RBC Capital Markets MLP Conference

November 2012

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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," "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.

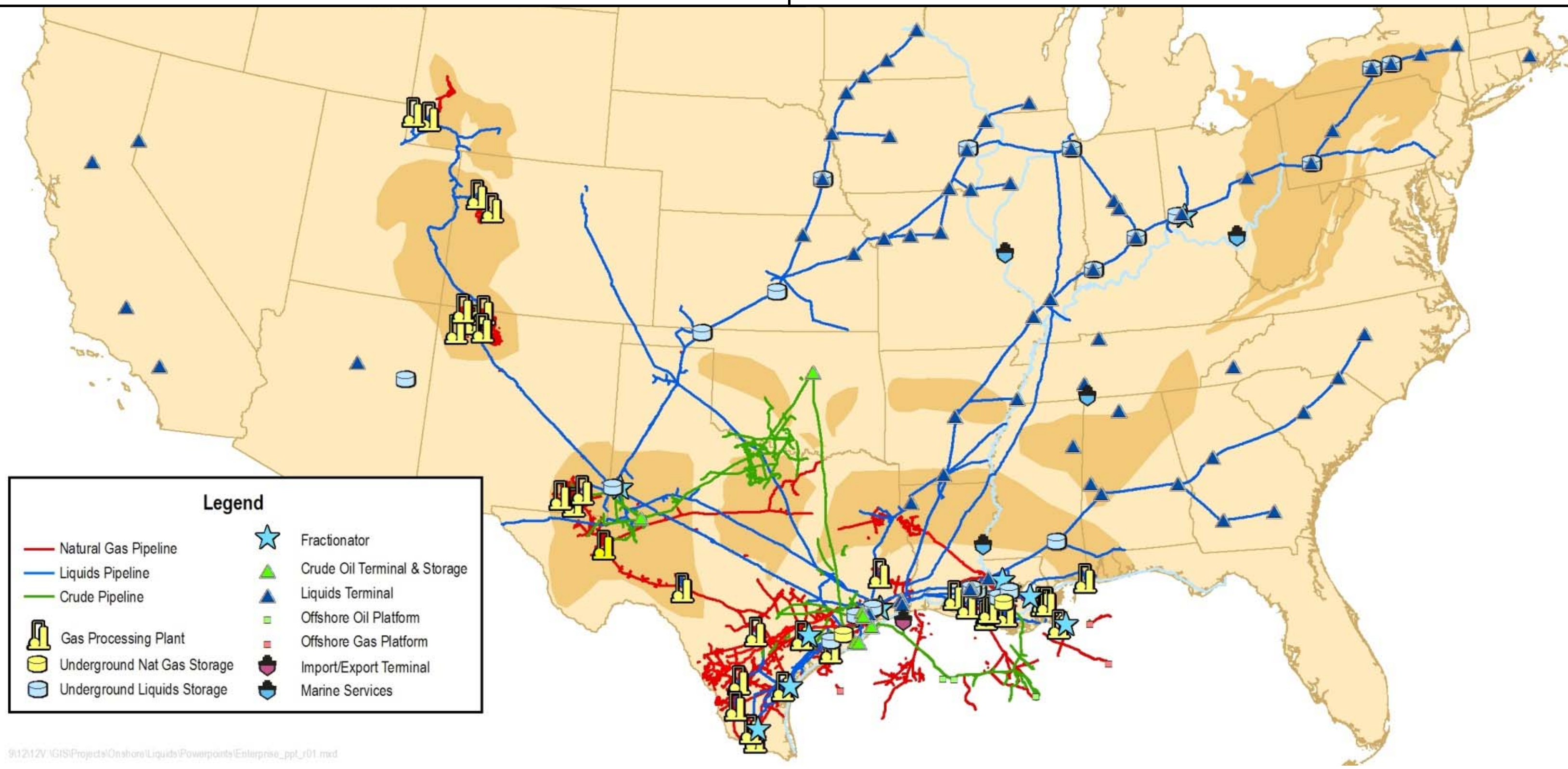
All forward-looking statements attributable to Enterprise or any person acting on our behalf are expressly qualified in their entirety by the cautionary statements contained herein, in such filings and in our future periodic reports filed with the Securities and Exchange Commission. Except as required 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

- Largest publicly traded energy partnership with an enterprise value of approximately $62 billion
  - 62nd on Fortune 500; 226th on Fortune Global 500
- Integrated midstream energy infrastructure serving producers and consumers of natural gas, NGLs, crude oil, petrochemicals and refined products
  - Transport over 4 million BPD of NGLs, crude oil, refined products and petrochemicals and 14 Bcf/d of natural gas
  - Access to major natural gas / NGL / crude oil supply basins in the U.S.
  - Pipelines connected to every U.S. ethylene steam cracker (largest consumer of NGLs) and ≈95% of refining capacity east of the Rockies
- Diversified businesses and sources of cash flow
- $7.7 billion of growth projects under construction
- Investor-friendly structure – no GP IDRs – lower cost of capital

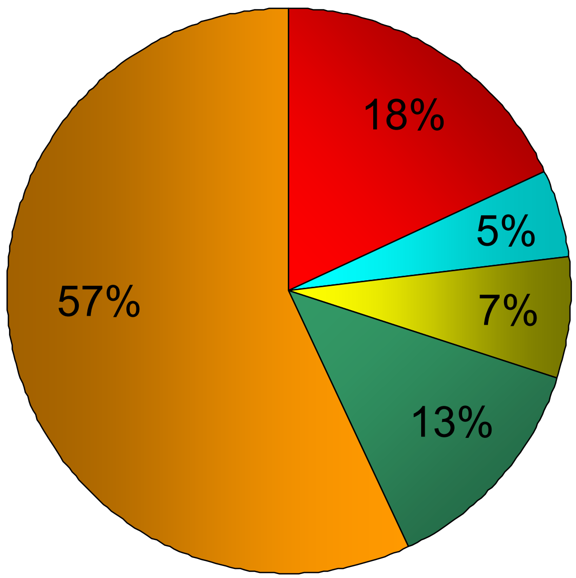
EPD Portfolio of Integrated Assets

Major Asset Overview	
• 50,700 miles of natural gas, NGL, crude oil, refined products and petrochemical pipelines • 190 MMBbls of NGL, refined products and crude oil, and 14 Bcf of natural gas storage capacity • 25 natural gas processing plants	• 21 NGL & Propylene fractionators • 6 offshore hub platforms • NGL import / export terminals • Butane isomerization complex; octane enhancement facility; high-purity isobutylene facility

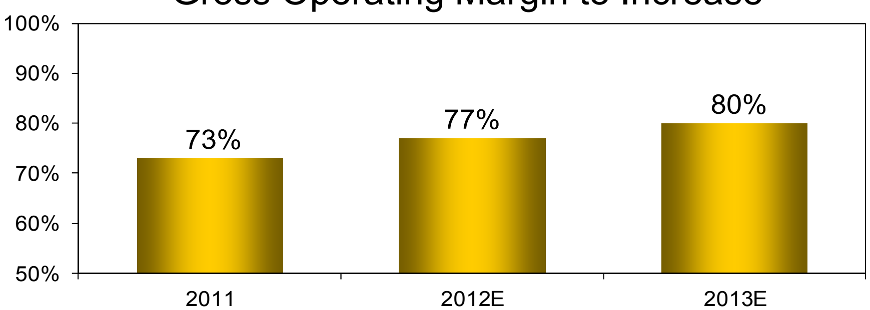


Geographic and Business Diversification Provide Multiple Earnings Streams

$4.3 Billion Gross Operating Margin
For 12 months ended September 30, 2012



Expect Fee-Based Contribution to Gross Operating Margin to Increase



NGL Pipelines & Services (57%)

- Natural gas processing & related NGL marketing activities
- NGL fractionation plants
- NGL import / export terminals
- NGL pipelines and storage

Onshore Natural Gas Pipelines & Services (18%)

- Natural gas pipelines & related marketing activities
- Natural gas storage facilities

Petrochemical & Refined Products Services (13%)

- Refined products and petrochemical pipelines
- Butane isomerization facilities
- Propylene fractionation facilities
- Octane enhancement and high-purity isobutylene facilities
- Marine terminals & transportation
- Related marketing activities

Onshore Crude Oil Pipelines & Services (7%)

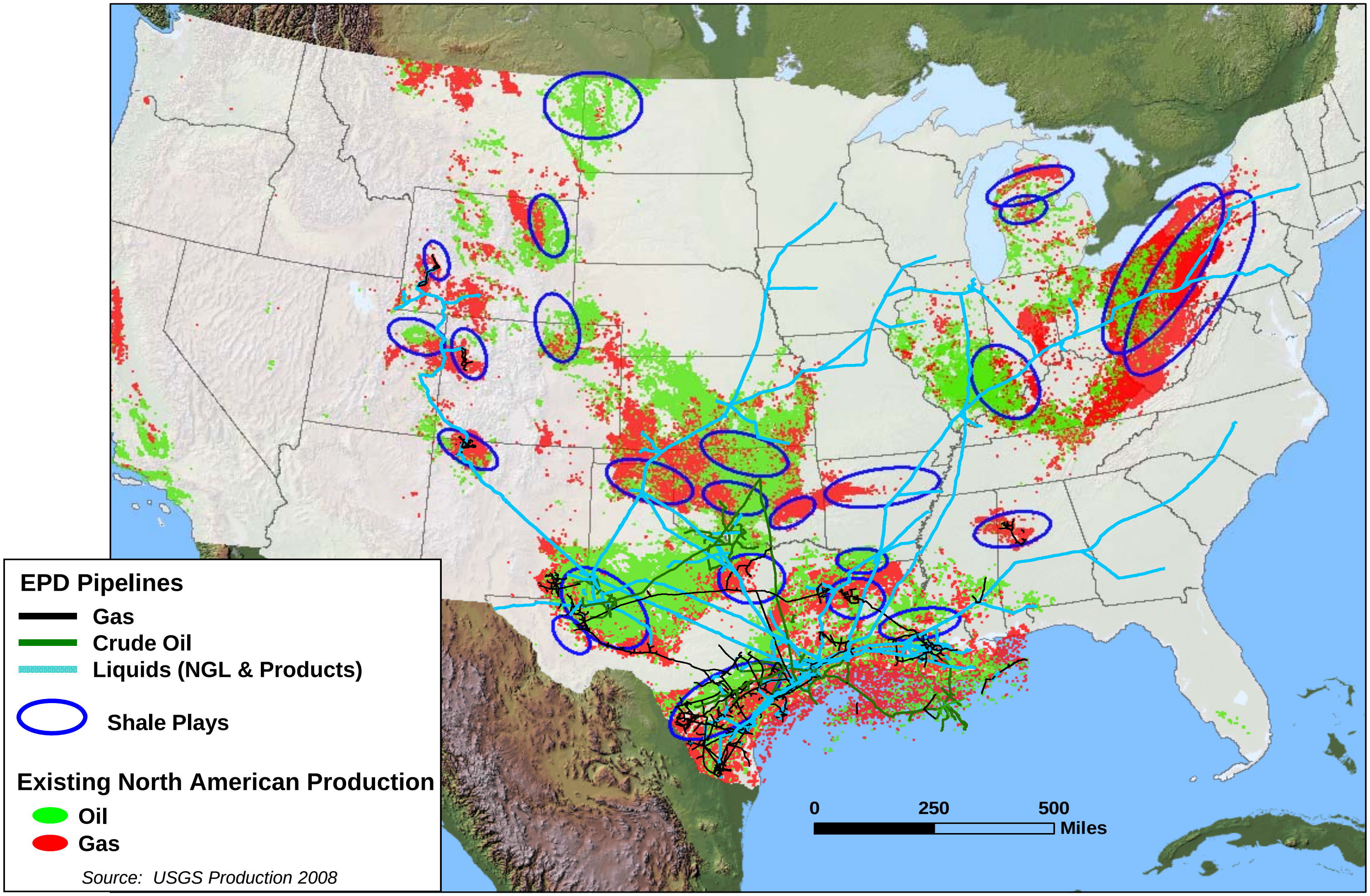
- Crude oil pipelines, storage terminals & related marketing activities

