RBC Capital Markets

EQUITY RESEARCH

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Master Limited Partnerships

RBC MLP Primer

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All values in US dollars unless otherwise noted.

Priced as of prior trading day's market close, ET (unless otherwise stated).

For Required Non-U.S. Analyst and Conflicts Disclosures, please see page 88.

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MLP 101: A Brief Overview

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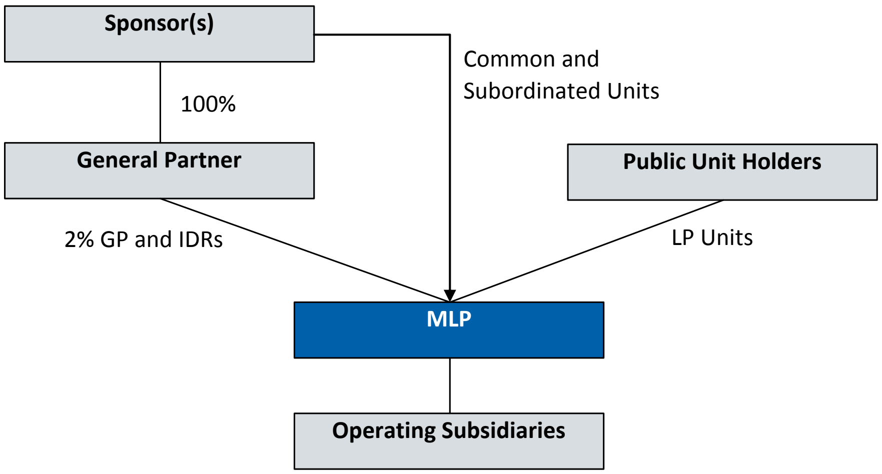
What is an MLP?

MLP structure



GP: General Partner; LP: Limited Partner; IDRs: Incentive Distribution Rights

Sample Incentive Distribution Rights Table

	Quarterly Distribution Target	Marginal Percentage Interest in Distributions	
		Unitholders	General Partner
Minimum Quarterly Distribution	$1.50	98%	2%
First Target Distribution	up to $2.00	98%	2%
Second Target Distribution	above $2.00 up to $2.50	85%	15%
Third Target Distribution	above $2.50 up to $3.00	75%	25%
Greater than Third Target Distribution	above $3.00	50%	50%

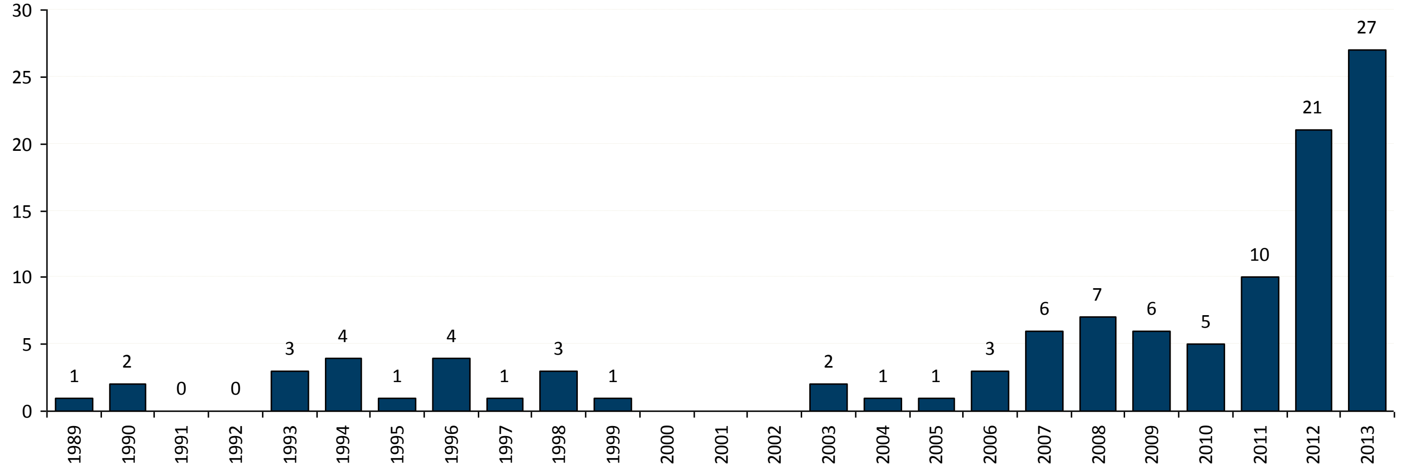
- **MLPs Are Partnerships, Not Corporations**
  - An MLP is a publicly traded partnership
  - Partnerships have a limited partner and a general partner
  - Limited Partners (LP)
    - Have a passive interest with limited rights/influence
    - Are entitled to cash distributions
    - Provide equity capital to grow the MLP
  - General Partner (GP)
    - Manages the partnership and typically has 2% ownership
    - Can benefit from incentive distribution rights (IDRs)
- **MLPs are Flow-Through Entities; Distributions, Not Dividends**
  - MLPs do not pay corporate level federal taxes
  - MLPs typically distribute 70%-100% of cash flow as distributions (not dividends) to LPs and GPs quarterly.
- **Requirements to Qualify as an MLP**
  - Under section 7704 of the IRS code an MLP must generate 90% or more gross income from qualifying sources.
  - Qualifying sources of income include: *"interest, dividends, real property rent, gain from sale or disposition of real property and income and gains derived from the exploration, development, mining or production, processing, refining, transportation (including pipelines transporting gas, oil, or products thereof), or the marketing of any mineral or natural resource (including fertilizer, geothermal energy, and timber)"*

Source: RBC Capital Markets; NAPTP; IRS.gov

MLP Private Letter Rulings (PLR)

Number of Companies Seeking IRS Guidance on Qualifying Income Climbs

Number of Private Letter Rulings Issued By the IRS



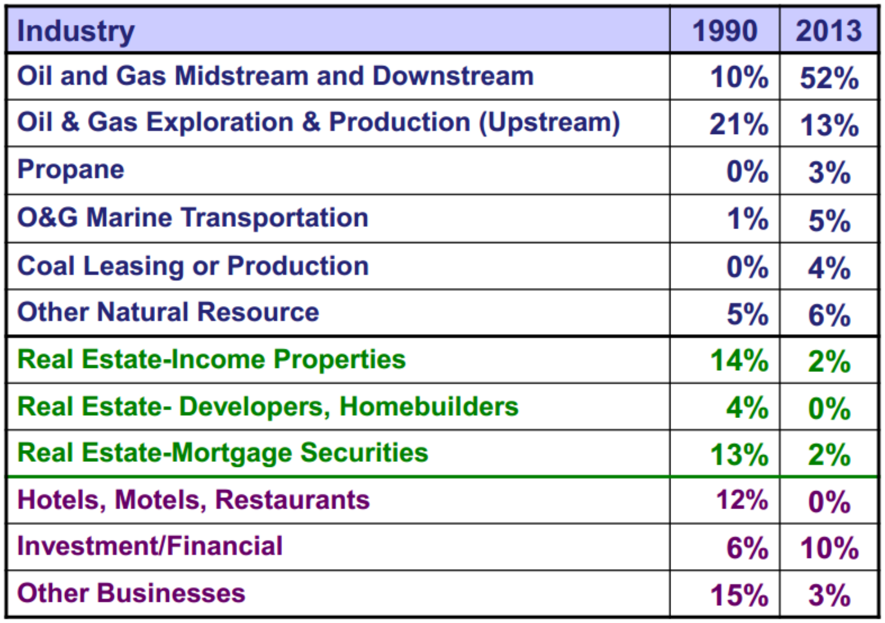
- An MLP or an organization considering an MLP structure may seek PLR from the IRS seeking guidance on qualifying income. While a PLR cannot be cited as precedent as it is specific to the company requesting it, a PLR can provide some indication on the IRS' view of a particular business area.

- Of the 109 PLR rulings issued by the IRS so far, ~44% of them were issued in the past two years.

Source: IRS.gov

MLP Industry Concentration

MLP Breakdown



Industry	1990	2013
Oil and Gas Midstream and Downstream	10%	52%
Oil & Gas Exploration & Production (Upstream)	21%	13%
Propane	0%	3%
O&G Marine Transportation	1%	5%
Coal Leasing or Production	0%	4%
Other Natural Resource	5%	6%
Real Estate-Income Properties	14%	2%
Real Estate- Developers, Homebuilders	4%	0%
Real Estate-Mortgage Securities	13%	2%
Hotels, Motels, Restaurants	12%	0%
Investment/Financial	6%	10%
Other Businesses	15%	3%

- An MLP is a financial structure not an “industry”.
- Businesses within different industries/sectors can generate qualifying income including energy, investment/financial and real estate.
- Currently, there are 134 MLPs, of which Energy MLPs account for the vast majority (~82%).
- Oil and Gas Midstream MLPs represent ~55% of Energy MLPs.
- The majority of MLPs are traditional MLPs in the sense that they pay a steady and potentially growing distribution.
- Some MLPs are structured as variable distribution MLPs, which pay out essentially all cash flow and have distributions that can fluctuate higher or lower on a quarterly and/or annual basis.
- Several non-traditional MLPs have emerged over the years, with operations in sectors such as fertilizers, refining, oilfield services among others.
- Some of these non-midstream MLPs may have more cash flow volatility due to the nature of their seasonal operations, reliance on less diversified asset base and exposure to commodity prices.

Source: NAPTP

List of MLPs in the Natural Resources Sector

Midstream

Access Midstream Partners, L.P.	ACMP
American Midstream Partners, LP	AMID
ARC Logistics Partners LP	ARCX
Atlas Pipeline Partners, L.P.	APL
Blueknight Energy Partners, L.P.	BKEP
Boardwalk Pipeline Partners, LP	BWP
Buckeye Partners, L.P.	BPL
Central Energy Partners, L.P.	ENGY
Cheniere Energy Partners, L.P.	CQP
Compressco Partners, L.P.	GSJK
Crosstex Energy, L.P.	XTEX
Crestwood Equity Partners LP	CEQP
Crestwood Midstream Partners LP	CMLP
DCP Midstream Partners, LP	DPM
Delek Logistics Partners, LP	DKL
Eagle Rock Energy Partners, L.P.	EROC
El Paso Pipeline Partners, L.P.	EPB
Enbridge Energy Partners, L.P.	EEP
Energy Transfer Partners, L.P.	ETP
Energy Transfer Equity, L.P.	ETE
Enterprise Products Partners L.P.	EPD
EQT Midstream, LP	EQM
Exterran Partners, L.P.	EXLP
Genesis Energy, L.P.	GEL
Holly Energy Partners, L.P.	HEP
Kinder Morgan Energy Partners, L.P.	KMP
Magellan Midstream Partners, L.P.	MMP
MarkWest Energy Partners, L.P.	MWE
Marlin Midstream Partners, LP	FISH
Martin Midstream Partners L.P.	MMLP
Midcoast Energy Partners, L.P.	MEP
MPLX LP	MPLX
Niska Gas Storage Partners LLC	NKA
NuStar Energy L.P.	NS
NuStar GP Holdings, LLC	NSH
Oiltanking Partners, L.P.	OILT
ONEOK Partners, L.P.	OKS
PAA Natural Gas Storage, L.P.	PNG
Phillips 66 Partners LP	PSXP
Plains All American Pipeline, L.P.	PAA
Plains GP Holdings, L.P.	PAGP
PVR Partners, L.P.	PVR
QEP Midstream Partners, LP	QEPM
Regency Energy Partners LP	RGP
Rose Rock Midstream, L.P.	RRMS
Southcross Energy Partners, L.P.	SXE
Spectra Energy Partners, LP	SEP
Summit Midstream Partners, LP	SMLP
Sunoco Logistics Partners L.P.	SXL
Tallgrass Energy Partners, LP	TEP
Targa Resources Partners LP	NGLS
TC PipeLines, LP	TCP
Tesoro Logistics LP	TLLP
TransMontaigne Partners L.P.	TLP
USA Compression Partners, LP	USAC
Western Gas Equity Partners, LP	WGP
Western Gas Partners, LP	WES
Western Refining Logistics, LP	WNRL
Williams Partners L.P.	WPZ
World Point Terminals, LP	WPT

Upstream

Atlas Energy, L.P.	ATLS
Atlas Resource Partners, L.P.	ARP
BreitBurn Energy Partners L.P.	BBEP
Constellation Energy Partners LLC	CEP
Dorchester Minerals, L.P.	DMLP
EV Energy Partners, L.P.	EVEP
Legacy Reserves LP	LGCY
Linn Energy, LLC	LINE
LRR Energy, L.P.	LRE
Memorial Production Partners LP	MEMP
Mid-Con Energy Partners LP	MCEP
New Source Energy Partners L.P.	NSLP
Pioneer Southwest Energy Partners, L.P.	PSE
QR Energy, LP	QRE
Seadrill Partners LLC	SDLP
Sprague Resources, LP	SRLP
Vanguard Natural Resources, LLC	VNR

Downstream

Alon USA Partners, LP	ALDW
Calumet Specialty Products Partners, L.P.	CLMT
CVR Refining, LP	CVRR
Global Partners LP	GLP
Lehigh Gas Partners LP	LGP
Northern Tier Energy LP	NTI
PetroLogistics LP	PDH
Star Gas Partners, L.P.	SGU
Susser Petroleum Partners LP	SUSP

Propane

AmeriGas Partners L.P	APU
Ferrellgas Partners, L.P.	FGP
NGL Energy Partners LP	NGL
Suburban Propane Partners, L.P.	SPH

Marine Transportation

Capital Product Partners L.P.	CPLP
Dynagas LNG Partners LP	DLNG
Golar LNG Partners LP	GMLP
KNOT Offshore Partners LP	KNOP
Navios Maritime Partners L.P.	NMM
Teekay LNG Partners L.P.	TGP
Teekay Offshore Partners L.P.	TOO

Coal

Alliance Resource Partners, L.P.	ARLP
Alliance Holdings GP, L.P.	AHGP
Natural Resource Partners L.P.	NRP
Oxford Resource Partners LP	OXF
Rhino Resource Partners LP	RNO

Other

CVR Partners, LP	UAN
Emerge Energy Services LP	EMES
Hi-Crush Partners LP	HCLP
OCI Partners LP	OCIP
OCI Resources LP	OCIR
Pope Resources	POPE
Rentech Nitrogen Partners, L.P.	RNF
SunCoke Energy Partners, L.P.	SXCP
Terra Nitrogen Company, L.P.	TNH

Royalty Trusts*

ECT Marcellus Trust I	ECT
Chesapeake Granite Wash Trust	CHKR
SandRidge Mississippian Trust I	SDT
SandRidge Mississippian Trust II	SDR
SandRidge Permian Trust	PER

* Treated as partnerships for tax purposes but they are royalty trusts rather than MLPs

This list is not comprehensive as it only includes Energy/Natural Resources MLPs. There are other publicly traded partnerships including those in real estate, financials services etc.,

Source: National Association of Publicly Traded Partnerships

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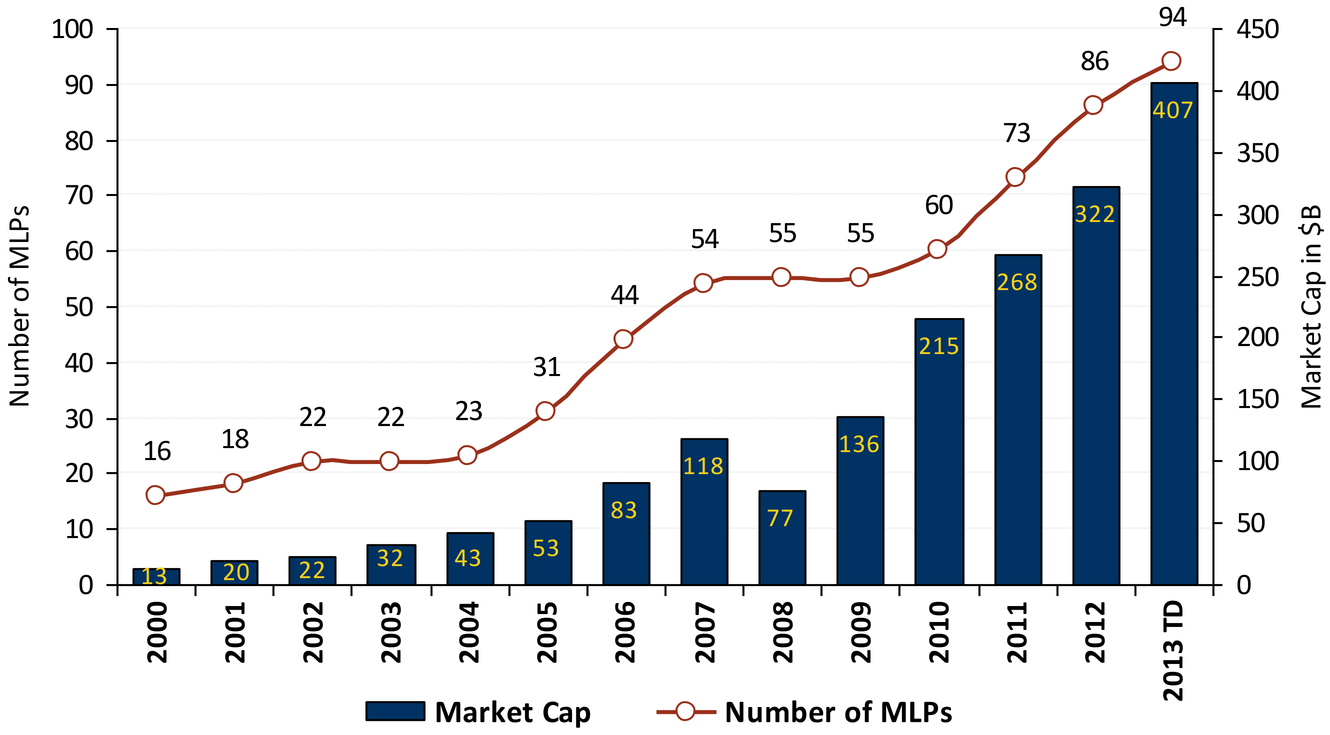
Number of Natural Resources MLPs and the Combined Market Cap



Source: RBC Capital Markets

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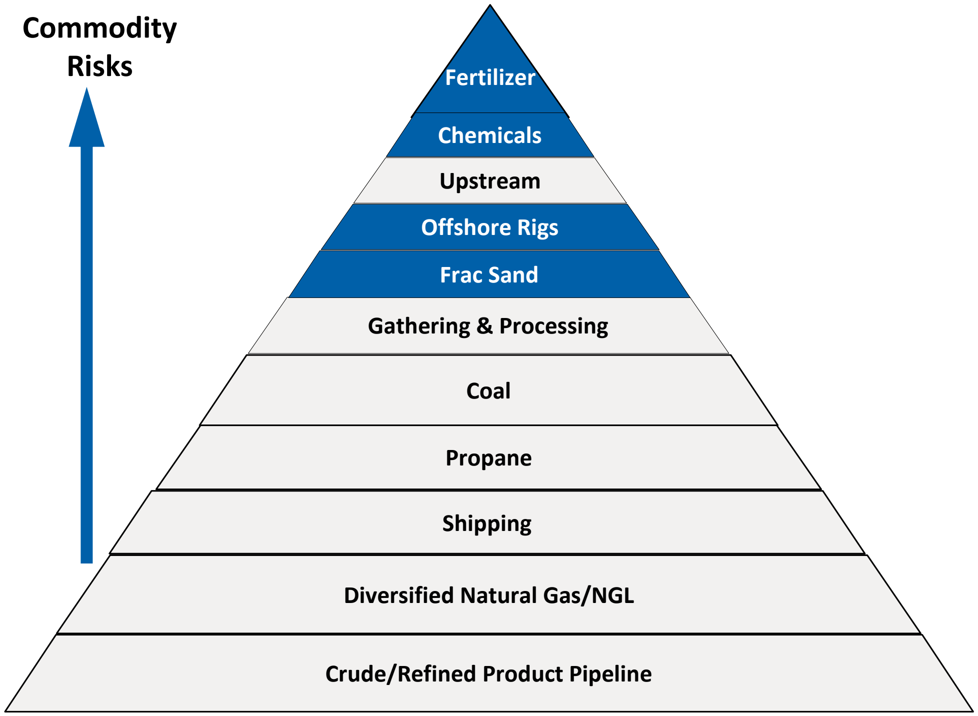
RBC Natural Resources MLP Subsector Pyramid

Natural Resources MLP Subsector Pyramid



Commodity Risks

Fertilizer

Chemicals

Upstream

Offshore Rigs

Frac Sand

Gathering & Processing

Coal

Propane

Shipping

Diversified Natural Gas/NGL

Crude/Refined Product Pipeline

- Energy MLPs cover a range of energy businesses, each of which has a unique risk profile
- Importantly, not all MLPs are pipelines, nor do all MLPs generate predictable fee based revenues/cash flow
- Energy MLPs can provide investors with both aggressive and defensive assets and cash flow
- Potential Risk Factors Include:
  - Commodity Price Exposure
  - Volume Sensitivity
  - Refinery Utilization
  - Macroeconomic Sensitivity
  - Depleting Asset Base
  - Weather

Source: RBC Capital Markets

Understanding MLP Taxation

- **Taxation is Unique for MLPs, Which are Tax-Advantaged Securities**
  - No double taxation – no federal level corporate taxes at the MLP; taxes paid by unitholders
  - The distribution is considered a return of capital and is not taxed when received (100% tax deferred)
  - Unitholders are allocated a share of the MLP's income and depreciation; the net of which is taxed at ordinary income rates in the year it was earned
  - Although income and distribution are not the same, the income that is taxed on average equates to ~20% of the distribution; consequently, investors typically view 80% of the distribution as "tax deferred"
  - A unitholder's cost basis declines each year by the amount of the distribution less the unitholder's allocated net income
  - When units are sold, depreciation recapture is taxed at ordinary income tax rates

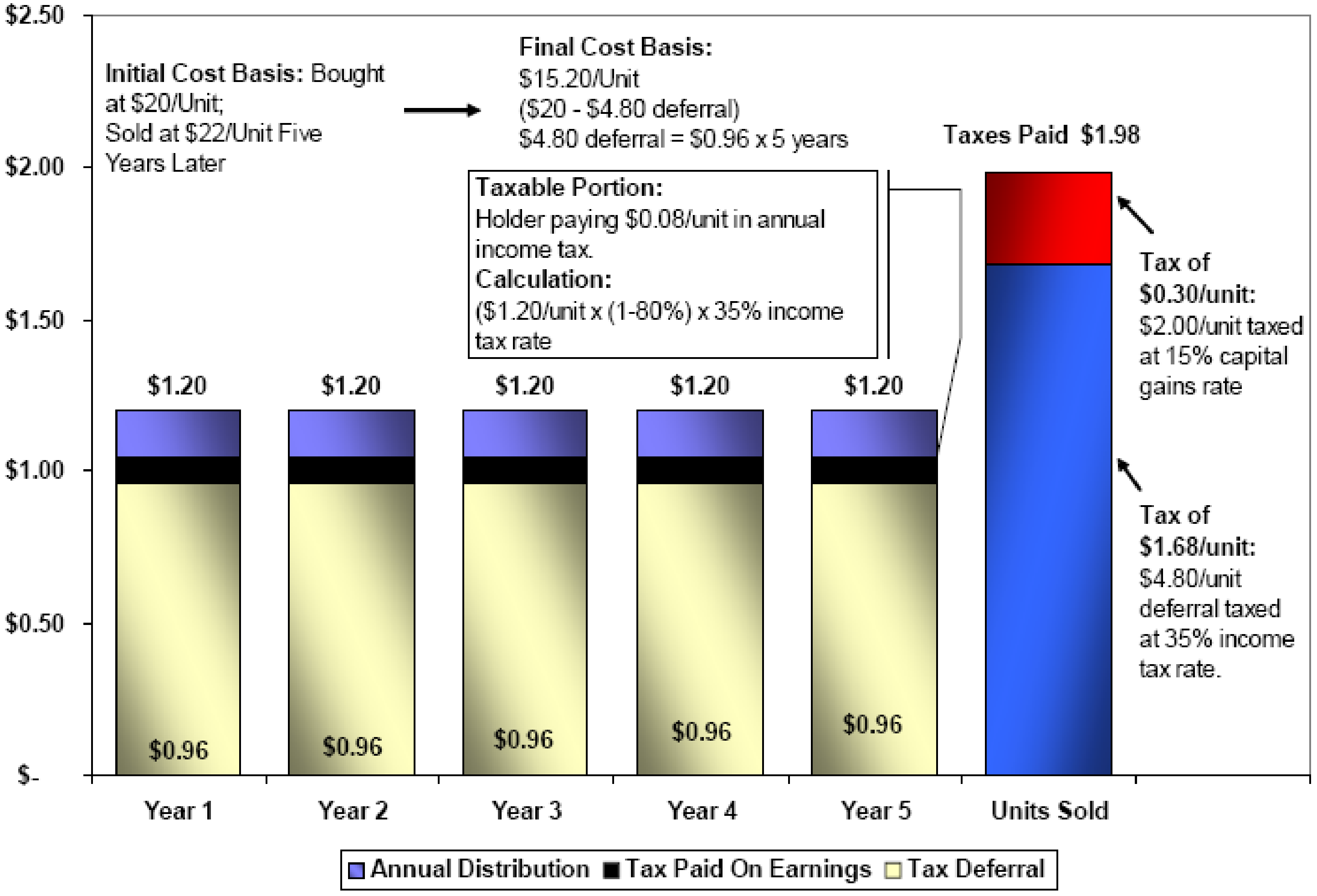
- **The Downside to MLP Taxation**
  - Schedule K-1 filings (instead of 1099s) may represent an administrative burden
  - Eventual income recapture when units are sold
  - IRAs, mutual funds, foreign owners, and pension funds have difficulty holding MLP units (directly) due to unrelated business taxable income (UBTI), nonresident state taxes, and timing of K-1 tax form

- **Are MLPs Suitable for an IRA?**
  - IRAs or other retirement plans are tax-exempt, so investors do not realize the full benefits of an MLP's tax advantages
  - Income allocated to an IRA may be considered unrelated business taxable income (UBTI) subject to tax
  - It will not be taxed as long as the amount of this income (and all other sources of UBTI), minus the IRA's share of partnership deductions, does not exceed $1,000 in any year
  - Even if there is some tax on the IRA's allocated share of partnership income, the partnership distributions should generally be high enough to provide a favorable return on an after-tax basis
  - The IRA custodian is responsible for filing an IRS Form 990T (unitholder does not pay tax directly)

Source: RBC Capital Markets

An MLP Tax Example

An MLP Tax Example



- **MLP Investor Buys Units at $20/Unit and Sells at $22/Unit Five Years Later (yielding 6%)**
  - Capital gain is the $2.00/unit difference between original cost basis and final selling price
  - Tax deferral (80%) totals $4.80/unit ($0.96 annually for five years)

Source: RBC Capital Markets

Owning MLPs Without a K-1

- **There are Several Ways to Gain MLP Exposure Without UBTI Generation**
  - I-Shares (KMR and EEQ)
  - Closed End Funds (CEFs)
  - Exchange Traded Notes (ETNs)
  - Exchange Traded Funds (ETFs)
  - Shipping MLPs that Generate 1099s
  - C-Corp General Partners
  - Open Ended Mutual Funds

- The most tax efficient means to invest in MLPs is through direct ownership of the securities

- I-Shares are equivalent to owning the MLP, with some differences: (1) Investors receive additional units rather than cash distributions, (2) Distributions are not taxable when received – shareholders only pay tax when I-Shares are sold, (3) I-Shares issue Form 1099, not Schedule K-1, and do not generate UBTI, (4) I-Shares are subject to capital gains tax when sold

- C-Corp general partners are high-growth due to IDRs but investors sacrifice current yield and lose tax advantages
  - As cash distributions per LP unit rise through different tiers (or splits), the GP is entitled to an increasing percentage of the incremental cash distributed by the partnership (commonly up to 50%)

- Shipping MLPs are based offshore and not subject to US Federal Income Taxes, but can be more volatile than traditional MLPs (and less liquid)

- CEFs, ETNs ETFs and Mutual Funds exhibit some tax leakage

Source: RBC Capital Markets

Valuation of MLPs

DCF Calculation Starting With Net Income

	Recurring Partnership Net Income
plus	Depreciation & Amortization
plus/minus	Non-cash Items
minus	Maintenance Capital Expenditure
Equals	**Available Cash Flow for Distribution**
minus	Cash Flow to General Partners
Equals	**Distributable Cash Flow**

DCF Calculation Starting With EBITDA

	EBITDA
minus	Interest Expense
minus	Maintenance Capital Expenditure
Equals	**Available Cash Flow for Distribution**
minus	Cash Flow to General Partners
Equals	**Distributable Cash Flow**

- **Different Valuations**
  - Yield or Yield Spreads (does not capture excess cash flow)
  - EV/EBITDA (need to adjust for GP take)
  - P/DCF
  - Distribution Discount Model (DDM).
- **Distributable Cash Flow (DCF) Is Key Metric**
  - Earnings not important
  - DCF = Free Cash Flow (similar to FFO for REIT industry).
- **Distribution Growth Key Driver For MLPs**
  - We derive our price targets through DDM
    - Key inputs: Debt leverage, distribution coverage and growth, IDRs, and risk-free rate.
  - We calculate DCF after the general partner's stake.

Source: RBC Capital Markets

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Understanding GP Incentive Distribution Rights (IDRs)

	Annual Dist Per	Unit O/S	LP Take	GP Take	LP Dist. in $MM	GP Dist. in $MM	Total Dist. in $MM	Cumulative GP Take
Declared Distribution	**$1.50**							
Minimum Quarterly Distribution	$1.50	500	98%	2%	750	15	765	
Total Distribution Paid					750	15	765	2%
Total Distribution Paid Per Unit					$1.50	$0.03	$1.53	2%
Declared Distribution	**$2.00**							
Minimum Quarterly Distribution	$1.50	500	98%	2%	750	15	765	
First Target Distribution	$2.00	500	98%	2%	250	5	255	
Total Distribution Paid					1,000	20	1,020	2%
Total Distribution Paid Per Unit					$2.00	$0.04	$2.04	2%
Declared Distribution	**$2.50**							
Minimum Quarterly Distribution	$1.50	500	98%	2%	750	15	765	
First Target Distribution	$2.00	500	98%	2%	250	5	255	
Second Target Distribution	$2.50	500	85%	15%	250	44	294	
Total Distribution Paid					1,250	65	1,315	5%
Total Distribution Paid Per Unit					$2.50	$0.13	$2.63	5%
Declared Distribution	**$3.00**							
Minimum Quarterly Distribution	$1.50	500	98%	2%	750	15	765	
First Target Distribution	$2.00	500	98%	2%	250	5	255	
Second Target Distribution	$2.50	500	85%	15%	250	44	294	
Third Target Distribution	$3.00	500	75%	25%	250	83	333	
Total Distribution Paid					1,500	148	1,648	9%
Total Distribution Paid Per Unit					$3.00	$0.30	$3.30	9%
Declared Distribution	**$3.50**							
Minimum Quarterly Distribution	$1.50	500	98%	2%	750	15	765	
First Target Distribution	$2.00	500	98%	2%	250	5	255	
Second Target Distribution	$2.50	500	85%	15%	250	44	294	
Third Target Distribution	$3.00	500	75%	25%	250	83	333	
Greater than Third Target Distribution	$3.50	500	50%	50%	250	250	500	
Total Distribution Paid					1,750	398	2,148	19%
Total Distribution Paid Per Unit					$3.50	$0.80	$4.30	19%

- General Partners (GPs) can be entitled to Incentive Distribution Rights (IDRs). IDRs provide incentive for the GP to grow the distributions at the MLP. As the underlying MLP grows its distribution and exceeds certain target distribution tiers, the GP is entitled to a higher percentage of the incremental distributions.

