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RICE UNIVERSITY

NATURAL GAS LIQUIDS IN THE SHALE REVOLUTION

BY

AL TRONER
PRESIDENT, ASIA PACIFIC ENERGY CONSULTING (APEC)

APRIL 29, 2013

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Introduction

This study complements the Baker Institute's "LNG Exports: Truth and Consequence," highlighting a major "consequence": The buildup of US gas production will promote a parallel sustained expansion of Natural Gas Liquids (NGL) output. For even *dry* gas, i.e. gas output containing minimal NGLs, will produce some liquids. As cats meow and dogs bark, increased gas production, based on the Shale Gas Revolution, will also result in an enormous buildup in NGLs – ethane, Liquefied Petroleum Gas (LPG also known as propane, butane/iso-butane) and condensate. We believe this surge of incremental NGL cannot be fully absorbed in the US market and that a NGL structural supply overhang in the US will provide a *Yin*, to Asia Pacific's attempt to lessen its structural dependence on Mideast supply, a complementary *Yang*.

This sustained NGL increase will impact many sectors, most notably petrochemicals, industry and transport, while converting the US into a NGL export powerhouse. Under current US Federal regulation, the export of crude oil is prohibited and the sale of gas abroad, in the form of LNG, is allowed under permit and with conditions. Other than the contentious issue of condensate, NGLs, like petroleum products, can be freely exported with minimal government review. We will focus on the problems and opportunities facing the US through 2020, due to this NGL drive.

What has been surprising over the course of 2012 is how little attention the trend has attracted – particularly by those, such as the US Department of Energy (DOE), who have the responsibility of tracking changes. DOE released two LNG studies in 2012, the latest in December by NERA Economic Consulting, looking at the broader economic impacts of LNG exports. The NERA Report did not even list NGL in this study's glossary.

We expect the buildup in LNG exports to sustain longer-term shale gas development, but NGL production has already begun to balloon. The DOE's Energy Information Agency provisional 2012 figures showed gas production up 7.4% from 2011's 65,853.02 MM CFD level. It should be noted that sales abroad of propane, butane and condensate will continue to grow, this before the first LNG export cargo departs.

NGL terminology is confusing; to further complicate the topic, American usage often differs from international norms. Ethane (C2 by the number of carbon molecules in this hydrocarbon) is not considered a NGL in many markets, particularly in Asia Pacific, in part because it can be burned just as easily as methane (C1), or what is known as natural gas. The US DOE does not track all condensate output, only condensate separated (i.e. *stripped*) in gas processing. This plant condensate, known in the US as "Natural Gasoline," an archaic term abandoned long ago elsewhere, usually makes up half or less of total condensate output. Field condensate, precipitating, or falling out of gas streams naturally at wellhead, is normally pushed back into black oil production and accounted crude and so banned from export. The latter makes up most output in condensate exporters as Qatar.

In early 2013, there were 20 LNG export proposals pending. How soon they will be built and how quickly they will reach full working capacity, will be shaped by a number of variables. We expect the NERA study, which concluded only a minimal rise in domestic gas prices due to LNG exports, will break the deadlock in LNG project permitting. Tudor, Pickering and Holt in 2012 forecast 5-6 BN CFD in LNG exports by 2020-2025. APEC's basic LNG outlook is for 8 BN CFD of LNG exports, about 60 MM MTA, at least test-running by 2020-2022. This implies wellhead output of up to 67.4BN CFD once gas is cleaned and NGLs stripped, producing a sustained rise in NGL production.

While many treat LNG exports as a completely separate issue from NGLs, gas production goes hand-in-hand with NGL output. We will only summarize rising gas consumption, but assume the domestic market's gas needs will support a sustained rise in NGL output. Gas used in power generation will continue to rise from a record high of 25.1 BN CFD in 2012 to 29 BN CFD by 2017 and account for 32% of power generation fuel, according to consultants Bentek. This will provide demand to prompt further project expansion.

The Shale Revolution will continue to unfold, and with careful establishment of guidelines on field operations, fracking will continue to unlock the potential of Marcellus/Utica shale, despite it being located in the densely populated Northeast US. Shale development on the US West Coast (defined under federal energy definition as PADD-5) will likely only occur post-2020. It will take some time before green opposition is persuaded, but the Shale Gas Revolution is here to stay.

A different objection comes from opposition to LNG exports. There have been concerns raised – and addressed directly by the NERA study – that exports would cause domestic gas and NGL supply to become too expensive for home use. Putting aside as to how legislation could compel companies to invest in unprofitable projects, this ignores analysis showing that optimum exports will be dictated by prices, with rising US gas prices eroding export competitiveness.

Industrial lobbying group "America's Energy Advantage," led by Dow Chemical chairman George Biltz, argued against exports, claiming that while US markets are free, their pricing is tied to global oil prices and they are "set by cartels in a non-transparent way." Unexplained is how then gas consumers were clever enough to detect this cartel's actions through opaque pricing of oil.[1]

A major focus, the view of NGLs inside the US market, is very different from a world view, not only Western markets. Different pricing systems for gas and NGLs outside the US can offer a significant incentive for American shale NGL producers to mount a far more substantial export drive. By mid-2012, it became clear that a structural oversupply of shale-derived NGLs would keep prices for these products soft for the medium term. NGL exports – parallel and complementing LNG sales – will be a basic support for

[1] World Petroleum Argus, "US gas consumers challenge export plans," Jan 18 2013, pg. 6.

continued NGL development. Without regular and growing exports, domestic NGL demand will tend to lag incremental supply for the foreseeable future.

We believe that the now decades-old US crude export ban has warped American producers' worldview, turning their marketing outlook inward. Even as this tidal wave of NGL output gathers, most US producers remain generally unaware of the emerging opportunities beyond American shores. We hope this study reveals some of the possible new directions in US NGLs and their future use in world markets.

Chapter 1. The Immediate Outlook: US Market Basics

A major difficulty in forecasting shale-derived production – whether for gas, NGLs or oil – is the accelerating pace of change. Last year's projections had been revised completely by early 2013. How quickly these forecasts change is seen in forecasts by the US DOE's Energy Information Administration (EIA) over the course of 2012.

From Jan.-May 2012 the EIA's forecasts of US incremental oil production were all well under a 200 MBD gain – with April oddly enough lower than the previous three months of outlooks. In June-Aug., forecasts moved toward the 400 MBD level for expected output gains, rising to the 500 MBD plus output level in Sept.-Nov. Yet by end-2012 through early 2013, forecasts zoomed upward with the December outlook rising to 870 MBD and January 2013 to 910 MBD. It is premature to label this "an upward bias," as some analysts have, but it illustrates how quickly forecasts change.

Yet some basic trends are concrete and unlikely to change in the medium term.

A. Gas Production

There will be a sustained buildup in gas production through this decade. By Nov. 2012, marketed gas production reached 69.36 BN CFD, just slightly below EIA estimates for 2013 gas supply, running ahead of their outlook. Gas production has risen for seven straight years, since 2005 and this has continued despite weak gas prices since 2011. In Sept. 2012, gas output rose to the highest level since 1973 – nearly three decades ago.

This has led to a slump in gas prices, with generally mild winters reinforcing a structural overhang resulting from the shale revolution, as the winter of 2011-2012 was the fourth warmest on record. Unseasonably warm weather confirmed companies to focus on liquids-rich gas. In April 2012, gas prices dropped below $2/MM BTU, the lowest in a decade and while gas regained strength later, by end-year averaged $3.20 MM BTU.

The EIA sees a gradual increase in average prices though, predicting an average Henry Hub price of $3.68/MM BTU in 2013, up nearly $1/MM BTU over the 2012 average of $2.78/MM BTU. Other forecasters are less optimistic. UK Bank Barclays predicted that gas prices could fall below $3/MM BTU, if this winter proves as mild as 2011-2012. Goldman Sachs agreed that the possibility of much weaker prices existed, but that they would stay above the 2012 average simply because of dual-capacity power generation. Shale pioneers, such as Chesapeake Energy, shut in gas output, but we believe added gas output will “keep a lid” on price gains.

B. All Gas Produces NGLs

Wet gas indicates a high average ratio of NGL to gas in production, *dry* gas, a low ratio. If gas production rises, NGL output inevitably increases too. It should be noted that explorers look to develop wet prospects before dry, as NGL provides added revenue and sometimes cash flow before the gas supply chain is completed and gas sales begin.

The Shale Revolution has wrought a vast change though in the relationship of gas to NGLs. Traditionally NGLs were a by-product of gas production. As gas prices softened over the course of 2009-2011, upstream operators increasingly turned to shale discoveries containing liquids, first black oil in Bakken and then, when easily exploitable known discoveries were developed, turned to oil and NGL-rich discoveries, such as the Eagle Ford and Marcellus/Utica basins. With developers’ increasing liquids, gas has gone from being the main product to a co-product – with some explorers subjecting it has become the by-product of NGL production.

C. Knowing the Unknown Substitute

To rephrase a tongue-tied official - we know that there is a lot that we do not yet know about the extent of reserves, shale geology, composition of NGL content and how to improve operating techniques to reduce costs. A good example has been the Marcellus Shale formation, with its underlying Utica reserve, stretching across much of New York State, across most of NW Pennsylvania, northern West Virginia and the eastern half of Ohio. The EIA in mid-2012 slashed its 2011 estimate of Marcellus unproven technically recoverable reserves from 410 TCF to 141 TCF, while cutting its total US estimate to 482 TCF from earlier estimates of 827 TCF. EIA claimed this was due to more data becoming available. Yet explorers over the course of 2012 suggested that Marcellus/Utica may well hold more gas and NGLs than EIA estimates.[2] And it is the *known unknown* that leads to forecasting uncertainty and widely varying outlooks – for gas, for NGLs and for oil.

We have worked with the more conservative, but balanced outlooks, because of this. Yet other factors make shale production forecasts so variable. Among the more important are:

- Oil prices are no longer set solely on market fundamentals; impact of oil as financial proxy. Price, of course, can make or destroy, both supply and demand.

[2] See, for further detail, WGI Nov 28 P4-5 “Marcellus: Low Cost, High Reserve Play”

- Much of the basic economics of shale development depend on the ratio of the value of gas to oil. The traditional proportion of 6 MM CF of gas as a Barrel of Oil Equivalent (BOE) of 6:1 no longer applies and even when it was traditionally accepted by the industry, we had doubts as to its accuracy. Yet as can be seen in the base case forecasts below, as early as 2009, the average WTI price was far greater than that of New York Mercantile Exchange (NYMEX) natural gas.

- A basic conceptual flaw in much forecasting is that analysts believe that oil, gas and NGLs can be measured in BOE. We believe the term *oil equivalent* is an oxymoron, as gas, oil and NGLs all work on differing drivers within the US and worldwide.

- Future NGL supply has incremental output not only dependent on producing added gas volume, but separating NGLs from the gas stream and processing undifferentiated NGL into separate, high-purity gas liquids, the latter a process called *fractionation*. Once NGL is separated from gas, cleaned and separated into streams of ethane, LPG and condensate, infrastructure is needed to store and transport NGLs to end-users.

- Infrastructure delays can *shut in* potential gas production, because NGL content in gas must be reduced, first to meet the US gas pipeline calorific ceiling – gas must be of a standard range of calorific value – second, because when NGL content exceeds even small levels, it falls out of the gas stream, *puddling* within pipes to clog flow.

- How quickly gas and NGL production rise also is shaped by progress in completing the end-user facilities to absorb additional output. For gas, this tends to focus on construction or conversion of power plants to use this boiler feed; for NGLs, where utilization is broad, but base petrochemicals will likely absorb much NGL output.

- Since systematic shale development is a recent phenomenon, forecasting experience is also limited. Initial production rate, rate of decline and gauging ultimate recovery vary widely, and in different parts of these huge deposits. Even shale formations believed to be *dry* contain *wet spots* that can greatly alter forecasts.

D. More with Less

Gas output rose again in 2012 even though most producers are earmarking less than10% of their upstream exploration/production budgets to dry gas and major shale gas producers shut in dry gas output. Still, less land rigs have continued to produce a greater volume of gas. Oil service company Baker Hughes's end-2012 survey of active drilling rigs showed 431 rigs drilling for gas. While this was a slight increase over the nearly 14-year low of active gas rigs in November, less than a quarter of rigs drilling were targeting gas. Ye the total number of active rigs remained high at an average of 1,763 wells. Still, 2012 had the highest gas output in a decade and 2013 will be higher still.

Why then more gas with less wells? In part, this has been a commercial response to low average gas prices – crude and NGL output pay the rent, while gas sales are strictly for maintenance. Yet it also is a reflection of advances in drilling efficiency, modernizing the US rig fleet, better survey and drilling techniques and continually improving operational skills, reducing costs while increasing output. Whether these gains will continue, is a major question for the Shale Revolution - and we will detail this further. The greatest unknown is whether the upstream can continue to improve operating efficiency.

E. US as Major Net Energy Exporter

The industry, government and the financial world are only now beginning to come to grip with a basic fact – that the US is emerging as a major, long-term exporter of energy, and that this will have multiple impacts in oil, gas and NGLs. The Shale Revolution began without government assistance – indeed some would argue that it occurred despite Washington, rather than because of Federal efforts. It was for the most part unanticipated and unheralded by the financial world. ExxonMobil in its end-2012 long-term forecast predicted that North America will become a net energy exporter by 2025. Oil production reached a 15-year high in September 2012, according to the EIA, as well as gas. Yet the role of NGLs remained undervalued in this and other forecasts.

The EIA concurs and in its end-2012 US production outlook (Dec. 2012 Short-Term Outlook) increased its forecast for US oil production sharply to 7.6 MM B/D by 2013. The agency forecast 10 MM BBLs of US crude production by 2015 and predicted that by about 2017 American oil production will outstrip Saudi output. Within the same period, by 2020, US NGL production is expected to rise by 1 MM B/D. Yet demand oil forecasts are flat – in 2012, total products demand in the US averaged 18.64 MM B/D, down from earlier estimates of 18.67 MM B/D and 2013 forecast is for a rise to 18.73 MM B/D

This continuing rise in oil output, based on shale liquids development, has two important implications for NGLs and NGL exports. This light, low-sulfur (*sweet*) oil – Eagle Ford roughly at 40-42 API (American Petroleum Institute) and Bakken at 42-44 API - contains substantial volumes of an important NGL – field condensate also known as “wellhead” or “lease” condensate. This precipitates or *falls out* of associated gas production in pumping oil. Shale-derived oil contains often large volumes of this that is accounted black oil, or crude. Domestic producers simply blend this NGL into crude production, rather than separate it, segregate it and sell it separate from crude, to reduce field costs. The net result is crude that is light and getting progressively lighter, particularly for Eagle Ford.

Eagle Ford is a test case, as it has grown lighter, due to rising condensate spiking, from about 37 API in 3Q, 2012, to 40-42 API by early 2013. If it continues to lighten, it will be difficult for many complex, large-scale refineries to handle large-volume output. This problem already has emerged for nearby coastal refineries of Texas and Louisiana, part of PADD-3. It also camouflages the extent of NGL added production, as field condensate output is hidden within crude. Eagle Ford officially has a ratio of roughly 80% crude, 20% condensate, but refiners suspect a 75:25% or even 67:33% split. Light product yield from processing suggests that condensate accounts for about a third of Eagle Ford output.

Yet in official EIA statistics, only condensate that is physically removed from gas flow in a processing plant is labeled NGL. This "plant condensate" is labeled – together with ethane and LPG - as a NGL. We will detail condensate further in Chapter 2.C.1.

F. Extent/Impact of NGLs Badly Underestimated

Because of its ambiguous position between petroleum and natural gas, retaining physical characteristics of both; because production and demand are scattered in most official statistics and because of different terminology and definitions in varied markets, we believe that the full size of the world NGL market has been seriously underestimated. A survey by the Midstream Energy Group in 2012 estimated global NGL demand of 11.89 MM B/D in the previous year: 1.79 MM B/D of ethane; 7.77 MM B/D of LPG, 2.33 MM B/D of "plant condensate." If this estimate was accurate and assuming world demand of about 89 MM B/D in 2011, NGLs made up roughly 13.4% of world oil use.[3]

Yet most condensate production – notably in East of Suez markets - is not *plant condensate*, but would, under US standards, be *lease condensate* and so defined is as *crude oil*. Large-scale producers, such as Qatar, Saudi Arabia, Iran and Australia, see far more of their condensate production come from field condensate rather than plant. Asia Pacific Energy Consulting has tracked East of Suez condensate for 20 years. In this region alone segregated condensate output topped 3 MM B/D in 2011, reaching almost 3.3 MM B/D by 2012. Further, much Asian ethane is not accounted a NGL and so is not reflected in statistics; LPG supply and demand figures often do not reflect market realities. Evidence suggests that 2011 NGL use topped 14 MM B/D, making up 16% of world demand.

This leads to a significant realization – in the US, half, or nearly half of liquids produced in 2012 were in reality NGLs and the impact of shale development in boosting NGL output will have broad impact on US liquids supply.

[3] Anne Keller, "NGL 12101 – The Basics," *Midstream Energy Group*, http://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=0CDMQFjAA&url=http%3A%2F%2Fwww.midstreamenergygroup.com%2Feia-workshop-on-ngls%2F&ei=zHt1UbmIPMHk2AXT34DICA&usg=AFQjCNEnpHdIq83Gl4nD_NjPSv3EpmKy4g&bvm=bv.45512109,d.b2I

Table 1. Shale Gas Impact on US NGL Supply

	2009	2010	2011	1-11/2012
NGL Supply (MBD)	2,727.09	2,911.75	3,085.76	3,257.10
% Share Imports	7%	6%	8%	6%
% Share Refining	23%	23%	20%	20%
% Share Field	70%	71%	72%	74%

Source: EIA

G. Where Do NGLs Fit In?

Increasing NGL output has been boosted by producers' focus on wet gas. Condensate differs from lighter NGLs in that it needs no specialized infrastructure for handling or transport. Once it becomes a liquid, it remains a liquid and in many ways can be used by refiners, at least in moderate volume, like crude. In contrast, LPG and ethane need pressure or refrigeration to remain liquids; their use depends on specialized and often dedicated infrastructure, and the ability to gain value in using them depends on large investment, particularly in petrochemicals.

H. How Much LNG, by When?

While only one LNG project has been fully permitted, Cheniere's (up to 20 MM MTA) export facility at Sabine Pass, many proposals remain pending. Estimates on future LNG exports range from as low as 23 MM MTA to as high as 120 MM MTA (equivalent to 4-16 BN CFD of dry gas). Yet companies such as Shell believe that the initial phase of LNG projects will be about 50 MM MTA or about 6.66 BN CFD of dry gas exports, more than enough to support a sustained rise in NGL output through end-decade. Shell is an interested party. As an international major, it plans to build petrochemical plants and possibly a Gas-To-Liquids (GTL) complex in the US and naturally watches future gas and NGL prices. With announced plans to export LNG from the Elba Island terminal Shell expects to expand its own LNG capacity by 7 MM MTA to 29 MM MTA by 2020. We have forecast 60 MM MTA in LNG capacity operating by 2020.

I. NGL Overhang Worsening, or "Export Hell?"

We take as a basic working assumption that the growth in shale-derived NGL production will outpace the ability of the USD domestic market to absorb incremental output at least until 2018. While crude exports are forbidden under federal regulation, and each LNG project must go through a long – and now oft delayed – permitting process, while ethane, LPG and plant condensate already have been freely exported.

A disturbing scenario though has been sketched out by Rusty Braziel, of RBN Energy, based on the relative value of natural gas, as recorded in Henry Hub pricing and a domestic weighted-price NGL barrel – all US NGLs are linked to oil prices.

RBN envisioned an *export hell* scenario, where LNG exports were allowed, but crude remained trapped in the US market. Since LNG prices will be based on Henry Hub gas averages, at least in part, and NGLs will be based on US domestic oil prices, this would dramatically impact US NGL prices and production. This forecast could reduce WTI prices by $20/BBL to $65-68/BBL, lifting Henry Hub gas to about $5.75/MM BTU.

The economics of gas processing are based mainly on the gas-NGL price spread, and low gas prices combined with high NGL values meant good returns for the NGL processors. At end-2012, the gas-oil price ratio was in mid-20s; based on futures outlook this falls to a lower ratio of about 20-25:1. RBN sees a far lower ratio of NGL value to that of gas in the future. If power demand increases relative gas prices, it would reduce NGL value too.

The phenomenon has been illustrated by end-2012 prices for gas and NGLs. The fractionation (*frac*) spread, i.e. the price of Henry Hub natural gas vs. the weighted average of domestic NGL prices in early December 2012 was about $6.13/MM BTU, with an assumed gas price of $3.56/MM BTU and an average weighted NGL price of $9.69/BBL. Braziel estimated that the spread is only of limited attractiveness at this $6 level and depressed operating rates when it falls to $4.50 or less.

If the Shale Revolution continues to increase light oil output – with much of that oil actually wellhead condensate - and LNG exports begin to reach substantial volumes, the price of gas will rise and NGLs, based on an oil marker, fall. A possible scenario, but we believe – at least in 2013 - that it may not play out in this manner, as condensate and LPG will be exported in increasing volumes, but still an interesting scenario to consider.[4]

J. A Base Case Forecast

But rather than give multiple, often contradictory forecasts, we will be taking our base case outlook from Deutsche Bank, which generally takes a middle-of-the road outlook for gas and oil production, demand and prices. The year 2010 was the *breakout* year for US shale gas. In that year, the US produced 58.4 BN CFD of dry gas and shale gas alone made up over 13.5 BN CFD. Shale gas made most of the 16.2% output increase.

As can be seen in the two tables below, the value of gas relative to oil has shifted enormously, in part due to that tremendous increase in US gas output. Rather than a 6:1 ratio, traditionally used for BOE, in 2012 the ratio was 33.4:1, at least in comparing the US paper price of WTI versus NYMEX gas futures. This decline in the relative value of gas to crude helped shift development into an intensive search for shale formations that would yield liquids – and made the production of NGLs a top exploration priority.

[4] Platts' Gas Daily, Dec 5, 2012, Platts News Headlines

Table 2. Production Forecasts: Gas Breakout 2010 *

	US	Canada	China
Total Gas Production	58.9	15.5	4.8
of which: Conventional	*24.3*	*9.5*	*0.2*
of which: Unconventional	*34.6*	*6.0*	*4.6*
Shale Gas	13.6	N/A	N/A
%Shale of Total Gas	23.2%	N/A	N/A
%Shale of Unconventional	39.4%	N/A	N/A

* US: Shale gas volumes have outpaced IEA forecasts 2011-2012. Canada/China: IEA does not give breakout of shale gas as % of unconventional, but a low share compared to US.

Table 3. Deutsche Bank Oil & Gas Price Forecasts

Year	WTI $/BBL	Brent $/BBL	Spread $/BBL	Gas NYMEX $/MM Btu	WTI/Gas Ratio
2009	62.09	62.67	(0.58)	4.16	14.9
2010	79.61	80.34	(0.73)	4.38	16.2
2011	98.14	110.91	(12.77)	4.03	23.6
Est. 2012	94.39	112.02	(17.63)	2.82	33.4
2013	96.26	112.50	(16.24)	3.75	26.7
2014	103.25	113.25	(10.00)	4.26	24.3
2015	100.00	110.00	(10.00)	4.50	22.2
2016	105.00	110.00	(5.00)	4.75	22.1

Source: Deutsche Bank Commodities Outlook, Jan. 8, 2013; pgs. 34-38.

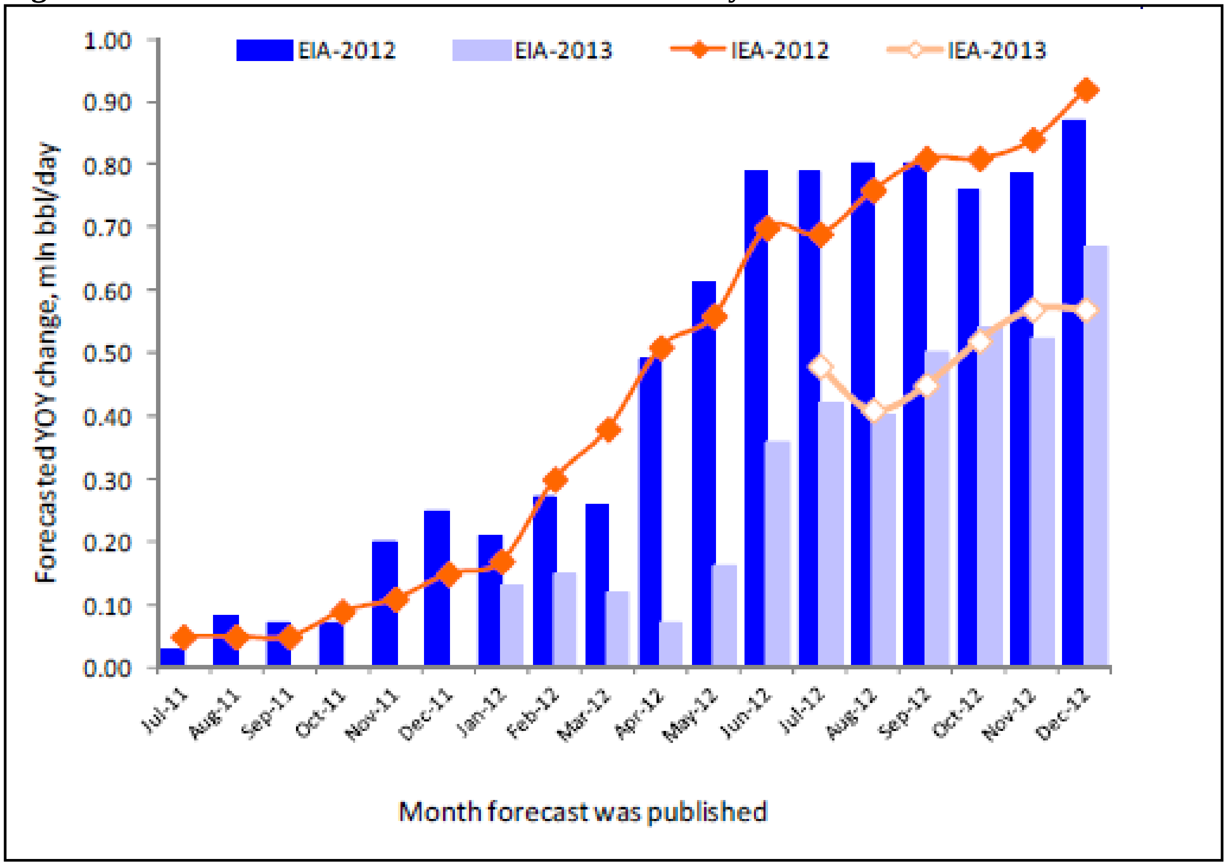
Table 4. US Gas Balance (Excludes storage and balances volumes)

	2009	2010	2011	Prov. 2012	Forec. 2013
Demand Sector	**US Gas Demand**				
Residential	13.2	13.2	13.0	11.8	13.3
Commercial	8.6	8.5	8.7	8.1	8.9
Industrial	16.9	17.9	18.4	18.6	18.7
Power	16.8	20.2	20.7	25.1	22.6
Other	5.4	5.4	5.8	6.0	6.0
Total	60.9	65.2	66.6	69.6	69.5
Supply Region	**US Gas Supply**				
Alaska	1	1	1.1	1	0.9
Gulf of Mexico	6.7	6.2	5	4.2	4.6
Rest of Cont. US	51.6	54.2	60.2	64	69.5
Marketed Production	59.3	61.4	66.2	69.2	69.6
Dry Gas Production	56.5	58.4	63	65.7	65.8
YOY %Change	2.6%	3.4%	7.8%	4.3%	0.2%

Source: Deutsche Bank Commodities Outlook, Jan. 8, 2013; pgs. 34-38.

One can also see from the gas supply/demand balance that the ability to consume gas within the domestic market has lagged behind the ability to add incremental gas volumes. This game of *consumption catch-up* will remain a constant in NGL outlooks.

Figure 1. 2012 & 2013 US Oil Production Forecasts by the IEA & US EIA



Source: US DOE/EIA, IEA, Deutsche Bank

Chapter 2. NGL Parameters

A. The Odd Man Out

The physical nature of NGLs distinguishes them from both petroleum and natural gas. All crude can produce at least some of all products from the lightest product, LPG, to the heaviest, residual or fuel oil. In contrast, only condensate among the NGLs can provide a full range of finished oil products. NGLs also differ from natural gas – in this case we refer only to dry gas or methane – in one key point: the main value of gas is in its calorific content, it is burned, i.e. its ability to create heat is its chief economic value. NGLs normally have their greatest value as a base material to create something else.

There are exceptions either way. Though methane is used in manufacture – to create methanol, which is important outside the US for the gasoline component Methyl Tertiary Butyl Ether (MTBE); for urea/fertilizer and for a number of other specialized uses, its calorific value is its main measure of worth – which is why gas is often quoted in as Millions of British Thermal Units (MM BTU).While NGLs can be simply burned, and their value set by how much heat they produce – ethane can be fired together with methane in small volumes in piped gas, and for propane residential/commercial heat is a major utilization – its greatest value is as a feedstock to produce other products. Condensate can and has been used in gas turbines for power generation – but has much higher commercial value as petrochemical feedstock or in a refinery slate. Similarly LPG's use in petrochemical yields far exceeds its value as a heating fuel. The key here is that NGLs are sold not on calorific value, but on potential end-product value.

Even more than natural gas – and completely opposite of oil and oil products – NGLs pricing systems differ considerably in US and foreign markets. While US producers can assert with some reason that propane and butane prices are a reflection of overall oil prices, in East of Suez markets the price of LPG is set overwhelmingly on Saudi posted prices. The Kingdom is a major producer and consumer of LPG, as well as the world's largest volume LPG exporter – though Qatar overtook the Kingdom in 2012. Even when both American and foreign markets are linked to the same base market – for example condensate is linked to the value of oil in both cases - the pricing mechanism will still often differ. US natural gasoline' prices move in tandem with crude; East of Suez condensate is linked to both crude products values, for naphtha and for gasoline.

There is a *negative value* to NGLs as well as a set of positive values. To transport gas, most NGL must be stripped from the gas stream, either piped gas or as LNG. We detailed *puddling*; in LNG tankers, high NGL content causes cargo instability. Further, in the US market the calorific ceiling value of piped gas is low compared to international standards, it is relatively *lean*, which is why US LNG import cargoes had to have NGL content reduced further before being fed into the national gas pipeline system.

