Citi GPS

ENERGY 2020

North America, the New Middle East?

Citi GPS: Global Perspectives & Solutions

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ENERGY 2020

North America, the New Middle East?

For the first time since 1949, the US has become a net petroleum product exporting country and has edged out Russia as the world's largest refined petroleum exporter. A simple explanation would point to lower demand and a struggling economy which requires less imported energy. But, that would only get you half the answer. US demand has fallen by some 2-m b/d since its peak in 2005 in part due to the recession but also due to a structural change due to demographic changes, policies on fuel efficiencies and the mass-commercialization of technologies. The more exciting part of the answer is on the supply side as the US has become the fastest growing oil and natural gas producing area of the world and is now the most important marginal source for oil and gas globally. Add to this steadily growing Canadian production and a comeback in Mexican production and you get to a higher growth rate than all of OPEC can sustain.

Five incremental sources of liquids growth could make North America the largest source of new supply in the next decade: oil sands production in Canada, deepwater in the US and Mexico, oil from shale and tight sands, natural gas liquids (NGLs) associated with the production of natural gas, and biofuels. Putting these together, North America as a whole could add over 11-m b/d of liquids from over 15-m b/d in 2010 to almost 27-m b/d by 2020-22.

The shale gas production boom that propelled the fundamental change in the natural gas markets in the US could begin to transform other sectors including power generation and transportation. Other incremental gains could come from LNG exports with North America acting as the swing supplier for the world. But the most momentous change looks likely to be in the re-industrialization of America based on dramatically lower cost feedstock than is available anywhere in the world, with the possible exception of Qatar.

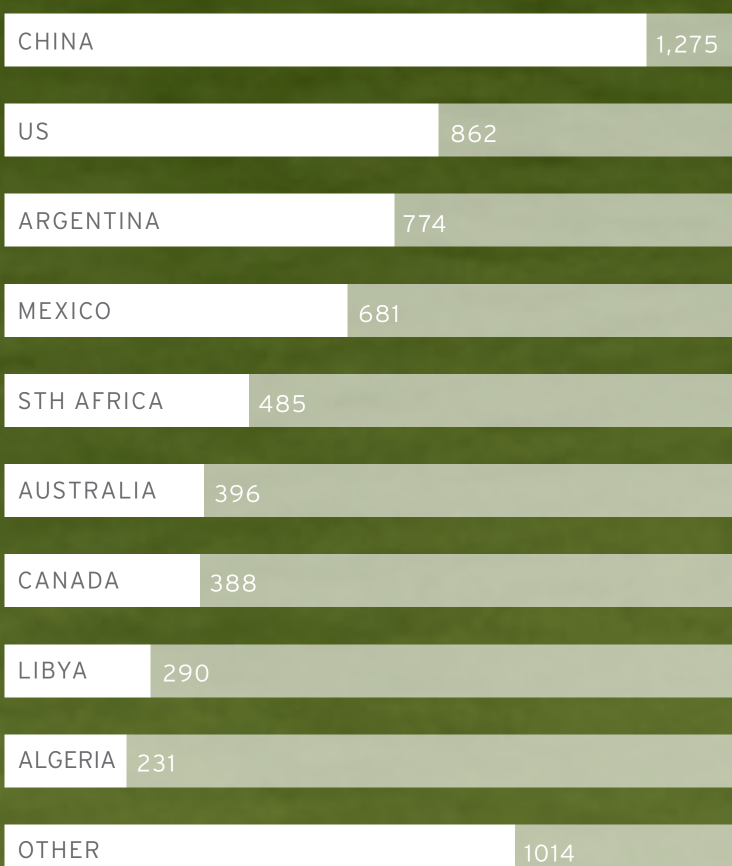
The economic consequences from this supply and demand revolution are potentially extraordinary. We estimate that the cumulative impact of new production, reduced consumption and associated activity may increase real GDP by 2.0 to 3.3%, or $370-$624 billion (in 2005 $) respectively. $274 billion of this comes directly from the output of new hydrocarbon production alone, while the rest is generated by multiplier effects as the surge in economic activity drives higher wealth, spending, consumption and investment effects that ripple through the economy. This potential re-industrialization of the US economy is both profound and timely, occurring as the US struggles to shake off the lingering effects of the 2008 financial crisis.

The reduced vulnerability of North America — and the world market — to oil price spikes also has deep consequences geopolitically, including the reduced strategic importance to the US of changes in oil- and natural gas-producing countries worldwide. Pressures towards isolationism in the US will likely grow, with consequences for global stability that can only just begin to become understood.

Whether the increase in production results in the US reducing its imports or whether net exports grow doesn't matter much to world balances. Either way, North America is becoming the new Middle East. The only thing that can stop this is politics — environmentalists getting the upper hand over supply in the U.S., for instance; or First Nations impeding pipeline expansion in Canada; or Mexican production continuing to trip over the Mexican Constitution, impeding foreign investment or technology transfers — in North America itself.

US Now a Net Exporter of Petroleum Products

TOP SHALE GAS BASINS BY RECOVERABLE RESOURCES (EST)

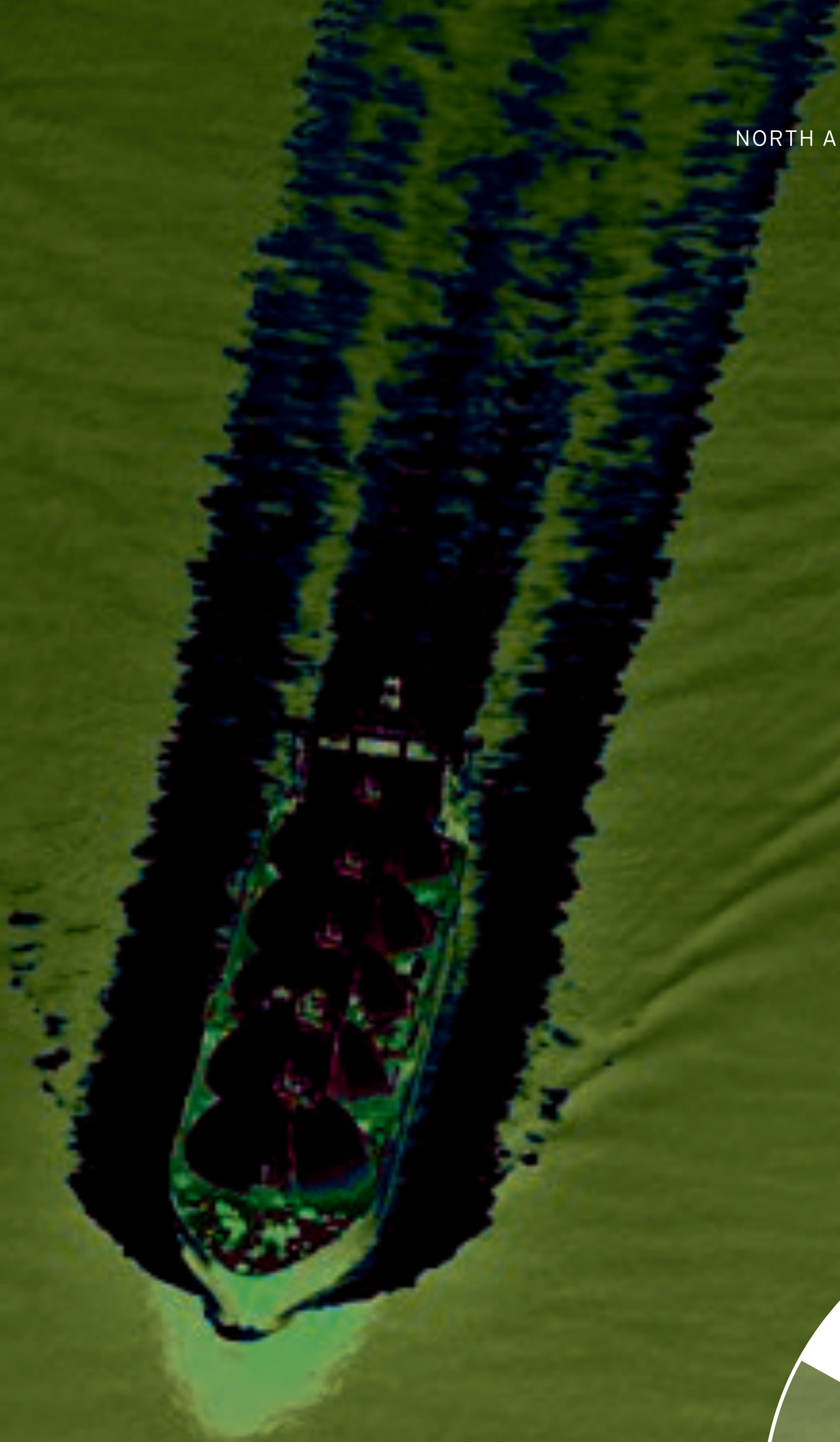


North American crude oil & natural gas liquids look to double to 26.6-m b/d by 2020 from 15.4-m b/d in 2011.

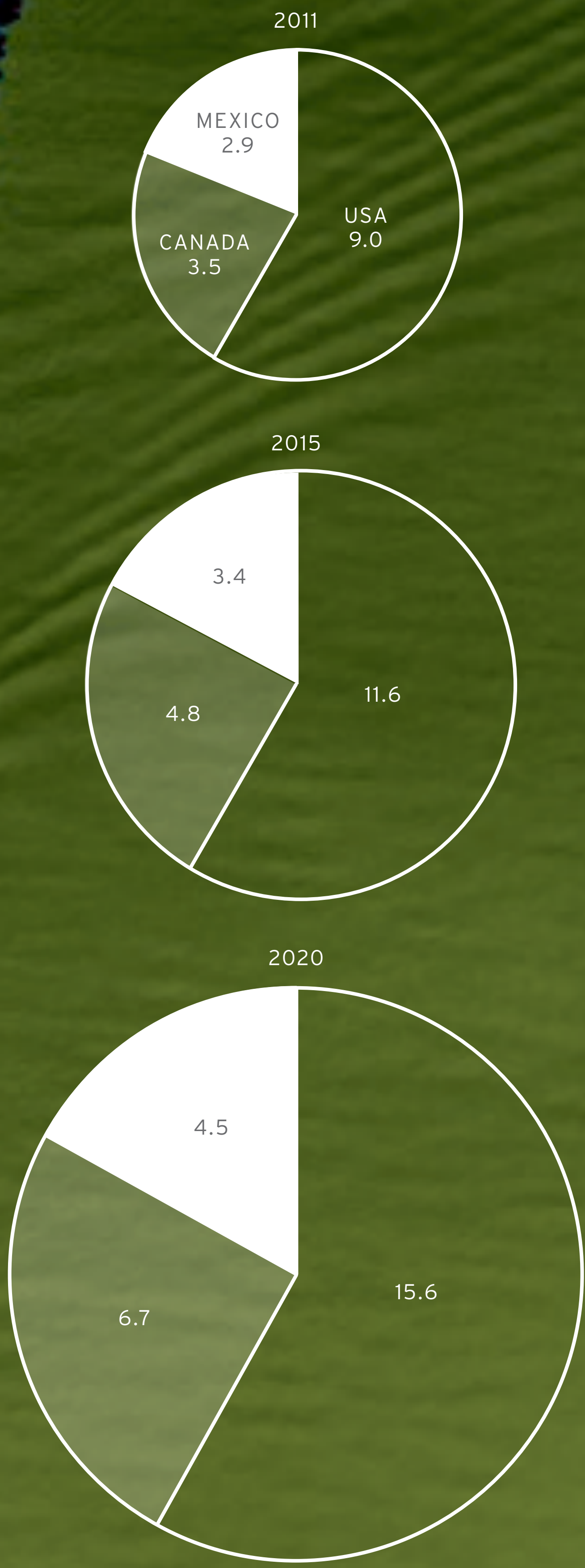
The US and Canada are on track to see natural gas output rise by 22 Bcf/d through 2020.

US demand for petroleum products likely to fall by 2-m b/d over next decade.

The cumulative impact of new production, lower consumption and associated activity could increase GDP by 2%-3%, creating 2.7-3.6m net new jobs by 2020 and $ appreciation of 1.6%-5.4%.



NORTH AMERICAN LIQUIDS SUPPLY PRODUCTION (M B/D)



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Energy 2020

The CIRA Commodities Group, in collaboration with fundamental equity research analysts in natural resources, is adopting the theme “Energy 2020” for a series of reports to be published over the course of 2012. A decade-long perspective puts into sharp focus some of the extraordinary energy supply and demand trends that are unfolding, without the noise of short-term factors.

This first report focuses on the supply revolution underway in North America, where the harnessing of new technologies onshore and offshore is laying the ground for growing surpluses in crude oil, natural gas liquids, petroleum products and natural gas, that has profound implications far beyond the energy sector. Thus our analyses also include economic and political impacts that might stem from what’s occurring in the hydrocarbon production base. These include impacts on employment, economic growth, the US current account balance and core energy security issues.

Other reports will focus on global gas and the potential emergence of gas-on-gas competition, and renewable energy. Each of these reports adopts the perspective of what the potential is for supply growth. In this current report, we indicate our awareness of political, economic and environmental obstacles to optimizing supply growth, but we have decided to focus on what maximum supply growth from North American might be. This focus will enable us as well as readers to have a clear benchmark of what might be, as obstacles to supply growth emerge in the years ahead. What we outline here is less a projection or a forecast than it is a benchmark of what could be attained in the absence of obstacles to growth.

North America as the new Middle East

Surging supply growth could transform North America into the new Middle East by 2020

North America has been the fastest growing oil and natural gas producing area of the world for the past half-decade. With no signs of this growth trend ending over the next decade, the growing continental surplus of hydrocarbons points to North America effectively becoming the new Middle East by the next decade; a growing hydrocarbon net exporting center, with the lowest natural gas feedstock costs in the world, supporting thriving exports of energy-intensive goods from petrochemicals to steel. The chapter "Oil supply growth: no end in sight?" describes the potential trajectory of US, Canadian and Mexican oil and natural gas liquids (NGLs) production growth this decade, while the later section "Shale gas revolution drives paradigmatic shifts across sectors" discusses the growth of shale gas and its transformative potential on multiple sectors.

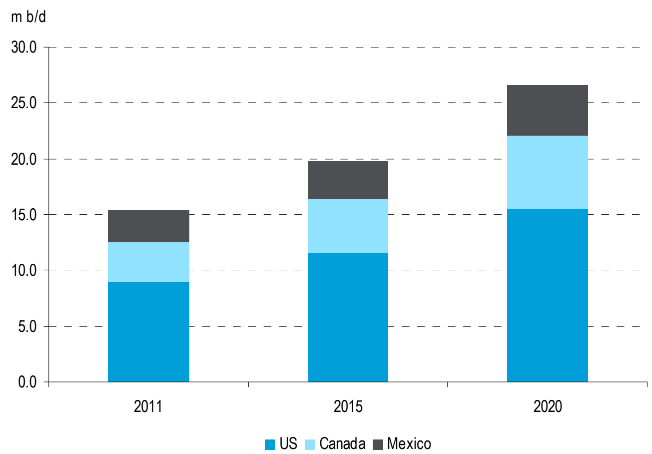
In this report, we focus on the possible, rather than providing a forecast, so as to offer a benchmark for the future

Of course what might happen over the course of this decade needs to be distinguished from what will actually unfold. US deepwater oil production reached a peak of around 1.75-m b/d in April 2010, when the Macondo well blowout in the US waters of the Gulf of Mexico led to a moratorium on drilling and allowed decline rates to set in there. Domestic political issues also set in, resulting in significant headwinds against increases in onshore Lower 48 output. It is impossible to forecast what other domestic issues will set in, whether in the US or abroad. Therefore this report focuses on the possible rather than providing a forecast of what’s to come. By setting out what now looks like a plausible path for production growth, we set some benchmarks for the future. Geological and technological advances can surprise to the upside, making our targets for 2020 too low. On the other hand, politics and accidents might intervene making our benchmarks too high. If that’s the case, readers will have some standards against which to evaluate evolving trends. The politics and regulations in question are discussed in the chapter "Yes, But Politics and policies look likely to point to second-best solutions".