- In the adjacent exhibit, we provide an example of IDRs. As the target distribution increases, the GP receives a higher proportion of the cash. Note that the increased proportion is on the incremental distribution (not the total distribution).

- Since the GP is entitled to an increasing percentage of the incremental distribution, distributions to the GP grow faster than distributions to the LPs. For example, when the distribution increases from $2.00 per unit to $2.50 per unit, cash distributions to LP unitholders increase 25% from the previous distribution target but the cash distributions to the GP increase 216%. Consequently, GPs are commonly called a “levered play on the growth of the underlying MLP”.

- While IDRs serve as an incentive to grow the underlying MLP, IDRs increase the cost of capital for the underlying MLP as the underlying MLP has generate sufficient cash to cover the distributions to both LPs and the GP.

Source: RBC Capital Markets

Understanding Cost of Capital

Calculation of Cost of Capital

	With IDR	
	Cost of Equity	
	Annualized Distribution	$5.00
÷	Current Unit Price	85.0
	Current Yield	5.9%
÷	GP Take	50.0%
	Cost of Equity	11.8%
	Percent of Equity	50.0%
	Equity Component of Cost of Capital	**5.9%**
	Cost of Debt	
	Interest Rate	3.0%
×	% of Short-term Debt of Total Debt	50.0%
	Short-Term Floating Rate	1.5%
	Interest Rate	7.0%
×	% of Long-term Debt of Total Debt	50.0%
	Long-Term Fixed Rate	3.5%
+	Short-Term Floating Rate	1.5%
	Cost of Debt	5.0%
×	Percent of Debt	50.0%
	Debt Component of Cost of Capital	**2.5%**
	Cost of Capital	
	Equity Component of Cost of Capital	5.9%
+	Debt Component of Cost of Capital	2.5%
	Cost of Capital	**8.4%**

	Without IDR	
	Cost of Equity	
	Annualized Distribution	$5.00
÷	Current Unit Price	85.0
	Current Yield	5.9%
÷	GP Take	0.0%
	Cost of Equity	5.9%
	Percent of Equity	50.0%
	Equity Component of Cost of Capital	**2.9%**
	Cost of Debt	
	Interest Rate	3.0%
×	% of Short-term Debt of Total Debt	50.0%
	Short-Term Floating Rate	1.5%
	Interest Rate	7.0%
×	% of Long-term Debt of Total Debt	50.0%
	Long-Term Fixed Rate	3.5%
+	Short-Term Floating Rate	1.5%
	Cost of Debt	5.0%
×	Percent of Debt	50.0%
	Debt Component of Cost of Capital	**2.5%**
	Cost of Capital	
	Equity Component of Cost of Capital	2.9%
+	Debt Component of Cost of Capital	2.5%
	Cost of Capital	**5.4%**

- In the adjacent table, we show how to estimate the cost of capital for two MLPs, one with IDRs and the other without IDRs. The table demonstrates that IDRs increase an MLP's cost of capital.

- As the declared distribution of the limited partner moves higher through the distribution tiers, cash received by GP increases, which consequently increases the cost of equity capital. When this happens, the underlying MLP needs to identify projects that provide returns adequate enough to cover distributions to both LP units and GP.

- In an effort to attain a competitive cost of capital, some MLPs have acquired their General Partners in the past.

- In addition, although not included in our example, we believe it is important to incorporate distribution growth when analyzing equity cost of capital. If ignored, a project or acquisition that may be accretive to distributable cash flow growth in the early years may actually be dilutive in the later years.

Source: RBC Capital Markets

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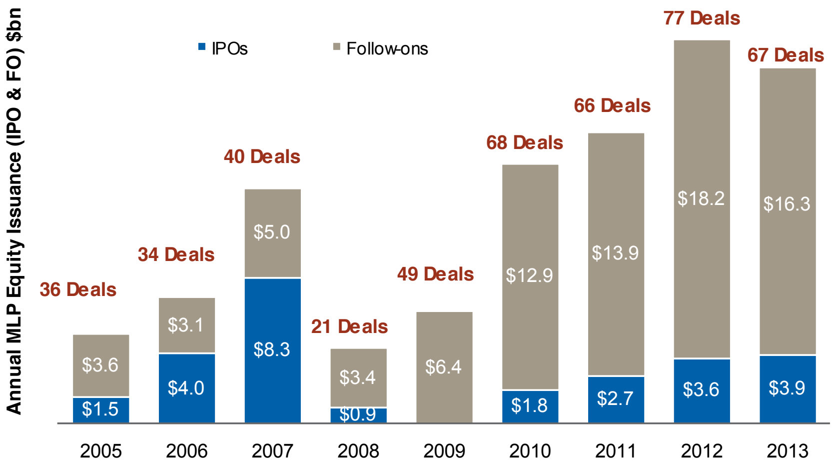
Capital Markets Accessible

Annual Equity Issuance - IPOs and Follow-ons



- Since MLPs pay out the majority of their cash flow as distributions, they typically issue debt and equity to finance growth projects or acquisitions. The financing mix for these projects is usually 50% equity and 50% debt.
- The capital markets remain accessible and MLPs have completed 67 deals including IPOs and secondary offerings to raise a total of $20.2 billion year to date. The total equity issuances year-to-date compares to $21.8 billion total in 2012.

Source: RBC Capital Markets, October 13th

General Partner – A Levered Growth Play on the Underlying MLP

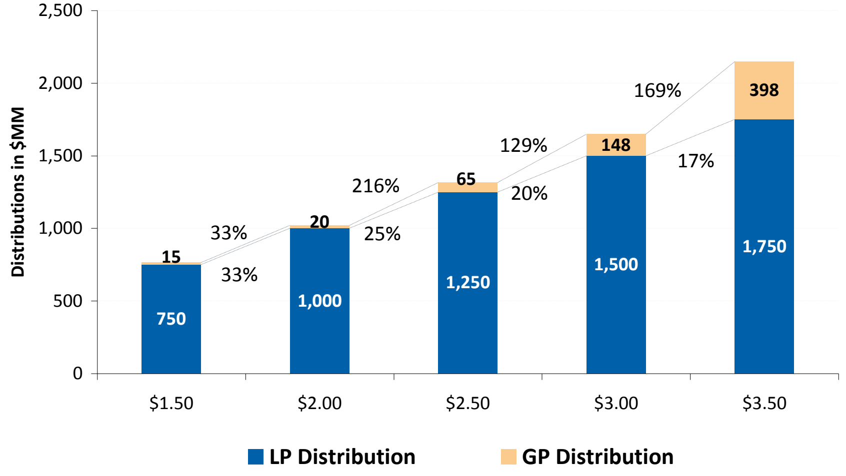
Splits Tiers

	Quarterly Distribution Target	Marginal Percentage Interest in Distributions	
		Unitholders	General Partner
Minimum Quarterly Distribution	$1.50	98%	2%
First Target Distribution	up to $2.00	98%	2%
Second Target Distribution	above $2.00 up to $2.50	85%	15%
Third Target Distribution	above $2.50 up to $3.00	75%	25%
Greater than Third Target Distribution	above $3.00	50%	50%

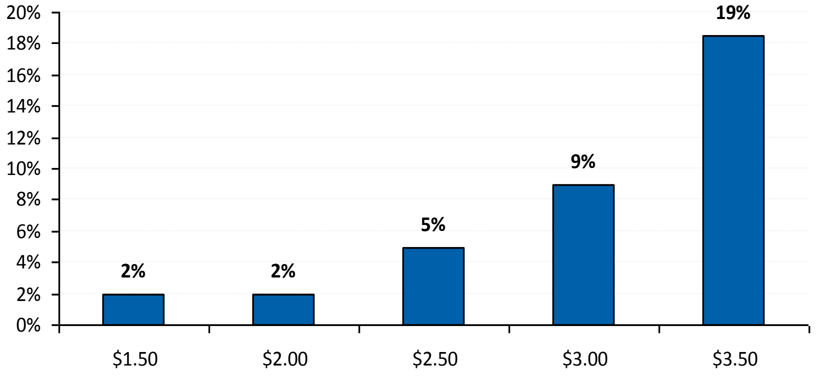
- As the underlying MLP grows its distributions, a GP with IDRs receives an increasing percentage of the incremental distribution. Thus, a GP is commonly called a "levered play on the growth of the underlying MLP". The GP multiplier represents the growth rate of GP distributions divided by the growth rate of LP distributions. For example if the MLP grows its distribution 5% but the distribution to the GP grows 10%, the GP multiplier is 2.0x.

- The cash received by GP as percent of total distribution increases as the declared distribution moves higher through the tiers. When the distribution reaches the 50% tier, in our example, the total cash received by the GP represents nearly 19% of the total cash distribution. Total cash distribution to the GP can grow to close to 50% the longer the MLP is in the 50% splits tier. However, the GP multiplier declines the longer the MLP is in the 50% splits tier.

GP Distributions Grow Disproportionately



Cash Received By GP As a % of Total Distributions



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Why Invest in MLPs?

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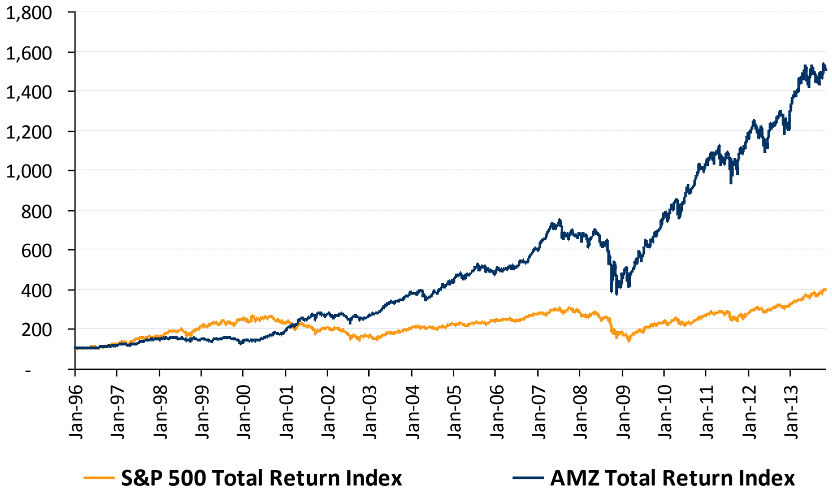
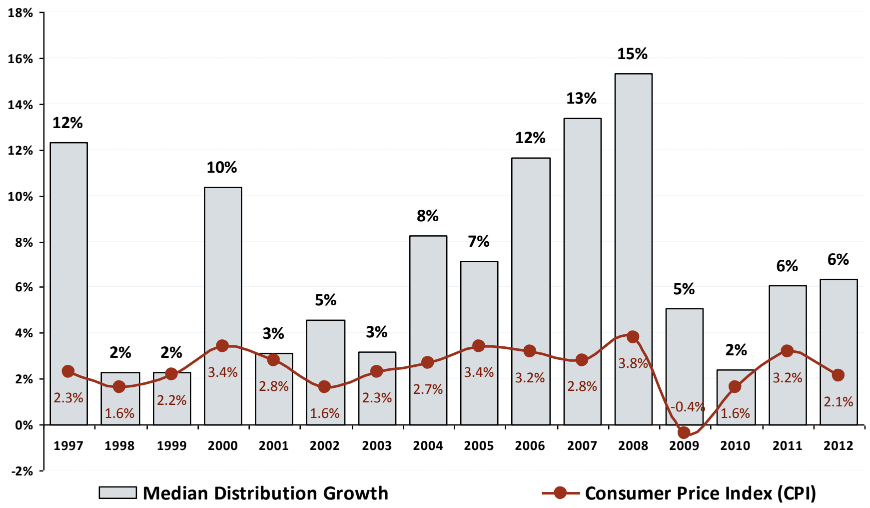
MLP Value Proposition

AMZ Total Return Index Vs. S&P 500 Total Return Index



MLP Distribution Growth Has Consistently Outperformed Inflation (As measure by CPI)



- MLPs typically distribute 70%-100% of cash flow as distributions and are thus considered a yield investment. However, unlike bonds, MLPs generally aim to grow their distributions over time. We believe this combination of "yield plus growth" drives compelling total return potential over time.
- The performance chart on this slide highlights that MLPs (as measured by the AMZ total return index) have outperformed the broader market (as measured by the S&P 500 total return index) on a total returns basis in the last 12 of 15 years.
- In addition, we view MLPs as an attractive inflation hedge given that distribution growth has outpaced inflation (as measured by the Consumer Price Index (CPI)) every year since 1997.
- As the vast majority of MLPs are Energy MLPs and more specifically, midstream focused, MLPs provide investors the ability to participate in the North American energy infrastructure build-out spurred by the growing development of shale and unconventional resource plays.

Source: Bureau of Labor Statistics, Bloomberg, FactSet

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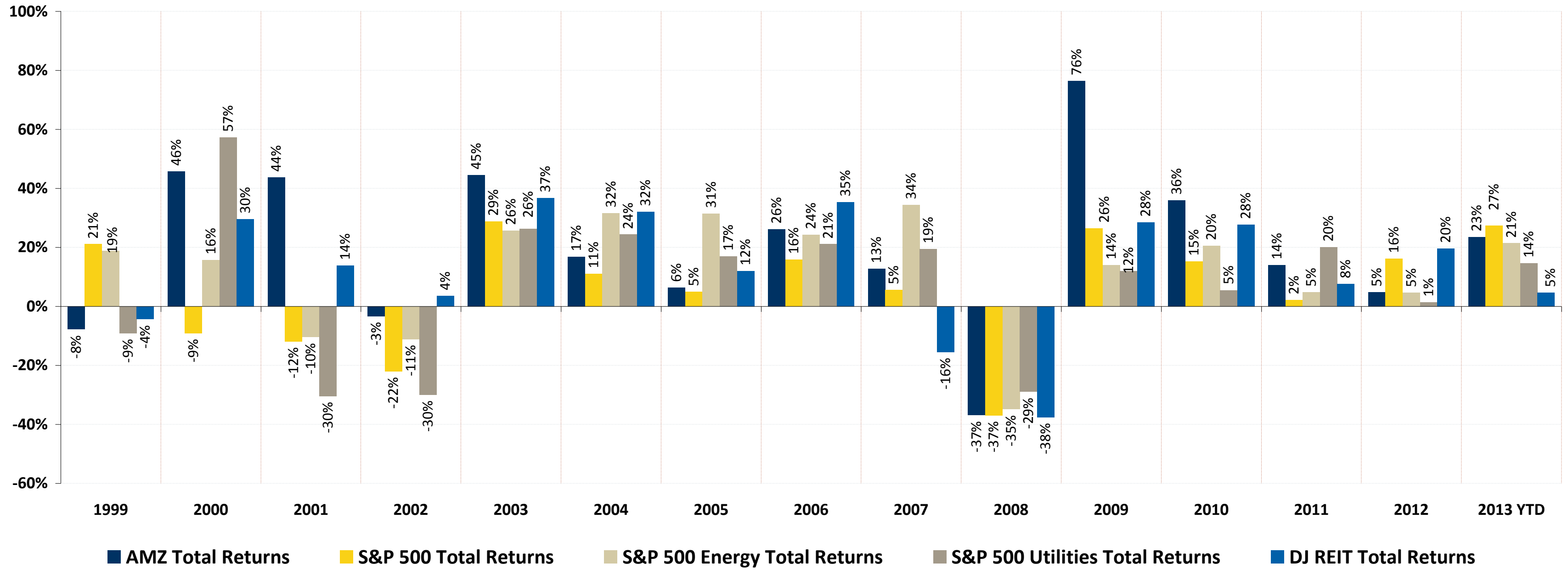
MLP Performance Trends

AMZ vs. Equity Indices – Total Returns



Source: Bloomberg

MLPs Provide Portfolio Diversification

AMZ Index Correlation With Commodities And Other Major Indices

	S&P 500	WTI Crude Oil	Natural Gas	10 YR	Utilities Index	REIT Index	Oil Services	E&P Index	S&P 500 Energy	High Yield	Investment Grade	Moody's BAA
2013 TD	59.8%	29.8%	-0.7%	14.3%	48.9%	56.7%	52.0%	44.9%	56.6%	37.2%	7.5%	7.9%
2012	58.2%	42.1%	-2.9%	35.6%	40.5%	51.4%	52.0%	52.8%	58.3%	40.8%	-9.7%	32.1%
2011	66.9%	41.4%	16.3%	35.8%	56.9%	65.7%	69.1%	70.2%	69.3%	29.3%	-12.8%	29.6%
2010	65.4%	59.2%	13.5%	29.9%	62.3%	57.3%	63.4%	69.6%	68.8%	29.4%	-6.5%	32.1%
2009	72.9%	45.8%	26.6%	29.7%	61.9%	51.7%	76.5%	78.8%	76.1%	11.6%	-15.2%	26.3%
3 YR	62.5%	38.7%	5.2%	29.5%	51.2%	60.3%	60.7%	60.1%	63.4%	33.3%	-3.7%	24.5%
5 YR	69.0%	46.0%	15.6%	31.1%	56.4%	56.4%	69.6%	70.6%	69.4%	25.8%	-11.1%	25.8%
10 YR	64.5%	40.7%	14.3%	26.1%	58.5%	47.2%	67.6%	69.9%	67.9%	21.2%	-1.9%	16.9%

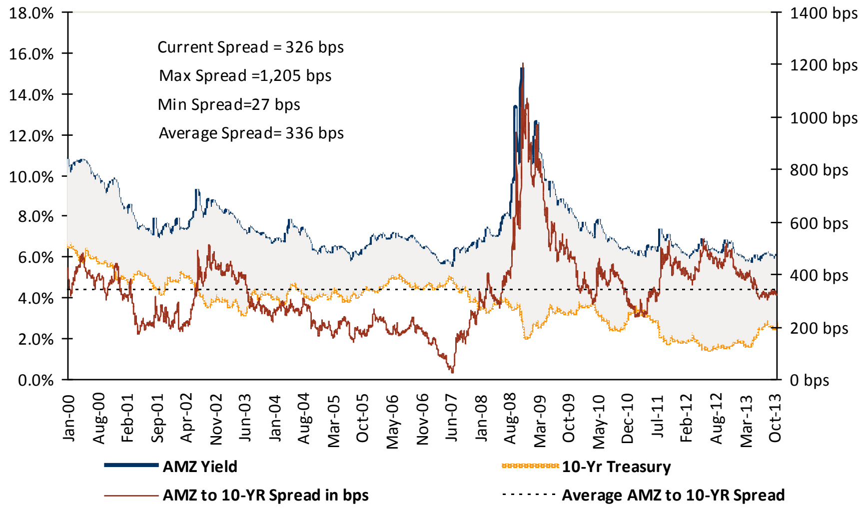
- MLPs provide investors with portfolio diversification. The exhibit on this slide highlights correlations between MLPs and various other investments. MLPs exhibit low correlation with other asset classes and hence can be used as a good diversification tool. Historically, the AMZ has held low correlation with commodities such as crude oil. While the correlation with crude oil increased in the recent years, it has declined in 2013.

- In 2013, AMZ index has exhibited low correlation with S&P 500, S&P 500 Energy Index, Oil Services Index, E&P Index and S&P 500 Utilities Index when compared to the historical averages. Note that the historical averages include the financial/credit crisis of 2008, when essentially all investments became highly correlated.

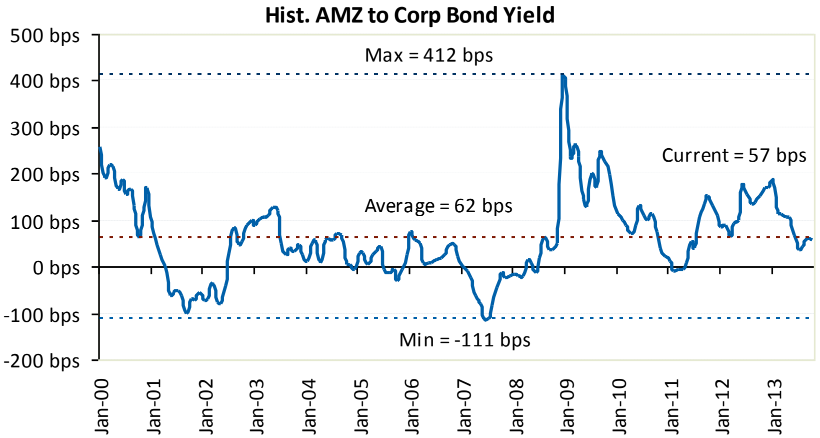
Source: Bloomberg

Interest Rate - An Important Driver of MLP Performance

AMZ Spread to 10-Yr Treasury



AMZ Spread to Corporate Bond Yield



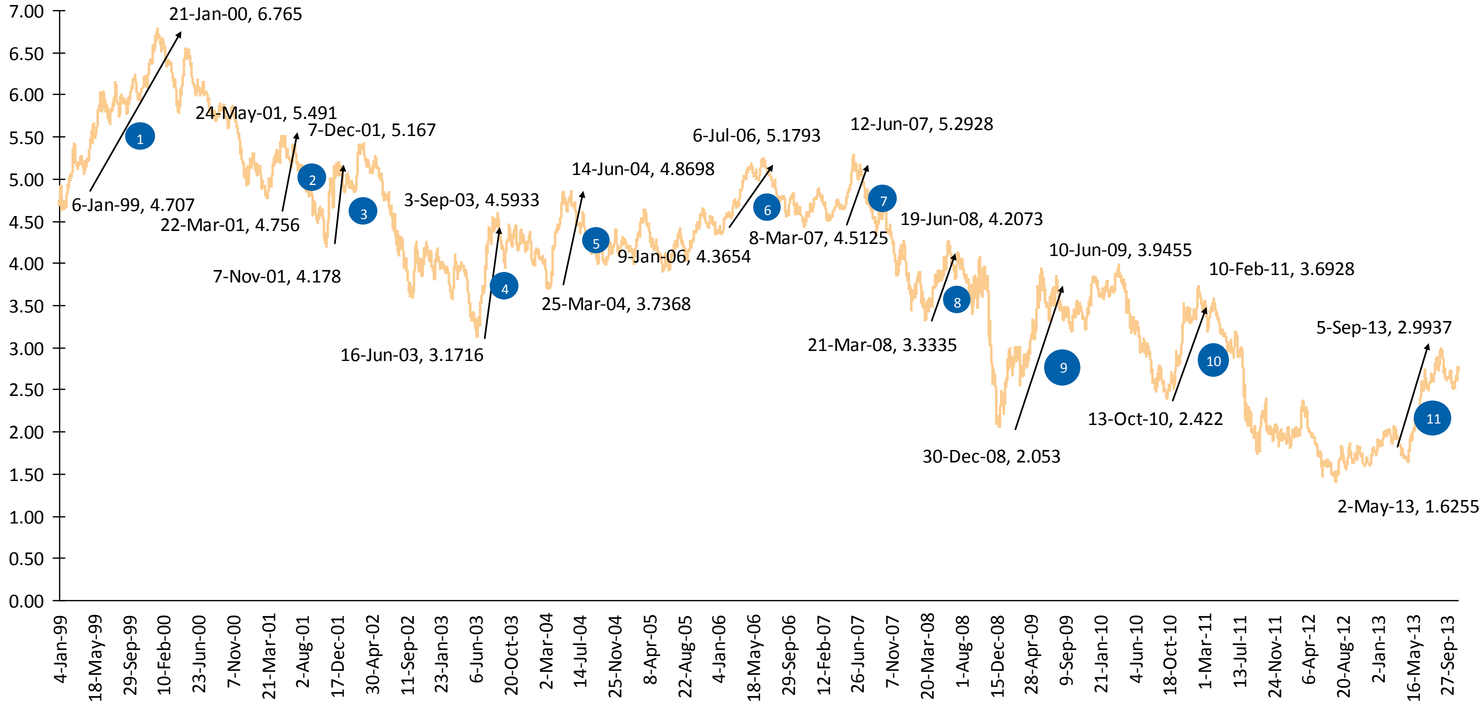
- Since MLPs are yield instruments, interest rates represent an important driver of MLP performance. Currently, MLPs are trading at a 326 bps spread to the 10-year Treasury compared to its historical average of 336 bps. However, the historical average includes the blowout of spreads that accompanied the financial/credit crisis in 2008/2009. Excluding the financial/credit crisis, we believe a normalized spread to approximately 250-300 bps.

- Since 2000, the US has been in a declining interest rate environment. Most MLPs came public in this period of declining interest rates.

- We isolated periods of rising rates within the broader declining rate environment to identify trends. We note that in these intermittent periods of rising rates, MLPs lagged the S&P 500 but tended to outperform Utilities and REITs. In the following slide, we observed 11 instances when 10-year treasury rates increased from trough to peak. Out of those instances, the AMZ underperformed the S&P 500 seven times but mostly outperformed Utilities and REIT indices.

Source: Bloomberg

In an Increasing Interest Rate Environment, AMZ Outperforms Utilities and REIT



	Trough	Peak	Days To Peak	10-Yr Treasury Increase	AMZ Price Performance	S&P 500 Index	S&P 500 Utilities Index	DJ Equity REIT Index
1	06-Jan-99	21-Jan-00	380	205.8 bps	-9%	13%	-3%	-
2	22-Mar-01	24-May-01	63	73.5 bps	20%	16%	14%	-
3	07-Nov-01	01-Dec-01	24	98.9 bps	-4%	2%	-5%	-
4	16-Jun-03	03-Sep-03	79	142.17 bps	1%	2%	-5%	8%
5	25-Mar-04	14-Jun-04	81	110.3 bps	-9%	1%	-3%	-9%
6	09-Jan-06	06-Jul-06	178	81.39 bps	0%	-1%	1%	9%
7	08-Mar-07	12-Jun-07	96	78.03 bps	6%	6%	3%	-6%
8	21-Mar-08	19-Jun-08	90	87.38 bps	8%	1%	10%	1%
9	30-Dec-08	10-Jun-09	162	189.25 bps	33%	5%	-6%	-3%
10	13-Oct-10	19-Feb-11	129	127.08 bps	8%	14%	0%	9%
11	02-May-13	05-Sep-13	126	136.82 bps	-3%	4%	-11%	-14%

Source: Bloomberg, Alerian, RBC Capital Markets

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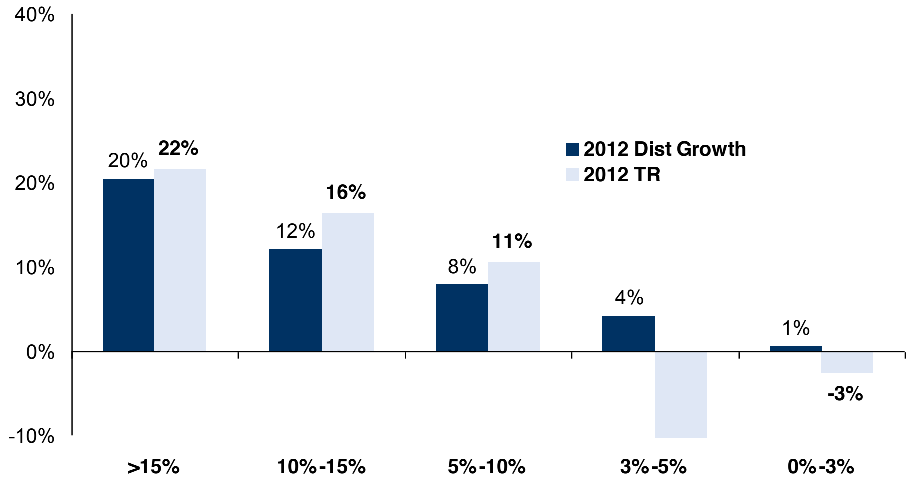
AMZ Performance vs. Changes to Fed Funds Rate

