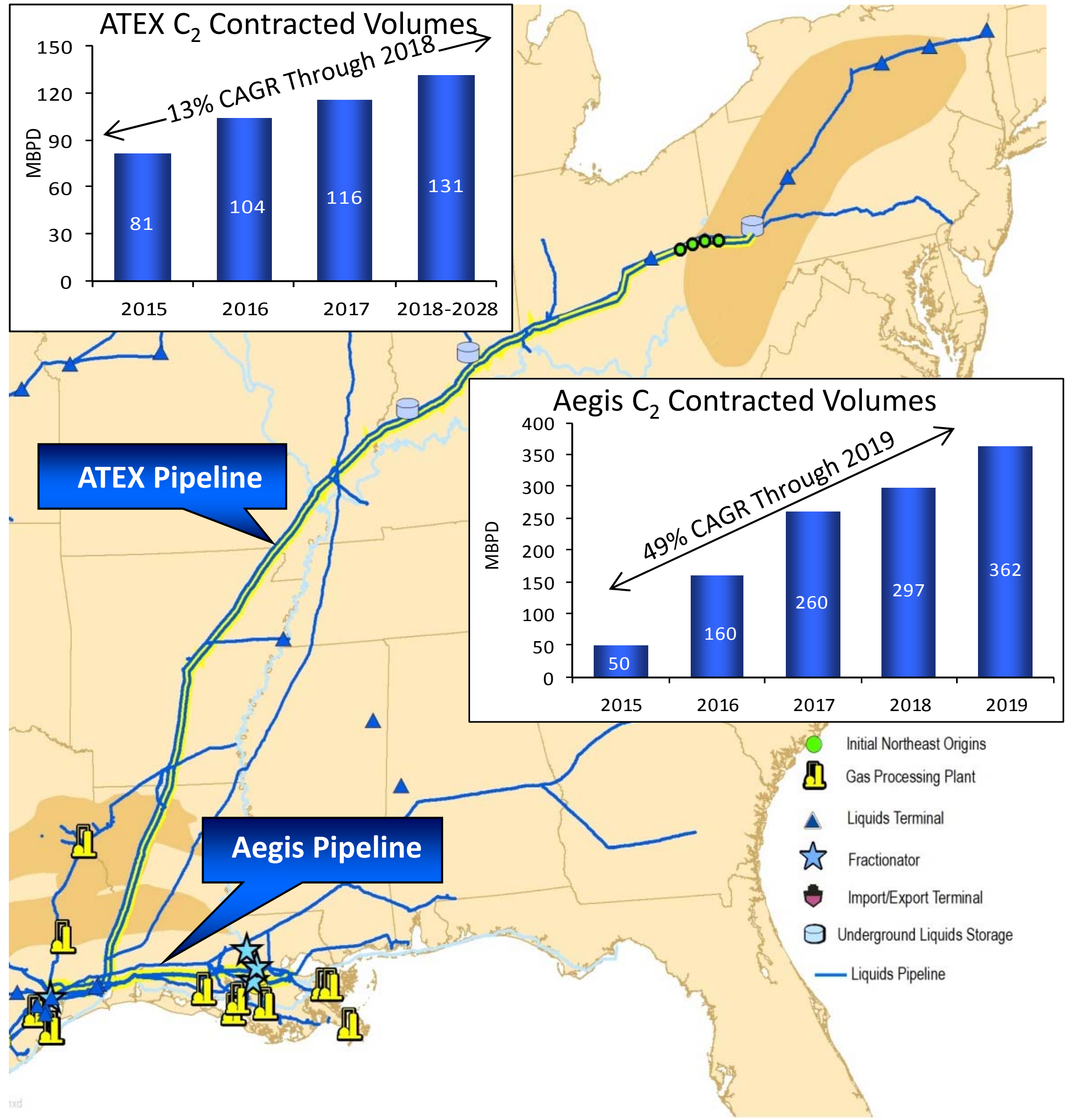
ETHANE TAKEAWAY SOLUTIONS PROVIDES ACCESS TO GULF COAST MARKETS

ATEX Pipeline

- Current capacity of 125 MBPD
  - Expandable to 265 MBPD; would require additional long-term agreements and 18 months to expand
- Connected to 4 NGL fractionators; currently moving ≈110 MBPD to Mont Belvieu
- 15 year ship-or-pay commitments

Ethane Header System

- 270-mile, 20” pipeline creates header system from Corpus Christi to Mississippi River in Louisiana, when combined with existing South Texas ethane pipeline
- Received commitments of ≈360 MBPD; in discussions for further commitments
  - Expandable beyond 400 MBPD with additional pipeline looping
- Currently moving ≈135 MBPD