The relationship between all NGLs and gas in the US market has been reshaped over the course of 2008-2013, as gas has gone from being the main driver for shale development to a parallel value for liquids production. As in Dr. Medlock's paper, we will focus on how price will set both production and volume and that without exports as a natural market mechanism, there may well be a future price that discourages incremental NGL output. Some basics should be set out on gas development, whether conventional or unconventional.

Among the more important are:

- Our basic assumption is that, all other factors being equal, (size and cleanliness of reserves, ease of field development, proximity to markets) wet gas, containing a high percentage of NGLs, is developed before dry gas, containing little NGL.

- Condensate production is dependent on the richness of the gas reserve, whether used for piped gas or LNG. This usually is expressed as wetness ratio, i.e. X Barrels (BBLs) of NGLs produced for Y volume of gas output.

- Traditional gas development projects, piped gas or LNG, depend on defined specific reserves from a particular field or fields. The Shale Revolution has allowed the development of many small fields, in a number of large shale basins, spread across the continental US, and provided an enormous reserve base for gas and NGL production. So long as new production is linked by pipeline to processing, it does not matter very much whether ethane or LPG or condensate is produced from field X or field Y – in essence, what has emerged is a continental system of NGL production. Unlike field-specific gas development, NGL output can be commercial even if at much lower wetness ratio than in a traditional field-specific project, and while transport has a cost, it allows production economies of scale never imagined.

- This is another reason shale output forecasting is inherently tricky - incremental NGL output could emerge from any shale development, and if too small on its own to be deemed "commercial," will soon be combined with NGL output from other development areas. This happened with Eagle Ford and the Permian Basin in Texas; the same trend is now emerging in the Bakken and Marcellus/Utica shale basins.

B. Basic Definitions

"What is in a name?" – in NGLs an awful lot, as most have a wide range of labels and at times different definitions. The very flexibility of NGL uses leads to much uncertainty. To avoid confusion, it is important to define the terms used in this study and how US market terminology and definitions differ from those abroad.

- **Natural Gas Liquids (NGLs):** Liquid hydrocarbons suspended as particles in gas, under conditions of subterranean pressure and temperature, are called NGLs. True gas consists of methane (one carbon molecule – C1); ethane (C2) is considered both an NGL in many regions (N. America, Europe and the Mideast), but a part of natural gas in most of Asia. Other NGLs consist of LPG (C3/C4, propane, butane and iso-butane) and condensate, C5 and heavier. While LPG is produced in substantial volumes in refining and ethane in limited volume, most NGLs originate from gas production. When NGL is contained within a gas stream, it is called "in a vapor phase."

- **How Pure is Pure?:** When separated into respective NGL components from ethane to iso-butane, at least 90% of the NGL stream has only one type of carbon molecule, which NGLs are known as "purity products." The term "Heavy NGLs" in the US refers to *natural gasoline* and butane/iso-butane, but this is somewhat misleading. The only heavy NGL that can be separated, stored and transported without special containment is condensate, a point which we will detail further below.

- **"Mixed" NGLs:** In the US market NGLs are often sold in a mixed stream, particularly in petrochemicals. The most common is ethane/propane called *E/P Mix*, consisting of 80% ethane/20% propane. Some regular buyers want a custom blend that differs in the proportion of these two NGLs.

- **Natural Gasoline:** This refers to heavy NGL, taken out of gas in plant processing, and the term, though widely used in the US market, generally is considered archaic in the rest of the world. In this study we will refer to this NGL simply as condensate.

Table 5. NGL Composition – A Snapshot

NGL/Composition	Vaporization / Boiling Point	Use	Notes
Ethane/C2 AKA C2	- 126F / - 88C	Petrochemical, Calorific	
Propane/C3 AKA C3	- 44F / - 42C	Petrochemicals/Residential/ Commercial/Transport	With butane used to enrich lean regasified LNG in Asian gas demand
Butane/C4 AKA N-Butane, Normal Butane, C4	32F / 0C	Petrochemical/Residential/ Commercial/Transport/Gasoline blending and high-purity butane used to make gasoline component isomerate	Part of LPG
Iso-butane AKA NX-NC4	11F / -12C	Residential/Industrial/Transport/Industrial process heat; gasoline blending & basis for component alkylate	AKA methylpropane; isomer of butane; different arrangement of hydrogen molecules; lighter than butane
Condensate/ mainly C5-C10 molecules	Wide range	Petrochemical feedstock; Full range of oil products; Solvent & ethanol production, diluent, gas turbine power generation	Many names; paraffinic or naphthenic; remains liquid without special containment.

Source: APEC

- **Gas vs. NGLs:** Gas, piped or in the form of LNG, consists overwhelmingly of methane, containing a single carbon molecule as often is referred to as 'C1'. NGLs, as they become progressively heavier, have more carbon molecules with condensate (C5 +) containing substantially greater calorific value per volume unit than ethane. Methane is also called "dry gas" – though piped gas or LNG does contain small volumes of ethane and tiny volumes of LPG.

- **Distinguishing NGLs:** As we have noted, the definition of each NGL as well as its commonly used name changes across the globe and for some products, such as ethane, there are differing definitions of whether this can be considered an NGL. We review each NGL from heaviest to lightest in Table 6 below.

Table 6. NGLs Defined

Product	Characteristics	Sectors
Methane (C1)	Dry gas; calorific value only; Piped or LNG' GTL feedstock	Power, heating, industry, GTL
Ethane (C2)	Both dry gas & NGL; major value as petchem feedstock; needs pipelines, big gas output	As in methane; also petchem
Propane (C3/LPG)	Needs containment; generally stripped from gas; higher capex and opex in transport; safer than butane	Generally home & business; transport use; gas supplement
Butane (C4/LGP)	Containment needed; higher BTU value; like propane, high capex & opex	Mainly industrial; also in transport
Condensate (C5+)	Light, sweet crude lookalike; almost always > 50% naphtha; Can be naphthenic or paraffinic; Moderate mid-distillate; once a liquid, remains a liquid; from wellhead or gas processing; some output sold as naphtha	Like crude, full range of products; strong impact on gasoline & petchems; can produce large volume of jet & ADO

Source: Asia Pacific Energy Consulting

- **Origin of Supply:** Condensate is derived solely from gas output, either wellhead or plant. When blended with crude, or *spiked*, the condensate content yields products indistinguishable from that product derived from the crude blend. LPG on the other hand, is derived both from gas production as well as refining – in 2012, refining accounted for just over 40% of world LPG, despite the tremendous buildup in gas-derived LPG output in the Mideast Gulf and the US. Yet countries with large and fast-expanding refining capacity, such as China, also are major LPG producers, though many refiners in developing economies use small-volume LPG output simply as process fuel. Ethane for commercial use comes almost exclusively from gas processing. While refining produces small volumes of ethane this too generally is used as refinery fuel - in 2011, US refiners produced about 34 MBD of ethane – compared to national supply that year of about 905 MBD.[5]

- **Extracting NGLs from Gas Streams:** NGLs are separated from gas streams through three different types of processing: through "Lean Oil" plants, refrigeration plants and cryogenic plants. The first uses a modified petroleum solvent and NGLs are naturally attracted to the *lean oil*. Refrigeration plants use propane to cool gas until NGLs fall out of the gas stream, while cryogenic plants super cool gas to remove almost all NGL content. A *Lean Oil* plant removes only a small portion of ethane – not more than 15%, while it can remove up to 99% of butane, iso-butane and condensate. Refrigeration plants remove 100% of propane and heavier NGLs and at least 85% ethane, while cryogenic, or turbo-expander, plants extract up to 90% ethane and 100% of all heavier NGLs. Cryogenic plants are most efficient, but most costly.

[5] EnVantage, "Outlook for US Propane Supplies," pg. 31, Jan 2012.

- **Condensate: NGL's Shape-Shifter:** There are many labels for condensate, including *NGLs*, *natural gasoline*, *petrochemical feedstock*, or even *paraffinic naphtha.* Defining condensate by its origin further confuses the issue with *field or lease condensate*, claimed to be quite different from *plant condensate.* This is nonsense. A simple definition should suffice. Condensate (C5+) is heavier than LPG and ethane and needs no special containment. Once it becomes a liquid, it remains a liquid. A whole condensate almost always yields 50% or greater naphtha outturn in distillation. This means that condensate can be treated like any light, sweet crude, or in some cases, as a naphtha equivalent, then as a clean product and uses standard oil infrastructure.

  Condensate can be considered a base material, equivalent to crude for refining, a petrochemical feedstock, a blending component, or boiler feed. Part of the *mystery* of condensate is that it has many labels; the *confusion* on condensate grows, as potential buyers confront a wide range of condensate uses. All condensates are light, generally 50 API rating or lighter and are sweet, containing little sulfur, generally less than 0.3%, often lower; they contain little metals (though mercury and other metals do occur), and the majority of outturn is naphtha, with little residual yield.

  Some consider condensate a form of ultra-light crude, but there are important differences: condensate output is dictated by gas production; therefore has limited price elasticity; production is always tied to gas operations, whether considered a by-product, a co-product or the main driver, and condensate will be produced whether NGL prices are high or low. A traditional gas field operator has gas output as its primary concern. Most of all, the need for specialized and dedicated infrastructure makes ethane and LPG production, storage, transport, and distribution more costly than that of condensate.

- **Condensate Vs. LPG Summary:** For lighter NGLs, specialized infrastructure is an issue. Yet LPG already is exported from the US in large volume by ship; ethane is only exported in limited volume, mainly to Canada. Internationally LPG trade is enormous in volume; most ethane trade is by pipeline, in North America and Western Europe and is tiny in comparison, and East of Suez has seen no ethane trade at all in recent years. While ethane has been shipped occasionally by tanker, such movements have been only sporadic – while LPG seaborne trade has gown steadily.

- **Summary: Differences Condensate/LPG**
  - LPG needs to be contained in pressurized and/or refrigerated tankage, while condensate can be stored like oil, or oil product;
  - LPG requires specialized and dedicated storage, transport and distribution infrastructure;
  - Condensate only occasionally uses dedicated infrastructure;
  - Storage of LPG is costly, even short term; while condensate costs little to store;

- Creating LPG supply has high capital costs, particularly for an export operation, while condensate, whether spiked or segregated, has much lower costs;
- LPG originates in gas-stripping and refining, condensate comes only from gas output;
- LPG is both a finished product and a feedstock;
- The high infrastructure cost for LPG often has producers selling output near the point of supply, particularly in developing economies. LPG often is used within the home market and is often price-controlled, but condensate is freely priced.

➢ **Condensate as NGL vs. Black Oil:** A factor that will shape future US condensate output is its relationship to oil, or *black oil*, as upstream shale developments increase their share of condensate in their *oil* production.

➢ **Condensate Vs. Crude Summary:**

- Often seen as light, low-sulfur crude, condensate outturn differs from black oil;
- Condensate light-end yield limits use in conventional distillation towers;
- Condensate is only derived from gas production:
- Condensate can be far lighter than even ultra-light crudes, ranging up to 78 API;
- Condensate contains few metals; generally these are at low concentration.
- *Sweet* and *Sour* mean a relatively low sulfur content compared to the same descriptions for black oil, as *sour* signifies a sulfur content of more than 0.2%, while in a crude oil this would be considered a sweet grade.
- Condensate is a byproduct of gas production and sales and output cannot be easily increased or reduced, even as oil prices change – it has limited price elasticity.
- Some condensates, used as direct feedstock for ethylene crackers, need clean storage and tankers, to prevent *dirty* contamination of residual *tail* or black oil.

If a substantial volume of condensate is spiked into oil production, it produces a lighter and sweeter crude blend, with a substantial outturn of light products as well as heavy residual, but proportionally less middle distillate, i.e. gas oil/diesel and kerosene/jet. This refining yield pattern is called a *dumbbell* or *barbell* outturn and avoided by refiners aiming to maximize mid-barrel products.

Producing a lighter, sweeter crude blend, by adding condensate, would appear to be an unmitigated good, but refiners can have too much of a good thing. Slates, or the type of crudes typically chosen by USGC refiners, all in PADD-3, have been designed to run heavy, sour grades. They need to have enough residual and heavy gas oil from simple refining or distillation, to fill their severe secondary units, which in turn convert this feedstock to lighter product. Tens of billions of dollars have been invested in PADD-3 coastal refineries to get the best yield possible from this heavy sour crude group – yet shale-derived crude is light and sweet.

Eagle Ford, in south-central Texas, is typical of the production emerging from shale development. It has lightened significantly since production began to build rapidly at end-2012 and appears to be lightening still. The reason for this – just as to a lesser extent Bakken – is because it contains a growing proportion of wellhead condensate, with the Federal export regulation promoting the spiking of field condensate into the crude pool.

The medium-term implications are clear – if condensate continues to grow as a proportion of crude production, much of incremental oil output from shale development will become increasingly unusable, particularly coastal refiners in PADD-3. In mid-2012, EIA Administrator Adam Sieminski caused a bit of a stir, when he suggested that without some remedial measures this trend would limit the utility of shale-derived crude oil.

Table 7. US NGL Supply - 2011

Supply	Volume (MBD)	%Share Total Supply	%Share NGL Type Supplied
Gas Processing	2,216.07	71.8%	
Ethane			*41.7%*
Propane			*28.5%*
Butane			*7.1%*
Iso-Butane			*9.5%*
Plant Condensate			*13.2%*
Refineries	619.16	20.1%	
Ethane			*3.2%*
Propane			*89.1%*
Mixed Butanes			*7.7%*
Imports	250.54	8.1%	
Propane			*77%*
Mixed Butane			*15%*
Condensate			*8%*

Source: EIA

Table 8. US NGL Consumption - 2011

Consumption	Volume (MBD)	%Share Total NGL Sold
Primary Petrochemicals (Ethane, Propane, Butane, Plant Condensate)	1,455	55%
Heating Fuel (Ethane, Propane)	500	19%
Gasoline Blendstock (Butane, Iso-Butane, Plant Condensate)	510	19%
Ethanol Denaturing (Plant Condensate)	20	< 1%
Fuel Exports (Ethane, Butane, Plant Condensate)	190	6%

Source: NGL 2012 – The Basics," June 6, 2012, by Anne B. Keller, Midstream Energy Group

The most obvious solution is to rescind the almost-total ban on crude exports, allowing the sale abroad of excess light, sweet crude – which should gain a premium over international average prices, and import lower-quality heavy, sour grades. This, at least in the medium term, is politically unacceptable, despite the same systems balancing that the US does for oil products. Yet a simple, or what scientists call an "elegant solution," would be to reverse the lightening trend by recognizing field condensate and allowing export, either alone, or blended with plant condensate output. This would provide a great incentive for shale operators to separate, segregate and sell condensate separately. It might well increase profitability of operations as well. Condensate internationally often sells at prices above crude. We will detail this further in the following section on NGL markets.

C. The Nature of NGL Demand; Comparison with World Markets

We now look briefly at each NGL from the heaviest group – condensate – through the lightest – ethane.

1. CONDENSATE

Characteristics

Condensate in the US is called *Natural Gasoline*, though it is simply plant condensate. All condensate is light and sweet - but there is relativity to these labels - a crude oil is considered *light* by USGC refiners, when it is at 36 API or higher and condensate sulfur levels are far below many internationally traded sweet grades, such as Oman (1.33%S). In base refining, a whole condensate almost always produces 50% or greater naphtha yield. This naphtha can contain a high percentage of paraffins, making it ideal as an ethylene cracker feedstock, or naphthenes and aromatics, which is useful in producing gasoline, gasoline components or as aromatic petrochemical feedstock. Unlike LPG or ethane, condensate is sometimes sold in disguise – very light condensate, skimmed from the top of the wet gas stream, is sold as the oil product naphtha in Saudi Arabia (A-180), the UAE (Pentanes Plus Naphtha) or Qatar (Plant Naphtha).

Utilization

Condensate's high naphtha yield is what causes problems for refiners in running large volumes of condensate rather than light crude. The high percentage of naphtha in outturn (also the basis of gasoline as well as petrochemical feedstock) means that refining towers get *overloaded* with light ends, due to insufficient overhead pipes and misadjusted refining cut points; working capacity is reduced and the tower becomes *bottlenecked*.

A condensate splitter is a special-built distillation tower designed to handle a slate that produces a majority of light end product and can run all condensate or a combination of condensate and very light crude oil. It should be noted that large refineries with big distillation towers – say 150-250 MBD capacity – can run small condensate volumes as *slate trim*, using light, sweet nature condensate to balance high-sulfur crudes. Some firms use *petrochemical pre-treatment* units that allow them to clean condensate for use as feedstock. This is in addition to condensate grades, such as Saudi A-180, which is sold simply as petrochemical naphtha.

In the US, gasoline production uses most plant condensate – nearly three-quarters of supply in 2011 – while petrochemical pants used only about 11% that year. In many foreign markets those percentages are almost reversed – condensate is mainly used as a petrochemical feedstock (aromatics as well as olefins). Petrochemical use of condensates in the US was declining even before the Shale Revolution, but the continuing buildup in ethane and LPG output will likely reduce condensate use in US petrochemicals further.

Pricing

Condensate generally is linked to oil prices rather than gas, though there are times that it is used in gas-turbine power generation (pls. see section below). Prices quoted for Mt. Belvieu *Natural Gasoline* are generally accepted in the US market for pricing. Mt. Belvieu is a gas gathering, NGL processing center located close to Houston. Instead, condensate pricing is linked to crude – normally to a standard regional marker, such as WTI, Brent or Dubai (also Dubai/Oman) or to a product. What differs most significantly is that US product orientation is slanted towards gasoline pricing, while East of Suez markets generally link to naphtha, the chief petrochemical feedstock. In some foreign markets sales are linked to a products basket – Algeria was notable in using a naphtha/gas oil-diesel formula, and some Mideast exports use similar formulae, but normally linkage, if to a product, is for a single product.

Export/Import

Condensate imports have declined as output increased, while exports have risen, though mainly to Canada. While most analysts are aware of the Canadian need to import condensate to use as a diluent to transport heavy synthetic crude derived from oil sands, they are not aware that it also makes up a part of a major Canadian syncrude blend called Synbit. Both have underpinned a sustained rise in US condensate exports.

Government regulation is pivotal for future condensate exports, as wellhead condensate is considered *crude*. Yet the US Commerce Department in its definition of Crude Oil ((#754.2 (1) License requirement) defines crude "as a mixture of hydrocarbons that existed in liquid phase in underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities …" All condensate exists as particles of liquid hydrocarbon suspended in gas at underground reservoir pressure and temperature. If plant condensate is exported, wellhead condensate – which comes from the same source and is not "in a liquid phase" underground, cannot be defined as crude.

US Norms Vs. Foreign Markets

A major difference between US condensate and foreign production is that there is no artificial distinction between plant and field output. A wide range of producers, including Norway, Algeria, Saudi Arabia, Qatar, Iran, the UAE, Australia and Indonesia generally combine plant and field condensate to create a condensate blend.

Many foreign markets have built substantial condensate splitting and petrochemical pre-treatment units, but despite the expected surge in US condensate output, only two concrete proposals are underway to build condensate splitters. Imported condensate was sold to US ethylene cracker operators in the past, but appears to have vanished in face of less expensive domestic feedstock.

In 2013, US refiners have an embarrassment of choices for light crude purchases. Foreign markets are often not as lucky, particularly in Asia Pacific, where much crude of this type comes from the Mideast. Over the course of 2012, condensate has been increasingly purchased as a proxy for light, sweet Gulf grades, particularly when there is a need to sharply increase gasoline or naphtha outturn.

Many condensates produce at least a moderate outturn of middle distillate, in particular jet/aviation fuel and demand for this product has supported condensate purchases in late 2012, as well as Japan's need for clean Jet/Kerosine for winter heating.

There are other condensate uses abroad. While the practice has declined in the US, condensate, when high in N+A content, is used as a gasoline blending component. Finally, in some Developing Economies condensate is used as a fuel in gas turbine power generation and as a fuel in exploration field operations.

2. LPG/BUTANE & ISO-BUTANE

Characteristics

Butane and iso-butane both consist of four carbon molecules. However, the two NGLs have a different compound structure, with normal butane (which for simplicity we shall just call butane) an "unbranched" structure; iso-butane's "branched" structure making it an isomer of butane. Both are highly flammable, colorless and easily liquefied from a gas stream – even the simplest NGL recovery system captures most of this heavy NGL. Butane can be kept a liquid only with specialized containment – using pressure or refrigeration. In LPG shipping, smaller tankers tend to be pressurized, larger, refrigerated or pressurized and refrigerated, to keep this NGL a liquid.

In the US butane and iso-butane usually are separated and kept segregated, whether produced in a refinery or from gas production. In foreign markets the two are often blended together. Butane/iso-butane is also labeled in the US market *Heavy NGL,* but needs special containment to remain a liquid, as does propane.

Utilization

The largest use of butane to manufacture gasoline, which accounted for about two-thirds of 2011 butane demand, as well as all iso-butane consumption. Butane is also a major feedstock in petrochemicals. Small volumes are used for butadiene, a key part of synthetic rubber, but also in industry, as a refrigerant and as aerosol propellant. Butane is also exported to Canada for use, with condensate, as a diluent in transporting syncrude.

Iso-butane is used 100% in creating gasoline and gasoline components, in particular alkylate. Alkylate is a high-octane, clean-burning gasoline ingredient that has replaced the use of lead and aromatics in preventing engine knock, and a key to unleaded gasoline.

Because of the dominant role of gasoline manufacture in butane and iso-butane, there is a noted *seasonality* to butane demand. Gasoline quality requirements – specifications – mandate less butane use to reduce gasoline vapor pressure during the hotter summer months in the US and Canada, as measured by Reid Vapor Pressure (RVP). Butane moves out of the gasoline pool during that season and demand falls sharply at mid-year. It should be noted that California and other PADD-5 states also require lower vapor pressure in gasoline than the US national standard.

Pricing

As is the case with condensate, Mt. Belvieu prices are generally accepted as the pricing basis for butane/iso-butane. These prices – quoted in gallons, rather than barrels or metric tons – are the basis of most American sales. Mt. Belvieu prices are linked to crude prices overall – but the relationship is more distant than in internationally traded condensate grades. In the Developing World most markets allow LPG sales only under government-set prices; since it takes considerable costs to build LPG infrastructure, price controls discourage expansion of production and limit utilization of butane.

Export/Import

Large volumes of butane, as well as propane, were exported in 2012, though most iso-butane output stayed in the domestic market. The impact of shale-derived butane has been clearly seen in rising exports. Total US LPG exports in 2011 were 148 MBD and this rose by 27% to top 188 MBD in the first half of 2012. The key export zone has been PADD-3, which saw its LPG exports rise 30% to 151 MBD in the first half of 2012. While only a minority of these sales abroad was butane, they were a large commercial trade volume and have steadily filled Atlantic Basin markets, first Latin America, then West Africa and by 2013 increasingly penetrated Europe.

US Norms vs. Foreign Markets

A major difference between US and global markets is that iso-butane often disappears from LPG field production figures abroad – it is simply put together with normal butane and sold as a combined stream, with butane dominating the mix. Saudi quality specifications, guaranteeing product quality, have a ceiling for iso-butane content, but that usually is not a problem for field LPG.

LPG originating from refining in many foreign markets usually follows the US pattern. Butane and iso-butane are separated and butane is sold as LPG; iso-butane normally is used to create alkylate or sold to another refiner with an alkylate unit.

Use of butane (and propane) as road transport fuel in the US is minimal; in many foreign markets it is a major competitor to gasoline and diesel. LPG can be used for automobile fuel, with minor vehicle modifications and has a major share of road fuel use in such diverse markets such as South Korea, Russia, Italy and Australia. In 2011, South Korea used roughly 51 MBD of butane and propane to fuel its cars. Advocates of using natural gas – methane – should consider the much greater calorific value of butane per volume unit, allowing a greater cruising radius and reducing the number of specialized fueling outlets needed.

3. LPG/PROPANE

Characteristics

Propane consists of three carbon molecules and together with butane/iso-butane, makes up LPG. It too must be extracted from the gas stream, separated from other NGLs and requires special containment. Refining also produces large volumes of propane as well as butane/iso-butane. Containing less calorific value per volume unit, propane often is preferred to butane where there are safety concerns, such as in disposable lighters or in backyard *gas* (i.e. propane bottle) BBQ grills.

Utilization

Propane is unlike other NGLs in that a majority of consumption is in residential/ commercial sectors – for heating and cooking. Propane traditionally was the first feedstock choice for ethylene crackers, but the slump in ethane prices is reducing propane's share of feedstock use as this alternative feedstock has become more attractive. These two sectors accounted for almost all consumption in the US market in 2011. Propane can be used in transport just as butane.

Pricing

Propane prices too are set on Mt. Belvieu quotes in cents/gallons, not $/barrels or $/ton. In international trade, prices for propane and butane usually are quoted in barrels or metric tons. Prices are linked to oil prices, but not only crude, because, as with butane, commercial volumes of propane come from refining as well as gas stripping. While many have been fixated on ethane as the main feedstock for future petrochemical production, they ignore the importance of both propane and butane as competing feedstocks, in particular for making intermediates (propylene & benzene/xylene/toulene – BTX) where ethane performs poorly (Pls. see following ethane section for further detail).

Prices for LPG are also shaped by competition with other potential petrochemical feedstocks. Petrochemical buyers – like refiners – use a simple formula called “back-pricing” to make their choices.

For example, compare the following formulas:

(1) Feedstock Back-pricing = Cost of feedstock by weight + efficiency of conversion into ethylene (or propylene or BTX) + value of by product + operating costs (OPEX) + feedstock losses

(2) Feedstock Back-pricing = Value of ethylene and by-products.

Export/Import

Propane makes up the majority of LPG exports and sales volumes abroad have been increasing rapidly over the course of 2012.

US Norms versus Foreign Markets

As detailed with butane, propane is a major road fuel in many foreign markets. Propane is used in Asia Pacific ethylene cracking and petrochemical feedstock demand has expanded rapidly in recent years. In contrast to the US, where there is substantial infrastructure to store, move by pipeline, tanker-truck or ship propane and butane, many LPG producing countries simply try to use any propane (and butane) produced near the point of supply, particularly refinery-derived LPG. This creates a certain price inelasticity – the propane is produced as a natural function of refining (though volumes are minimized) and is sold at low prices near the refinery simply because it costs too much to build infrastructure to export it for a better price.

4. ETHANE

Characteristics

Consisting of only two carbon molecules, ethane is the lightest NGL, though often is lumped together with methane as dry gas. Of all the NGLs, ethane has the highest conversion factor for ethylene, though is less effective for creating propylene and is not used for BTX. While prized as an ethylene cracker feedstock, ethane produces little byproduct – and often a NGL is chosen by petrochemical buyers not only on its primary value, but the value of by-products. Ethane has its greatest petrochemical impact where there is gas/NGL infrastructure and large-volume gas production, mainly North America, Western Europe and the Mideast Gulf. It will make up a large share of NGL output.

Utilization

On a yield comparison, ethane yields 77.7% ethylene and propane only 42%. (A full list of ethylene conversion factors follows below.) In countries with limited gas production, ethane is usually retained within the gas stream to the limits of carrying capacity and simply burned. There has begun an enormous and relatively quick-paced shift in US petrochemical feedstock for ethylene crackers. As recently as 2005, heavy feedstocks made up 40% of ethylene cracking feed, while in 2013 this should fall to roughly 20%. Petrochemical companies are betting on moderately priced ethane to base a sustained expansion for olefin capacity.

Petrochemical feedstock use, however, is far more attractive as a value proposition. The problem is that the ethylene crackers have to be built, or existing plant has to be converted from flexi-crackers, using liquid feedstock, to ethane use. In tandem these two factors, the upstream/midstream need to complete gas-stripping/NGL processing infrastructure, and downstream, the need to complete ethane-based ethylene cracking capacity to absorb incremental output, have slowed the development of Marcellus shale reserves. Field development is running ahead of the gas/NGL infrastructure to separate, clean and transport output. This has delayed new production – wells remain unconnected and even if connected and infrastructure was completed, there is limited ability of petrochemicals to utilize the output. The ATEC Express pipeline to Texas, home to most US ethane-based petrochemical capacity, will ease the problem, but the full solution will come from the commissioning of large, new ethane-based plants in the Northeast.

Pricing

Mt. Belvieu provides ethane's pricing basis though Conway, Kansas is a secondary pricing point often used by sellers as a *double-check* on Mt. Belvieu. The two gas/NGL gathering centers are linked by pipeline, but ethane stocks often build to overhang first at Conway, deep in the interior, while Mt. Belvieu is located close to the majority of US ethylene cracking capacity on the USGC. When ethane prices fall near or equal to methane value, production is shut in, though this may change if exports grow by end-decade. While many analysts predict a long in ethane, lasting through 2016, we believe there will be at least some delay in most new ethylene crackers starting up, and some projects will be abandoned. The possibility of an ethane long running through end-decade we believe is substantial, unless export efforts are redoubled.

According to Platts data, in January 2013 profits for an ethane-based ethylene cracker averaged above the $1,100/MT mark, which translates into a $650/MT return on feedstock costs, when the price of spot ethane is taken into account. In early 2012 and much of 2011, ethane was traded at below $0.34/Gal, or $14.28/BBL. In 2012, ethane prices were at a 10-year low, allowing for average ethylene cracker margins of $750/MT, if only ethane was used as feedstock. Olefin companies five years ago thought that ethylene margins of as little as $220.00/MT were acceptable, if not desirable.[6]

Export/Import

Only very limited volume of ethane is exported to Canada; Mexico may well develop as a future piped ethane market by 2020. A proposal to ship ethane in cryogenic tankers, converting an old LNG carrier, has been most commonly mooted and has been studied by a number of companies, both to bring excess ethane from the Northeast to the USGC before grassroots ethylene crackers start up in that section of the country and to export to foreign markets, notably Asia Pacific. Export of an ethane/propane (E/P) mix to European markets will begin in 2013 from Marcus Hook, a site near Philadelphia. There has been scattered seaborne ethane-only trade in the past, but of minimal volume. Though the economics of moving ethylene by ship are far better than ethane, the high entry cost for creating ethylene capacity – at least $7 billion in the US for a 1.0 MM MTA plant – makes this idea worth considering. Growing Marcellus ethane output may also mean a regionalization of this ethane long.

US Norms versus Foreign Markets

As mentioned earlier, ethane is often burned as piped gas, up to pipeline tolerance. This use as *heating*, i.e. calorific value, is minimal in the US market, but quite substantial in countries with moderate-volume gas output or no petrochemical capacity.