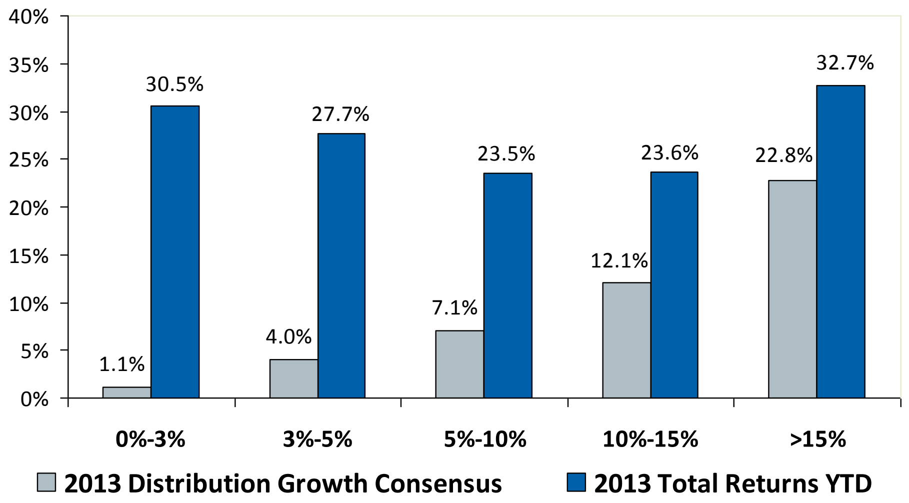
Announcement Date	Fed Funds Rate Level	Change Direction	Rate Change (in BPS)	AMZ Price Returns from Date of		AMZ Price Return Until Next Fed Rate Change Announcement	S&P 500 Price Return Until Next Fed Rate Change Announcement
				+1 Day	+7 Days		
31-Jan-96	5.25%	Down	-25 bps	0.0%	0.5%	6.8%	24.3%
25-Mar-97	5.50%	Up	25 bps	0.3%	-1.2%	9.7%	32.9%
29-Sep-98	5.25%	Down	-25 bps	-0.7%	-3.1%	-4.2%	-4.1%
15-Oct-98	5.00%	Down	-25 bps	1.2%	4.4%	2.0%	8.4%
17-Nov-98	4.75%	Down	-25 bps	0.0%	-0.4%	-3.8%	18.6%
30-Jun-99	5.00%	Up	25 bps	0.1%	1.1%	2.9%	-0.9%
24-Aug-99	5.25%	Up	25 bps	0.2%	-0.4%	-9.7%	2.3%
16-Nov-99	5.50%	Up	25 bps	0.1%	-2.6%	-2.2%	-0.8%
02-Feb-00	5.75%	Up	25 bps	0.7%	-2.0%	-2.4%	3.4%
21-Mar-00	6.00%	Up	25 bps	1.1%	-1.1%	0.1%	-2.8%
16-May-00	6.50%	Up	50 bps	0.7%	-0.4%	24.0%	-12.5%
03-Jan-01	6.00%	Down	-50 bps	-0.8%	3.7%	11.0%	1.9%
31-Jan-01	5.50%	Down	-50 bps	-0.6%	0.9%	1.7%	-14.3%
20-Mar-01	5.00%	Down	-50 bps	-1.4%	-0.5%	4.0%	4.3%
18-Apr-01	4.50%	Down	-50 bps	0.9%	4.8%	9.0%	0.9%
15-May-01	4.00%	Down	-50 bps	-0.7%	0.7%	-3.5%	-2.6%
27-Jun-01	3.75%	Down	-25 bps	-0.9%	0.2%	81.1%	19.4%
21-Aug-07	3.50%	Down	-25 bps	2.3%	2.6%	-40.5%	-24.5%
17-Sep-01	3.00%	Down	-50 bps	-0.7%	-6.0%	-2.6%	0.0%
02-Oct-01	2.50%	Down	-50 bps	1.2%	2.6%	3.2%	4.9%
06-Nov-01	2.00%	Down	-50 bps	0.3%	1.1%	-4.0%	1.9%
11-Dec-01	1.75%	Down	-25 bps	-1.9%	-0.3%	-12.3%	-19.5%
06-Nov-02	1.14%	Down	-61 bps	-0.5%	-1.2%	24.2%	6.5%
25-Jun-03	1.00%	Down	-14 bps	0.4%	2.3%	5.2%	16.5%
30-Jun-04	1.25%	Up	25 bps	0.9%	3.5%	1.0%	-6.6%
10-Aug-04	1.50%	Up	25 bps	-0.3%	0.8%	6.3%	4.0%
21-Sep-04	1.75%	Up	25 bps	0.2%	2.4%	2.7%	3.1%
10-Nov-04	2.00%	Up	25 bps	0.5%	1.6%	1.8%	3.1%
14-Dec-04	2.25%	Up	25 bps	0.4%	1.6%	7.3%	-1.2%
02-Feb-05	2.50%	Up	25 bps	-0.5%	-2.2%	-1.5%	-0.8%
22-Mar-05	2.75%	Up	25 bps	-3.0%	-2.8%	0.6%	-0.8%
03-May-05	3.00%	Up	25 bps	-0.2%	0.8%	5.1%	3.3%
30-Jun-05	3.25%	Up	25 bps	0.8%	1.7%	2.5%	2.7%
09-Aug-05	3.50%	Up	25 bps	-0.5%	-2.5%	0.9%	0.0%
20-Sep-05	3.75%	Up	25 bps	-0.7%	-0.8%	-2.4%	-1.2%
01-Nov-05	4.00%	Up	25 bps	0.0%	-1.2%	-3.5%	4.8%
13-Dec-05	4.25%	Up	25 bps	0.6%	-1.9%	2.4%	1.4%
31-Jan-06	4.50%	Up	25 bps	-0.7%	-1.6%	-0.5%	1.7%
28-Mar-06	4.75%	Up	25 bps	0.4%	-0.3%	1.6%	2.5%
10-May-06	5.00%	Up	25 bps	-0.7%	-3.3%	-2.2%	-5.8%
29-Jun-06	5.25%	Up	25 bps	0.2%	0.4%	21.3%	16.0%
18-Sep-07	4.75%	Down	-50 bps	0.6%	-1.2%	2.5%	0.7%
31-Oct-07	4.50%	Down	-25 bps	-0.7%	-2.4%	-5.3%	-2.2%
11-Dec-07	4.25%	Down	-25 bps	0.1%	-1.4%	-2.6%	-10.3%
22-Jan-08	3.50%	Down	-75 bps	-0.9%	2.5%	2.5%	4.0%
30-Jan-08	3.00%	Down	-50 bps	0.7%	-0.2%	-9.0%	-5.8%
18-Mar-08	2.25%	Down	-75 bps	-2.0%	0.2%	7.5%	4.5%
30-Apr-08	2.00%	Down	-25 bps	-0.5%	0.9%	-39.5%	-28.1%
08-Oct-08	1.50%	Down	-50 bps	-4.5%	17.8%	20.3%	-4.5%
29-Oct-08	1.00%	Down	-50 bps	3.3%	2.1%	-17.3%	-6.6%
16-Dec-08	0 to 0.25%	Down	-75 bps	-0.1%	-6.3%	104.9%	43.8%
Fed Funds Rate Directional Change		**Up**		**0.0%**	**-0.4%**	**2.8%**	**2.0%**
		Down		**-0.2%**	**0.9%**	**5.2%**	**1.4%**

- In the adjacent chart, we show how the AMZ responds to changes in Federal Funds rate. The key takeaway from this exhibit is, when the Federal Reserve increases the Federal Funds rate, the AMZ price return increases on average by 3% in the interim period until the next rate change. This compares to a 2% increase in S&P 500.
- However, when the Federal reserve lowers the rate, the AMZ price return increases on average over 5% until the next change in interest rate. This compares to a 1% increase in S&P 500.

Higher-Growth MLPs Historically Outperformed

2013 MLP Distribution Growth vs Total Returns





← **2012 Distribution Growth Buckets** →

← **2013 Distribution Growth Buckets** →

- Historically, distribution growth had been a major driver of MLP total returns
- In 2012 those MLPs with the fastest distribution growth tended to outperform those with little or no distribution growth
- In 2013, MLPs with the fastest distribution growth have outperformed the rest of the MLPs; however, those with 0-3% distribution growth have outperformed every other group except the fastest growers. We attribute this to the restructurings and M&A activity several MLPs have undertaken to improve their positioning.

Source: Factset & Bloomberg; RBC Captial Markets

Energy Midstream Sector: Key Attributes We Favor

Focus on Growth

- We favor MLPs and GPs with visible, above-average multi-year distribution growth potential.
  - High return organic growth projects
  - Dropdown acquisitions
  - Third party acquisitions
- Low risk cash flow profile and high distribution growth potential can command meaningful valuation premiums.

What else do we favor?

- Favor crude and NGL levered MLPs as we see continued near to medium term growth opportunities around crude oil and NGL production.
- Critical asset scale and diversity across basins and value chain
  - Increases flexibility and market access
  - Lowers operational and execution risk.
- Cash flow Stability/Visibility
  - High degree of fee-based margin
  - Take or pay contracts
  - Other contractual risk protection (i.e., minimum volume commitments)
- Screens well on other general risk metrics including trading liquidity, debt leverage and distribution coverage.
- Favored names include high / “hyper” growth MLPs, C-Corp GPs, and low risk, large cap diversified MLPs.

Source: RBC Capital Markets

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Key MLP Terms

- **Distributable Cash Flow (DCF) -** DCF is the cash available to pay common unit holders after distributions to the general partner.
- **Distribution –** The amount of cash distributed by the MLP on a quarterly basis.
- **Distribution Coverage Ratio –** Calculated as total available cash flow divided by total distributions paid (to GP and LP). The higher the distribution coverage ratio, the safer the distribution growth profile.
- **Dropdown –** An asset sale by the parent or sponsor company to the underlying MLP is known as dropdown. GP's could structure the underlying MLP as a vehicle that relies on dropdowns for growth.
- **Incentive Distribution Rights (IDR)** – IDRs enable the GP to earn an increasing share of the distribution as the MLP achieves certain targeted distribution tiers. IDRs incentivize the GP to grow the MLP. However, IDRs increase the MLP's cost of capital as new projects or acquisitions completed by the MLP must provide returns that are high enough to cover both GP and LP distributions.
- **Maintenance Capex / Growth Capex –** No standard definition exists for maintenance capital. However, maintenance capital is generally viewed as the capital required to maintain an MLP's capacity, volumes and/or operating income longer-term. Capital that increases an asset's capacity is classified as growth capex.
- **Minimum quarterly distribution (MQD) –** Typically set at inception, the MQD is the amount an MLP plans to pay to its unit holders once it is able to generate sufficient cash flow from its operations. MLPs do not guarantee distribution.
- **Subordination Period / Subordinated Units –** Upon IPO of an MLP, the GP or sponsor typically holds subordinated units. Subordinated units are not entitled to receive any distributions until the common units have received the MQD plus any arrearages. After a subordination period, these units convert to common units on a one-for-one basis. However, the subordination period may be accelerated depending on the timing of the distribution increases.

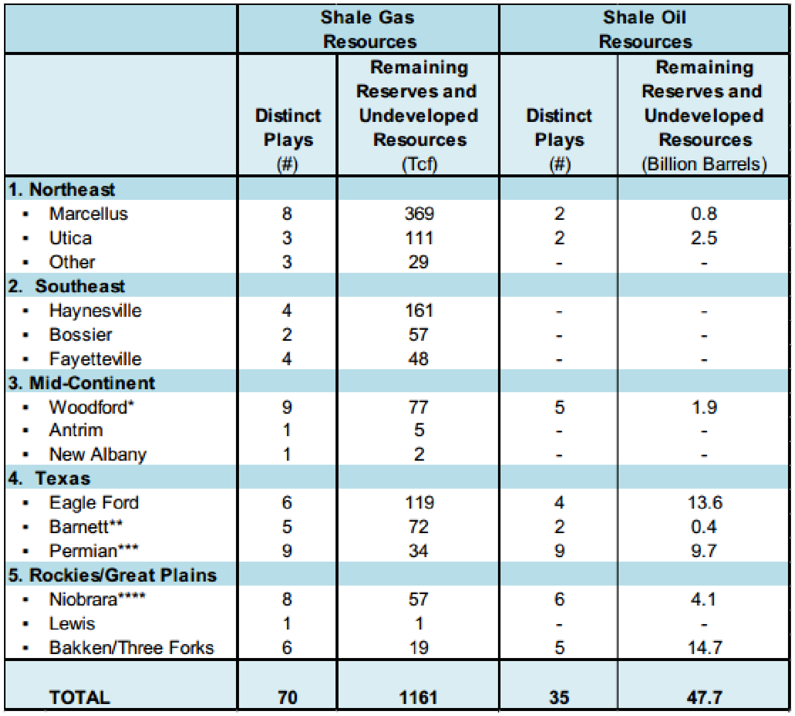
Source: RBC Capital Markets

Introduction to North American Energy Plays

RBC Capital Markets

Introduction to US Shale Plays

Recoverable Resources By Shale Play



	Shale Gas Resources		Shale Oil Resources	
	Distinct Plays (#)	Remaining Reserves and Undeveloped Resources (Tcf)	Distinct Plays (#)	Remaining Reserves and Undeveloped Resources (Billion Barrels)
1. Northeast				
▪ Marcellus	8	369	2	0.8
▪ Utica	3	111	2	2.5
▪ Other	3	29	-	-
2. Southeast				
▪ Haynesville	4	161	-	-
▪ Bossier	2	57	-	-
▪ Fayetteville	4	48	-	-
3. Mid-Continent				
▪ Woodford*	9	77	5	1.9
▪ Antrim	1	5	-	-
▪ New Albany	1	2	-	-
4. Texas				
▪ Eagle Ford	6	119	4	13.6
▪ Barnett**	5	72	2	0.4
▪ Permian***	9	34	9	9.7
5. Rockies/Great Plains				
▪ Niobrara****	8	57	6	4.1
▪ Lewis	1	1	-	-
▪ Bakken/Three Forks	6	19	5	14.7
TOTAL	**70**	**1161**	**35**	**47.7**

*Woodford includes Ardmore, Arkoma and Anadarko (Cana) basins.
**Barnett includes the Barnett Combo.
***Permian includes Avalon, Cline and Wolfcamp shales in the Delaware and Midland sub-basins.
****Niobrara Shale play includes Denver, Piceance and Powder River basins.

- In the US, large quantities of crude oil and natural gas are trapped in non-permeable shale rock. The increase in crude oil prices combined with technological advances in hydraulic fracturing and horizontal drilling have made recovery of much of this oil and gas economically feasible.
- In the adjacent table, we show the recoverable resources by shale play as estimated by the Energy Information Administration (EIA). The most important shale plays are the Bakken in North Dakota and Montana; Barnett in Texas, Utica and Marcellus in the east. Other major shale plays include the Niobrara in Wyoming and Colorado and the Eagle Ford and Permian in Texas.
- EIA estimates a total of 1,161 Tcf of technically recoverable wet and dry shale gas in the US. The US has already produced about 37 Tcf of shale gas.
- EIA estimates 47.7 billion barrels of technically recoverable shale oil and condensate. The US has produced only a modest amount of shale oil/condensate from major shale plays.

Source: EIA

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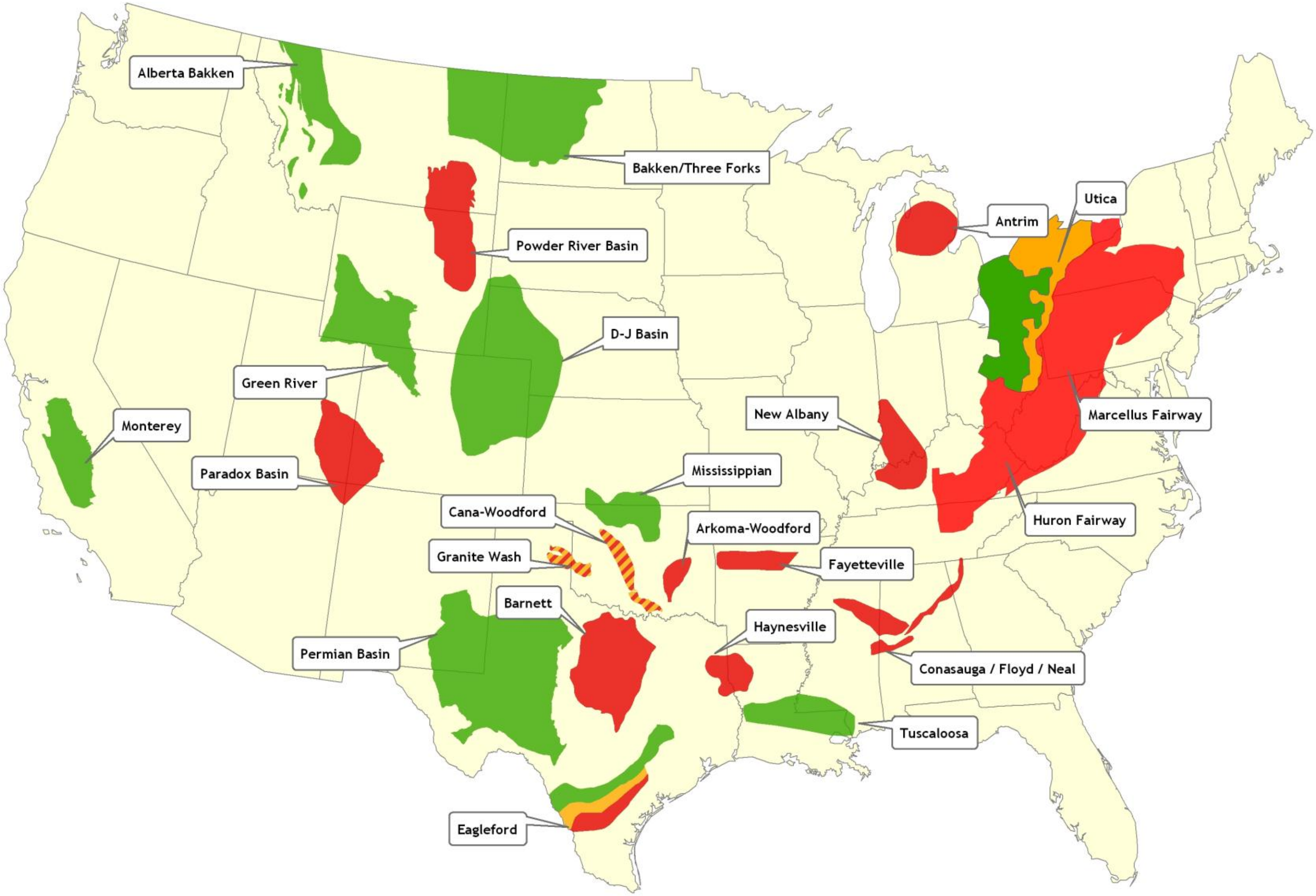
US Shale Plays

US Shale Plays



Source: RBC Capital Markets Estimates, EIA, and USGS

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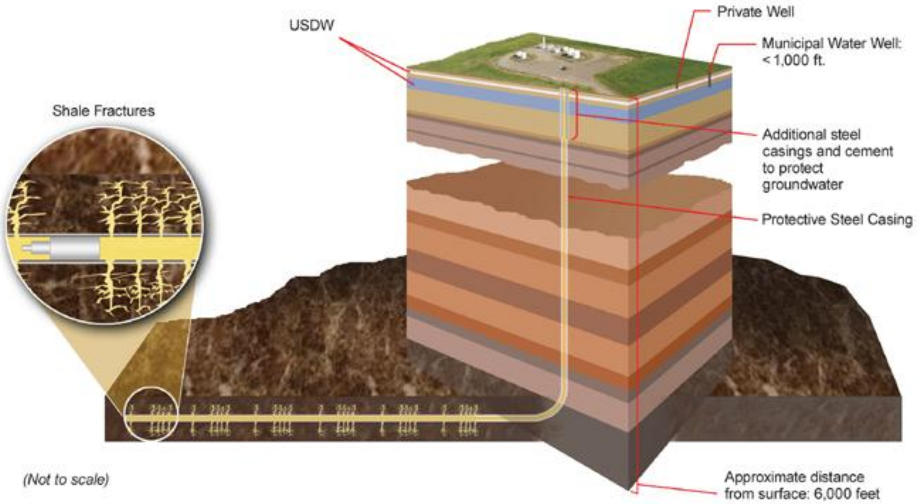
Hydraulic Fracturing

Hydraulic Fracturing



Steel casing lines the well and is cemented in place to prevent any communication up the wellbore as the fracturing job is pumped or the well is produced. Shallow formations holding fresh water that may be useful for farming or public consumption are separated from the fractured shale by thousands of feet of rock.

- Hydraulic fracturing involves the injection of large amounts of water and sand and small amounts of chemical additives into low-permeability subsurface formations to enhance oil and/or natural gas recovery. The pressure of the pumped fluid creates fractures that improve flow, and propping agent maintain the fractures open so the hydrocarbons can flow from the reservoir into the wellbore.
- Most hydraulic fracturing occurs a mile or more below the water table.
- Water and proppant, which is used to keep the fissures open, make up 99.5% of the materials used to fracture a reservoir.

Source: U.S Department of Energy, Image from NETL via EIA

Canada Oil Sands

Canadian Oil Sands

- Canadian Association of Petroleum Producers (CAPP) projects total Canadian oil production to increase from 6.7 MMbbls/d in 2012 to 6.7 MMbbls/d in 2030. Of the total production in 2030, CAPP expects 5.2 MMbbls/d (~78%) to come from oil sands.

- **Oil Sands** – Oil sand is a natural mixture of sand, clay, water and bitumen, which is a heavy and extremely viscous oil. While oil sands are found in several countries, the largest is the Athabasca oil sands of northeast Alberta.

- **Bitumen Extraction** – There are two ways to extract bitumen.

    - Surface mining: Uses large mining trucks and shovels to scrape the surface of the ground and collect the oil found in the sand.

    - In-situ production: Injects steam deep into the ground. The steam heats the bitumen and forms a mixture of bitumen and water that flows to the surface similar to conventional oil. Once on the surface, the water is separated from the bitumen.

- Bitumen has a thick and viscous texture and must be treated before it can be used by refineries. Following the extraction, the bitumen will be processed into petroleum products. As Bitumen is too thick to flow, it is typically thinned with diluent, which is usually a light crude or condensate.

Source: Alberta Geological Survey and Canadian Association of Petroleum Producers

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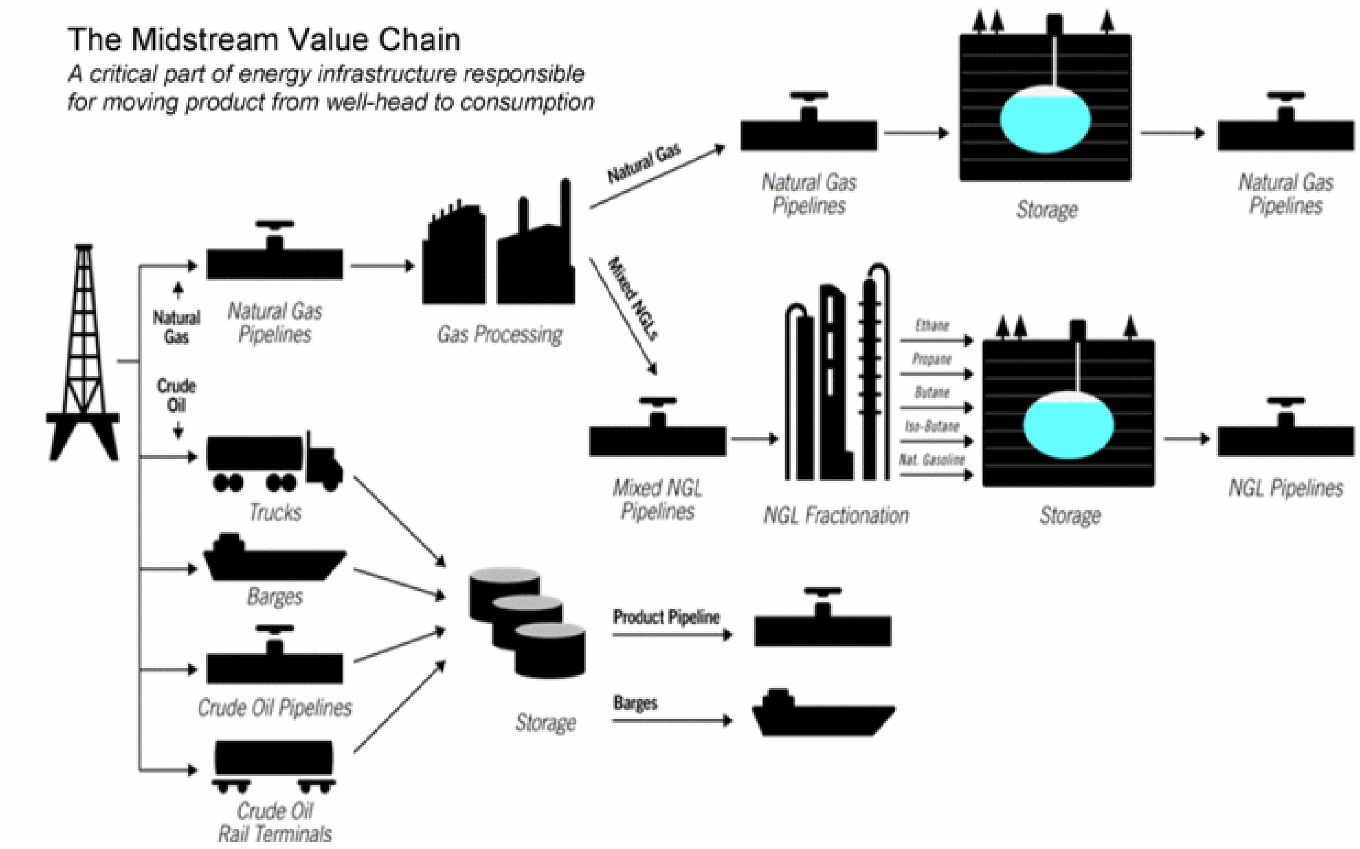
Midstream Value Chain

RBC Capital Markets

Midstream Value Chain

Midstream Value Chain



The Midstream Value Chain

A critical part of energy infrastructure responsible for moving product from well-head to consumption

Source: Crosstex Energy

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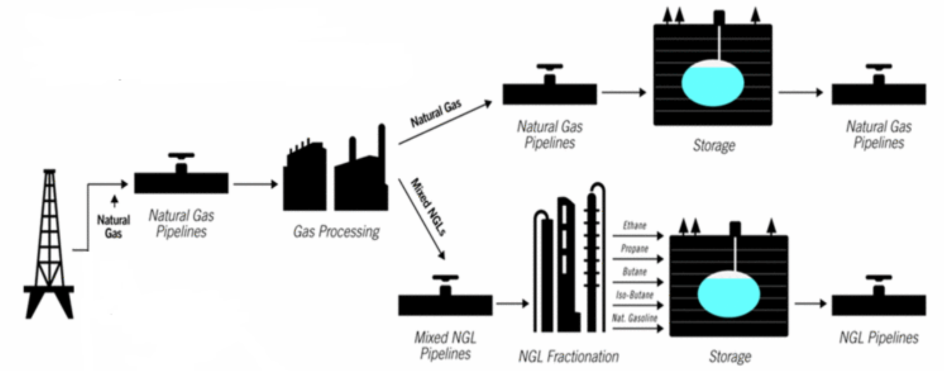
Natural Gas Value Chain

RBC Capital Markets

Natural Gas Value Chain

Natural Gas Value Chain



- **Gathering –** A network of generally small diameter pipelines that transport raw (untreated) natural gas from the wellhead to downstream pipelines or a central location for treating and processing.
- **Compression –** Increases the pressure of natural gas so that natural gas can be delivered to a higher pressure system, processing system or pipeline.
- **Treating and dehydration –** Natural gas stream that contains contaminants, such as water vapor and carbon dioxide is dehydrated to remove the saturated water. The natural gas stream is then treated to remove carbon dioxide and hydrogen sulfide.
- **Processing –** Removes the heavier natural gas liquids (NGLs) from the natural gas.
- **Fractionation –** Separates the raw NGL mix to purity products (ethane, propane, butane, iso-butane, natural gasoline/pentanes).
- **Storage, transportation and marketing** – Once the raw natural gas has been treated/processed and the NGLs have been fractionated into individual components, both natural gas and the NGL purity products are stored, transported and marketed to their respective end-use markets.

Source: Crosstex Energy and RBC Capital Markets

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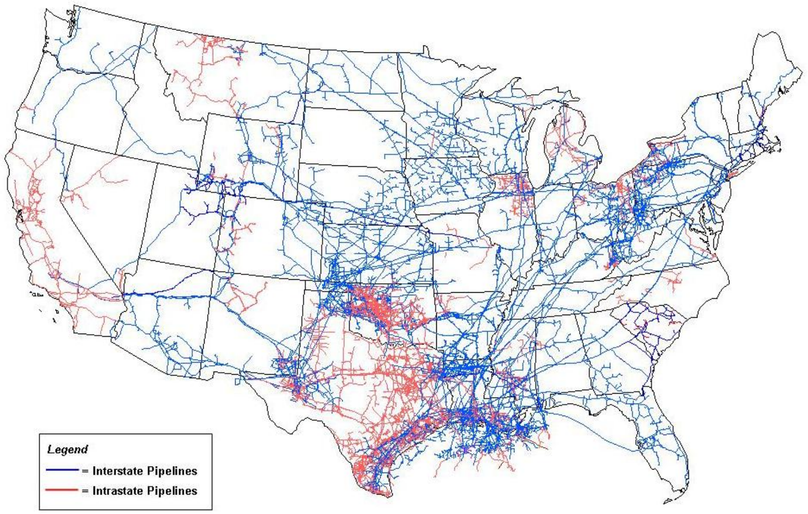
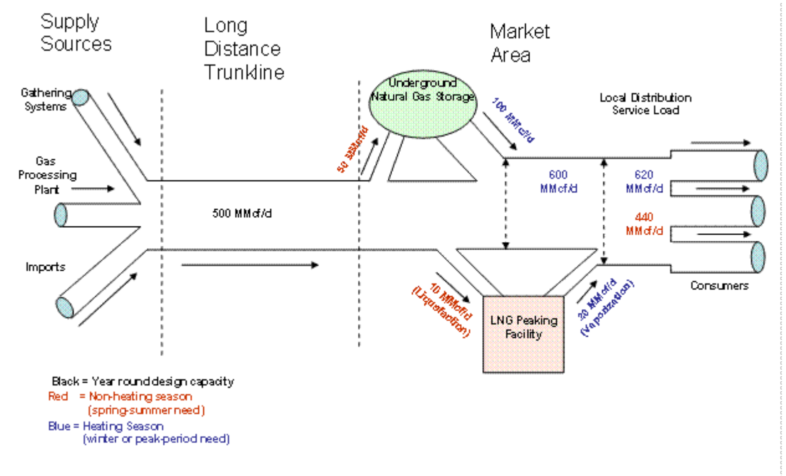
Natural Gas Transportation Network

US Natural Gas Pipeline Network



Generalized Natural Gas Pipeline Schematic



Note: MMcf/d = million cubic feet per day. Areas shown are not proportional to capacity volumes indicated. Other natural gas transmission pipelines may interconnect with and supplement the supplies of the mainline transmission or local distribution company in the market area to meet peak period demands.
Source: Energy Information Administration, Office of Oil and Gas

- As shown in the adjacent exhibit, the U.S. natural gas pipeline network is a highly complex transmission and distribution grid. The natural gas pipeline grid comprises of:
  - **Interstate –** Pipeline systems that cross one or more States. Interstate represents about 70% of all natural gas pipelines installed in the United States.
  - **Intrastate –** Natural gas pipelines that operate within state borders and link natural gas producers to local markets and to the interstate pipeline network. Of total natural gas pipeline miles, ~29% are intrastate pipelines.
- **Transportation Network Design:** The natural gas transportation network is designed to meet its firm transportation shippers' peak demand. As shown in the adjacent schematic, the network uses transmission pipelines, underground natural gas storage sites and liquefied natural gas (LNG) peaking facilities to manage demand.
- Interstate natural gas pipelines do not take title to natural gas, but rather charge a reservation fee or fee for service
- Pipeline operators typically sign shippers under long-term firm transportation contracts (guaranteed service to shippers, take-or-pay contracts that are not volume dependent). Operators can also offer interruptible service (revenues tied to volumes, not guaranteed service, typically higher rates than firm transport).

Source: EIA, Office of Oil and Gas

Natural Gas Pipeline Ratemaking

- Natural gas pipeline operators are subject to comprehensive oversight by state and federal regulatory agencies as the pipelines could have market/monopoly power. The Federal Energy Regulatory Commission (FERC) regulates Interstate pipeline and storage facility rates through the **ratemaking** process. Under the Natural Gas Act, pipeline operators must charge rates that are deemed "fair and reasonable". The steps involved in ratemaking include:
  - **Cost of Service Study** to determine costs associated with operating the pipeline.
  - Appropriate **allocation of costs** to various customer groups (industrial, residential etc.,) who are responsible for those costs.
  - **Rate Design** to determine a rate that provides operators with some level of acceptable return. The rate design could be based on demand (most common on interstate) or volume (typical) or just a flat monthly fee.