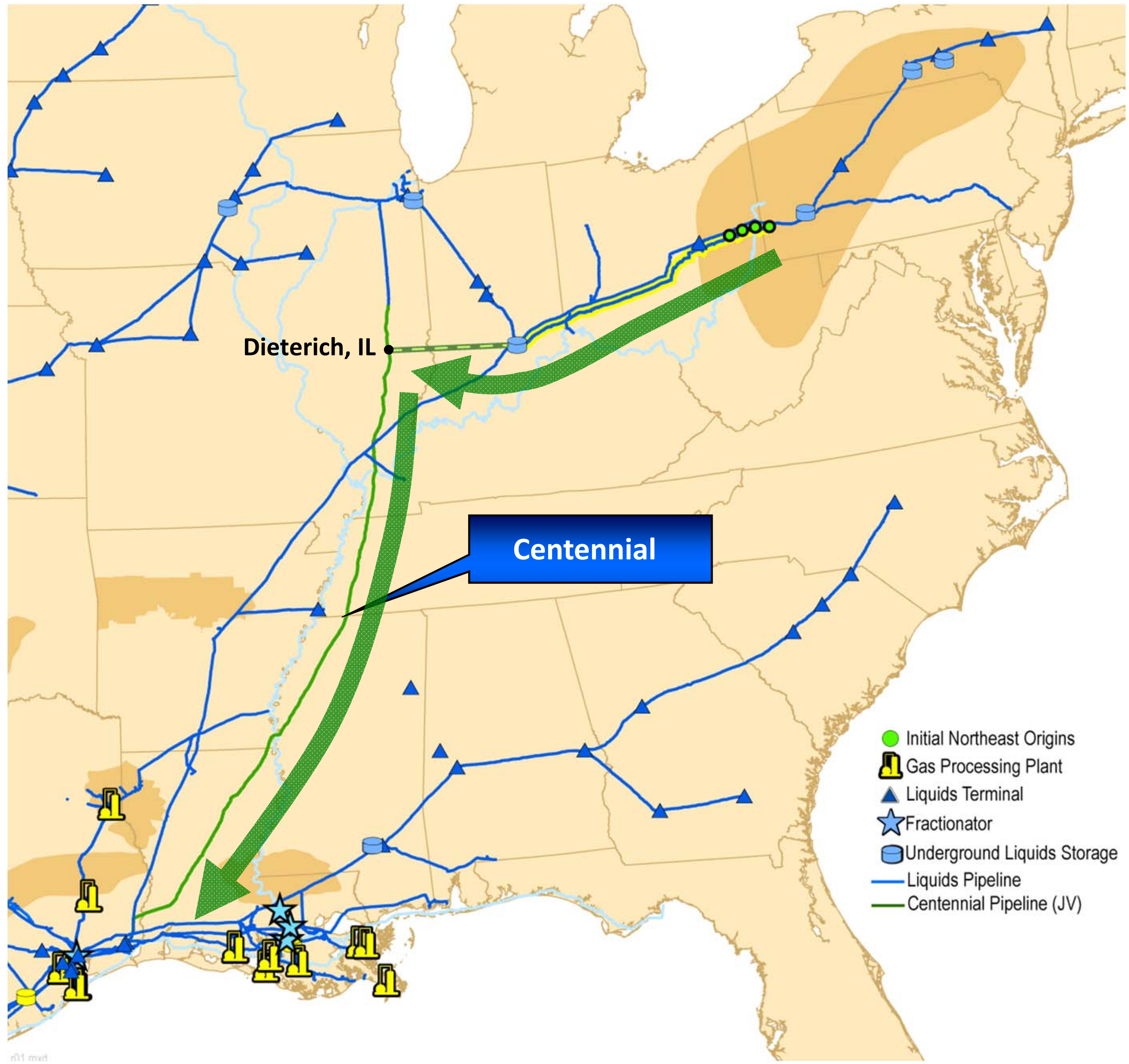
POTENTIAL TAKEAWAY PROJECT FOR NORTHEAST PURITY NGLs

Centennial Pipeline

- 800-mile, 26” / 24” northbound refined products pipeline from Beaumont, TX to Bourbon, IL; idle since 2011
- 2 MMBbls of refined products storage at Creal Springs, Illinois
- Owned 50 / 50 by Marathon (“MPC”) and EPD

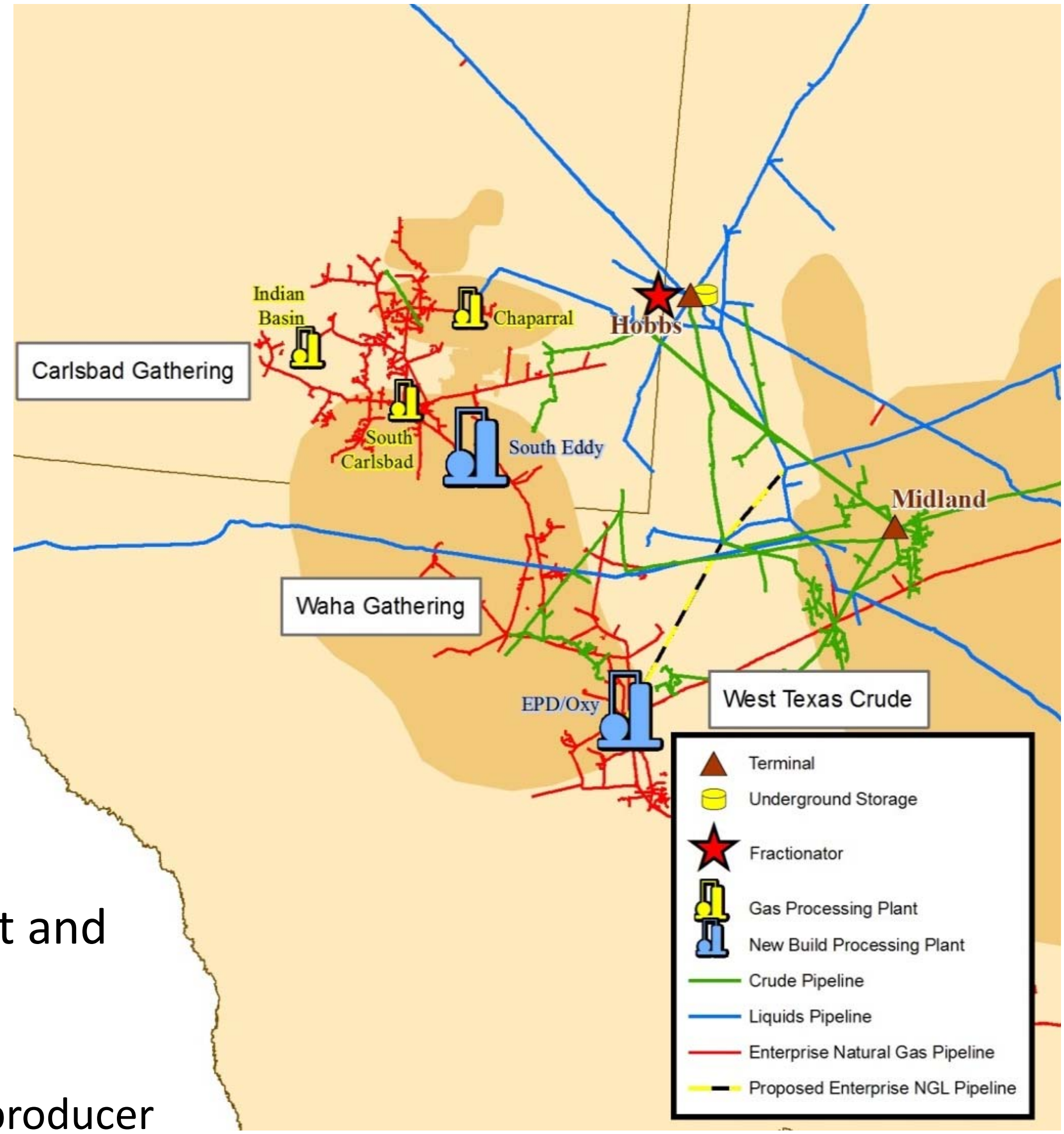
Potential Repurposing Project

- Combination new build and repurposing of sponsor–owned pipelines
- Would connect Marcellus / Utica fractionators to Centennial
- Reverse Centennial’s pump stations; possibly install additional pump stations
- NGL product capacity of up to 230 MBPD
- Construction period: ≈18–24 months
- Status: currently evaluating



EXPANDING FOOTPRINT IN PERMIAN BASIN
Bringing Gas Processing Capacity to 800 MMcf/d