Offshore Pipelines & Services (5%)

- Natural gas pipelines
- Crude oil pipelines
- Platform services

Existing Wells and Shale Plays

It's No Coincidence



Shale Plays: Long–Term Future Development Potential

Play	Estimated Acres	Remaining Locations	Wells per Year	Potential Years of Drilling
Marcellus	15,000,000	175,000	1,650	100
Utica	13,000,000	50,000	600	80
Eagle Ford	10,000,000	100,000	2,500	40
Mississippian	6,500,000+	30,000+	600	50
Barnett	4,000,000	30,000 *(>19,000 drilled)*	1,000	30
Haynesville / Bossier	3,500,000	50,000	1,000	50

- Hydrocarbons from shale rocks are the source for conventional oil and gas
- We have known about shales and their potential for years but could not extract their oil and gas in economic quantities
- Horizontal drilling and fracking techniques now enable hydrocarbon recovery from the natural fractures found in shales

Source: Enterprise Fundamentals

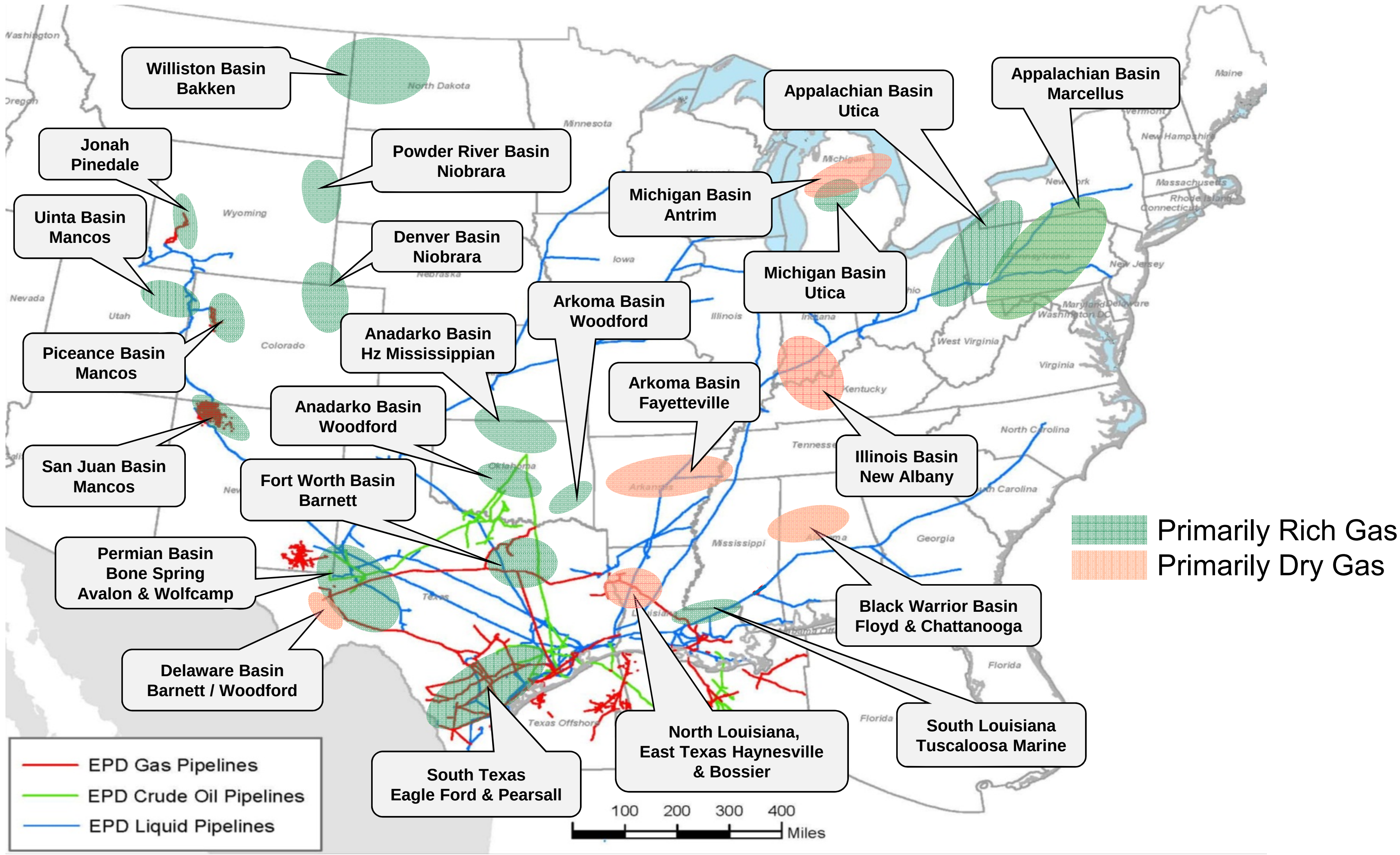
Timeline to Energy Security
Two 2020 Forecasts, Same Answer

Liquid Petroleum Products *(MBPD)*	2007	2012 YTD	**2020** ***EPD***	**2020** ***PIRA****
U.S. Consumption *(excl. exports)*	20,700	18,500	19,000	19,700
U.S. Production *(incl. refinery gain & renewables)*	8,500	10,900	15,000	16,200
Net Imports Required	12,200	7,600	4,000	3,500
Net Imports from Canada / Mexico	3,500	3,100	4,000	2,400
Imports from Rest of World	8,700	4,500	0	1,100

** PIRA assumes Canadian exports to China displace volumes available to the U.S.*

Sources: EIA, PIRA and EPD Internal Forecasts

Continually Evaluating Emerging Shale / Non-Conventional Plays



Visibility to Growth: ≈$7.7 Billion in Major Capital Projects Under Construction

In Service Date	1Q12	2Q12	3Q12	4Q12	2013	2014–2015
Haynesville Gas Gathering Pipeline – SE Stanley & Treating Facility	DONE					
Eagle Ford Mixed NGL Pipeline (Phase I) & Ethane Cavern		DONE				
Eagle Ford Yoakum Gas Processing Facility (Phase I) (300 MMcf/d)		DONE				
Seaway Crude Oil Pipeline Reversal (Phase I)		DONE				
Avalon / Bone Springs 8" Crude Oil P/L & 10" West Texas Crude Oil P/L		DONE				
Eagle Ford Crude Oil Pipeline & Terminal – Lyssy to Sealy			DONE			
Eagle Ford Yoakum Gas Processing Facility (Phase II) (additional 300 MMcf/d)			DONE			
Eagle Ford Crude Oil Pipeline – Houston Area			DONE			
Mont Belvieu NGL Fractionator 6				DONE		
ECHO Terminal & Oil Pipeline Interconnect Houston Area				DONE		
Eagle Ford Natural Gas Gathering & Transportation				√		
Eagle Ford 36" Natural Gas Pipeline – Word to Wilson				√		
Mont Belvieu West Storage				√		
Eagle Ford Extend Mixed NGL Pipeline – Alvin to Mont Belvieu				√		
Eagle Ford Yoakum Gas Processing Facility (Phase III) (additional 300 MMcf/d) (1Q 2013)					√	
NGL Export Facility Expansion at Houston Ship Channel					√	
Mont Belvieu DIB & Propylene Splitter 4 Expansions (1Q 2013)					√	
Enterprise / Plains JV - Eagle Ford Crude Oil Pipeline (2Q 2013)					√	
Texas Express NGL Pipeline – Skellytown to Mont Belvieu (2Q 2013)					√	
Avalon / Bone Springs Gathering System (Phase II) (2Q 2013)					√	
Eagle Ford Mixed NGL Pipeline (Phase II) (2Q 2013)					√	
Mont Belvieu Mixed NGL Pipeline & Pump Expansion (2Q 2013)					√	
Mont Belvieu NGL Fractionators 7 & 8 (4Q 2013)					√	
Front Range NGL Pipeline (4Q 2013)					√	
Seaway Crude Oil Pipeline Looping (capacity up to 850 MBPD) (1Q 2014)						√
Mid-America NGL Pipeline Expansion – Rocky Mountain Segment (1Q 2014)						√
ATEX Ethane Pipeline – Marcellus / Utica Shale (2Q 2014)						√
State Line Gathering Pipeline Expansions (3Q 2014)						√
Offshore Crude Oil Pipeline – Lucius SEKCO (50%) (3Q 2014)						√
Propane Dehydrogenation Unit (3Q 2015)						√
Miscellaneous – Other						√
Total Capital Costs *(Billions)*	$0.2	$0.6	$1.0	$1.2	$2.5	$4.2