- **Rates on Interstate Natural Gas Pipelines**: FERC establishes rates based on one of the following methodologies:
  - The ***cost of service method*** detailed on the next slide.
  - The ***negotiated rate method***, which allows a pipeline operator to charge a rate that is agreed upon by the operator and shipper(s). Shippers usually have the option to choose a "recourse rate", which is based on cost of service method.
  - The ***market based method*** in which the operator has to demonstrate that it lacks market power and thus allowed to charge rates based on market conditions.

  Shippers can challenge the rates by filing a complaint with FERC.

- **Rates on Intrastate Natural Gas Pipelines**: Intrastate natural gas pipeline operators are regulated by state agencies.

Source: American Gas Association

Cost-of-service

What is Cost-of-Service?

- **Cost-of-service** is the amount of revenue a regulated gas pipeline company must collect from rates charged to consumers to recover the cost of doing business. These costs include operating and maintenance expenses, depreciation expense, taxes and a reasonable return on the pipeline's investment.

The Cost-of-Service Formula: The basic formula to calculate cost-of-service is as follows:

Rate Base x Overall Rate of Return = Return
+ Operation & Maintenance Expenses
+ Administrative & General Expenses
+ Depreciation Expense
+ Non-Income Taxes
+ Income Taxes
- Revenue Credits
= **Total Cost-of-Service**

- **Rate Base** is estimated as follows:

Gross Plant
-Accumulated Depreciation
= Net Plant
-Accumulated Deferred Income Taxes
+Working Capital
= Rate Base

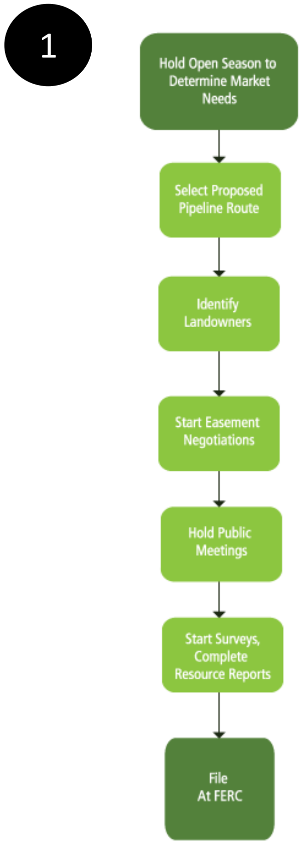
Definitions

- **Gross Plant:** The original cost of the plant, or facilities, owned by the pipeline.
- **Working Capital**: Federal Energy Regulatory Commission recognizes working capital as an additional investment by the pipeline upon which it is entitled to earn a reasonable return. This item includes cash working capital, prepayments, and materials and supplies.
- **Returns:** After tax returns allowed by FERC.
- **Operation and Maintenance Expenses (O&M)** represent the pipeline's expenses to maintain its utility plant and equipment, or the cost of running the physical pipeline system.
- **Administrative & General Expenses** include salaries and wages, office supplies, outside services, regulatory commission expenses, rents and general plant maintenance.
- **Revenue Credits**: A reduction to the cost-of-service. For example, if a pipeline has processing facilities, it could extract salable liquids from the gas stream. FERC projects the level and the price for the products and credits this amount to the cost-of-service.

Source: Federal Energy Regulatory Commission Cost-of-Service Rates Manual

Natural Gas Pipeline & Storage Permitting Processes

PROCESSES FOR NATURAL GAS CERTIFICATES
Applicant's Planning Process



1

Hold Open Season to Determine Market Needs

Select Proposed Pipeline Route

Identify Landowners

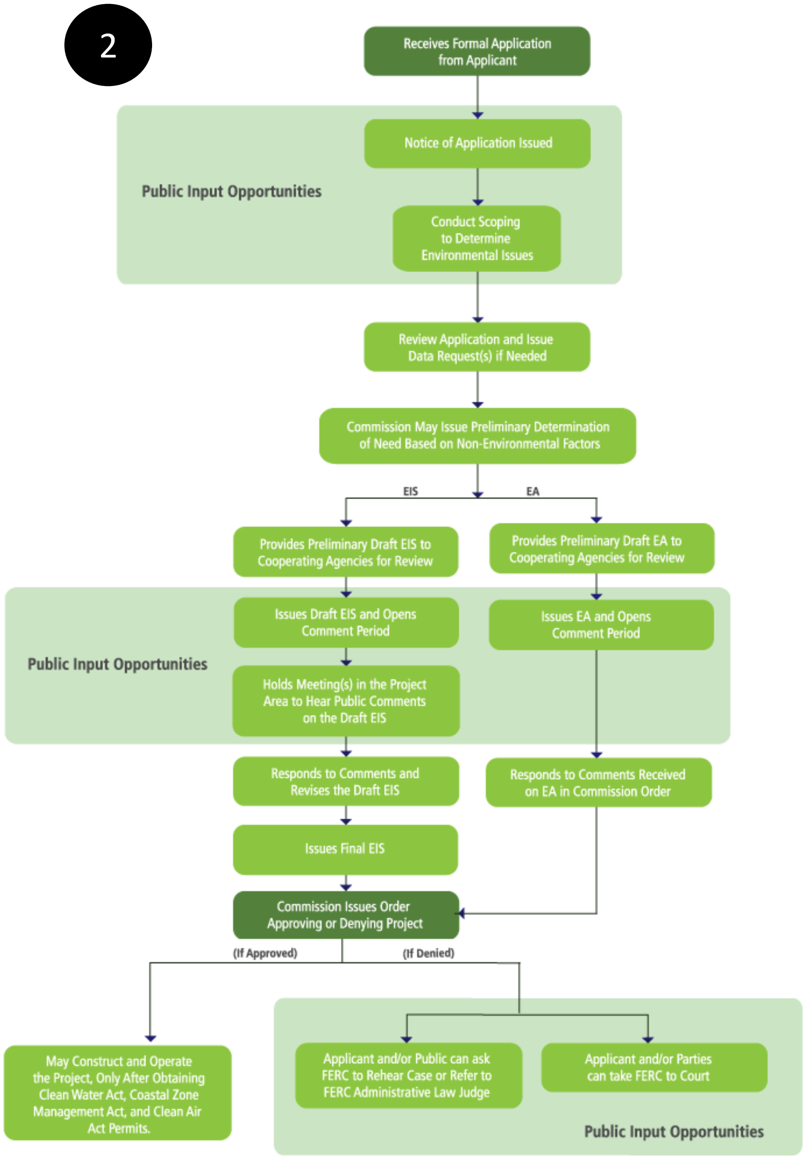
Start Easement Negotiations

Hold Public Meetings

Start Surveys, Complete Resource Reports

File At FERC

PROCESSES FOR NATURAL GAS CERTIFICATES
Application Process



2

Receives Formal Application from Applicant

Public Input Opportunities

Notice of Application Issued

Conduct Scoping to Determine Environmental Issues

Review Application and Issue Data Request(s) if Needed

Commission May Issue Preliminary Determination of Need Based on Non-Environmental Factors

EIS

EA

Provides Preliminary Draft EIS to Cooperating Agencies for Review

Provides Preliminary Draft EA to Cooperating Agencies for Review

Public Input Opportunities

Issues Draft EIS and Opens Comment Period

Issues EA and Opens Comment Period

Holds Meeting(s) in the Project Area to Hear Public Comments on the Draft EIS

Responds to Comments and Revises the Draft EIS

Responds to Comments Received on EA in Commission Order

Issues Final EIS

Commission Issues Order Approving or Denying Project

(If Approved)

(If Denied)

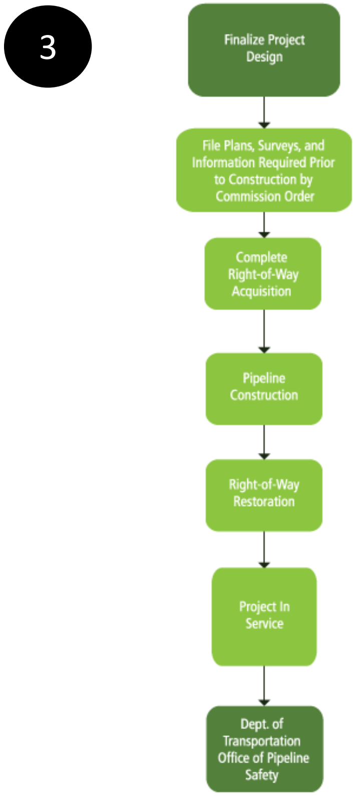
May Construct and Operate the Project, Only After Obtaining Clean Water Act, Coastal Zone Management Act, and Clean Air Act Permits.

Applicant and/or Public can ask FERC to Rehear Case or Refer to FERC Administrative Law Judge

Applicant and/or Parties can take FERC to Court

Public Input Opportunities

PROCESSES FOR NATURAL GAS CERTIFICATES
Construction Process



3

Finalize Project Design

File Plans, Surveys, and Information Required Prior to Construction by Commission Order

Complete Right-of-Way Acquisition

Pipeline Construction

Right-of-Way Restoration

Project In Service

Dept. of Transportation Office of Pipeline Safety

Source: Federal Energy Regulatory Commission

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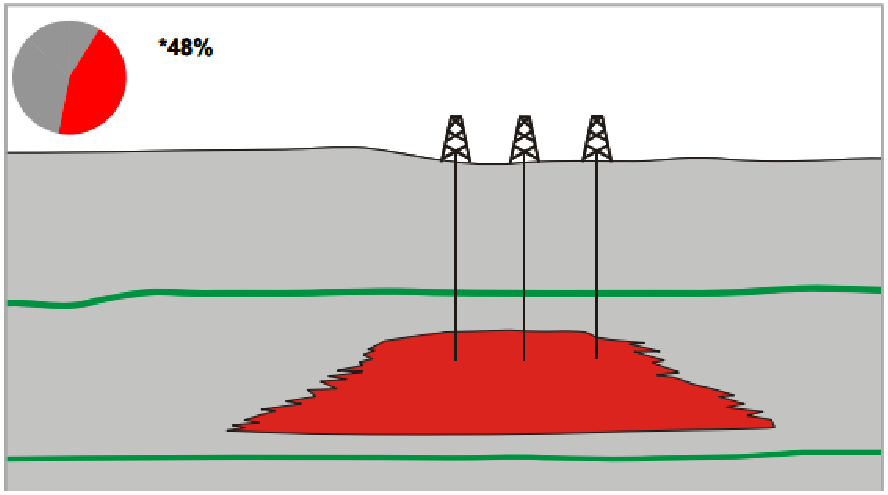
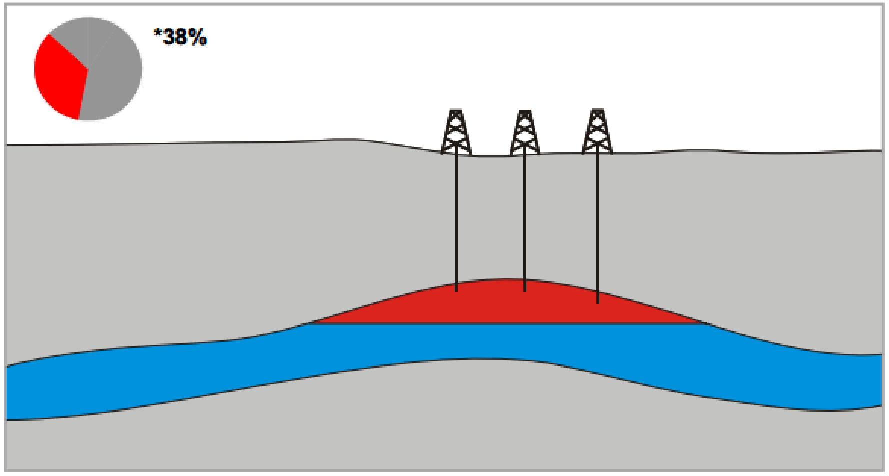
Natural Gas Storage Basics

Depleted Reservoir – Stratigraphic Trap



Depleted Reservoir – Structural Trap



* Represents proportion of gas storage facilities in the U.S (EIA)

- **Natural Gas Storage** serves to balance the divergence between the seasonal and daily variability of gas consumption and gas production, which has less daily/seasonal variability.

- **Operating Characteristics of Underground Storage Facilities**
  - ***Base Gas or Cushion Gas*** – Amount of gas required to maintain pressure of the storage facility.
  - ***Working Gas*** – Amount of gas that is available and withdrawn during the normal operations.
  - ***Deliverability Rate (Withdrawal)*** – Amount of gas that can be released from a storage facility on a daily basis.
  - ***Injection Rate*** - Amount of gas that can be injected into a storage facility on a daily basis.

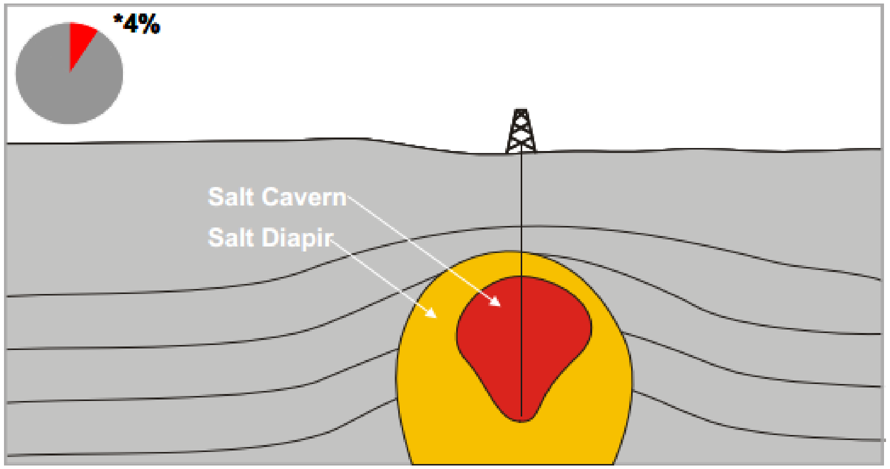
- **Three Types of Natural Gas Underground Storage Facilities** – Depleted Reservoir, Aquifer and Salt Cavern.

- **Depleted reservoirs** are naturally occurring underground formations that originally contained oil and/or natural gas. Key characteristics:
  - Account for a large percentage of storage capacity in the US as they are abundant in the high population density regions.
  - Typically require very large amounts of base gas (~50%) but high quality reservoirs require less.
  - Have the lowest deliverability and injection rates and low cycle rate facilities.

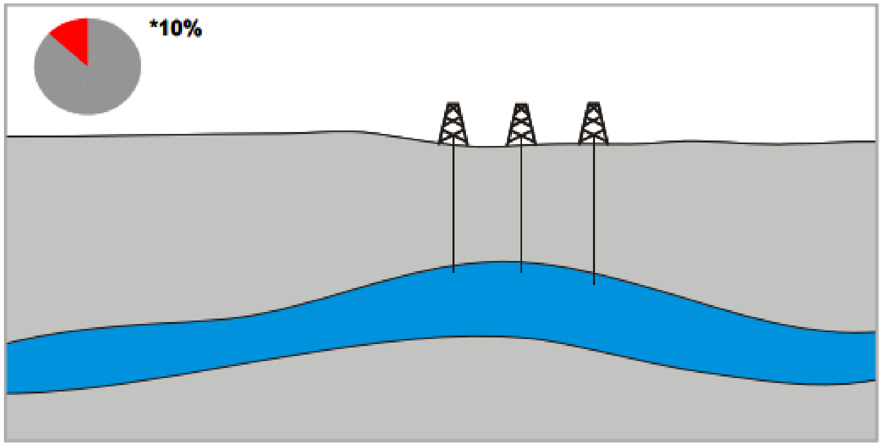
Source: EIA,Niska

Natural Gas Storage Basics

Salt Cavern – Storage Reservoir



Aquifer



- **Salt Caverns** are natural underground formations created from natural salt deposits and exist in two forms, salt domes or salt beds. Key characteristics include:
  - Very low base gas requirement (20 to 30%)
  - The highest deliverability and injection rates
  - High cycling characteristics, 12 times per year.
- **Aquifers** are underground porous, permeable rock formations that act as natural water reservoirs, which may be reconditioned and used as natural gas storage facilities. Key characteristics include:
  - Are the most expensive type of storage facility
  - Typically operated with a single winter withdrawal period
  - Extensive additional infrastructure required
  - Base gas requirement could be as high as 90%

* Represents proportion of gas storage facilities in the U.S (EIA)

Source: EIA, Niska

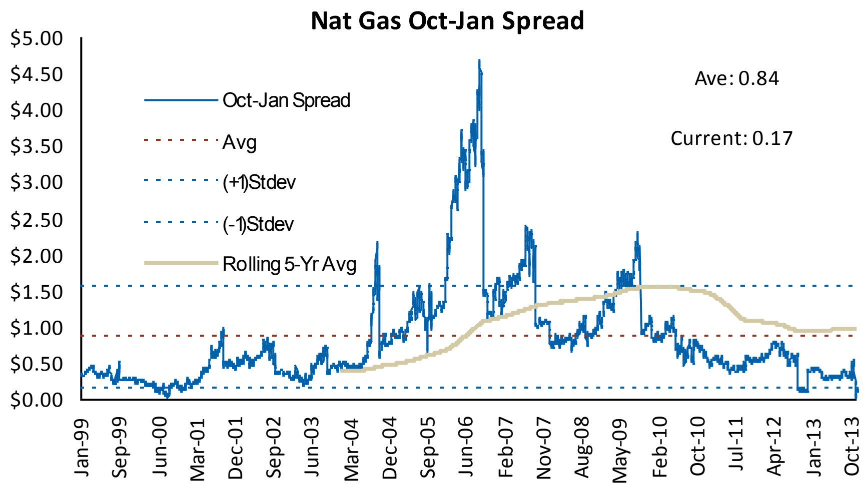
How Natural Gas Storage Operators Generate Revenue

- Natural gas storage operators generate revenues by leasing storage capacity under Long Term Firm contracts and on Short Term Firm contracts (Park and Loan Activities). Natural gas storage operators also collect variable fees associated with these contracts and could employ optimization strategies depending on market conditions.
  - **Long Term Firm (LTF)** – Customers pay a monthly reservation fee for a right to inject, store and withdraw natural gas. Storage operators also collect a variable fee on the actual volumes injected/withdrawn. While the contract provides customers the flexibility to inject or withdraw gas, it also obligates customers to remove the injected the gas at the end of the contract. The LTF contract is akin to having a call option on natural gas price spreads.
  - **Short Term Firm (STF)** – Storage operators allow customers to inject a specified quantity of gas on a particular date and withdraw it on a future date. Simultaneously, storage operators can enter into transactions to offset the STF contracts and thus capture opportunities created by volatile natural gas prices. Consider the following example:
    - Assume that the spot natural gas price in July is $3.00/MMBtu, natural gas forward in January is $3.75/MMBtu and natural gas forward in February is $4.00/MMBtu. Also assume that the storage cost for 6 months is $0.25/MMBtu and financing cost is $0.10/MMBtu.
    - A customer enters into an STF contact with a storage operator to inject 1 contract (10,000 MMBtu) of natural gas in July and withdraw in January. This means the customer sold at higher forward price of $3.75/MMBtu and bought at spot price of $3.00/MMBtu and expects to make a profit of $4,000 after storage and financing costs.
      => (($3.75-$3.00-$0.25 -$0.10)*10,000) = $4,000.
    - Since the February futures price of $4.00 greater than January price, storage operators can enter into an offsetting contract, to inject in January and withdraw in February for a fee based on the January to February spread. The result in January would be that the second transaction offsets the first transaction resulting in no net flow obligation during January, and therefore, a fuel savings to the operator.
  - **Optimization Opportunities –** Storage operators can use underutilized storage capacity (both contracted and not contracted) to purchase and sell natural gas for their own accounts. By employing proprietary optimization strategies, storage operators can take advantage of spot and intraday opportunities that arise out of price fluctuations.

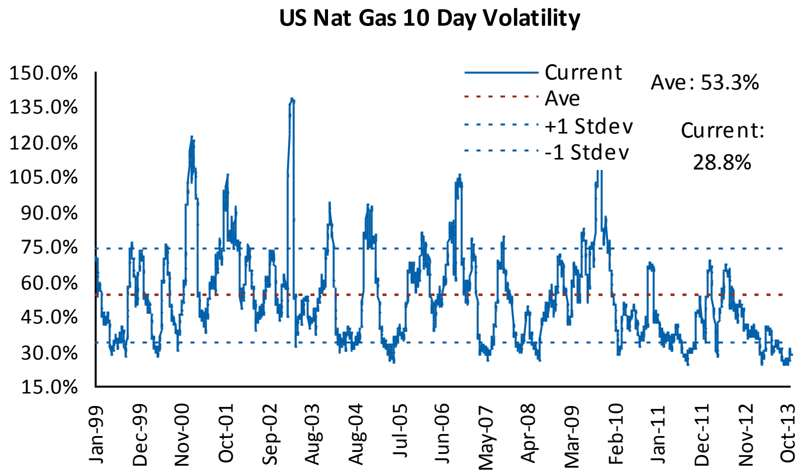
Source: CME Group

Natural Gas Storage – Market Drivers

Natural Gas Seasonal Spreads



Natural Gas Price Volatility



- **Natural Gas Prices**– Higher natural gas prices equate to higher value for the inventory in the storage and in a volatile natural gas price environment, greater changes in absolute prices. Further, higher prices increase storage value as natural gas storage helps mitigate the impact from price fluctuations.

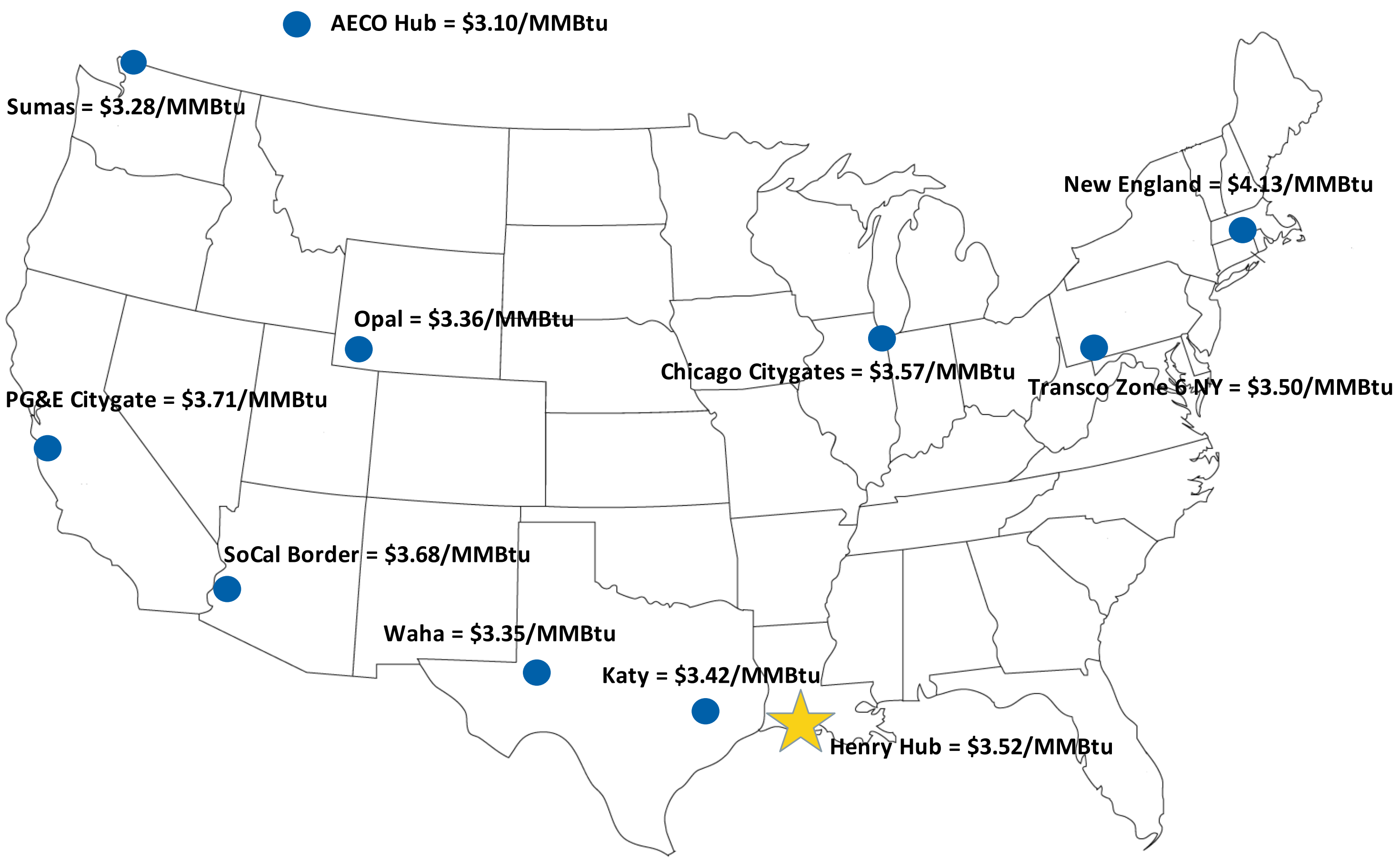
- **Natural Gas Basis Differentials** – Storage operators tend to benefit when basis (geographic) differentials widen. For example, if the storage operator has access to multiple interconnecting pipelines with imperfect prices, the storage operator can inject gas from low cost pipeline to storage and then withdraw and sell it to high cost pipeline (natural gas is fungible).

- **Seasonal Spreads –** Wide summer/winter spreads increase the intrinsic value of storage as customers are more likely to store natural gas in the summer and sell it in the winter.

- **Natural Gas Price Volatility –** Natural gas price volatility increases the extrinsic value of storage because it provides opportunities to optimize storage.

Source: Bloomberg, RBC Capital Markets

Natural Gas Prices In North America



Source: Bloomberg, RBC Capital Markets

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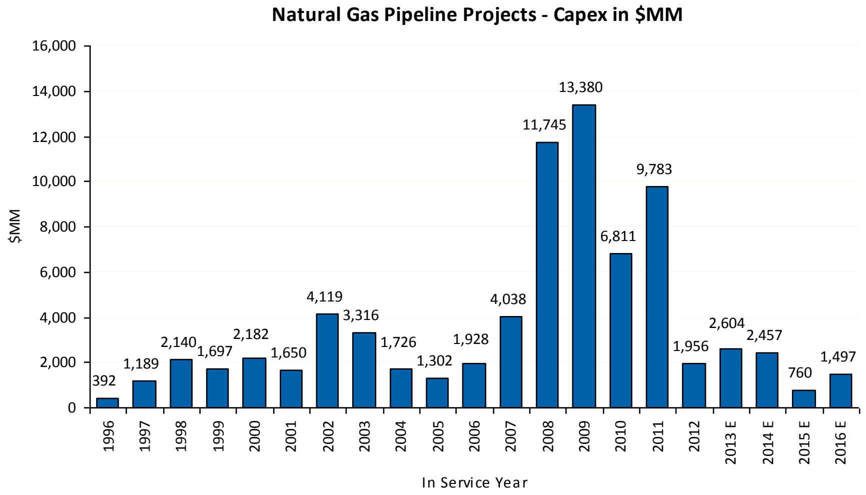
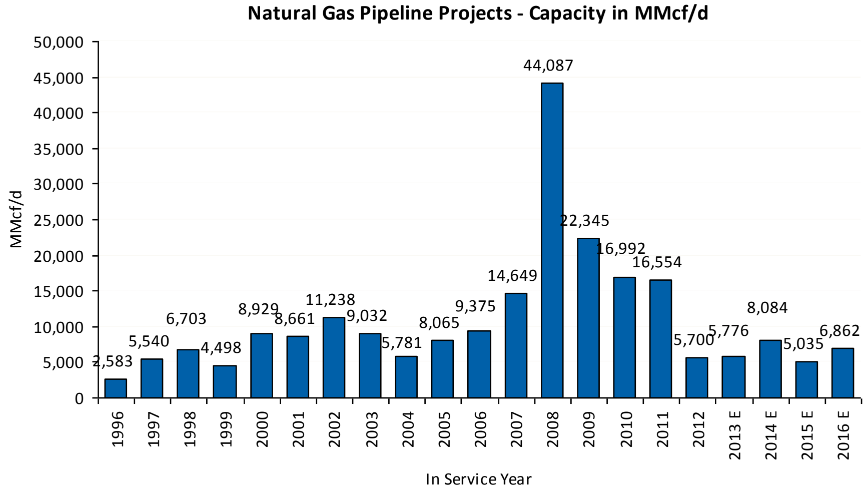
Natural Gas Pipeline Near-term View Cautious

US Natural Gas Pipeline Projects – Capex in $MM



US Natural Gas Pipeline Projects in MMcf/d



Near-term View

- Nearly $46B of natural gas pipeline expansion capital (+110Bcf/d of capacity) from 2007-2011 narrowed basis differentials.
- Emerging shale plays (i.e., Marcellus), have altered regional supply/demand dynamics.
- Gas on gas competition, flattened basis across the U.S. and changing gas flows has led to discounting on contract renewals depending on the direction of flow.
- Re-contracting risks and reduced utilization rates in some areas likely to persist in the near term to medium term.