Table 9. Ethylene Conversions on Weight Basis*

Feedstock	Ethylene Yield
Ethane	77.7%
Propane	42%
Propylene	14.8%
Butadiene	8.6%
Butylene/Butane	0.8%
Benzene	3.4%
Fuel Gas	70% (questionable)
Toluene	0.8%
Pyrolysis Gasoline	8.6%

Note: *Maximizing ethylene
Source: RBN Energy

Yet it should be noted that the strong probability of moderately priced – if not severely discounted - ethane supply has prompted many international base petrochemical companies to invest in the US market. Less expensive feedstock is a key element in the competitiveness of future US ethylene crackers and the emergence of shale NGLs

[6] "US chemical makers stuffing their piggy banks ahead of expansion boom, expenses," Platts Blog, By Bernardo Fallas | January 29, 2013

presents a challenge to Mideast producers, which has traditionally relied mainly on cheap ethane and LPG to underpin a massive expansion in olefin capacity.

D. How NGLs Became a Shale Gas Driver

Table 10. US Gas Output (In BN CFD)

	2010	2012 (Est.)	2015	2017
Total Gas	**58.9**	**69.4**	**72.5**	**78.5**
Conventional	24.3	25.5	22.3	20.4
Other Unconventional	21.0	23.3	24.1	25.0
Shale	13.6	20.6	26.0	33.1
%Share Shale Gas/Total Gas	**23.1%**	**29.7%**	**35.9%**	**42.2%**

Source: APEC, IEA, DOE/EIA

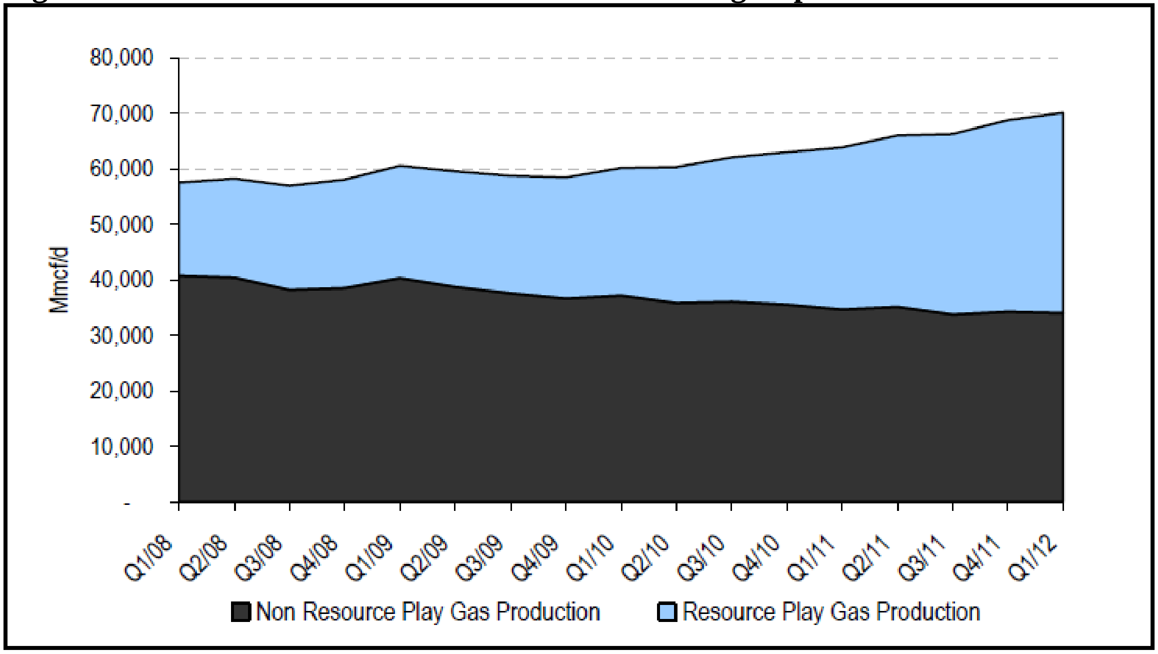
1. "IN THE BEGINNING …"

Fracking uses controlled explosions to open impermeable gas and oil reservoirs. Operators then inject water and chemical blends, under pressure, to force hydrocarbons to the surface. Shale formations have been known for decades and fracking, in some form, has been used since the beginning of the oil and gas industry, some 150 years ago. What is different now is that it is a programmed, systematic application of hydrocarbon recovery. Both its scale and sophistication now is substantially greater than when first experimental efforts began in 2006-2008 and could not have been imagined even by grizzled roughnecks a decade ago.

Systematic fracking in shale projects began as an attempt to exploit unconventional gas reserves that previously were deemed subcommercial. Yet as marketed gas production began to steadily rise from 2009's level of 59.4 BN CFD of marketed dry gas to 61.32 BN CFD in 2010 and gaining 4.53 BN CFD in 2011 to reach 69.36 BN CFD through Nov. 2012.

Much of that incremental gas production came from shale projects with this new area of gas production not only underlying the overall rise in gas output, but more than making up for a sustained decline in offshore, Gulf of Mexico, gas volumes.

Figure 2. North American Gas Forecast: The Growing Importance of US Shale Gas



Source: Canadian Imperial Bank of Commerce (CIBC)

Gas prices, both physical trade set on Henry Hub prices and gas futures, as shown by the NYMEX, began to decline. The year 2010 was the turning point, as a soft economy which reduced gas demand, plus rapidly building domestic gas output made shale gas production far less profitable, if relying solely on gas sales revenue. As gas prices softened, field operators turned to liquids-rich finds.

We are using NYMEX prices in the figure below, as they are by definition looking forward and though they sometimes differ from Henry Hub prices, they do reflect the sentiment of a broad range of the oil and gas sector. NYMEX gas prices in 2010 actually rose by 5.3% over 2009's $4.16/MM BTU level – but that was more due to a wave of relief that the US economy avoided a full economic crash the previous year. By end-2010 – and reflected in the 2011 - average prices began to rapidly soften, and that trend has continued throughout 2012. The average NYMEX gas price in 2012 of $2.82/MM BTU was an extraordinary 30% below the previous year's average price level.

Table 11. Average NYMEX Gas Prices

Year	WTI $/BBL	Brent $/BBL	Spread $/BBL	Gas NYMEX $/MM Btu	WTI/Gas Ration
2009	62.09	62.67	(0.58)	4.16	14.9
2010	79.61	80.34	(0.73)	4.38	16.2
2011	98.14	110.91	(12.77)	4.03	23.6
Est. 2012	94.39	112.02	(17.63)	2.82	33.4

Source: Deutsche Bank Commodities Outlook, Jan. 8, 2013; pgs. 34-38.

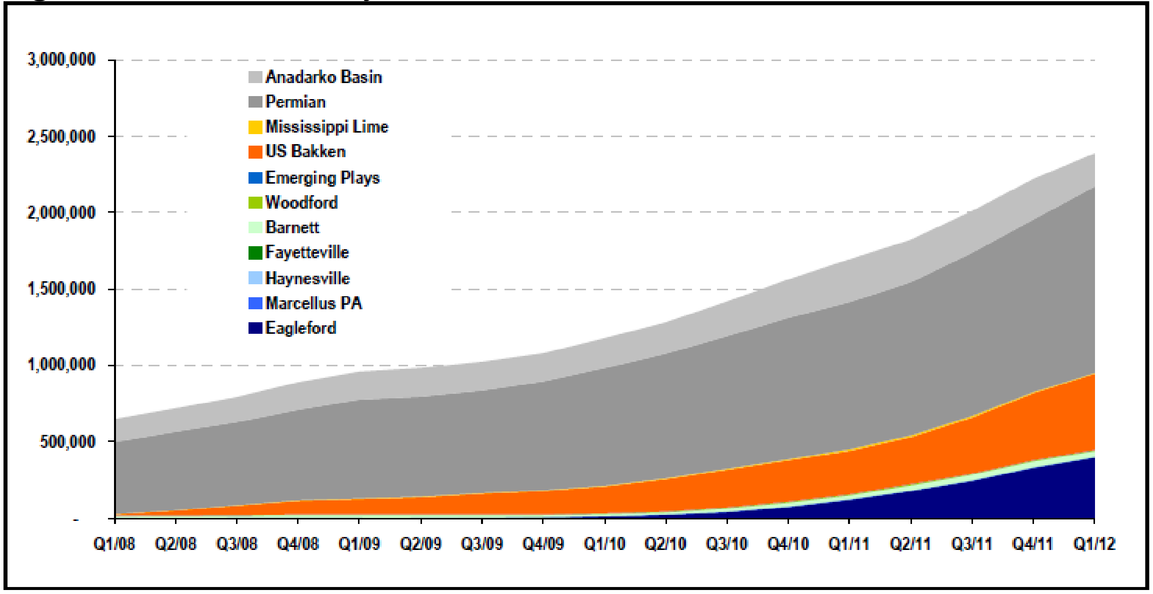
2. ACT THE SECOND

With gas sales providing barely enough revenue to cover development and operating costs, explorers began to turn away from dry shale development in the Barnett and Fayetteville basins (Texas, Arkansas, Louisiana), to liquids-rich prospects. Bakken, an enormous shale reserve covering much of the state of North Dakota and extending far into Canada and Montana, was the first target of opportunity, and black oil production was the driver. Eagle Ford, located in southern Texas and extending well into Mexico, became the second area of liquids-driven shale development.

Why focus on shale-derived oil? A quick glance at Table 11. above shows that it was not so much the absolute value of gas – which until the second half of 2010 held up relatively well, but the value of gas to oil. Traditionally the relationship gas and oil, as reflected in a barrel of oil equivalent – the heat produced by burning 1 barrel of crude oil is accounted as 5,800 CF of gas for 1 barrel of oil. (Though this standard is used by the US Internal Revenue Department and so adopted in American financial documents, the more common international field practice is a conversion of 6,000 CF to 1 BBL, the famous 6:1 value ratio. This BOE methodology has long been used by the financial sector to account for gas reserves as “converted” to oil, though conceptually it is inaccurate – gas can never be equivalent to oil, as gas generally is burned, while oil – and NGLs – often have a market value far higher than their calorific value. By 2009, the futures price of crude, as measured by WTI to NYMEX gas had fallen to a ratio of 14.9; by 2010 to 16.2 and by 2011 to 23.6. When a producer had any choice as to which potential reserve to develop first, it was obvious that wet, particularly oil-rich shale formations had top priority.

Considerable differences between the two shale basins became evident by 2012. Bakken oil production began rising rapidly by 2011 and by 2012 pushed North Dakota into third spot as an oil-producing state by volume, behind Texas and Alaska. Eagle Ford followed, as explorers found that it also contained large volumes of NGLs and that, in order to maximize profitability, all NGL output had to be utilized, with the field condensate making a particular impact on oil output. By October 2012, some 30% of the *crude* produced from Eagle Ford was in reality field condensate.

Figure 3. Oil Production by Shale Basin



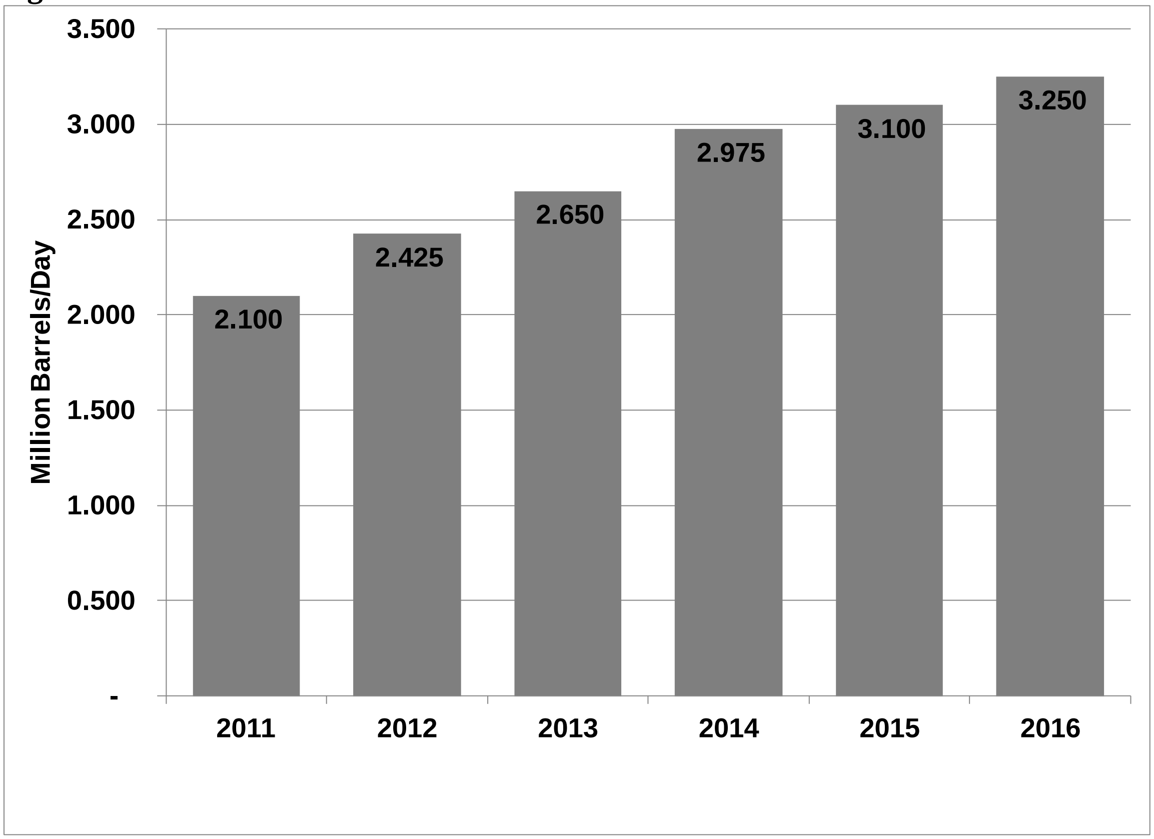
Source: Canadian Imperial Bank of Commerce (CIBC)

Once known oil-rich shale gas discoveries began development, upstream operators turned to NGL-rich fields. Drilling began to focus on the Marcellus formation in the Northeast of the US, as well as the underlying Utica shale formation, wetter though smaller in extent than Marcellus. Other explorers began to appraise and develop wet shale areas in Oklahoma's Cana-Woodford basin and in Niobrara basin, mainly in Colorado. Explorers with limited survey realized the enormous size of California's Monterey shale basin.

The liquids emphasis, however, shifted – NGLs became the development target, as the easy and known oil formations were already put into play. NGL output began to rise sharply, with production of 2.1 MM B/D in 2011 rising to 2.425 MM B/D in 2012 and expected to reach 2.65 MM B/D in 2013, a gain of over 26% in two years.

Shale gas development is now driven as much by liquids as gas. The IEA 2013 base case output puts shale oil production in 2013 at about 2.4 MM B/D. NGL forecasts average well over 2.6 MM B/D. It is fairly certain by the end of this year that shale will account for between a quarter and a third of all US liquids output, crude and NGL combined. Shale output will underpin a rise of at least 900 MBD to 7.3 MM B/D for US oil output.

Figure 4. North American NGL Forecast Production



Source: Russell Braziel, RBN Energy, Crude & Midstream Liquids, Presentation, Aug 16, 2012 at Colorado Oil & Gas Association

This has also had an impact on the traditional relationships between crude, gas and NGLs. In 2000, gas was still considered a poor relation of oil and though seen as an increasingly important part of US energy use, incremental supply was expected in the form of LNG. As late as in 2008, new LNG receiving terminals were being proposed – and DOE projections showed a steady increase in US gas imports. The Shale Revolution overturned these assumptions. Shale projects also changed the relationship of gas to NGL. Traditionally gas was the dog and the NGL was a by-product *tail* of that output – one did not increase or decrease gas production from a wet field because condensate prices rose above crude, or fell sharply. The need was to provide gas for the main sales contract. Shale development shifted NGL from a by-product of gas output to a co-product, and increasingly as gas prices appeared to settle in for a long spell of *softness*, NGLs have became a production driver, just like oil. The tail has begun to wag the dog.

3. ENCORE OR INTERMEZZO?

Big changes too have been continuing in the shale upstream. Increased operating experience, new well fluids, better surveying have increased shale reserves, while decreasing costs. Increasing operational efficiency, as much as any other single factor, had been responsible for the shale underpinning a surge in US production.

Fewer wells are producing more gas. In November 2013, the number of rigs drilling for gas fell to its lowest level in 13 years – yet gas production continued to rise. A massive effort has begun to expand gas and NGL infrastructure –to produce the raw gas, separate the NGLs, process them into final products and transport them to end-users. Even if politics interfere, momentum will tend to keep shale project output at high levels.

Yet the sector's move to create the infrastructure to produce additional NGLs perversely enough has also led to an overhang of supply – most notably for ethane – as the plant to use this additional NGL has yet to be completed. This has led to a buildup of stock in Mt. Belvieu, the key pricing point, and by end-2012 all US NGLs prices were depressed.

In Jan. 2013, ethane prices were 64% blow prices a year earlier and only were 10% of the value of WTI – itself discounted to international crude prices represented by Brent. Propane in early 2013 was selling at 40% of WTI price, compared to a value 56% of WTI in January 2012. In Conway, Kansas, another important NGL collection point, prices fell below even that level. Producers stopped stripping ethane completely or shut in output, an echo of gas producers' efforts in 2011-2012. Shale output is not for the faint of heart.

While the opening of new export facilities will support price increases for most NGLs, ethane remains particularly vulnerable as exports will be limited for many years. Once current projects to debottleneck operating ethylene crackers and to recommission idled capacity are completed – most likely by end-2013 - incremental ethane will have no place to go – until new plant starts up by end-2016, or more likely 2017. NGLs make up a major part of profitability of onshore wells. Occidental Petroleum (Oxy), one of the largest US independents, estimated that each $1/BBL drop in the value of the average weighted NGL barrel reduces its quarterly profit by about $8 million – and Oxy is mainly a conventional gas producer in the American market.[7]

While we expect NGL prices to recover in the short term and while the ethane balance will remain a worry for some time, it too will reach equilibrium. We believe that energy analysts – and policy makers – should pay far more attention to two basic indicators that will help flag changes, in particular that of NGL-rich gas projects.

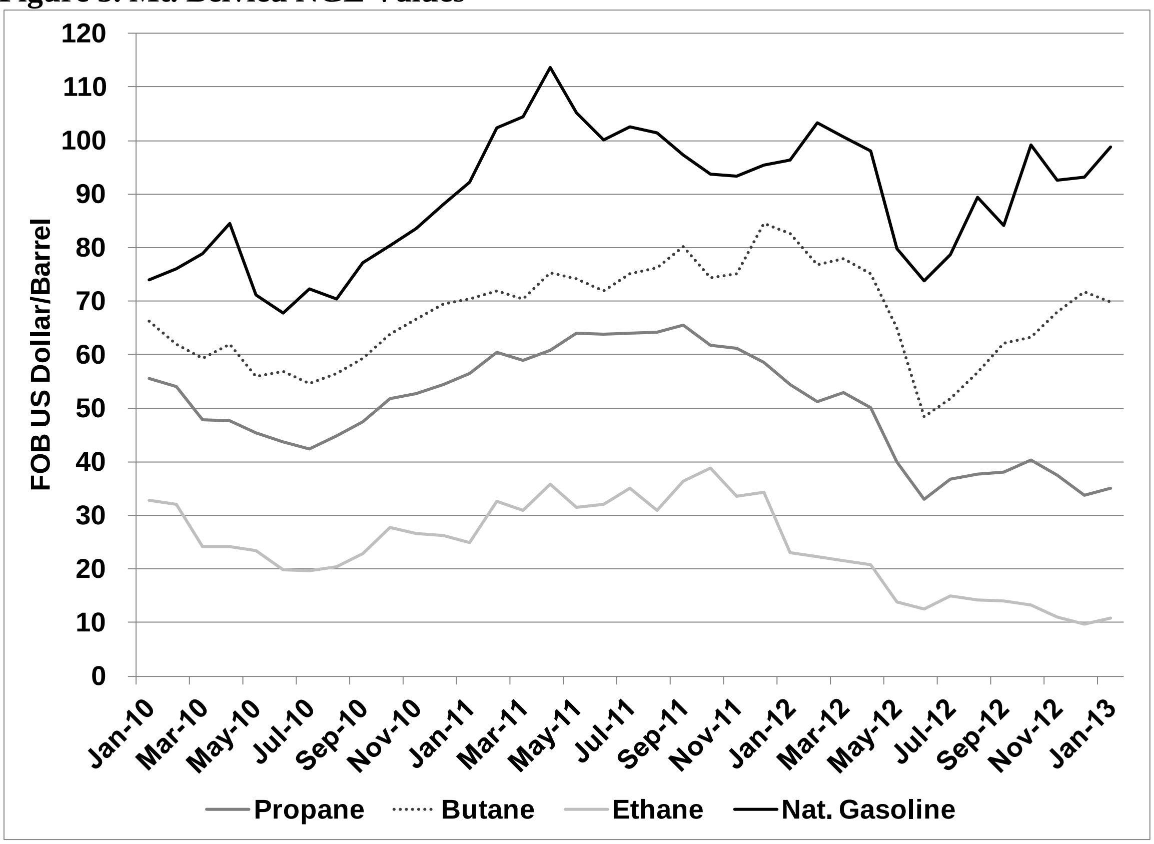
The first tool measuring NGL profitability is the *fractionation spread*, not to be confused with fracturing a shale structure. There are many ways to measure a fractionation spread, but the simplest is the difference between the price of natural gas and the weighted average price of the NGL barrel derived from fractionation on a BTU basis. This *Frac Spread* is a simple calculation of the value difference between natural gas and NGLs. The wider this spread becomes, the more favorable the market for NGL production, as NGLs

[7] WPA Jan 11, p7, "Producers stung by NGL slump"

increase their value over the base price of gas. NGL output will be reduced once the spread narrows to $4.50/MM BTU or less.[8]

Another way of measuring value has been introduced briefly earlier – the relative value on a calorific basis of gas to oil. If WTI is divided by the price of gas, you get a rough measure of gas profitability; a slightly better calibration compares gas to oil on a calorific basis, using BTUs for comparison in the US market. Though both methods are simplistic – calorific value is an inaccurate indicator of a NGL's worth, but the *financialization* of crude prices, as financial institutions have increasingly used Brent or WTI prices as a value proxy for dollar, Euro or gold, support these simple calculations of relative worth. The last time gas has been worth so little to oil was decades ago and that at base, is what made shale producers turn to NGLs.

Figure 5. Mt. Belvieu NGL Values



Source: Petroleum Argus, Reuters

[8] RBN Energy, "NGLs in 50 X crude-Gas Ratio World"

E. Different Strokes for Different Folks: The Shale Basins

Liquids pay for shale development now, not gas. This section examines the profitability of shale development and in detail some selected shale basins, including Bakken, Eagle Ford and Marcellus/Utica, that impact US production of NGLs and crude. These were chosen to represent the many shale basins under development: Bakken, because it began as a mainly oil play that will become a substantial NGL producer; Eagle Ford, because from inception it was clear that NGL would be almost as important as oil output, and Marcellus/Utica, because as a NGL producer output will focus on ethane, with Utica providing a smaller volume of oil mixed with condensate.

Producers would like to avoid the expression shale-derived oil, much preferring *tight oil* as a more accurate description. Such reserves as in Bakken are trapped between two layers of shale deposits. In the Permian basin of northern Texas, shale development has been seen only in the western section of the basin, the Wolf Camp & Bone Springs shale developments. Permian oil output is so mixed between conventional and shale-associated output that no *pure* tight oil assay is readily available, though Permian output appeared to be in part similar to Bakken/Eagle Ford and in other areas, a heavier (37-38 API) higher sulfur (0.3-0.4%S) crude grade. We purposely excluded this region though, as it appears that conventional fields will continue to dominate production – though oil output should rise to about 1.4 MM B/D by end-year. For the same reason we have excluded Niobrara.
Though it is true that even dry gas produces limited NGL, we have excluded a number of limited NGL plays, such as Fayetteville, Barnett and Haynesville basins.

The high variability of NGL production – and its impact on profitability – can be seen in the Table 12 below. The Rate of Return on Capital Employed (RORCE) due to NGL output varies widely. In NGL terms, Eagle Ford and Marcellus exceeded Bakken output.

Table 12. RORCE – Selected NGL Producing Fields (%)

Field	RORCE
Eagle Ford – Liquids Rich	59%
Marcellus/SW – Liquids Rich	55%
Marcellus Shale/SW	40%
Bakken/Three Forks	40%
Barnett/Core	30%
Cana Woodford	29%
Marcellus/NE	28%
Barnett/Southern - Liquids	23%
Barnett/Dry	17%
Powder River CBM	6%

Source: NGL 2012 – The Basics," June 6, 2012, by Anne B. Keller, Midstream Energy Group

The role of independent upstream companies, most notably independents Continental and EOG, in tight oil and NGL production is underplayed. BP has been the only major in the top tier of shale NGL producers and Enterprise the only independent producer of substantial oil as well. The other companies, producing at least 100 MBD of NGLs, such as DCP Midstream, Aux Sable Liquid Products and Targa, were mid-stream companies focusing on stripping, cleaning and separating NGLs from gas.

Part of this calculation of NGL's profitability in shale development comes from its *wetness*, i.e. the volume of gas liquids produced per MM CFD of gas. Formations with substantial black oil and NGL output are the most profitable we believe in the medium term – Eagle Ford is among the leaders in this regard and had, unlike Bakken in the Northern Great Plains, an established gas/NGL infrastructure and close proximity to the refining heartland of coastal Texas/Louisiana.

Table 13. Gallons of Natural Gas Liquids per MCF by Shale Play

Rich Gas Sales	NGL GPM *
Avalon/Bone Springs **	4.0 – 5.0
Bakken **	6.0 – 12.0
Cana-Woodford	4.0 – 6.0
Eagle Ford ***	4.0 – 9.0
Granite Wash	4.0 – 6.0
Green River **	3.0 – 5.0
Niobrara **	4.0 – 9.0
Piceance-Uinta	2.5 – 3.5
Montney	3.0 – 4.5
Marcellus-Utica ***	4.0 – 9.0

Note: * GPM = Gallons Per MCF; ** Oil Shale Plays; *** Oil & Gas Shale Play
Source: Energy Policy Research Foundation, Inc. (EPRINC), Lighting up the Prairie, Sept. 2012; pg. 18.

Yet we can roughly estimate what NGL output on average would be the breakout of shale derived NGLs. The rule of thumb used in recent years is that NGL output, on average and in aggregate shale will yield 40% ethane, 50% LPG and 10% condensate. Yet rising NGL output from Eagle Ford, Marcellus and to a lesser extent Bakken will change the mix of NGLs. How quickly this can shift is seen in the table below from mid-2012.

Table 14. NGL Mix & Yield

NGL	2009 Average		Dec 2011 Average	
	MBD	%Share	MBD	%Share
Ethane	768	40%	1,005	43%
Propane	547	29%	669	28%
Butane	134	7%	165	7%
Iso-Butane	191	10%	212	9%
Condensate	267	14%	306	13%
Total	1,907		2,357	

Source: NGL 2012 – The Basics," June 6, 2012, by Anne B. Keller, Midstream Energy Group

Explorers at the beginning of the shale development surge in 2010 predicted a 10% p.a. rise in output through mid-decade. In fact, we have far exceeded this forecast increase so far, only through 2012. A more sophisticated analysis comes from RBN Energy in its "Golden Age" article of March 18, 2012, where the company concluded that the *typical* NGL barrel produced in the US from shale formation in 2012 would average 42% ethane, 45% LPG (29% propane, 10.5% butane and 5.5% iso-butane) and 13% condensate.

APEC sees a slightly different pattern emerging in the medium term. We expect ethane to make up at least 40% of output, which may well increase to 42% later, due to ethane-slanted production from the buildup of Marcellus/Utica NGL production. Yet there the minimal ethane market in the US Northeast is dependent on the conversion to ethane of a handful of ethylene crackers now operating there. New large-scale olefin complexes will only start up 2017-2018. Boosters claim the ATEX pipeline will allow easy sales to the vast market of USGC petrochemical plants, but this must compete with Mt. Belvieu supply from a great distance. Transport costs will make this supply costly. We believe the lack of ethylene cracking in the northeast, combined with transport costs will limit the growth in ethane output, possibly increasing the amount of potential ethane-rich gas being *shut in*. In any case ethane's share of the NGL output barrel will rise – but likely more slowly than many believe.

Our outlook is slightly less optimistic for LPG than the RBN forecast as well. New NGL infrastructure in the Bakken formation now allows producers to strip the full range of NGLs from gas production – much of which was wasted as *flare gas*, as there were no facilities to either process nor transport output. As of mid-2013, Bakken producers were flaring more than 700 MM CFD of wet gas and losing both gas and more importantly, NGL revenue. Upstream analysts believe that Bakken NGLs, unlike Marcellus, will be slanted towards the heavier NGLs – butane, iso-butane and condensate and this too will shape future output. In October 2012, on a 12-month basis, North Dakota's oil output rose 250 MBD, almost all of that from shale. There were large volumes of NGLs lost – they will underpin a sustained growth in heavier NGLs from this basis through 2017.

Table 15. US Average Yield by NGL

NGL	% of Total NGL
Ethane	40%
Propane	27%
Butane/Iso-Butane	18%
Plant Condensate	15%

Finally, as Eagle Ford crude production builds rapidly, output was 327 MBD for the first 9 months of 2012, there has been growing realization of the problem and opportunities in condensate. As current regulations allow, we are only accounting plant condensate *natural gasoline* as condensate production. We expect the current regulatory regime to remain for some time and field operators will continue to push as much field condensate as possible into their crude. In this short-term outlook our 2013 NGL barrel averages are given in Table 15.

The proportion of condensate in crude will rise as Eagle Ford producers exploit the *condensate zone*, further south than the oil-focused northern development area. By end-2012 condensate had risen, as a proportion of crude, to about 33%, and refiners, processing this crude have found naphtha yields as high as 43%. Light crude normally produces only 22-24% naphtha in distillation. Average crude has become much lighter – in the first three quarters, Eagle Ford oil averaged 37-38 API; by 2013 it averaged 40-42 API. Further confirmation of condensate's increasing impact has been seen in rising plant condensate output and this is slanting the NGL barrel to condensate, at least in Eagle Ford production.