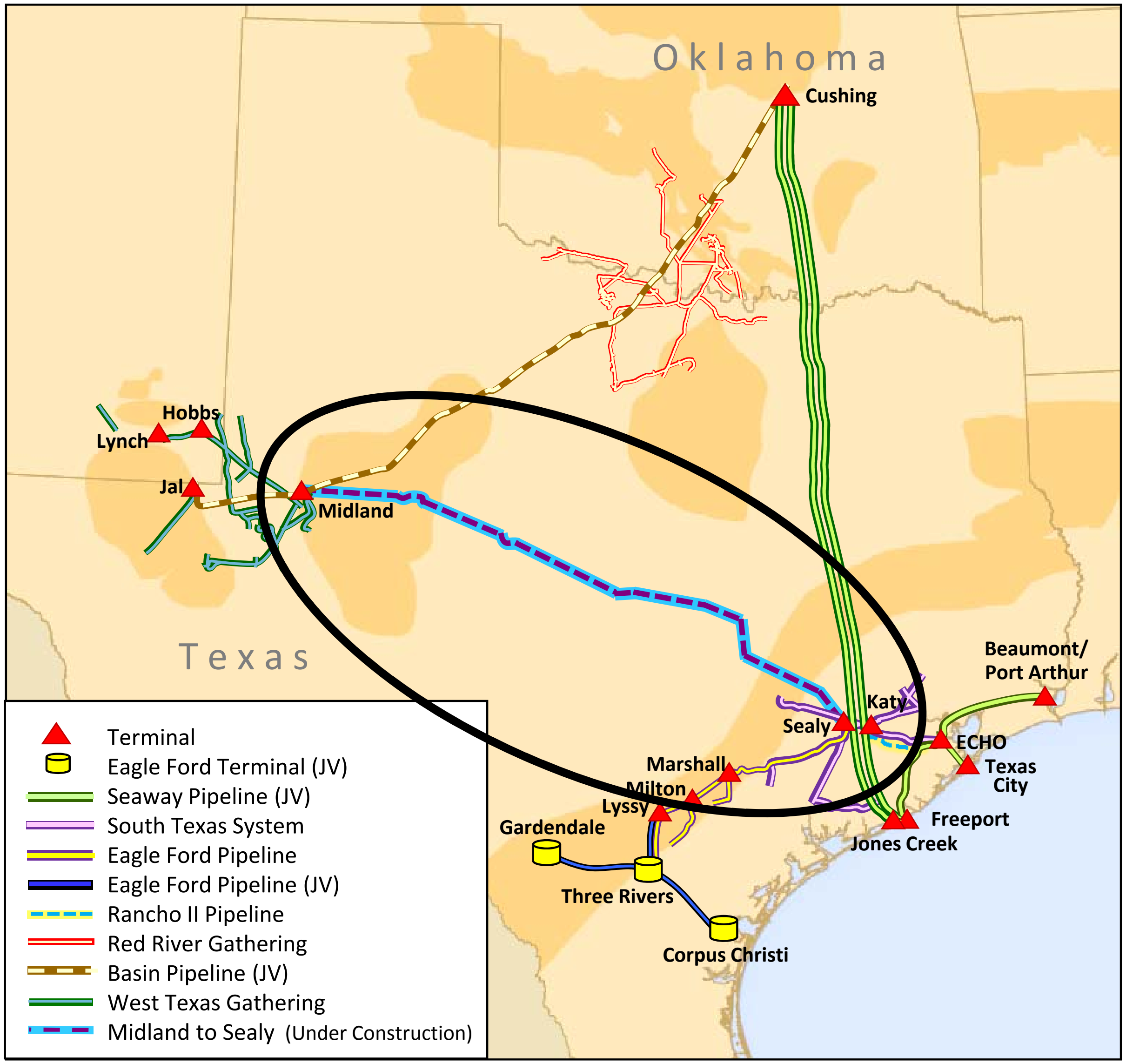
- **South Eddy** cryogenic gas processing facility and related pipelines
  - 200 MMcf/d natural gas; 25 MBPD NGLs
  - Constructed 90 miles of new gathering pipelines; 71-mile pipeline extension of MAPL system
  - Supported by long-term fee-based contracts
  - Completed May 2016
- **Delaware Basin 50/50 Oxy JV** cryogenic gas processing plant and related pipelines
  - 150 MMcf/d natural gas; >22 MBPD NGLs
  - EPD will build an 82-mile, 12" NGL pipeline to connect to Chaparral pipeline providing access to Mont Belvieu
  - Supported by long-term fee-based contracts
  - Completed August 2016
- **Delaware Basin** cryogenic gas processing plant and related pipelines ***(announced 6/20/16)***
  - 300 MMcf/d natural gas; 40 MBPD NGLs
  - Supported by long-term contracts from a major producer
  - Startup expected 2Q 2018



Source: EPD Fundamentals

MIDLAND TO HOUSTON CRUDE OIL PIPELINE

From the Permian Supply Hub to Multiple Markets

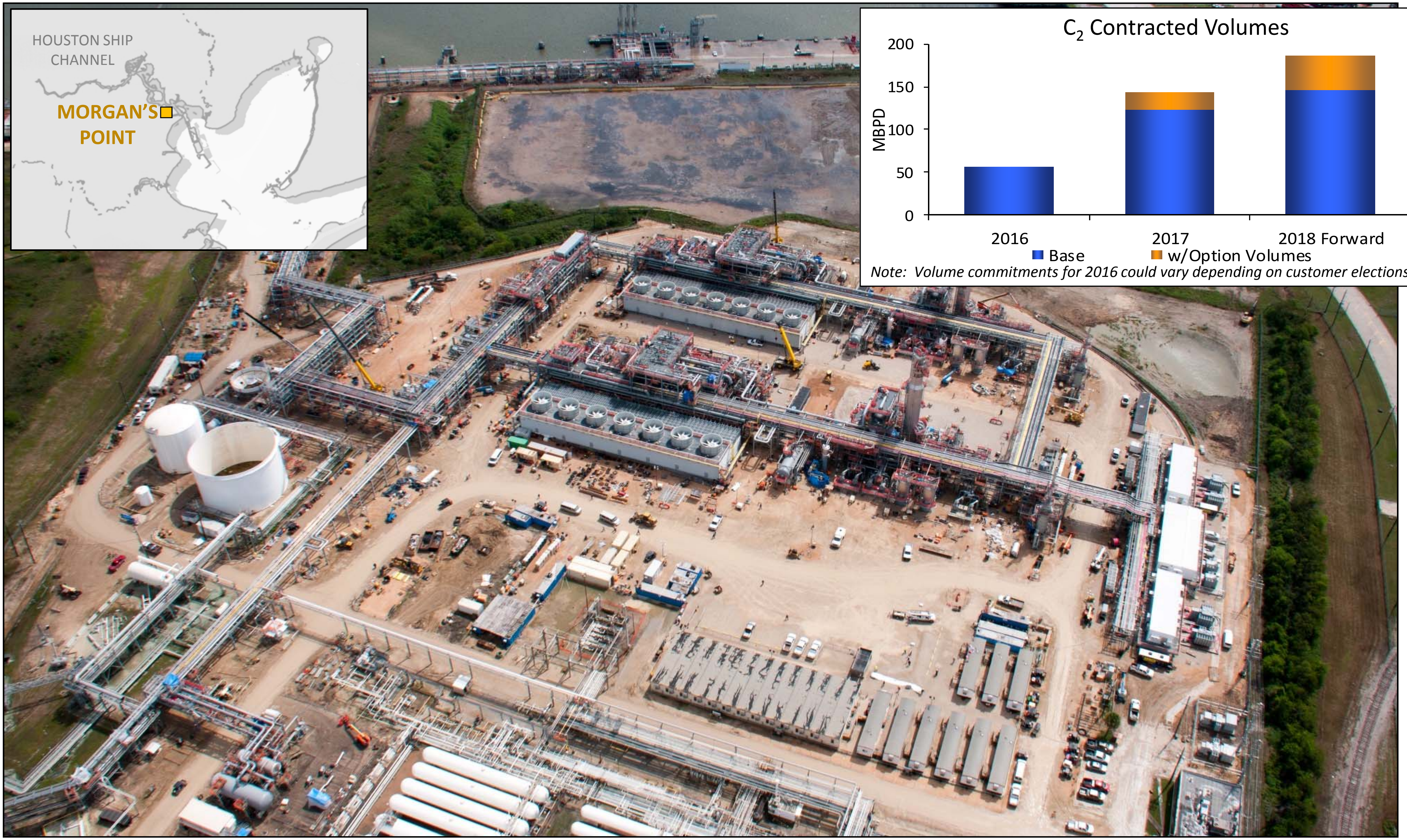


- 400-mile, 24” pipeline from Midland to Sealy, Texas
- ≈60% of initial capacity of 300 MBPD contracted
  - Capacity expandable to 450 MBPD
- Supported by long-term contracts
- Expected in-service: mid-2018
- Competitive advantages
  - Origin not dependent on 3rd party pipelines
  - Direct transport from Midland to Gulf Coast
  - Four segregations: WTS, WTI, Light WTI and condensate
  - Destination can efficiently distribute barrels to markets on the Texas Gulf Coast

CRUDE DISTRIBUTION SYSTEM

Interconnectivity: The Enterprise Business Model

ETHANE EXPORT FACILITY
Largest of Its Kind



Note: Volume commitments for 2016 could vary depending on customer elections.