Source: EIA, RBC Capital Markets

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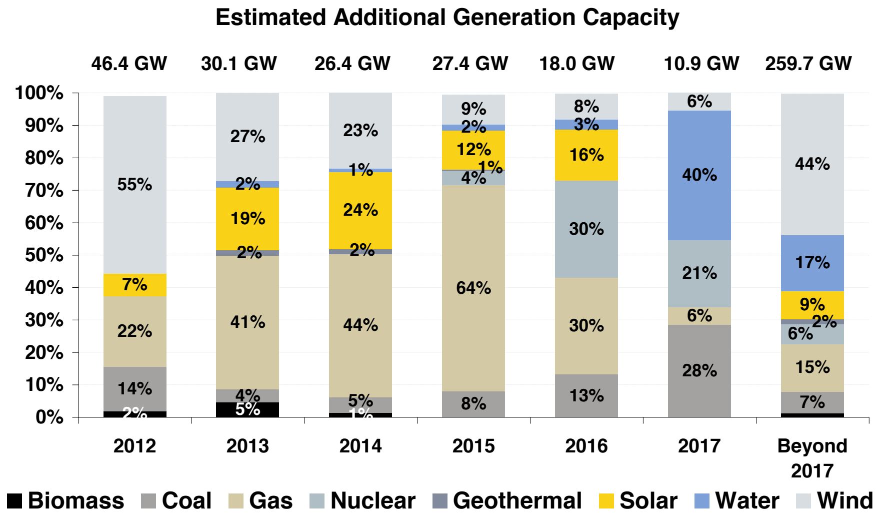
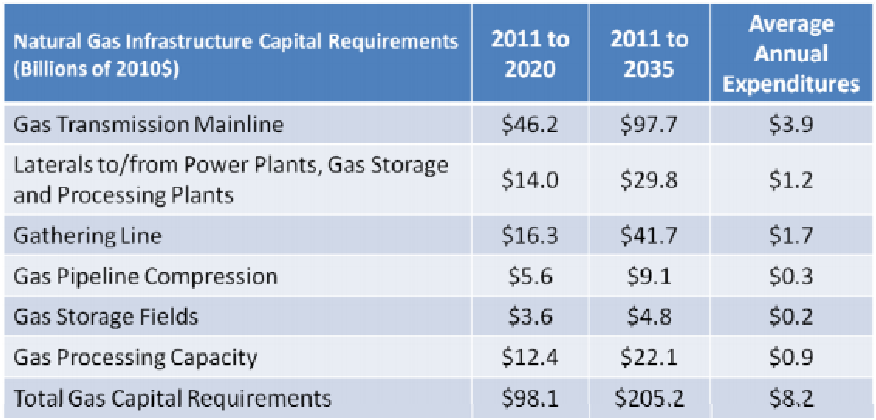
Natural Gas Pipeline – Fundamentals More Favorable Long Term

US Power Generation Capacity



US Natural Gas Infrastructure Capital Estimates



Natural Gas Infrastructure Capital Requirements (Billions of 2010$)	2011 to 2020	2011 to 2035	Average Annual Expenditures
Gas Transmission Mainline	$46.2	$97.7	$3.9
Laterals to/from Power Plants, Gas Storage and Processing Plants	$14.0	$29.8	$1.2
Gathering Line	$16.3	$41.7	$1.7
Gas Pipeline Compression	$5.6	$9.1	$0.3
Gas Storage Fields	$3.6	$4.8	$0.2
Gas Processing Capacity	$12.4	$22.1	$0.9
Total Gas Capital Requirements	$98.1	$205.2	$8.2

- **Long-term view - Fundamentals more favorable**:
  - 95GW of potential gas fired power generation additions (from 2012-2017+) could drive incremental natural gas demand of ~8Bcf/d
  - Increase in industrial demand (can add ~3Bcf/d of natural gas demand)
  - Potential LNG exports (licenses for 32Bcf/d of non-FTA export capacity filed, 6.6Bcf/d approved and we believe less than a third likely move forward given the expense).

- Increasing natural gas demand should drive the need for greater utilization of natural gas pipeline and storage capacity and potentially capacity additions.

Source: INGAA, EIA, RBC Utilities Team, RBC Capital Markets Estimates

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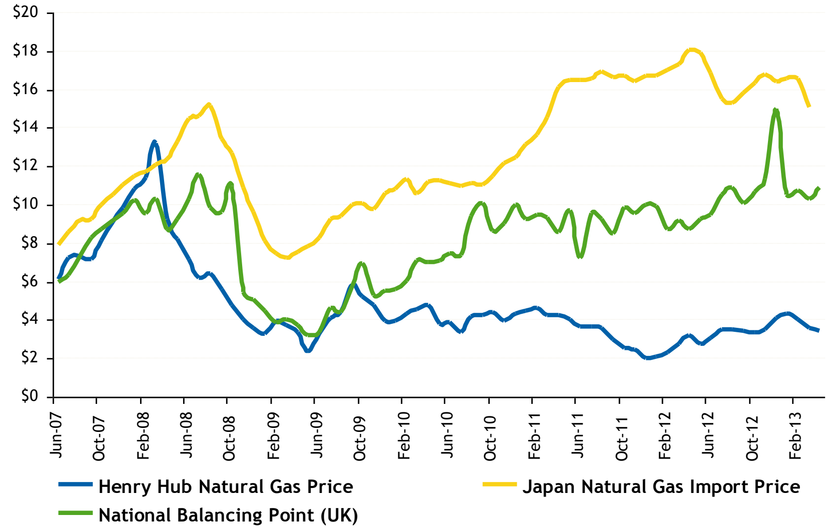
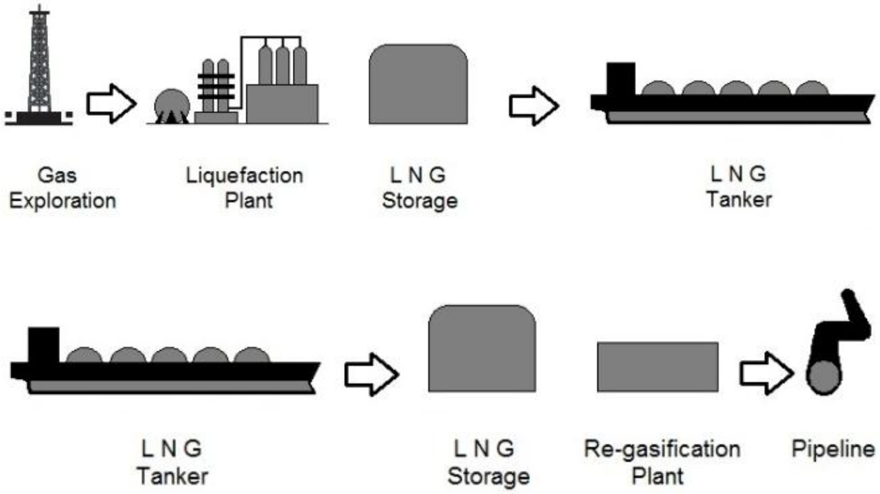
An Introduction to Liquefied Natural Gas (LNG)

Global Natural Gas Prices



LNG Export/Import Schematic



- Given the shale-driven increase in natural gas production in the US, the Henry Hub natural gas price has hovered at or below $4/MMBtu for the past several years. Meanwhile, natural gas prices in many parts of the world have trended substantially higher.

- LNG is natural gas that is cooled to -260° Fahrenheit until it converts to liquid. Converting natural gas to LNG, a process that reduces natural gas volume by about 600 times, allows it to be transported internationally via cargo ships. Once delivered to its destination, the LNG is warmed back into its original gaseous state.

- **Import terminal** – Facility that has the regasification capability, the process of warming (LNG) until natural gas returns to its gaseous state.

- **Export terminal** – Facility that has the capability to liquefy and store natural gas so it can be loaded on to ships and exported. In order to export, a facility in the US requires approval from the US Department of Energy to export to Free Trade Agreement (FTA) nations (typically granted immediately) and /or non-FTA nations (typically a longer approval process). The facility must also receive Federal Energy Regulatory Commission approval.

Source: Bloomberg, LNG Facts, Intech

LNG Project Models

Sample LNG Tolling Arrangement

Purchaser	LNG Purchased	Fixed Fee Component	Percent of Fixed Fee Subject To Inflation	Variable Fee - Based on Volumes
Contract 1	286.5 bcf/year (5.5 Mtpa)	$2.25/MMBtu	15.0%	5% of NYMEX Henry Hub
Contract 2	182.5 bcf/year (3.5 Mtpa)	$2.49/MMBtu	13.6%	
Contract 3	182.5 bcf/year (3.5 Mtpa)	$3.00/MMBtu	15.0%	

- There are three types of LNG project models depending on the underlying economics of the project and the risk appetite of the company pursuing the project.

- **Tolling Model:** In a tolling model, similar to natural gas pipelines, the liquefaction facility does not assume any commodity price risk and does not own the natural gas reserves. Instead, the facility will receive a take-or-pay tolling fee to provide liquefaction services. A sample tolling arrangement is shown in the adjacent exhibit. A tolling arrangement could include inflation escalators and a variable fee component for sourcing natural gas for the customers.

- **Integrated Model:** Under the integrated model, the LNG facility or the project is owned by an entity (or entities) that also owns natural gas reserves. In this model, since the economic interest of the entire value chain is aligned, the LNG project is typically well positioned to take advantage of the market opportunities. The producer can control production and obtain cost savings as a result of an integrated operation.

- **Merchant Model:** In this model, an entity (or entities) owns the LNG facility, but usually does not own any natural gas reserves and has to rely on third party suppliers for natural gas. The owner of the LNG facility assumes the commodity price risk as it purchases natural gas, processes it into LNG and then sells LNG to buyers.

Source: RBC Capital Markets, Baker Botts LLP

LNG Export Facility Projects In the US

LNG Export Projects

Company	**Quantity (Bcf/d)**	**FTA Applications**	**Non-FTA Applications**
Sabine Pass Liquefaction, LLC	2.20	Approved	Approved
Freeport LNG Expansion, L.P. and FLNG Liquefac	1.40	Approved	Approved
Lake Charles Exports, LLC	2.00	Approved	Approved
Carib Energy (USA) LLC	0.03 : FTA /0.01 : non-FTA	Approved	Under DOE Review
Dominion Cove Point LNG, LP	1.00	Approved	Approved
Jordan Cove Energy Project, L.P.	1.2 : FTA / 0.8 : non-FTA	Approved	Under DOE Review
Cameron LNG, LLC	1.70	Approved	Under DOE Review
Freeport LNG Expansion, L.P. and FLNG Liquefac	1.40	Approved	Under DOE Review
Gulf Coast LNG Export, LLC	2.80	Approved	Under DOE Review
Gulf LNG Liquefaction Company, LLC	1.50	Approved	Under DOE Review
LNG Development Company, LLC (d/b/a Oregon	1.25	Approved	Under DOE Review
SB Power Solutions Inc.	0.07	Approved	n/a
Southern LNG Company, L.L.C.	0.50	Approved	Under DOE Review
Excelerate Liquefaction Solutions I, LLC	1.38	Approved	Under DOE Review
Golden Pass Products LLC	2.60	Approved	Under DOE Review
Cheniere Marketing, LLC	2.10	Approved	Under DOE Review
Main Pass Energy Hub, LLC	3.22	Approved	n/a
CE FLNG, LLC	1.07	Approved	Under DOE Review
Waller LNG Services, LLC	0.16	Approved	n/a
Pangea LNG (North America) Holdings, LLC	1.09	Approved	Under DOE Review
Magnolia LNG, LLC	0.54	Approved	n/a
Trunkline LNG Export, LLC	2.00	Approved	n/a
Gasfin Development USA, LLC	0.20	Approved	n/a
Freeport-McMoran Energy LLC	3.22	Approved	Under DOE Review
Sabine Pass Liquefaction, LLC	0.28	Approved	Under DOE Review
Sabine Pass Liquefaction, LLC	0.24	Approved	Under DOE Review
Venture Global LNG, LLC	0.67	Pending Approval	Under DOE Review
Advanced Energy Solutions, L.L.C.	0.02	Pending Approval	n/a
Argent Marine Management, Inc.	0.00	Pending Approval	n/a
Eos LNG LLC	1.60	Pending Approval	Under DOE Review
Barca LNG LLC	1.60	Pending Approval	Under DOE Review
Total of all Applications Received		**33.82 Bcf/d**	**32.41 Bcf/d**

Nearly 6.6 bcf/d of Non-FTA export applications have been approved As of Nov 4, 2013.

Source: Department of Energy

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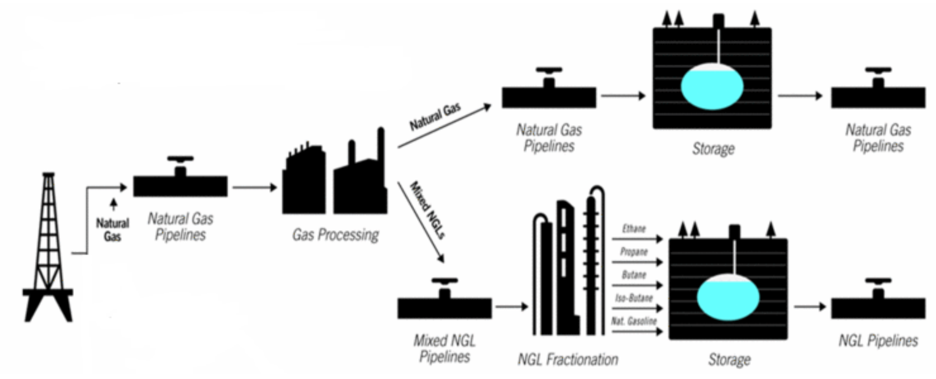
Natural Gas Liquids Value Chain

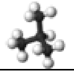
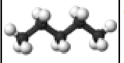
RBC Capital Markets

Introduction to Natural Gas Liquids

NGL Value Chain



NGL Attributes

Natural Gas Liquid	Chemical Formula	Applications	End Use Products	Primary Sectors
Ethane	C_2H_6 	Ethylene for plastics production; petrochemical feedstock	Plastic bags; plastics; anti-freeze; detergent	Industrial
Propane	C_3H_8 	Residential and commercial heating; cooking fuel; petrochemical feedstock	Home heating; small stoves and barbeques; LPG	Industrial, Residential, Commercial
Butane	C_4H_{10} 	Petrochemical feedstock; blending with propane or gasoline	Synthetic rubber for tires; LPG; lighter fuel	Industrial, Transportation
Isobutane	C_4H_{10} 	Refinery feedstock; petrochemical feedstock	Alkylate for gasoline; aerosols; refrigerant	Industrial
Pentane	C_5H_{12} 	Natural gasoline; blowing agent for polystyrene foam	Gasoline; polystyrene; solvent	Transportation
Pentanes Plus*	Mix of C_5H_{12} and heavier	Blending with vehicle fuel; exported for bitumen production in oil sands	Gasoline; ethanol blends; oil sands production	Transportation

- **What are NGLs?** Natural gas liquids (NGLs) are hydrocarbons composed exclusively of carbon and hydrogen. NGLs can be found in liquids rich natural gas plays or oil plays (with liquids rich associated gas). NGLs represent a mixed stream of products including ethane, propane, butane, isobutane, and natural gasoline (pentanes).
- NGLs have a variety of end markets, but are primarily used as inputs for petrochemical plants. Despite recent weakness in some NGL purity products (especially ethane), producers still receive an attractive price uplift and remain incented to drill in liquids rich plays.
- Natural gas processing facilities removes the heavier NGLs from the natural gas stream.
- **Fractionation –** The separation of raw NGLs into purity products (ethane, propane, butane, iso-butane and natural gasoline) for end-use sale.
- **Storage, transportation and marketing** – Once the raw NGLs have been fractionated into individual components, they are stored, transported and marketed to their respective end-use markets. NGL transportation and storage operators typically generate fee based cash flows under take or pay contracts or volumetric based contracts.

Source: CrossTex, EIA

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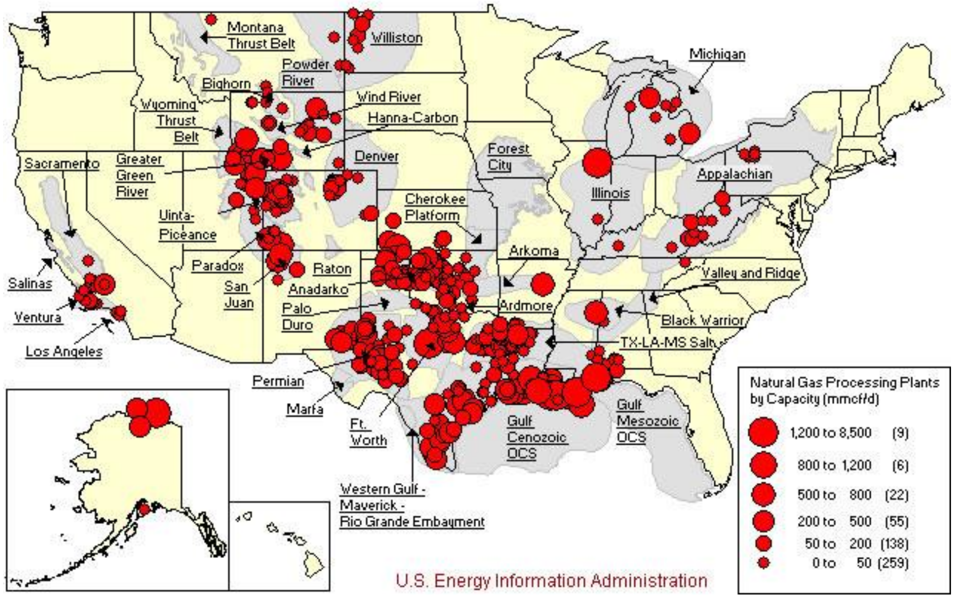
Revenues Generated By Gathering, Fractionation and Processing

US Processing Capacity

US Total Processing Capacity in MMcf/d

EIA Region	2012	2013 E	2014 E	2015 E	Total	Breakdown %
California	200	0	0	0	200	1%
Rockies	285	160	950	200	1,595	11%
Northern Tier	100	425	100	0	625	4%
Texas Inland	1,460	1,745	875	100	4,180	29%
Texas Gulf Coast	450	550	400	0	1,400	10%
Mid-Continent	260	950	200	0	1,410	10%
SE New Mexico	0	250	100	0	350	2%
Marcellus/Utica	1,060	3,195	400	0	4,655	32%
Total	**3,815**	**7,275**	**3,025**	**300**	**14,415**	**100%**

US Natural Gas Processing Plants



- Gathering is generally a volumetric fee based businesses with no direct commodity price exposure. However, low commodity prices impact volumes and thus indirectly impact gathering revenues.

- Processors typically generate revenues under the following main contracts structures:
  - **Fee-based contracts –** The processor receives a fixed fee based on the volumes of gas processed. Fee based contracts have no direct commodity price exposure but demand for processing can decline when natural gas prices are low (drilling/production declines).
  - **Percent of proceeds (POP)** – Typically the processor sells the natural gas and NGLs and retains an agreed upon percentage of the proceeds. POP contracts generally align producer and processor interests as both the producer and processor are long both natural gas and NGLs and benefit when natural gas and NGL prices increase.
  - **Keep-Whole Contracts –** The processor takes title to the NGLs and returns an equivalent heat content amount of natural gas to the producer. Processors are long NGLs and short natural gas and benefit when NGL prices increase and natural gas prices decline.

Source: EIA

US Rich Shale Plays

US Shale Plays

Rich Plays	NGL (GPM) Content*
Avalon/Bone Springs**	4.0 to 5.0
Bakken**	4.0 to 10.0
Barnett	2.5 to 6.0
Cana-Woodford	4.0 to 6.0
Eagle Ford***	4.0 to 9.0
Granite Wash	4.0 to 6.0
Green River**	3.0 to 5.0
Niobrara**	4.0 to 9.0
Piceance-Uinta	2.5 to 3.5
Green River	2.5 to 3.5
Marcellus (Rich)	4.0 to 9.0
Utica***	4.0 to 9.0

* gpm – gallons of NGLs per 1000 cu. ft.

** Oil Shale Plays

*** Both an Oil and Gas Shale Play

Source: EIA

NGL Price Uplift – Why Drill For Natural Gas in a Low Natural Gas Price Environment?

NGL Price Uplift Example

	Dry Gas	2.0 GPM	3.0 GPM	4.0 GPM	5.0 GPM	6.0 GPM	7.0 GPM	8.0 GPM	9.0 GPM
Recovered Components									
Ethane		$0.24	$0.36	$0.48	$0.60	$0.72	$0.84	$0.96	$1.08
Propane		$0.71	$1.06	$1.42	$1.77	$2.13	$2.48	$2.84	$3.19
Iso-Butane		$0.29	$0.44	$0.58	$0.73	$0.87	$1.02	$1.16	$1.31
n-Butane		$0.14	$0.21	$0.29	$0.36	$0.43	$0.50	$0.57	$0.64
Natural Gasoline		$0.20	$0.31	$0.41	$0.51	$0.61	$0.71	$0.82	$0.92
Residue Gas	$3.54	$2.94	$2.65	$2.35	$2.05	$1.75	$1.45	$1.16	$0.86
T&F ($0.25/gal)	**$0.00**	**$0.50**	**$0.75**	**$1.00**	**$1.25**	**$1.50**	**$1.75**	**$2.00**	**$2.25**
Total Stream Value	**$3.54**	**$4.03**	**$4.28**	**$4.52**	**$4.77**	**$5.01**	**$5.26**	**$5.50**	**$5.75**
Net NGL Price Uplift	**$0.00**	**$0.49**	**$0.74**	**$0.98**	**$1.23**	**$1.47**	**$1.72**	**$1.96**	**$2.21**

Assumptions

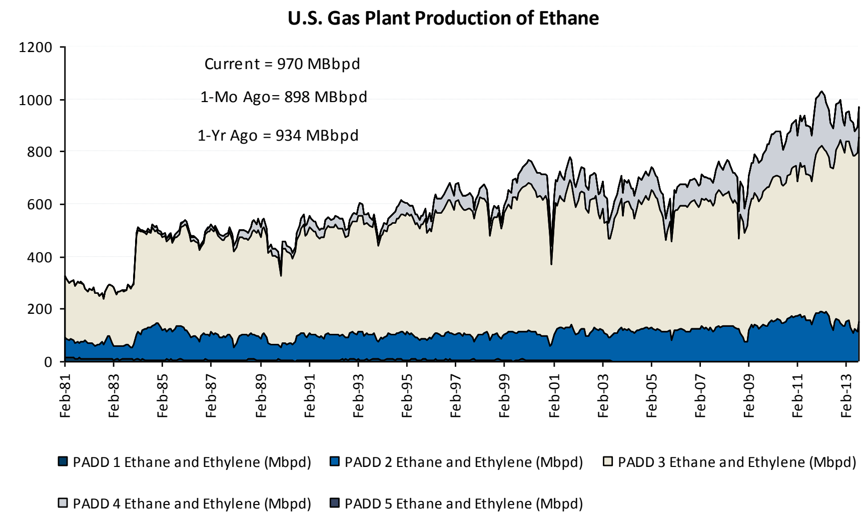
- We do not assume any ethane rejection or propane loss.
- Our assumed barrel composition is Ethane – 50%, Propane – 30%, Iso Butane – 10%, Normal Butane – 5% and Natural Gasoline – 5%.
- The MMBtu/Barrel conversion rates used are Ethane – 3.082, Propane – 3.836, Iso Butane – 3.974, Normal Butane – 4.326 and Natural Gasoline – 4.620 based on EIA data.
- Our Transportation and Fractionation (T&F) assumption is $0.25 per gallon.

- NGLs in the natural gas stream can be more valuable than natural gas on an MMBtu basis. Higher NGL prices provide incentive to drill in liquids-rich gas plays given the price uplift as illustrated by the following example:
- Commodity Prices
  - Natural Gas is $3.54 MMBtu
  - Ethane is $3.27 MMBtu ($0.24/gallon)
  - Propane is $12.93 MMBtu ($1.1813/gallon)
  - Iso Butane $15.38 MMBtu ($1.4550/gallon)
  - Normal Butane $13.85 MMBtu ($1.4263/gallon)
  - Natural Gasoline $18.56 MMBtu ($2.0413/gallon)
- Based on the aforementioned commodity prices, a rich gas stream with an NGL content of 5 GPM (gallons per Mcf) can provide producers with a $1.23/MMBtu (+35%) uplift for a total stream value of $4.77/MMBtu (vs $3.54/MMBtu for natural gas).
  - Natural Gas - $2.05
  - Ethane 50% - $0.60
  - Propane 30% - $1.77
  - Iso Butane 10% - $0.73
  - Normal 5% - $0.36
  - Natural Gasoline 5% $0.51
  - **Total value $4.77 (after subtracting $0.25/gal of T&F)**

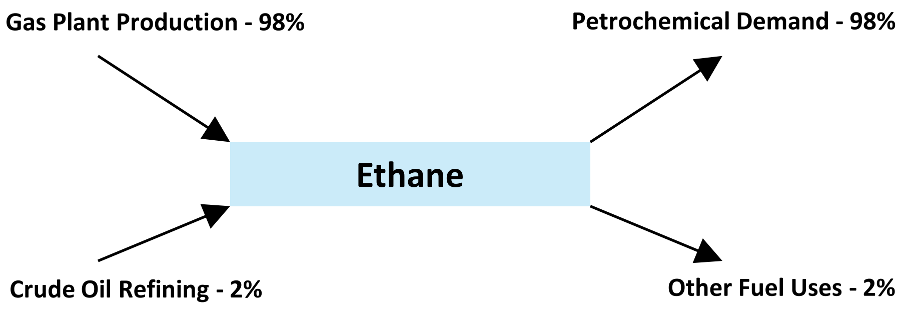
Source: RBC, EnVantage, EIA

Ethane

US Gas Plant Production of Ethane



Ethane - Supply and Demand



Gas Plant Production - 98%

Crude Oil Refining - 2%

Ethane

Petrochemical Demand - 98%

Other Fuel Uses - 2%

- Ethane is normally a gaseous, straight-chain hydrocarbon. It is colorless gas and boils at -127.48º F. Ethane is a largely extracted from the raw natural gas stream, but is also a by product of crude oil refining. Its primary use is as a petrochemical feedstock for ethylene production. Its chemical formula is C_2H_6.

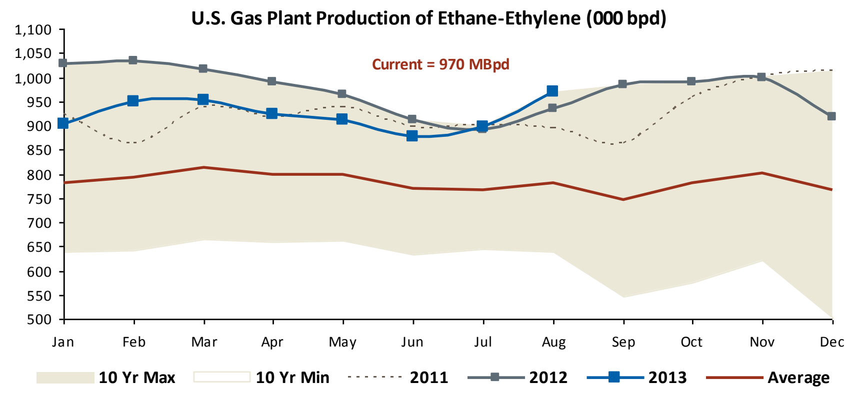
- Nearly 970 Mbpd of ethane is extracted from the US gas plants (excluding 220 Mbpd of ethane rejection), while ~40 Mbpd is supplied from the refinery gas streams. Of the ~970 Mbpd supplied by the gas plants, nearly 75% is supplied by gas plants in PADD 3.

- Some of the key drivers of ethane fundamentals include
  - **Natural Gas-to-Crude Oil Ratio**: Ethane processing margins and Ethane feedstock economics are inversely related to the ratio.
  - High crude oil prices support ethane prices.
  - Gross price spreads between ethylene feedstocks and the demand from petchem facilities.

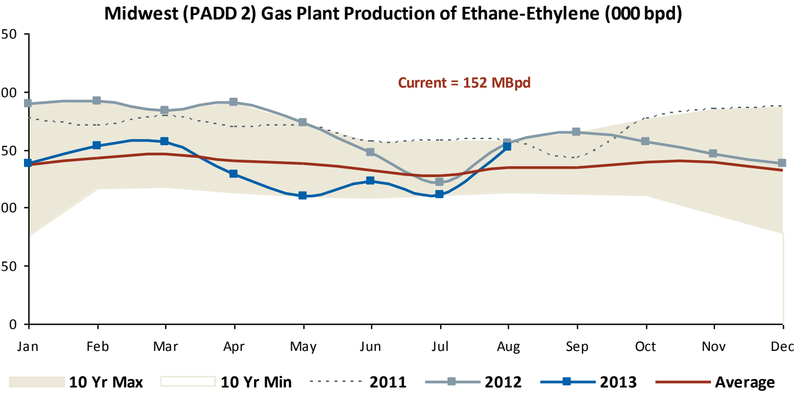
Source: EIA, RBC Capital Markets

Ethane Production Data

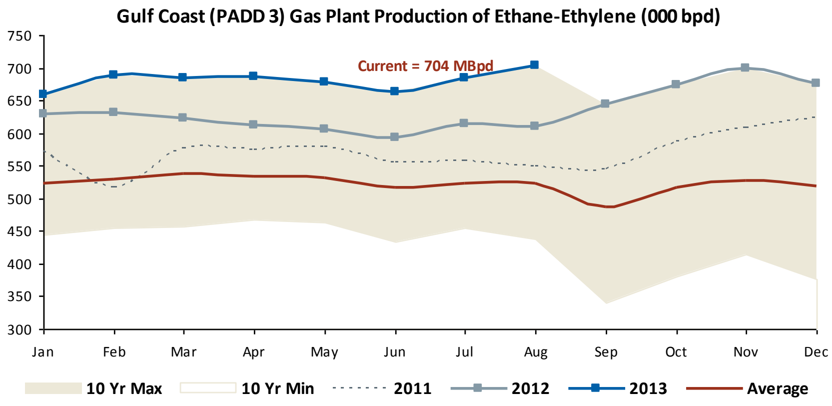
US Gas Plant Production of Ethane-Ethylene



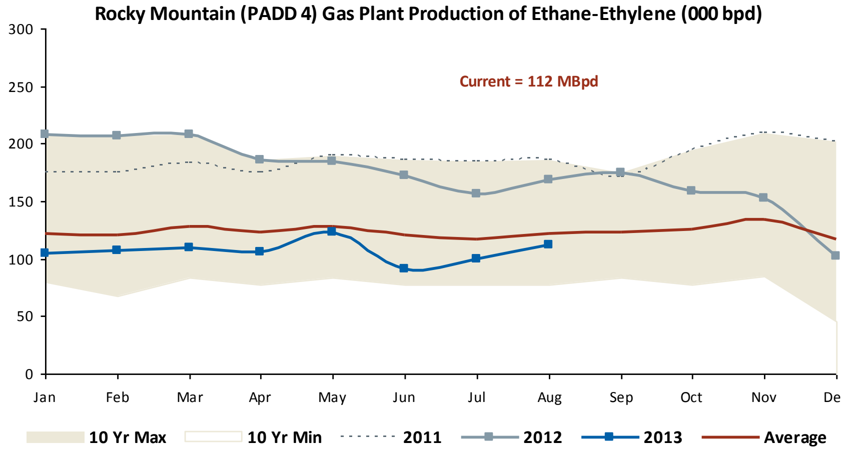
PADD2 Gas Plant Production of Ethane-Ethylene



PADD3 Gas Plant Production of Ethane-Ethylene



PADD4 Gas Plant Production of Ethane-Ethylene



Source: EIA, RBC Capital Markets

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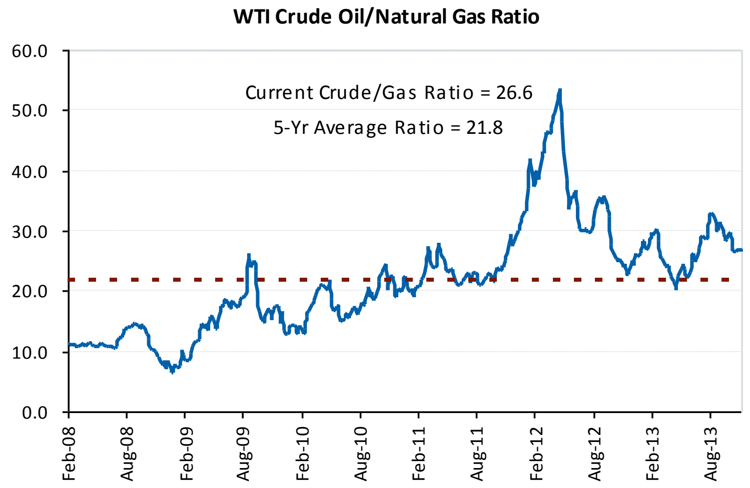
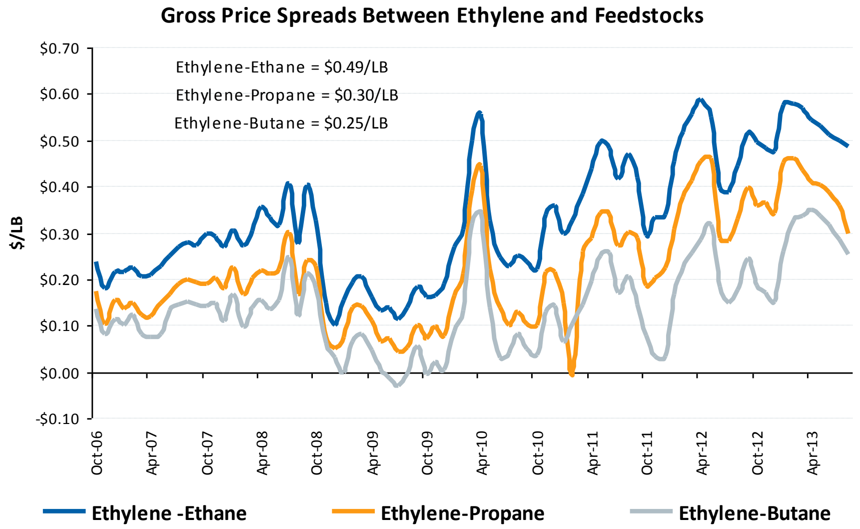
Ethane – Key Drivers

Crude Oil to Natural Gas Ratio



Price Spreads Between Ethylene and Feedstocks



- The gas-to-crude oil ratio plays an important role in driving ethane fractionation spreads (explained later) and in driving ethane demand. Ethane cracking is very sensitive to the gas-to-crude ratio.