Completed ≈$2B of capital projects thus far in 2012

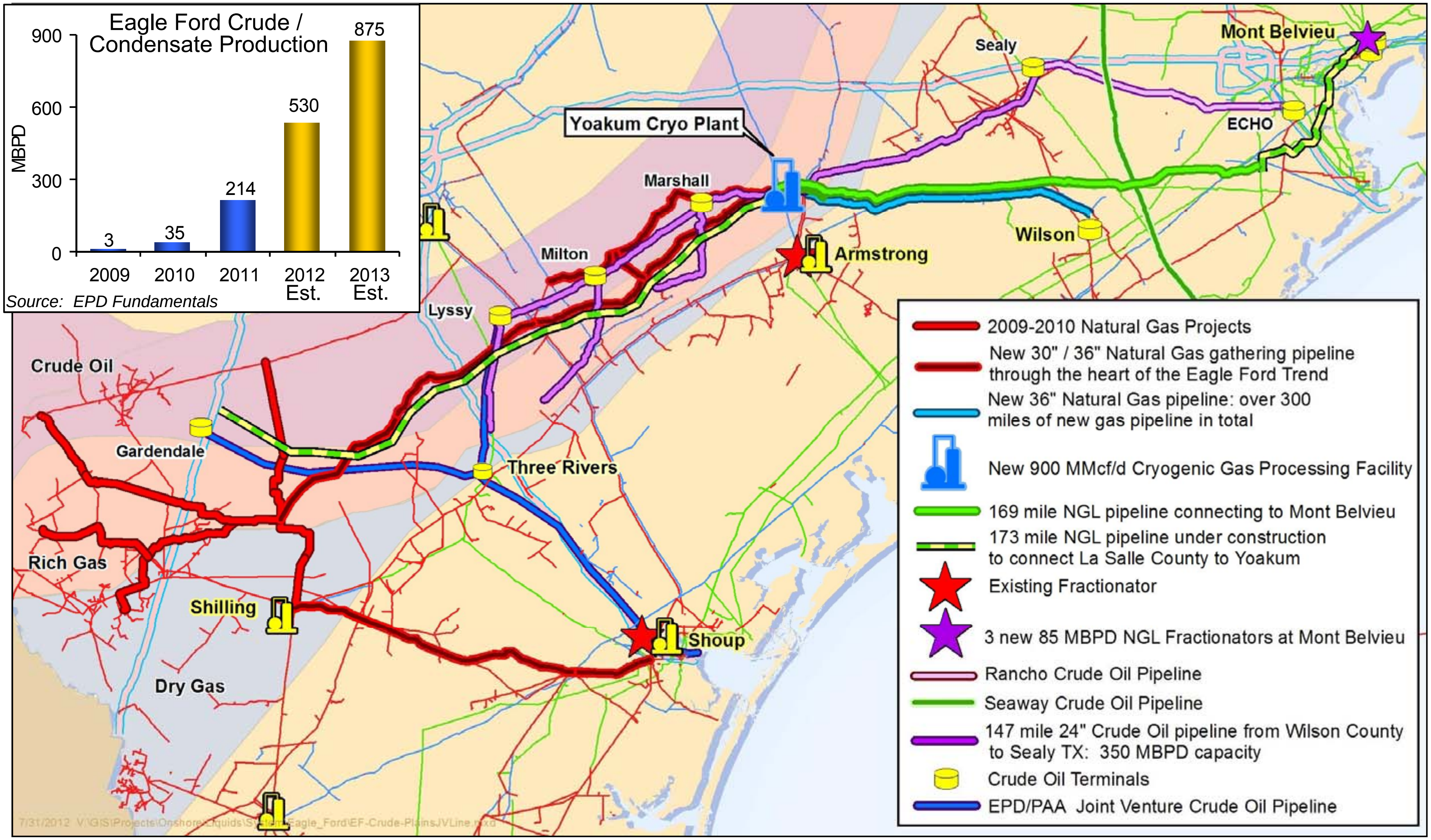
≈$7.7B

Major EPD Growth Projects

Shale Plays Drive EPD's Western NGL Pipeline Expansions: ≈$1.0 Billion

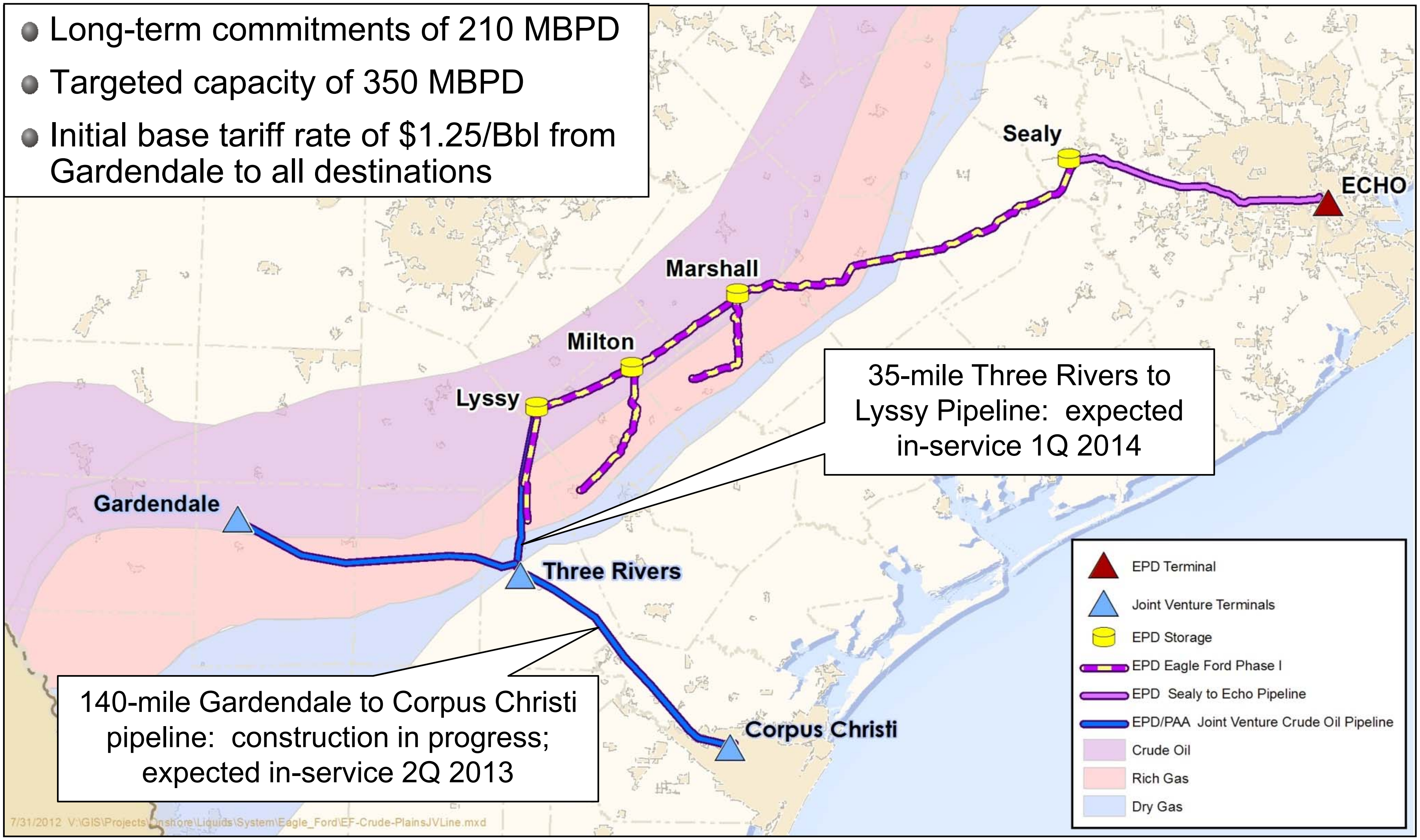
- MAPL Rocky Mountain NGL Pipeline Expansion
  - 218 miles of 16" pipeline loops and 18 pump modifications to increase capacity from 275 MBPD to ≈340 MBPD
  - 10-year, ship-or-pay agreements
  - Expected in-service: 1Q 2014
- Texas Express NGL Pipeline
  - EPD (35%), Enbridge Energy Partners (EEP – 35%), Anadarko (APC – 20%) and DCP (10%)
  - EPD to construct / operate 580 miles of 20" pipe from Skellytown to Mont Belvieu
  - 10-year, ship-or-pay agreements
  - Capacity of 250 MBPD expandable to 400 MBPD; expected in-service: 2Q 2013
- Front Range NGL Pipeline
  - JV between EPD, APC and DCP – 1/3 each
  - EPD to construct / operate 435 miles of 12" / 16" pipe from DJ Basin to MAPL and Texas Express pipeline
  - 10-year, ship-or-pay agreements
  - Capacity of 150 MBPD, expandable to 230 MBPD; expected in-service: 4Q 2013

EPD's Eagle Ford Shale Projects
Cumulative Capital Expenditures ≈$4 Billion

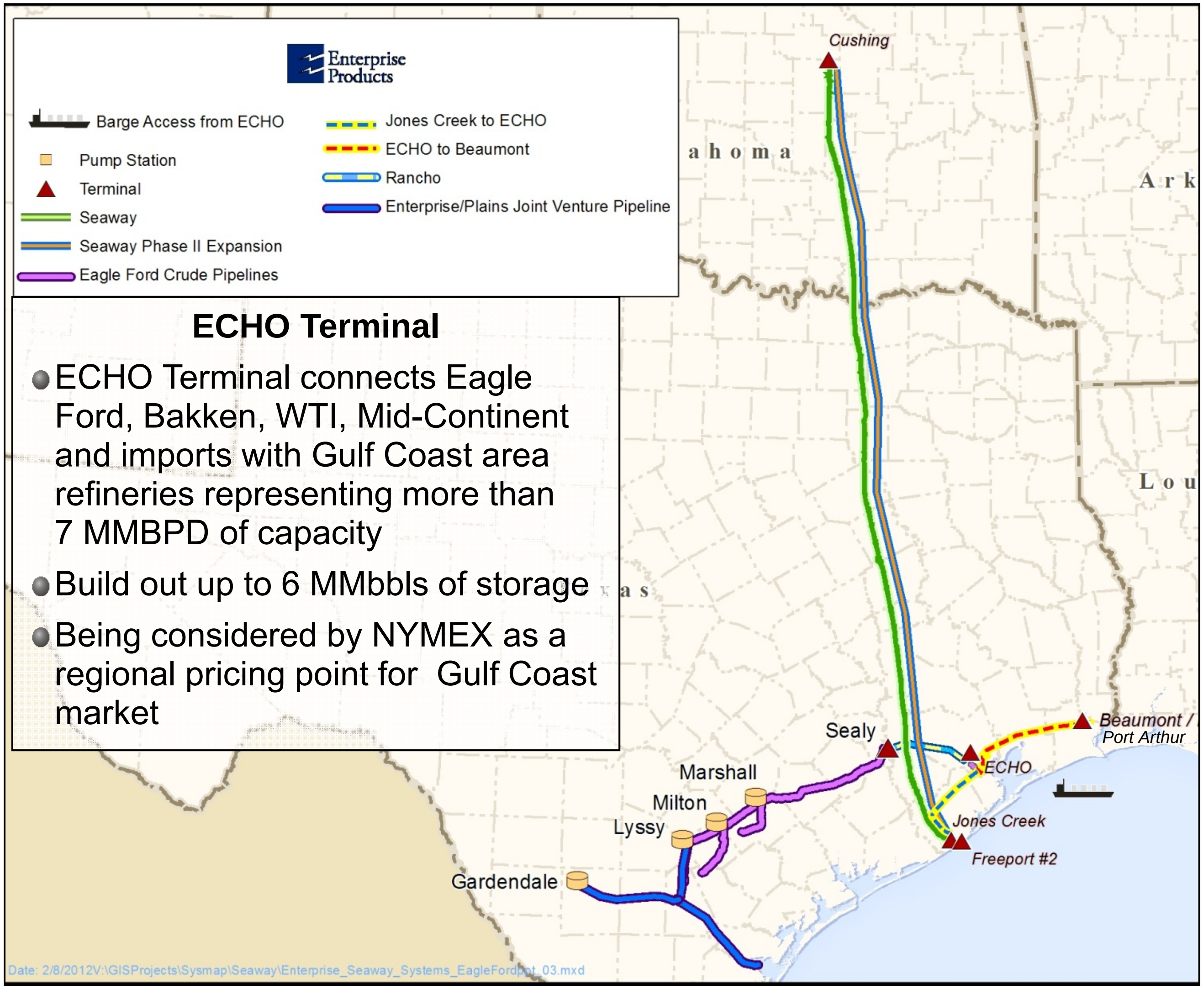


EPD 50% / PAA 50% Crude Oil Pipeline Joint Venture

- Long-term commitments of 210 MBPD
- Targeted capacity of 350 MBPD
- Initial base tariff rate of $1.25/Bbl from Gardendale to all destinations