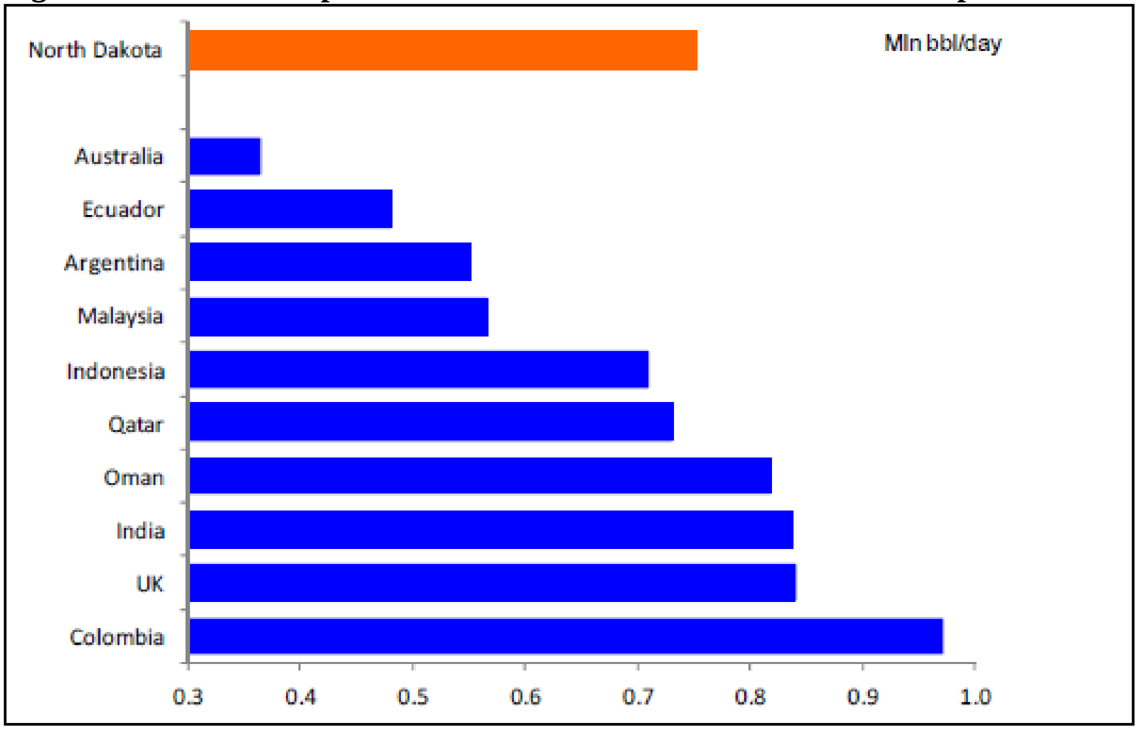
If field condensate continues to increase in Eagle Ford crude blend, it will become usable only in modest volume in complex USGC refineries as it has little *bottom*, i.e. heavy product needs to provide feedstock to severe secondary units, in particular cokers. An ongoing debate will grow, as proponents push the regulatory agency, the Department of Commerce, to make it profitable to separate and segregate field condensate for export. This simple solution remains controversial, but the alternative – since crude cannot be exported – will be growing discounts on Eagle Ford oil. Eventually incremental tight oil output will be capped. If field condensate was exportable, then we could easily see condensate production jump to at least 20% of US NGL output and a slower, but steady rise in crude output. (For further details on both points, see the Eagle Ford section below.)

1. BAKKEN

While seen largely as an oil-producing province, Bakken has considerable potential to sharply increase its NGL output, paralleling the region's dizzying rise in oil output. We estimate that NGL output topped 75 MBD in 2012 and was rapidly increasing, based on the sharp increase of output recorded by shale producers. In 2012, PADD-2 saw a 132 MBD gain primarily from Bakken shale projects, and North Dakota moved into second place behind only Texas for total oil output. North Dakota alone accounted for more than three quarters of crude production from that administrative district. In fact, the single state of North Dakota, excluding plant condensate, produced more crude than a number of international oil producing countries.

Bakken is situated mainly in North Dakota, but also extends into neighboring states as well as Canada's Saskatchewan and Manitoba. Gas reserves have been rising steadily in recent years, as further shale deposits have been drilled and appraised, and the completion of vital pipelines and just as important, gas stripping and NGL fractionation plants, should underpin a sustained, broad-based rise in NGL output. In 2011, proven and possible gas reserves totaled 1.85 TCF, which should double by 2014. In 2010 the state estimated recoverable reserves of 4 BN BBLS of oil and 148 MM BBLs of NGL. At end-2010, the North Dakota Pipeline Authority forecast 80 MBD of NGL output by 2013. Their analysis of typical production in this state (conventional and shale) showed a breakout then of 84.7% crude, 13% NGL and 2.3% gas. According to the state authority, NGL output would rise at a ratio of 1 BBL of additional NGL for every 6.515 BBLs of incremental oil.[9]

Figure 6. Shale Oil has put North Dakota on the Global Crude Oil Map *



* Qatar produciton shows crude oil only; for other countries black oil and segregated condensate.

The chief impediment has been the lack of gas/NGL infrastructure. If 2012 oil output approached 800 MBD - by November it had risen to 733 MBD - then NGL production should have approached 125 MBD – not 75 MBD. Yet 2013 will likely become the year NGL output gets into gear. Oil producers have been as keen as mid-steam companies to get infrastructure up and running, as NGL production increases total production revenue. A powerful incentive to build this infrastructure building is pending. The state legislature has considered legislation to require producers to utilize associated gas production within a year of well startup. North Dakota flared 700 MM CFD by mid-2012 and though this had been reduced to 300 MM CFD by end-year, unless new infrastructure is completed, flaring will rise again sharply by 2017.

Pipelines and fractionation are the key choke points. Oneok Partners is the biggest NGL company operating in Bakken and is expanding its gas processing and fractionation capacity by nearly 50%, Its focus had been on expanding exports to Canada, but now reorienting to the domestic market. The new $500 million Bakken NGL Pipeline will transport 60 MBD of mixed NGLs from Richland County, Montana, to Weld County,

[9] North Dakota Pipeline Authority, Sept 2, 2010, Paper

Colorado, hooking up to the national network. Rival Vantage, a mid-stream company that had focused on ethane recovery, will add full NGL recovery and fractionation, but the top priority remains an ethane pipeline from the Hess NGL complex in Tioga N.D. to the Canadian pipe network at Empress, Alberta and will supply ethane to Nova's olefin plant in Joffre.

The third major project is the most ambitious the Alliance-Aux Sable Wet Gas Pipeline (sometimes referred to as the Tioga Lateral) that will transport a pressurized mix of gas, ethane and LPG some 1,600 miles from Canada to the Chicago area, gathering NGL output from multiple projects along its path. While condensate (C5+) will be removed, the project will process some 2.1 BN CFD of gas, transporting about 80 MBD of NGLs.

Table 16. NGL Pipelines

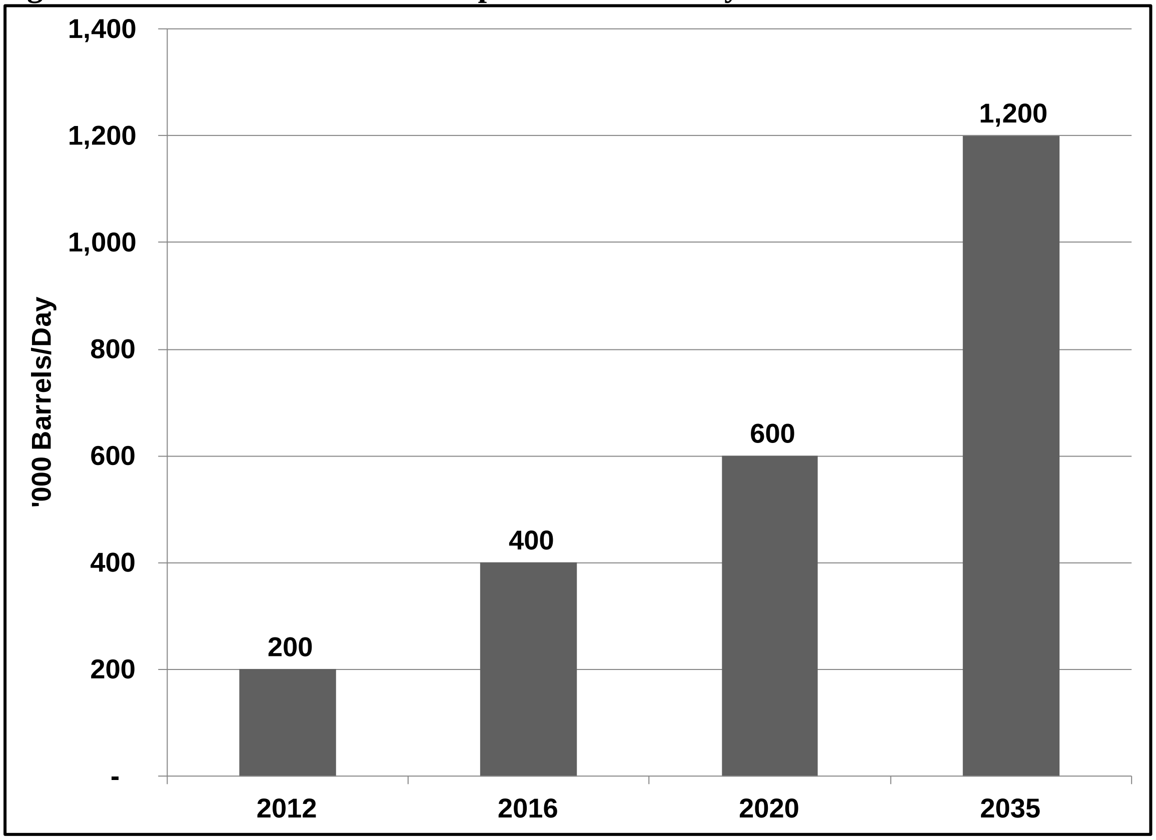
Name	Startup	Capacity (MBD)	Notes
Oneok Bakken/NGL Pipeline	2Q-2013	60	Mixed NGLs, with parallel expansion of gas processing & fractionation
Alliance – Aux Sable Wet Gas Pipeline (Tioga Lateral)	3Q-2013	80	Moves only ethane and LPG; Aux Sable also expanding fractionation.
Vantage Ethane Pipeline	2Q-2013	45	Mainly ethane

Source: APEC

In 2012, the main NGL impact of Bakken was in condensate production and its export, by limited pipeline linkage, but for the most part by expensive rail-car, to eager Canadian buyers. By mid-2012, Bakken-derived condensate provides much of the surge in US condensate exports, nearly doubling to 125 MBD by half year and rising to over 140 MBD by end-2012. We expect, at least in the medium term, a continuing rise in exports to Canada, supplemented by rail and pipeline exports from Eagle Ford. But Bakken condensate exporters are deluded, if they believe that Canada wants to absorb all their output – which will rise sharply over the next five years. This assumption is illustrated by the chart below, from a mid-2012 report by CERI, a Canadian energy think-tank.

It predicts that Canadian need for diluent will rise from about 350 MBD in 2012, with 200 MBD of that imported, to about 480 MBD by 2016 and top 650 MBD by 2020 and more than 500 MBD of that condensate supply purchased abroad.

Figure 7. Canadian Condensate Import Needs – Solely as Diluent



Source: CERI, Aug 2012

Oddly enough the study did not highlight explicitly the use of condensate as an essential component in the Synbit blend – adding a *top* to the blend of oil-sands derived mainly middle distillate, as well as some bitumen to provide a heavy component *bottom* to this oil blend. This will remain a major need of Canadian oil sands producers. Nor did it address the *recycling* of condensate in pipeline transport of syncrude west to Asia.

We disagree with CERI's outlook for two basic reasons: first is that Canada, like any country, will not let another country do for it what it can do itself. CERI's outlook for condensate production in Alberta was flat, about 100 MBD through 2017-2018. There was no recognition either of the large gas volumes needed to supply pending LNG projects in British Columbia. The gas for these plants will have to come from Alberta, as much as British Columbia and while Canadian government forecasts of 66 MM MTA of LNG capacity operating by 2017 are ridiculous, it is realistic to expect two LNG projects totaling 20 MM MTA by 2020. Much of this future gas to feed LNG exports will come from Canadian wetter shale deposits and wet finds will always be developed first.

Table 17. LNG Project List

Project	Location	Partners	Capacity (MM MTA LNG/BN CFD Dry Gas)
Kitimat LNG	Kitimat, BC	Chevron/Apache (50% each)	10.0/1.33
BC LNG	Kitimat, BC	LNG Partners/Haisia First Nations (50% each)	1.8/0.24
LNG Canada	Kitimat, BC	Shell (40%), Mitsubishi/Petrochina/Kogas (20% each)	12.0/1.60
Pacific Northwest LNG	Prince Rupert, BC	Petronas (100%)	Up to 18/2.39
Exxon LNG	Prince Rupert, BC	Exxon/Imperial (50% each)	Assumed 10.0/1.33
Nexen-CNOOC BC LNG	Prince Rupert, BC	Nexen, Inpex, JGC	Assumed 5.0/0.67
BG LNG	Prince Rupert, BC	BG (100%)	24.0/3.19

Source: WGI Jan 2, 2013

Even using a back-of-the-envelope set of calculations, it is clear that sizable condensate supply will emerge from LNG exports. It must be remembered that Canadian condensate producers suffer no export controls. We should be aware that butane too, in limited volumes, is used to transport syncrude in Canadian pipelines.

Table 18. Walking through an LNG Project Wellhead Output/Reserves Formula

	Lowest Case	Highest Case
1 MM MTA LNG = 133.33 MM CFD dry clean gas*; 20 MM MTA LNG = 2.67 BN CFD dry gas		
Gas Lost in Liquefaction	2% = 2.72 BN CFD	4% = 2.78
Removed Inerts	3% = 2.80 BN CFD	5% = 2.92
Removed NGLs	10% = 3.08 BN CFD	20% = 3.50
Gas Buffer Needed for Buyer Concerns	25% = 3.85 BN CFD	

Note: *Overwhelming consisting of methane.
Source: APEC

So a project that plans the sale of 20 MM MTA of LNG should use 3.08 BN CFD to 3.50 BN CFD or 1.12-1.27 TCF a year of dry clean gas. This is equal to 22.48-35.55 TCF over a 20-year project life. Yet buyers want to have an assurance that gas reserves are sufficient to underpin a long-term sales agreement. The normal size of this potential supply *buffer* ranges from a quarter to a third of annual gas sales set, some 25-33.3% needed in additional reserves. Therefore, a 20 MM MTA LNG project would need as a gas buffer an additional 5.62 TCF on the low end of our range and 11.83 TCF additional gas for this buffer for our maximum volume calculation. Total gas for the project would have to be 28.10 TCF to 47.39 TCF.

In conventional gas development a gas reserve is considered dry, normally producing 10-15 BBLs of condensate per MM CFD; moderately wet at 16-35 BBLs/MM CFD and very wet at 36-60 BBLs/MM CFD. If the average of gas produced for LNG use is moderate, i.e. in this 16-35 BBL range, the resulting condensate, field and plant combined, would be in the range of 49-56 MBD at 16 BBLs/MM CFD wetness; at 35 BBLs/MM CFD it would be 107-123 MBD. This is a conservative outlook. Explorers surveying North Monterey basin shale reserves have a very high wetness ratio though earlier appraised gas reserves in British Columbia tended to be dry. Some analysts suggest that the buildup in US gas production will back out Canadian piped gas exports to the US, making this gas inexpensive and ideal for LNG. We think that LNG projects will still develop their own gas resources, rather than depend on others.

Our second objection is based both on relative costs of syncrude and shale projects, and the impact of international oil prices on development. Since CERI's condensate calculation is a function of building syncrude output, it is worth looking at drivers for incremental output. Unlike shale development, syncrude is highly capital intensive - we estimated a 2012 break-even price at about $72/BBL for syncrude production. When international oil prices soften, smaller syncrude developers often delay, or at times simply shelve, developments. Analysts normally forecast the syncrude buildup as a smooth upward line, when reality is more like a step pyramid, with pauses in building volume, due to the unsteady funding and completion of capacity expansions.

This in turn assumes that international oil prices change steadily and at a moderate rate. It does not take into account increasingly volatile international oil prices and how Brent, in particular, has become a financial proxy used by investors to represent value changes in dollar, euro, gold etc. Volatility is here to stay and will impact future syncrude output. We see a step-pyramid pattern of incremental capacity. When the international price of oil tumbles, it will delay or cancel investment plans for some operators. The call on condensate therefore will be stretched out and ultimately may not reach 4.5 MM B/D capacity by 2020. This view, we believe is overly optimistic.

The buildup in NGL infrastructure has been paralleled by increasing pipeline capacity for moving additional oil barrels to distant buyers. At mid-2012 Independent Continental led all black oil producers with an average output of 61 MBD, while independents EOG, Whiting and Hess all produced between 40-50 MBD.[10]

[10] CLR Vision "Bakken: Changing the World," Continental Resources, Oct 9, 2012

Table 19. Oil Pipelines

Year	Project	Capacity (MBD)
2013	Enbridge BPEP	120
2014	High Prairie	200
2014	Pony Express	200
2015	Enbridge Sandpiper	325
2015	Oneok Bakken Express	325
2015	Keystone XL (Partial)	200

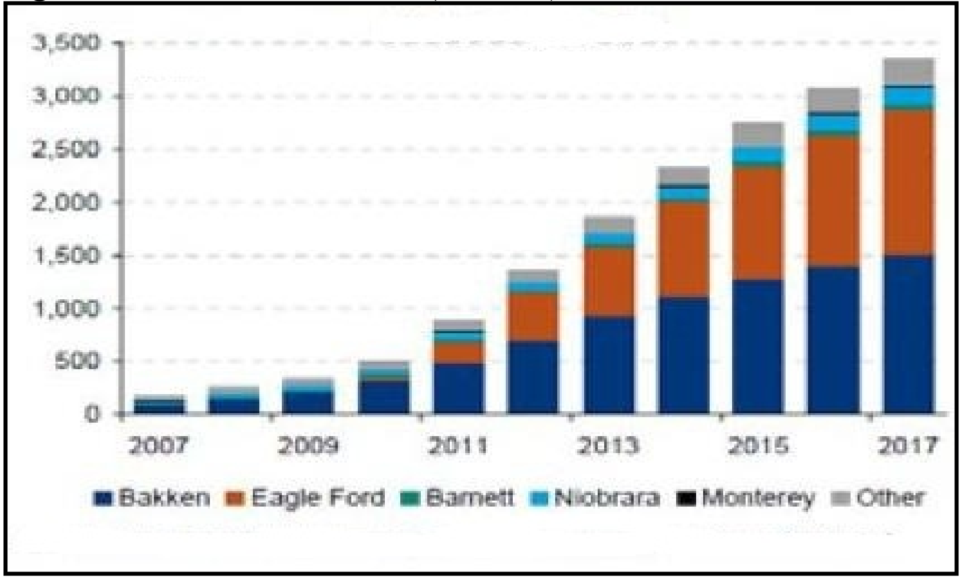
Source: "Bakken: Changing the World," Continental Resources, Oct. 9, 2012.

Pipelines will allow Bakken to overcome its deep discount to Brent prices – in particular pipeline access to USAC refiners and that the discount will fall to about $5/BBL by 2018. In contrast, Eagle Ford, in Texas, is at no point more than 300 km distant from the Gulf Coast, home to the bulk of US refining and petrochemicals. Even so, some Eagle Ford condensate moves to Canadian buyers, in part because condensate output is lighter and preferred by producers, using the Southern Light pipeline and the Reversed Cochin Line.

2. EAGLE FORD

While Bakken has been promoted as an oil play that only will begin to realize its NGL potential in 2013, Eagle Ford has been seen by explorers as an oil/NGL combined development from the very beginning. There are really three separate plays in the Eagle Ford basin, with the oil-prone zone furthest north, gradually changing to a condensate-rich NGL zone as one moves towards the coast, with a dry gas zone closest to the Gulf of Mexico. Surprisingly, there is little analysis done on NGL only by region. But BofA (Bank of America) Merrill Lynch Global's forecast below, broadly in agreement with DB's outlook, illustrates Eagle Ford's importance. The two areas will account for the bulk of the 3.2 MM B/D in tight oil output by 2017, and 4.0 MM B/D by 2020. Eagle Ford will account for a larger share of tight oil output, surpassing Bakken output by 2017.

Figure 8. US Shale Production (In MBD)



Source: BofA Merrill Lynch, Global Energy Weekly, "Energy Carrying America," July 6, 2012, Pg. 6

Yet a good deal of that Eagle Ford crude is in reality field condensate spiked into black oil. Our own outlook is conservative, but still represents a rise in shale-derived oil output.

Table 20. Forecast Buildup in Shale Basin Production (In MM B/D)

Basin	No Change Scenario			20% More Efficiency or Rigs		
	1/2012	2016	2020	1/2012	2016	2020
Bakken	0.509	1.100	1.400	-	1.450	1.650
Eagle Ford	0.422	1.200	1.600	-	1.400	1.900
Total	**0.931**	**2.300**	**3.000**	**-**	**2.850**	**3.550**

Sources: APEC, CIBC, EIA

EPRINC in March 2012 concluded that much of the Eagle Ford development activity early in the year was in the condensate zone, as much as the black oil area. Further, EPRINC concluded the full potential for oil production was then still not fully exploited and that expanding infrastructure could move Eagle Ford production capacity to higher levels than earlier forecast.

The Texas Railroad Commission, (TRRC) the state's agency that monitors the oil and gas sector, confirms these trends. In the first nine months of 2012, gas production fell 10% to 525 MM CFD, but plant condensate only declined 4.2%. Output of condensate during 2008-2012 rose only 28% compared to an increase in oil output of 96%. It is clear that much of this *black oil* was field condensate, roughly 20% of the oil output in 1-9/2012.

Table 21. Texas Total Oil/Condensate Production, TX RR Com (IN MBD)

Year	Oil	Plant Condensate
2012 Est. Final	1,897	183
2011	1,175	191
2010	1,011	155
2009	958	135
2008	966	143

Source: Texas Railroad Commission

Table 22. Comparing Eagle Ford vs. Bakken

Comparisons	Eagle Ford	Bakken
Depth (Ft)	5,000-11,000	8,000-11,000
Reservoir Thickness (Ft)	80-174	< 140
Organic Matter (%)	3-6	8-10
In Place Reserves (MM BOE/Sq Mile)	50	5-15
Initial Pre-Well Production (BOE/D)	300-2,000	300-2,000
Estimated Ultimate Recoverable Reserves (MM BBLs)	200+	200-700
Drilling Costs (Drilling/Completion in MM $)	4-7	5-9
Exploration Costs (Finding/Development in $/BOE)	, 20	10-25

Source: "Fifty Shades Lighter – What should be done with condensates?", RBN, Oct. 11, 2012.

A comparison of Eagle Ford to Bakken illustrates some interesting differences. Bakken reserves are deeper, generally hold thicker *seams* of oil, gas and NGLs and have been estimated to be more widely distributed over a far large area than Eagle Ford. Ultimate recoverable reserves of Bakken were believed to be far greater than Eagle Ford and made up the majority of output, with far less condensate and limited overall NGL production.

Yet geography plays a role too. Bakken is distant from most refining and petrochemical plant, while Eagle Ford is almost atop the USGC. North Dakota was sparsely populated with minimal oil and gas infrastructure; Texas in contrast has long had an enormous pool of educated labor available for almost any work imaginable in the energy sector – drilling costs, because of labor and support infrastructure, generally have been higher in Bakken, and geography, at least in part, explains North Dakota's exploration costs. Texas already had a large-scale and sophisticated gas gathering, processing and distribution system, paralleled by large-scale NGL stripping, fractionation and gathering. It is important to note that Eagle Ford was ready for large-scale NGL output from the beginning. Bakken had to largely construct much of its gas/NGL infrastructure.

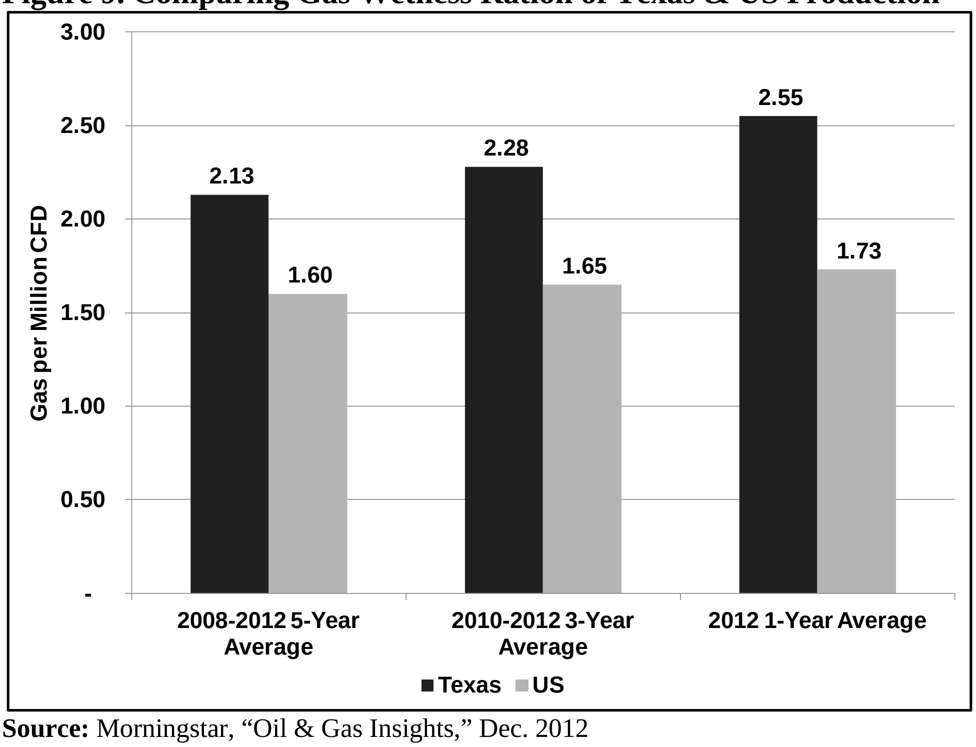
Average gas wetness in Texas is higher than the national level. Analysis by Morningstar showed wet gas production began to build in 2009 and increased steadily through 2012. US average GPM rose from 1.3 to 1.45 at that time. Marcellus too was a part of the overall NGL buildup, but in contrast to Eagle Ford's average production breakout of 60% oil, 30% gas and 10% NGL, Marcellus output was 90% gas and the remainder NGLs. Despite the national rise in NGL output, Eagle Ford and Permian developments kept

Texas at the top of the league with the former averaging 6-8 GPM at end-2012 at least double the state average and triple the national wetness level.

Yet problems do exist due to the enormous buildup in output. In 2009, Eagle Ford produced virtually no crude and very limited NGL output – yet by end-2012 liquids output was believed to top 700 MBD and NGL production approached 300 MBD, with more than a fifth of that plant condensate. While Eagle Ford already had infrastructure in place, much of it was designed for drier gas, half or less the current GPM ratio. At times over the course of 2012, pipeline puddling became a major problem, and companies accelerated efforts to reconfigure and expand processing plants – and added considerable NGL storage, a major factor in the commercialization of ethane and NGLs.

The nature of Eagle Ford production also created hiccups. NGL output is often *lumpy*, because it emerges in large volumes only when the gas supply chain is completed. In Eagle Ford output also was lumpy, because of high pressure wells and the increased use of multi-well drilling pads, which put much of the new production *upfront*. Initial NGL output is often higher than forecast and when decline begins, the rate of decline is rapid and ultimately irreversible. [11] International gas developers have had considerable experience in this, but shale NGL output continues to surprise.

Figure 9. Comparing Gas Wetness Ration of Texas & US Production

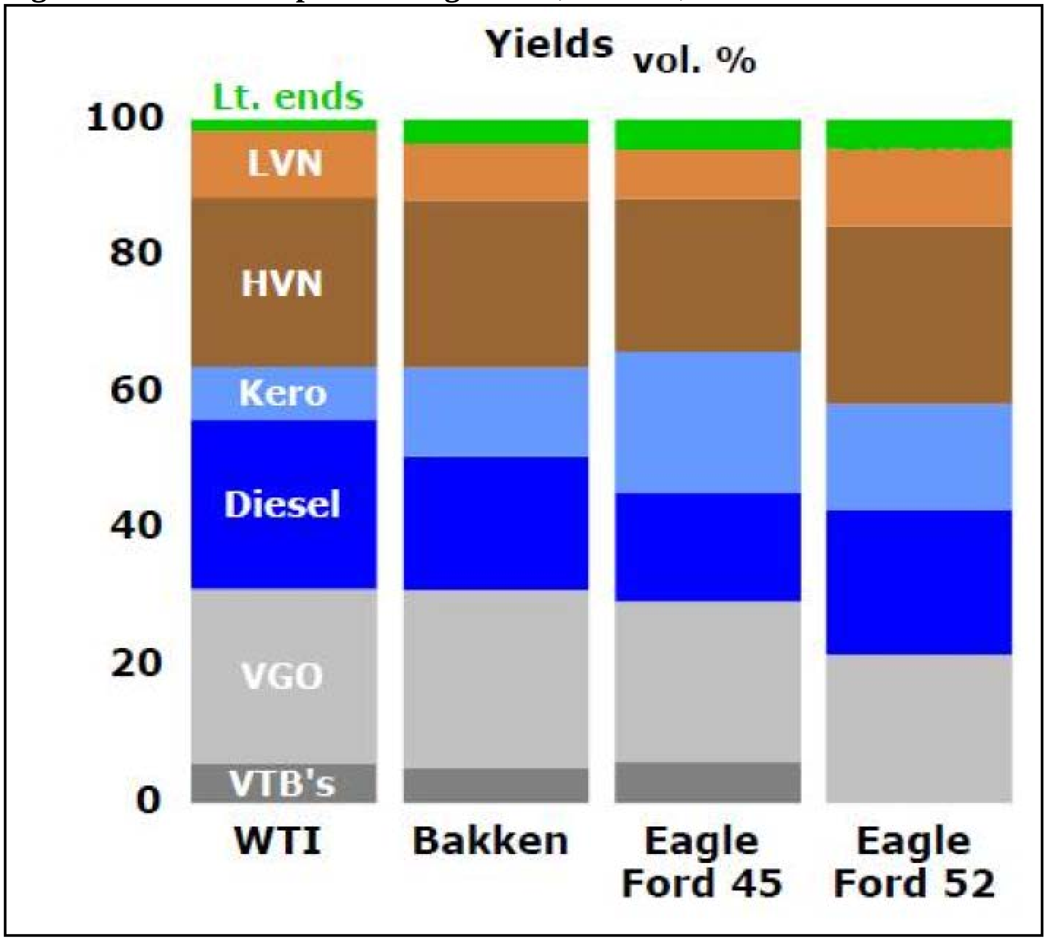


Source: Morningstar, "Oil & Gas Insights," Dec. 2012

[11] Rusty Braziel, "Lumpy - Soaking Wet – Moving Fast – that's Eagle Ford NGLs?" *RBN Energy*, http://rbnenergy.com/lumpySoakingWetMoving-Eagle-Ford-NGLs (accessed 12 April. 2013)

We estimate that at least 30% of Eagle Ford crude output in 2013 is field condensate, and still rising, a far higher proportion than Bakken. This has far-reaching ramifications for product balance, refining, export policy and international crude prices. A key question: When we refer to Eagle Ford crude, the question often is - Which one?