The North American crude oil and natural gas liquids base appears to have the potential to nearly double from 15.4-m b/d in 2011 to almost 27-m b/d by 2020. Combined with this two-fold increase is a continued reduction in US petroleum demand, the rate of which could also accelerate — this structural, secular decline in American liquid fuel consumption is discussed in greater detail in the section "US oil demand in decline".

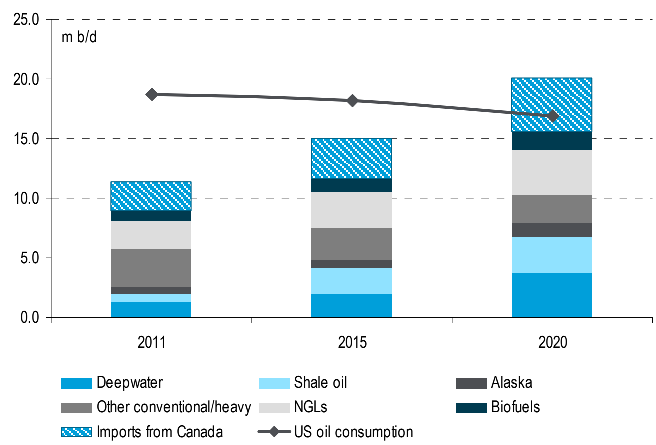
Tellingly, this past year, the US moved from being a net importer to a net exporter of petroleum products. With oil production up about 7% from end-2010 and natural gas liquids surging 11% over the same period, total US liquids production appears to have risen by 7% y-o-y to 9.2-m b/d by end-2011. As a consequence, total imports of crude oil and refined products appear to have fallen by 1.6% last year in the US alone to just under 11-m b/d by end-2011, with crude oil imports down 3.2% between 2011-average and 2010-average, and products imports down 8%, on a roughly accelerating basis through the year. Bolstering the huge increase in net petroleum product exports to 1.255-m b/d by end-2011 was a surge in NGL exports over 2011 by 17% y-o-y over 2010. Extrapolating these trends and adding to it stable domestic Mexican production and growing Canadian output and a picture emerges which points to a clear and growing total hydrocarbon surplus for North America. The potential for the US to become a major exporter of petroleum products, and even crude — and corresponding constraints from pipeline infrastructure and export controls — are discussed in the chapter "North America: residual 'supplier' to global markets" as well as the implications for differentials between WTI, Brent and other crude prices.

Figure 1. North American total liquids production could almost double from over 15-m b/d at end-2011 to almost 27-m b/d in 2020



Source: Citi Investment Research and Analysis

Figure 2. By 2020, the US could see combined domestic supply and Canadian imports reach over 20-m b/d, while US oil demand falls 2-m to below 17-m b/d leaving a 3-m b/d surplus available for export



Source: Citi Investment Research and Analysis

Politics are the main obstacle to this scenario, rather than technology or geology

Yet extrapolating this trend may be somewhat misleading. The main obstacles to developing a North American oil surplus are political rather than geological or technological. Some of these obstacles are based on environmental factors, especially, but not only, in the United States, where trade-offs between enhancing supply on the one hand and enhancing environmental objectives on the other hold the balance. Some of the obstacles are based on revenue-sharing and the rights of competing groups, especially in Canada, where First Nation objectives can impede the optimal level of hydrocarbon development consistent with best practices.

This is due to impediments imposed by First Nations to pipeline evacuation of crude oil on Canada's Pacific Coast, which can result in curtailment of investments in oil sands expansion lest new output becomes 'stranded' and prices fall as a result below the costs of production. And some of the obstacles are constitutional, particularly in Mexico, that block potentially robust resources onshore and offshore from receiving capital mobilization from abroad, thus resulting in continued underperformance of the resource base.

Natural gas production could be less sensitive to politics, but pipeline constraints and protectionist opposition to exports could still stymie this

There are fewer obstacles to developing a natural gas surplus — certainly in the cases of Canada and the United States — although regulatory and other impediments also exist, including politics in the United States that might potentially smack of resource nationalism, and politics in Canada that might continue to impede adequate export pipeline development. In the US, two new developments that might impede growth are protectionism by the petrochemical industry, looking to ban or limit natural gas exports in order to preserve a competitive cost advantage for downstream exports, and anti-refining sentiments by environmentalists trying to limit both imports of Canadian crude and exports of "dirty" refined petroleum products.

But in all cases, North American natural gas could fuel a new industrial revolution in energy-intensive sectors

The main obstacles in Mexico are similar to those that also impede oil development – restrictions on the import of foreign capital, human resources and technology. However, in all cases, North American natural gas looks likely by the end of the decade to be able to support globally competitive energy-intensive industries, with energy input costs among the lowest in the world.

Figure 3. Abundant shale plays, accessed by hydraulic fracturing and horizontal drilling technology, are a key driver behind North America becoming the globe's "energy island" by 2020; EIA map of North American shale plays

Source: EIA

The changing outlook for domestic energy production and consumption unleashed by the supply revolution and new demand efficiencies discussed above has wider ramifications beyond changing the domestic energy landscape. In particular, they have potentially transformative impacts on the US and on global economics.

We estimate that the cumulative impact of new production, reduced consumption, and associated activity could increase real GDP by an additional 2% to 3%, creating from 2.7 million to as high as 3.6 million net new jobs by 2020. Furthermore, the current account deficit could shrink by 2.4% of GDP, a 60% reduction in the current deficit, by 2020. This could also cause the dollar to appreciate in real terms by +1.6 to +5.4% by 2020. These estimates suggest that the energy sector in the next few decades could drive an extraordinary and timely revitalization and reindustrialization of the US economy, creating jobs and bringing prosperity to millions of Americans, just as the national economy struggles to recover from the worst economic downturn since the Great Depression. It would not only improve incomes and create jobs, but also improve national energy security and reverse perennial current account deficits, long a source of angst for policymakers. The "Economic Consequences" chapter discusses these potentially incredible impacts, with further technical details in an appendix.

Note: *throughout this report, "petroleum" is used to refer to crude oil and petroleum products and natural gas liquids (NGLs); "liquids", used in isolation, typically refers to NGLs; "total liquids" refers to crude oil, petroleum products, NGLs and biofuels. "Frack" or "fracking" refers to hydraulic fracturing. Other common abbreviations include:*

- "-m b/d" – millions of barrels per day, "-k b/d" – thousands of barrels per day
- "-m bbls" – millions of barrels
- "-m boe" – millions of barrels of oil equivalent, "-k boe" – thousands of barrels of oil equivalent
- "-Bcf/d" – billions of cubic feet per day
- "MMBtu" – millions of British thermal units
- "y-o-y" – year-on-year

Oil Supply Growth: No End in Sight?

The concept of peak oil is being challenged by multiple sources of oil and liquids production growth

Five incremental sources of liquids growth could make North America the largest source of new supply in the next decade: oil sands production in Canada, deepwater in the US and Mexico (focused on the Gulf of Mexico), oil from shale and tight sands, natural gas liquids (NGLs) associated with the production of natural gas, and biofuels. The US alone could add 6.6-m b/d to bring liquids from 9-m b/d at end-2011 to over 15.6-m b/d in 2020-22. In total, North America as a whole could add over 11-m b/d of liquids from over 15-m b/d in 2010 to almost 27-m b/d by 2020-22.

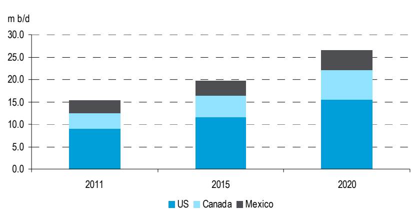
Figure 4. North America Total Liquids Supply Projections

m b/d	2011A	2015E	2020E
US	9.0	11.6	15.6
Canada	3.5	4.8	6.7
Mexico	2.9	3.4	4.5
Total	**15.4**	**19.8**	**26.8**

Growth	2011-15E	2015E-20E	2011-20E
US	2.6	4.0	6.6
Canada	1.3	1.9	3.2
Mexico	0.5	1.1	1.6
Total	**4.4**	**7.0**	**11.4**

Source: Citi Investment Research and Analysis

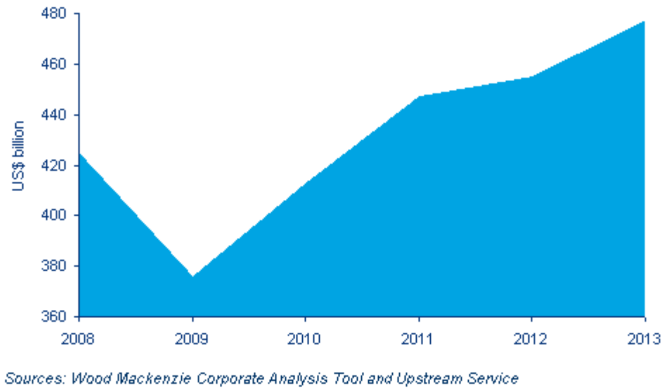
Figure 5. Projected North American Total Liquids Production 2011-20E



Source: Citi Investment Research and Analysis

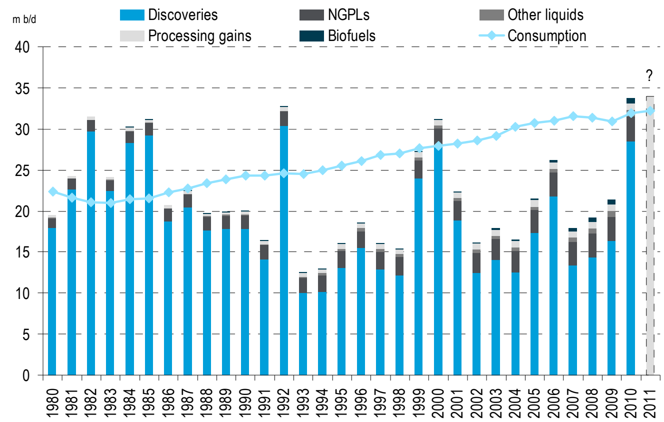
The increase in liquid growth, and the shale revolution in particular, is challenging the concept of peak oil. The belief that global oil production has peaked, or is on the cusp of doing so, has underpinned much of crude oil's decade-long rally (setting aside the 2008 sell-off). The belief was bolstered by the repeated failure of supply to live up to the optimistic forecasts put forward by various governmental and international energy agencies. The International Energy Agency (IEA), the industry benchmark, made a habit of putting forth forecasts for the coming year of big gains in non-OPEC supply, only to spend the next 18 months revising those forecasts lower. But that pattern looks set to change, mainly because of the new shale oil and gas plays in the US, but also because of deepwater in the Gulf of Mexico, and Canadian oil sands. Production from these (and the associated liquids from shale gas plays) is rising so fast that total US oil production is surging, even as conventional oil production in Alaska and California is continuing its structural decline, and Gulf of Mexico production is now coming out of its post-Macondo (April 2010) drilling slump. Starting in 2009 (more than five years following the global surge in upstream capex), new discoveries — excluding extensions and revisions to existing fields — started to surge (see Figure 5), with 2010 being the first year in a quarter of a century when oil discoveries (taking into account NGLs and other liquids, refinery processing gains and biofuels) were greater than oil consumed, (see Figure 6). Initial data for 2011 is pointing in the same direction.

Figure 6. Global Actual and Planned Upstream Spending 2008-13



Source: Wood Mackenzie

Figure 7. Global Oil Discoveries Since 1980 plus Other Liquids, versus Consumption (m bbls)



Source: IHS, IEA, BP, Citi Investment Research and Analysis

This has been the response to longer cyclical drivers of global capital expenditures, namely, higher oil prices

The recent surge in US liquids output, in volume terms, which is driving the North American oil scene, is part of a long-term cyclical pattern that encompasses the global petroleum sector. Over the last several decades, total OPEC production led supply growth, particularly in the 1970s, but has basically stagnated ever since. OPEC production today is marginally higher than it was in 1980. The late 1970s and the 1980s and 1990s saw non-OPEC take the lead on production growth, with high prices in the 1970s leading to a total growth of ~15-m b/d from new source production in the Soviet Union (especially Russia and the Caspian countries), Mexico, the North Sea and the North Slope of Alaska. That surge led to weak prices for nearly two decades, and with weak prices came a collapse in upstream capex after 1981.

It has been higher prices in the last decade that, like higher prices in the 1970s, are leading to a resurgence in exploration and have unleashed three technological revolutions. US shale oil is one of them, but it has been preceded by the technological revolutions facilitating the tapping into vast hitherto non-commercial resources in deepwater and shale plays. Now the US is poised once again to become the largest liquid producer in the world and looks almost certain to overtake Russia and Saudi Arabia before the decade is over.

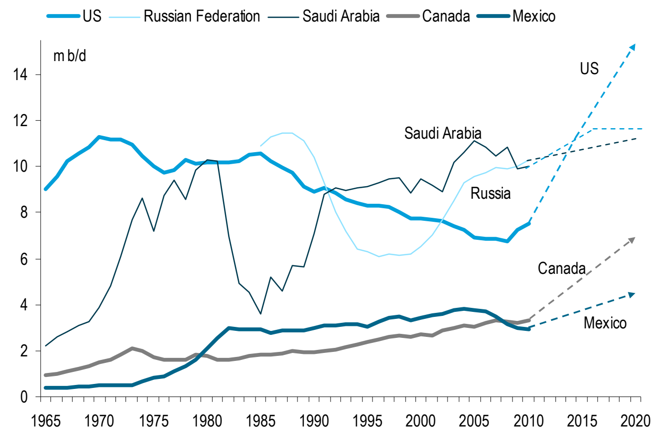
The US was the largest oil producer in the world, gaining that rank when Russian production collapsed at the start of the Russian Revolution and holding onto it until the 1970s — US output peaked at 11.3-m b/d in 1970. Since then it has faltered, declining fitfully to a nadir of 6.8-m b/d in 2007, counting both oil and NGLs; but 2007 saw the turning point, with current trends pointing to US supply overtaking Saudi Arabia and Russia. Last year, total production was up ~2-m b/d above 2006 to 8.8-m b/d on average over 2011, with ~9-m b/d by end-2011.

And this is during a time of a structural, secular decline in US oil consumption, with crude and product imports already plummeting

At the same time, consumption, which saw a trough of 15.2-m b/d in 1983 at the end of the high-price induced recession and hit a peak of 20.8-m b/d in 2005, where it plateaued and then fell sharply during the 2008 financial crisis. A strengthening recovery in the US saw a false positive indicator when oil consumption rose 2% in 2010 year-on-year, but the business cycle masked deeper, structural declines in demand driven by long-term factors such as demographic change and fuel efficiency. It turns out that the bulk of the 2010 demand increase, mirroring the dramatic drop in 2009 demand, is attributable to inventory movements at the secondary and tertiary levels.