Seaway Crude Oil Pipeline Relieves Cushing Bottleneck

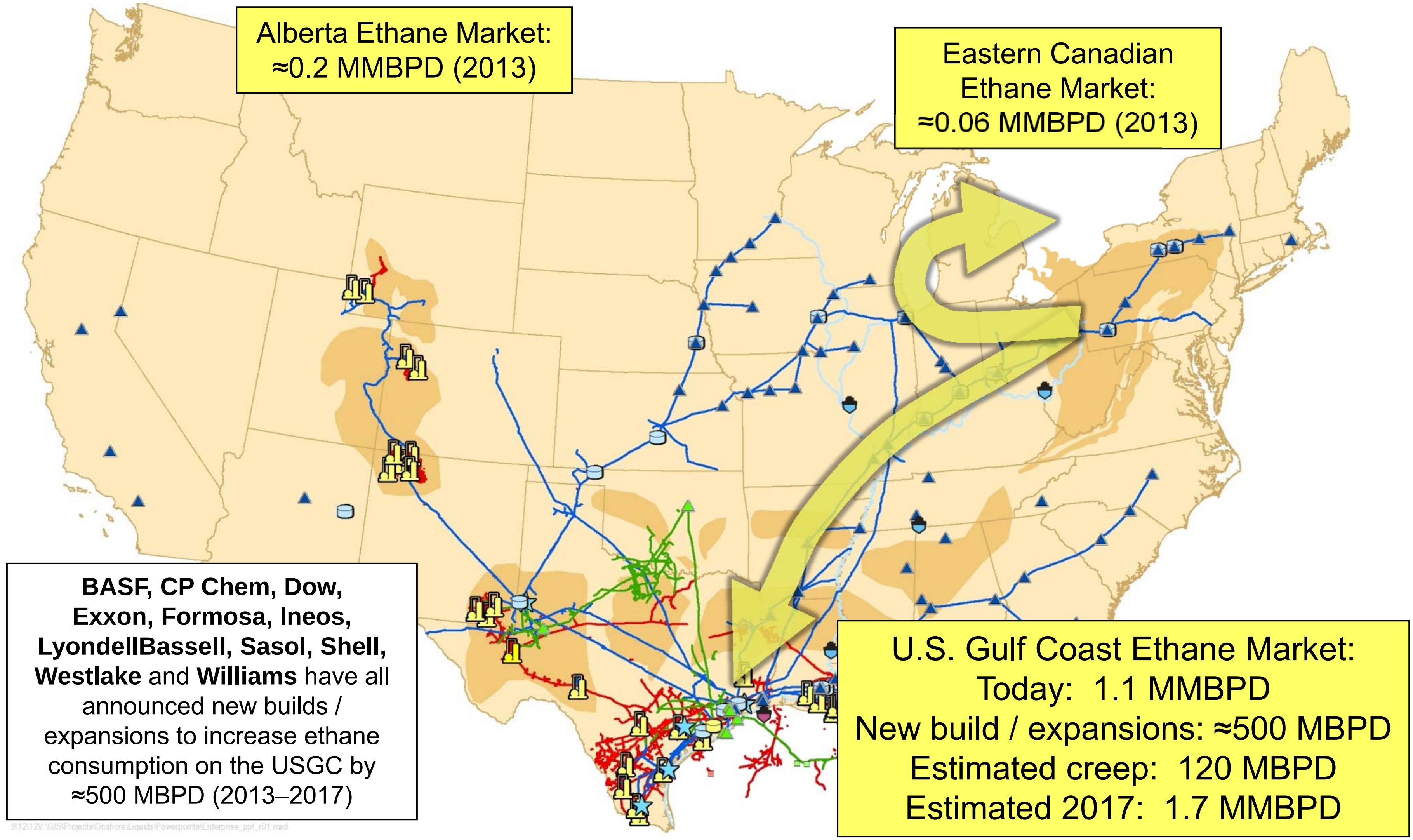


ECHO Terminal

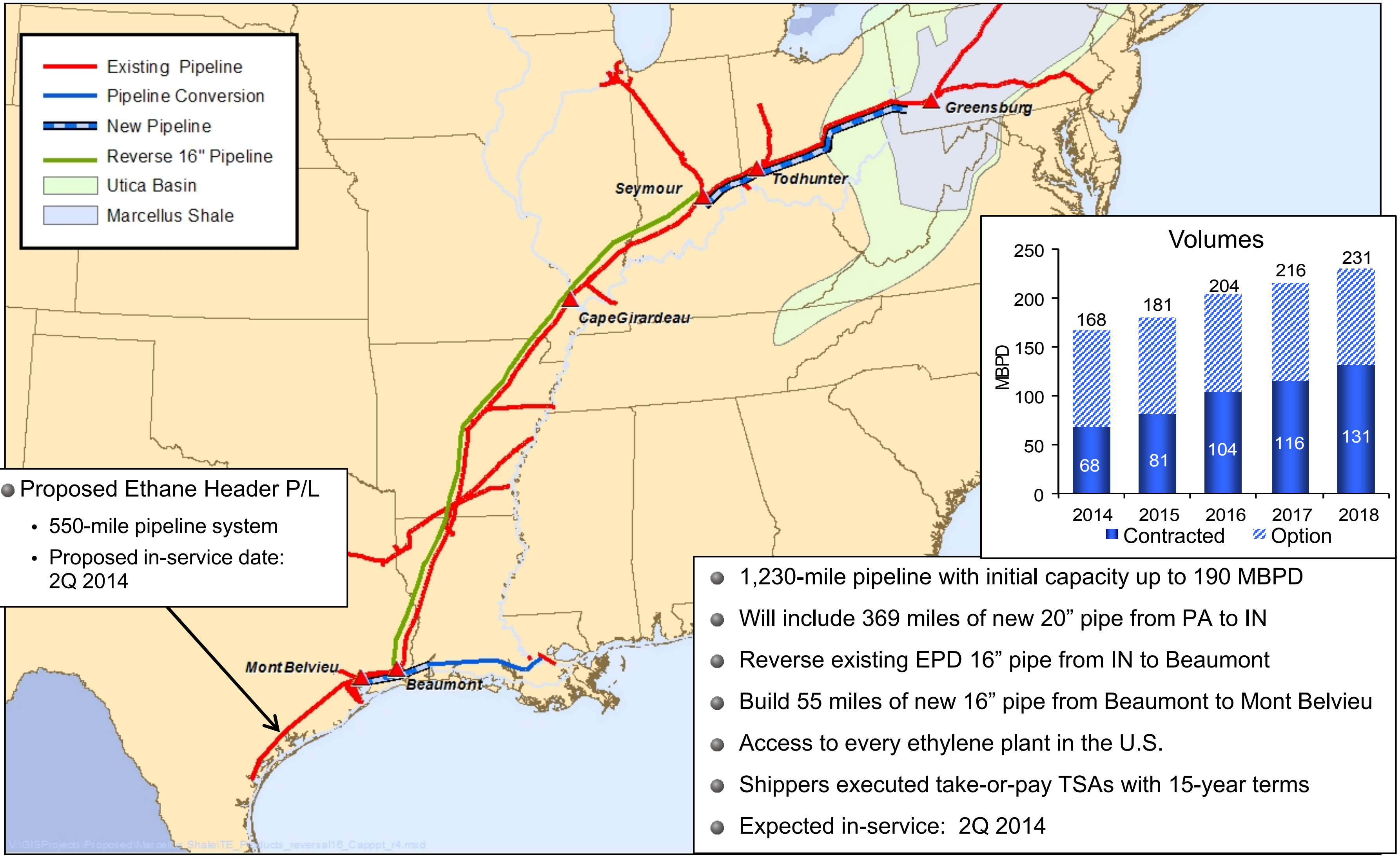
- ECHO Terminal connects Eagle Ford, Bakken, WTI, Mid-Continent and imports with Gulf Coast area refineries representing more than 7 MMBPD of capacity
- Build out up to 6 MMbbls of storage
- Being considered by NYMEX as a regional pricing point for Gulf Coast market

- Joint Venture reversed flow of Seaway and plans to expand capacity to provide Gulf Coast access for Mid-Continent, Bakken and Canadian crude oil
  - Pipeline began moving crude oil from Cushing to Freeport in 2Q 2012
  - Modifying to flow at full capacity by 1Q 2013
  - Building 512-mile, 30-inch parallel pipeline along Seaway to expand capacity to 850 MBPD of mixed light / heavy crude oil service in 1Q 2014
- Supported by commitments of up to 20 years

Largest (and Growing) Ethane Market is on the U.S. Gulf Coast



Appalachia to Texas (ATEX) Express P/L
Transport Ethane from Marcellus / Utica Shale

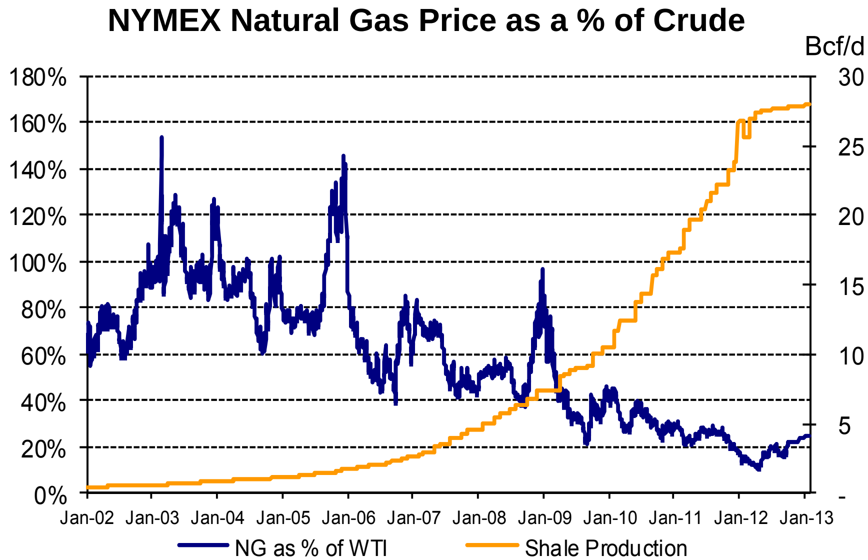


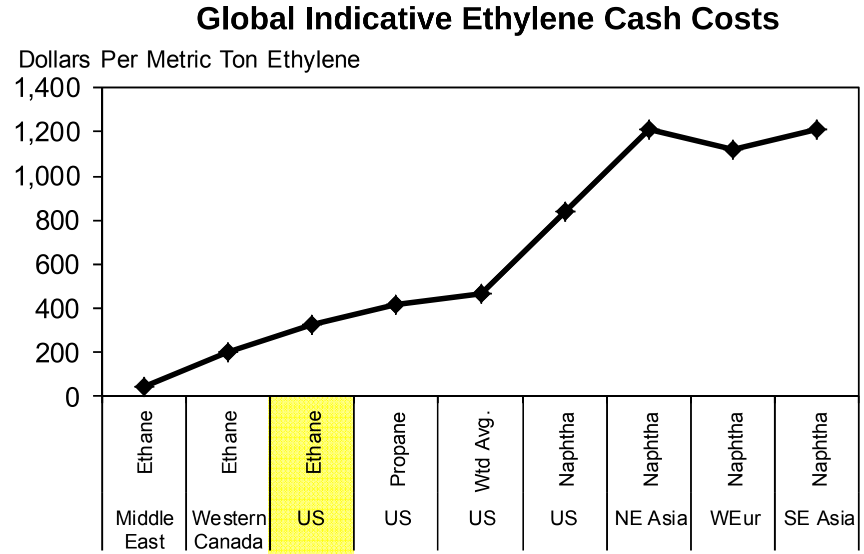
- Proposed Ethane Header P/L
  - 550-mile pipeline system
  - Proposed in-service date: 2Q 2014