Figure 10. Yield Comparison Eagle Ford, Bakken, WTI



Source: Industry

Refiners have noted that the light product yield for LPG and naphtha (which produces both gasoline and petrochemical feedstock) has been far higher than the norm from a light crude grade of 38-45 API, almost double the expected outturn. Eagle Ford wells have yielded output ranging from 28-62 API. Other factors point to heavy – and increasing – spiking of condensate into Eagle Ford crude. USGC refiners point out that most shipments of this crude grade vary considerably in API and often in yield pattern. While claims of Bakken's quality consistency at 42 API and 0.1%S have been overstated, it is clear that Eagle Ford crude/condensate needs far more blending and often must be treated to reduce vapor pressure (RVP) at wellhead. Still the US Department of

Commerce has not considered this *processing* of a sub-surface non-liquid and has refused at least one request to have wellhead condensate declared, like plant, a NGL.

Table 23. Eagle Ford 39 Yield

Product	Cut (Degree F)	Vol. %
Light Ends	55-175	8
Lt. Naphtha	175-300	18
Hvy Naphtha	300-400	12
Kero	400-500	12
Gas Oil	500-650	16
VGO	650-1,050	15
Residual	1,050+	5

Source: Industry

Just a quick look at recent assays released above shows how widely Eagle Ford yields have varied. The crude is trending lighter and will likely continue to lighten as more condensate is added to the blend. In terms of the *Light Ends* i.e. naphtha and LPG, this ranges from 37% for Eagle Ford-52; 34% for Eagle Ford -45 and 38% for Eagle Ford-39, and refiners had difficulty in processing this light, sweet oil and planning for far greater volumes, in ways that government policy makers can hardly imagine.

Yet not only refiners and producers are perplexed. Platts, an industry price assessment agency, began to record pricing for Eagle Ford crude in October 2012. While, of course, product yields in distillation change according to cut points set by the refiner, it is interesting to note a fair amount of variation in Platts' assays as well.

Table 24. Platts Eagle Ford Assay Information -1

Product	Cut (Degree F)	Vol. %
LPG	< 85	2.2
Lt. Naphtha	85-200	9.2
Hvy Naphtha	200-350	19.7
Kero	350-450	16.6
Gas Oil	450-650	21.8
VGO	650-1,050	22.4
Residual	1,050+	8.1

Source: Platts Methodology Website, January 2013.

Yet in below presentation Platts puts Eagle Ford at 45 API with the following yield pattern:

Table 25. Platts Eagle Ford Assay Information - 2

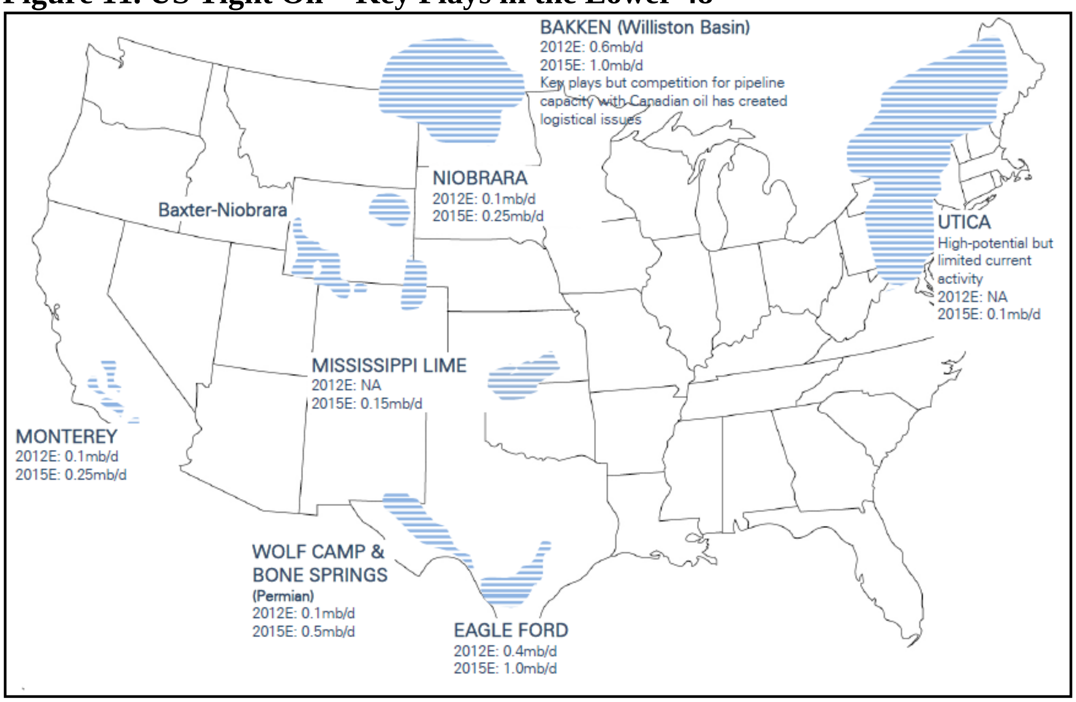
Product	Vol. %
LPG	4
Naphtha	40
Kero/Gas Oil	30
VGO	21
Residual	5

Source: Platts Commodities Week, "Major Supply, Demand Trends in US LPG/NGLs," Oct 16, 2012, Suzanne Evans.

Clearly Eagle Ford underlines how important field condensate will be to overall US oil production. According to a January 2013 Deustche Bank (DB) outlook, the bank estimated that by 2015 both Bakken and Eagle Ford will produce at least 1 MM BBLs of oil each, with a high side forecast of up to 2.5 MM B/D, out of a total of five shale *key plays,* cited by the study. And much of that will be condensate.

Who then cares whether the crude contains much condensate? USGC refiners are one group vitally concerned. With Eagle Ford output building, and at the same time rapidly lightening, an enormous volume of discounted crude is flowing right at their doorstep. But this, together with increased output from the Permian basin tends to be too light to accommodate fully in the current refining configurations

Figure 11. US Tight Oil – Key Plays in the Lower 48



Source: Deutsche Bank, Integrated Oils: Oil & Gas for Beginners, p.264

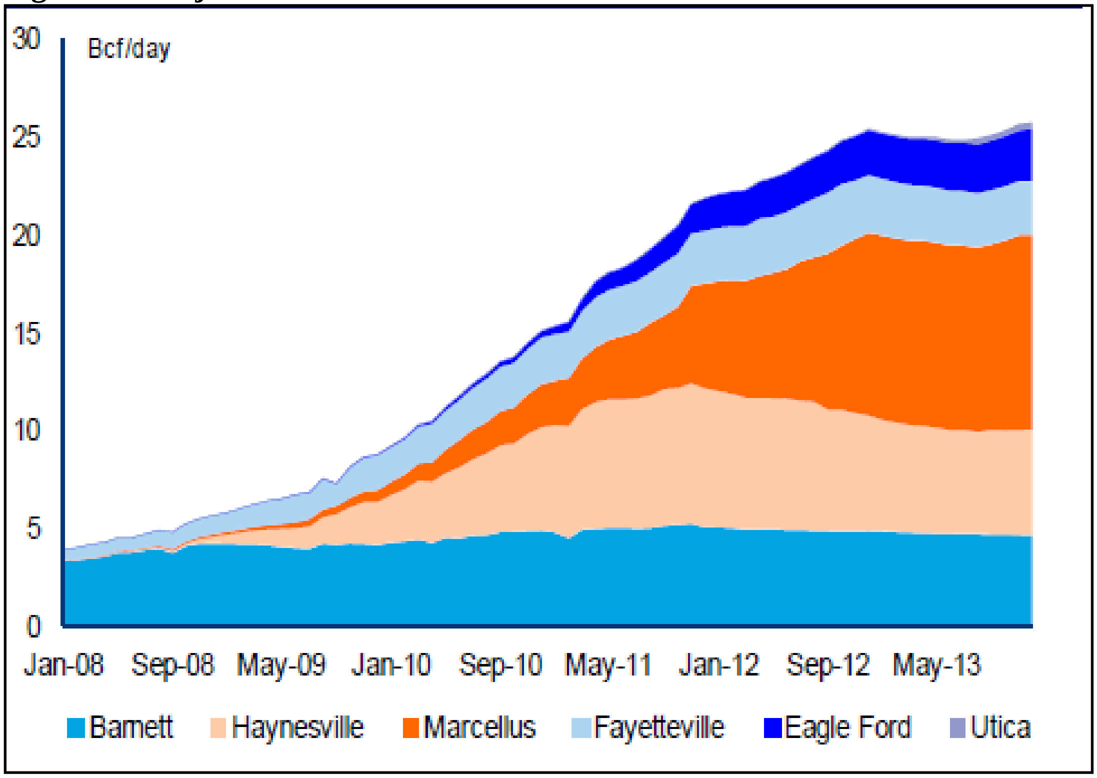
3. MARCELLUS/UTICA

Marcellus and the slightly later development of Utica represent the next great shale development. If Bakken represents NGL coming only now into its own, and Eagle Ford a shale development with oil shaped by condensate, then Marcellus/Utica represents a basic wet gas play, that will depend strongly on NGL recovery in its initial development phase and Utica already producing limited volume oil.

The heavily ethane-slanted NGL production from Marcellus presents certain problems, typical for ethane-dominated shale developments. As detailed, at a size of at least 104,000 sq miles the development is enormous and its wetness varies tremendously. It also underlies heavily populated areas. Companies have focused much attention on the geographic zone where Pennsylvania, Ohio and West Virginia meet.

While wetness for Marcellus ranges enormously, the Utica stratum beneath is believed to be considerably wetter and in late-2012 yielded its first oil output. Due to its proximity to the energy-hungry cities of the Northeast, these reserves have relatively low transport costs and a basic processing infrastructure. Yet ethane production has only limited petrochemical outlets in the Northeast US.

Figure 12. Major Shale Gas Production



Source: Deutsche Bank's Gobal Market Outlook; Jan. 8, 2013.

As can be seen in Figure 12, Marcellus/Utica has already begun to make its impact felt, and by mid-2013 will account for almost half of total shale-derived gas production of over 25 BN CFD. Its share will remain substantial, perhaps expanding to half of all shale gas production this year, depending on how much gas production is shut in for dry gas projects. Marcellus gas output rose from 500 MM CFD in 2009 to 4.4 BN CFD by 2013.

Not only does Marcellus/Utica illustrate the problems of ethane in shale development, it also highlights the difficulties in forecasting probable NGL output. We believe future NGL output will outstrip the more conservative outlooks current for future output. Some end-2012 forecasts illustrate the range of views on future NGL output. Forecasts by consultants Raymond James and IHS/CERA show a range by 2015 of 300-500 MBD of total NGLs. Both agreed that gas will have a higher calorific content than seen in gas now pumped and a lower percentage of ethane in the NGL outturn, no more than by 2015. They forecast far higher calorific gas and less ethane, at maximum 45% of NGL output.

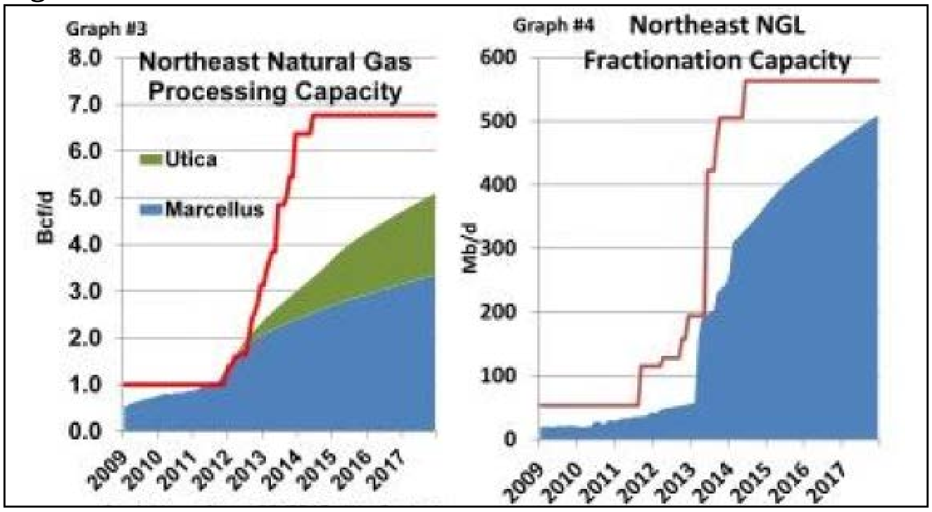
In contrast, Bentek and, En*Vantage claim a ceiling of only 360 MBD for Marcellus by 2015 and up to 55% ethane output. Yet even if these lower forecasts are right, that yields 200 MBD of ethane – roughly enough to supply a single 1 MM MTA ethylene cracker.[12]

A more sophisticated analysis by RBN showed that once gas transport, NGL separation and processing capacity were installed, total NGL output could average up to 600 MBD. We agree with the optimists for future NGL production, but believe, like the more cautious, that it will take longer than expected to complete mid-stream facilities and new petrochemical plants. Propane output, about 30% of NGL yield, is also rising. Forecasts for propane could allow for a much higher NGL plateau, perhaps as much as 730-740 MBD by end-2018. No one knows yet, but there are signs. As with Eagle Ford, Marcellus possessed basic gas infrastructure before shale development began. The problem has not been handling additional gas, but exploiting the NGLs contained within the gas. By end-2012, mid-stream projects had begun to catch up with upstream drilling.

By end-2012, there were an estimated 22 gas processing complexes underway, as well as 11 projects to expand or build new NGL fractionation plants across the Northeast US. As of October 2012, there was 1.6 BN CFD of NGL/gas processing in place. By 1/2018, if all current projects are completed, this will rise to nearly 7 BN CFD of gas handling capacity, much of that due to start up by 2014. Fractionation of NGLs, the ability to separate NGL into separate clean streams, will rise to more than 500 MBD by 2017.

[12] Suzanne Evans, "Major Supply, Demand Trends in US LPG/NGLs" (seminar, Platts Commodities Week, Hilton Americas, Houston, Texas, Oct 16, 2012).
Ethane converted at 3.234 MBD = 10 MM CFD

Figure 13. Fractionation of NGLs



Source: RBN Energy, Braziel 10/9/2012.

From January 2011 through October 2012, Marcellus gas output rose to 4 BN CFD; this is expected to rise to 9 BN CFD by end-2017. Why? Because an enormous number of wells have been drilled to *wet spots*, to produce NGLs and a large inventory of wells have yet to be completed or hooked up into a gas/NGL pipeline system.

Financial analysts believe that Marcellus/Utica will be extremely profitable, in part because of its location and the ever increasing upgrades to reserves. Reserve forecasts had risen and estimated costs of developing those reserves had fallen. Standard & Poors (S&P) calculated that RORCE would be higher than many previous forecasts, roughly 12% for the development of dry gas and up to 30% for wet gas, assuming a long-term price averaging $3.50/MM BTU, slightly above end-2012 levels. S & P concluded that Marcellus costs were the key to its greater profitability than other gas plays, even the very wet gas reserves in Eagle Ford, claiming that this was “Due primarily to the lower finding, development and production costs associated with Marcellus.” S & P conclusions were reinforced by a study by ITG Investment Research at end-2012 that claimed Marcellus had a breakeven level of only $3.83/MM BTU.

More drilling and technical analysis in 2012 suggested that Marcellus/Utica could hold larger reserves than earlier estimated. The EIA in mid-2012 slashed its 2011 estimate of Marcellus technically recoverable reserves from 410 to 141 TCF, while cutting its total US estimate to 482 TCF from an earlier 827 TCF. EIA claimed this was due more data becoming available. Yet trends in exploration refute this. Generally, learning more about difficult geologic formations tends to increase reserve estimates. ITG claimed Marcellus holds 330 TCF of technically recoverable gas, up to 50% of all US shale gas.

A better estimate of reserves will only come when infrastructure can fully keep up with potential production buildup. By end-2012, field reports suggested more than a 1,000 gas wells in the Marcellus structure were awaiting to hook up to gas pipelines still not completed. Analysts estimated that if all of these wells were commissioned by mid-2014, Marcellus output would rise by 2.4 BN CFD.[13]

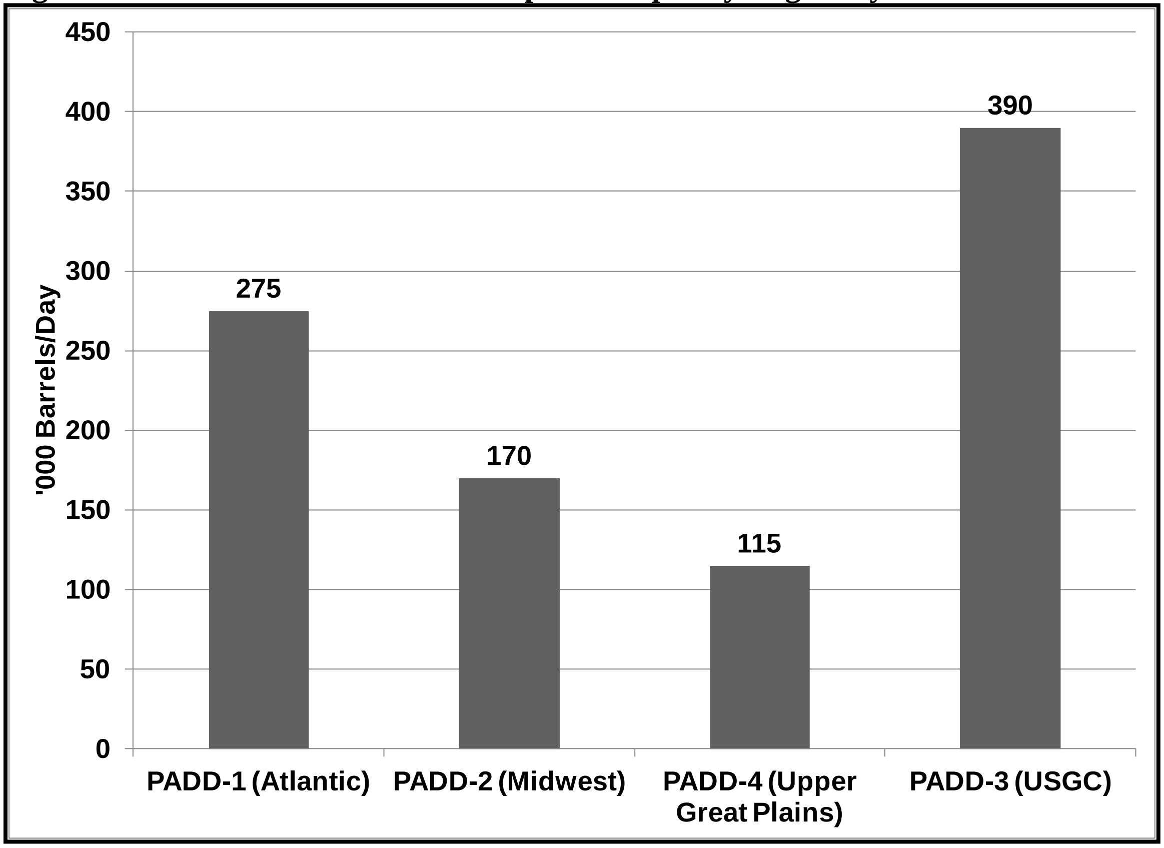
A problem in tracking Marcellus/Utica is that EIA figures for the district PADD-1 cover much of the basin, but significantly not Ohio, tracked in PADD-2 figures. Ohio makes up slightly less than 15% of Marcellus acreage and possibly more of Utica, making it difficult to get aggregate production figures for gas/NGL output for the whole shale basin. The Ohio output gets *lost* with Bakken and other PADD-2 output. This will become even more significant, when Utica shale output builds – it is older, deeper and richer than Marcellus. Chesapeake, a major acreage holder in both, estimated Utica shale on average had reserve quality similar to, but likely to prove superior to, Eagle Ford – better-quality deposits and geology and close to a ready market – at least for gas. While there has been vocal opposition to fracking in general and shale development in particular in the highly populated Northeast US, we believe a major development driver will be the need for local governments to increase revenue in hard economic times, and in the traditionally poor region of Appalachia to boost employment, as the coal industry shrinks.

The immediate concern though is finding commercial outlets for ethane sales. Sunoco's Mariner East pipeline will take NGLs to the Atlantic for US and European sales. A large-scale export terminal at Marcus Hook, New Jersey, will ship mixed Ethane/Propane (E/P) cargoes to Europe, though cryogenic export of pure ethane is far in the future. The Mariner West pipe will allow for ethane sales to the NOVA ethylene cracker in Ontario, Canada. Most important is the ATEX pipeline to transport 190 MBD of mixed NGLs through the Ohio River valley and southwest, ending at Mt. Belvieu, to feed the USGC.

Marcellus, together with Eagle Ford, will sustain a prolonged rise in US propane supply, with PADD-1, only somewhat behind PADD-2 in adding incremental propane barrels. Already signs of gap between production and domestic demand have appeared in the US market, even as LPG exports rose in 2012. Some forecasts show a supply overhang of as much as 200 MBD by 2016, though net propane exports will top 200 MBD by that time.

[13] "Marcellus: Low Cost, High Reserves play," *World Gas Intelligence*, http://www.energyintel.com/Pages/ArticleSummary/786891/Marcellus--Low-Cost--High-Reserve-Play (accessed 12 April. 2013).

Figure 14. Forecast – Incremental Propane Output by Region by 2016



Source: "Impact of Shale Liquids on Regional Propane Supply," RBN Energy, January 2012 presentation.

4. OTHER BASINS

A study of this length can only focus on a handful of the more important NGL shale development areas that will yield NGLs in the medium term. Beyond the Permian Basin (mixed conventional and shale development) we briefly touch on the following basins:

- **Cana Woodford/Mississippi Lime:** The first is known mainly as a wet gas play and will produce large-volume output; the second is more a tight oil area, both of which are located in northern Oklahoma extending into Kansas. Substantial NGL will be produced from shale reserves deep below mature and declining conventional oil fields by 2020. Producers have established infrastructure relatively close to the USGC.

- **Niobrara and Baxter-Niobrara:** Both structures have been more noted for tight oil production – and should produce about 250 MBD of black oil by 2016. Yet the NGL potential of these structures, located mainly in Wyoming, will have to await the completion of gas and NGL infrastructure in Bakken to the northeast, as well as Colorado to the south. This is a longer-term development for shale-derived NGL.

- **Monterey:** A very much longer-term development is that of the large and wet Monterey Enormous shale structure running from South/Central California, which together with associated North Monterey and other wet gas structures runs far north into Canada. Surprisingly the California Department of Conservation published moderate draft rules for fracking in December 2012, and we believe that at least in a limited fashion, development could start in the second half of the decade. The core structure covered 1,750 sq miles at an average depth of 11,000 ft, averaging 6.5% in organic content. EIA estimated recoverable reserves of up to 15 BN BBLs of oil.

F. Far and Away: A Look at Medium-Term NGL Balances 2012-2017

This report's overall theme is that the buildup in US NGL output is structural, integral to the Shale Revolution and that, even if the current drive completes additional refining, petrochemical and industrial plants, the US will shift to large-volume, regular NGL exports, impacting not only Western markets, but Asia Pacific and the Mideast as well.

NGL exports have already begun to impact East of Suez, as Asian buyers lined up for sales from the newly expanded Enterprise LPG terminal in early 2013 and have begun to consider US supply as a safety for when Mideast export volumes fall. Enterprise will add further capacity and Targa will complete its terminal expansion by end-2013, adding 300 MBD of LPG export capacity. A soft domestic market and strong foreign demand will increase LPG exports through 2014. As of early 2013, US ethane and propane supply were long; added output through 2017 will maintain a supply overhang. Strong exports have kept butane and condensate prices from declining as expected. The Big Picture then is that gas wetness on average will continue to increase through 2017. A conservative estimate by consultants Bentek could easily be exceeded, if mid-stream facilities start up earlier than expected.

Table 26. Forecast – Total NGL Output

Year	Average Wetness (MM B/D)	Show GPM Approx. (GPM)
2012	2.4	1.43
2013	2.7	1.54
2014	2.9	1.61
2015	3.1	1.64
2016	3.4	1.66
2017	3.8	1.69

Source: "The Future of the US NGL Markets," Kristen Holmquist, Bentek Energy, May 2012; GPM for 2017 estimated by APEC.

The element of time, as much as cost, is often underweighted in NGL forecasts, because, just like LNG projects, there are many steps that have to be executed in coordination. Bentek concluded that many project promoters underestimated completion deadlines and project costs. Bentek estimated that in mid-2012 to drill a gas well takes roughly 3 months to completion at a cost of $5 million. To commission a gas processing plant would take 18 months, with a capacity of 200 MM CFD, allowing 20 MBD of mixed NGL output, at a cost of about $110 million. The construction of a fractionation unit, with the capacity of 75 MBD propane and 38 MBD ethane, would also take 18 months and cost $260 million. A 90 MBD ethane-based ethylene cracker, if all went to plan, would take three years to complete and cost $2 billion. These estimates are overly optimistic, but the underlying principle though is valid. Additional demand for ethane and to some extent petrochemical use of propane in the medium term will come mainly from debottlenecking and recommissioning of idled plant. What then happens in the meanwhile? There are a wide range of opinions and almost as many differing forecasts.

Yet in pricing, some basic themes though have emerged. Gas value has decoupled almost completely from that of oil and in 2012 it was common to see daily values of 40:1. We expect prices to recover by 2017, but gas will likely remain moderately priced. Ethane volumes have been building, which has been pressuring prices heavily by end-2012. Propane, despite a massive rise in exports, has seen prices weaken over the course of 2012; butane less so. Margins have been positive for US ethane-based ethylene crackers, increasing ethylene/polyethylene exports, roughly by a quarter in 2012.

Upstream and mid-stream factors supported expansion. While the fractionation spreads of 2011-2012 have narrowed substantially in the second half of last year, the prospect of rich pickings supported massive mid-stream investment to utilize the NGL emerging from liquids-rich gas reserves. Bakken, Eagle Ford and Marcellus/Utica will underpin a massive rise in Purity NGLs. Bentek at end-2012 predicted that shale-play gas will rise from about 30 BN CFD as of 1/2012 to 42 BN CFD by 1/2014 and to 47 BN CFD by 1/2017, and gas processing capacity will increase more than 21% over this period. The question is whether NGL midstream and ultimately the *absorption* sector for NGLs – most important, petrochemicals - will keep pace.

Even as basic a calculation as forecasting total raw NGL output finds a wide range of opinion. By 2015, Bentek had forecast 3.2 MM B/D; EnVantage 2.32 MM B/D; investment banker Raymond James 2.95 MM B/D. Yet Morningstar predicted only a 2% p.a. rise in NGLs through mid-decade. Putting aside Morningstar, whose outlook appears to be under-informed, it is clear that crystal-ball gazing allows for a wide variance in outlook. We summarize some of the more interesting forecasts in the table below

Table 27. Ethane Demand/Supply

Company	By Year	Demand	Supply
Raymond James	2015	1.24	--
Raymond James	2016	Est. 1.28	1.30
Raymond James	2018	1.55	--
Bentek	2015	1.57	1.57
Wells Fargo	2017	1.73	1.67
EnVantage	2018	1.80	1.50

Source: Platts Commodities Week, "Major Supply, Demand Trends in US LPG/NGLs," Oct 16, 2012, Suzanne Evans

Which outlook is preferred makes a big difference in one's view of future NGL profits. A weighted NGL barrel traditionally was worth 60% of the average price of US crude marker WTI. By end-2012, that proportion fell to 43%. While producers are counting on pipelines to transport ethane/propane to consumers, this is a risky assumption.

Another approach is suggested by Simmons & Company, and while APEC differs with this outlook somewhat – for example the impact of new NGL infrastructure in Bakken - we believe overall these projections represent a fairly reliable *base case* outlook, though our forecast differs to some extent, both on regional output and NGL breakout.

Table 28. Impact of US Fractionation Additions (In MBD) *

Region	New Capacity	Added NGL Outturn				
		Ehane	Propane	Butane	Iso-Butane	Condensate
2012	**200**	**77**	**52**	**14**	**14**	**22**
USGC	140	54	36	10	10	16
Northeast	60	23	16	4	4	6
2013	**673**	**220**	**176**	**48**	**48**	**73**
USGC	507	155	132	36	36	56
Northeast	166	65	44	12	12	17
2014	**283**	**110**	**74**	**20**	**20**	**31**
USGC	175	68	46	12	12	20
Northeast	108	42	28	8	8	11
Incremental 2012-2014	**1,156**	**407**	**302**	**82**	**82**	**126**

Source: "Wave of Midstream Investment Expected to Unleash Tidal Shift in NGL Supplies," 9/21/12, Pg 6, Simmons & Company International.

Table 29. Detailed NGL Projections *

Product	Actual	Preliminary	Forecast		
	2011	2012	2013	2014	2015
Ethane	926	1,003	1,159	1,382	1,438
Propane	631	695	801	951	989
Butane	157	182	212	253	263
Iso-Butane	211	215	244	286	296
Condensate	291	305	349	411	427
Total	**2,216**	**2,400**	**2,765**	**3,283**	**3,413**

Note: *Assumes 90% utilization rate and estimated NGL production breakout of Ethane 43%, Propane 29%, Butane 8%, Iso-butane 8%, Plant Condensate 12%.
Source: "Wave of Midstream Investment Expected to Unleash Tidal Shift in NGL Supplies," 9/21/12, Pg 6, Simmons & Company International.