LONG TERM PROPYLENE MARKET STRONGER THAN EXPECTED

- PDH competition is reduced with 6 projects cancelled or indefinitely delayed
- Propylene supplies have declined with ethylene cracker utilizing light-end feedstock
- International demand for propylene has resulted in attractive export opportunities
- Low prices do not mean low margins in the propylene business; spreads do not necessarily contract
  - Low price environment has stimulated propylene derivative construction; consumers are anxious to secure long-term supply

PDH FACILITY

- Produce up to 1.65 billion lbs/year (25 MBPD) of PGP
  - Consume 35 MBPD of propane
- 100% of capacity subscribed under fee-based contracts with investment grade companies averaging 15 years
  - No volume ramp after completion
- Transitioned to new primary construction contractor December 2015; productivity significantly increased
- Expected completion: 1Q 2017 with projected in service 2Q 2017

ETHYLENE EXPORT: CULTIVATING DEMAND

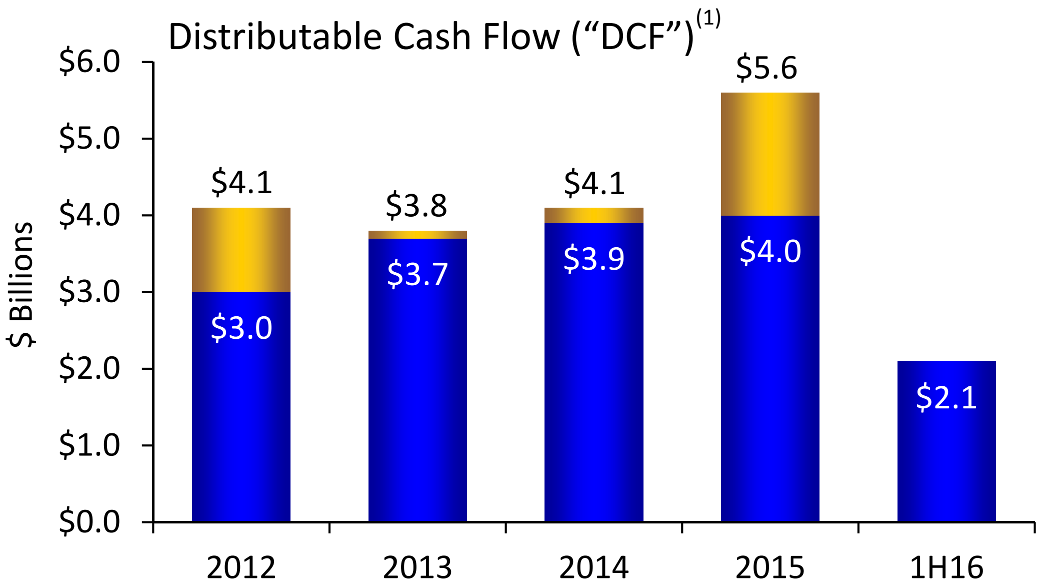
Enterprise's export position for LPG, Ethane and Propylene can be broadened to include Ethylene

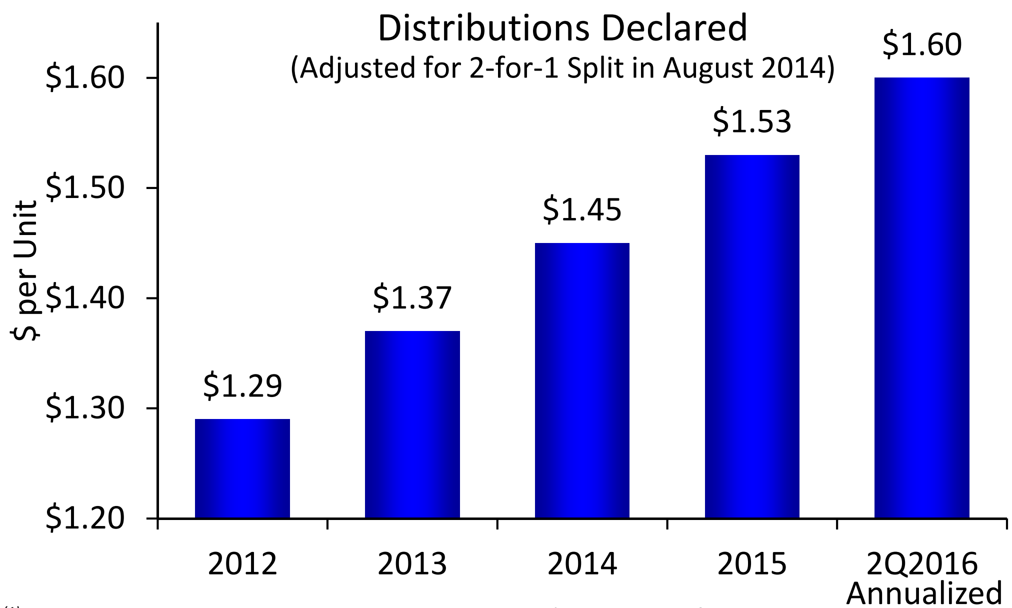
- Asian demand for ethylene continues to grow beyond local production; Asia is looking to diversify with stable shale-advantaged pricing
- The 40% expansion in ethylene production in the U.S. will result in an over supplied U.S. ethylene market
  - Domestic producers need to reach global markets, otherwise the operating capacity of U.S. crackers will be reduced as new builds are completed
  - The LPG and ethane export model has forged the path to connect foreign consumers to the shale revolution…ethylene export is the next logical step

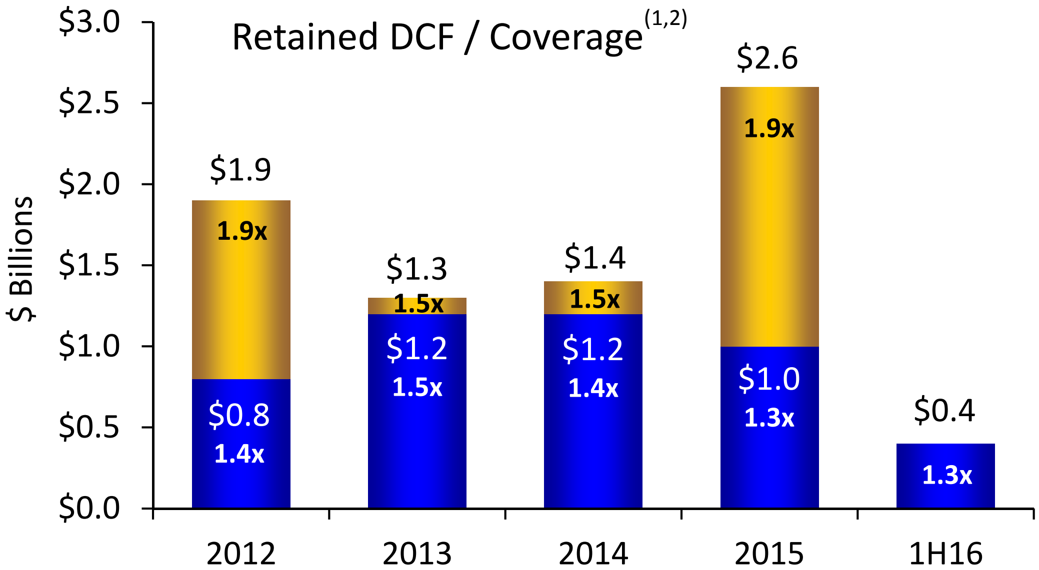
Economics are very similar to the Ethane Export project …and any NGL can be exported from an Ethylene terminal