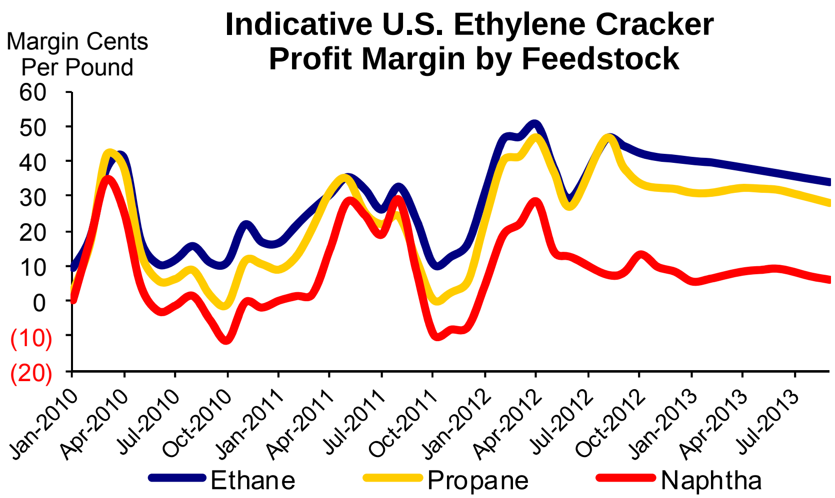
- 1,230-mile pipeline with initial capacity up to 190 MBPD
- Will include 369 miles of new 20” pipe from PA to IN
- Reverse existing EPD 16” pipe from IN to Beaumont
- Build 55 miles of new 16” pipe from Beaumont to Mont Belvieu
- Access to every ethylene plant in the U.S.
- Shippers executed take-or-pay TSAs with 15-year terms
- Expected in-service: 2Q 2014

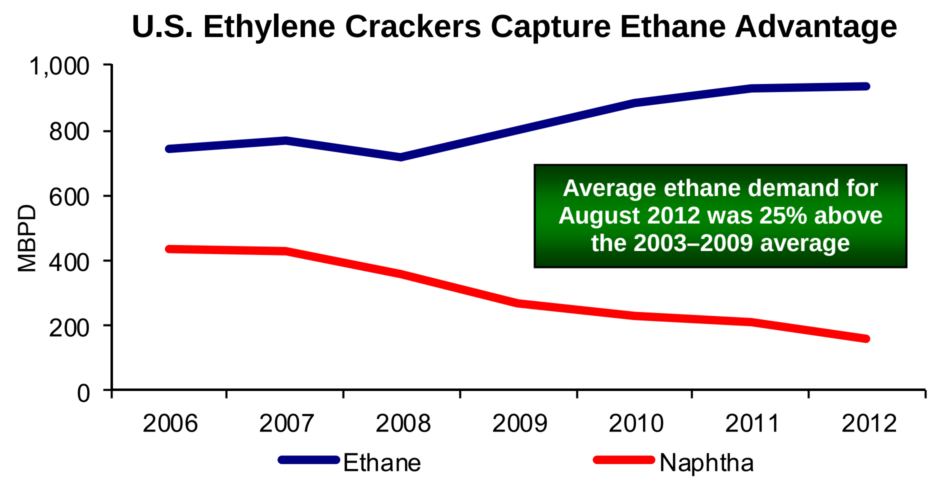
NGL Demand Growth by Petrochemical Industry

Low Gas to Crude Spread Drives U.S. NGL Advantage







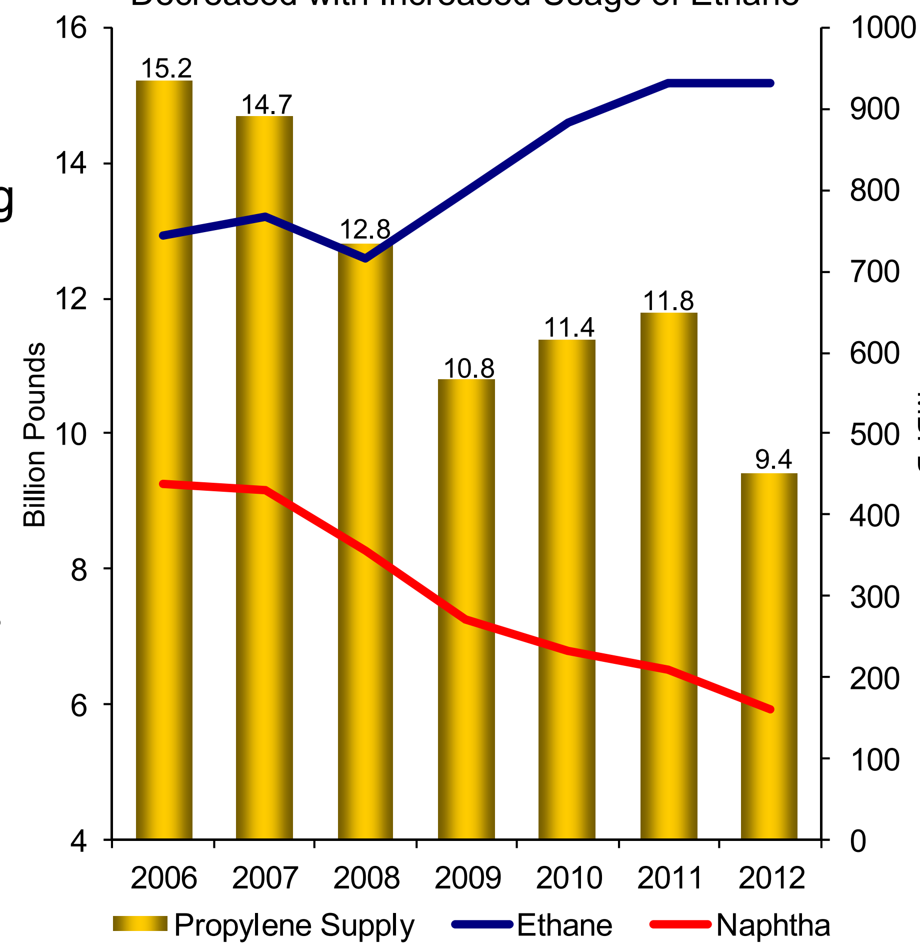


Sources: EPD Fundamentals, EIA and CMAI

Note: Assumes ethylene crackers operate at 93% capacity. Annual creep forecasted to only occur from 2014–2016.

Increased Ethane Usage Reduces U.S. Propylene Supply

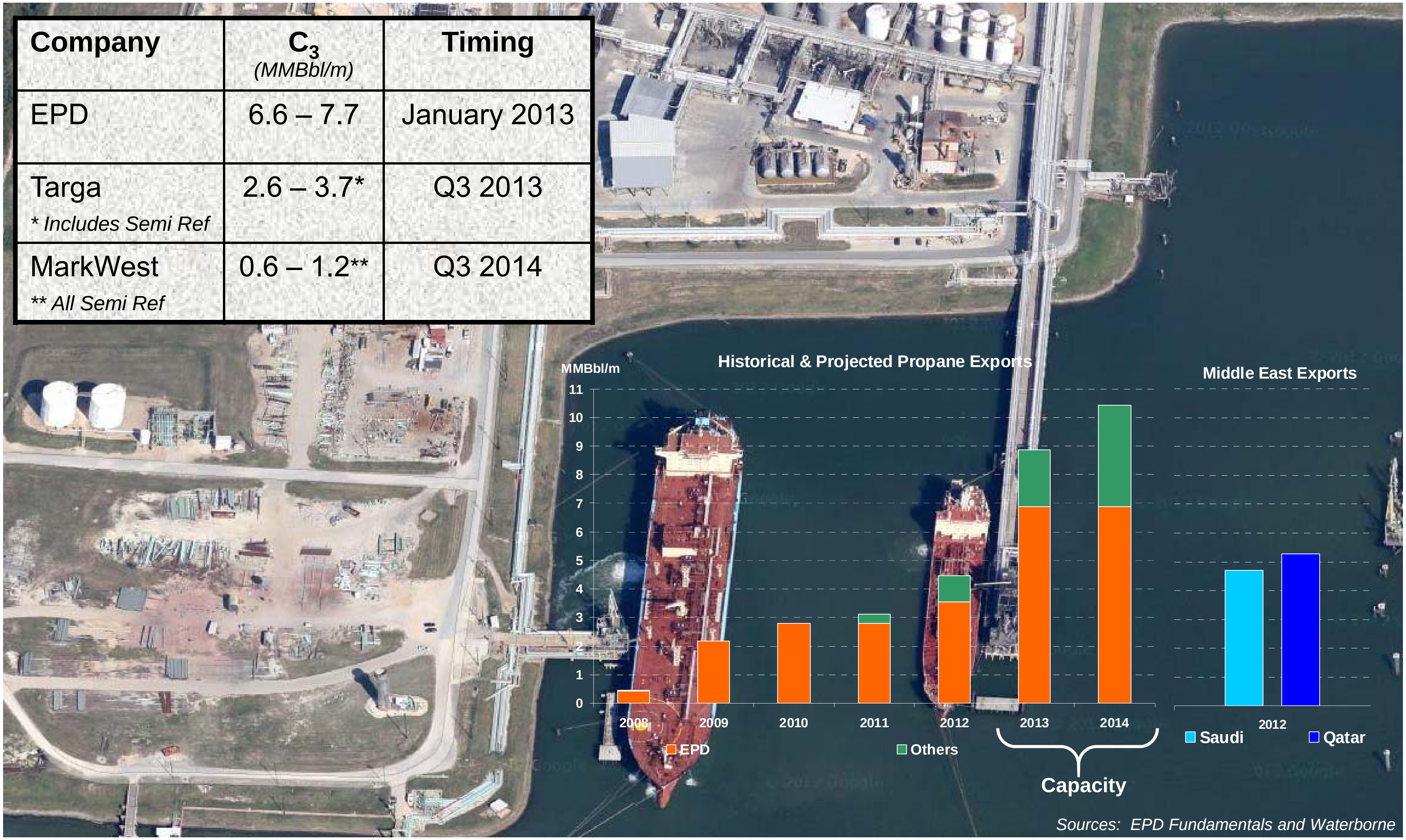
- Demand for ethane continues to increase vs. naphtha as ethylene crackers favor NGL feedstocks vs. crude oil derivatives
- Shift to higher margin ethane cracking has significantly reduced propylene production from U.S. crackers by 5.8 billion lbs. (38%) since 2006
- U.S. propylene demand remains steady at ≈ 33 billion lbs. per year
- Incremental production from Propane Dehydrogenation (PDH) technologies are required to balance U.S. propylene supply and demand
- Today, PDH produced propylene represents only ≈4.6% of supply
- Expected to increase 9.6% by 2016