- Low gas-to-crude price ratios (high crude-to-gas) and high crude prices provide a healthy BTU price spread between crude oil and natural gas to enable the processing of rich gas plays.

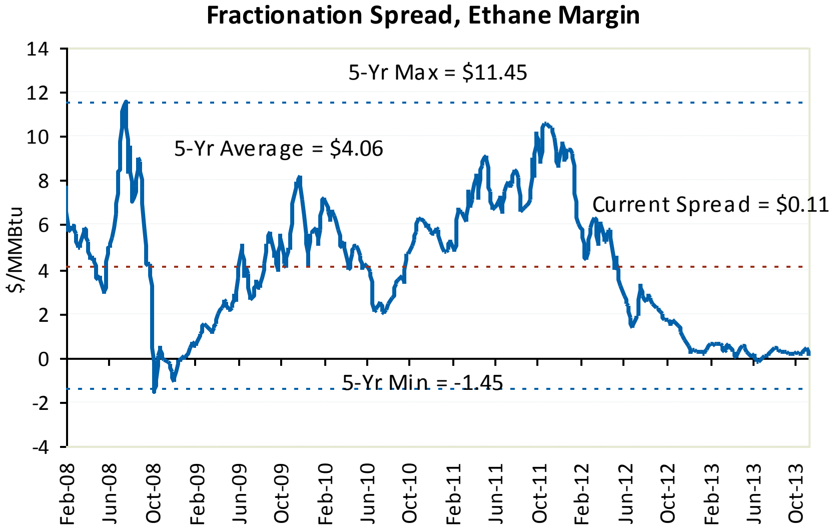
- Petrochemical plants use a steam cracker to turn naphtha and light hydrocarbons into ethylene, propylene, and materials used for chemical applications. These products are then transported to chemical and polymer facilities and converted into olefin-based products.

- Currently, the gross price spread between ethylene and ethane is greater than the gross prices spreads between ethylene and other feedstocks. Petrochemical plants prefer cheaper feedstock and as a result favor ethane over other feedstocks based on the higher spreads, as illustrated in the adjacent chart.

Source: Bloomberg, RBC Capital Markets

Ethane – Fractionation Spread

Fractionation Spread, Ethane Margin



- Ethane = $0.24/gallon
- Natural gas = $3.54/MMBtu
- NGL barrel consists of 50% ethane
- MMBtu/gallon of ethane is 0.0734
- Shrink Factor = $3.54*0.0734 = $0.26/gallon
- Estimated price per barrel of ethane $0.24*42 = $10.08/Bbl
- Deduct shrink per barrel to obtain the margin per barrel = $10.08-($0.26*42)= -$0.83/Bbl.

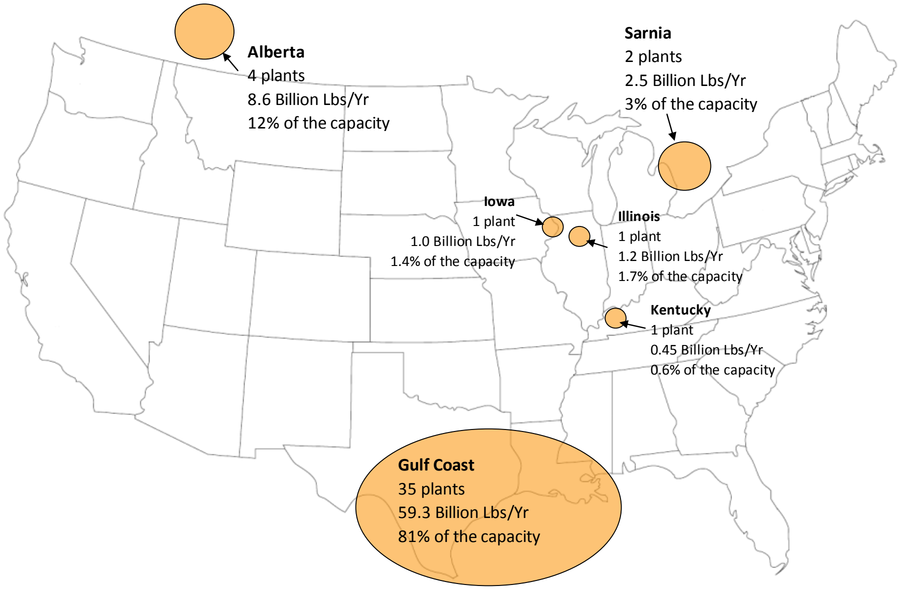
- The fractionation spread is a measure of gross profitability of the gas plants. It is calculated as the difference between the revenue from sales of NGLs contained in a gas stream as liquid and their value if left in the gas pipeline and sold at gas prices.
- If it is uneconomical to extract ethane from the natural gas stream, ethane is "rejected" back into the natural gas stream. However, pipeline specifications and the ability to blend with dry gas determine the limit for ethane rejection. The following example calculates frac spread:

- Assume Ethane at $0.24/gallon, natural gas at $3.54/MMBtu and that an NGL barrel consists of 50% ethane.
- According to EIA, MMBtu content per barrel of ethane is 3.082. Therefore, the MMBtu/gallon of ethane is 0.0734.
- When ethane and NGL components are extracted from the natural gas stream, the process results in a reduction in the total heat (Btu) content of the natural gas stream equal to the heat content of the liquids extracted. Therefore, we have to account for the shrink factor. To get the energy equivalent basis per gallon of ethane we multiply natural gas prices by the conversion factor of 0.0734. ($3.54*0.0734 = $0.26/gallon).
- The final step is estimate price per barrel of ethane and deduct shrink per barrel to obtain the margin per barrel, which is the ethane fractionation spread.

Source: Bloomberg, RBC Capital Markets

North American Steam Cracking Capacity

Current Total Cracking Capacity (Includes Propane, Naphtha and other feedstocks)



Expansions and New Crackers Ethane Demand (Ethane Consumption ’000 b/d)

'000 b/d	Location	2013E	2014E	2015E	2016E	2017E
LyondellBasell	Various Crackers	1	23	30	--	--
Williams	Geismar, LA	4	13	--	--	--
Westlake	Lake Charles, LA	7	--	7	--	--
Ineos	Chocolate Bayou, TX	--	6	--	--	--
ExxonMobil	Baytown, TX	--	--	--	94	--
Formosa	Point Comfort, TX	--	--	--	50	--
CP Chem	Cedar Bayou, TX	--	--	--	--	94
Dow	Freeport, TX	21	--	--	--	94
OxyChem/Mexichem	Ingleside, TX	--	--	--	--	34
Total Add't Ethane Demand		**33**	**42**	**37**	**145**	**223**

- We estimate that total cracking capacity of 73 Billion Lbs/year in the US with nearly 81% of that capacity in the Gulf Coast. Of these crackers, we estimate that ethane represents roughly 40% of the feedstock mixture, propane represents 20% and naphtha represents about 30%.

- In the near term, chemical companies with plant flexibility to switch from heavier-feedstock to a broader spectrum of NGLs are doing so, depending on the prices of the NGL components. Additionally, chemical companies are pursuing smaller expansion projects to take advantage of the cheaper feedstock.

- Beyond 2016, RBC’s Chemicals team estimates 13-19 Billion Lbs/year of additional cracking capacity from new ethylene crackers.

Source: Bloomberg, RBC Capital Markets

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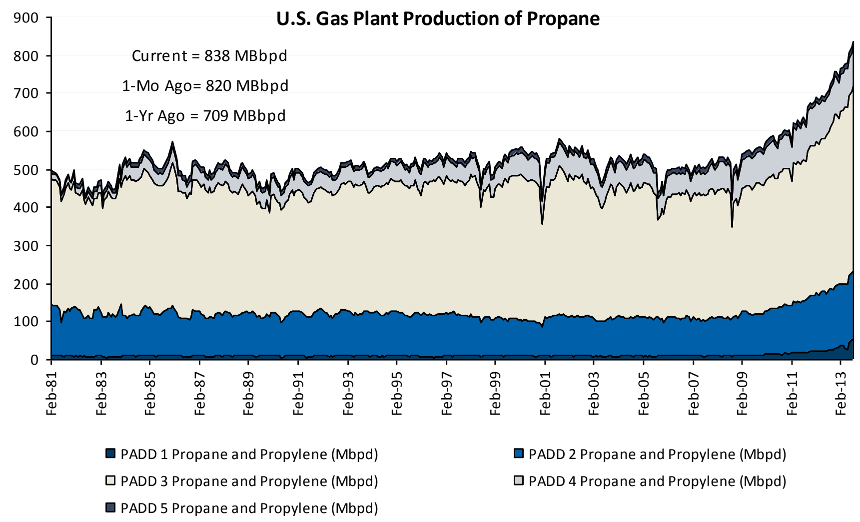
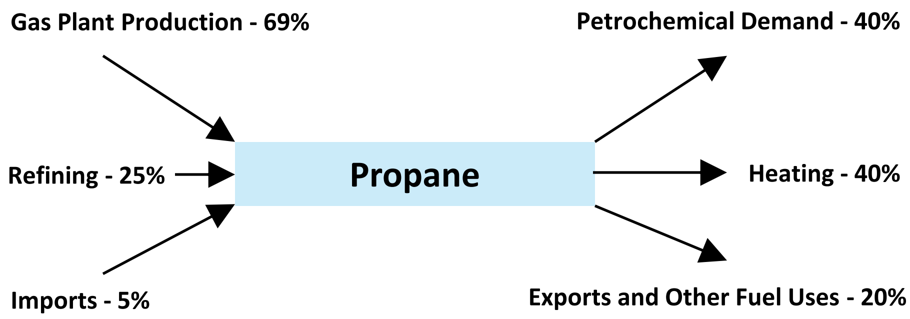
Propane

US Gas Plant Production of Propane



Propane - Supply and Demand


Gas Plant Production - 69%

Refining - 25%

Imports - 5%

Propane

Petrochemical Demand - 40%

Heating - 40%

Exports and Other Fuel Uses - 20%

- Propane is an odorless hydrocarbon (C_3H_8) gas at normal pressures and temperatures. When pressurized, it is a liquid with an energy density 270 times greater than its gaseous form.
- Propane has a wide variety of applications including in petrochemical plants, residential heating, commercial, transportation and agricultural applications.
- Propane fundamentals are determined by the following factors.
  - Propane is used as a feedstock for both propylene and ethylene. Gross price spread between these products and propane vs. the spread with other feedstocks such as naphtha, ethane etc. is an important driver.
  - Propane plays an important role in agriculture. Specifically, it plays a crucial role in post-harvest processing applications as propane-powered drying systems are used in crop drying.
  - The US has become a net exporter of propane. Projects for more than 1,500 Mbpd export capacity by 2015 have been proposed.
  - Weather is a major driver of propane demand as propane is used in home heating.

Source: Bloomberg, RBC Capital Markets

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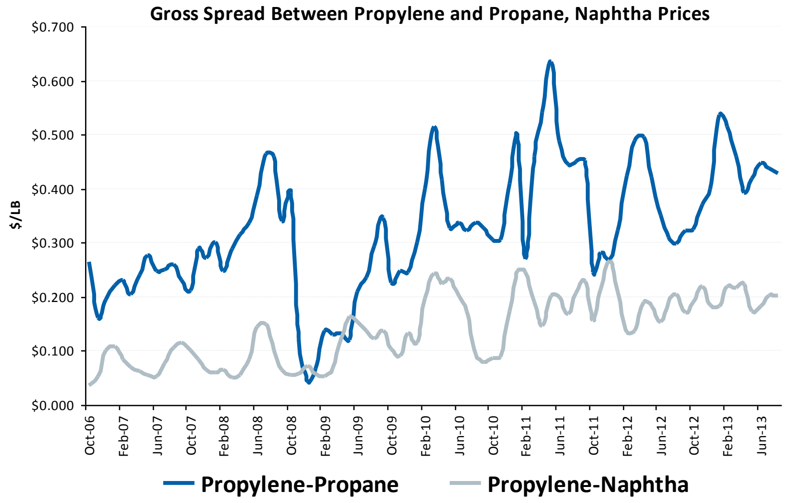
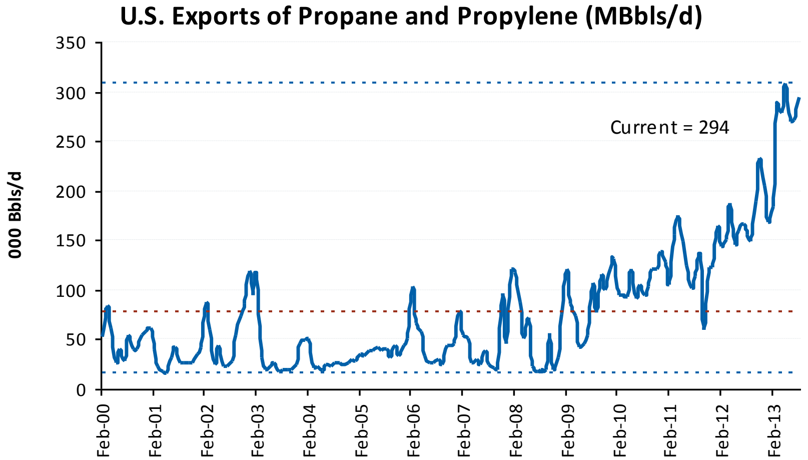
Drivers of Propane Fundamentals

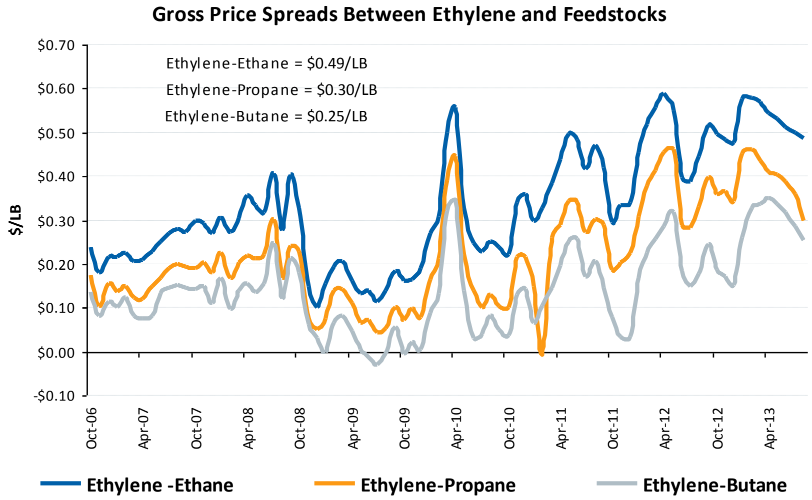
Price Spread Between Propylene and Propane/Naphtha Prices



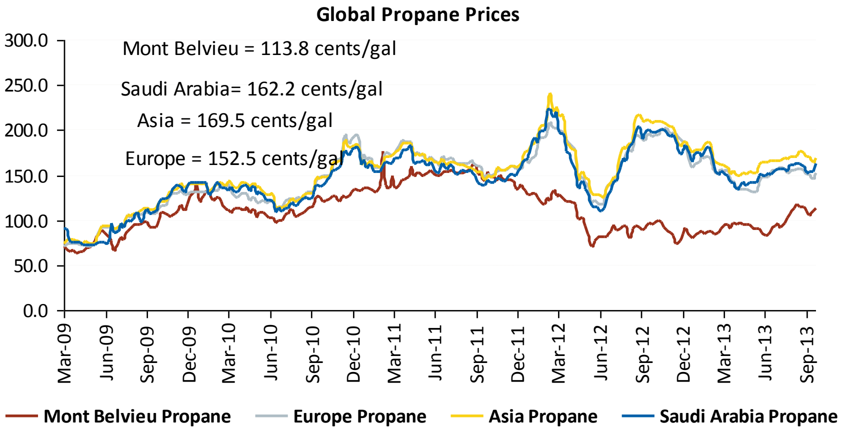
US Exports of Propane and Propylene



Price Spreads Between Ethylene and Feedstocks



Global Propane Prices Supportive of Export



Source: Bloomberg, RBC Capital Markets

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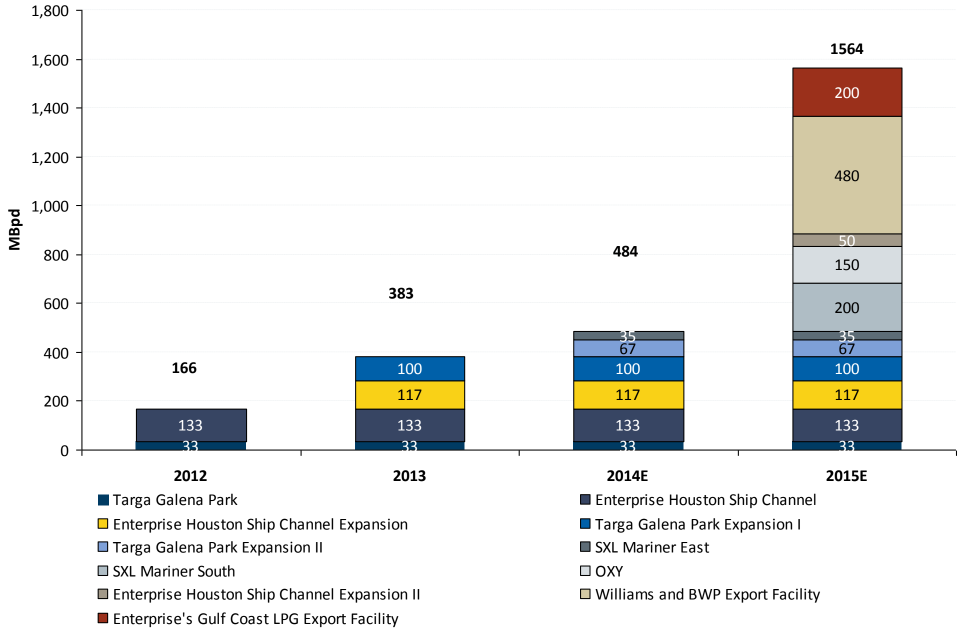
NGL Exports – Capacity Ramping with Project Development

Current and Proposed LPG Export Facilities



- Midstream operators continue to develop export projects for ethane, propane, butane and natural gasoline, as pricing differentials relative to international markets remain wide, especially for propane and butane.

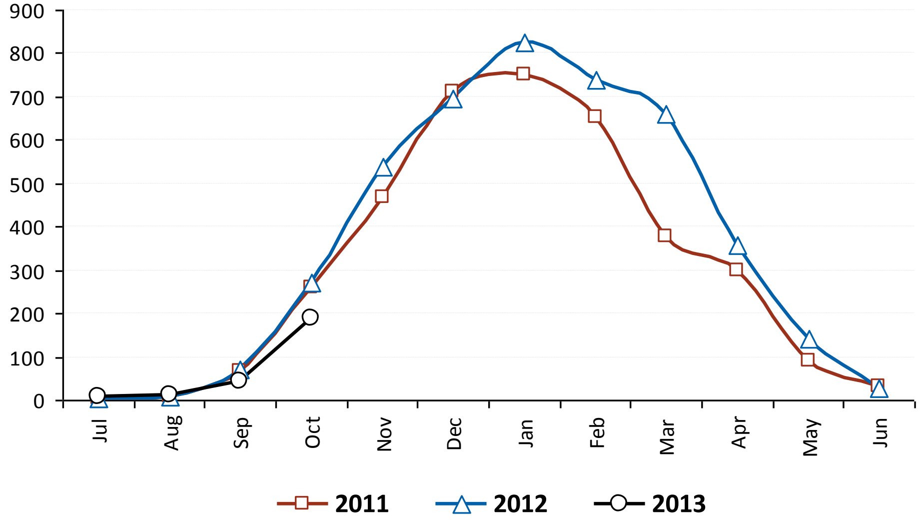
- We have identified at least 480 Mbpd of incremental LPG export capacity additions through 2014. We also note that other midstream operators have proposed additional projects beyond 2014.

- While some projects may not come to fruition (i.e., Vitol shelved its Coastal Caverns LPG export project citing execution risks), we believe that projects underpinned by long-term contracts, such as Enterprise Products Partners' Gulf Coast facility, are likely to proceed.

Source: Bloomberg, RBC Capital Markets

Heating and Cooling Degree Days

Heating Degree Days – Month Total

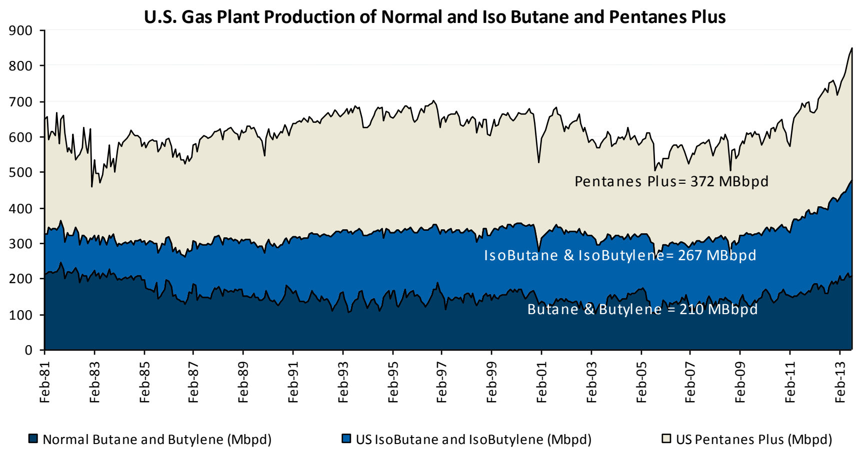


- **Heating Degree Days** (HDD) is the indicator for household energy consumption for heating. HDD represent the total number of degrees needed for the month to bring the average temperature up to 65°.
- To calculate the HDD for the month, obtain the average temperature for the month. If the temperature is above 65°, there are no heating degree days in that month. If temperature is below, subtracting the calculated number from 65° equates to the HDD.
- Similarly, the **Cooling Degree Days** (CDD) are obtained by subtracting 65° from the average temperature estimated. also based on the day's average minus 65°. They relate the month's temperature to the energy demands of air conditioning.
- The heating degree season begins July 1st and the cooling degree day season begins January 1st.

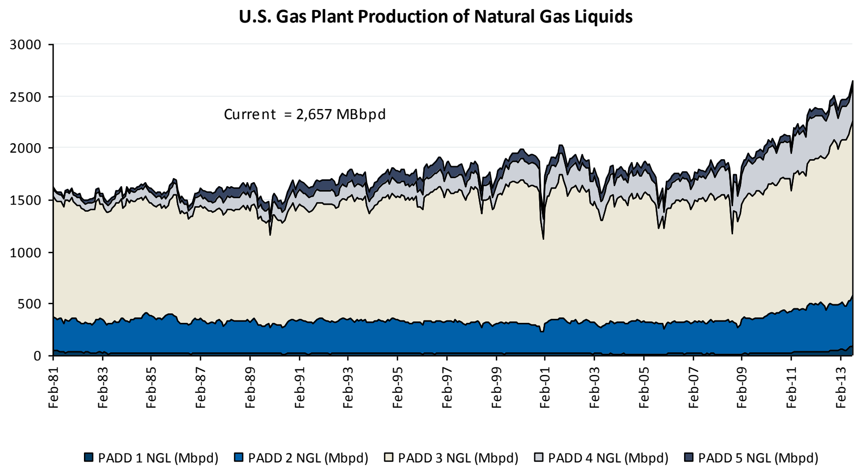
Source: National Oceanic and Atmospheric Administration

Normal Butane, Iso Butane and Natural Gasoline

US Gas Plant Production of Normal Butane, Iso Butane and Pentanes Plus



US Gas Plant Production of Natural Gas Liquids



- **Butane**
  A type of gas at room temperature and atmospheric pressure that is highly flammable, colorless and easily liquefied gas. ~78% of butane comes from natural gas production, 18% from refining and 4% from imports. Approximately 48% of butane is used in refinery blending, with the remaining used in isomerization, petrochemical applications, exportation and as diluents.

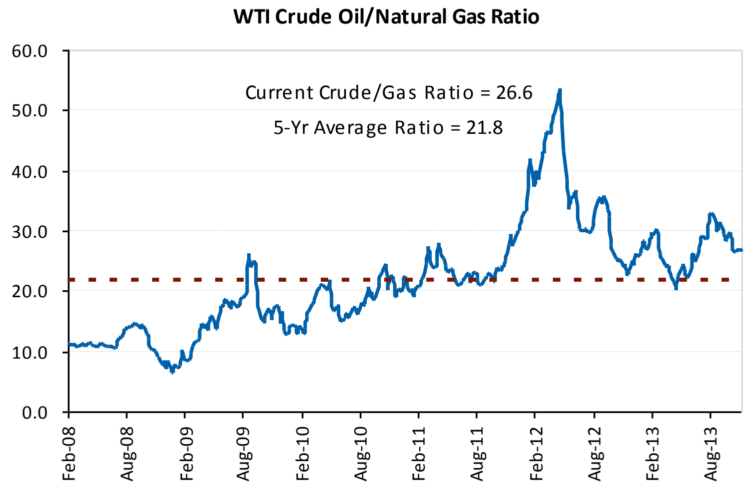
- **Iso-Butane**
  An isomer of butane and is commonly used as a feedstock in the petrochemical industry. Approximately 70% of iso-butane is from natural gas production, 25% from isomerization, and 5% from imports. It is primarily used in refinery blending (~92%), and the rest is exported.

- **Natural Gasoline**
  Natural gasoline is a liquid natural gas hydrocarbon mixture, which is mostly consists of pentanes. Natural gasoline is usually blended with ethanol or butane to obtain vehicle fuels. The majority of natural gasoline can be sourced from production of natural gas or produced by extraction processes.