FINANCIAL UPDATE

STRONG FINANCIAL RESULTS

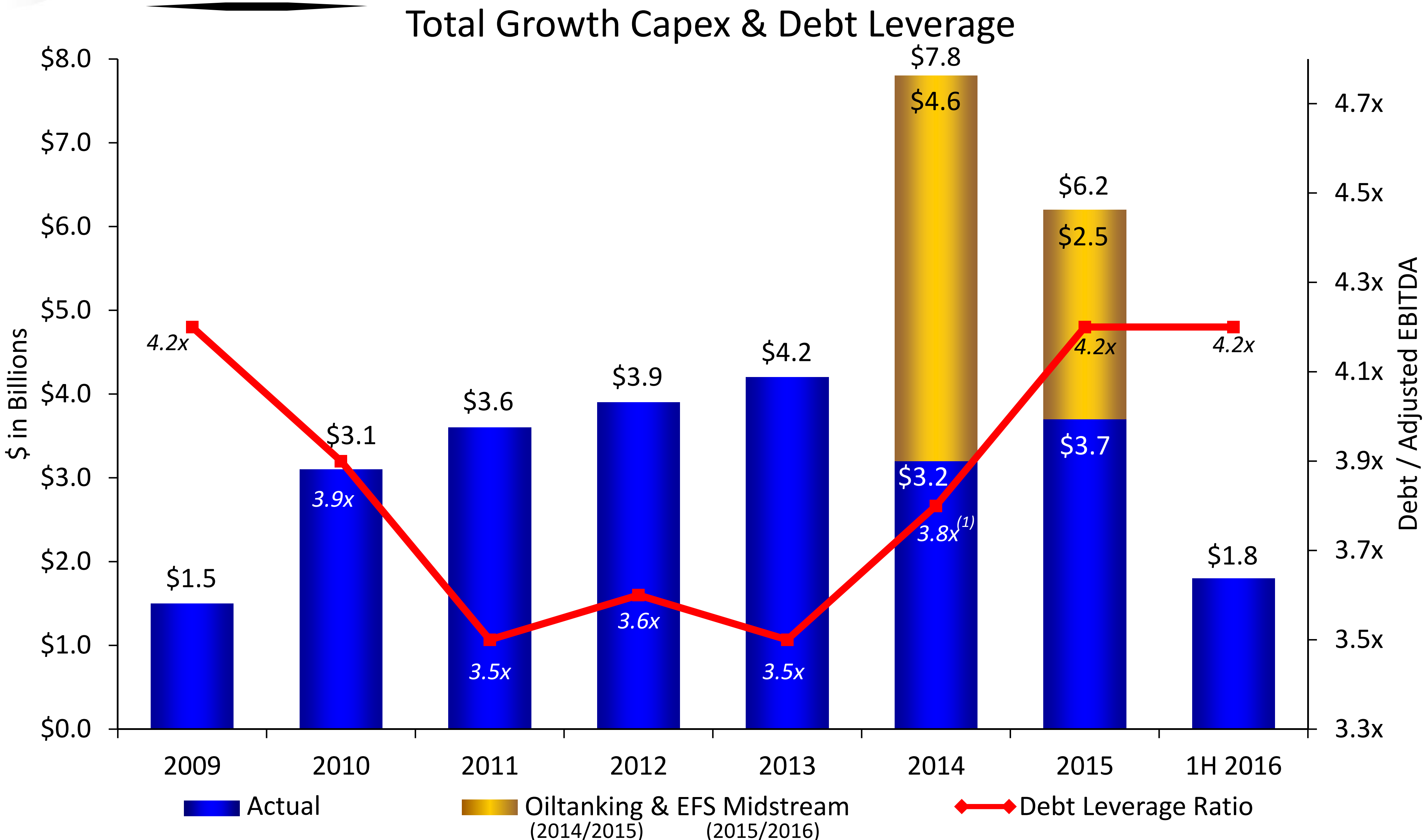






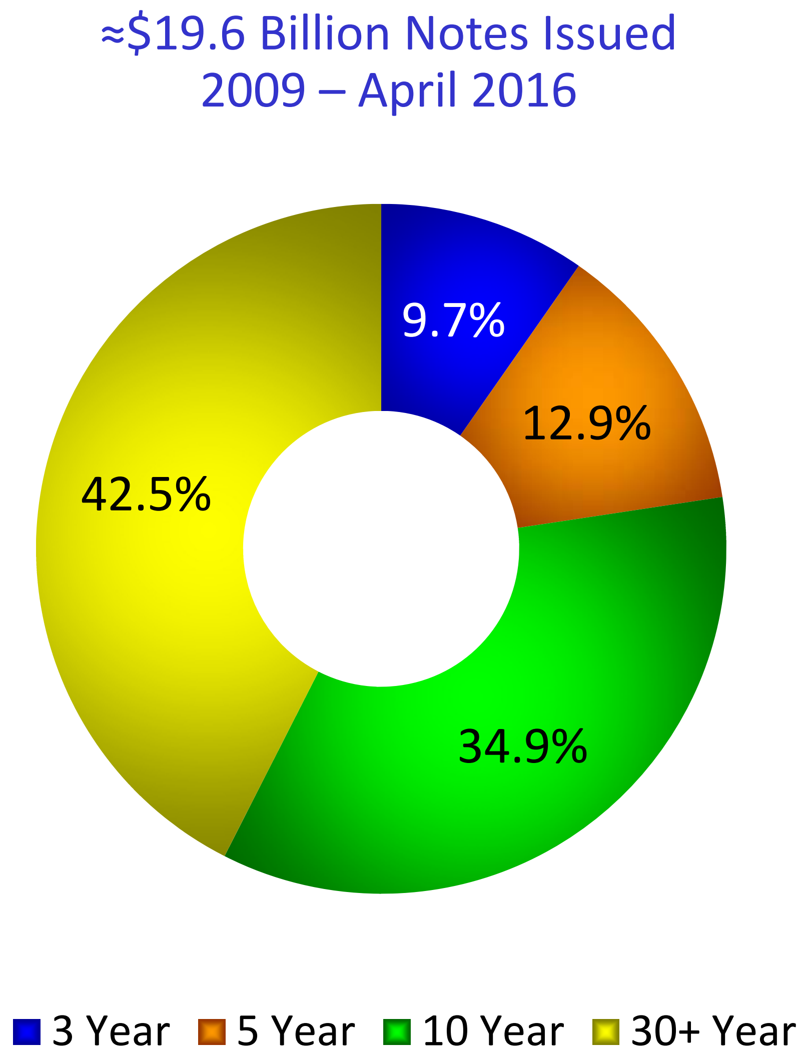
(1) *Each period noted includes non-recurring transactions (e.g., proceeds from asset sales and property damage insurance claims and payments to settle interest rate hedges).*
(2) *Retained DCF represents the amount of distributable cash flow for each period that was retained by the general partner for reinvestment in capital projects and other reasons.*