Sources: CMAI, EIA and Hodson

Enterprise – Import / Export Facilities

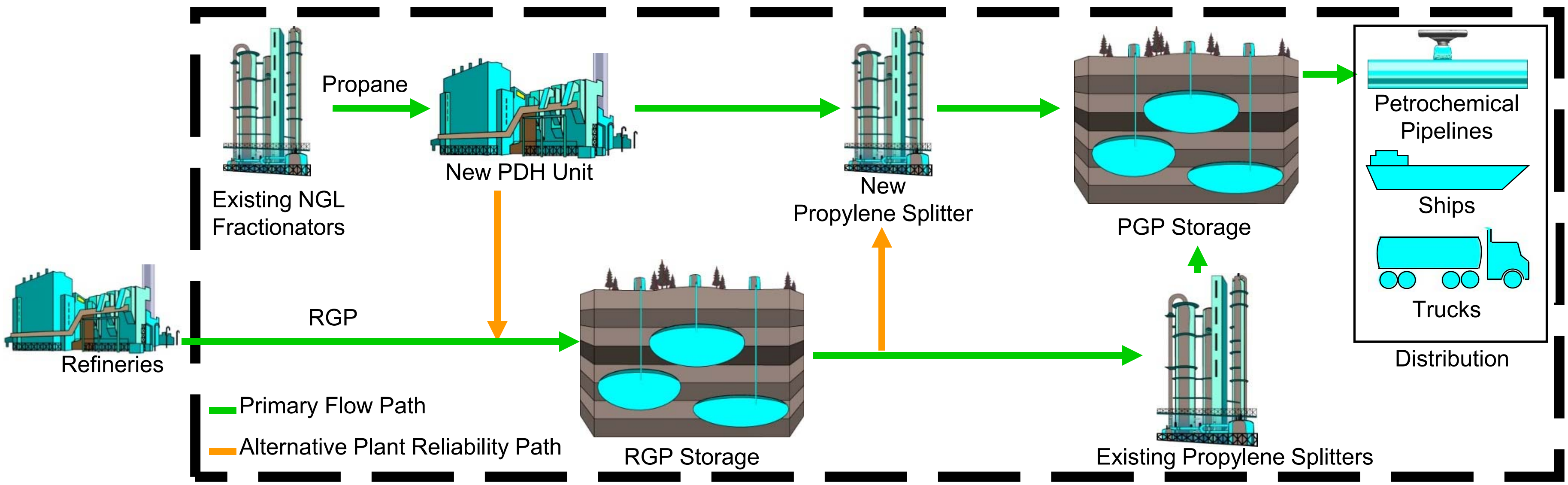
Company	C_3 (MMBbl/m)	Timing
EPD	6.6 – 7.7	January 2013
Targa ** Includes Semi Ref*	2.6 – 3.7*	Q3 2013
MarkWest *** All Semi Ref*	0.6 – 1.2**	Q3 2014



Sources: EPD Fundamentals and Waterborne

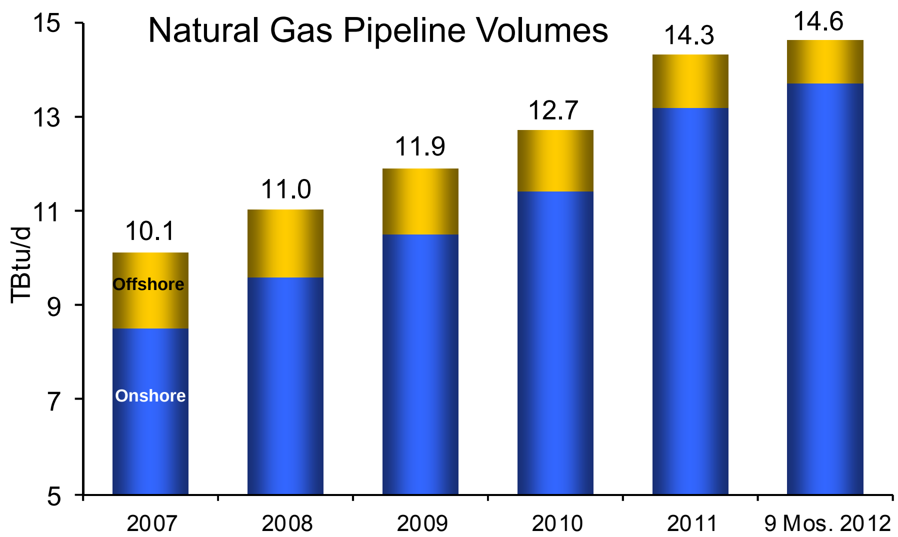
Propane Dehydrogenation Plant (PDH)

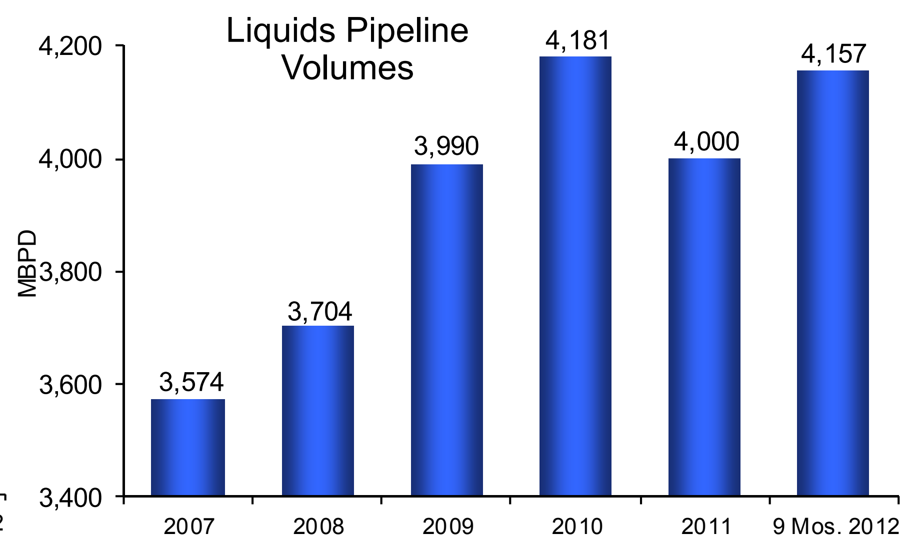
- EPD announced plans to build one of the world's largest PDH units along the Texas Gulf Coast
- Will consume up to 35 MBPD of propane to produce up to 1.65 billion lbs. per year (25 MBPD) of polymer grade propylene
- Will integrate with EPD's existing NGL and propylene fractionation / splitter facilities to provide operational reliability and flexibility
- Supported by 10–15 year fee-based contracts with investment grade companies
  - No commodity risk
  - ≈75% of capacity currently subscribed
- Expected to begin commercial operations in 3rd quarter 2015