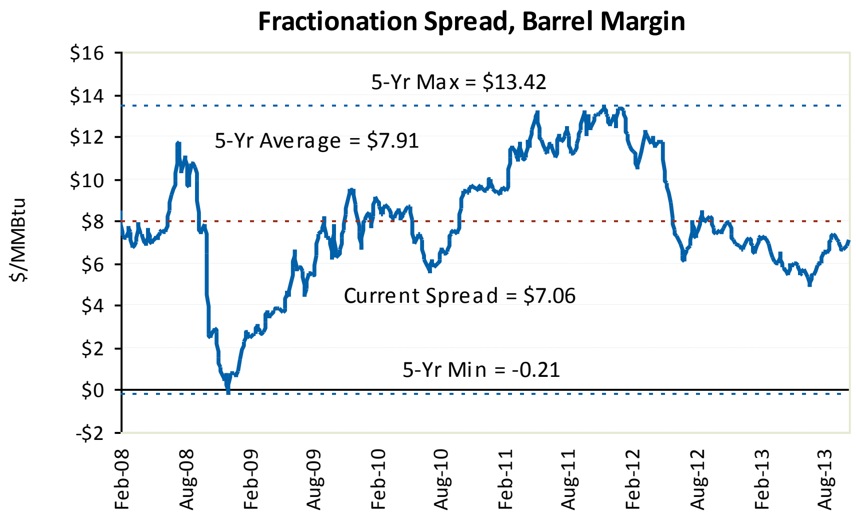
Source: Bloomberg, RBC Capital Markets

NGL Fundamentals

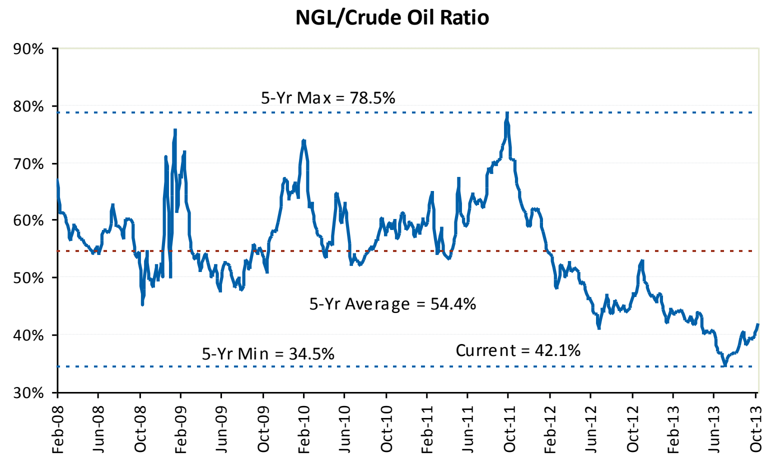
WTI/Natural Gas Ratio



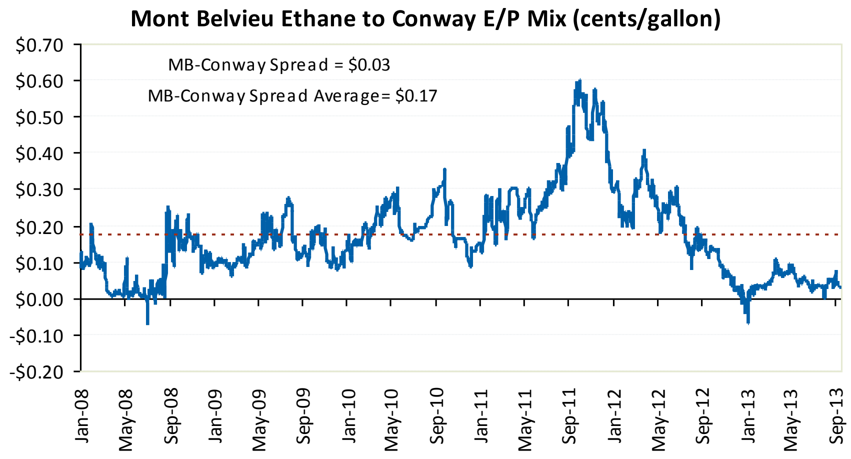
Fractionation Spread, Barrel Margin



NGL/Crude Ratio



Mont Belvieu Ethane to Conway E/P Mix



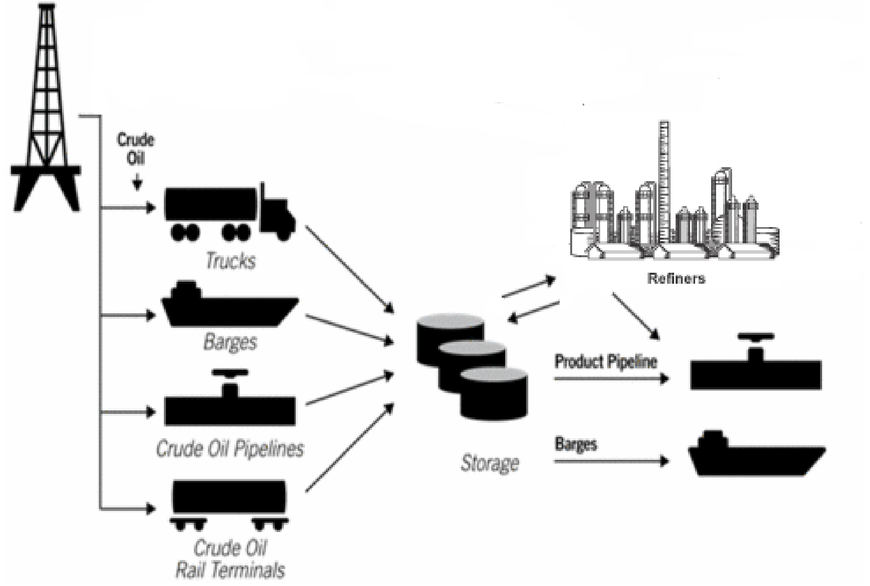
Source: Bloomberg, EIA, RBC Capital Markets

Crude Oil and Refined Products Value Chain

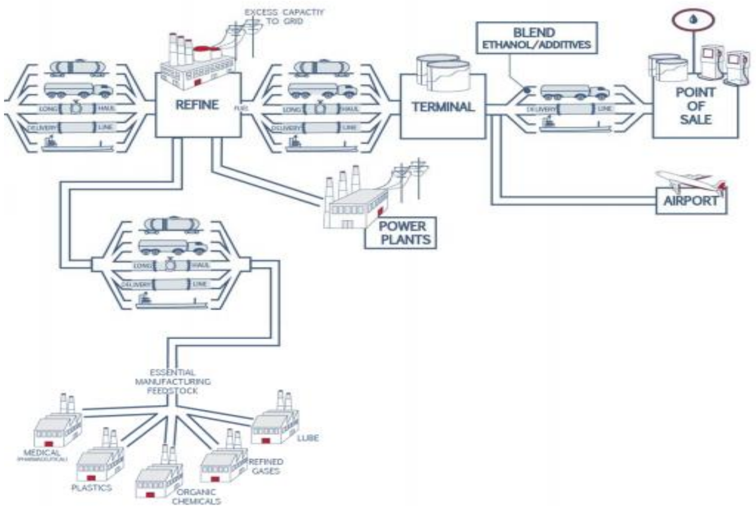
RBC Capital Markets

Crude Oil Value Chain

Crude Oil Value Chain (From Wellhead to Refineries)



Crude Oil Value Chain (From Refineries to End Market)



- From the well head, crude oil is gathered, delivered to short-term storage or to refineries for processing.
- **Crude Oil/Refined Product Transportation:** Pipeline transportation is generally the lowest cost method for shipping crude oil and refined products. Pipelines generate revenues primarily by charging customers tariffs and fees for transporting crude oil and refined petroleum products.
- Under the Interstate Commerce Act, liquids pipelines are considered common carriers. Pipelines do not take title to the product and cannot discriminate against shippers (must charge same rates and if nominations exceed capacity of the pipeline, then the pipeline must allocate capacity on a pro-rata basis).
- Other means of transportation include trucks, barges and rails, which are widely used in areas with limited/no access to pipelines.
- **Storage Terminals:** Facilities in which crude oil is transferred to or from a storage facility or transportation system. Storage terminals serve refineries by providing inventory management.
- Once crude oil is processed at refineries, it is shipped to end markets, such as feedstock manufacturers, power plants, or end users after blending.

Source: Crosstex Energy, SemGroup and RBC Capital Markets

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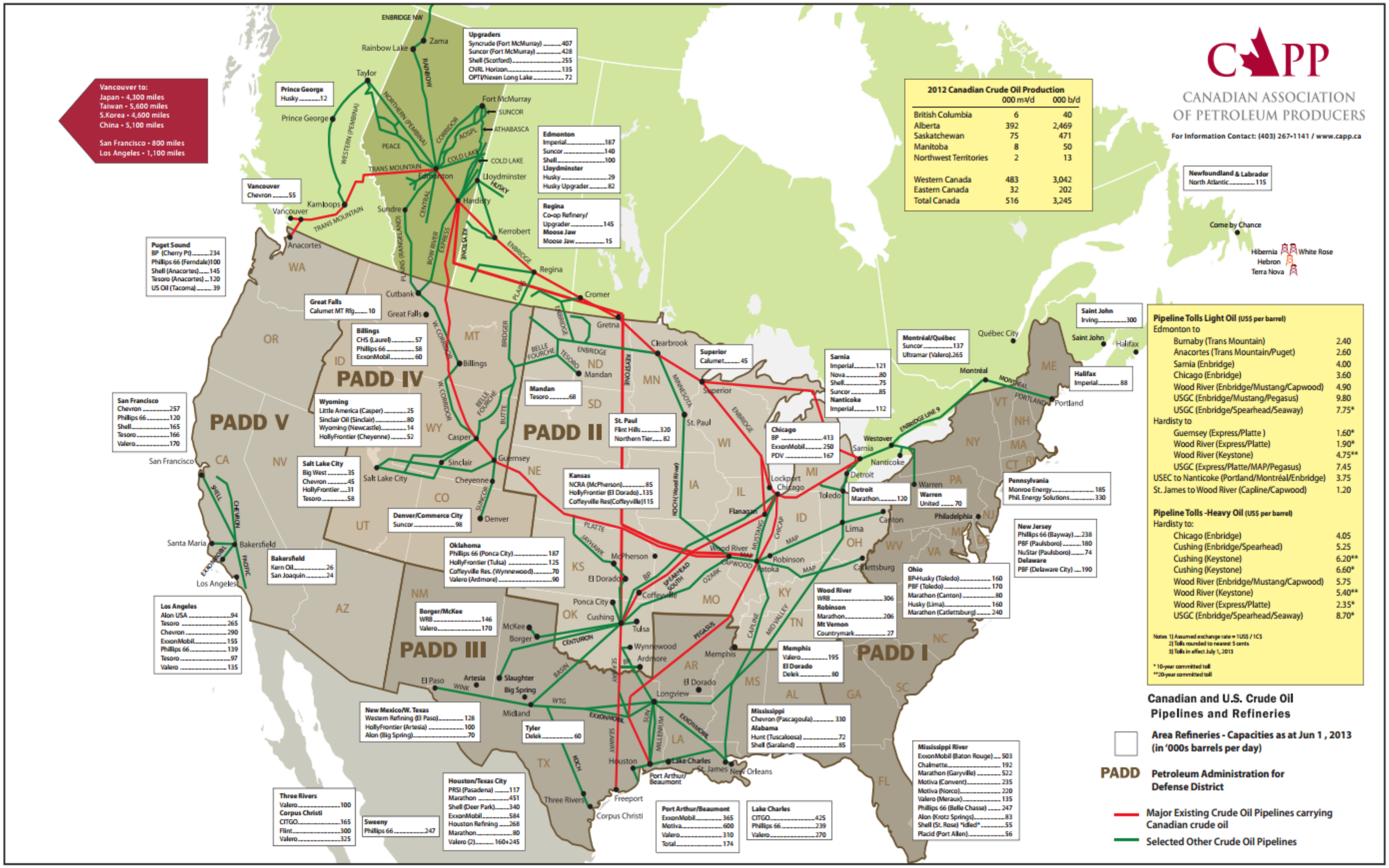
North American Crude Oil Pipelines

Major North American Crude Oil Pipelines



2012 Canadian Crude Oil Production	000 m³/d	000 b/d
British Columbia	6	40
Alberta	392	2,469
Saskatchewan	75	471
Manitoba	8	50
Northwest Territories	2	13
Western Canada	483	3,042
Eastern Canada	32	202
Total Canada	516	3,245

Pipeline Tolls Light Oil (US$ per barrel)	
Edmonton to	
Burnaby (Trans Mountain)	2.40
Anacortes (Trans Mountain/Puget)	2.60
Sarnia (Enbridge)	4.00
Chicago (Enbridge)	3.60
Wood River (Enbridge/Mustang/Capwood)	4.90
USGC (Enbridge/Mustang/Pegasus)	9.80
USGC (Enbridge/Spearhead/Seaway)	7.75*
Hardisty to	
Guernsey (Express/Platte)	1.60*
Wood River (Express/Platte)	1.90*
Wood River (Keystone)	4.75**
USGC (Express/Platte/MAP/Pegasus)	7.45
USEC to Nanticoke (Portland/Montréal/Enbridge)	3.75
St. James to Wood River (Capline/Capwood)	1.20
Pipeline Tolls -Heavy Oil (US$ per barrel)	
Hardisty to:	
Chicago (Enbridge)	4.05
Cushing (Enbridge/Spearhead)	5.25
Cushing (Keystone)	6.20**
Cushing (Keystone)	6.60*
Wood River (Enbridge/Mustang/Capwood)	5.75
Wood River (Keystone)	5.40**
Wood River (Express/Platte)	2.35*
USGC (Enbridge/Spearhead/Seaway)	8.70*

Notes 1) Assumed exchange rate = 1US$ / 1C$
2) Tolls rounded to nearest 5 cents
3) Tolls in effect July 1, 2013

* 10-year committed toll
**20-year committed toll

Canadian and U.S. Crude Oil Pipelines and Refineries

☐ **Area Refineries - Capacities as at Jun 1 , 2013 (in '000s barrels per day)**

PADD **Petroleum Administration for Defense District**

🟥 Major Existing Crude Oil Pipelines carrying Canadian crude oil

🟩 Selected Other Crude Oil Pipelines

Source: Canadian Association of Petroleum Producers

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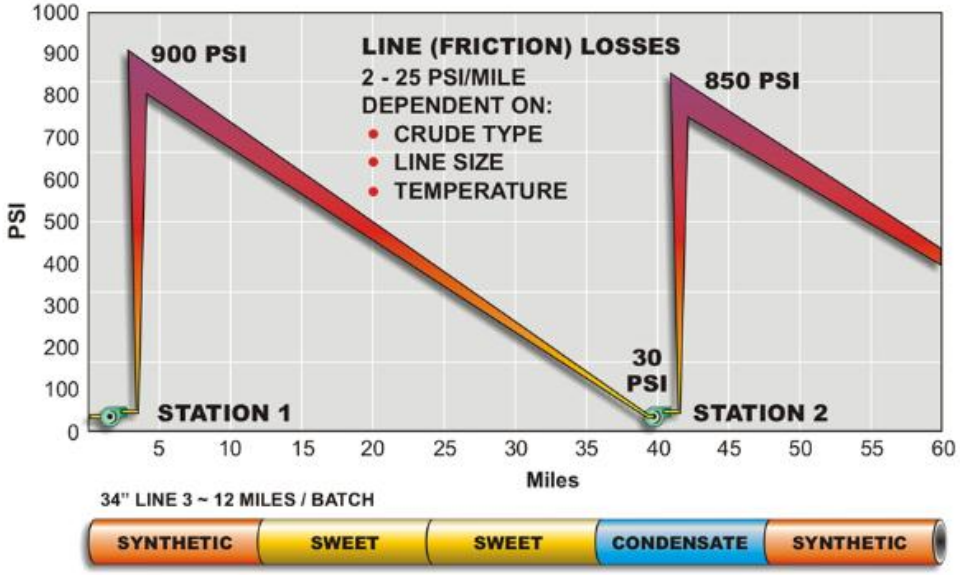
Pipeline Batching

Pipeline Transportation - Batching

Pumps Maintain Pressure Lost Due to Friction



- Crude oil and refined product pipelines are operated in a segregated, or batch mode. Some mixing occurs between batches and the liquid mix that forms in between batches is known as transmix, which is removed and reprocessed.
- Pipeline operators do not assume ownership of the transported product in the pipeline system
- Pipeline operators use Supervisory Control and Data Acquisition systems or SCADA systems to monitor and control the flow rates and pipeline pressures remotely.
- Oil moves through pipelines at 3-8 miles per hour and is propelled by centrifugal pumps. As oil or refined product moves through pipelines, it loses pressure due to friction. Therefore, the pressure needs to be increased again to propel the oil through the pipeline.
- Centrifugal pumps located every 30 to 50 miles along the pipeline maintain the pipeline’s pressure. These pumps increase the pressure to ensure that the products are move to their final destination.

Source: Enbridge

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Crude Oil/Refined Products Pipeline Tariff

- Crude oil and refined products pipelines generate revenues through fixed fee tariffs on the volumes transported typically with periodic fee escalators indexed to FERC's PPI escalators. The various tariff rate types are as follows.
  - **Initial Rates:** A pipeline operator must justify an initial rate for a new service by (a) filing a cost-of-service to support such rate, or (b) filing a sworn affidavit that there is a negotiated rate, a rate is agreed to by at least one non-affiliated shipper.
  - **Indexed Rates:** According to the indexed rates, a rate may be changed, at any time, to a level not to exceed the ceiling level. The current period ceiling level equals the product of the previous index year's ceiling level and the most recent index published by the FERC. From July 1, 2011 through July 2016 the index is based on PPI for finished goods plus 2.65%. FERC reviews the index rate every five years.
  - **Settlement Rates:** An operator may change a rate without regard to the ceiling level if the proposed change has been agreed to, in writing, by each party who, on the day of the filing of the proposed rate change, is using the service covered by the rate.
  - **Market-Based Rates:** Carrier must demonstrate that it lacks significant market power in the in the origin market and the destination market. These filings require a relatively lengthy application. If the application is approved, the carrier may set rates at levels the market will bear.
  - **Cost-of-Service Rates:** Carrier must show that there is a substantial divergence between the actual costs experienced by the carrier and the rate resulting from the application of the index such that the rate at the ceiling level would preclude the carrier from being able to charge a just and reasonable rate within the meaning in the Interstate Commerce Act

Source: Federal Energy Regulatory Commission

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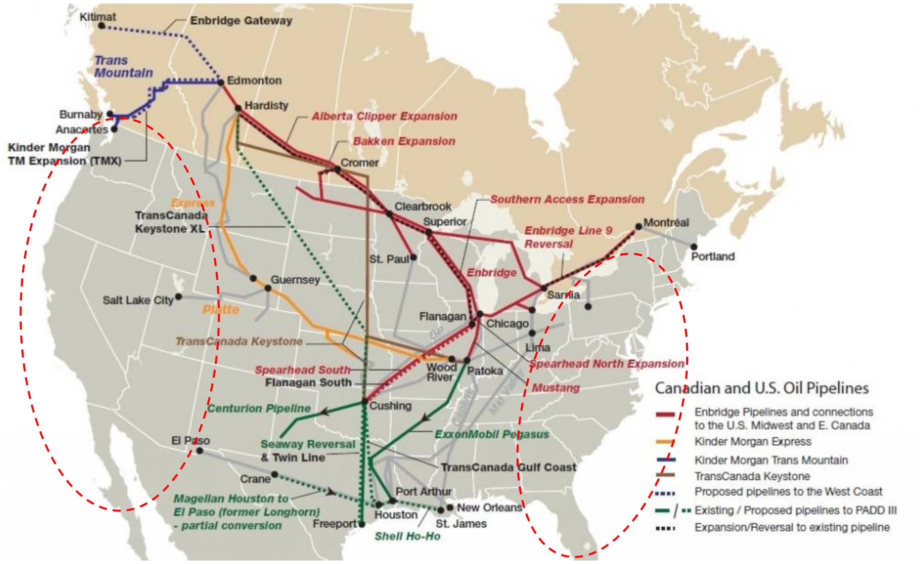
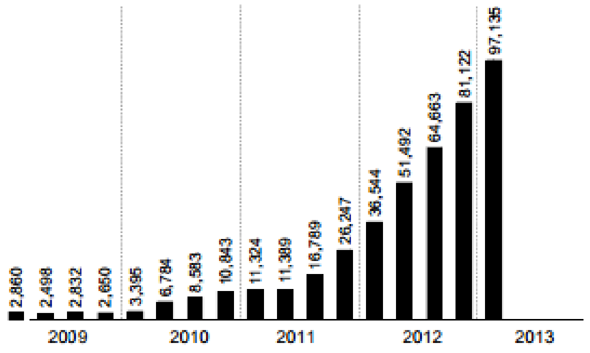
Crude By Rail

Limited Pipeline Infrastructure in West and East Coasts



Growth in Crude Oil Rail Carloads since 2009

Originated Rail Carloads of Crude Petroleum on U.S. Class I Railroads: Q1 2009 - Q1 2013



Source: *AAR Quarterly Commodity Statistics*

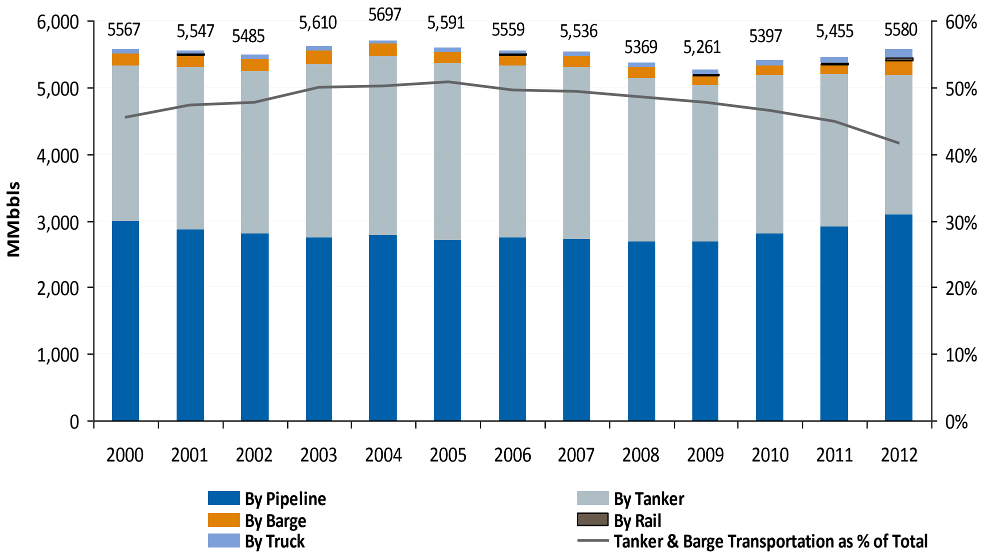
- Pipeline infrastructure in the US has lagged the sharp rise in North American crude oil production. Given the optionality that the rail transportation provides, transportation of crude by rail has become more important over the past few years.
- In 2008, U.S. Class I railroads originated just 9,500 carloads of crude oil. By 2011, carloads originated were nearly 66,000, and in 2012 they increased to 234,000 carloads.
- Assuming each car can hold 700 barrels, 97,135 carloads originated in 1Q13 indicates, over 750 MBpd of crude oil moved via rail in that quarter.
- Limited pipeline infrastructure exists on the East and West coasts. Imports largely met the East and West Crude refinery demand. The development of the domestic shale plays supports transportation of crude by rail to the refineries in these regions.
- While some crude-by-rail operators benefit from long term contracts, crude oil price differentials in different basins largely drive the economics of rude-by-rail.

Source: Association of American Railroads

Crude By Barge/Tanker

Trucks and Barges Represent 42% of the Deliveries to US Refineries

Refinery Receipts by Method of Transportation



- According to EIA, shipments of crude oil via trucks and barge to refineries represented nearly 42% of the total.
- In PADD 3, the crude tank barge trade is booming as producers continue to use waterborne transportation to bypass pipeline congestion. The Port of Corpus Christi reported that coastal barge and tanker movements of crude from the Eagle Ford (mostly headed out of Corpus to Houston or St James, LA) are up 37 % as of the end of August to 387 Mb/d. Activity of tankers and barges increased from 84% in 2007 to 94% in 2012.
- Most refineries in the US, particularly the 50% of refining capacity in the Gulf Coast, have waterborne access in place to receive imported supplies from coastal locations. Refineries receive more crude oil by barges than by rail and truck.

Source: EIA, RBC Capital Markets

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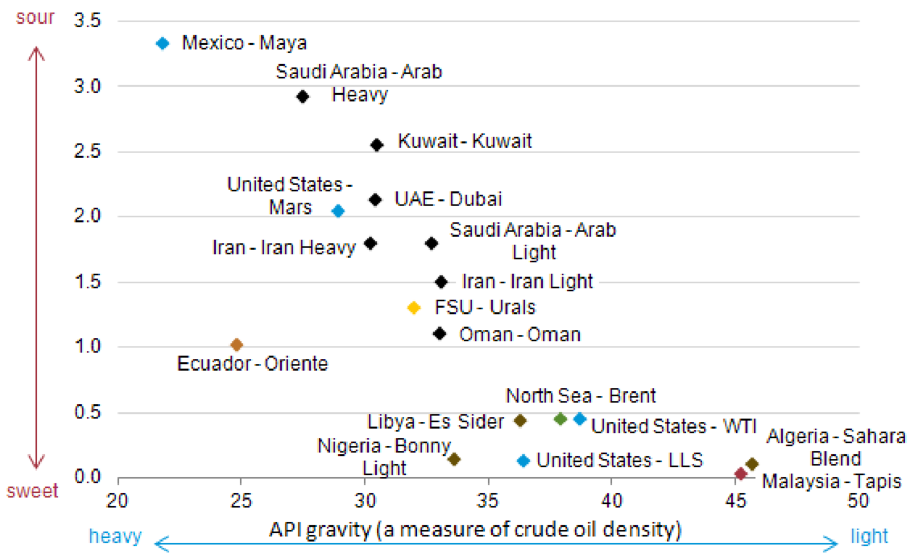
Crude Oil Market Fundamentals - Types of Crude Oil

Different Types of Crude Oil

Light →→→→→→→ Medium →→→→→→→ Heavy

Density and Sulphur Content of Various Crude Oil Grades



- Density and sulphur content are the two most important characteristics of crude oil. Crude oils that are light have lower density (higher API gravity) and crude oils that are sweet have lower sulphur content and usually priced higher than heavy and sour crude oil.

- The American Petroleum Institute (API) developed API gravity to measure the relative density of various petroleum liquids, which is expressed in degrees. Light crude oil has API > 31.1 degrees; Medium crude has API is between 22.3 and 31.1; Heavy has API < 22.3; Extra Heavy has API < 10.0

- **West Texas Intermediate (WTI)** is a high quality crude oil from which better gasoline can be refined from a single barrel than from most other types of oil available on the market.

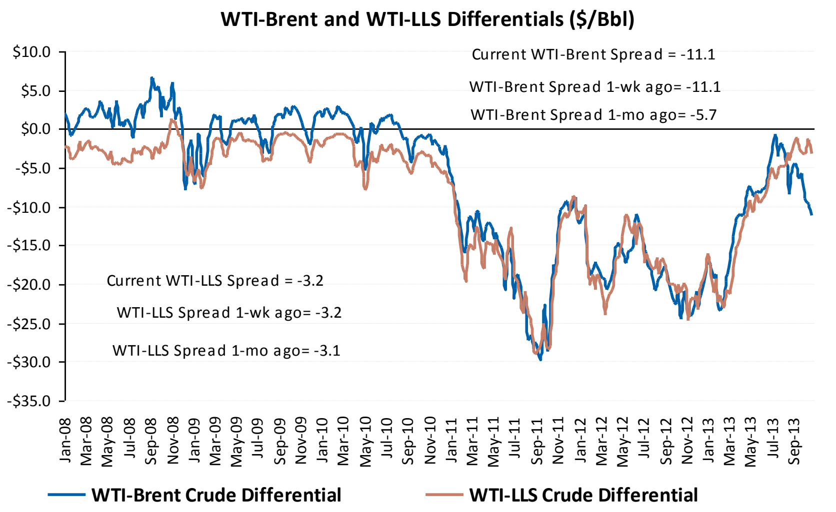
- **Brent Blend** is a combination of different oils from 15 fields throughout the Scottish Brent and Ninian systems located in the North Sea. Brent Blend is not as light as WTI. Brent Blend remains a major benchmark for other crude oils in Europe or Africa.

- **OPEC Basket** represents a collective seven different crude oils from Algeria, Saudi Arabia, Indonesia, Nigeria, Dubai, Venezuela and the Mexican Isthmus. The prices of OPEC oil are typically consistently lower than either Brent Blend or WTI due to its heavier nature.

Source: Bloomberg, EIA

Crude Oil Market Fundamentals – Prices

WTI-Brent and WTI-LLS Price Differentials


WTI-Brent and WTI-LLS Differentials ($/Bbl)

Current WTI-Brent Spread = -11.1

WTI-Brent Spread 1-wk ago= -11.1

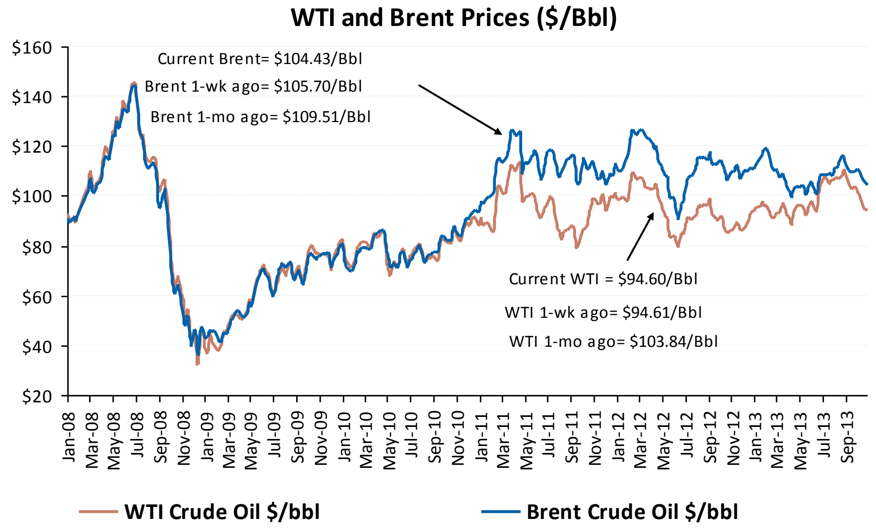
WTI-Brent Spread 1-mo ago= -5.7

Current WTI-LLS Spread = -3.2

WTI-LLS Spread 1-wk ago= -3.2

WTI-LLS Spread 1-mo ago= -3.1

WTI-Brent Crude Oil Prices


WTI and Brent Prices ($/Bbl)

Current Brent= $104.43/Bbl

Brent 1-wk ago= $105.70/Bbl

Brent 1-mo ago= $109.51/Bbl

Current WTI = $94.60/Bbl

WTI 1-wk ago= $94.61/Bbl

WTI 1-mo ago= $103.84/Bbl

- WTI and Brent are light crude oils and theoretically should be priced very close to each other with Brent prices typically trading at a slight discount to WTI reflecting delivery costs to transport Brent into the U.S. market.

- Prior to 2011, Brent and WTI crude oil prices tracked closely. However, in early 2011, the relationship between Brent and WTI changed. Since then, WTI has traded at a persistent discount to Brent. Increased production of U.S. light sweet crude oil combined with limited pipeline capacity to move the crude from production fields and storage locations to refining centers put downward pressure on the price of WTI crude oil.