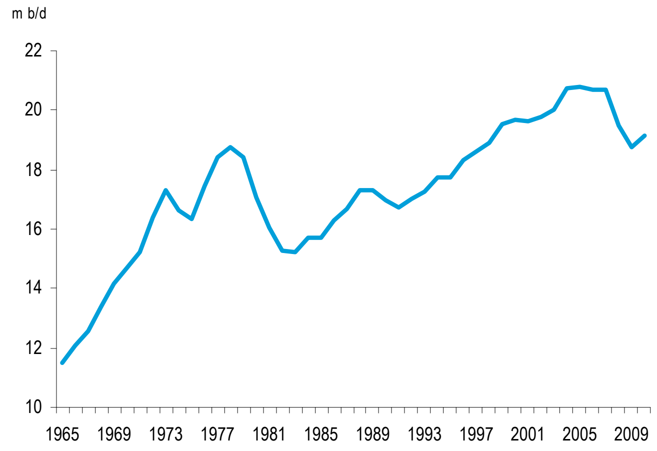
Meanwhile, and as a consequence of the supply and demand trends, total (gross) imports of crude oil and petroleum products fell from a peak of 13.6-m b/d in 2006-07 to December 2011's nadir of ~10.9-m b/d with average crude imports over 2011 down 3.2% and average refined product imports over 2011 down 5.4% y-o-y.

Figure 8. US production could overtake Saudi Arabia and Russia's this decade



Source: BP, Citi Investment Research and Analysis

Figure 9. US consumption saw declines from the 2008 recession, but is also in structural decline from the mid-2000s



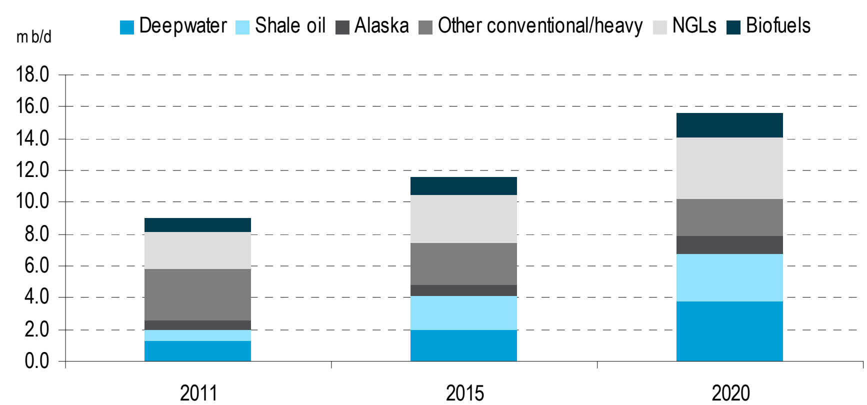
Source: BP, Citi Investment Research and Analysis

US 2020: Robust and sustainable supply growth from multiple sources

The US supply growth story is being driven by deepwater and shale, and these in turn by the new technologies that are unlocking their potential

While US output growth is now centering on tight formations (i.e. shale), it is also growing from other oil sources and more robustly than any other country in the world. With total liquids output of about 7.3-m b/d in 2009, 7.5-m b/d in 2010, and 8.8-m b/d in 2011, the US can be expected to see large incremental gains in deepwater oil (post-BP Macondo), in tight oil in a half dozen or so basins, and in NGL output associated with shale gas. Total liquids could rise from about 9-m b/d at end-2011 to over 15-m b/d by 2020. Note: This total includes biofuels, the prospects of which are dependent on comparative economics versus other liquid fuels as well as regulatory support, but could increase from 0.9-m b/d in 2011 to 1.5-m b/d by 2020, which would still be short of the RFS-mandated ~2-m b/d by then.

Figure 10. Projected US Total Liquids Production 2011-20E



Source: Citi Investment Research and Analysis

Figure 11. US Liquids Supply Projections

m b/d	2011A	2015E	2020E
Deepwater	1.3	2.0	3.8
Shale oil	0.7	2.1	3.0
Alaska	0.6	0.7	1.1
Other conventional/heavy	3.2	2.7	2.3
Oil	5.8	7.5	10.2
NGLs	2.3	3.0	3.8
Total petroleum	8.1	10.5	14.1
Biofuels	0.9	1.1	1.5
(Mandated)	*0.9*	*1.3*	*2.0*
Total liquids	**9.0**	**11.6**	**15.6**

Growth	**2011-15**	**2015-20**	**2011-20**
Deepwater	0.7	1.8	2.5
Shale oil	1.4	0.9	2.3
Alaska	0.1	0.4	0.5
Other conventional/heavy	-0.5	-0.4	-0.9
Oil	1.7	2.7	4.4
NGLs	0.7	0.8	1.5
Total petroleum	2.4	3.6	6.0
Biofuels	0.2	0.4	0.6
(Mandated)	*0.4*	*0.7*	*1.1*
Total liquids	**2.6**	**4.0**	**6.6**

Source: Citi Investment Research and Analysis

Deepwater

After a moratorium on drilling in the wake of the BP Macondo disaster, deepwater production is bouncing back

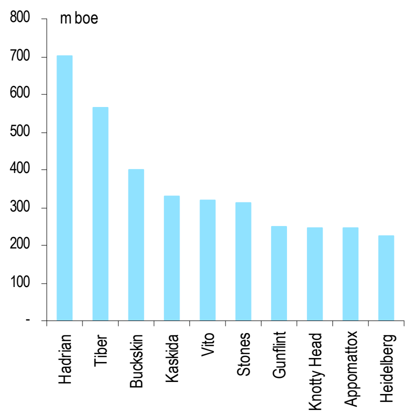
In the ten years before the April 2010 BP Macondo well blowout disaster, the US was holding what many analysts considered to be a permanent one-third share of deepwater resources, one of the fastest growing new sources of oil in the world. A moratorium on drilling in the US Gulf of Mexico following the disaster — where virtually all deepwater licenses are held in US coastal waters — threatened to become permanent. But with a new regulatory regime now in place for the United States, the pace of licensing and drilling pre-Macondo has resumed less than two years later.

and could see a hockey-stick trajectory that takes total Gulf of Mexico output from 1.3-m b/d today to 3.75-m b/d by 2020

The resumption of deepwater production could see the US back on the hockey stick production trajectory it was on in early 2010. This means it could well recoup the depletion lost since 2010 and still rise some 2-m b/d above that level to 3.75-m b/d or more. Total Gulf of Mexico output of 1.75-m b/d in April 2010 slipped to 1.2-m b/d by December 2011 but looks to resume growth by 2013 before then accelerating, replacing depleted output of some 500-k b/d and adding another 2-m b/d by 2020.

Projects under development and probable projects are forecast to drive Gulf of Mexico production growth to ~2-m boe/d by 2015, with those already under development or on stream growing to 1.8-m boe/d alone. Together, this implies over 280-k boe/d of growth every year from 2014 onwards; adding upside potential sees growth accelerating towards the nd of the decade. (Total production currently includes ~3-Bcf/d or more of gas production, or around 500- to 600-k boe/d, but this is expected to fall, as newer developments tend to have lower gas-to-oil ratios.)

Figure 12. Deepwater Gulf of Mexico Top 10 Probables by Reserves



Source: Wood Mackenzie

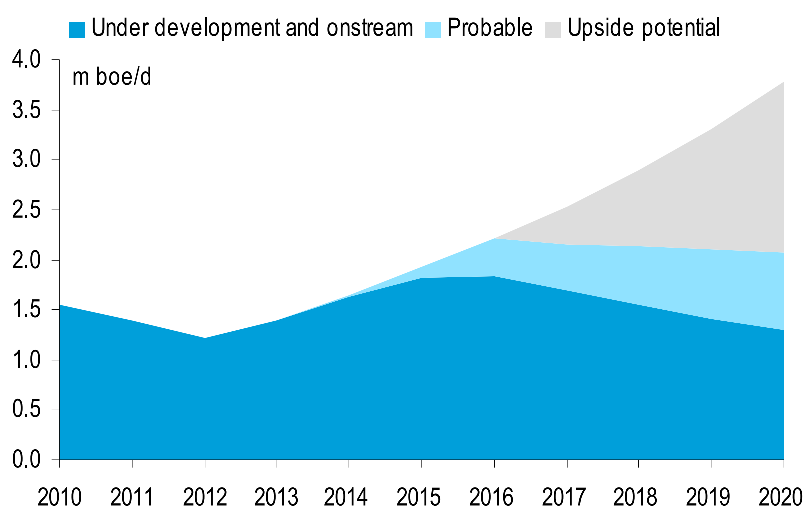
Contributions to this growth come from current production ramping up, including Atlantis, Perdido, Shenzi, Silvertip, Tahiti, Thunder Horse production, along with several other fields coming online in 2014-16, including Big Foot, Gunflint, Hadrian, Jack, Knotty Head, Lucius, Moccasin, St. Malo, Stones, Tubular Bells and Vito. Tiber, Buckskin, Kaskida, Appomattox and Heidelberg fields provide further probable volumes.

These new fields may be riskier, due to geological and technological challenges, but have significant upside in volume and value. The probables hold an estimated 4.2 billion boe in recoverable reserves — around a third of current deepwater commercial reserves in the Gulf of Mexico — and are located in frontier and emerging plays. They benefit from large field sizes, and hence economies of scale, but are pre-salt or ultra-deep plays that are challenging to drill and relatively costly, as well as requiring new pipeline infrastructure than established areas which may have these already available. Depending on the reservoir, some of these may require subsea pumps and water injections to boost flows. But Chevron suggests that technological improvements look to increase recovery factors from 10% to 20% in the Lower Tertiary, through seafloor pumps, long-life in-well pumps, optimized waterflood and gas injection EOR.

The major obstacles remain regulatory ones, since major companies are willing to invest

Regulatory factors remain the largest constraint. BP, Chevron, ExxonMobil, Petrobras and Shell, which hold the majority of the reserves, are most acutely restrained by permitting and licensing rather than the willingness to invest. That these are already easing is a positive sign and drive our potential upside projections going forward.

Figure 13. Deepwater Gulf of Mexico Total Liquids Production Projections



Source: Citi Investment Research and Analysis, Wood Mackenzie

with first volumes expected soon from FPSOs, which help maximize returns before other costly facilities are built, as well as providing initial data on flow and reservoir quality

Indeed, the first volumes look to be produced soon from an FPSO (floating, production, storage and off-loading) in the deepwater Gulf of Mexico. In the Lower Tertiary play, the Petrobras Cascade and Chinook projects' success is expected to initiate wider use of FPSOs in the first phase of field development, which helps to maximize returns before costlier facilities are built. This would also act as an extended well test for the field, providing further data on flow and reservoir quality. And independents are also returning to ultra-deep as well as shallow water sub-salt plays.

The pacing of Gulf of Mexico licensing and drilling has return to pre-Macondo levels, while rig availability should ease in the medium term, and along with it, drilling costs

In our view, the expected growth of over 280-k boe/d for 2015 and 2016 could be sustained and accelerate with continued development of Gulf of Mexico resources, as long as the political context remains favorable. And at worst, breakeven costs are likely to stay in the $55-$70/bbl range for new resources in ultra-deepwater and subsalt resources. Rig availability is challenging in the near term in terms of ramping up drilling activities in the Gulf after many rigs departed for better opportunities in international markets when the drilling moratorium was imposed after Macondo. Recently deepwater day rates have been on the upswing due to a shortage of rigs with near-term availability. While in the very near term costs might be subject to an inflation peak, more rigs should become available in 2013 and 2014 as new deepwater rigs currently under construction are completed and the deepwater vessel market becomes more competitive, leading drilling costs to come off substantially.

Alaska

Attention is returning to Alaska, which could reverse declines and see 0.5-m b/d of production growth by 2020

Much attention is again focusing on Alaska, where production peaked in 1988 at 2.03-m b/d, but declined to 583-k b/d last year. With much of the current production very heavy, transit times from the North Slope have shot up from 3 days at its lowest point to 15 days last year, and the TAPS pipeline could eventually close once oil throughput falls to the 300- to 500-k b/d range.

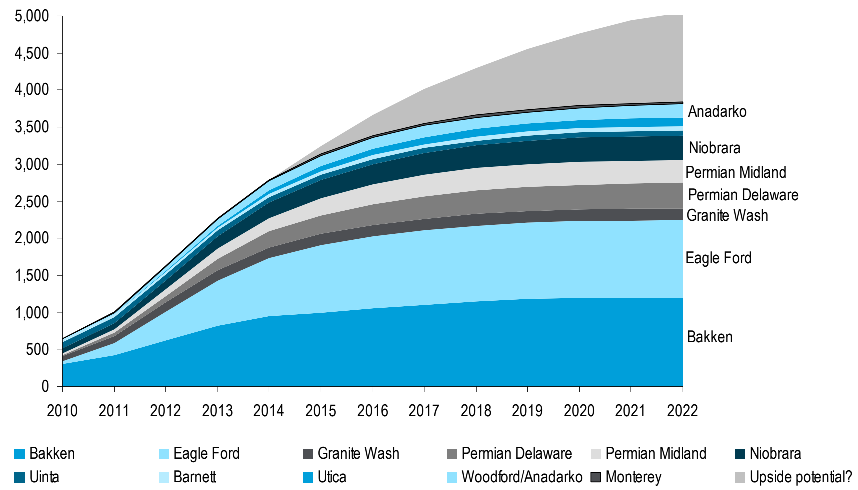
While politics continue to impede drilling in the Chukchi Sea and the Arctic National Wildlife Refuge (ANWR), there are a number of candidates for new production, with current plans focused on heavy oil, oil from source rocks and even product liquids from transforming current stranded gas into petroleum production. Heavy oil is found in several local formations including Milne Point and West Sak, both near pipeline infrastructure. Source rock contains light, tight oil and could be exploited much in the same way that shale is exploited. Companies working on each of these — the heavy and tight oil formations — believe that each of them could add 250-k b/d to Alaskan flows by 2020. Shell meanwhile looks like it could be fully permitted to drill this summer, with its Oil Spill Response Plan (OSRP) approved by the federal Bureau of Safety and Environmental Enforcement (BSEE), as well as requirements for a dual-rig system with a second rig standing by to drill a relief well in the event of a blowout and spill.

Tight oil: Base-load US oil production growth

And the shale revolution which has driven massive gains in natural gas production is now doing the same for oil, with potential shale liquids production growth of +3.8-m b/d by 2020

US shale liquids could see production growth of +3.8-m b/d by 2020, with +2.3-m b/d in shale oil and +1.5-m b/d in NGLs. A closer look at each of the major US shale plays shows that reserves are substantial, production is growing, and well productivity is increasing. It also highlights several themes. There is clearly a learning-by-doing process, some of which is particular to the local geology, which implies accelerating growth. Variability of geology can mean different drilling depths, varied suitability of vertical versus horizontal drilling, use of acid fracking versus other fracking techniques, driving varying costs between plays. Shale plays with liquids as well as gas are fostering a bias towards liquids-rich plays, in light of low US natural gas prices, which has implications for allocation of resources among gas and liquids production. In general, shale liquids production growth has continued despite constraints due to regulation, takeaway infrastructure bottlenecks (whether by pipeline, rail or truck), service cost inflation and even weather (as in early-2011 when cold weather conditions slowed North Dakota production).

Figure 14. US shale liquids projections could see +3.8-m b/d of growth by 2020



Source: Citi Investment Research and Analysis

The terms shale oil and oil shale are often confused. Shale oil, like shale gas, is oil produced from shale reservoirs. Oil shale, on the other hand, is a sedimentary rock that contains kerogen, which yields oil when heated to extreme temperatures. Oil shale production peaked at about 20-k b/d in 1980, with Estonia accounting for two-thirds of global production; by 2000 this had fallen to below 10-k b/d according to the United States Geologic Survey , despite the apparently huge global reserves, due to the high economic and environmental costs associated with production. To distinguish shale oil from oil shale, the term "tight oil" is sometimes used. The shale oil revolution is the subject of this report.