G. Impacts of NGL by sector

When NGLs have been separated from gas, the undifferentiated gas liquids flow is called a *Y-grade* NGL stream. It is semi-processed product and so has no posted sales price. It needs to be further separated into constituent finished products through fractionation to yield *purity product* suitable for end-user consumption. In global markets, NGL prices are shaped by many sectors, most notably refining, particularly the processing of condensate, by petrochemicals, both olefins and aromatics and by product blending. We have touched on how US NGL terminology – and definitions – often differs somewhat from global usage. We will detail in this chapter how NGL will impact specific energy sectors, in the US and abroad. We examine the changes by each NGL.

1. REFINING

Condensate will reshape American refining in a number of ways, obvious and subtle. First, it is boosting total tight oil output The table below summarizes 2012-2013 outlooks of the IEA, consultants Wood McKenzie and the EIA/DOE.

Table 30. US Shale Oil Production Outlooks

	2013	2014	2015	2016	2017	2018	2019	2020
IEA	1.8	2.3	2.7	3.1	3.3	N/A	N/A	N/A
WMC	2.4	2.9	3.4	3.8	4.1	4.4	4.5	4.6
EIA (Dec 2012)	2.4	2.5	2.6	2.7	2.7	2.7	2.8	2.8
EIA All (Jan 2013)	7.3	7.9	N/A	N/A	N/A	N/A	N/A	N/A

Source: Deutsche Bank

By 2017, we expect at least 4 MM B/D of tight oil output, somewhat less than half of all US crude output, depending on which total oil forecast is taken as most accurate. Already the Shale Revolution has impacted American refining.

The Big Picture

Shale Oil is generally light and sweet to begin with. As detailed earlier, the consistent addition of wellhead condensate makes crude blends even lighter and sweeter, as seen clearly in Eagle Ford crude, less so with Bakken. When Bakken production began to build in 2011, inland refiners rejoiced – here was a source of low-sulfur, easy to refine feedstock, heavily discounted, as transport to bring new output to refining centers was minimal. Many refineries, running at low capacity or shuttered as uneconomical to operate, sprang back to life, recording steady profits operating simple plant using Bakken. Tight oil provided a new lease on life to old refineries, many of which would have been junked long ago, if cleanup costs for refinery sites were not so high.

Yet the US heartland was not the only refining region impacted. A good deal of the largest, most sophisticated refineries in the US are in the USGC and designed to run heavy, sour crude slates. The prospect of discounted domestic crude, particularly as Eagle Ford output rose rapidly, prompted a massive back-out of light crude imports. By mid-2012, nearly 200 MBD of crude purchased abroad was pushed back into the Atlantic Basin by USGC refiners and by end-2012 large independents, such as Valero, Marathon, Phillips 66 and Tesoro, combined a base capacity of 2.96 MM B/D and purchased no light crude from abroad.

The dilemma of wellhead condensate is that while it has revived marginal refineries in the interior of US, it presents a challenge to USGC refiners operating among the most sophisticated plants. All these refinery units need sufficient volume of fuel oil or heavy gas oil (known as Vacuum Gas Oil (VGO)) as their feedstock to yield further light product. There is a physical limit to the volume of light sweet crude that refiners with deep secondary capacity can utilize, if they intend to fully use these units. The choice is particularly difficult for plants that have just completed expensive and far reaching upgrading – such as Motiva's Port Arthur, Texas complex or Marathon's Garyville plant. The Garyville refinery is typical in that it was designed for heavy, sour Canadian syncrude – but now has large and growing volumes of discounted Eagle Ford on the doorstep. This refiner, like its competitors, must decide whether they will utilize their cokers (known as *loading the coker*), add additional distillation to handle light crude or skip the purchase of opportunity crude, i.e. discounted domestic supply. Tight oil has rendered large investments in many severe secondary units, if not meaningless, then certainly of far less economic viability.

Already international oil markets have felt the impact of NGL in crude. The back-out of light crude imports had through 2012 reduced the premium that Brent-linked light, sweet crudes traditionally maintained over heavy sours. While Brent's absolute price level remained strong, supported by its use as a financial tool, the premium commanded by light crudes, best for making gasoline, has declined. Yet the proper *safety valve* for a rapidly building supply overhang cannot be used – crude cannot be exported. We judge that it is politically unacceptable to lift this ban at least in the medium term.

The back-out of light crude exports is also causing a *back-in* of tight oil growing into a structural overhang, made worse by the growing presence of wellhead condensate. In early 2013, Maria van der Hoeven warned that while the Shale Revolution has underpinned a ballooning of US crude production, the US market can absorb only so much of this light sweet crude. She cautioned, if the crude export ban continued, this eventually will result in the US unable to develop all available shale resources.[14]

Fight, Flight …or Fiddle?

There are three stages of *accommodation* for USGC refiners attempting to best use light, sweet tight oil, mainly from Eagle Ford. Refineries have already begun the initial backing out of 36 API + crude (and in parallel almost all condensate) imports and at latest this will be completed by 2015. The second stage is to squeeze a bit more of this shale-derived crude/condensate mixture into refinery runs by blending it carefully into mid-weight/heavy grades to add marginal volume. The final stage is refinery investment.

[14] Reuters, "Export Ban Could limit US Oil Boom," *CNBC*, http://www.cnbc.com/id/100439702 (accessed 12 April. 2013).

The least expensive way simply to convert a tower to running more tight oil is by adding tower overheads and adjusting cut-points. Koch reconfigured its Flint Hills, Texas, plant this way. Alternatively a refiner could expand an existing tower and reconfigure it, which is what Valero is doing in Houston, Texas. Finally, a company can invest in an entirely new tower – which has been rumored at a number of refiners.

Yet this phenomenon of condensate in crude forcing refiners to shift gears is not solely a USGC trend. Marathon reconfigured its Canton, Ohio, (78 MBD) and Catlettsburg, Kentucky, (233 MBD) refineries to accept emerging Utica crude, which has averaged, in initial output, an API of 45-50, indicating it too contains a large slug of condensate. While these are not splitters designed solely to run condensate - we understand that the total volume Marathon has been processing is no more than 10% of base refining capacity - it demonstrates that refiners geared to heavy, sour crude use, will shift at least partially to accommodate tight oil.

Condensate & Splitting

A second aspect to the impact of NGLs on refining is that of plant condensate, which has taken a different but in some ways just as difficult a path to market. Just as refiners have taken a cautious path in building new capacity to handle light crude/condensate mixtures, they have been slow to add condensate splitting capacity to process large volumes of plant condensate that we expect to emerge by 2017. In Texas, Kinder Morgan will commission a 50 MBD splitter by 2014 nearby Houston, a facility that will likely be expanded to 100 MBD by mid-decade. Commercial arrangements have already been agreed with BP, the only major with large-scale domestic NGL output, for supply of condensate and offtake of products. Preliminary planning has begun for a second grassroots splitter proposal, of somewhat smaller capacity, reportedly backed by mid-stream and trading companies. As noted earlier, Marathon’s announced building of splitting capacity is somewhat exaggerated. No other solid splitter proposal has emerged in the US market, despite rapidly building condensate production.

What is striking is how slowly the US downstream has adapted to the changing nature of US oil supply. USGC refiners have expressed two major concerns: They feel uncertainty, at least through the medium term, of the US gasoline market, which has shown feeble growth in recent years and, if EIA forecasts are correct, will shrink in 2013. A parallel worry has been selling the remainder of light product yield, in particular paraffinic naphtha, which has been backed out of petrochemical feedstock use.

While plant condensate has been used in gasoline manufacture and blending, much of the incremental output has moved to Canada for use as diluent. By 2017, we expect that Canadian sales may well not be enough to prevent a supply overhang. Traditionally the price drivers for this NGL have been gasoline and domestic crude. Yet in relationship to crude, prices have softened in recent years, due to rising output, uncertain gasoline demand and the shift to other petrochemical feedstocks. Plant condensate made up 13-

15% of field NGL output in recent years, depending on estimates, and we believe it will increase both in absolute volume and as a proportion of total NGL output.

Other NGL will have substantial impacts on US refining too, notably butane and iso-butane. Butane made up about 9-11% of NGL output in 2012 and together with iso-butane accounted for slightly less than a fifth of NGL production last year. Butane is a key component of gasoline blending and highly seasonal. In winter it is used to improve ignition quality, but during the summer driving season, it is restricted as it raises the vapor pressure in gasoline. It is also a regional product, not only because summers are hotter in Florida than Maine, but because vapor pressure is also impacted by elevation – high-altitude Denver has different RVP ceilings than coastal New Jersey. Further, California sets its own stricter RVP standards which further limit butane use. Butane also is used as feedstock for aromatic petrochemicals, such as resins and styrene.

In the US market, a distinction is made between LPG derived from refining and from gas stripping. Typically refining butane contains olefins, which have to be removed if this NGL will be used for quality gasoline blending. High-quality butane is labeled as being of TET standard, named after the butane facility operated by the Energy Transfer Partners LP and Regency Energy Partners LP joint venture, (LST), at Mont Belvieu. Non-TET quality more typically is the base material to create isomerate, a key gasoline component. TET butane normally sells at a premium to non-TET grade.

Iso-butane, which made up about 5-7% of 2012 NGL output, is a key NGL for gasoline as well and has great importance in the US market, where gasoline is the pivotal refinery product. Iso-butane is slightly lighter than butane and forms the basis of alkylate, another component in blending gasoline. Unlike butane, iso-butane is used almost exclusively for gasoline in the US; but its seasonal value varies inversely to butane in gasoline use. In summer, butane values generally are the lowest and iso-butane the highest. In many foreign markets it is simply used together with butane up to LPG quality limits.

Wet shale production has increased butane and iso-butane output, as LPG yield from refining has been falling in recent years. In foreign markets butane and iso-butane are not separated in field production. Both have feedstock value to create gasoline components, but only if a refinery is equipped with isomerization or alkylation units. Diesel is the majority road fuel in Europe and Asia, though gasoline demand is substantial.

Propane and ethane do not play a major role in refining, though, when having difficulty finding a buyer, can be used for process/heat and power generation. This, however, is more common in less sophisticated refineries in Developing Economies. Yet normally if a sufficient volume of butane – or propane for that matter – is produced in refining, the outturn is gathered, stored and sold to end-users. Exports rose sharply – though not as much as propane – in 2012 and are expected to continue to expand.

2. PETROCHEMICALS

Propane made up about 27-29% of 2012 NGL output. Field stripping of gas accounted for about 70% of supply last year and that proportion is growing, as shale output increases NGL volumes. While field propane production is fairly steady over the course of a year, refinery-derived LPG volumes are lowest during the winter, and in part that accounts for the substantial volume of propane storage across the US market.

Propane, like natural gas, is a residential/commercial major heating fuel and has other residential uses in the US, such as *gas* BBQ grills. In foreign markets, LPG has these same heating/residential sectors of demand, but also is a major road transport fuel, though not currently in the US. In the winter of 2011-2012, heating accounted for about 57% of propane demand. High demand seasonality also supports the operation of substantial LPG storage across the US. While there was a TET vs. non-TET standard for propane sales traditionally, this had almost vanished by 2012 as a pricing factor. In US petrochemicals, butane is the preferred aromatics feedstock, propane dominates ethylene cracking.

In the petrochemical sector, NGLs differ in value and in utility, because they have different conversion efficiencies in creating the three major intermediates needed in making petrochemical intermediates – ethylene, propylene and BTX. The first two create olefins, mainly plastics; BTX are the intermediates for aromatic petrochemicals, such as styrenes and resins. As can be seen in Table 31 below, ethane has the highest conversion for ethylene cracking, but both butane and propane have substantial ethylene yields. The US market traditionally used ethane, propane and plant condensate as trim for ethylene cracking. Since 2011, US olefins shifted sharply to ethane use. While ethane is optimal for producing ethylene, it is less useful to create propylene. Refinery catalytic cracking had provided most US propylene supply, but low utilization rates meant less refinery supply.

Table 31. US Olefin Simplified Plant Yields *

Feedstock	Petrochemical Outturn				Oil Products	
	Ethylene	Propylene	Butadiene	Benzene	Motor Fuel	Heating Fuel
Ethane	74.7%	3.0%	2.2%	70.0%	1.9%	17.5%
Propane	43.7%	17.0%	2.4%	2.0%	6.1%	28.8%
Butane	37.7%	23.8%	3.2%	1.9%	8.5%	24.9%
Par. Naphtha	30.5%	18.9%	5.2%	3.8%	25.2%	16.5%
Kero	24.6%	14.3%	4.3%	3.5%	28.8%	23.0%
Gas Oil	21.3%	14.5%	4.7%	3.2%	29.4%	27.0%

Note: * Plant condensate can vary widely in composition, but overall tends to be light and inclined to be paraffinic. This is represented in the table by the paraffinic naphtha yield.
Source: Platts, Oct. 2012

Propane, however, can help alleviate the propylene supply shortage by using a number of technologies: Propylene Dehydrogenation (PHD), Methanol-to-Olefins (MTO) and Methanol-to-Propylene (MTP) to produce additional supply. Developing Economies, particularly in Asia Pacific, experienced an even greater shortage of propylene than in the

US and are actively exploring new production means. Each new technology has its own strengths and weaknesses. MTP has high capital costs, but low operating costs; PDH has low capital but high operating costs and since dependent on propane big swings in feedstock. MTO produces not only propylene, but other olefins as well. Shale-derived propane could make a valuable contribution to future propylene supply and exports.

Those who forecast a sustained revival of the US petrochemical sector, see ethane as the ace in the hole for ethylene cracking. Traditionally manufacturers used up to 60-70% ethane in their ethylene crackers, often seeing that share fall sharply, when alternative feedstocks were less expensive or yielded a greater overall processing value. Compared to Europe, or the Mideast, but particularly Asia Pacific, US olefin companies long have enjoyed relatively greater feedstock flexibility. As with a merchant refiner, USGC petrochemical plants are capable of shifting their use of feedstock quickly and efficiently, within the technical limits of their ethylene cracker, and it is not unusual for a unit to move from ethane and propane, to a combination of naphtha, propane and butane, and access supply from pipelines, barge or seaborne cargoes.

The prospect of long-term moderately priced ethane has the petrochemical sector gearing up. The past decade has seen base petrochemical production in North America and Europe shifting to the Mideast Gulf and East Asia. Saudi Arabia, Qatar, the UAE and Kuwait offered discounted feedstock to lure investment; Asia, particularly China, promised long-term demand growth, gradual liberalization of markets and the need for imported finished and semi-finished petrochemical products.

The Shale Revolution will be a game-changer, because the prospect of discounted feedstock, coupled with the sector's technological prowess and operational flexibility will increase greatly the competitive strength of US firms. European petrochemical giants Shell and Total already have planned large, integrated olefin complexes, based on shale-derived NGL feedstocks. Most US based companies have already put into motion plans for expanding ethylene cracking capacity, and international American petrochemical companies such as Dow are hedging their investment bets in Saudi Arabia and China, by undertaking large scale projects also in the US.

Some analysts claim that ethane never trades in world markets. This is not strictly correct. Ethane in small volumes has been exported to neighboring markets for years; both Canada and Mexico plan to build new ethylene crackers or expand old facilities, based on imported ethane. Limited piped ethane sales have also been seen for decades in Europe. While tanker sales of ethane have been rare, and often in a combination of E/P mix, the completion of an export terminal near Philadelphia will boost exports by 2015.[15]

It is the physical nature of ethane that makes it a *hand-to-mouth* petrochemical feedstock and partially explains the small volume of international ethane trade. It is difficult to

[15] Callie Mitchell, "Carbon rich Value High – NGL Trading and Pricing Part III: Ethane," *RBN Energy*, http://rbnenergy.com/carbon-rich-value-high-ngl-trading-part-III-%20ethane (accessed 12 April. 2013).

transport and to store, with a vapor pressure of 543 psig@70 Deg. F (21.1 Deg,. C) and a boiling point of -127 Deg. F (-88.3 Deg. C). Ethane must be kept under pressure, or low temperature to remain a liquid, just as LPG.

Yet due to the flood of ethane supply emerging from the Shale Revolution, we believe that these sector assumptions must be re-examined. Plans are well underway for piped export of ethane as well as ship borne E/P cargoes. If the price of ethane falls close to, if not equal to that of Henry Hub methane, the first reaction will be to shut-in NGL-yielding gas fields that produce mainly ethane. The longer-term response is to consider more efficient ways to move ethane by ship – and cryogenic transport, utilizing the same cooling technology used to liquefy LNG gas as well as containing larger shipments of LPG. If the capital and operating costs of creating such a supply chain are exceeded by the *default* value of ethane as petrochemical feedstock, versus simply burning it, some companies will move forward. And while ethylene is certainly more economical to ship than ethane, if the entry cost of building an ethylene cracker is at least $3 billion, and cost run up to $8 billion, – then export opportunities will emerge. It is better than simply burning ethane.

When one considers the immediate prospects for gas prices, the *wiggle room* between the value of crude and products derived from crude for petrochemical feedstock, such as naphtha, there is some commercial space to consider investment. Traditionally US natural gas prices were 60% of the value of crude. Yet while the base price of Nynex gas is expected to recover somewhat in 2013, according to DB projections, the ratio of US gas to WTI will remain at a low ratio of 26.7, actually lower than recorded in 2012. Burning ethane is simply wasteful in the US market, though small volumes are consumed in refinery operations. There is only a single non-calorific market for ethane, ethylene cracking, with the default utilization simply burning it, though a small percentage of residential propane contains up to 5% ethane.

Though the relatively low calorific value of other NGLs allows piped gas to carry a small volume of ethane in the gas stream (some 2-5% ethane, depending on the maximum BTU content allowed in gas), if higher proportion of ethane within gas is carried, puddling, by stopping gas flow, could cause a pipeline explosion.

Table 32. The Ethane Race (In MBD)

	Actual				Prov.	Forecast				
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Supply (1)	701	769	869	926	1,003	1,159	1,382	1,438	1,438	1,438
Demand (2)	685	807	880	950	1,000	1,060	1,097	1,097	1,248	1,529
Long/Short (+/-)	+34	-19	+9	-4	+23	+120	+305	+361	+210	-1

Notes: (1) Supply is all from gas plant production other than a standard 20 MM CFD from refineries and blenders, used as process fuel, 2010-2017; slightly less (18/19 in 2008-2009. (2) Demand is assumed to be all in ethylene cracking, avoiding the use of ethane as simply boiler feed, a calorific-only value that is equal to piped methane gas.

Source: Simmons & Company, Sept 2012 study, p10

The chief market drivers for ethane are processing/transport capacity, followed by ethylene cracking demand. When neither keeps up with the pace of potential ethane supply, this NGL's values quickly softens, falling to the price level of US domestic natural gas, and production begins to be shut in. So the race is on to get sufficient ethylene cracker capacity up and running to absorb potential ethane output. We have already detailed how mid-stream efforts have tended to lag upstream potential ethane output. We believe that there will be few grassroots ethylene crackers starting up before 2017, with the bulk of incremental new olefin capacity only starting up by 2018.

Table 33. Ethylene Cracking Capacity Construction

Region	Operator	Location	Capacity	Startup
USGC			**8.89**	
	Dow Chemicals	Hahnville, LA	0.40	2012
	Westlake	Lake Charles, LA	0.23	2013
	Williams	Geismar, LA	0.27	2013
	Ineos	Chocolate Bayou,	0.15	2013
	Dow Chemicals	Plaquemine, LA	1.20	2014
	Dow Chemicals	Freeport, TX	0.50	2014
	Lyondell/Basell	Channelview, TX	0.23	2014
	Lyondell/Basell	La Porte, TX	0.39	2014
	BASF-Total	Port Arthur, TX	0.12	2014
	Formosa USA	Port Comfort, TX	0.80	2016
	ExxonMobil	Baytown, TX	1.50	2016
	Occidental/Mexichem	Ingleside, TX	0.60	2016
	ConocoPhillips	Baytown, TX	1.50	2018
	Sasol	Lake Charles, LA	1.00	2018
Northeast US			**1.77**	
	Aither	Pending, WV	0.27	2016
	Shell Chemical	Monaca, PA	1.50	2018
Others			**3.88**	
	Westlake (1)	Calvert City, KY	0.18	2014
	Nova Chemicals	Sarnia, Ontario	1.20	2016
	Nova Chemicals	Joffre, Alberta	1.45	2017
	Braskem/Idesa	Coatzacoalcos, Veracruz	1.05	2016
Total			**14.54**	

Source: Industry

While ethane consumption has risen sharply since 2008, increasing an estimated 46% (about 315 MBD) through 2012, supply will still outstrip potential demand for some time. We earlier noted realistic timeframes for building NGL infrastructure. While much has been written on incremental ethane from Marcellus/Utica shale development, few analysts have weighed the time needed to create that full ethane supply chain. The old gas planners' cliché that it will take longer and cost more than expected, we believe still holds true. Yet the impact will be enormous, as the following table illustrates.

The US long has operated the largest volume of ethylene cracking. While the fast-track expansion of Chinese olefin capacity has caught analysts' attention - by 1/2013 it topped 17 million MM MTA - US installed plant has remained significantly larger. A combination of new plants, and the debottlenecking and recommissioning of idled US ethylene furnaces, could add slightly under 11 MM MTA to American capacity. That is greater than the ethylene cracking capacity of either Saudi Arabia or Qatar in 2012. Yet it is likely that US olefins will remain larger, and certainly more profitable.

Shale-derived ethane will have another important impact, supporting the emergence of a second major focal point of base petrochemical capacity, centered on the shale wet gas zone, at the nexus of Pennsylvania, West Virginia and Ohio. In 2012, Texas and Louisiana accounted for more than 90% of US ethylene cracking capacity, yet by 2018 at least 1.7 MM MTA of olefin capacity will start up in the northeastern US and may well expand further by 2020. Local government and businesses hope that Marcellus/Utica shale-derived NGLs will revive industry as much as petrochemicals in the region, raising new tax revenue and increasing employment.

Yet it all goes back to midstream infrastructure and a question of timing. There must be a need to have petrochemical buyers who can use ethane as feedstock. As 2013 opened, ethylene cracking lagged considerably behind the ability of shale projects to produce it. This leads to shut-in of Marcellus/Utica production, as the ethane-enriched gas is too high in calorific value to travel by pipeline. Under US market parameters, this gas would be *sub-specification* simply because it was too rich to use the national gas transport grid.

This could impact the national buildup of NGL production. Capital Advisors estimated that by end-2013 potential ethane output could rise to 1.1 MM B/D, an increase of 5.7% in a single year. Yet the financial analyst forecast that ethylene cracker capacity using ethane would only rise to 1.05 MM B/D by 1/2014, an increase of 7.4%, but insufficient to absorb all potential ethane. Capital Advisors estimated that the upstream was *rejecting* some 30 MBD of ethane, leaving it in gas and shutting in the potential production at end-2012 – and that this volume could very well increase.[16]

As noted earlier, potential consumers of NGLs and gas have opened a sustained campaign to restrict exports of LNG, claiming that the NERA report for the US government was "baffling" and flawed" and that some $90 billion in new petrochemical projects could be put at risk. It fails to give "due consideration to the importance of manufacturing to the US economy."[17]

[16] "Widespread US ethane rejection expected in 2013, limited by BTU specs: paper," *Platts*, http://www.platts.com/RSSFeedDetailedNews/RSSFeed/NaturalGas/6987988 (accessed 12 April. 2013).
[17] From PIW, pg. 3, 17 Dec. 2012.

Yet the NERA study made little, if any mention of the pricing of NGLs and it concluded LNG exports would cause only a moderate rise in domestic prices over the medium term, with US gas prices rising no more than $0.33/MM BTU once exports began and increasing by a further $0.22-1.11/MM BTU, in the five years after exports began. Further, the NERA study concluded that a likely volume ceiling for LNG sales abroad was roughly 75 MM MTA, the equivalent of about 10 BN CFD of gas. A University of Texas study, released shortly after the NERA report, supported this conclusion, asserting that if LNG projects at Lake Sabine, Golden Pass and Freeport all started up by 2020, using collectively 7 BN CFD of gas, some 14 MM MTA equivalent or roughly 11% of 2012 demand, it would have little impact on industrial markets.[18]

Dow's argument demonstrates a rather odd logic. Exports do not *enfeeble* US petrochemical industry, but strengthen it by guaranteeing that shale development will provide moderately priced feedstock for decades – possible only if shale field operators can gain adequate return on investment. Government intervention to force the long-term discounting of NGL prices neither serves national security aims, the traditional argument for the crude export ban, nor promotes petrochemical sector self-sufficiency. Rather it is an obstacle to the long-term growth of shale development. It is better for petrochemicals to have long-term assurance of somewhat discounted feedstock than a medium-term period of dirt-cheap feedstock followed by an irreversible fall in NGL feedstock supply. Dow should examine its Saudi investment closely to see Aramco's difficulties in supplying ethane to domestic petrochemical projects, as it cannot recover upstream costs.

A further point left unaddressed is that foreign markets use different pricing basis for NGL sales and this has particular impact on ethylene. Throughout 2012 a partially ethane-based US olefin sector recorded considerable feedstock advantage over Asia Pacific's mainly naphtha-based ethylene crackers. The full range of NGLs emerging from shale projects will be able to meet feedstock needs for propylene and BTX as well, a feedstock advantage accentuated by different NGL pricing systems in the US.

Of course, exporting finished or semi-finished products is generally more profitable than the sale of NGLs as a base material, but restricting NGL sales solely on spurious claims by potential consumers of their right to heavily discounted feedstock should be viewed with skepticism. "Qui bono" (For whose good) should be the principle guiding exports.

3. TRANSPORT

While many analysts have predicted enormous growth in the area of transport through the next generation, oddly forecasters over-emphasize the role of natural gas in substituting for oil use, while underplaying – or ignoring altogether - the potential role of NGLs, in particular condensate and LPG, both propane and butane. Even such well-respected

[18] From PIW, pg. 10, Dec. 12

industry leader such as Exxon, in its end-2012 long-term outlook underplayed NGLs' role, while putting greater emphasis on natural gas use.

NGLs though have already a considerable role in transport and that role will grow. We have already discussed in earlier sections the use of butane and iso-butane in the production of gasoline components and in direct blending. Other uses for NGLs in transport should be explored for the vast US market.

A common point that impacts all transport fuel markets is the role of government in setting taxes on their use and tariffs in their impact on relative fuel competitiveness. The justification for penalizing diesel and promoting gasoline, when the current tax/tariff structure was implemented in the early 1970s, was that diesel was dirty and gasoline clean. Yet since then diesel engines have improved greatly in efficiency and current top-quality diesel burns more cleanly than many gasoline grades in modern engines.

Yet LPG burns even more cleanly than either transport fuel; it has made for easy substitution in a wide range of markets abroad from Japan to Italy, as well as new OECD members such as South Korea and developing markets such as Russia. These markets are among the top 10 consumers of LPG for road transport and LPG use has been successful in urban traffic, reducing air pollution and is ideal for short-haul travel.

Australia's experience has been illuminating. As cited earlier, gasoline demand growth 2000-2005 in this market was one of the leaders in OECD countries. Government efforts to shift transport demand, particularly in cities, to LPG use included modest credit guarantees for retail outlets to add LPG tanks; a small tax rebate for vehicle owners to convert to LPG fuel use and making retail cost of LPG cheaper than gasoline at the pump. It worked - first slowing, then capping, and finally reducing gasoline demand.

Utilizing existing infrastructure is the key to quick, inexpensive and successful introduction of a new fuel into transport use. Since many alternatives to gasoline or diesel as the major transport fuels either need substantial infrastructure investment (LNG, CNG) or modification of vehicle engines (LPG), government policy is central to popularizing a new fuel option. Unlike multi-billion plans to build CNG and LNG along the US Interstate highway system, introducing LPG as alternative fuel, in view of the supply long building, makes enormous commercial sense. While we expect gas to impact long-haul trucking and bunker, we also expect NGLs to become an alternative to gasoline and diesel use in transport. We believe, where gas can be used, LPG can be used better.

Further, condensate, even plant condensate, can produce substantial amounts of gasoline, and at least moderate volumes of middle distillate, if run through a special-design splitter. Splitters such as Dubai's ENOC plant, often focus on aviation fuel output, as well as diesel. Together, these two NGLs, even if CNG, LNG and perhaps GTL also contribute to a broader range of available transport fuels, can make a difference. The US should draw some lessons from these foreign market examples.

H. Ways and Means: Infrastructure Past and Future

By 2013, rail transport was notably supplemented by pipeline sales of Bakken and Eagle Ford crude. Moving output to market was the main driver in a 50% rise in the number of rail cars shipping crude, NGLs and oil products from 2009-2012 – but crude dominated.

Table 34. Fractionation Construction (Greenfield/Expansion)

Owner/Operator	Location	Capacity	Startup
Texas (Eagle Ford, Permian, Barnett Shale Gas Basin)		**843**	
Gulf Coast	Mt. Belvieu, TX	43	2012
Enterprise/Train-6	Mt. Belvieu, TX	85	2012
Southcross	Refugio, TX	23	1Q, 2013
ChevronPhillips Chemical	Sweeny, TX	22	1Q, 2013
Enterprise WT-1	Mt. Belvieu, TX	10	1Q, 2013
Lone Star NGL	Mt. Belvieu, TX	100	1Q, 2013
Crosstex	Acadia, LA	40	2Q, 2013
Targa	Mt. Belvieu, TX	100	2Q, 2013
Oneok/MB-2	Mt. Belvieu, TX	75	2Q, 2013
Enterprise/Train-7	Mt. Belvieu, TX	85	3Q, 2013
Enterprise/Train-8	Mt. Belvieu, TX	85	4Q, 2013
Lone Star NGL	Mt. Belvieu, TX	100	1Q, 2014
Oneok/Mb-3	Mt. Belvieu, TX	75	1Q, 2014
Pennsylvania (PA)/W. Virginia (WV)/Ohio (OH) - (Marcellus/Utica Shale Gas Basins)		**516**	
Williams/Moundsvill-1	Marshall, WV	13	2012
Williams/Moundsvill-2	Marshall, WV	30	2012
Dominion	Marshall, WV	36	1Q, 2013
Cheasepeake/M3 & EV Energy	Harrison, OH	90	2Q, 2013
MarkWest Liberty	Washington, PA	38	2Q, 2013
MarkWest Liberty	Marshall, WV	38	2Q, 2013
Williams	Marshall, WV (Ft. Wetzel)	30	3Q, 2013
Dominion	Marshall, WV	23	3Q, 2013
Williams	Marshall, WV (Ft. Wetzel)	30	3Q, 2013
Williams/Moundsville-3	Marshall, WV	30	4Q, 2013
MarkWest Utica	Harrison, OH	60	4Q, 2013
MarkWest Utica	Harrison, OH	40	1Q, 2014
MarkWest Liberty	Marshall, WV	38	2Q, 2014
Williams	Marshall, WV (Ft. Wetzel)	20	3Q, 2014?
Others		**70**	
QEP	Sweetwater, Utah	10	2Q, 2013
Oneok/Brushton	Ellsworth, Kansas	60	2Q, 2013
Total		**1,429**	

Source: Platts Commodities Week, "Major Supply, Demand Trends in US LPG/NGLs," Oct 16, 2012, Suzanne Evans

For NGLs, alternative transport by rail, or ship, becomes much more complicated. While plant condensate can and does move by pipeline, rail and tanker, almost all ethane moves by pipeline as well as the majority of LPG. This section details progress the industry has made in creating processing and transport for NGLs, as well as LPG export facilities. Yet we must also examine the mid-stream plant needed to create market-quality NGLs. Primary in processing is fractionation, the separation of an undifferentiated NGL stream into market-ready *purity product*.