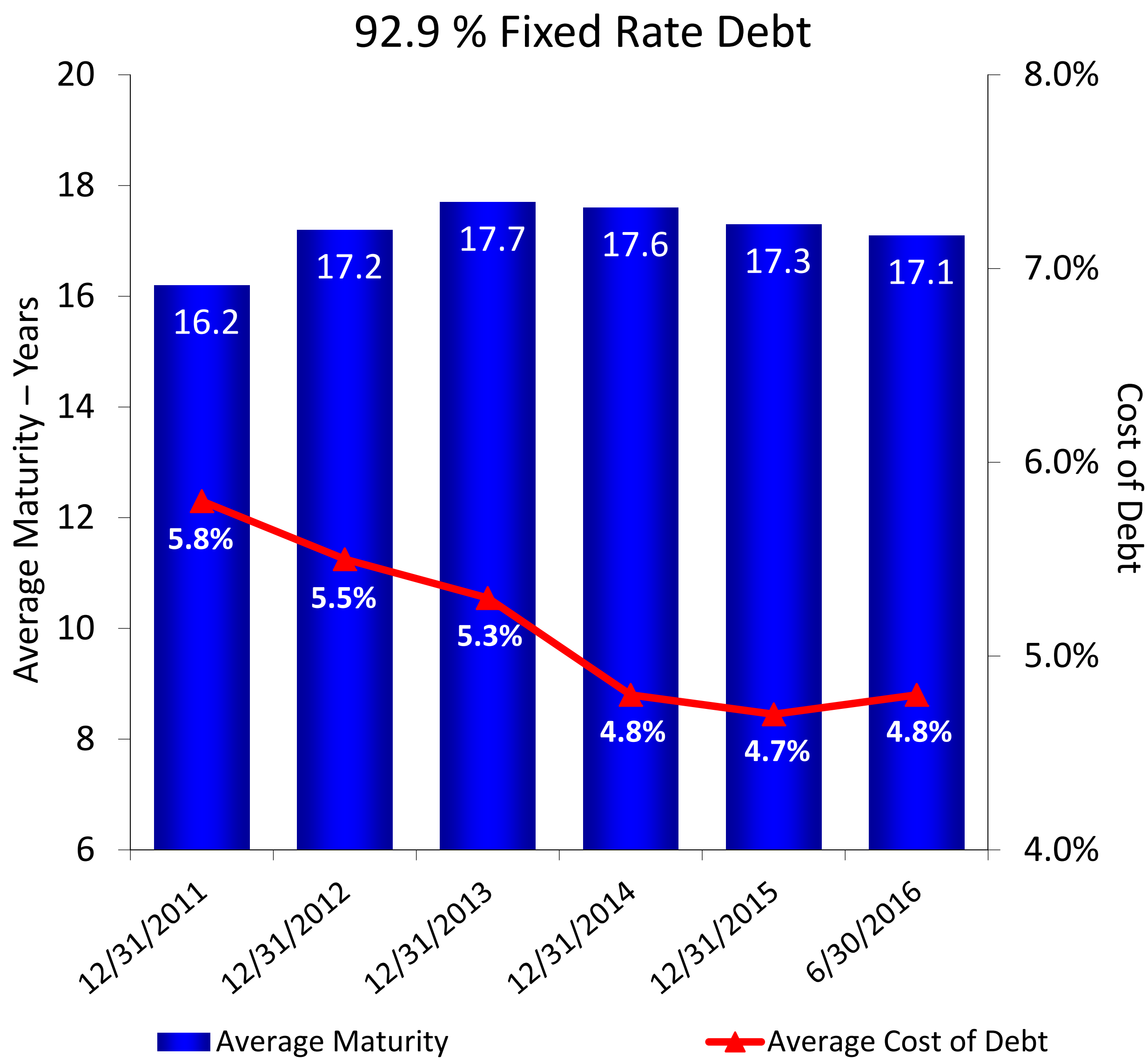
HISTORY OF FINANCIAL DISCIPLINE WHILE EXECUTING GROWTH STRATEGY



(1) *Proforma includes full year EBITDA for Oiltanking.*

STRENGTHENING DEBT PORTFOLIO
Extending Maturities Without Increasing Costs





INVESTOR TAKEAWAYS
EPD'S MLP MODEL WORKS!

- BBB+/Baa1 credit rating provides financial strength / access to capital
- No GP IDRs provides financial flexibility and lower cost of capital
  - EPD's current 10-year WACC (50% 10-year debt / 50% equity) at less than 7% is consistent with historical average since IPO and supports DCF / unit accretion from new projects
- Actively pursuing development of new organic growth projects
  - Marine terminal and related assets to support ethylene exports
  - Expand terminals to support increasing exports of refined products, crude oil, condensate and propylene
  - Expand iBDH capacity to fully utilize integrated downstream assets to increase production of octane additives and petrochemical feedstocks
  - Expand natural gas pipeline capacity in Texas for exports to Mexico and in Louisiana to provide supply diversity for growing industrial demand
  - Processing plant in Permian to support growing production

APPENDIX

VISIBILITY TO GROWTH: MAJOR CAPITAL PROJECTS

≈$4.6B In–Service 2015/1H16; ≈$5.6B Under Construction

NGL Pipeline & Services

In Service Date	2015	1Q 2016	2Q 2016	3Q 2016	4Q 2016	2017–2018
LPG export facility on Gulf Coast (up to 16 MMBbls/mo)	**Done**					
Aegis ethane pipeline – 270 miles	**Done**					
Mont Belvieu brine handling expansion (2015 & 2017)	**Done**					√
South Eddy (Permian) gas plant – 200 MMcf/d & related pipelines (2Q 2016)			**Done**			
Ethane export facility on Gulf Coast (3Q 2016)				**Done**		
Delaware Basin gas plant (Oxy JV) – 150 MMcf/d & related pipelines (3Q 2016)				**Done**		
South Texas 16" ethane pipeline expansion (2017)						√
Delaware Basin (Permian) gas plant – 300 MMcf/d & related pipelines (2018)						√

Crude Oil Pipelines & Services

In Service Date	2015	1Q 2016	2Q 2016	3Q 2016	4Q 2016	2017–2018
Appelt & Beaumont storage terminal expansions, including 58 acre expansion (2015–2018)	**Done**	**Done**	**Done**	√		√
ECHO addt'l 4 MMBbl (total capacity ≈6.5 MMBbls) & 55 miles of 36" pipelines (2015–2018)	**Done**					√
Rancho II 36" crude oil pipeline (2015)	**Done**					
Permian 25-mile, 10" crude gathering pipeline (2015)	**Done**					
Eagle Ford (JV) – crude oil pipeline expansion & gathering (2015) & dock (2018)						√
Midland to Sealy 24" crude oil pipeline (2018)						√
EFS gathering & condensate pipeline projects (2016–2018)				√		√

Petrochemical & Refined Products Services

In Service Date	2015	1Q 2016	2Q 2016	3Q 2016	4Q 2016	2017–2018
Refined products export dock – Beaumont expansion (2Q 2016 & 1Q 2017)			**Done**			√
Propane Dehydrogenation Unit ("PDH") (2017)						√
Expansion of propylene pipeline system (2016–2017)				√	√	√
Other	**Done**					√