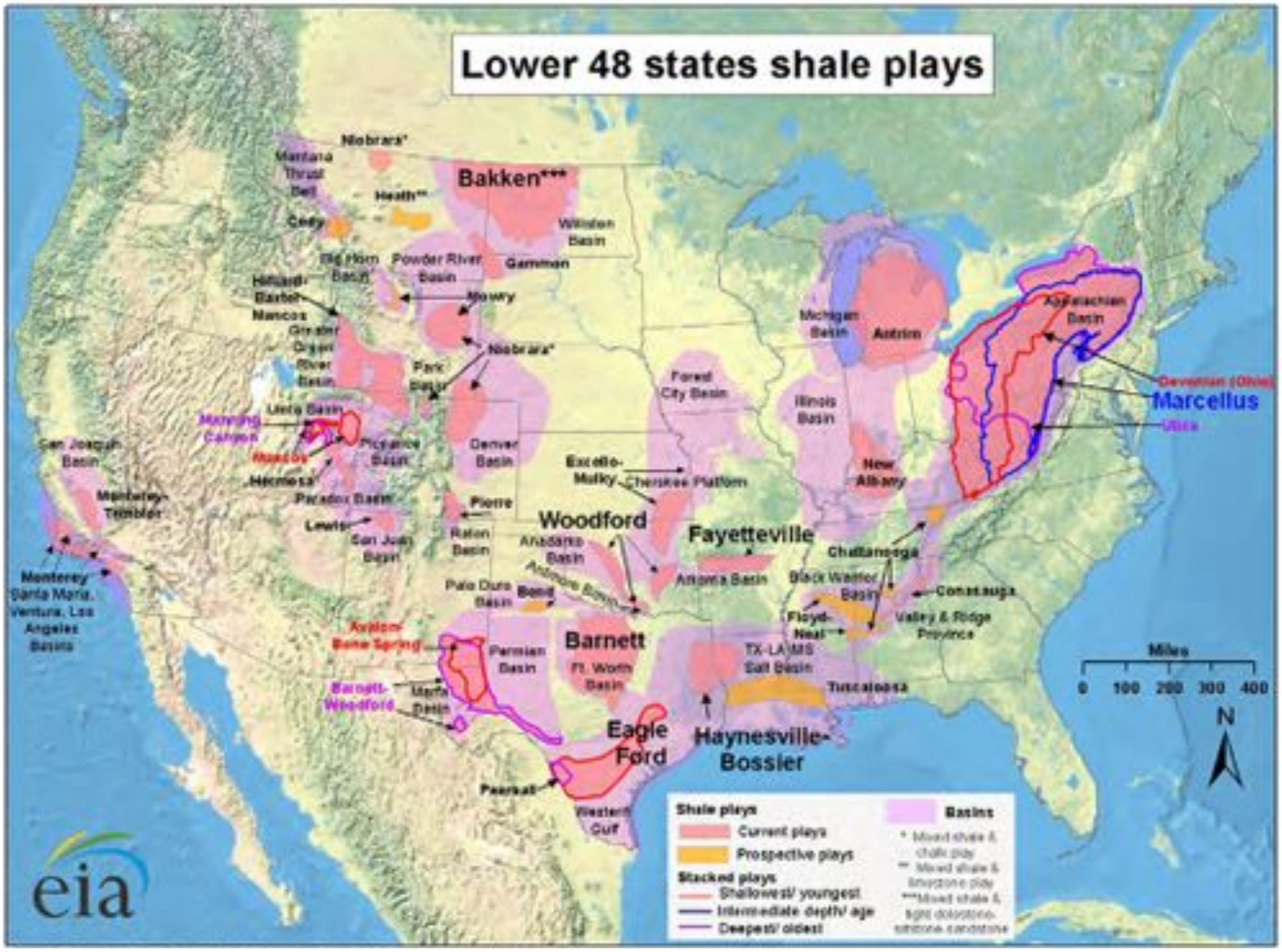
And the US benefits from well-known geology and a robust pipeline network and ecosystem of midstream operators and merchants

It is no accident that the shale gas and tight oil revolutions are occurring in North America. Shale rock has been tapped for more than 60 years and the locations of US geological basins are well known even if their reservoir performance is only now being unlocked. What's more, the US has an extraordinary network of pipeline lines and a robust history of midstream operators and merchants — and even so the production has been outpacing infrastructure.

The major tight oil plays to date have been the Bakken and Eagle Ford, although considerable interest is brewing in the Utica shale in eastern Ohio, as well as other plays in Texas (Wolfcamp, Avalon/Bone Spring, Barnett), California (Monterey), and the heart of the mid-continent's Niobrara and Mississippi Lime. The Granite Wash and Anadarko Basin liquids-rich plays are also seeing gains. Forecasts that add up production trajectories for currently known and anticipated projects see over 2-m b/d of growth between now and 2020. Going beyond known projects, IHS CERA sees more than 3-m b/d of production by 2020, and has demarcated more than 50 billion barrels of commercially available reserves already unlocked[1].

[1] See Philip H. "Pete" Stark, "Shale Gas, Tight Oil and EOR Creating Rare Opportunity for Industry and Nation," The American Oil & Gas Reporter, (February 2012)

Figure 15. US Lower 48 Shale Plays



Source: EIA

Bakken production has been a mainstay of US production growth, hitting 546-k b/d in January 2011 and could reach 1-m b/d by 2015

The **Bakken** is officially estimated to hold 3.65 billion barrels of technically recoverable oil, although Continental, the largest acreage holder in the area, has publicly increased its estimates of oil in place to over 90 billion bbls, implying technically recoverable reserves could be 36 billion boe. The Bakken is located in the Williston Basin in Montana and North Dakota, and also extends into Manitoba and Saskatchewan in Canada. The Bakken has been a key driver of broad US production growth, reaching at 546-k b/d in January 2011, and should easily exceed 700-k b/d in 2012 and reach 1-m b/d by 2015. Bakken production has been increasing rapidly, reflecting two effects — a surge in number of producing wells, but also increasing productivity per well.

As a relatively mature play for shale, several core counties — McKenzie, Mountrail, Williams and Dunn — have been identified in the Bakken. McKenzie and Mountrail counties are considered the core of the play, with initial production (IP) reaching 600 boe/d with an average 12-month rate of 300-k boe/d. Williams and Dunn counties are more average, and could see stronger growth by improving operational efficiency. Service cost inflation has began to cut into company margins, suggesting that operational efficiency in these areas should be an increasingly important driver of growth from 2012 and onwards.

Well-known constraints on production include limited infrastructure — truck, rail, pipeline laterals — both for takeaway of its crude output, as well as capacity to ship-in water and fracking materials. And weather-related delays as seen in the first half of 2011 — freezing conditions constraining production in the winter, and later, flooding in the spring – could again exacerbate this, although 2011-2012's warmer winter has allowed production to continue at a rapid clip. The results of these infrastructure problems have been blowouts in the differential between the price of Bakken production, recently receiving steep discounts to WTI, a similar, but actually slightly less high quality crude oil priced in Cushing, Oklahoma (see our 27 February 2012 note, “End Game”, for more on the implications of the North American crude glut on the WTI-Brent spread).

The Eagle Ford could grow even more quickly than Bakken, given its better access to Gulf Coast refining centers, and could reach as much as 1-m b/d by the end of the decade

The **Eagle Ford** shale gas and oil play is located within the Texas Maverick Basin, and is made up of three zones: an oil zone, a condensate zone, and a dry gas zone. It is estimated to hold 3.35 billion barrels of technically recoverable reserves, and looks likely to more than double output to over 400-k b/d in 2012 (from zero a few years ago), driven by the Black Hawk area in DeWitt and Karnes counties in the northeast and Webb in the southwest. Unlike the Bakken, it is easier to add takeaway pipeline to the Eagle Ford and move its light sweet crude to the heart of the Texas and Louisiana refinery systems, which might well allow Eagle Ford output to grow even faster than Bakken output going forward. It is possible the Eagle Ford could reach as much as 1-m b/d of output before the end of the decade.

Production from the Eagle Ford has a high carbonate content, which makes the formation more brittle and ideal for hydraulic fracturing, and enjoys some of the strongest economics onshore in the US, with average well costs now around $8 million per horizontal well in 2010-11. However, until pipeline takeaway grows amply there still could be curtailments in production. The liquids content of Eagle Ford hydrocarbons production has increased as production migrates from the drier, gassy zone to the wetter, oily zone, driven by an exodus from exposure to low natural gas prices in the $2-$3/MMBtu range. Yet the play is so robust and price differentials are so great between oil and gas in the United States that oil production in the area remains profitable even if gas is given away at a price of $1-2/MMBtu.

Other plays, such as the Utica, show great potential, while the Niobrara is improving since early positive signs, though it faces more challenging, highly faulted geology

The **Utica** field, stretching from eastern Ohio to Pennsylvania and from New York State to Ontario and Quebec, has shown great potential with high initial production rates announced, and very favorable economics as compared to onshore E&P in the US. Thus, there could be some 30 active rigs by end-2012, with core counties identified over the year. At this stage, Carroll County is considered the best prospect for significant wet gas resources.

The **Niobrara** spreads throughout the Rockies, and commingles with the gas-rich Wattenberg field and the oily Silo field. The prospects for Niobrara were piqued by EOG's Jake well in late 2009, which produced 50-k bbls in the first three months. But this has proved hard to replicate, although performance picked up in late 2011, particularly in the core Wattenberg field. Niobrara geology is highly faulted, making horizontal drilling more challenging.

The stacked conventional and unconventional plays in the Permian Basin are reinvigorating a mature oil-producing region

The **Permian Basin** in West Texas is comprised of numerous stacked conventional and unconventional plays, and includes significant plays in the Delaware basin such as Avalon and Bone Springs as well as the Midland basin. Major potential could come from Spraberry Wolfcamp, although this is being held up by higher horsepower rigs being used in the Haynesville shale gas play in East Texas; if drilling there falls with continued low natural gas prices, there could be greater development in this area. Pioneer, EOG, Berry Petroleum and El Paso are among the major players in the Wolfcamp. As an example, Pioneer's second completed well in the shale play had a 24-hour IP of 807 boe/d and a peak 30-day average natural flow rate of 677 boe/d, of mostly oil. The well had a 5,800 foot lateral with 30 frack stages. The **Avalon** and **Bone Springs** plays have an average estimated ultimate recovery (EUR) of 300-k bbls per well and approximately 1.58 billion bbls of technically recoverable oil. The play has a reported depth from 6,000 to 13,000 ft and a thickness ranging from 900 to 1,700 ft.

California has potentially the largest tight oil reserves, with seismic activity leading to natural fracked geology accessible by vertical wells with acid fracking – but proposed regulatory changes could severely challenge this

The largest tight reserves could well be in **California**, with the EIA estimating over 15 billion barrels of technically recoverable reserves, several times greater than at least official Bakken and Eagle Ford reserves. The prospectivity of the region stems from the natural fracking that is caused by high levels of seismic activity in the geological faults in that state. The main prospect is Monterey/Santos shale, which has its own specific geological features, and is increasingly well understood through seismic imaging and drilling of exploratory wells. Venoco and Occidental, two of the major companies in Monterey, together completed California's largest ever 3-D seismic shoot. Drilling activity in this area increased throughout 2011, hitting 40 rigs in October, and up 100 wells in 2011 compared to the year before. Occidental was particularly active in drilling in the San Joaquin basin, finding that the geology, comprising many faults as a result of longstanding seismic activity, is best accessed through vertical wells with acid fracking. Use of vertical wells is more economic than horizontal drilling, and meant Occidental's completed well costs were only around $3.5 million. The geology of Monterey shale suggests lower initial production rates but also less steep decline curves compared to the Bakken. But California's regulatory framework might well result in the projected potential 1-m b/d of incremental production for the state never being reached.

The US West Coast region includes shale oil plays in the San Joaquin and Los Angeles basins. Located within these basins is the Monterey/Santos shale oil play with a total area estimated at 1,752 square miles. Monterey, in particular, has an average EUR of 550-k bbls per well and approximately 15.42 billion barrels of technically recoverable oil. Occidental reported vertical well costs of $3.5 million, and with EURs guidance from 400-700-k boe, total finding and development costs are around $7 to $8/boe.

The **Uinta** is seeing both horizontal and vertical development at various depths in a number of areas within the play, with reported drill and completion costs ranging from $2.8 million to $4.5 million, suggesting promising economics going forward. But it does face issues with whether there will be enough refining capacity to take black and yellow wax crude.

Tight, shale oil lies at the heart of US energy independence and the prospect of North America becoming the new Middle East

There is little doubt that the US tight oil play lies at the heart of US energy independence and North America becoming the new Middle East. And while as much as 5 million barrels per day of incremental oil and liquids production is at stake, risks to fulfillment abound. Few of these risks appear to be geological. The biggest ones appear to be lack of takeaway infrastructure — the US production base here is in many ways land-locked and takeaway infrastructure has lagged. Related environmental policy obstacles also abound, including opposition to imports from Canada also restricting takeaway from North Dakota.

Then there are oil prices and related costs. Landlocked oil prices tend to be discounted to waterborne market levels and the costs of developing tight oil are also high, largely in the same area as the costs of developments in deep water. The frenzy of exploration and development is leading concomitantly to cost inflation, at least in the short term, so that the cost squeeze might also restrict development in the next few years. Finally, there are issues related to the rapid decline rates of initial flows, but so far enhanced efficiencies have more than made up for what were initial depletion rates.

NGLs – the not-so-hidden bonanza

Meanwhile, NGL production growth has been a major part of the shale story

While the growth of tight oil production has been extraordinary, just as stunning has been the growth in natural gas liquids and condensates associated with shale gas exploitation. Of the 600-k b/d of liquids growth from December 2010 through December 2011, more than 200-k b/d of that growth has been in NGLs. Current projections of further growth are tied to projections of natural gas production growth, although a significant amount of NGL output has, as in the case of oil, been stymied by lack of pipeline takeaway, resulting in significant price differentials across the US. We see 1.5-m b/d or more of NGL growth between 2011-20 in the US.

but also facing some pipeline constraints

The rapid growth of liquids production is leading to a build-out of liquids pipeline and fractionators to accommodate the increase. Although all announced expansions and new construction should come into service in phases leading up to 2015, further expansion is expected as the growth of liquids production continues. The relative scale of these new transport and processing projects contributed to a delay in having the infrastructure needed to meet the growing supply of liquids. The case in point was the very wide price spreads between ethane in Mont Belvieu, TX and Conway, KS because of bottlenecks in the system.

as transportation infrastructure is rapidly building out to keep up with its rapid growth

The industry is rapidly catching up. To illustrate the rapid pace of construction, Enterprise Product Partner's Mont Belvieu, TX, NGL fractionation and storage complex, already the largest in the world, is undergoing $6.5 billion's worth of expansion to process additional liquids, such as those produced from the Eagle Ford shale in the nearby South Texas. In the nearer term, the Frac Train V fractionator that the firm bought online in October 2011 is already at full utilization processing liquids from the Eagle Ford. Frac Train VI would be coming online by 4Q'12. See our 17 February 2012 "Cracker & Fracker Tour Takeaways" research note for more discussion.

All of these announced expansions or new constructions should come into service in phases leading up to 2015, and further expansions are expected as the growth of liquids production continues. Fractionation capacity would expand by 490-k b/d, with associated NGL pipeline capacities to the complex rising by 1-m b/d.