A broad-based building campaign has been underway that will greatly expand NGL processing in the US. While the expansion of the large-scale NGL processing system in Texas was expected – Texas by end-2014 should complete almost 850 MBD of fractionation plant. What was unanticipated until recently was the growth of NGL capacity in the northeast US, where about 515 MBD of capacity will start up by 2015.

Total US fractionation capacity will rise 40% to 4.6 MMB/D by 2015, if all is completed as scheduled. Even assuming normal delays, a tremendous leap forward in NGL output will be assured. Capital costs were not trivial – in 2012, a 100 MBD fractionation plant was estimated to cost about $400 million, though most expansion will come from debottlenecking existing plants. Most new capacity is located near Mt. Belvieu, which will remain the center for US fractionation, with capacity rising to 1.7 MM B/D by 2015.

While the Northeast has emerged as a NGL center at least comparable to Conway, Kansas – and will likely overtake Conway as ethylene crackers start later in the decade - Mt. Belvieu will retain its leading role in NGLs, because of the sheer concentration of NGL, refining and petrochemical facilities close to this hub; its predominant role in setting national NGL prices and because the majority of LPG export capacity for the US is also located nearby on the USGC.

Once cleaned and separated, NGLs have to get to the users. We have already detailed the key role that Enterprise's ATEC Express pipeline will play in relieving the ethane overhang in the Northeast by transporting output to Mt. Belvieu by 2014. The following listings show the enormous extent of pipeline construction both, for moving mixed NGLs as well as ethane-specific pipelines, focusing on Marcellus/Utica output.

Table 35. Scramble for Infrastructure

Pipeline Name	Owner/Operator	Linking	Capacity	Distance	Startup
NGL Line Projects			**1,344-1,956**	**5,528**	
Arbuckle	Oneok	Barnett Shale/Mt. Belvieu	60	440	2012
Sand Hills	DCP Midstream	Permian & Eagle Ford Shale/Mt. Belvieu	200-350	700	2012
W. Texas Gateway	ETP & Regency JV	Permian Shale/Mt. Belvieu	96	530	1Q-2013
Cajun-Sibon Extension	CrossTex	Mt. Belvieu/Acadia, LA	70	130	1Q-2013
Overland Pass	Oneok & Williams	S. Wyoming Shale/Conway	115	760	1Q-2013
Bakken	Enterprise/Yoakum Oneok	Bakken Shale/Overland Pass	60-135	525	1Q-2013
Texas Express	Enterprise/Enbridge/Anadarko	Skellytown, tX/Mt. Belvieu	250-400	580	1Q-2013
Southern Hills	DCP Midstream	Conway/Mt. Belvieu	150-250	580	1Q-2013
Sterling III	Oneok	Conway/Mt. Belvieu	193-250	720	4Q-2013
Front Range	Enterprise/Enbridge/Anadarko	Niobrara Shale/Skellytown	150-230	435	4Q-2013
Mid-America	Enterprise	San Juan Basin/Hobbs, NM	65	128	1Q-2014
Ethane Line Projects			**350-380**	**1,449**	
Mariner	Mark West	Marcellus-Sarnia/Ontario, Canada	50-65	350	3Q-2013
ATEC Express	Enterprise	Marcellus/Utica/Mt. Belvieu	190	369	1Q-2014
Mariner East	Sunoco	Marcellus/Philadelphia, PA	65	300	2Q-2015
Vantage	Vantage	Bakken/Alberta, Canada	45-60	430	3Q-2013

Source: Platts Commodities Week,"Major Supply, Demand Trends in US LPG/NGLs," Oct 16, 2012; Suzanne Evans

As processing capacity emerges for Marcellus/Utica output, NGL production in PADD-1, particularly for ethane, will rise so seven-fold by 2017 from estimated 2012 production of less than 65 MBD. Marcellus will supply the Northeast and USGC and export to Canada by pipeline and by tanker to Europe. If midstream and upstream coordinate commissionings better, our ethane forecast may be exceeded, as many new fields set to start up contain higher proportions of ethane than had been the norm, with some virgin acreage now under development expected to yield 60% in NGL outturn.

Yet that is a medium-term development. More immediate is the gearing up for a massive increase in LPG, predominantly propane, exports, as can be seen by the listing below, which will add more than 700 MBD of terminal capacity to sell output abroad.

Table 37. LPG Export Infrastructure

Site	Owner/Operator	Product	Capacity	Startup	Notes
Houston Ship Channel	Enterprise	Propane	115	2012	Multiple tanker loading
Beaumont, TX	Vitol	Propane	100-200	1Q-2013	1.24-2.48 MM BBLs storage (100,000-200,000 MT)
Galena Park, TX	Targa Resources	Propane	84	3Q-2013	Can load up to 4 VLCG tankers monthly
Houston Ship Channel	Phillips 66, Occidental, TransMontaigne	Propane/Butane	430	1Q-2014	Can load pipeline to Mt. Belvieu
Total			**729-829**		

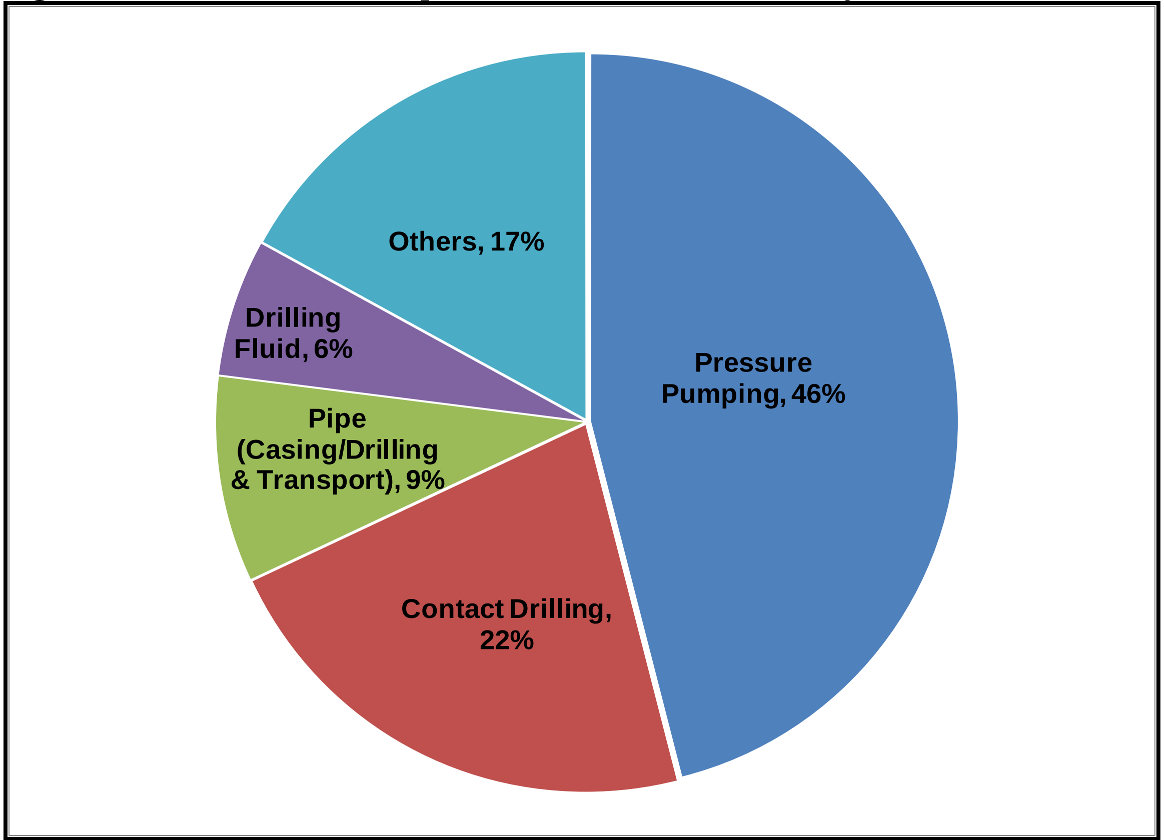
Source: Platts Commodities Week, "Major Supply, Demand Trends in US LPG/NGLs," Oct 16, 2012; Suzanne Evans

To give a sense of the scale, Qatar led exporters in 2012 by selling about 700-730 MBD of LPG, on preliminary calculation. Texas alone will add half as much export capacity in three years and with an expanded Panama Canal by 2015, Asia Pacific sales beckon.

I. "The Future Is Not What It Used To Be": The Impact of Technology on Upstream Operations

Another aspect of the Shale Revolution that has received insufficient attention has been the role of increasing efficiency in upstream operations. Improving drilling and pumping efficiency directly impacts capital costs for unconventional drilling, as seen below.

Figure 15. Oilfield Services Capex Across Unconventional Plays



Source: "The Shale Evolution – Examining Claims of a new normal in the U.S. Natural Gas Market," Morningstar, Oil & Gas Insights, Dec 2012

While the technology for basic horizontal drilling and hydraulic fracturing were invented some time back, with modern techniques introduced by the 1980s, it was only in the 1990s that such techniques were expanded, adapted and used in a systematic and programmed fashion. Further, it has only been since 2005 that these practices rapidly spread through US exploration, underpinning this Shale Revolution.

Most wells are drilled by specialist firms, which are contracted to exploration companies. North America is dominated by four large companies which at end-2012 accounted for about half of the rigs operating in US and Canada: Precision Drilling (374), Helmerich & Payne (290), Nabors (390) and Patterson-UTI (206).

The number of rigs used in US well-drilling has not changed much since the 2008 peak, yet the nature of the drilling fleet is changing rapidly, allowing for increased efficiency. The older mechanical rigs used in conventional wells were energy wasteful and lacked directional control. Rigs using Silicon-Controlled Rectifiers (SCR) gave drillers better control over their wells at a lower cost. The motors used in rigs too have changed with Direct Current (DC) rigs allowing substantial power and speed controls, but the newer AC machines providing precision and flexibility – key elements for drilling shale. In 2008, the US fleet consisted of 1,000 older mechanical rigs, another 600 with SCRs and DC motors and a further 250 with AC motors. By 2012, mechanical rigs fell to 600 units and SCR rigs to 500, but AC machines rose to 600 active units, according to Helmerich.[19]

The payoff has been greater drilling efficiency and reduced drilling costs. Helmerich and Payne claimed their latest rotary rigs can drill a horizontal well in 15 days, half of the time of older equipment. Continental Resources calculated a single rig can drill up to 12 wells in 2013 – compared to 11 wells in 2012 and 8 wells in 2010. Rising field efficiency has been the driver behind the paradox of fewer wells producing ever more gas from 2008 to 2012. In the US in 2008, there were 1,700 active rigs drilling onshore and about 83% were focused on gas. By 2012, there were 1,830 land-based rigs and about 520 of them, or 28%, were targeting gas. By end-year total active rigs dropped to the same level recorded in 2008, with less units drilling for gas. Yet gas production rose.[20]

Oil service company Schlumberger has been making the case that the industry has been opting more and more for "smart fracking," rather than use brute force to gain flow. Consistently falling fracturing costs have been a major driver in the Shale Revolution. Smart fracking will be targeted at only those horizontal well sections promising the best yields – whether oil, NGLs or gas.

There is other evidence of increased drilling efficiency. Continental, the leading oil producer in Bakken, observed that its drilling used eight rigs in 2010 for 135 wells; in 2013, 12 units drilled 262 wells. The number of wells each rig drilled annually rose dramatically. Further, *Stimulation Costs* i.e. fracking, as well as pumping/support costs also declined. Continental estimated fracking costs per *stage* fell 14% to $98,000 in the year ending 3Q, 2013 – and the company plans further cuts in stimulation costs.

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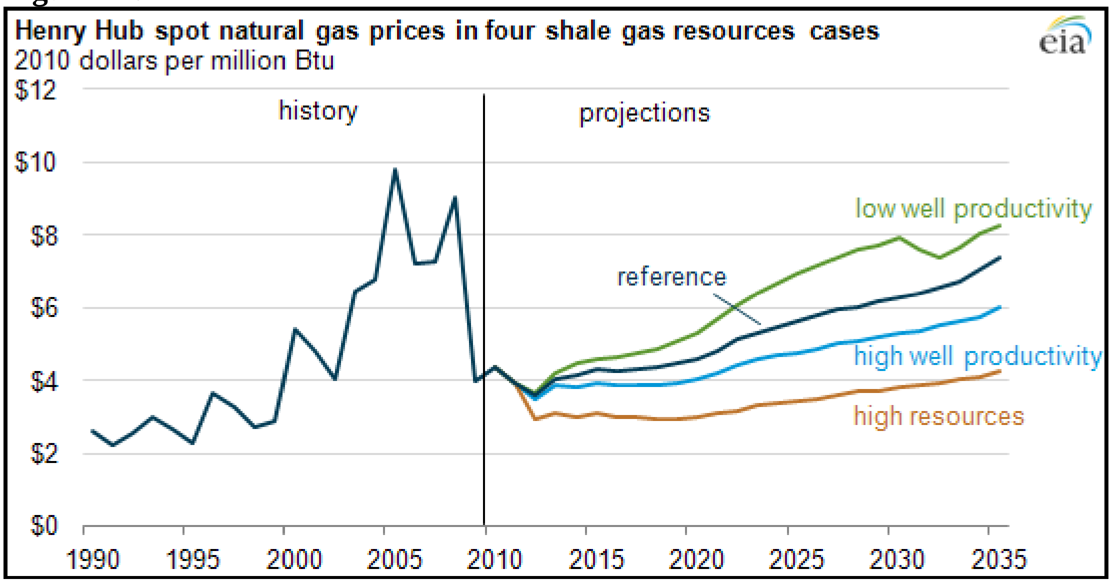
[19] John Kemp, Thomson Reuters, "Inside Oil, Beyond the Headlines," Feb. 11-12.
[20] Precision Drilling: "High Performance, High Value" (Ultimate Oil Services and ENP Conference, NY, Dec 3-4, 2012).

Explorers have been upgrading rigs, learning from experience, employing more advanced drilling bits and mud motors. The time for single well cut (well spud to next well spud) has decreased from 50 to 37 days, and increased use of multiple-well or *ECO-Pad* systems allows completion of multiple wells (minimum four) in 100 days. Continental targeted average well costs of $8.20 million in 2013, more than 20% below 2008 levels.[21]

But will well efficiency continue to improve? This has a direct impact on future NGL output from shale development as can be seen in the EIA forecast below.

Figure 16.



Source: U.S. Energy Information Administration, Annual Energy Outlook 2012.

EIA Notes to Figure 16:

- **Low Well Productivity Case** (green line): Production per shale gas well is assumed to be 50% lower than in the reference case, nearly doubling the per-unit cost of developing the resource.
- **High Well Productivity Case** (light blue line): The EUR per shale gas well is assumed to be 50% higher than in the reference case, nearly halving the per-unit cost of developing the resource.
- **High Resources Case** (orange line): The well spacing for all shale gas plays is assumed to be 8 wells per square mile, which increases the well density in about half the shale gas plays, and the EUR per shale gas well is also assumed to be 50% higher than in the reference case.

[21] CLR Vision, "Bakken: Changing the World," Continental Resources, Oct 9. 2012.

This EIA chart rightly emphasized the importance of continuing to reduce upstream costs as well as its impact on gas – and by extension – NGL markets, with particular impact on price as a reflection of future supply.

In the Reference, or Base Case, prices begin to firm by 2014 and slowly increase through 2020, yet remain on average at 4.50/MM BTU or lower. This assumes continued improvements in upstream operational efficiency, though perhaps not at the rate recorded in 2008-2012.

In the High-Well Productivity Case the EIA shows the impact of reducing costs by increasing productivity per well and how additional supply keeps gas price – and by extension NGL prices – from rising more than modestly through 2020. In the High Resources Case the driving assumption is that multi-well drilling, allowing for more wells to be completed within the same surface area, will boost productivity – and total output – even further. All impact production volumes and of course supply impacts price.

J. The Big Picture: An Emerging Yin/Yang of World NGL Markets

We have touched upon the impacts of the expanded Panama Canal earlier, but in this section we will explore the broader changes in transport economics that will emerge. We will detail some of the export possibilities emerging from the structural supply overhang developing in US NGLs and how that compliments and promotes Asia Pacific's structural supply short. As US producers begin to grasp the full implications of new transport economics, we believe a *Yin/Yang* of mutual benefit to both exporters and imports will emerge. And world NGL markets will be reshaped by the US Shale Revolution just as much as the global gas markets will be by US LNG exports.

1. New Doors Open

While slightly delayed, the Panama Canal expansion will create an entirely new set of options for NGL exporters, particularly producers close to, or with pipeline access to, the USGC. While the revamp of the canal is now set for commissioning by May, 2015, already condensate and LPG producers are gearing up to push sales not only to Europe, but west to Asia. The refurbished canal also will allow for the sale of substantial volumes of crude, oil products, NGLs and LNG. The $5.25 billion expansion will cut transit time from the USGC to Japan from 32 days to roughly 21 days voyage.

An important point in the renovation was expansion of the width of the canal's lock, from 110 ft (33.85 M) to 180 ft (55.4 M) as well as lengthening of each lock from 1,050 ft (333.8 M). This will allow most broad-beamed but moderate draft tankers, such as used in LNG and LPG transport, access directly to Pacific Rime markets. In 2012, Asia Pacific used 2.7 MM B/D of LPG, importing nearly 40% of that, mostly from the Mideast Gulf.

There are both similarities and differences in the transport parameters for LNG/LPG and liquids tankers. Both are shipped in similar types of broad-beamed tankers with relatively shallow draft. Both tend to be rated in the volume of cargo that they can carry rather than in ship deadweight tons – for example a special-build LPG tanker that could transit the old Panama Canal was classified as a 73,000 CM carrier. Using a conversion of 1.9 CM per MT and a proportion of 70% propane and 30% butane, this tanker would be, in standard shipping terms, about 38,000 DWT. Small volumes of LPG were exported to Japan in special-design LPG tankers able to transit the current Panama Canal. No LNG currently moves through the canal. LPG/LNG terminals need cryogenic storage and the ability to offload specialized products. Asia has the greatest number of cryogenic terminals in the world, as most markets lack a national gas pipeline system.

But the key difference is *boil-off*. LNG, when it heats up, reconverts to its gaseous state over the course of a voyage. This is termed *boil-off*. LNG tankers use this regasified cargo as ship's fuel or discharge it, though the latest class of Qatari carrier re-liquefy LNG aboard, to conserve cargo. In contrast long-distance LPG carriers either use refrigeration alone, or together with pressurization, to retain full cargo. Smaller LPG tankers iare generally pressurized. Distance reduces the volume of cargo delivered for LNG, but not for LPG.

The reconfigured Panama Canal will allow the passage of all LNG tankers other than the Qatari *Q-Flex* and *Q-Max* classes, carrying 220,000 CM and 240,000 CM, respectively. Almost all current operating or planned LPG tankers will be unable to utilize the canal route, fully opening the door to the booming Asia Pacific market. Houston-Chiba, Japan, is about 8,400 nautical miles – roughly a 20% greater distance than Qatar to Japan. This tends to make smaller cargoes of LNG less competitive say compared to large shipments from Canada's West Coast, but allows for very competitive sale of LPG.

Yet these are not all of the impacts of the upgraded canal – condensate could move in conventional oil tankers, and the expanded canal will be able to handle passage of ships up to 160,000 DWT. Oddly, this is the most common ship size used in long-haul sales by Qatar for sales to NE Asia and other distant customers.

2. ALREADY UNDERWAY

Why does Asia look so attractive, both for short and long term prospects? A number of factors are in play:

<u>Push Factors</u>

- Increased NGL output will come from the need to increase revenue from shale gas production. While substantial efforts are underway to construct plants to utilize all incremental NGL output, we believe they will fall short – leaving a continued supply overhang depressing prices. This is the *Yin*, to Asia's *Yang* in world NGL balances.

- Opponents of exports will find that their argument is contradictory and ultimately self-defeating. If an export ban is placed on LNG, it will scupper attempts to expand and broaden shale development, ultimately reducing future gas and NGL output. Markets will limit exports of NGLs as much has LNG, but the potential of additional sales will keep upstream investment humming, expanding total gas and NGL output.

- While many think of petrochemicals as the main outlet for new NGL production, gas liquids can have a major impact on transport fuels. Both US government and the industry itself see fairly modest growth in US transport fuel use, at least for the conventional fuels gasoline and diesel.

- US LPG exports even by early 2013 had more or less filled the easily accessible LPG markets of the Atlantic Basin and began to penetrate the Mediterranean, traditionally the home territory for Mideast Gulf exporter Aramco. Any further push east will result in price competition with Mideast LPG exporters.

- Since condensate does not need specialized containment, it is a leading candidate for sale to Asian markets. Concern about the future of US domestic gasoline demand has led to only limited investment in splitters to process condensate in volume. Further, refiners believe that light shale-derived crude alone should easily meet future US gasoline needs. Plant condensate is lighter and paraffinic, excellent for Asian olefins.

- If the US government should take the most logical, easiest step to correct the field condensate problem, it should allow the separation, segregation and export of condensate separated from crude, underpinning large-scale exports for Asia, helping to improve the balance of trade, while providing revenue to reduce the national debt. This is rational, easily accomplished and easier than overturning the crude export ban.

Pull Factors

- Asia Pacific has continued to be the leading growth area for oil since the 1990s, through boom and bust. While demand growth has slowed during the past recession, it never fell, only grew more slowly.

- While many Western analysts remain obsessed with China, Asian growth has been spread across the entire region, and no other part of the Developing World looks likely to challenge this region as oil demand leader for some decades. By 2014, Asia Pacific will use more oil than North America, including Mexico. While demand growth will likely slow, a growth of 3-4% is easily achievable through 2020.

- Asia Pacific is structurally dependent on Mideast export supply – not only for crude (about two-thirds), but LNG, NGLs and oil products – in particular naphtha, which remains still the primary feedstock for Asian petrochemical production.

- Asian markets have been trying to reduce their dependence – though they know that for the foreseeable future they cannot eliminate it – on Mideast imports. For crude buyers have scouted the globe; for LNG inter-regional arbitrage has become commonplace. While NGL imports from other regions have lagged, we believe there is an incipient interest in Asia Pacific in broadening its range of suppliers.

- While Asia Pacific tends to be overall a diesel rather than a gasoline market, another *draw* for US NGLs will be the role that they can play in freeing naphtha use for gasoline manufacture in the biggest, and fastest growing, gasoline market in the region, China. In 2012, preliminary statistics suggested that naphtha demand topped 1 MM B/D for petrochemical feedstock, about double the volume used in 2005 at 522 MBD. This has been paralleled by growing gasoline needs. China's 2012 gasoline use topped 1.6 MM B/D, more than gasoline demand in Japan, South Korea and Australia combined

  Finally, the Asian petrochemical sector in particular is ready for change and already has moved to diversify both the type of feedstocks that can be utilized, reducing naphtha needs, and broadening its range of feedstock suppliers. A number of times in the recession of 2008-2012, Asian companies saw their market rallies cut short by sharp increases in the price of term naphtha exports from the Mideast.

- Asia olefin capacity has expanded rapidly since 2000 and the chief petrochemical exporters in the region, Japan, South Korea, Taiwan and to a far lesser extent, Singapore and Thailand, are dependent on imported feedstock. Chinese import needs, both for feedstock and intermediates, such as ethylene, have helped support the global market since 2008. The Shale Revolution will allow for a sustained rise in American exports of petrochemicals and NGL feedstocks, and Asia will need both.

3. ASIA PACIFIC NGLS

Preliminary statistics for 2012 showed that Asia Pacific condensate demand reached 1.5 MM B/D, while LPG consumption approached 2.7 MM B/D. More than half of the condensate was imported, mainly from the Mideast Gulf and Qatar, and Saudi Arabia sold most of their combined 1.4 MN B/D of exports to Asian markets.

Table 38. Asia Pacific Condensate Utilization

Disposition Year	2011	2013	2015
Refining	475	498	537
Condensate Splitting	855	985	1,260
Petrochemicals	103	84	84
Power Generation	9	5	9
Other/Field Use	12	10	11
TOTAL	**1,454**	**1,582**	**1,901**

Source: "Condensate East of Suez 2012," Asia Pacific Energy Consulting

Ethane plays a far less significant role in Asia Pacific than in the US. Only Australia uses ethane as its sole primary cracker feedstock and only Malaysia and Thailand are major Asian consumers. China does not even have a pricing system for ethane distinct from natural gas. No international pipeline trade in ethane exists in the region.

Table 39. Current East of Suez Splitting Capacity by Country

Country	By 1/2012	By 1/2015		By 1/2017	
	Total	Expansion	Total	Expansion	Total
MIDEAST GULF	**1,122**	**227**	**1,418**	**388**	**1,737**
Qatar	200	-	200	143	343
Saudi Arabia	196	-	265	-	196
UAE	492	-	492	-	492
Iran	234	168	402	245	647
Iraq	-	59	59	-	59
ASIA PACIFIC	**1,042**	**474**	**1,516**	**136**	**1,652**
India	15	-	15	-	15
Pakistan	6	-	6	-	6
Bangladesh	1	3	4	-	4
Indonesia	-	-	-	-	-
Vietnam	16	-	16	30	46
Malaysia	74	-	74	-	74
Singapore	69	103	172	-	172
Thailand	138	-	138	-	138
Brunei	-	-	-	98	98
Taiwan	69	-	69	-	69
China	195	88	283	-	283
Japan	119	-	119	-	119
South Korea	262	280	542	-	542
Russian Far East	-	-	-	-	-
Australia	45	-	45	-	45
New Zealand	30	-	30	-	30
Papua New Guinea	3	-	3	8	11
GRAND TOTAL	**2,164**	**701**	**2,865**	**524**	**3,389**

Source: "Condensate East of Suez 2012," Asia Pacific Energy Consulting

While in 2012 naphtha still dominated Asian petrochemicals, both olefins and aromatics, East Asia has begun to move away from its high naphtha dependence. A number of ethylene crackers have begun to utilize LPG as a regular feedstock, while splitter capacity – often used to feed side-by-side petrochemical plants – has expanded rapidly since 2005. In 2012, Asia Pacific consumed more than 1 MM B/D of condensate, in direct furnace feed or processed through splitting and this will easily top 1.2 MM B/D by 2015.

While ethane exports on cryogenic tankers are only a future possibility, LPG and condensate sales are a current reality – and the opening of a direct west route for USGC exporters represents a basic shift in trade patterns, making USGC exporters more competitive, while backed by a surge in shale-derived NGL supply. Mideast exporters will have to compete on NGL markets as much as gas exports and it has been recently that large-scale Mideast Gulf sellers have taken the threat seriously of US NGL exports.

4. JAPAN AWAKES

If Asia Pacific operates the greatest number of LNG and LPG receiving terminals, it is Japan that is the regional leader. Japan possesses substantial cryogenic tank capacity and in 2012 purchased a record 87.2 MM MTA of LNG, equal to about 11.6 BN CFD of gas.

Japan has long been the world’s largest-volume LNG importer and it is the largest-volume LPG importer in Asia. Lack of a national gas network, plus regionalization by both utilities and refiners mean that there are receiving terminals throughout the archipelago. Japan is a modest-scale LPG producer – from refining, not gas output – of about 130 MBD in recent years, but imported 400 MBD in CY 2012.

LPG from the US has begun to appear more regularly in Japanese supply. While FY 2011 (ending March 31 2012) saw Japan importing 12.63 MM MTA (roughly 398 MBD), the US only had a 35% share of total imports, or some 4.4 MM MTA (133 MBD). The Japan LP Gas Association (JLPGA) forecast at end-2012 that US supply would rise steadily over the medium term and should make up a majority of Japanese LPG imports.

The expansion of USGC LPG export facilities and the revamped Panama Canal will be key elements in this export drive. The JLPGA predicted that larger LPG carriers – of 45,000 DWT rather than the current 38,000 DWT – will sharply cut transport costs and halve the voyage time to 20 days. JLPGA expects demand to grow by 20-30% by 2017. Japan, like Korea, uses LPG to raise calorific value for imported lean LNG cargoes.

Astomos Energy, a LPG distributor, is typical in building on its small contract that it currently holds with Enterprise. The company expects its US LPG import to rise from 16 MBD to 60 MBD – or 2 MM MTA – by 2015, while considering further imports. Japan maintains strategic stocks of 3 MM MT, half held by the private sector. Increased imports in part will come from petrochemical firms searching to broaden their feedstock supply with cheaper alternatives. Comparative feedstock costs support this. At end-2012 the cost of ethylene was about $320/MT in the US based on ethane feedstock, while ethylene based on naphtha feedstock averaged about $1,100/MT in NE Asia.

5. A BROAD JOINT VENTURE PATH

While Asian companies have been buying into upstream shale development projects – highlighted by the Petrochina/CNPC purchase of 49.9% of Encana at end-2012 – other Asian firms have been looking at the midstream/downstream implications of the Shale Revolution and in particular the NGLs that shale development yields.

Sinopec's buy-in for Devon shale projects in 2012 followed shale investment by Marubeni in Hunt and earlier purchases by Mitsui and Mitsubishi in Eagle Ford acreage. These companies, as well as Korean and Taiwanese firms, are examining possible NGL imports from the US and are mulling petrochemical joint ventures with US companies.