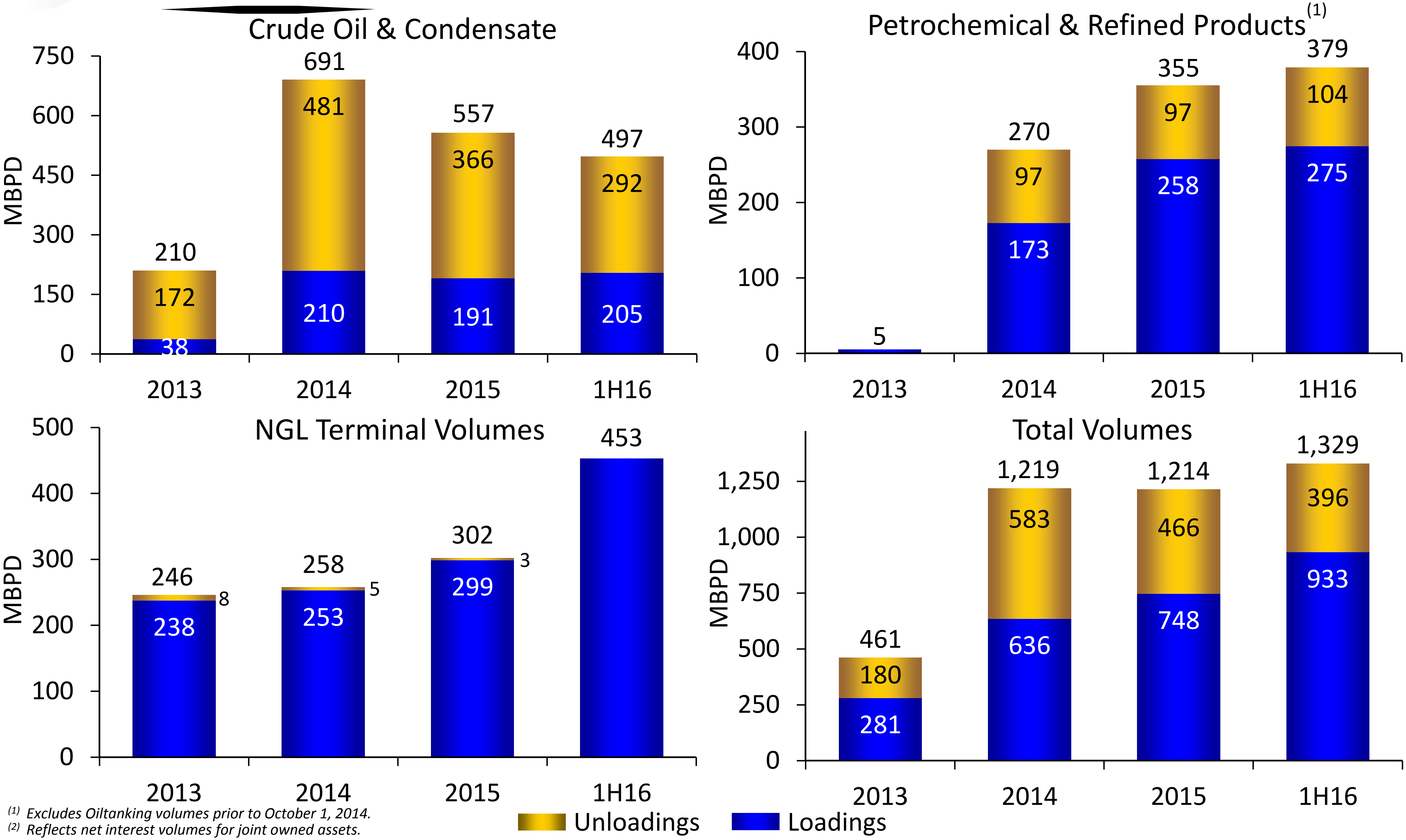
	2015	1Q 2016	2Q 2016	3Q 2016	4Q 2016	2017–2018
Value of capital placed in service ($ Billions)	$ 2.7	$ 0.3	$ 0.6	$ 1.0	$ -	$ -
Value of remaining capital projects to be placed in service ($ Billions)	$ -	$ -	$ -	$ 0.2	$ 0.2	$ 5.2

REGIONAL NGL HUBS: GULF COAST VS. EAST COAST – NO COMPARISON

	USGC	East Coast
SUPPLY		
Diversity	7 unique basins linked	1 basin for all supply
2016	≈4.1 MMBPD	Estimated ≈0.8 MMBPD
STORAGE		
Capacity	≈300 MMBbls (salt dome)	≈11 MMBbls (granite / hard rock)
Per Well Scale	≈20 MMB with upside	≈1 MMB
Expansion Cost	$5–$15 / Bbl	$65–$85 / Bbl
Expansion Time	2–3 years for ≈5 MMBbls	2–3 years for ≈1 MMBbls
DEMAND		
Local	Ratable via chemical demand: >1.5 MMBPD rising to >2.3 MMBPD by 2018 across all molecules	Highly Seasonal, limited to C_3 and C_4 (no local C_2 demand)
Export	≈1 MMBPD across all NGLs	<150 MBPD across all NGLs
INTANGIBLES	Supportive Regulatory Environment	Restrictive Regulatory Environment

Sources: EPD Fundamentals and EPD Operations

MARINE TERMINAL / DOCK ACTIVITY



(1) Excludes Oiltanking volumes prior to October 1, 2014.
(2) Reflects net interest volumes for joint owned assets.

NON–GAAP RECONCILIATIONS

TOTAL GROSS OPERATING MARGIN

We evaluate segment performance based on our financial measure of gross operating margin. Gross operating margin is an important performance measure of the core profitability of our operations and forms the basis of our internal financial reporting. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results.

The term "total gross operating margin" represents GAAP operating income exclusive of (i) depreciation, amortization and accretion expenses, (ii) impairment charges, (iii) gains and losses attributable to asset sales, insurance recoveries and related property damage and (iv) general and administrative costs. Total gross operating margin includes equity in the earnings of unconsolidated affiliates, but is exclusive of other income and expense transactions, income taxes, the cumulative effect of changes in accounting principles and extraordinary charges. Total gross operating margin is presented on a 100% basis before any allocation of earnings to noncontrolling interests. The GAAP financial measure most directly comparable to total gross operating margin is operating income.

	For the Year Ended December 31,					For the Six Months Ended	For the Twelve Months Ended
	2011	2012	2013	2014	2015	June 30, 2016	June 30, 2016
Gross operating margin by segment:							
NGL Pipelines & Services	$ 2,184.2	$ 2,468.5	$ 2,514.4	$ 2,877.7	$ 2,771.6	$ 1,502.8	$ 2,928.6
Crude Oil Pipelines & Services	234.0	387.7	742.7	762.5	961.9	379.7	892.0
Natural Gas Pipelines & Services	675.3	775.5	789.0	803.3	782.6	355.1	741.8
Petrochemical & Refined Products Services	535.2	579.9	625.9	681.0	718.5	330.3	692.9
Offshore Pipelines & Services	228.2	173.0	146.1	162.0	97.5	-	7.1
Other Investments	14.8	2.4	-	-	-	-	-
Total segment gross operating margin (a)	3,871.7	4,387.0	4,818.1	5,286.5	5,332.1	2,567.9	5,262.4
Net adjustment for shipper make-up rights (b)	-	-	(4.4)	(81.7)	7.1	10.6	19.2
Total gross operating margin (non-GAAP)	3,871.7	4,387.0	4,813.7	5,204.8	5,339.2	2,578.5	5,281.6
Adjustments to reconcile non-GAAP gross operating margin to GAAP operating income:							
Subtract depreciation, amortization and accretion expense amounts not reflected in gross operating margin	(958.7)	(1,061.7)	(1,148.9)	(1,282.7)	(1,428.2)	(718.5)	(1,415.8)
Subtract non-cash impairment charges not reflected in gross operating margin	(27.8)	(63.4)	(92.6)	(34.0)	(162.6)	(14.8)	(65.1)
Subtract operating lease expenses paid by EPCO not reflected in gross operating margin	(0.3)	-	-	-	-	-	-
Add net gains or subtract net losses attributable to asset sales, insurance recoveries and related property damage not reflected in gross operating margin	156.0	17.6	83.4	102.1	(15.6)	(13.7)	(26.9)
Subtract general and administrative costs not reflected in gross operating margin	(181.8)	(170.3)	(188.3)	(214.5)	(192.6)	(79.0)	(177.4)
Operating income (GAAP)	$ 2,859.1	$ 3,109.2	$ 3,467.3	$ 3,775.7	$ 3,540.2	$ 1,752.5	$ 3,596.4

(a) Within the context of this table, total segment gross operating margin represents a subtotal and corresponds to measures similarly titled and presented with the business segment footnote found in our consolidated financial statements.
(b) Gross operating margin by segment for NGL Pipelines & Services and Crude Oil Pipelines & Services reflect adjustments for shipper make-up rights that are included in management's evaluation of segment results. However, these adjustments are excluded from non-GAAP total gross operating margin in compliance with recently issued guidance from the SEC.