Source: Bloomberg, RBC Capital Markets

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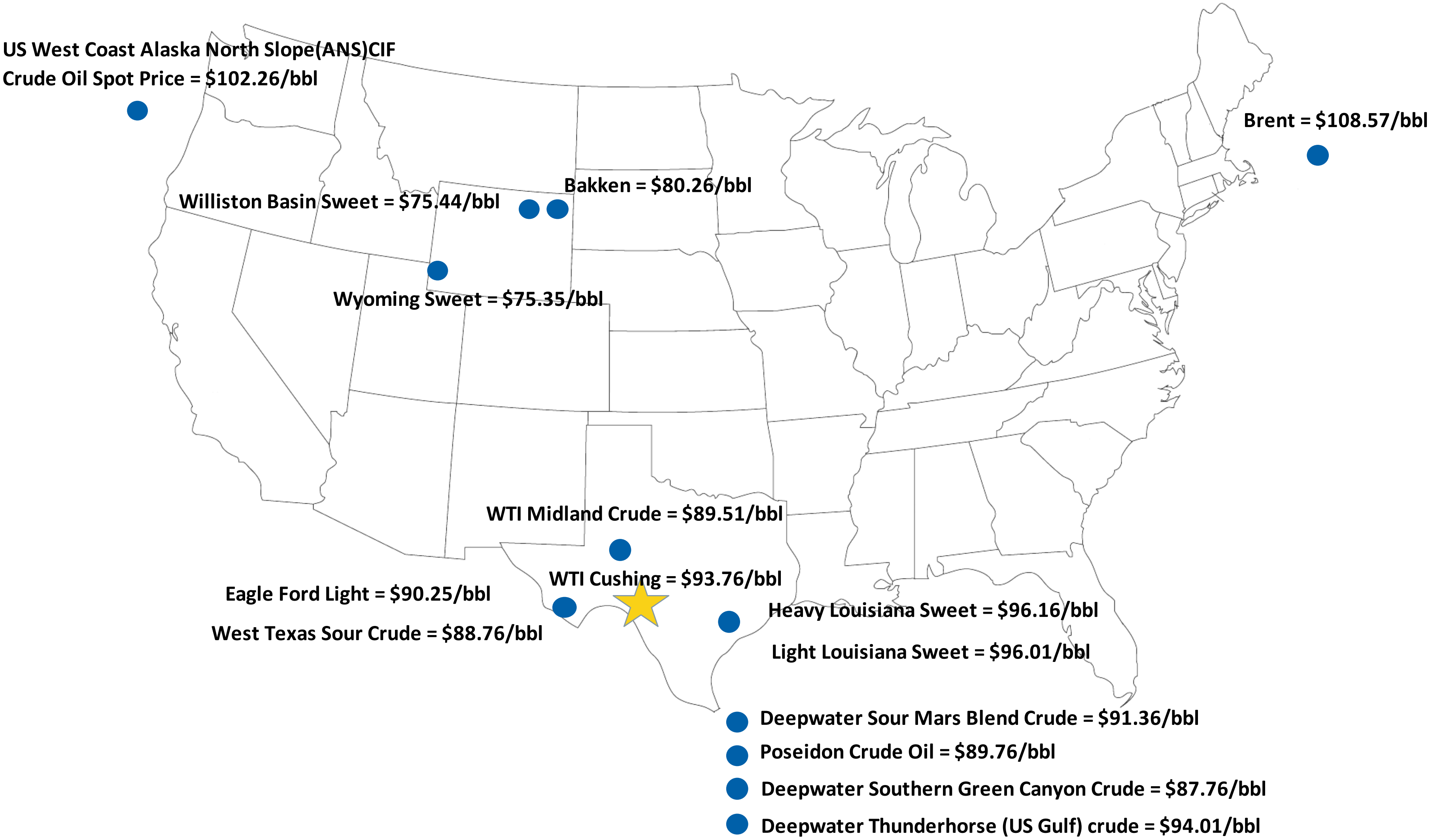
Crude Oil Prices



Source: Bloomberg, RBC Capital Markets

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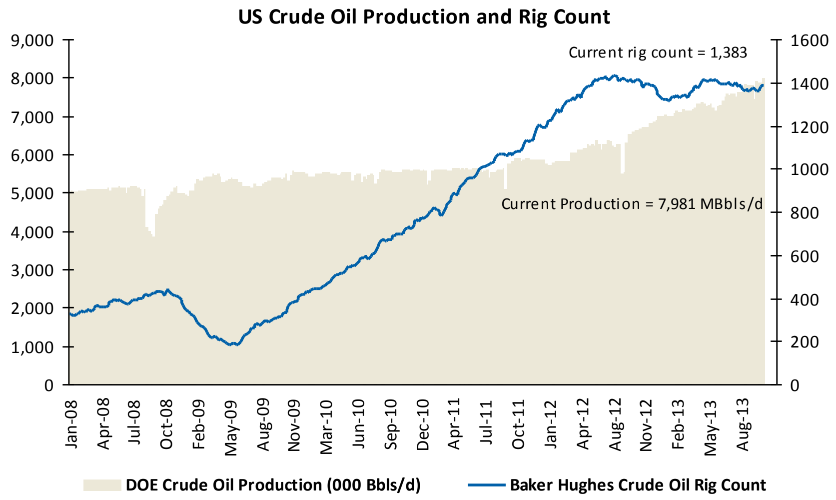
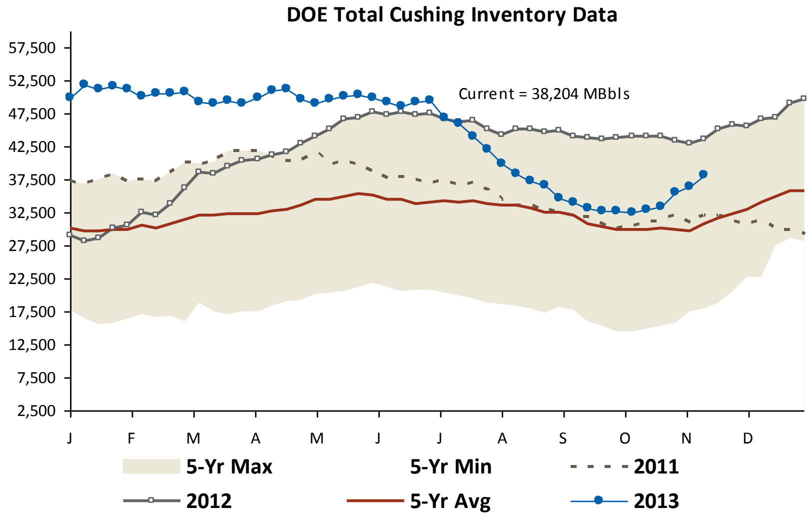
Crude Oil Market Fundamentals – Production and Inventory

US Crude Oil Production



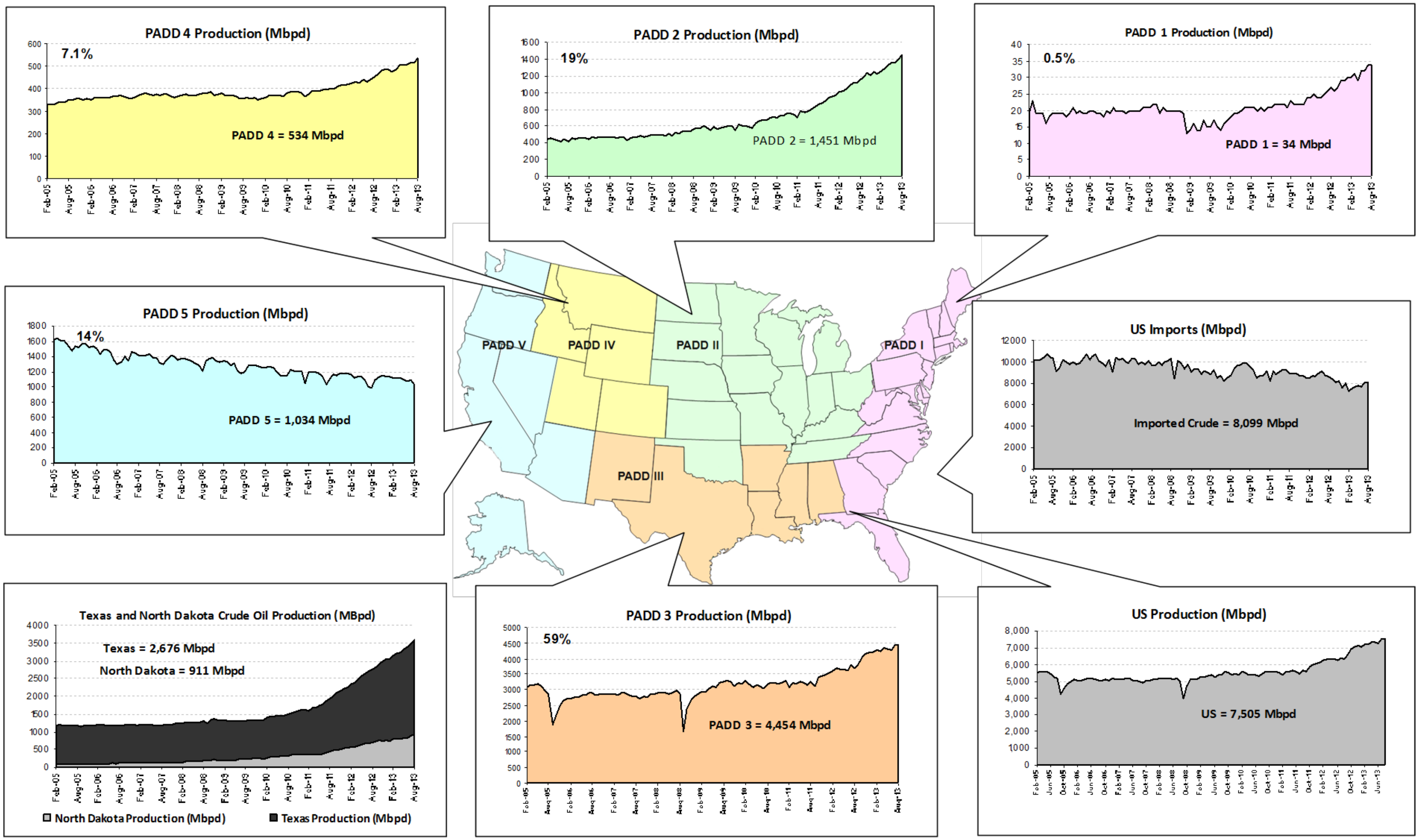
DOE Total Cushing Inventory Data



- US Crude Oil Production –Various industry sources estimate crude oil production to increase between 3.1-3.6 MMbpd from 2012 to 2016, and by 2020, production is expected to increase 4.5-5 MMbpd from 2012.
- The Canadian Association of Petroleum Producers (CAPP) projects that total Canadian oil production will more than double by 2030. CAPP expects 5.2 MMbbls/d (~78%) out of the total estimated 6.7 MMbbls/d in 2030 to be produced from oil sands.
- Sweet crude is easier to refine and safer to extract and transport than heavy sour crude. Light crude also causes less damage to refineries and thus results in lower maintenance costs over time as sulfur is corrosive.

Source: EIA, Canadian Association of Petroleum Producers, RBC Capital Markets

Crude Oil Market Fundamentals – US Crude Oil Production by PADDs



PADD % - As a Percentage of US Crude Oil Production

Source: EIA, RBC Capital Markets

Crude Pipeline & Logistics - Production Growth Drives Infrastructure Demand

US Tight Oil Production Forecasts

IEA Est. US Light Tight Oil Production (Mb/d)

	2010	2011	2012	2013	2014	2015	2016
Williston Basin	270	400	580	730	800	840	880
Barnett	20	20	30	40	50	50	50
Eagle Ford	30	100	140	200	260	340	390
Monterey	10	10	10	20	30	40	50
Niobrara	30	40	60	70	90	100	120
Utica	0	0	0	0	10	50	90
Other Light Tight Oil	20	50	50	80	80	110	120
Total Light Tight Oil	**380**	**620**	**870**	**1,140**	**1,320**	**1,530**	**1,700**
Other Crude / Condensate	5,090	5,040	4,910	4,750	4,630	4,750	4,920
Total Crude / Condensate	**5,470**	**5,660**	**5,780**	**5,890**	**5,950**	**6,280**	**6,620**

INGAA Estimated NGL & Oil Pipeline Infrastructure Capex

NGL Pipeline Infrastructure	**2011-20**	**2011-35**	**Average Annual**
Miles of Transmission Mainline (1000s)	10.6	12.5	0.5
Cost of Transmission Mainline (Billions 2010$)	$12.3	$14.5	$0.6
Oil Pipeline Infrastructure	**2011-20**	**2011-35**	**Average Annual**
Miles of Transmission Mainline (1000s)	13.0	19.3	0.8
Cost of Transmission Mainline (Billions 2010$)	$19.6	$31.4	$1.3
NGL and Oil Pipeline Infrastructure	**2011-20**	**2010-35**	**Average Annual**
Miles of Transmission Mainline (1000s)	23.6	31.8	1.3
Cost of Transmission Mainline (Billions 2010$)	$31.9	$45.9	$1.8

- **Growing Production and Changing Flow Patterns:** Rapid growth in US and Canadian production and refinery conversions drive long-term demand for additional infrastructure: gathering (pipeline, truck), transportation (pipeline, rail and barge) and staging (terminalling and storage).
  - According to EIA data, US consumes ~19MMbpd of crude oil, of which US produces nearly 7.5MMbpd.
  - Various industry projections indicate that US crude oil production could grow by 4MMbpd over the next 5-7 years, with light sweet crude oil representing the majority of the increased production.
  - Light sweet crude oil production growth likely to outpace US refiners' ability to handle light sweet crude oil (even after backing out imports) – will require several different solutions including rail, barge, truck and pipeline transportation capacity, condensate transport to Canada, condensate splitters, increased blending capabilities and potential reconfiguration of refiners.
- **Expect Sustained Investment in Pipeline Infrastructure as Long-term Solution:** INGAA study estimates capital requirements of over $40 billion for oil pipeline infrastructure over the next 25 years. Although some areas, such as the Permian Basin, appear balanced from a production growth/pipeline capacity perspective, longer term growth projections and changing flows likely to require additional capacity.

Source: EIA, Interstate Natural Gas Association of America (INGAA), Bloomberg

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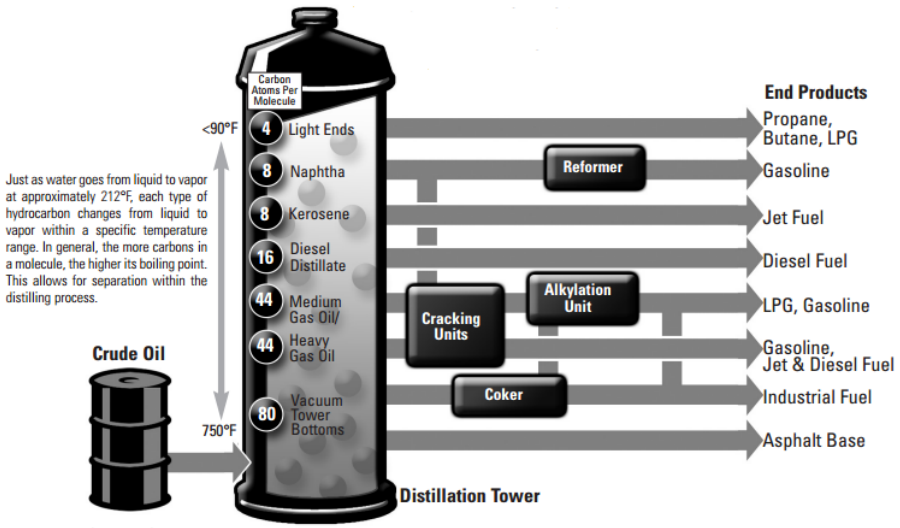
Refinery Basics

The Refining Process



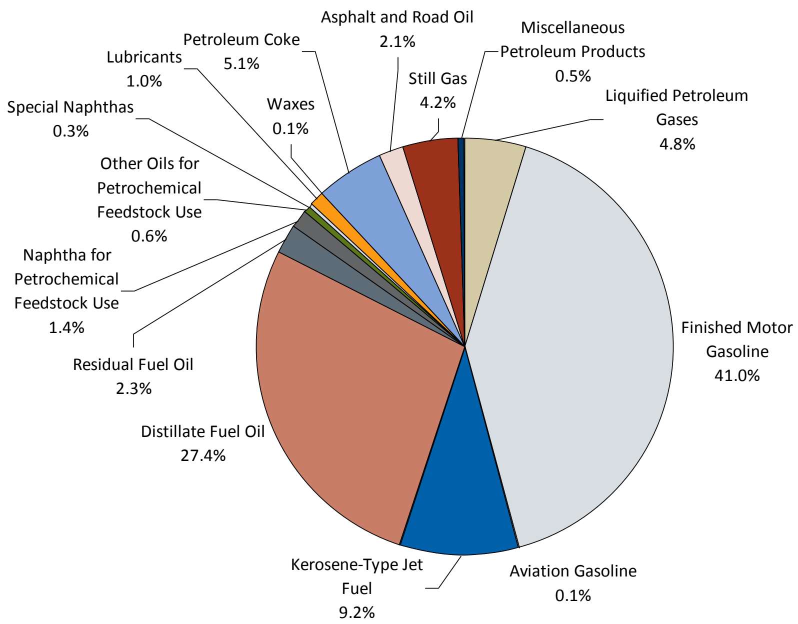
Just as water goes from liquid to vapor at approximately 212°F, each type of hydrocarbon changes from liquid to vapor within a specific temperature range. In general, the more carbons in a molecule, the higher its boiling point. This allows for separation within the distilling process.

- **Refining Process**: There are three major processes that refine crude oil into finished products: Separation, Conversion and Purification.
- The **Separation** process separates crude oil into its naturally occurring components using distillation (i.e., the application of heat to crude oil in a series of distillation towers). Yield refers to the percentage of each of the separated components or product streams.
- The **Conversion** process converts low value heavy oil into high value gasoline, which has simpler carbon chains.
  - Fluidized Catalytic Crackers (FCCs), Cokers and Hydrocrackers break complex carbon chains.
  - Catalytic Reformer and Alkylation put back some complex chains.
  - Delayed Coker converts Vacuum Tower Bottoms into more valuable products.
  - Catalytic Reforming increases the octane number of gasoline blend components and generates hydrogen for use in the refinery hydrotreaters.
- **Purification** removes sulfur through hydrotreating.

Source: ExxonMobil

US Refinery & Blend Production

US Refinery Yield



Crack Spread

WTI	$95.00 /bbl
Brent	$106.00 /bbl
RBOB Gasoline Price	$2.7500 /gallon
Heating Oil Price	$3.0000 /gallon
Gallons Per Barrel	42

5:3:2 Spreads Example

$$\text{WTI} \quad \frac{42\times(3\times\$2.75+2\times\$3.00)-5\times\$95.00}{5} = \$24.70$$

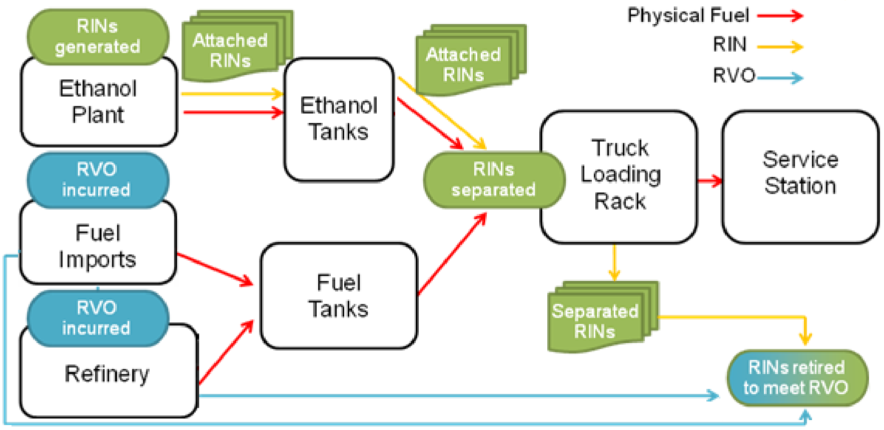
$$\text{Brent} \quad \frac{42\times(3\times\$2.75+2\times\$3.00)-5\times\$106.00}{5} = \$13.70$$

- **Refining Crack Spreads**
  Represent the price differential between crude oil and petroleum products extracted from crude oil. These spreads effectively represent refining margins. Refineries produce many products from crude oil and the proportion of each product extracted can be varied to suit market demands to some degree.
- Most refiners used a crack ratio A:B:C to hedge price exposures where A represents a number of barrels of crude oil, B represents a number of barrels of gasoline and C represents a number of barrels of distillate fuel oil.
- The most commonly used crack spreads are 3:2:1, 5:3:2 and 2:1:1.
  - 3:2:1 – 3 bbls crude = 2 bbls gasoline + 1 bbls heating oil/diesel
  - 5:3:2 – 5 bbls crude = 3 bbls gasoline + 2 bbls heating oil/diesel
  - 2:1:1 – 2 bbls crude = 1 bbls gasoline + 1 bbls heating oil/diesel
  - 6:3:2:1 – 6 bbls crude = 3 bbls gasoline + 2 bbls heating oil/diesel + 1 bbl residual fuel oil

Source: EIA

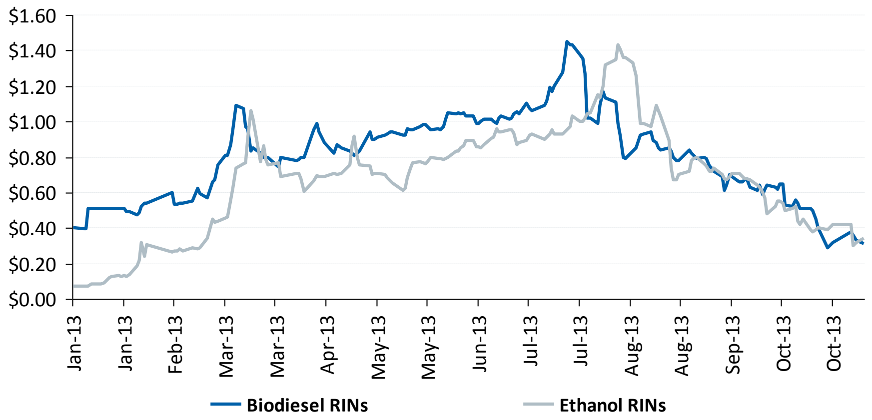
Renewable Identification Numbers (RINs)

The Lifecycle of a Renewable Identification Number (RIN)



RIN: Renewable Identification Numbers; RVO: Renewable Volume Obligations

2013 Renewable Identification Number (RIN) Prices



- **Renewable Identification Numbers (RINs)**
  The U.S. Environmental Protection Agency introduced RINs to increase the amount of biofuels in gasoline. RINs are used for both recordkeeping and flexibility in meeting the Renewable Fuel Standard (RFS) target and each RIN has a 38-digit code.

- A RIN is generated when a gallon of biofuel is made. U.S. Refiners that blend renewables need to purchase RINs to meet their federal renewables targets. Hence, as RINs prices increase, refining margins decrease.

- Ultimately, RINs will end up in the hands of petroleum refiners or gasoline importers to be used for compliance purposes; however, any company can trade RINs. When renewable fuels are blended into gasoline and diesel or sold to consumers, the RIN representing the renewable attribute of the fuel becomes separate from the physical biofuel, then can be traded.

Source: EIA, Bloomberg, RBC Capital Markets

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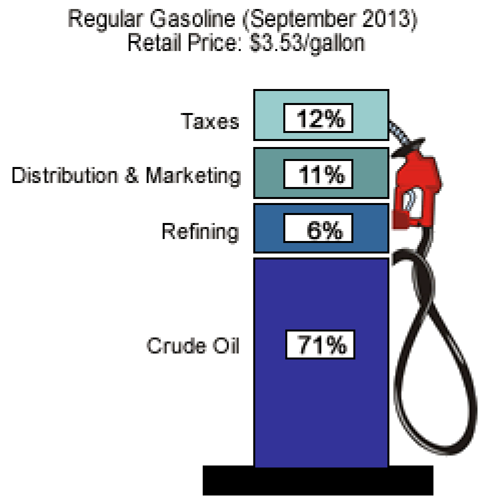
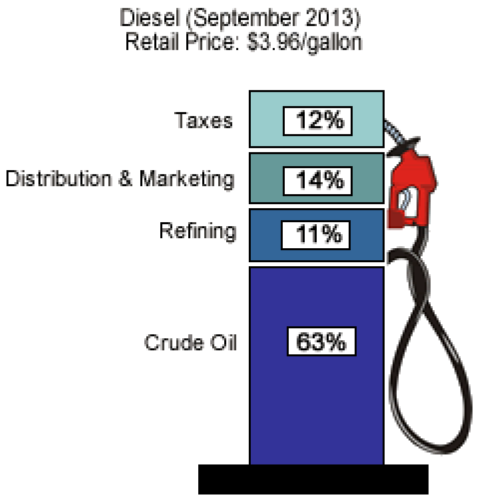
Cost Components of Gasoline Prices

Cost Components of Gasoline and Diesel Prices





- Crude Oil, refining, distribution and marketing, and taxes are the major cost components for the retail price of a gallon of gasoline.
  - **Crude Oil Cost:** the cost of crude oil purchased by refiners.
  - **Refining Cost:** the spread between the cost to process crude oil into gasoline and the wholesale price of gasoline.
  - **Wholesale Margin:** the difference between the cost to purchase wholesale gasoline and the retail price of gasoline.
  - **Taxes:** $0.18/gallon by the federal government and an average of $0.22/gallon by the state governments.
- Crude oil usually represents the largest cost component of gasoline despite the fact that the portion of components can vary over time. For instance, spot prices for wholesale gasoline is not passed through retail prices immediately, as a result, the refining component would expand while distribution and marketing component will contract.

Source: EIA

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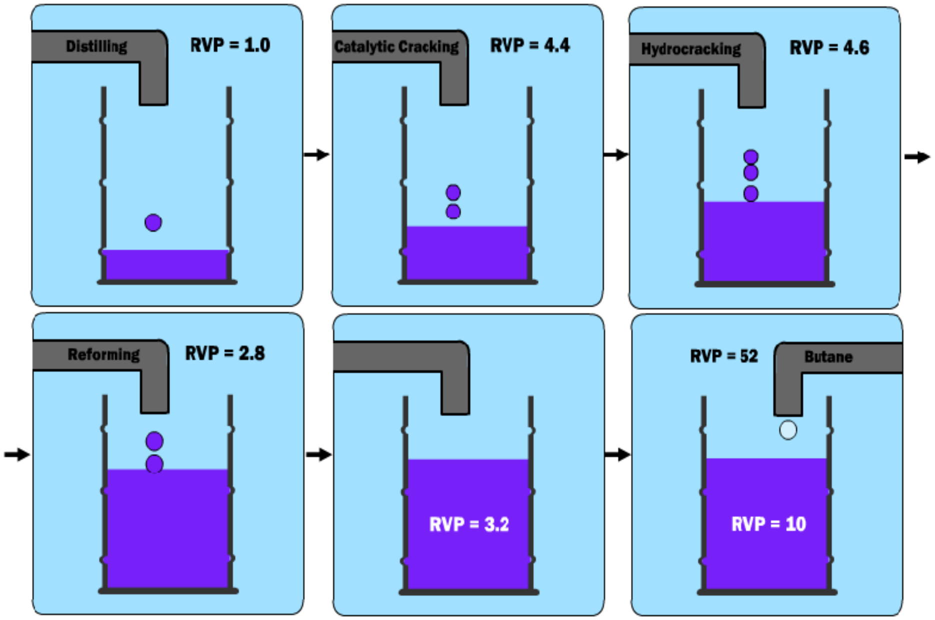
Basics of Butane Blending

Butane Blending



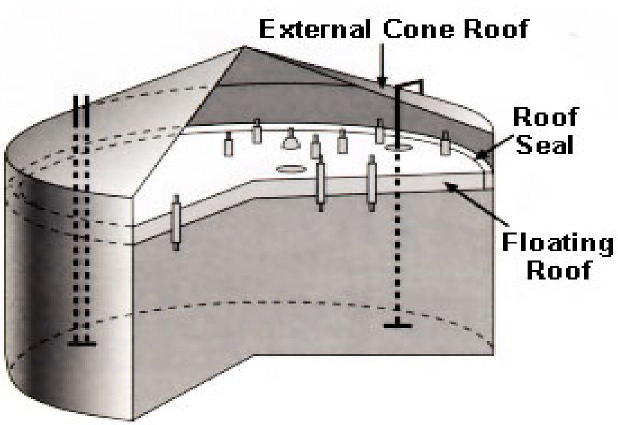
After crude oil gets processed through various steps at refineries, including distilling, catalytic cracking/hydrocracking and reforming, it is blended with Butane, which has vapor pressure of ~52 psi, to have RVP increased to the required level.

- Gasoline can be produced in different blends but each blend has to meet two main specifications 1) Octane Levels and 2) Reid Vapor Pressure or RVP, which measures the volatility of the gasoline.
- RVP changes with outside temperature. During summer months, the EPA requires that the RVP on gasoline blends be below 7.8 psi. A higher pressure gasoline blend can pressure up the gas tanks. However, when the weather gets cooler, EPA allows RVP specifications to increase (up to 15 psi).
- Butane is abundant and is a cheap gasoline blend. However, butane has high vapor pressure of 52 psi. Since the gasoline pressure has to be lower during summer months, only a limited quantity of butane is used as a blend due to its high pressure.
- When the EPA specifications are slightly relaxed during winter months (typically beginning September 15th), more butane is blended.
- Since butane is relatively cheap compared to gasoline prices and could remain so given the growing NGL production, refiners and terminal operators capable of blending butane should continue to see significant benefits to their margins.

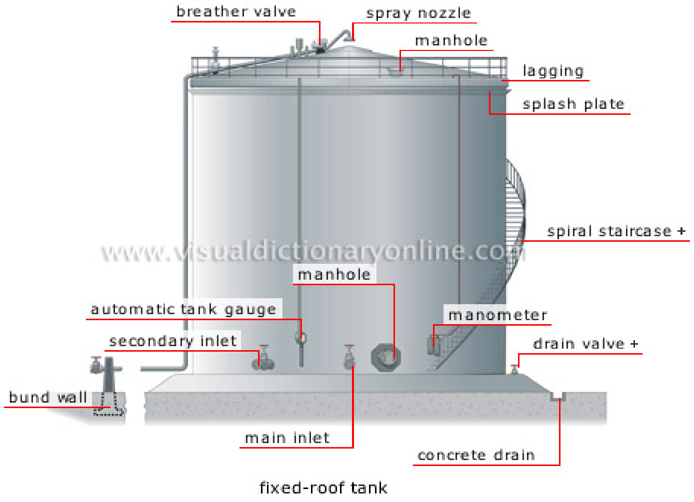
Source: Energy Policy Research Foundation Inc.

Storage Tanks

Floating-Roof Tank



Fixed-Roof Tank



- Storage tanks temporarily hold produced liquids and compressed gasses prior to the shipment of the finished products. There are different types of storage tanks and the most commonly used and the least expensive ones are fixed roof tanks, which are resistant to passage of vapor.

Types of Tanks for Liquids	Uses
Fixed-Roof Tanks	The most common and least expensive ones.
External Floating Roof Tanks	Evaporative losses are limited
Internal Floating Roof Tanks	Rises and falls with the liquid level
Domed external floating roof tanks	Usually result from retrofitting and external floating roof tank with a fixed roof to block the wind
Horizontal tanks	Small storage tanks with easy accessibility.
Pressured Tanks	For liquefied gases such as propane, butane and LPG.
Variable Vapor Space Tanks	Equipped with expandable vapor reservoirs to accommodate vapor volume fluctuations.
LNG Tanks	A specialized type of storage tank with very low temperature of -162 Celsius.

Source: Varec Tank Gauging, Phillips 66, visualdictionaryonline.com

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Terminals

Terminals in the Value Chain

- Terminals are industrial facilities for the storage of oil and/or gas products, which are usually transported to end users or other storage facilities.

- Companies charge customers a throughput fee, which is for receiving products into the terminal and delivering them to trucks, barges, ships or pipelines, as well as fees for leasing storage capacity on either a short-term or long-term basis.

Source: EIA

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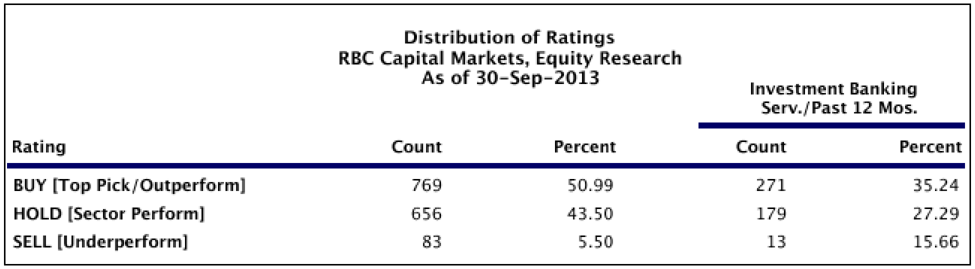

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