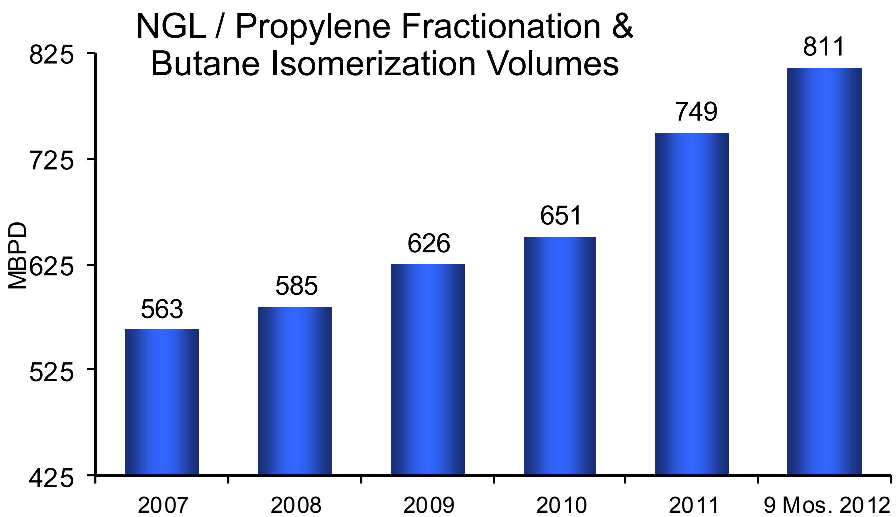


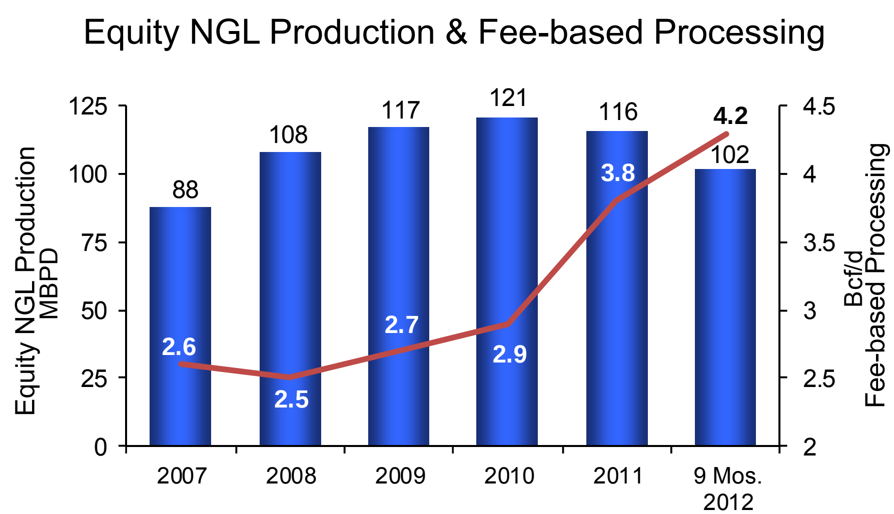
Financial

Solid Operating Performance[1]…



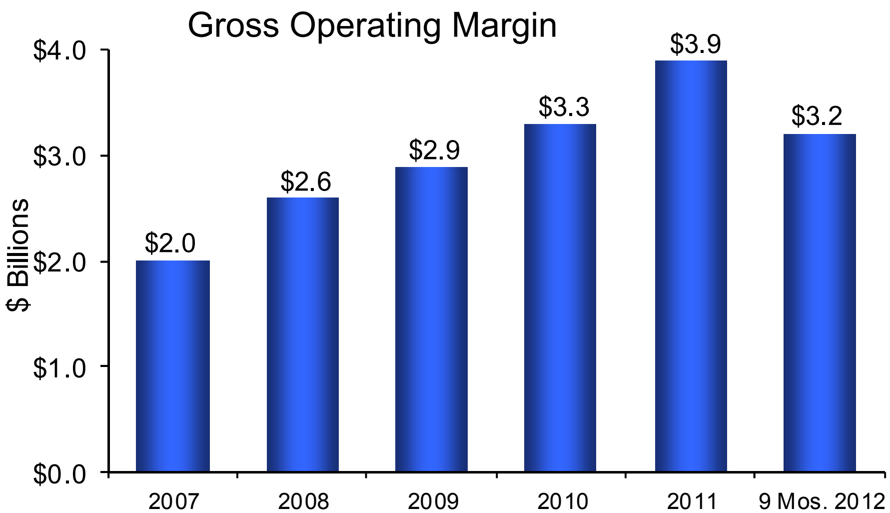


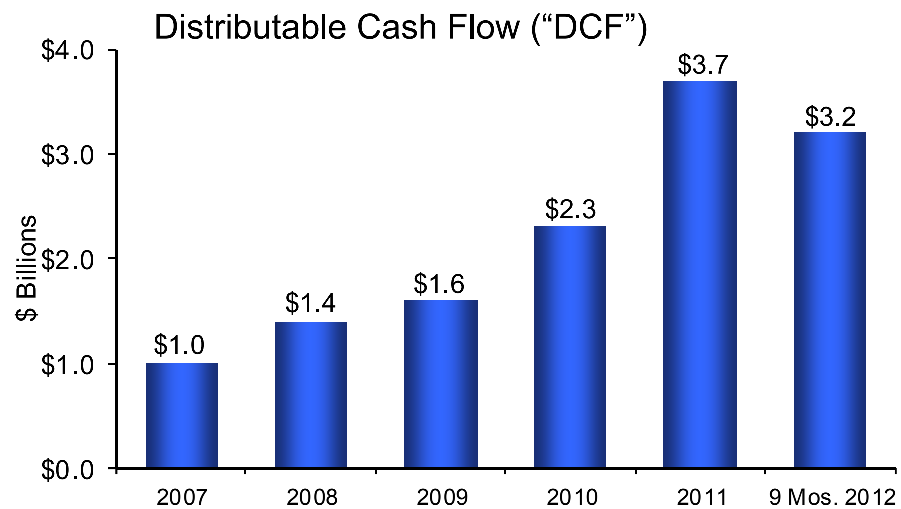


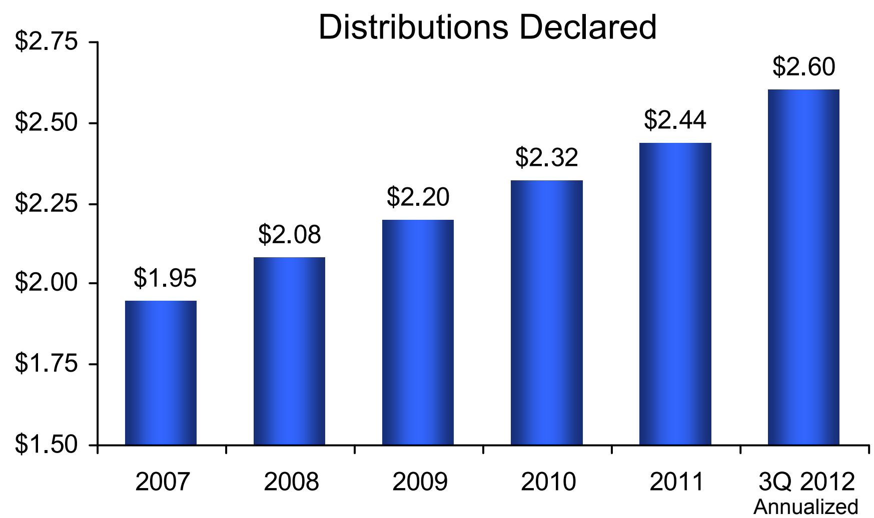


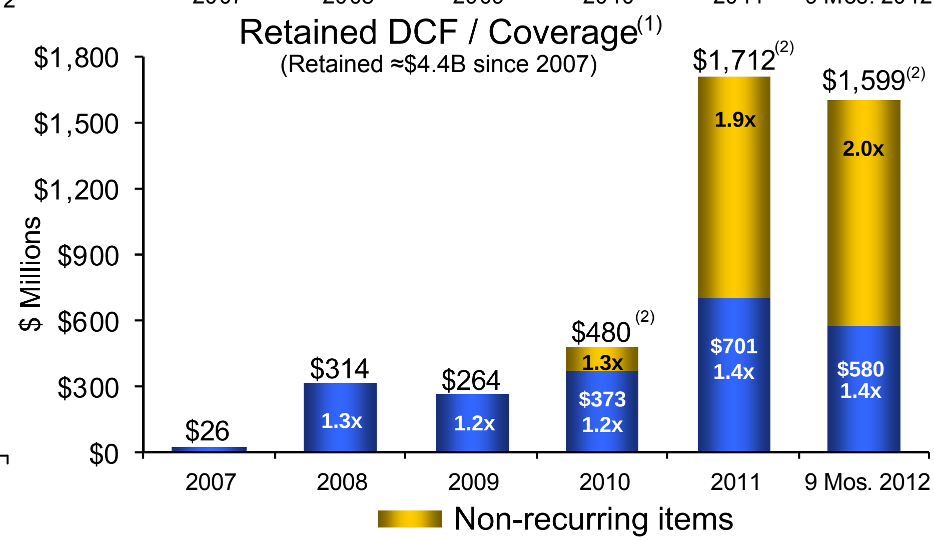
[1] *Volumetric data for periods prior to 4Q 2009 include TEPPCO.*

…Drives Strong Financial Results



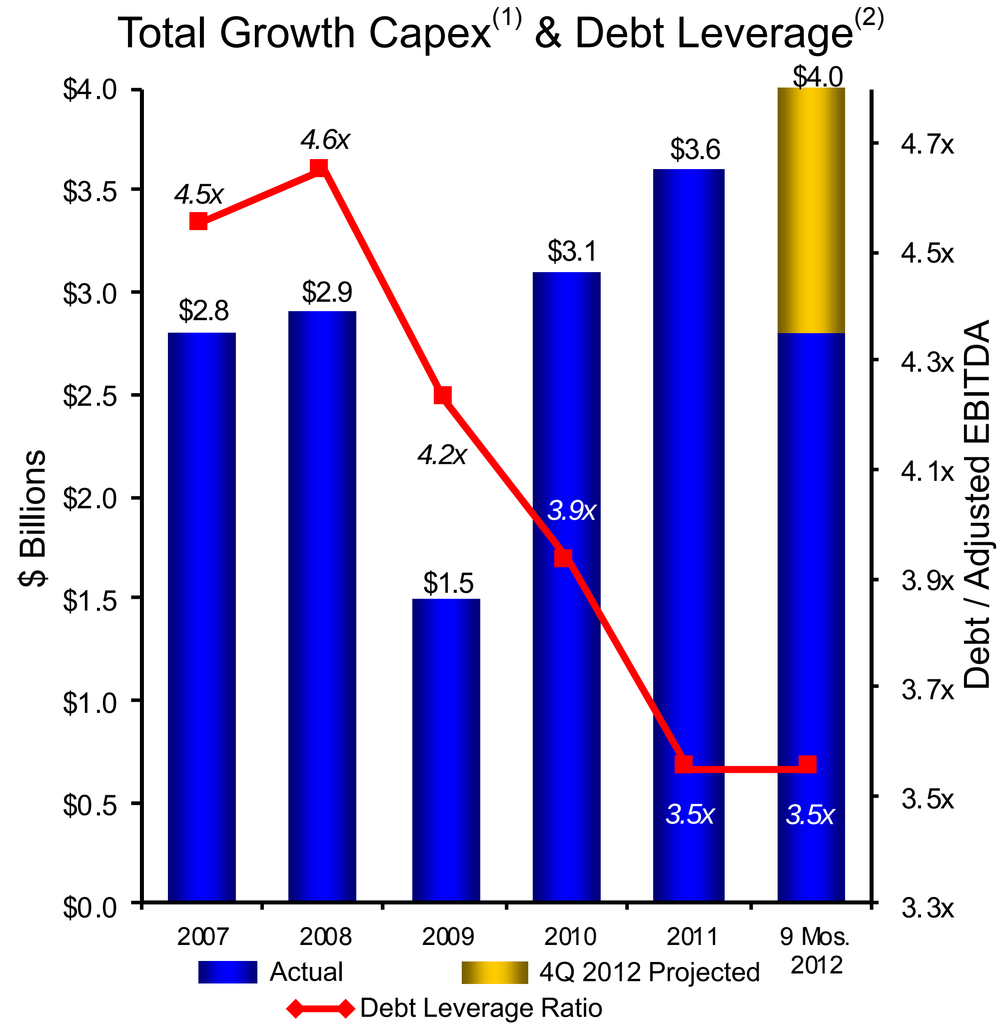






(1) Retained DCF represents the amount of distributable cash flow for each period that was retained by the general partner for reinvestment in capital projects and other reasons.
(2) Each period noted includes non-recurring transactions (e.g., proceeds from asset sales and property damage insurance claims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

History of Financial Discipline While Executing Growth Strategy



- ≈$5.1 billion of capital growth projects were completed on-time and ≈7% under budget since 2009
- Funded growth investments through issuance of debt and equity, retained DCF and proceeds from asset sales
- Sold $2.2 billion low-return, non-core assets in 2011 / 2012; potential incremental DCF from redeployment assuming:
  - 15.0% ROR ≈$170 million
  - 12.5% ROR ≈$120 million

(1) *Represents cash used in investing activities as presented on our Statements of Consolidated Cash Flows before changes in restricted cash, proceeds from asset sales and related transactions, and sustaining capital expenditures.*
(2) *Coverage ratio reflects total debt adjusted for the average 50% equity credit that the rating agencies ascribe to the Junior Subordinated Notes.*

EPD Financial Snapshot

Unit Price / Yield		
EPD LP Unit Price (November 13, 2012)	$	50.75
Current Annualized Cash Distribution Rate	$	2.60
Current Yield		5.12%

Units Outstanding / Daily Volume / Market Cap		
Units Outstanding (Millions, as of October 31, 2012)		900
Daily Unit Float (Million Units)		1.1
Daily Unit Float ($Millions)	$	56
Equity Market Capitalization ($Billions)	$	46
Total Enterprise Value ($Billions)	$	62
Fortune 500 Ranking (2012)		62nd

Debt Capitalization (as of September 30, 2012)		
Senior Unsecured Debt ($Billions)	$	14.4
Junior Subordinated Debt		1.5
Total Debt Principal	$	15.9
Ratio of Debt to LTM Adjusted EBITDA [1]		**3.5x**
Weighted Average Interest Rate [2]		**5.6%**
Weighted Average Debt Maturity [2] (Years)		**12.9**
Liquidity [3] ($Billions)	**$**	**3.4**
Senior Unsecured Debt Rating		
Moody's / S&P / Fitch		Baa2 / BBB / BBB
Outlook		Positive / Positive / Stable