ADJUSTED EBITDA

Adjusted EBITDA is commonly used as a supplemental financial measure by our management and external users of our financial statements, such as investors, commercial banks, research analysts and ratings agencies to assess: (1) the financial performance of our assets without regard to financing methods, capital structures or historical cost basis; (2) the ability of our assets to generate cash sufficient to pay interest and support our indebtedness; 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 included in this presentation may not be comparable to similarly titled measures of other companies. The following table reconciles non-GAAP Adjusted EBITDA to net cash flows provided by operating activities, which is the most directly comparable GAAP financial measure to Adjusted EBITDA (dollars in millions):

	For the Year Ended December 31,					For the Six Months Ended	For the Twelve Months Ended
	2011	2012	2013	2014	2015	June 30, 2016	June 30, 2016
Net income (GAAP)	$ 2,088.3	$ 2,428.0	$ 2,607.1	$ 2,833.5	$ 2,558.4	$ 1,240.2	$ 2,591.4
Adjustments to GAAP net income to derive non-GAAP Adjusted EBITDA:							
Subtract equity in income of unconsolidated affiliates	(46.4)	(64.3)	(167.3)	(259.5)	(373.6)	(177.5)	(351.7)
Add distributions received from unconsolidated affiliates	156.4	116.7	251.6	375.1	462.1	234.5	431.1
Add interest expense, including related amortization	744.1	771.8	802.5	921.0	961.8	484.7	967.0
Add provision for or subtract benefit from income taxes	27.2	(17.2)	57.5	23.1	(2.5)	8.3	6.9
Add depreciation, amortization and accretion in costs and expenses	990.5	1,094.9	1,185.4	1,325.1	1,472.6	733.4	1,453.2
Add non-cash asset impairment charges	27.8	63.4	92.6	34.0	162.6	15.2	65.5
Add non-cash net losses or subtract net gains attributable to asset sales, insurance recoveries and related property damage	32.8	20.0	15.7	7.7	18.9	13.7	28.7
Add non-cash expense attributable to changes in fair value of the Liquidity Option Agreement	-	-	-	-	25.4	21.1	35.0
Add losses and subtract gains attributable to unrealized changes in the fair market value of derivative instruments	(25.7)	(29.5)	1.4	30.6	(18.4)	68.3	59.8
Adjusted EBITDA (non-GAAP)	3,995.0	4,383.8	4,846.5	5,290.6	5,267.3	2,641.9	5,286.9
Adjustments to non-GAAP Adjusted EBITDA to derive GAAP net cash flows provided by operating activities:							
Subtract interest expense, including related amortization, reflected in Adjusted EBITDA	(744.1)	(771.8)	(802.5)	(921.0)	(961.8)	(484.7)	(967.0)
Subtract provision for or add benefit from income taxes reflected in Adjusted EBITDA	(27.2)	17.2	(57.5)	(23.1)	2.5	(8.3)	(6.9)
Subtract net gains attributable to asset sales and insurance recoveries	(188.5)	(106.4)	(99.0)	(109.8)	(3.3)	-	(1.8)
Add deferred income tax expense or subtract benefit	12.1	(66.2)	37.9	6.1	(20.6)	4.3	(4.6)
Add or subtract the net effect of changes in operating accounts, as applicable	266.9	(582.5)	(97.6)	(108.2)	(323.3)	(294.6)	(367.2)
Add or subtract miscellaneous non-cash and other amounts to reconcile non-GAAP Adjusted EBITDA with GAAP net cash flows provided by operating activities	16.3	16.8	37.7	27.6	41.6	(13.4)	6.6
Net cash flows provided by operating activities (GAAP)	$ 3,330.5	$ 2,890.9	$ 3,865.5	$ 4,162.2	$ 4,002.4	$ 1,845.2	$ 3,946.0

DISTRIBUTABLE CASH FLOW

Distributable cash flow is an important non-GAAP financial measure for our limited partners since it serves as an indicator of our success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not we are generating cash flows at a level that can sustain or support an increase in our 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 following table reconciles non-GAAP Distributable Cash Flow to net cash flows provided by operating activities, which is the most directly comparable GAAP financial measure to distributable cash flow for the periods presented (dollars in millions):

	For the Year Ended December 31,					For the Six Months Ended
	2011	2012	2013	2014	2015	June 30, 2016
Net income attributable to limited partners (GAAP)	$ 2,046.9	$ 2,419.9	$ 2,596.9	$ 2,787.4	$ 2,521.2	$ 1,219.7
Adjustments to GAAP net income attributable to limited partners to derive non-GAAP distributable cash flow:						
Add depreciation, amortization and accretion expenses	1,007.0	1,104.9	1,217.6	1,360.5	1,516.0	763.4
Add distributions received from unconsolidated affiliates	156.4	116.7	251.6	375.1	462.1	234.5
Subtract equity in income of unconsolidated affiliates	(46.4)	(64.3)	(167.3)	(259.5)	(373.6)	(177.5)
Subtract sustaining capital expenditures	(296.4)	(366.2)	(291.7)	(369.0)	(272.6)	(117.7)
Add net losses or subtract net gains from asset sales, insurance recoveries and related property damage	(155.7)	(86.4)	(83.3)	(102.1)	15.6	13.7
Add cash proceeds from asset sales and insurance recoveries	1,053.8	1,198.8	280.6	145.3	1,608.6	27.9
Add non-cash expense attributable to changes in fair value of the Liquidity Option Agreement	-	-	-	-	25.4	21.1
Add net gains or subtract net losses from the monetization of interest rate derivative instruments	(23.2)	(147.8)	(168.8)	27.6	-	-
Add deferred income tax expenses or subtract benefit	12.1	(66.2)	37.9	6.1	(20.6)	4.3
Add non-cash asset impairment charges	27.8	63.4	92.6	34.0	162.6	15.2
Add or subtract other miscellaneous adjustments to derive non-GAAP distributable cash flow, as applicable	(25.8)	(39.5)	(15.7)	73.2	(37.4)	88.7
Distributable cash flow (non-GAAP)	3,756.5	4,133.3	3,750.4	4,078.6	5,607.3	2,093.3
Adjustments to non-GAAP distributable cash flow to derive GAAP net cash flows provided by operating activities:						
Add sustaining capital expenditures reflected in distributable cash flow	296.4	366.2	291.7	369.0	272.6	117.7
Subtract cash proceeds from asset sales and insurance recoveries reflected in distributable cash flow	(1,053.8)	(1,198.8)	(280.6)	(145.3)	(1,608.6)	(27.9)
Add net losses or subtract net gains from the monetization of interest rate derivative instruments	23.2	147.8	168.8	(27.6)	-	-
Add or subtract the net effect of changes in operating accounts, as applicable	266.9	(582.5)	(97.6)	(108.2)	(323.3)	(294.6)
Add or subtract miscellaneous non-cash and other amounts to reconcile non-GAAP distributable cash flow with GAAP net cash flows provided by operating activities, as applicable	41.3	24.9	32.8	(4.3)	54.4	(43.3)
Net cash flows provided by operating activities (GAAP)	$ 3,330.5	$ 2,890.9	$ 3,865.5	$ 4,162.2	$ 4,002.4	$ 1,845.2

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