Japanese trading houses Mitsubishi, Mitsui, Marbueni and Itochu, China's Sinopec and CNPC/Petrochina, as well as Korean conglomerates SK and Samsung all have been actively seeking joint-venture proposals, utilizing shale-derived NGLs, but for US plant as well as NGL imports. A number of petrochemical companies that have operating plants in East of Suez markets and the US also appeared keen to expand their operations coordinating US and Asian developments. Formosa Plastics, Westlake, Chevron Phillips, Williams and LyondellBasell all have operating ethylene crackers in the USGC and are expanding capacity in these complexes.[22]

6. THE BOTTOM LINE

The easiest way to move and store NGL should be priority in export sales; plant condensate is obvious once Canadian import thirst slackens. For NGLs needing special containment, propane exports will rise sharply, while butane sales abroad will also increase, though not as much.

One first tries to sell lemonade, but if capacity is insufficient to squeeze lemons, the next step is to sell lemons. US petrochemical companies and refiners will first sell intermediates (i.e. ethylene, BTX), followed by finished petrochemical and refined products, gasoline components etc. But parallel to this will be the sale of NGLs themselves, with Asia a prime marketing target.

We expect other shale developments to emerge in other markets, notably China and Australia in Asia Pacific, but as we detail in the following section, it will take large capital investment and some lead time before shale makes any appreciable impact on gas, NGL and oil production in these two countries.

[22] WPA, "Asian firms seek chemical boosts from US shale boom," Oct 12.

Oil, gas and NGL prices will be shaped by American NGL exports. This will come about because of a number of linked drivers:

- To produce the gas that will be exported in part as LNG, US shale development has to continue to grow. That growth will be underpinned by liquids production, in good part, by liquids that are NGLs, not crude.

- While we believe that increased LNG supply from the US will force fairly quick changes to international supply/demand balances, eventually the volume of exports will stabilize as it becomes less profitable to export LNG. No one truly knows, if that level is 20, 40, 75 or 100 MM MTA, but it is clear that there will be considerable and growing pressure on prices now based on the oil-linked Japan Crude Cocktail (JCC). Sellers' expectations of buying LNG at Henry Hub prices, plus manufacture and transport costs are unrealistic; just as fantastic, in our view, is that LNG sellers can long defend the current JCC formula, at least in its current form.

- Shale-derived LPG will too impact Asia Pacific pricing. Both propane and butane prices are set off of Aramco's posted price for delivered LPG to Japan. While competitors are loathe to admit it, their sales to NE Asia are pitched at a level normally just below the Saudi price level – high enough to record a profit, low enough to undercut Saudi price dominance. Aramco's CP price is only loosely linked to Saudi crude export prices - at best it is a once-removed value. Yet petrochemical feedstock purchases have an even looser relationship to crude prices, but rather with the cost of competing feedstock produced from domestic refining (LPG/Japan) or from gas stripping (LPG, ethane and condensate/Malaysia) or from imported feedstock, mainly naphtha but also condensate and LPG. Steady NGL sales from the US cannot help but reshape Asia Pacific LPG prices.

- Similarly, the export of even small volumes of US condensate will remake Mideast and Asian price relationships, particularly as American plant condensate will be highly suitable to Asian ethylene cracker use. As Saudi Arabia has considered Asia to be its special reserve area for LPG exports – the region accounts for up to 80% of Aramco's sales abroad - and Qatar sees Asia as its own special market for LPG and condensate sales. Qatari export of segregated condensate topped 600 MBD by end-2012 and roughly 80% of that went to Eastern markets. Marketer Tasweeq's NGL exports are almost entirely dependent on the quantity of gas produced and there is limited price elasticity in sales. Even if modest volumes of American condensate move to Asia, then pricing will have to be adjusted to meet new competition.

K. Is Shale gas/NGL development replicable & in what Timeframe

A pivotal point in the question of shale gas-derived NGLs will be whether the American experience is replicable and if so, in what timeframe? The scope of this study allows only a cursory look at the conditions that promoted the rapid success of the Shale Revolution.

The table below summarizes APEC's view of five prime country candidates for shale development on four continents. We then will focus solely on China, as it most likely would have the greatest impact on our expectations of a NGL supply/demand *Yin/Yang* '.

Table 40. Five Prime Country Candidates for Shale Development

Shale Project Basics	US	Canada	China	Australia	Argentina
Size Reserves	5	5	5	3	4
Quality Reserves	5	5	3	3	4
Pricing Mechanisms	5	5	2	5	2
Gas Transport Network	5	4	2	3	2
Gas Process Capacity	5	5	2	4	2
Size Petchem	5	3	5	2	2
Feedstock Flexibility	5	5	2	4	2
Total	**35**	**32**	**21**	**24**	**18**

As can be seen in Table 40 above, the US has some advantages, upstream, midstream and downstream, and many of these pluses existed before shale development was a dream.
In a dozen active basins the US has an enormous shale resource base, but China does too. Only China exceeds American shale reserves on a crude first survey accounting, and the quality of many of these is often excellent both in expanse, thickness of shale, percentage of organic matter and porosity. Even dry gas deposits often have wet spots with considerable oil and NGL potential. US free market prices give an incentive to development and the existence – though badly needing expansion and upgrading - of a gas and NGL transport network, made it relatively easy to get output to buyers. Large-scale gas (and NGL) processing capacity operated before the Shale Revolution and has expanded, while base petrochemical capacity was the world's largest even before this revolution. US petrochemical companies have long operated sophisticated, highly flexible operations, using multiple feedstocks. The fast-track emergence of shale-derived gas, NGLs and oil production in part was due to the existing infrastructure, but more due to the sector understanding the profits possible in shale development. It had nothing to do with government policies; most shale developments are on private or state-leased land.

For China, in comparison, many obstacles must be overcome. The priority need is for a full national gas transport network as well as regional NGL pipelines. NGLs have long been ignored in China, though condensate has grown in importance over the past decade. Without the means of getting shale-derived output to market, development will be slow and uneven. While substantial gas and NGL processing exists in China, the total capacity is inadequate to support a sustained increase in shale gas processing. For the US, the building of infrastructure was a brown-field exercise, expanding and revamping what already was operating. For China, this will become a program of green-field investment.

China's Ministry of Land and Resources claimed an estimated 885 TCF of potentially recoverable shale gas reserves in 2012, exceeding the EIA's earlier estimate of in-place reserves totaling 1,275 TCF. Either estimate would make China the largest holder of shale gas reserves – if they are believed. Explorers express considerable doubts on these reserve estimates as well as how much of this resource base could prove commercial.

While it is quite clear that China's potential shale reserves are enormous, located in at least seven basins and stretching across this huge continental country, there have also been concerns about the quality of known finds. Chinese shale is at deeper depths, often formed of shale of poor porosity, in remote regions of China. Some companies, notably ExxonMobil, have questioned whether the US is an accurate indicator of future development output in other countries. The company has accessed Chinese shale reserves and believed much of China's shale deposits consist of very dry gas. Beijing is far more upbeat, setting ambitious production targets far higher than Chinese upstream experts believe achievable. Most shale basins have yet to be surveyed, let alone drilled and less than a dozen exploratory wells were completed by 1/2013. The government has set an ambitious output target of 630 MM CFD of shale gas by 2015 and 5.8-9.78 BN CFD by end-decade. Achieving these production targets will be at best difficult.

China is of two minds on the role of foreign upstream participation. On one hand the government wants fast progress in development and the production targets set by the government assume a pace of boosting production equal to that of the US, 2008-2012. Yet in the two offerings of shale tracts for development, foreign companies were for the most part shut out and contracts were awarded to politically connected, but quite inexperienced domestic firms. Acreage awards in early 2013 saw greater though still limited foreign company participation. CNPC and Sinopec realize that without foreign operating experience progress on shale development will be slow – and that is part of the reason for these firms and CNOOC, to buy into shale projects in the US and Canada.

While the public goal is to quickly raise shale gas production, Chinese state companies have focused more on shale-associated liquids, crude and NGLs. And while the government has promised that all shale project production will be free of price controls, there exists no free market pricing of NGLs in China's domestic production. Condensate is price-controlled as a crude equivalent; domestic LPG, whether produced from field or in a refinery, is price-controlled and ethane does not even have a pricing mechanism – it is burned as methane or natural gas. Unless the government acts swiftly to establish NGL pricing for shale projects, developers will have no idea of future revenue, making them reluctant to invest in supporting infrastructure.

We see shale gas making a significant impact only at some time in the next decade, and the NGL and crude impact of such development remains fuzzy. Australia has begun its first shale gas output late 2012, but its future as a shale producer is even less certain. While Australia has two large shale basins and first gas has been produced, we expect upstream efforts to be focused on offshore conventional LNG, floating LNG and Coal Bed Methane (CBM) proposals first.

In the end, we expect that Exxon's long-range forecast will remain essentially correct, with North America, mainly the US, accounting for about a fifth of all incremental gas supply through 2020; that the continent will increase unconventional gas supply faster than anywhere else, meeting 75% of demand by 2040; that the US and Canada will become net exporters of NGLs, gas and oil by 2025; and finally, that the world market's ability to absorb US-origin LNG will be roughly in the range of 76 MM MTA of LNG – or 10.13 BN CFD of dry, clean output.

L. Geopolitical Tectonics

Supply/demand, pricing and trade relationships between the main regions of the world will be remade by the Shale Revolution and we are already seeing signs of how profound these shifts will be by mid-decade. As in the modern theory of world geology, global tectonics, the continents have begun to drift and seismic changes are underfoot. We will focus on the impacts on North America, Asia Pacific, the Mideast Gulf and Europe in this brief survey, detailing our anticipated changes in oil, gas and NGLs.

1. NORTH AMERICA

A combination of Canadian oil sands-derived syncrude, plus US tight oil, coupled with a likely rebound in Mexican production, will make North America, as a regional unit, for the most part self-sufficient in oil production. Rising tight oil output already has backed out light sweet grades into the Atlantic Basin market. Canadian crude will begin to reshape Asia Pacific crude markets, just as it did the US market over the past decade. Light and heavy crudes, sweet and sour crudes, will find new pricing relationships over the course of this decade, even without US crude exports.

The goal of *energy independence* is a mantra that all politicians chant, but few in the energy sector truly believe. The US can, through shale development, lessen its dependence on imported hydrocarbons, and as the sudden flip-flop from plans to import LNG, to exporting it have demonstrated, sector trends can emerge with startling rapidity. Shale allows for North America, but particularly the US, to become a net hydrocarbon exporter, but this does not mean all imports cease. Attempts to restrict exports through legislation will reduce the further investment needed to realize shale's full potential.

Complete autarky has little meaning in the energy sector and no relevance for a modern economy. The net result of US export regulation is to make shale-derived output increasingly unusable for domestic refiners, yielding products, such as gasoline or petrochemical feedstock that will be in surplus. Yet even if current regulations remain unchanged, the refurbishment of the Panama Canal will allow for regular sale of plant condensate to Asia as easily as Europe, particularly as Canadian imports decline.

What proponents of restrictions on gas export do not appear to fully comprehend is that no industry, in energy, telecommunications or retail can be compelled to invest in ventures that will certainly produce financial loss. The short-sighted pleadings to restrict gas (and by extension NGL) exports to guarantee long-term discounted feedstock is self-defeating. Depressed NGL prices will eventually lead to the drying up of future supply.

We expect LNG exports to begin by 2015 and despite government permitting delays, build to large-volume liquefaction by 2020, perhaps 30-40 MM MTA from the US and an additional 20 MM MTA at least test-running in western Canada. To support this enormous volume of gas exports, considerable wellhead production will be needed and that output will also yield large volumes of NGLs. US LNG exports are not limited by the size or physical characteristics of a specific gas find, but utilize continental resources, harnessed by the gas network, to export large volumes from multiple loading points.

LNG exports will have the greatest impact first on the Atlantic Basin, and only later and to a lesser extent on Asia Pacific, as Panama Canal restrictions, even after renovation, do not permit the largest LNG carriers passage. However, they will have a profound impact in East of Suez pricing systems and a loosening of strict oil-linkage through the JCC has already begun. Sales to Europe will increase European consumers from Russian piped gas pricing demands as well as undercut international LNG sellers' claims to a *security premium* for sales to the continent.

We believe that forecasters generally have underestimated the impact of gas supply needed for Canadian LNG on future NGL production in this market. While some export of condensate for Canadian syncrude will likely continue through 2020, Canada will not automatically absorb all condensate and butane that US producers can ship to them.

Gas derived from the Shale Revolution will reshape the US power industry and very likely provide a credible alternative – with use of NGLs – to gasoline and diesel use as the main road fuels. Moderately priced gas will underpin a renaissance of US industry, some analysts believe.

NGLs, as much as crude, provide necessary revenue to continue developing shale gas projects. As detailed throughout this study, they will have profound impacts, at home and abroad, on the petrochemical sector; provide less expensive and plentiful components for gasoline manufacture and contribute greatly to reducing the US trade imbalance both in the products derived from NGLs and the sale abroad of NGLs themselves.

The US will reshape global production of base petrochemicals. European petrochemical giants, such as Shell, Total and Lyondell Basell, have decided to invest further in US plants, while American international companies, such as Dow, have hedged their Mideast investment bets by also planning US ethylene crackers.

In NGLs, gas and even to some extent oil, the US renaissance challenges the geopolitical power of the Mideast Gulf to set and maintain hydrocarbon prices. No doubt OPEC and particularly the heart of the organization, the Mideast Gulf, will remain a primary voice in international markets for decades to come. Asia Pacific in particular can begin easing its unhealthy dependence on the volatile Mideast Gulf and will move to broaden the range of suppliers and type of feedstocks, base petrochemical plants will use.

2. ASIA PACIFIC

That the price deltas for international crude will shift steadily over the course of this decade is indisputable. And that Asia Pacific would like to limit its heavy dependence (more than two-thirds of total consumption) on Mideast crude is also irrefutable. Yet two tendencies will shape Asian oil supply by 2020. The growing supply of Canadian, heavy, sour crude derived from oil sands, which gives enormous middle distillate yields, will be suited to the region's demand barrel and ease any upward price pressure on Mideast heavy sours, due to their increased use by new Gulf refineries. Yet pressure on light, sweet crudes has been felt across the Atlantic Basin for all Brent-linked grades. How much longer will it be before Mideast Gulf crudes of similar nature are also impacted?

Canada, rather than the US may well impact physical gas supply to Asia more profoundly than American LNG projects – cargoes moving from British Columbia are considerably closer to NE Asia markets of Japan and South Korea, than Qatar or Australia, let alone the USGC. Yet the commitment of a number of Asian importers to US term LNG contracts is readily reshaping price mechanisms and weakening oil's exclusive role in dictating LNG prices. Spot LNG prices approaching $19.75/MM BTU, seen in early 2013, will not be easily achieved when sizable North American LNG is available.

As earlier noted, US NGLs will support the current reshaping of Asian petrochemicals, with Asian buyers broadening feedstocks and its range of feedstock suppliers. Less easily perceived is the extent of that shale-derived NGLs may well shape future Asian gasoline supply. Butane and iso-butane are the base material to create components isomerate and alkylate, the basic building blocks of gasoline. Condensate can provide both base-stock for blending, as well as N+A naphtha for making reformate, another important component used in blending and upgrading gasoline. Further, LPG importing countries, attempting to lessen their dependence on gasoline and diesel as transport fuels, may find that US LPG cargoes, through the Panama Canal, can help supply alternative fuel needs.

The US is already a regular exporter of ethylene to Asia and the ballooning of ethane supply, due to shale development, running ahead of the ethylene crackers meant to absorb this NGL, make it possible that ethane exports to Asia may emerge by end-decade. Unlike the E/P exports now planned for sales to Europe, these exports would likely depend on cryogenic transport. Though we believe that this possibility may prove commercial, it may well take some time to emerge.

Most of all for Asian imports – of crude, of gas, of NGLs – the emergence of relatively inexpensive shale-derived production allows them a choice. Asia Pacific will remain structurally dependent on Mideast supply for the foreseeable future, but does not have to be a fully captive buyer. The Mideast will face growing competition in what most Gulf exporters considered their own marketing backyard.

3. THE MIDEAST GULF

Gulf exporters have been slow so far to react to the challenge of the Shale Revolution, preferring to believe that its importance has been exaggerated. The general belief has been that even if shale-derived supply growth continues to expand, it will only indirectly impact their sales of NGLs, petrochemicals and crude.

Yet shale's impact on world LNG markets was grasped fairly quickly by Qatar which in 2012 put up its own proposal to export US gas with partner Exxon from the Golden Pass LNG terminal. Yet the more profound impact of shale-derived gas is not in additional LNG supply but how profoundly US-based exports will shift Asian buyers' LNG prices. New contracts increasingly are set on a combination of crude-linked JCC and some form of Henry Hub pricing, resulting in more than modest gains for LNG buyers.

Yet oil exports too are beginning to be impacted, as Mideast crude exporters search for new markets to replace Western buyers now supplied by discounted light grades pushed out of the US market. The pricing relationship between heavy/light and sweet/sour crudes is very much in flux and Mideast sellers have only just begun in late 2012 to take notice.

We believe though that the Shale Revolution may produce the broadest impact in NGLs, first in LPG and then later condensate markets. US LPG exports, which have already flooded Latin America, West Africa and NW Europe, have begun to penetrate into the Mediterranean, long the marketing preserve of Mideast sellers, notably Aramco. Competition will emerge short term for Mideast marginal LPG markets, such as the Mediterranean – longer term the Panama Canal will present a challenge in Asia. Condensate exports so far have had minimal impact, as Canada has been absorbing most of the incremental output, but we believe this will change later this decade and with the access west that the revamped Panama Canal will give USGC exporters.

Yet a more deep-rooted NGL-linked change will come from the influence of long-term moderately priced feedstock feeding an American petrochemical renaissance. Mideast base petrochemical capacity has expanded steadily since 2000 on the basis of NGL feedstocks and attracting multi-billion investments by companies such as Dow, Shell and Sumitomo, by offering long-term discounted petrochemical feedstock. Yet gas exploration and development has not been able to keep up with cancerously high demand growth – particularly for additional power generation. All Mideast markets are caught in the same Goldilocks dilemma in future gas/NGL production. They must increase the price paid for gas and NGLs, in order to attract foreign explorers to find and then develop new production – current prices generally do not even cover exploration costs – while keeping prices low for domestic consumers and to attract foreign petrochemical investment. Since Gulf governments do not trust markets to set the price that "is just right," each struggles to reconcile these contradictory pressures.

The Mideast Gulf will remain the center of oil, gas and NGL market attention for many more decades, but more broadly OPEC's geopolitical influence will be somewhat curtailed by the US and its large-scale, relatively low-cost NGL, gas and oil production. The Shale Revolution will see the US by 2020 export condensate and LPG volumes on a scale equivalent to that of Qatar and Saudi Arabia, reshaping global market dynamics.

4. EUROPE

While Europe will benefit from the emergence of American exports, this region most of all will suffer from most of the negative impacts emerging from the Shale Revolution. In Europe, commercial shale deposits are known in the UK, in the Ukraine and Poland, as well as other potential areas. Yet generally negative public and government attitudes to shale development make it unlikely, even when the resource base is sufficient, to see large-scale shale development in this region, though the UK may well be the exception. France had banned the exploration or utilization of shale fracturing by 2012; Germany in 2013 severely restricted shale exploration, though not banning it. Initial survey of shale deposits in Poland has proved disappointing, while in the Ukraine, where geologic prospects were upbeat, companies face quiet Russian pressure to cease shale exploration.

The Shale Revolution has meant that US LNG exports, as they emerge, will tend to be, at least initially, aimed at Western markets and the main impact will be to increase European supply security, while providing price competition to Russian piped gas supply. Russian gas sales to western Europe have been falling in volume for some years; sellers face increasing buyer opposition to what they see as high prices; the European Union has repeatedly investigated Russian commercial practices and pricing. Shale-based NGLs also make it much more difficult for Russian companies, such as Gazprom and Novatek, to launch high-cost LNG projects such as Yamal LNG, which is expected to cost at least $30 billion, perhaps much more, when lower-cost US LNG supply emerges.

European buyers can also benefit from less expensive LPG, as the EU remains a major importer of Mideast propane and butane, and price competition, particularly in the Mediterranean, is doubly welcome. Yet condensate is of limited value to European downstream, and petrochemical capacity will likely continue to shrink, even though E/P imports will likely begin soon.

While European refiners will face price competition, importers will see a steady rise in light-end supply avails from US refineries, and in particular gasoline, gasoline components and aviation fuel (jet/kerosine) avails will grow. The European refining sector will continue to shrink, with US light product exports simply accelerating a trend that began some years ago.

Similarly the run-down in European base petrochemical plant began before the Shale Revolution became apparent, but will likely accelerate the shrinkage of ethylene cracking capacity across the continent, as companies look to regions with *advantaged feedstock*, i.e. North America or the Mideast Gulf, or close to the center of continuing demand growth, i.e. Asia Pacific, particularly East Asia. There are few measures that the EU can take to reverse this decline, other than perhaps allow the Shale Revolution to spread to Europe, a future we believe unlikely to emerge.

Conclusions

- **Truth or Consequences Continued**: In Dr. Medlock's 2012 paper, he argued that the impact of allowing US LNG exports on future US domestic gas prices will likely be moderate. To claim that gas exports will prompt a dramatic rise in domestic prices that will cripple American industry and power generation – and whose costs will be borne by the average residential gas consumer – shows a simplistic view of how markets work. No modern economy, in energy, nor any other sector, can achieve full economic autarky, producing and consuming solely what it needs.

- **A Commercial Coda:** If anything, we believe that restriction of LNG or NGL exports, allowed under present regulation, ultimately ensure the size, duration and commercial viability of future gas and NGL production. As is the case with condensate splitters, no investing company, particularly an international giant such as Dow Chemical, wants to build a massive olefin complex only to find that it becomes a stranded investment in only a few years, due to a lack of NGL feedstocks.

- **New World View:** Reality has a way of upsetting a regulatory worldview, as can be clearly illustrated in the success of US explorers in reversing decades of decline of production. The industry's shale oil efforts have surprised even boosters with the size of production gains and the likelihood that increased oil output will be a mainstay of American upstream for some time to come. While we remain skeptical of some IEA claims of the US overtaking and remaining ahead of Saudi Arabia as the world's largest oil producer, it is clear a seismic shift in the oil world has occurred and the geopolitical ramifications have yet to be fully understood.

- **A Question of Condensate:** Yet the advent of large-volume, light and very low-sulfur crude output from shale will prove a mixed blessing for US refiners and may well lead to easing – rather tightening – of export restrictions. If shale oil continues to become lighter, this output cannot be easily processed by refiners without significant operational problems. A diet solely of tight oil for USGC refiners would be like feeding marzipan to a diabetic – they cannot process the material without danger to their commercial health.

- **"The Art of the Possible":** We believe that permitting crude exports remains politically unacceptable, yet an elegant and yet simple solution would be to lift the ban on field condensate exports – in fact a recognition of what this NGL truly is, not a liquid beneath the ground, but like propane, butane or ethane, a series of liquid molecules suspended in a gas reservoir. Shale producers only spike condensate into crude because there is no incentive to separate and segregate this output – it is considered black oil by the federal government. If it was profitable to do so – and condensate exports can prove at times more profitable than crude oil sales – they certainly would take the initiative, as they have already done with LPG.

- **More Gas Means More NGLs:** We expect that the long-term volume of NGLs will be at least as significant as US LNG, since NGLs have many values beyond their ability to produce heat (calorific value), unlike gas in the form of LNG – we also think that their impact on world balances profound. Yet since NGLs in some ways resemble, in their commercial behavior, gas, and in other ways are similar to crude and oil products, their future influence is underestimated.

- **How High is Up?:** Forecasts vary widely for future output from shale development, even on a relatively shorter medium-term basis, i.e. a five-year outlook. Incremental oil and gas development assessments vary widely, NGLs, though a function of gas production will vary considerably on the *wetness* of the gas produced. We take a conservative view - tight oil output rising to 3.6-4.0 MM B/D of shale-derived oil, a gain of roughly 12 BN CFD of gas capacity and a further 1.5-1.8 MM B/D of NGLs look likely. The EIA in early 2013 forecast that marketed gas production would rise this year to 70.02 BN CFD.

- **Gas & NGLs:** What is clear is that increasing gas production is dependent upon developing gas with substantial liquids production as well. For NGLs this has meant that output has gone from being a by-product of gas, to a co-product and in some ways, it can be reasonably argued, has made gas a by-product of NGL development. The tail has come to wag the dog

- **The Nature of Gas & NGLs:** What differs for gas and NGLs is that because of the physical nature of these hydrocarbons, needing specialized transport, storage and support infrastructure, increments come out *lumpy* in large volumes quickly rather than in a slow and gradual curve upward. Yet in the end the US system is fairly well balanced, underlining a fundamental feature of the US Shale Revolution: the sharp rise in output and its utilization built on earlier systems of gas, NGL and oil transport; on a sophisticated system of refining and product distribution, the effort has been more of a brown-field program of expanding and upgrading physical assets, rather than building them from scratch.

- **Prices for Both Will Recover:** Though the EIA in its January 2013 outlook lowered its forecast average Henry Hub gas price by $0.21/MM BTU to $3.53/MM BTU, we expect gas and NGL prices to recover somewhat by 2014 and that though liquids will still carry much of the revenue burden for future shale development, gas will regain some price strength once gas/NGL infrastructure and end-users start up, absorbing incremental output.

- **Sector Utilizations:** Ethane‘s chief market is petrochemicals; propane's main market is heating/cooking and petrochemicals; butane mainly is used to make gasoline and in industry and petrochemicals. LPG also is used in many foreign markets in road transport. Condensate acts as a light, sweet crude equivalent, but almost always produces more than half naphtha, part of which can be converted into gasoline.

- **Same Difference:** We have emphasized the different nature of shale basins, focusing on Bakken, Eagle Ford and Marcellus of the many areas now eyed for shale exploration and development. While Bakken is seen mainly as an oil producer, Eagle Ford as an oil/NGL area and Marcellus as a gas production center, all will significantly impact future US NGL output. Permian, Utica, Niobrara and Cana-Woodford will add tight oil production by 2015; Monterey is a longer-term prospect.
- **Pins in a Row:** We have emphasized the difficulties inherent in coordinating upstream development, mid-stream processing and transportation construction and downstream end-users for NGL production and utilization. As in constructing the many complex links in a LNG supply chain, NGLs take time and planning to bring fully into play. We expect some lag through 2017, with midstream and downstream trying to catch up with unparalleled upstream successes, but a vast construction program makes it likely that the US will add enormous volumes of NGL use.

- **NGL Exports already Begun:** Yet until demand catches up with supply, NGL exports are necessary to keep markets in a rough balance. It must be noted that NGL content must be reduced to a minimum to transport gas either by pipeline or as LNG, and in the US, since the calorific ceiling for piped gas is fairly low, this means most NGL has to be removed before transport. That NGL is either used in the domestic market or exported. Limited-volume ethane exports are only by pipeline to neighboring markets. This often results in delay in commissioning ethane-rich gas deposits, as has been seen in Marcellus/Utica, until ethane can be marketed.

- **Improving Ways and Means:** Which is why the US gas and NGL sector is in the midst of a massive construction boom, both to process output and separate the NGLs into end-user products. This must then be shipped to buyers, mainly by pipeline. In the period 2012-2017, the US will add as much NGL capacity, processing and transport, as most NGL producing countries now operate. By 2017, US exports of LPGs and condensate will challenge Mideast exporters in Europe and Asia. Already shale-derived LPG has flooded the Atlantic Basin and condensate makes up a sizable percentage of Canadian imports for synfuel use.

- **Upstream More from Less:** A chief driver in the unexpected success of shale development has been the ability of operators to quickly learn from their mistakes and continually improve upstream practices. This operational efficiency has been a major driver, both in reducing costs and expanding output far more rapidly than even shale proponents thought possible. Future outlooks of production of gas, NGLs and oil vary substantially on whether the sector will continue to increase its ability to do more with less, throughout the decade, lowering costs and making some uneconomical but known shale reserves commercial

- **A Key Point:** This fundamental point is that while technology has been important in the Shale Revolution, it has been the reutilization of old technology with new operating techniques that has consistently lowered costs, allowing less gas wells to produce more gas than even 3 years ago. The wide divergence in production outlooks, in part at least, is due to the forecasters' view of future exploration improvements.

- **Transport Routes Will Shift Exports:** Moving NGLs is not solely a domestic affair. Changes in shipping routes and transport costs will make US NGL exports more competitive going west to Asia, through the newly refurbished Panama Canal. While distance can limit long-haul LNG sales, due to boil-off – cargo is lost according to voyage distance – with LPG the expanded route to the Pacific will open Asia Pacific to US NGL regular exports, first LPG and condensate and in the future ethane in addition to ethylene, using cryogenic tankers.

- **A *Yin /Yang Emerging*:** A structural supply overhang in NGLs in the US will complement Asia Pacific's fundamental desire to reduce dependence on the Mideast Gulf NGL, gas and oil supply, with the *Yin* of the US market matching the *Yang* of Asian demand, particularly in the petrochemical sector. A revamped Panama Canal will allow the USGC to become an important supplier for Asian import needs.

- **Slower, Longer, Costlier:** We believe that the US Shale Revolution is replicable, and as geologists and explorers look more closely at the shale resource base, estimates of potential will continue to rise. In early 2013, a reassessment of Britain's shale resources indicated possible reserves of 1,300-1,700 TCF of gas – compared to a 2010 estimate of only 5.3 TCF. But having potential does not immediately translate into commercial supply. Our experience of gas projects in general can be summarized as an inverse of the Olympic slogan, in this case "Slower, Longer, Costlier" rather than "Higher, Faster, Stronger." Commercial gas and NGL output will come in Britain, as much as it will in China and Australia, but the impact will likely be felt in any meaningful fashion post-2020.

- **NGL's Geopolitical Fall-Out:** Most of all the Shale Revolution offers a possible shift in world energy geopolitics. North America – if Washington could learn to understand the importance of Canada and Mexico to the US – will shift from net NGL, gas and oil imports, to exports. Energy independence is an illusion, but minimal dependence on foreign energy suppliers is possible. The Mideast must face a structural challenge that will force exporters to re-examine their basic assumptions of pricing, domestic market price controls as well as their future sales direction. Asia Pacific will finally have a long-term supply alternative that will allow the region to reduce, though not eliminate, its structural energy import dependence on the highly unstable Mideast Gulf. Europe may well be the biggest loser – though North American NGL and oil product exports will provide a cheaper supply source than the Mideast – unless it moves quickly to explore the potential of the Shale Revolution.