[1] *This calculation reflects total debt principal, which has been adjusted for the average 50% equity credit that the rating agencies ascribe to the Junior Subordinated Debt.*
[2] *Debt maturity assumes first call dates for the Junior Subordinated Debt.*
[3] *Includes unrestricted cash and available capacity under EPO's bank credit facility.*

EPD and AMZ MLP Index

Attractive Total Return vs. 8 Other Asset Classes

2006	2007	2008	2009	2010	2011	9M 2012	10-Year CAGR [1]	5-Year CAGR [1]	3-Year CAGR [1]
REIT 33.1%	Commodities 40.7%	IG Bonds -6.6%	MLP Index 76.4%	**EPD 41.0%**	**EPD 17.8%**	**EPD 19.9%**	**EPD 18.1%**	**EPD 19.7%**	**EPD 31.0%**
EPD 29.3%	**EPD 16.9%**	Hedge Funds -19.1%	**EPD 64.7%**	MLP Index 35.9%	MLP Index 13.9%	S&P 500 16.4%	MLP Index 17.3%	MLP Index 14.0%	MLP Index 25.1%
Non-US Equity 26.9%	MLP Index 12.7%	High Yield -21.3%	Commodities 50.3%	Small Cap Equity 26.9%	High Yield 7.2%	REIT 15.0%	Commodities 11.3%	High Yield 7.8%	S&P 500 13.2%
MLP Index 26.1%	Hedge Funds 12.6%	**EPD -30.1%**	High Yield 39.3%	Commodities 20.4%	IG Bonds 5.2%	Small Cap Equity 14.2%	Small Cap Equity 10.2%	IG Bonds 6.6%	Small Cap Equity 13.0%
Small Cap Equity 18.4%	Non-US Equity 11.6%	Small Cap Equity -33.8%	Non-US Equity 32.5%	REIT 17.9%	Commodities 2.1%	High Yield 11.1%	Non-US Equity 8.7%	Commodities 4.0%	Commodities 12.9%
S&P 500 15.8%	IG Bonds 6.1%	MLP Index -36.9%	Small Cap Equity 27.2%	S&P 500 15.1%	S&P 500 2.1%	Non-US Equity 10.6%	High Yield 8.4%	Small Cap Equity 2.2%	High Yield 12.0%
Hedge Funds 13.9%	S&P 500 5.5%	S&P 500 -37.0%	S&P 500 26.5%	High Yield 12.5%	Hedge Funds -2.5%	MLP Index 8.5%	S&P 500 8.0%	Hedge Funds 2.1%	REIT 11.0%
High Yield 8.2%	High Yield 2.2%	Commodities -42.8%	REIT 25.1%	Non-US Equity 8.2%	REIT -2.5%	IG Bonds 7.6%	Hedge Funds 6.8%	S&P 500 1.1%	IG Bonds 7.4%
IG Bonds 4.5%	Small Cap Equity -1.6%	Non-US Equity -43.1%	Hedge Funds 18.6%	IG Bonds 8.1%	Small Cap Equity -4.2%	Hedge Funds 4.5%	IG Bonds 5.4%	Non-US Equity -4.8%	Hedge Funds 5.3%
Commodities 0.4%	REIT -14.7%	REIT -48.2%	IG Bonds 17.3%	Hedge Funds 10.9%	Non-US Equity -11.7%	Commodities 3.2%	REIT 5.3%	REIT -5.7%	Non-US Equity 2.6%

(1) CAGR calculations based upon closing prices ending the last trading day of the third quarter for each period.

Commodities: S&P World Commodity Index; EPD: Enterprise Products Partners L.P.; Hedge Funds: CS Tremont Hedge Fund; High Yield: Vanguard High Yield US Corporate Fund; IG Bonds: Vanguard Intermediate Term US Investment Grade Fund; MLP Index: Alerian Index; Non-US Equity: MSCI Daily Total Return EAFE Index; REIT: S&P REIT Index; S&P 500: S&P 500 Index; Small Cap Equity: Russell 2000 Index

Source: Bloomberg L.P.

Past results may not be indicative of future performance.

Non-GAAP Reconciliations

Gross Operating Margin

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by our management in deciding how to allocate capital resources among business segments. The following table reconciles non-GAAP gross operating margin to operating income, which is the most directly comparable GAAP financial measure to gross operating margin (dollars in millions):

	For the Year Ended December 31, 2007	2008	2009	2010	2011	For the Nine Months Ended September 30, 2012	For the Last Twelve Months Ended September 30, 2012
Gross operating margin by segment:							
NGL Pipelines & Services	$ 848.0	$ 1,325.0	$ 1,628.7	$ 1,732.6	$ 2,184.2	$ 1,836.5	$ 2,471.0
Onshore Natural Gas Pipelines & Services	493.2	589.9	501.5	527.2	675.3	565.5	764.5
Onshore Crude Oil Pipelines & Services	109.6	132.2	164.4	113.7	234.0	252.7	319.7
Offshore Pipelines & Services	171.6	187.0	180.5	297.8	228.2	131.0	190.6
Petrochemical & Refined Products Services	342.0	374.9	364.7	584.5	535.2	437.2	574.6
Other Investments	3.1	31.3	41.1	(2.8)	14.8	2.4	5.9
Total gross operating margin	1,967.5	2,640.3	2,880.9	3,253.0	3,871.7	3,225.3	4,326.3
Adjustments to reconcile non-GAAP gross operating margin to GAAP operating income:							
Amounts included in operating costs and expenses:							
Depreciation, amortization and accretion	(647.9)	(725.4)	(809.3)	(936.3)	(958.7)	(785.1)	(1,041.4)
Non-cash asset impairment charges	-	-	(33.5)	(8.4)	(27.8)	(57.6)	(80.2)
Operating lease expenses paid by EPCO	(2.1)	(2.0)	(0.7)	(0.7)	(0.3)	-	-
Gains related to asset sales and property damage insurance recoveries	7.8	4.0	-	44.4	156.0	34.1	164.7
General and administrative costs	(131.9)	(144.8)	(182.8)	(204.8)	(181.8)	(130.2)	(173.7)
Operating income	$ 1,193.4	$ 1,772.1	$ 1,854.6	$ 2,147.2	$ 2,859.1	$ 2,286.5	$ 3,195.7

Note: Gross Operating Margin has been presented as if EPD were Enterprise GP Holdings for all periods prior to the Holdings Merger, which was completed in November 2010.

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 Nine Months Ended September 30,
	2007	2008	2009	2010	2011	2012
Net income	$ 762.0	$ 1,145.1	$ 1,140.3	$ 1,383.7	$ 2,088.3	$ 1,810.6
Adjustments to GAAP net income to derive non-GAAP Adjusted EBITDA:						
Equity in income of unconsolidated affiliates	(13.6)	(66.2)	(92.3)	(62.0)	(46.4)	(42.2)
Distributions received from unconsolidated affiliates	116.9	157.2	169.3	191.9	156.4	67.5
Interest expense (including related amortization)	487.4	608.3	687.3	741.9	744.1	572.8
Provision for (benefit from) income taxes	15.8	31.0	25.3	26.1	27.2	(23.5)
Depreciation, amortization and accretion in costs and expenses	661.7	739.9	830.0	974.5	990.5	812.6
Adjusted EBITDA	2,030.2	2,615.3	2,759.9	3,256.1	3,960.1	3,197.8
Adjustments to non-GAAP Adjusted EBITDA to derive GAAP net cash flows provided by operating activities:						
Interest expense (including related amortization)	(487.4)	(608.3)	(687.3)	(741.9)	(744.1)	(572.8)
Benefit from (provision for) income taxes	(15.8)	(31.0)	(25.3)	(26.1)	(27.2)	23.5
Gains related to asset sales and property damage insurance recoveries	(67.4)	(4.0)	-	(46.7)	(155.7)	(102.9)
Non-cash asset impairment charges	-	-	33.5	8.4	27.8	57.6
Loss on forfeiture of investment in Texas Offshore Port System	-	-	68.4	-	-	-
Net effect of changes in operating accounts	457.6	(414.6)	250.1	(190.4)	266.9	(910.2)
Other miscellaneous adjustments	19.6	9.0	11.0	40.6	2.7	(77.2)
Net cash flows provided by operating activities	$ 1,936.8	$ 1,566.4	$ 2,410.3	$ 2,300.0	$ 3,330.5	$ 1,615.8

Note: Adjusted EBITDA has been presented as if EPD were Enterprise GP Holdings for all periods prior to the Holdings Merger, which was completed in November 2010.

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 flow at a level that can support 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 its unitholders. 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 (dollars in millions):

	For the Year Ended December 31,					For the Nine Months Ended September 30,
	2007	2008	2009	2010	2011	2012
Net income attributable to partners	$ 533.6	$ 954.0	$ 1,030.9	$ 1,266.7	$ 2,046.9	$ 1,804.4
Adjustments to GAAP net income attributable to partners to derive non-GAAP distributable cash flow						
Depreciation, amortization and accretion	523.8	562.2	725.5	980.2	1,007.0	817.9
Distributions received from unconsolidated affiliates	73.6	98.6	127.4	128.2	156.4	67.5
Equity in income of unconsolidated affiliates	(29.7)	(59.1)	(61.4)	(69.0)	(46.4)	(42.2)
Sustaining capital expenditures and cash payments to settle asset retirement obligations	(167.5)	(195.9)	(179.0)	(251.5)	(299.7)	(292.9)
Losses (gains) related asset sales and property damange insurance recoveries	5.4	(3.7)	0.1	(46.7)	(155.7)	(102.9)
Proceeds from asset sales and property damage insurance recoveries	12.0	16.0	3.5	105.9	1,033.8	1,167.4
Net income attributable to noncontrolling interest – merged affiliates	13.9	17.2	31.3	150.1	20.9	-
Other miscellaneous adjustments	36.1	(11.1)	(35.1)	(7.5)	(26.7)	(171.8)
Distributable cash flow	1,001.2	1,378.2	1,643.2	2,256.4	3,736.5	3,247.4
Adjustments to non-GAAP distributable cash flow to derive GAAP net cash flows provided by operating activities:						
Sustaining capital expenditures and cash payments to settle asset retirement obligations	167.5	195.9	179.0	251.5	299.7	292.9
Proceeds from asset sales and property damage insurance recoveries	(12.0)	(16.0)	(3.5)	(105.9)	(1,033.8)	(1,167.4)
Net income attributable to noncontrolling interests	30.6	41.4	75.7	175.6	41.4	6.2
Net income attributable to noncontrolling interest – merged affiliates	(13.9)	(17.2)	(31.3)	(150.1)	(20.9)	-
Net effect of changes in operating accounts	441.3	(357.4)	284.7	(202.1)	266.9	(910.2)
Operating cash flows attributable to merged affiliates in our recast financial statements			197.8	28.7		
Other miscellaneous adjustments	(23.8)	12.3	31.6	45.9	40.7	146.9
Net cash flows provided by operating activities	$ 1,590.9	$ 1,237.2	$ 2,377.2	$ 2,300.0	$ 3,330.5	$ 1,615.8

Note: Distributable Cash Flow for periods prior to the fourth quarters of 2010 and 2009 is presented based on the historical results of EPD prior to the Holdings and TEPPCO Mergers, respectively.