Figure 16. Gulf Coast Fractionation & NGL Y-Grade Pipeline Capacity

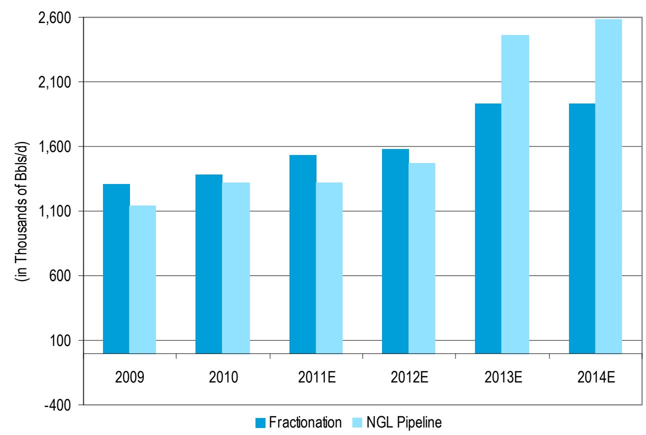
Mt. Belvieu and Louisiana Fractionation & Y-Grade Pipeline Capacity

Fractionation Operators	Capacity (Mbbl/d)	Expansion (Mbbl/d)	Total (Mbbl/d)	Time- Line
Enterprise Products Partners LP (EPD)	714	75	789	4Q 12
Targa Resources Partners LP (NGLS)	361	143	504	2Q 12 & 1Q 13
ONEOK Partners LP (OKS)	160	75	235	1H 13 & 2H 13
Lone Star	0	200	200	1Q 13 & 1Q 14
Others	228	0	228	
Total	**1,463**	**493**	**1,956**	

NGL Pipelines into Mont Belvieu	Capacity (Mbbl/d)	Expansion (Mbbl/d)	Total (Mbbl/d)	Time- Line
Chaparral (EPD)	125	0	125	
LDH Pipeline (ETP & RGNC)	145	0	145	
West Texas LPG (CVX & APL)	230	0	230	
Seminole (EPD)	240	0	240	
Other	200	0	200	
Sterling I (OKS)	105	0	105	
Sterling II (OKS)	90	0	90	
Arbuckle (OKS)	180	60	240	1H 12
Yoakum NGL Pipeline (EPD)	0	90	90	2H 12
Sterling III (OKS)	0	250	250	2H 13
Sandhills Pipeline (DCP)	0	110	110	2013
Southern Hills (DCP: Refined Production Conversion)	0	150	150	2013
Lone Star	0	200	200	2013
Texas Express Pipeline (EPD, EEP, & APC)	0	280	280	2Q 13
Marcellus Ethane Project (EPD)	0	125	125	
Total Pipeline Capacity into MB	**1,315**	**1,265**	**2,580**	

Source: Citi Investment Research and Analysis

Figure 17. Mont Belvieu Midstream Capacity



Source: Citi Investment Research and Analysis

As long as this infrastructure is still being constructed, ethane demand should outstrip supply before new pipelines and fractionators can deliver these new supplies. From its use of ethane, the North American petrochemical industry is gaining substantial advantages over overseas competitors, which typically rely on naphtha as a feedstock for ethylene making. (We explore the shale hydrocarbon impact on the petrochemical sector in the section “Shale gas revolution drives paradigmatic shifts across sectors”.) Higher ethylene cracking capacity utilization in the petrochemical sector, particularly as the sector shifts its feedstock use from naphtha to ethane due to the cost advantage, boosts demand near term; step-wise expansion of ethylene cracking facilities over the next five years or more would further increase this demand in the long run, for as long as the ethylene-ethane margin is wider than the ethylene-naphtha margin.

For propane, export facilities are also about to double in size to accommodate this growth of liquids production. Enterprise Product Partners is currently making enhancements to the refrigeration facility at the Houston Ship Channel export terminal to facilitate this growth.

All in all, very strong growth at both ends of the NGL value chain, from the supply of liquids upstream, to expansions in the petrochemical and other industrial sectors downstream, is driving the rapid midstream infrastructure build-out needed. These midstream expansions may only be in the beginning stage.

Biofuels

Biofuels, while mandated, sees production growth severely constrained by falling US gasoline demand

Biofuels could add a modest 0.6-m b/d to the balance, with around 0.9-m b/d currently produced in the US, which could reach 1.5-m b/d by 2020, short of the Renewable Fuels Standard (RFS) mandated volume of ~2-m b/d.

The key constraint for the biofuels outlook is the long-term secular decline of US gasoline demand, which could fall from 9-m b/d in 2010 to 7.4-m b/d in 2020, due to demographic changes, fuel efficiency and mass commercialization of new vehicle technologies. This is discussed in the later section "US Oil Demand in Decline".

And given renewable biofuels production is already close to the mandated level, the remaining mandate-driven growth is hoped to come from cellulosic and other advanced biofuels. But the technology for this has been proceeding at a snail's pace, posing another constraint for biofuels volumes to keep apace with the RFS mandates.

Figure 18. US Renewable Fuel Standard (RFS) Mandated Biofuel Volumes

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Renewable biofuel	585	685	783	822	859	900	939	978	976	978	978	978	976	978	978
Advanced biofuel	**0**	**39**	**62**	**88**	**130**	**179**	**245**	**359**	**472**	**587**	**718**	**848**	**976**	**1,174**	**1,370**
Cellulosic biofuel	0	0	0	0	33	65	114	196	276	359	457	554	683	881	1,044
Biomass-based diesel	0	33	42	52	65	0	0	0	0	0	0	0	0	0	0
Undifferentiated advanced biofuel	0	7	19	35	33	114	130	163	195	228	261	294	293	294	326
Total RFS	585	724	845	910	989	1,080	1,184	1,337	1,447	1,566	1,696	1,826	1,952	2,153	2,348

*Biomass-based diesel standard was combined for 2009/2010

Source: IEA, Citi Investment Research and Analysis

And fuel ethanol has already hit the 10% ethanol "blend wall"

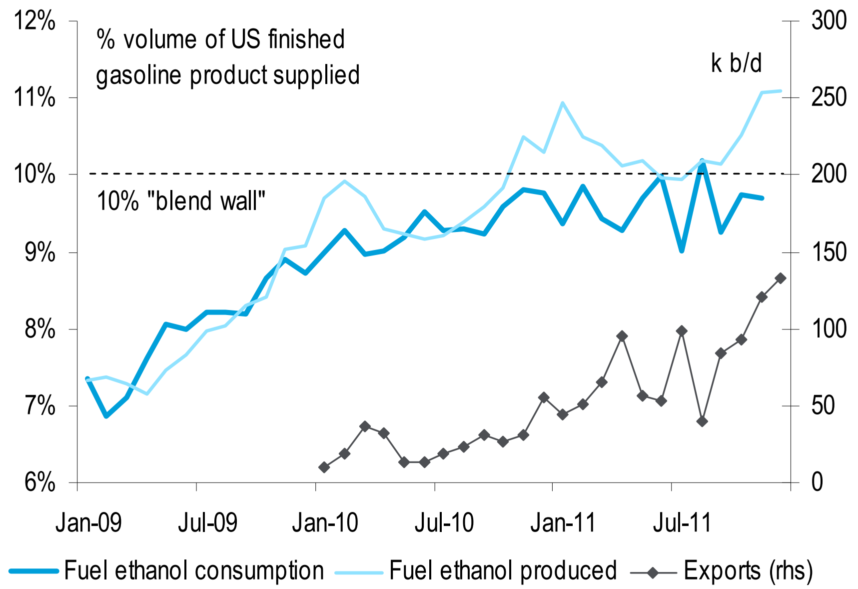
Meanwhile, fuel ethanol, categorized as "renewable biofuels" in the RFS mandates, looks to have hit a ceiling in the US, with further growth coming only from exports, particularly to Latin America as well as Europe. Domestic demand in 2011 was around 900-k b/d, around 10% of gasoline demand by volume. Growth in domestic ethanol demand would require higher levels of blending than the current 10% standard, besides the primary problem of secularly declining gasoline demand, which could fall by 1.6-m b/d by 2020.

Previous support for the industry in the form of a blenders' tax credit, and an import tariff on ethanol, were allowed to expire at the end of 2011, although they were not strictly necessary to keep production economic.

E15, and particularly E85, remain slow-moving prospects

An E15 waiver by the EPA — which would allow an ethanol blending to increase to 15% of finished gasoline volumes — could come about but faces delays from the need to safety test its use in vehicle engines and other regulatory compliance issues, as well as refitting fuel stations in terms of pumps and labeling standards. Flex-fuel vehicles that would allow the use of E85 remain limited. Meanwhile, abundant domestic supply of oil weakens the energy independence argument for using biofuels, if not the environmental argument, while competition from natural gas vehicles could limit biofuels demand even further.

Figure 19. US fuel ethanol has hit the ethanol blend wall, with surplus production (above ethanol used for blending into gasoline) driving growing exports



Source: EIA, Citi Investment Research and Analysis

But export markets should be there to take up the surplus, particularly in Latin America

Export markets have been concentrated in Brazil —itself the most mature biofuels market with supportive policies and significant domestic supply — at 57-k b/d in December 2011, as well as Canada (28-k b/d) and other countries in Latin America and Europe. Brazilian demand growth is relatively robust, for gasoline and thus ethanol for blending, but its domestic supply has recently struggled to keep up with demand, pushing up sugar-based ethanol prices, and encouraging imports from the US. US production is already spilling over the "blend wall", which looks to stay in place for the medium term with limited moves to an E15 waiver or E85 via greater penetration of flex-fuel vehicles into the vehicle fleet.

Meanwhile, a list of selected projects identified by the IEA in its Medium Term Oil and Gas Markets (MTOGM) 2011 sees planned capacity additions of 18-k b/d of ethanol production, 10-k b/d of cellulosic ethanol production and 5-k b/d of biodiesel production between 2011-16 (see Figure 20).

Thus, fuel ethanol production already looks to be in surplus to domestic demand, given the 10% blend wall, and this can be seen in ethanol stock builds as well as growing fuel ethanol exports, which hit a record high of 133-k b/d in December 2011. Further declines in US gasoline demand create an even larger overhang for export, even with higher levels of fuel ethanol blending.

Figure 20. Selected Biofuel Project Start-Ups

	Project	Output	Capacity (k b/d)	Start year
USA	Aventine Renewable Energy - Aurora, Nebraska	Ethanol	7	2011
USA	Aventine Renewable Energy - Mt Vernon, Indiana	Ethanol	7	2011
USA	Abengoa - Hugoton, Kansas	Cellulosic ethanol	7	2013
USA	Dynamic Fuels - Geismar, Louisiana	Biodiesel (BTL)	5	2011
USA	Aemetis - Keyes, California	Ethanol	4	2011
USA	Coskata - Green County, Alabama	Cellulosic ethanol	4	2015e
USA	Vercipia (Verenium/BP) - Highlands County, Florida	Cellulosic ethanol	2	2013
USA	POET - Emmetsburg, Iowa	Cellulosic ethanol	2	2012
Canada	Lignol - Vancouver, British Columbia	Cellulosic ethanol	1	2015e
Canada	Enerkem - Edmonton, Alberta	Cellulosic ethanol	1	2012

Source: IEA, Citi Investment Research and Analysis

US liquid fuels demand is in decline

This newfound hydrocarbon cornucopia comes at a time of declining US liquid fuels consumption

This phenomenal growth of oil and liquids production in the US, which is likely to outpace the most aggressive projections of Iraqi output, is all the more remarkable in that it comes against a backdrop of secularly declining US domestic demand, which could fall by as much as 2-m b/d between 2010 and 2020, mostly through declines in gasoline demand (see discussion later). This is on top of the decline in US demand of ~1.5-m b/d since 2007.

Shale plays are not like conventional plays

Shale oil and gas do not see conventional production profiles and declines, but instead are a kind of "just-in-time" production system

As well as the impressive production growth of shale oil, natural gas production in the US and Canada could grow by as much as 22-Bcf/d from now to 2020 (14-Bcf/d in the Lower 48 States and 4-Bcf/d each in Canada and Alaska), depending in large part on gas demand requirements. These growth trajectories must be seen in context. Shale plays are not like conventional plays; analytically, it requires a very different mindset to understand them.

Once infrastructure is in place, new drilling or completion activities can be suspended in response to lower prices, as seen in the inventory build-up of drilled-but-not-producing wells. Traditionally, a field once seeing production begin also sees it rise and then fall as fields are depleted.

While tight oil and shale gas drilling has a lower probability of hitting "dry holes", due to the well-known geography of reserves, the major difference is that the process of drilling-fracturing-completion-and-production is akin to a manufacturing process that lends itself a sort of "just-in-time" production management. This ability is one of the revolutionary impacts of this new development.

Gas-to-Liquids (GTL)

GTL remains a hope for the future but faces high capital costs

As for GTL processes, these remain hopes for the future and indeed they might not even become viable. On the surface, although a gas-to-liquids (GTL) facility could explicitly link the end-product price to high oil prices, technical issues and opportunity costs could reduce the appeal of GTL development. Thus, with a number of obstacles and challenging economics, a GTL plant is unlikely to contribute to additional gas demand within the 2020 timeframe. Developing a GTL project faces three key risks: future prices of oil and products where the end-product of GTL would be sold to; future prices of the natural gas feedstock; and the capital cost of a GTL plant. While oil prices could stay high, or at least in certain regions globally that the liquids produced from the GTL process could be shipped, natural gas prices could face some upward pressure in North America, especially if the highly probable surge in demand were to take place by the middle or late in this decade. (See the "Natural Gas" section for details.)

particularly compared to gas liquefaction projects

However, it is the capital cost and the associated opportunity cost that could make GTL less attractive compared with a gas liquefaction project, GTL's closest competitor in project development. With only two proprietary technologies that are commercial, interests in new GTL projects are limited. The construction time is long. Assuming that the Fisher Tropsch process in converting gas to liquids is used, typically 70% of the product produced would be diesel and 30% naphtha. Naphtha is widely used as a feedstock in the petrochemical industry, but the abundance of relatively lower cost ethane and other natural gas liquids is giving the petrochemical industry in North America a cost advantage over overseas competitors that have to rely on naphtha in producing ethylene. GTL's ability to produce diesel is attractive, given access to the global middle distillate market, which is a major driver of the world's oil demand growth. But the capital cost of a GTL plant could be astounding. Shell's Pearl project in Qatar, with a capacity of producing 140-k b/d of liquids, cost around $19 billion including upstream costs. Chevron's Escravos project in Nigeria, capable of producing 33-k b/d of liquids, cost $8.4 billion to build. Sasol's Oryx project in Qatar with 34-k b/d of capacity cost $1.2 billion to build, but it was started in the early 2000s before the run-up in global commodity prices.

The per-unit cost of building a GTL project in North America would likely be at the middle of this range. If carbon legislations were to be enacted, as were the case in British Columbia, Canada, the 0.2-ton of carbon dioxide emitted per barrel of liquids produced by GTL would add $5/bbl of extra emission costs to production, assuming the $24/ton carbon tax in place in B.C. Hence, with these obstacles and comparatively challenging economics, we assume that a GTL plant is unlikely to contribute to an increase in gas demand before 2020.

Alaskan gas production and exports

Alaskan LNG exports could resume this year, with exports of associated gas from the North Slope possible at the turn of the next decade

Meanwhile, the holders of Alaska's vast natural gas resources are again laying out plans for LNG exports and these will undoubtedly recur this year. ConocoPhillips is re-opening its liquefaction facilities in Kenai it suspended earlier. Separately, transporting associated gas from the North Slope and liquefying it in a new liquefaction terminal at the port of Valdez for exports, for example, could add 4-Bcf/d by end-2020. There is about 35-Tcf of natural gas in the Prudhoe Bay areas with a likely 100-tcf of additional resources in other North Slope areas, including the ANWR. With the shale gas revolution unfolding in the Lower 48 states, this gas would never be needed in continental North America and plans are underway for a north-south pipeline aimed at large–scale liquefaction projects by the next decade.

Canada 2020: The oil sands growth factory, with shale as well

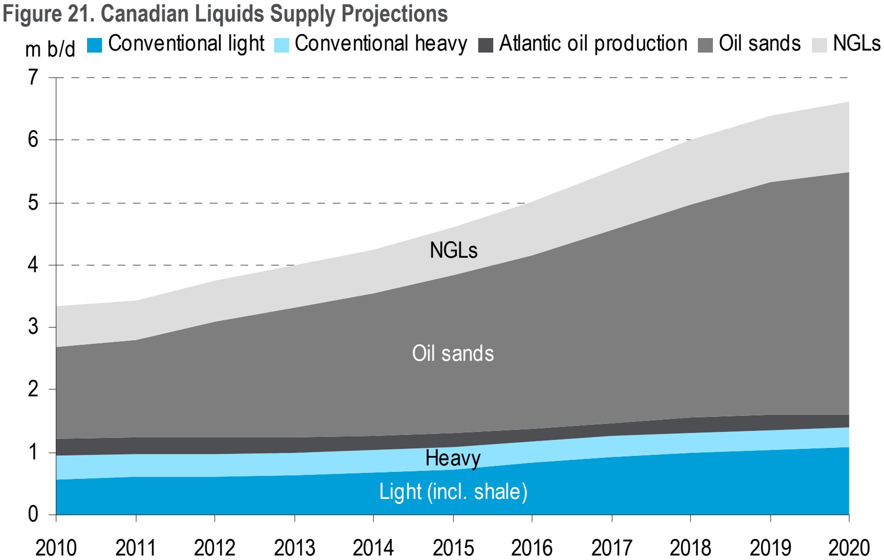
Canadian oil sands, tight oil and NGLs could grow +3-m b/d to reach 6.5-m b/d by 2020

Canada and Venezuela were the main incubators for oil sands and heavy oil development, with Venezuela in recent years seeing the heavy oil revolution peter out while Canada enjoys an investment regime that enables it to flourish. Although the bulk of Canadian incremental production comes from Alberta's oil sands, tight oil and NGLs also show promise, driving total liquids growth of as much as +3-m b/d from 3.5-m b/d in 2011 to 6.5-m b/d by 2020. This potential 6.5-m b/d compares favorably with US total liquids production of 9-m b/d and ~10-m b/d levels in both Russia and Saudi Arabia.

of which oil sands could grow an average and sustained +210-k b/d each year to 2020 and beyond

Canadian oil sands growth was obstructed by price uncertainty between mid-2008 and mid-2009, but investment flows, once they resumed, have been continuing vigorously. The average cost of oil sands exploitation, which like shale oil sees a wide range, had been rising rapidly before 2008 and has now dropped to the $50-$60 range. This was as oil sands output grew by 600-k b/d between 2000 and 2008, by which time total oil sands output reached over 1.2-m b/d. Oil sands now look likely to grow by a sustained +210-k b/d on average each year to 2020, and as far as 2030, with the major constraint being the growth in takeaway capacity, or logistics system, as in the Bakken and elsewhere. On a month-to-month basis, unplanned outages happen, which are critical and unpredictable on a short-term basis, but the longer-term trajectory is conducive to continued supply growth.

Figure 21. Canadian Liquids Supply Projections



Source: Citi Investment Research and Analysis

The projected trajectory is driven both by production growth in existing projects as well as new projects coming online, some sooner than previously anticipated. This growth is likely to be mostly in diluted bitumen given lagging additions of upgrader capacity, which should increase in relative terms heavier crude volumes into the US, (although this should be overwhelmed by light crude from multiple other North American sources).

There are three major regions in northern Alberta — Athabasca, Cold Lake and Peace River — containing some 170 billion barrels of established reserves, according to the Alberta Energy Resources and Conversation Board (ERCB) as of end-2009. Of the remaining established reserves, 136 billion barrels is recoverable by in situ methods and 34 billion barrels is recoverable by surface mining. In situ recovery involves conventional methods of production, as well as other techniques including injection of steam, water or solvents to allow the viscous bitumen to flow to the surface.

Mined bitumen is typically upgraded into light crude oil in an integrated facility, although Imperial's Kearl Lake mining project, one of the largest new capacity additions in the near term, does not have an upgrader onsite, and thus will provide diluted bitumen to the market. Heavier and heavier volumes are expected going forward for Canadian oil sands as upgrading capacity falls behind. In situ methods are growing and projected to overtake production volumes produced by mining methods by around 2016.

Figure 22. Canadian Oil Sands Production 2011-20 (k b/d)

Project	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Athabasca Oil Sands Project	190	235	255	265	285	305	335	355	370	370
CNRL Kirby	-	-	-	6	16	26	36	40	40	40
Christina Lake	20	33	58	75	98	123	158	193	218	218
Cold Lake	150	150	150	150	155	165	175	180	180	157
Fort Hills	-	-	-	-	-	40	80	120	160	160
Foster Creek	105	118	120	122	132	142	165	184	210	210
Great Divide Project	16	18	20	20	20	20	20	20	20	20
Hangingstone	8	8	9	12	22	32	40	40	40	40
Horizon	60	103	124	141	143	152	167	207	238	279
Jackfish	38	45	58	68	73	80	93	103	105	105
Joslyn	-	-	-	-	-	-	30	50	80	100
Kai Kos Dehseh	8	14	19	19	24	34	50	65	80	80
Kearl	-	27	50	90	130	160	200	220	235	265
Long Lake	42	33	40	44	48	53	59	64	71	78
MEG Christina Lake	25	25	30	50	60	60	60	60	60	60
MacKay River	30	30	30	30	30	35	50	65	70	70
Orion	6	10	13	16	18	20	20	20	20	20
Peace River	9	10	12	12	12	12	12	12	12	12
Primary CNRL Cold Flow	25	24	23	22	21	20	19	18	17	16
Primary CNRL Pelican Lake	45	46	64	76	80	80	72	65	58	52
Primary Cenovus Pelican Lake	22	25	30	35	40	40	38	36	34	33
Primary Penn West Seal	6	8	12	14	16	16	15	13	12	11
Primary Shell Canada Seal	14	16	16	15	14	12	11	10	9	8
Primrose/Wolf Lake	101	120	120	120	120	120	120	120	120	120
Suncor Mining Project	255	266	278	278	278	278	278	278	278	278
Suncor SAGD Project	79	131	191	219	229	229	229	229	229	229
Sunrise	-	-	-	5	10	35	45	66	75	106
Surmont	25	27	27	27	33	42	52	74	102	110
Syncrude Project	289	305	322	340	405	405	405	405	405	405
Tucker	8	12	18	22	22	22	22	22	22	22
Total Liquids (k b/d)	**1,576**	**1,839**	**2,089**	**2,293**	**2,534**	**2,758**	**3,056**	**3,334**	**3,570**	**3,674**

Source: Citi Investment Research and Analysis, Wood Mackenzie

Growing production volumes are overwhelming pipeline capacity throughout the North American midcontinent

Lack of pipeline and other capacity could constrain output in the future, but even in the near-term pipeline capacity should continue to be tested time and time again. Existing takeaway infrastructure primarily goes south to the US Gulf Coast via Cushing or Patoka. Post-2017, new options could add further volumes west to the Pacific via the proposed 525-k b/d Enbridge Northern Gateway pipeline to Kitimat, BC and the Kinder Morgan Trans Mountain line expansion from 280-k b/d to 600-k b/d to bring oil to central British Columbia, Vancouver and Washington by 2017 or later. Expansions and extensions/reversals to Enbridge's Line 5 and Line 9 respectively could also add further volume eastwards to the Atlantic. Here again there are risks from regulatory opposition on environmental grounds, while other risks come from falling energy prices, which could make marginal projects uneconomic, with projects pushed back to later, higher-price periods.

Figure 23. Canada Total Liquids Supply Projections

m b/d	2011A	2015E	2020E
Oil sands	1.6	2.5	3.7
Tight oil	0.0	0.1	0.5
NGLs	0.6	0.8	1.1
Conventional	1.3	1.3	1.2
Total	**3.5**	**4.7**	**6.5**

Growth	2011-15E	2015E-20E	2011-20E
Oil sands	1.0	1.3	2.1
Tight oil	0.1	0.4	0.5
NGLs	0.2	0.4	0.5
Conventional	0.0	-0.1	-0.1
Total	**1.3**	**2.0**	**3.0**

Source: Citi Investment Research and Analysis

But oil sands are not the only story; shale resources could see modest growth too

Meanwhile, tight oil production is expected to grow to respectable levels, potentially reaching 500-k b/d by 2020. A good deal of this production growth looks like to stem from extensions in Canada of Williston Basin/Bakken production, although some growth can be expected in gas-related plays in British Colombia. Already there has been interest in horizontal drilling in emerging liquids plays including the Lower Shaunavon in southwest Saskatchewan, the Birdbear near Lloydminster, the Cardium in Alberta, and the Viking formation that straddles Alberta and Saskatchewan.

with an associated bounty of NGLs

Correspondingly, NGL output in Canada is also expected to grow and could increase by +500-k b/d by 2020. Much of this incremental NGL output is associated with shale gas production in British Columbia, but also East of the Rockies in Alberta and Saskatchewan.

Separately, Atlantic Canadian production, generally in slow decline, sees an uptick from the expected startup of the Hebron Project in 2017.

And in terms of natural gas, Canada has shale gas resources in the Horn River and Montney shales in Western Canada, helping to drive 4- to 6-Bcf/d of total production gain between now and 2020, primarily on tightening supply-demand balances both in Canada and the US in the latter half of the decade. (See the section "Shale gas revolution drives paradigmatic shifts across sectors" for details).

Again the obstacles are political rather than technological or geological

Obstacles to sustainable and robust Canadian production growth abound and can be summarized by three interlocking issues: export outlets, First Nations issues, and environmental policy. All of these are discussed in detail later. The vetoing — at least for the time being — of the Keystone XL pipeline by President Obama this past January set up a wave of resource nationalism in Canada, aimed at pushing exports of oil to the Pacific Basin, rather than the Atlantic Basin.

The Pacific Basin should have been the focus of Canadian producer attention all along, with the fastest growth of petroleum product demand in the world. It is crude short and it should be bringing the most consistent and highest netbacks to the well head for Canadian producers of any export destination. When producers focused their attention on delivering to the US market, the US was the fastest growing oil demand country in the world and its production appeared to be in permanent decline. But it's extremely costly and difficult to build pipeline to the West Coast of Canada, not simply because of the cost of laying pipe in mountains but because the landowners are fractious "First Nations" who own the land rights and right-of-ways. Then over and above environmental issues associated with greenhouse gas emissions during oil sands exploitations, Canadian inhabitants of West Coastal areas are particularly vigilant against potential oil spills just as are their American neighbors south of the Canadian/US border.

Mexico 2020: The lingering aftermath of the Mexican Revolution of 1938

The history and politics of Mexico's hydrocarbon sector is placing a stranglehold on deepwater and shale development

Mexican "oil independence" is associated with the Mexican Revolution in the late 1930s, which freed the country of oil dominance by companies operating out of the US. The "wisdom" of Mexico's taking national control over its oil sector was "proven" by the discovery of the super giant Cantarell field in 1976, the second largest oil field ever discovered with 36 billion barrels of oil in place, and around half of this recoverable. Cantarell rose to a record production level of over 2.1-m b/d by 2004-05, giving Mexico's government and opposition little reason to worry about the problem of falling production, leaving it as an issue for the distant future; but of course, Cantarell has since declined precipitously.

Mexico has been frozen out of both the deepwater and shale revolutions, not because of a lack of potential, but because of a surfeit of self-imposed obstacles to getting capital, technology or human resources mobilized for discovery and exploitation. Now, with recognition of these potential resources, efforts are underway to find openings to start a new round of exploitation, which, if successful, should see Mexican output rising significantly.

but 2011 could be the turning point

Total Mexican liquids production reached a peak of 3.8-m b/d in 2004 (with crude oil alone at 3.38-m b/d) before falling to 2.9-m b/d in 2011 (with crude oil accounting for 2.5-m b/d of this). It is our judgment that 2011 might have seen the low point in Mexican production for the timing being and that onshore and offshore production, starting in 2012, looks likely to stem the erosion and start to reverse it.

Total liquids production could rise to over 4.5-m b/d by 2020, from deepwater and onshore shale

If everything goes well, total liquids production could rise to over 4.5-m b/d by 2020, a jump of 1.6-m b/d. Attention has been focused on the Ku Maloob Zaap (MZ) complex, which has stagnated at around 840-k b/d, while Cantarell output has shrunk to ~400-k b/d (between 2007 and 2010 Cantarell output plunged at a 30% CAGR). The biggest hopes were on the complex Chicontepec area where instead of rising to over 500-k b/d even with foreign help Pemex has been unable to increase output much above 50-k b/d. Deepwater Gulf of Mexico appears to hold some 30 billion barrels of potential reserves, but is underexplored, and has been slowed by the post-Macondo drilling push-back. Yet if discoveries are soon made, deepwater production could add over 1-m b/d by the end of the decade. Drilling is scheduled to ramp up this year, but Pemex's lack of deepwater drilling experience and expertise might make a reachable target impossible to get to because of restrictions on foreign oil company participation.

including extensions of the Eagle Ford shale play in Mexico

The onshore is also not standing still. Theoretically, growth from liquids and onshore could be +1-m b/d by 2020. Indeed, shale gas reserves could be as high as 680-Tcf as estimated by EIA, although Pemex assesses a more conservative 150- to 460-Tcf, behind only China, the US and Argentina. Meanwhile, Pemex is investing $8 billion to drill 4,000 wells and produce 1-Bcf/d of shale gas. Mexico's first shale gas well in summer 2011 confirmed that the Eagle Ford shale play extends into Mexico. There is little doubt that the Eagle Ford extends across the Mexican border, but whether it and other shale plays can be exploited by Pemex in cooperation with independent service companies is as much an open question as whether Pemex will be able on its own to exploit what appears to be highly robust deepwater resources.

More substantial energy reforms might follow the upcoming Mexican elections later this year.

Figure 24. Mexico Shale Resources

Source: EIA ARI World Shale Gas Resources

The shale revolution worldwide

Shale gas and tight oil have made the US the fastest growing producer of gas and oil and the shale revolution now looks set to make an impact not just in North America, but worldwide lat this decade and into the 2020s.

It appears that the same shale geology is abundant throughout the world. EIA commissioned a study on shale gas resources worldwide published in April 2011 report, which identified large technically recoverable resources in China, the US, Argentina, Mexico, South Africa, Australia, Canada, Libya, Algeria, Brazil, Poland and France (in descending order of size of estimated resources), for a total of 6,622-Tcf — and this is only in the areas studied — there could be significant upside. Furthermore, some if not many of these areas should be promising for shale liquids as well (see Figure 25).

Figure 25. Estimated shale gas technically recoverable resources for selected basins

Europe	Tcf
France	180
Germany	8
Netherlands	17
Norway	83
U.K.	20
Denmark	23
Sweden	41
Poland	187
Turkey	15
Ukraine	42
Lithuania	4
Others	19
North America	Tcf
United States	862
Canada	388
Mexico	681
Asia Pacific	Tcf
China	1,275
India	63
Pakistan	51
Australia	396
Africa	Tcf
South Africa	485
Libya	290
Tunisia	18
Algeria	231
Morocco	11
Western Sahara	7
Mauritania	0
South America	Tcf
Venezuela	11
Colombia	19
Argentina	774
Brazil	226
Chile	64
Uruguay	21
Paraguay	62
Bolivia	48
Total assessed	6,622

Source: EIA World Shale Gas Report, April 5, 2011

Of the list, it is notable that China has the largest identified reserves at an estimated 1,275-Tcf. As a country with significant resources in absolute terms, it is nevertheless an acutely resource-poor nation on a per capita basis, and increasingly so over time as per capita energy demand increases in line with income. Abundant, domestic sources of shale gas hold the promise of substituting away from dirtier (but abundant) coal, as well as reducing reliance on foreign (particularly, Russian) gas. Shale liquids would also be a boon for similar reasons. Already, Chinese National Oil Companies (NOCs) are investing in US companies with positions in shale plays, in order to learn the technologies that are driving this revolution. But development is likely to be slow in the medium term, hinging on the build-out of a still-nascent country-wide pipeline network, as well as being at an earlier point on the curve for technological and geological learning-by-doing.

The shale oil wagon has recently come to Argentina, with Repsol YPF reporting a big discovery last year at the Vaca Muerta shale formation in the Lomo La Lata Norte field in Neuquen Basin, 650 miles southwest of Buenos Aires. The 23 billion boe shale oil find includes 80% shale oil, or around 741-m bbls of light, 40-45 API oil. This is following sizable oil finds earlier this year and last year, with earlier discoveries of 10-50-m boe in July 2011 and 150-m bbls in May 2011, after finding 4.5-Tcf of unconventional gas in December 2010. The Neuquen shale has been compared to the Eagle Ford in geology. Already, International Oil Companies (IOCs) have enthusiastically entered the play, with perhaps 100 exploration wells to be drilled this year by the likes of Repsol YPF, ExxonMobil, Total and Royal Dutch Shell, with Chevron and Statoil also considering options. EIA's study assessed Argentina to have the third largest technical recoverable shale gas resources in the world, at 774-Tcf.

So the technology and geology look to be in place, but politics looks to be the sticking point. Policy changes continue to shift the landscape for exploration and production. Renewed interest in exploring Argentina's resources has been helped by an easing of previous government price controls (imposed after the 2001-02 economic collapse) which was holding back investment — the price producers received for oil was as low as $42/bbl under a variable export tax — but this price rose to almost $70/bbl over the last year. However, foreign exchange controls were issued in October, requiring that oil exporters repatriate all foreign currency export revenues in an effort to stem capital flight, raising the possibility that extracting profits from Argentina might become more problematic. And the recent standoff between YPF and President Kirchner could be cause for worry. But IOCs look to be taking this in their stride, with the potentially bountiful shale resources seemingly worth the risk. Also, the gas price controls allow for imports of LNG in winter at very favorable levels of $20/MMBtu or higher.

US Oil Demand in Decline

US oil demand is in structural, secular decline, driven by demographic changes, fuel efficiency and new transportation technologies

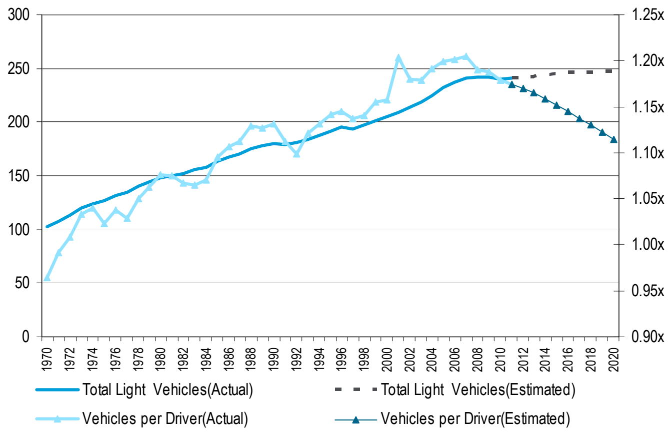
The demand in the US for major petroleum products has fallen substantially between 2005 and 2011, with year-end 2011 data pointing to a drop of 1.5-m b/d over the last seven years. Going forward, demand could fall by as much as an additional 2-m b/d due to demographic changes, policies on fuel efficiency and the mass commercialization of new technologies, countered somewhat by continued economic and population growth. Gasoline demand could fall to 7.4-m b/d in 2020 from 9.0-m b/d in 2010 and distillate demand for road use could fall to 1.7-m b/d in 2020 from 2.1-m b/d in 2010.[2] Our scenario assumes that the adoption of new technology could drive about half the decrease in consumption, with the other half coming from changes in the population make-up and rising efficiency standards. Electric, hybrid and natural gas vehicles (NGVs) could begin encroaching on the market shares of gasoline and diesel engines in a meaningful way within three more years. See the section "Shale gas revolution drives paradigmatic shifts across sectors" for details on NGVs.

Slow-to-flat light vehicle fleet growth as the number of vehicles per household and per driver falls this decade, driven by demographic and generational changes

First, although the number of vehicles on the road has recently fallen in absolute terms to 241 million light vehicles, we believe that the subsequent rise in the rest of the decade should be much slower than the healthy pace seen between 1970 and the mid-2000s. Vehicle density, or the number of vehicles per household, is trending downward, slowing the rate of increase in the number of vehicles on the road and hence liquid fuel consumption. A similar measure, the number of vehicles per driver, under the same rubric of "vehicle density," is also decreasing. The decline in vehicle density could be a generational, long-term shift driven by demographic changes. The growth of the nuclear family likely encouraged the purchases of additional vehicles, besides the wealth effect coming from an improving economy over time. Structurally, from the move to the suburbs requiring additional vehicles for commuting, to shuttling children and the family for various occasions, the need for additional vehicles, perhaps of different sizes, has necessitated more car purchases. But the transition to adulthood for younger members of the family, as well as the retirement of the baby boomer generation, appears to be a significant factor causing vehicle density to fall. Citi's auto analyst's survey shows how a decline of density appeared to be most pronounced for older generations (Figure 27). To counter this decline, vehicle density among younger generations would have to climb to offset the overall drop for the population as a whole. However, housing-related polls seem to indicate a preference for urban living among the younger, Gen-X and Millennial generations.

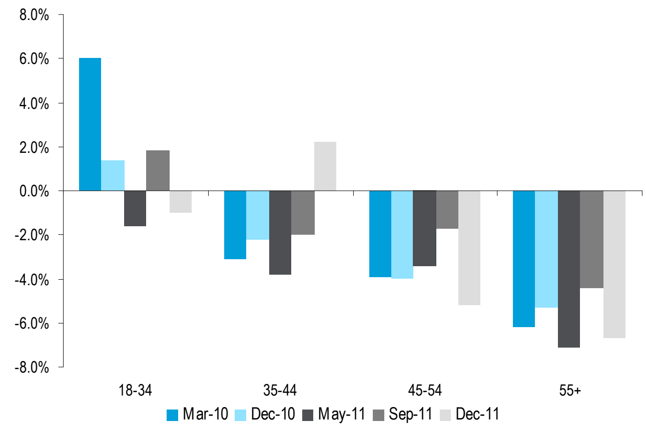
[2] We restrict our definition of heavy duty vehicles to "Truck, combination", "Bus" and "Motor Bus" as defined by the Bureau of Transportation Statistics.

Figure 26. Total Light Vehicles and Vehicles per Driver (Actual and Forecasts)



Source: FHWA, Wards & Citi Investment Research and Analysis

Figure 27. Vehicle Density by Age Group

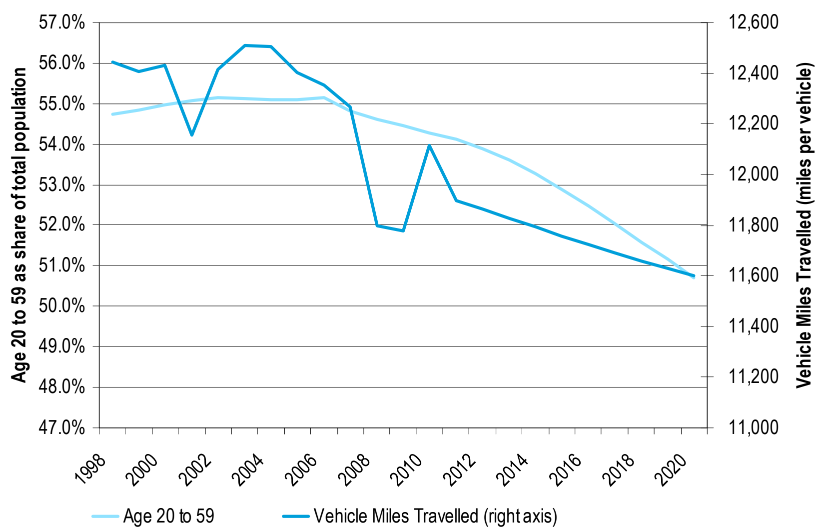


Source: Citi Investment Research and Analysis

while an aging population puts downward pressure on vehicle miles traveled per passenger vehicle

Second, the increase in the elderly population is resulting in a sizeable change in driving habits, with particular impact on Vehicle Miles Traveled (VMT) per passenger vehicle. VMT could fall by 4.2% between 2010 and 2020, reaching 11,600 miles/year by 2020. VMT peaked in 2003 and 2004, averaging 12,500 miles driven per year (see Figure 28). The retirement wave should reduce the need for daily commuting, potentially offsetting the cumulative impact of having longer road trips, if the oldest population cadres undertake trips more often. New habits after the oil price spike in 2008 and the subsequent recession may also have contributed to this change in the amount of driving taking place. The net result is a decline in VMT, just as the younger generations preference for urban living, noted above, cuts down the need for longer commutes as well.

Figure 28. Vehicle Miles Traveled vs. Age 20-59 as Share of Total Population



Source: Census, Citi Investment Research and Analysis and the continued tightening of the CAFE standards are driving accelerated fuel efficiency improvements

Third, fuel efficiency improvements are accelerating as the CAFE standards tighten. The national, fleet-wide fuel efficiency could increase by about 0.4 to 0.6-miles per gallon (MPG) every year between now and 2020. Although it appears to be a small number, compared with the more than 1-MPG of annual improvements mandated in new light-duty vehicles sold, raising the average fuel efficiency level of the national vehicle fleet made up of nearly 250 million vehicles would have a sizeable impact. Between 2010 and 2020, the weighted-average fuel economy of the entire fleet nationally could rise by 16%. Along with the 4.2% decline in Vehicle Miles Traveled during the same period, both effects would more than offset the small growth in the number of total vehicles on the road due to population growth.

CAFE: Congress enacted the Corporate Average Fuel Economy (CAFE) standard in 1975 to improve the average fuel economy of cars and light trucks (including vans, pickups and sport utility vehicles) sold in the US in order to reduce dependence on imported oil. The standard is a sales-weighted average of fuel economy (miles per gallon – MPG) of each manufacturer's fleet of current model year passenger cars or light trucks weighing 8,500 pounds or less and manufactured for sale in the US. The National Highway Traffic Safety Administration (NHTSA) regulates CAFE standards and the US Environmental Protection Agency (EPA) measures vehicle fuel efficiency.

with alternative vehicles — electric and natural gas vehicles — providing gradual, but significant substitution, particularly later in the decade

Sales of alternative vehicles could provide an extra push in lowering overall petroleum demand in the transport sector. Sales could surge as the technology matures and infrastructure develops. In the light-to-medium duty vehicle segments that primarily use gasoline as a fuel, alternative vehicles should gain market share, reduce gasoline demand by another 0.6-m b/d from our base case of 8.0-m b/d, pushing gasoline demand down to around 7.4-m b/d in 2020. The erosion in market share of gasoline could come from both electric and natural gas vehicles. Although the number of alternative vehicles sold seems small at the outset, technology diffusion does take time, especially when concerning goods that require substantial physical investments. In particular, the network effect is very important. The chicken-and-egg problem of needing infrastructure to promote growth, while also requiring a critical mass of vehicles on the road to justify that infrastructure could in fact lead to an acceleration in substitution later in the decade, when the market is more developed.

Even natural gas vehicles, which seem to have a greater prospect in the heavy-duty fleet, could pick up the slack left by electric vehicles. For example, GM and Chrysler announced on March 5, 2012, that they would be making natural gas-power pick-up trucks. DHL, UPS and other consumers with major vehicle fleets are also making the change from traditional liquid fuels of diesel or gasoline to natural gas. As these shifts proliferate, technologies become standardized and the infrastructure of refueling stations begins to develop, changes could permeate to non-fleet vehicles.

Natural gas vehicles could be a significant wildcard, and would likely be first introduced in fleet vehicles

In the heavy-duty vehicle segment, the market entry by natural gas vehicle could reduce diesel demand from heavy duty trucks by as much as 0.6-m b/d, possibly increasing natural gas demand by 3.3-Bcf/d by 2020. Although the lack of meaningful fuel-efficiency standards, as well as continued economic and population growth could raise the energy demand of heavy-duty trucks to 2.3-m boe/d in 2020 from 2.06-m boe/d in 2010 on an energy equivalent basis, actual diesel demand could fall to 1.7-m b/d by 2020 in a more aggressive hypothetical scenario, as the sale of alternative vehicles, especially natural gas, increases. Fleet-wide conversions are taking place, both organically in major transport companies such as UPS and DHL, as well as externally as seen in joint ventures such as the one between Navistar and Clean Energy Fuels. Navistar is a major manufacturer of commercial trucks and diesel engines; Clean Energy Fuels Corp is a provider of natural gas as a transportation fuel and also manufactures related equipment. See the section "Shale gas revolution drives paradigmatic shifts across sectors" for details on NGVs.

Shale Gas Revolution Drives Paradigmatic Shift Across Sectors

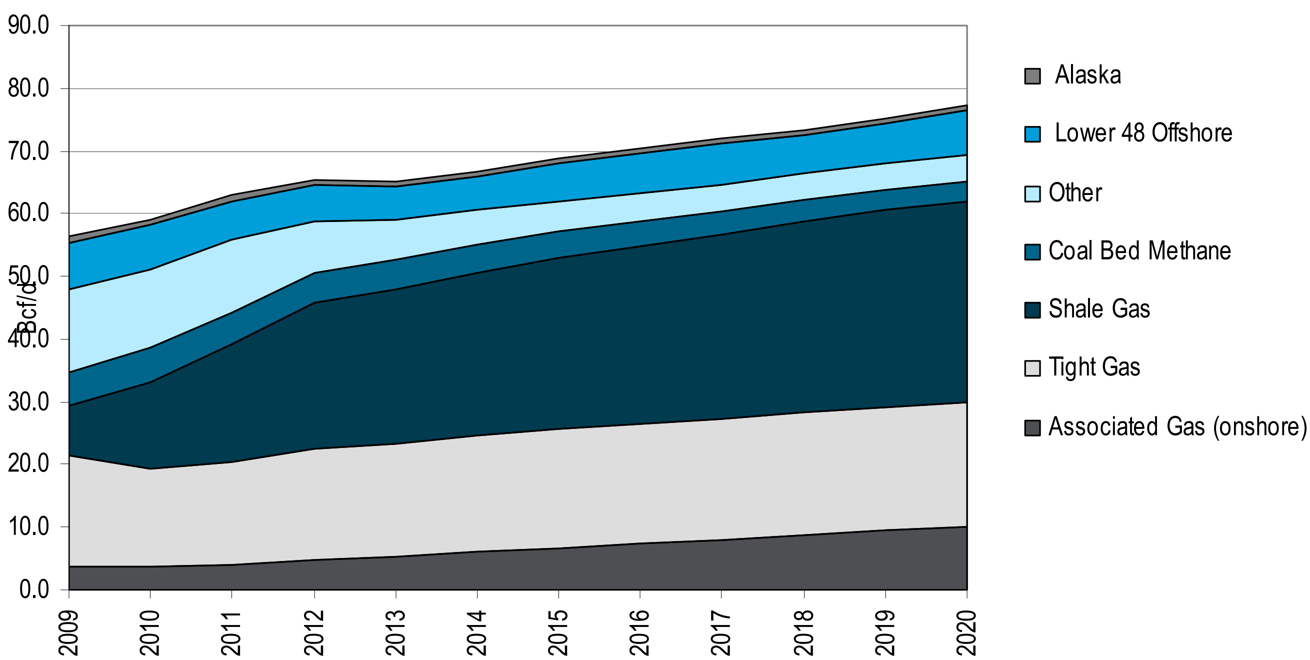
Natural gas production was the starting point of the game-changing shale revolution, and is beginning to transform multiple industries and sectors

The shale gas production boom that propelled the fundamental change in the natural gas market in the US could begin to transform other sectors, both in North America and abroad. These include a shift in global trade flows in gas, a step-wise jump in gas-fired use in power generation, a dramatic rise in natural gas use in land- and marine-based transportation, and a resumption of solid growth in residential/commercial requirements. But the most momentous change of all looks likely to be in the re-industrialization of America based on dramatically lower cost feedstock than is available anywhere in the world, with the possible exception of Qatar.

Natural gas production has been surging, and looks to continue its strong growth through 2020, with a reacceleration in the middle of this decade

Gas production in the Lower 48 states of the US could grow by 14-Bcf/d to as much as 18-Bcf/d between now and 2020 on top of the current base of 62-Bcf/d, perhaps even more. This development is highlighted by a reacceleration of growth starting in the middle of the decade when the domestic gas supply-demand becomes more balanced. Prices that are below $3/MMBtu recently have shattered natural gas drilling in the US. But with demand growth, production could be rapidly expanded as increases in natural gas create prices that should be constructive for gas drilling again, although associated gas production from liquids drilling could contribute between 40 to 50% of new hydrocarbon production from liquids producing wells. Direct exports of natural gas through LNG exports and indirect exports through international trade in petrochemicals and other products that use gas either as a feedstock or fuel, could extend the impact of this resource boom in North America to the rest of the world.

Figure 29. US Natural Gas Production Projection



Source: EIA, Citi Investment Research and Analysis

While the tremendous growth of gas production, if not slowed or reversed, would weigh heavily on prices, low prices are increasingly promoting the type of demand increase that should put North America on an entirely new path as a major exporter of products derived from gas and to some degree from exports of natural gas itself. The growth rate of shale gas production in the Lower 48 continues to largely surprise to the upside, as technological improvements and learning-by-doing in various stages of drilling and production keep making new production gains possible. Although major producers, such as ExxonMobil and BHP Billiton, could maintain their drilling activities through the low price period, a slowdown in production may hinge on two factors: the continued shift towards drilling in liquids-rich locations and financing constraints placed on dry natural gas production.

The power sector has experienced a significant impact, with residential and commercial sectors also seeing substitution of heating oil for gas

In the US, gas production growth has had the most pronounced impact on the power sector so far, where low gas prices make gas-fired power plants much more competitive against conventional base-load coal units. This should accelerate through the decade ahead. Coal's traditional 50% market share in power generation fell to the low-40% range in just the three years since 2009. Upcoming emission regulations should impose additional compliance costs on coal-fired plants, thereby reducing coal demand and generation, encouraging a change in the power fleet and lowering associated emissions. The residential and commercial sector is also experiencing a change, where heating oil as a traditional fuel for home heating, particularly in the Northeast, is being replaced by natural gas as long as infrastructure is available.

But the major transformations could be in a new industrial revolution driven by cheap, domestic shale gas, and a dramatic shift in transport sector fuel use to natural gas, as well as exports

But the most profound changes, with global implications, are the deployment of the shale drilling/completion technology across the globe, the resurgence of the industrial sector in the US, shifts in the transport sector fuel use, and even exports of natural gas internationally. Industrial processes are being retooled to use natural gas, instead of oil derivatives, due to gas's cost advantage. It is this cost advantage in fuel and feedstock supply in North America that is partly contributing to the revival and expansion of the industrial sector. Even the transport sector, given the persistently wide price spread between oil and natural gas on an energy equivalent basis, is finally making the step toward conversion, with natural gas vehicles encroaching on the market share of gasoline- and diesel-powered engines faster than many had believed possible. This abundance of gas should also affect global natural gas trade flows, as gas starts being exported from the continental US, ending the era where the US is a global gas island, which only imports but never exports. We will outline these developments in sections below.

The US production base is a just-in-time system

The natural gas production glut has created abundant production and pipeline infrastructure as well as accumulation of knowledge and equipment that lays the foundation for "just-in-time" production growth in the future as demand rebounds mid-decade

The surge in gas supply since 2009 has laid the foundation for more just-in-time production growth in the long run. The rise in drilling and production activities has led to an increase in the availability of skilled professionals and equipment, enabling producers to ramp up production if needed. The production glut has also encouraged a rapid build-out of pipeline infrastructure across the continent. Besides causing a collapse in regional gas price differences that previously persisted for years, infrastructure investments ease the transport bottlenecks in bringing supply to demand centers. These infrastructure improvements help supply meet both short-term increases in consumption, such as those due to weather, and longer-term rises in gas usage, such as a recovery in the economy and a resurgence of industrial activities. In addition, the vast number of geological and engineering studies performed in various oil- and gas-producing regions provides the knowledge base necessary to locate new drilling sites, reducing the possibility of finding “dry holes”, that is, wells that are uneconomic to produce.

But in the near term, abundant supply weighs on the natural gas market

However, the residual impact of this production surge should continue to weigh heavily on the market in the next two years, exacerbated by the very mild 2011-2012 winter in North America. As a result of high gas inventories and demand not yet catching up to the production gains since 2009, this supply overhang should linger even though gas prices have fallen to the low-$2/MMBtu price level at the beginning of 2012. This level was last seen more than a decade ago. The downward pressure on price looks likely to remain severe, even with the shift from direct gas drilling to liquids drilling. Low prices in the market because of this excess gas have and should continue to induce price-sensitive demand in the form of coal-to-gas switching[3] in the power generation sector.

From now to 2014, production growth could slow from the rapid, 4-Bcf/d year-on-year pace of the last two years. With low gas prices along the forward curve, producers, while still growing production in 2012 given previous momentum, are increasingly shifting to liquids and slower future dry gas growth. Without coal-to-gas switching, the market would be 5- to 7-Bcf/d "out-of-balance" (5-Bcf/d if gas were to average around $3 in 2012). However, dry gas rig counts would continue to fall as the forward curve falls and flattens. This reduces the attractiveness of hedging, which secures future cash flow from gas production. Production could still grow by 2-Bcf/d in 2012 over 2011, despite lower production levels at the end of 2012 than in the beginning of the year. High inventories would likely spill over into 2013, keeping prices low, just as Held-By-Production drilling activities[4] wind down and the drilling carry expires. Without the subsidy from drilling carry and protection from prior hedges, some producers would be vulnerable to low prices. In a low-price environment faced with continued cost increase, particularly in labor costs, this squeeze on profit should continue to depress drilling activity for dry gas. Production growth could be 0.5- to 1.0-Bcf/d between 2012 and 2013.

Natural gas demand might actually stagnate for a while in the near future before kicking up in the middle years of the decade. Coal-to-gas switching in particular may have reached a peak and will need to await the forced retirement of coal-fired plants. Low prices might also bring faster than currently expected supply impacts, given the steep decline rates of shale without new capital expenditures. It would not be surprising to see supply grow by 0.5-Bcf/d at most or even flatten, with the major increment of growth coming from associated gas production reaching perhaps 2-Bcf/d in a combined 2013-14 time horizon.

The middle of the decade should see a resurgence of demand across five key sectors

Between 2015 and 2017, surging demand growth simultaneously in five sectors should tighten the supply-demand balance and is likely beyond the reach of immediately available incremental supply. The focus on liquids drilling after a prolonged period of low gas prices could leave little spare capacity in the short term for gas-directed drilling to meet this surging demand. Prices could rise to $5/MMBtu sometime in the middle of the decade and even higher, possibly $8/MMBtu, if a demand spike, perhaps along with a temporary surge in weather-related demand, cannot elicit a quick response in production. But the subsequent production increase could bring gas prices back down to $5/MMBtu or below later in the decade.

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[3] Coal-to-gas switching refers to the situation where the cost of generation from natural gas-fired power plants falls below that of coal plants. As such, natural gas plants generate more and coal plants less, encroaching on the generation share of coal.

[4] In the continental U.S., for producers to secure the mineral rights on private land, they typically sign land leases with owners of mineral rights underground. Leases generally stipulate minimum work programs, without which leases expire and are not renewed. Once production begins, the mineral rights are usually held by the producer for specified time periods, which can be quite long, hence the desire for producers to drill despite low prices. This kind of drilling is called “Held-by-Production” drilling.

Natural gas prices are likely to hit their bottom this year, as, in the out years, demand growth begins to catch up while supply growth stalls on low prices. Excess gas from an inventory overhang and year-on-year production growth should shrink, as the natural gas market resets at the start of each winter. With slow-to-flat production growth, a normal winter combined with structural increases in demand would help to reduce the coal-gas substitution needed to clear off the excess gas. This would ease the downward price pressure on the market. By 2015, major demand components should see strong growth and prices should be correspondingly higher.

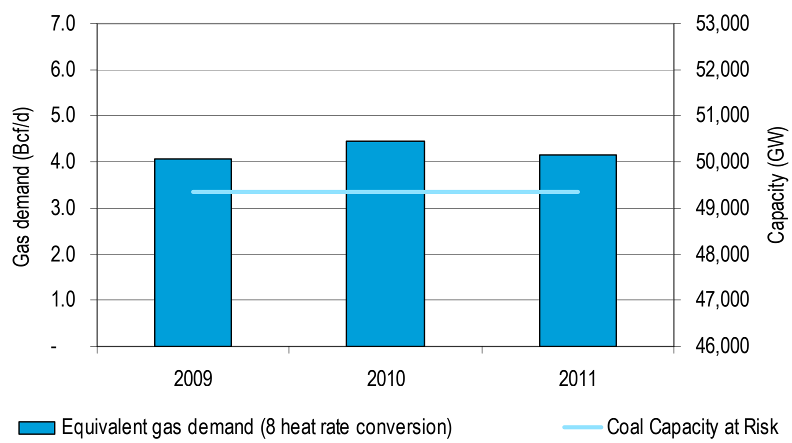
The five sectors of the economy driving demand increases include: (1) accelerated retirements of coal-fired power plants leading to more gas-fired generation; (2) industrial demand from brownfield and greenfield expansions; (3) rising residential and commercial demand due to a combination of fuel switching from heating oil to gas and a reduction in vacancies that brings back lost demand; (4) LNG exports, starting with Sabine Pass; and (5) natural gas vehicles and their use of LNG or Compressed Natural Gas (CNG).

(1) Accelerated retirements of coal-fired power plants

Emissions rules and regulations drive accelerated coal plant retirements in favor of natural gas-fired power generation

Stringent emission rules, including both CSAPR[5] (or its replacement) and boiler MACT[6], would cause significant coal plant retirements. By law, emission standards have to tighten in 2014 due to previous National Ambient Air Quality Standards[7]. Between 3- and 4-Bcf/d of additional gas demand could result, given the 45 to 50 GW of retirements expected during 2014-2016. Further, if carbon regulations ever come into existence, they would favor gas over coal, given that an efficient gas combined cycle plant emits less than half of the carbon as a coal plant.

Figure 30. Coal-fired power plant retirement estimates and their generation level in 2009, 2010 and 2011 represented in gas-equivalent units



Source: Ventyx Velocity, Citi Investment Research and Analysis

[5] CSAPR, or Cross State Air Pollution Rule, is EPA's emission rule regulating the emission of sulfur dioxides (SO2) and nitrogen oxides (NOx), where an abundance of the former causes acid rain and the latter causes both acid rain and smog. The rule grew out of a series of replacement rules emanating from the Clean Air Act (1970) and the Clean Air Act Amendments (1990). Coal plants are primary targets due to their high SO2 and NOx emissions

[6] MACT or MATS, which stands for "Maximum Achievable Control Technology" or "Mercury and Air Toxics Standards," respectively, refers to the EPA rule, with a previously expected implementation date in the middle of this decade, to "reduce emission of toxic air pollutants...from new and existing coal and oil-fired power plants."

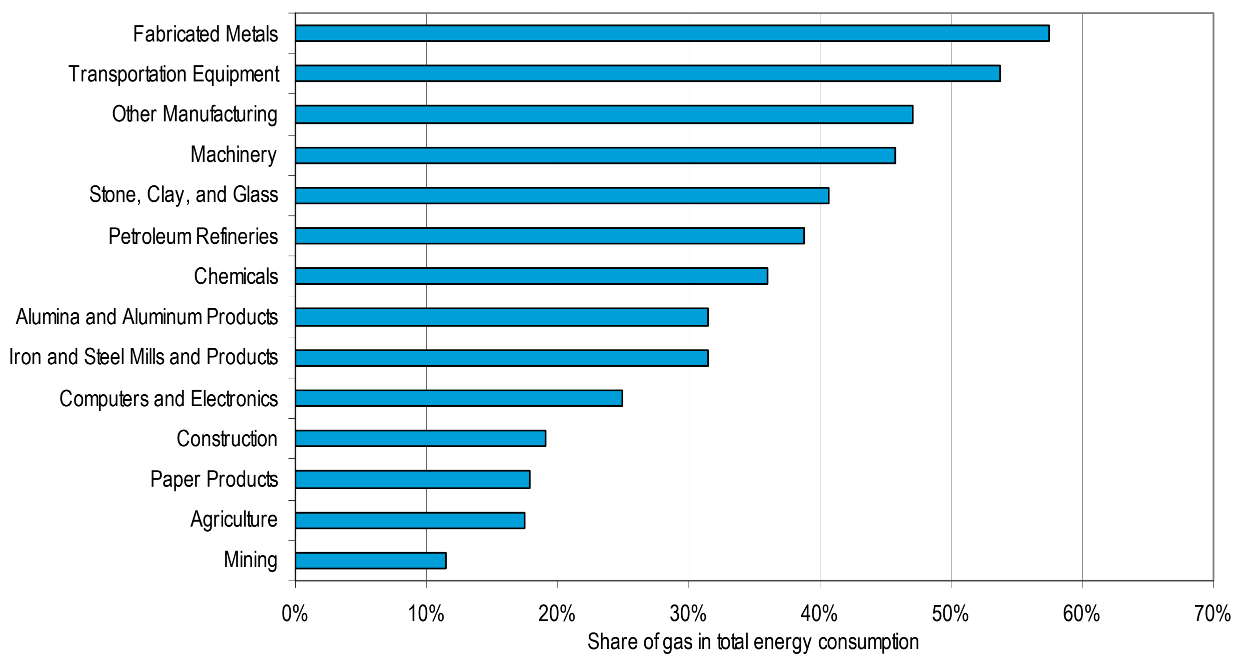
[7] NAAQS refers to the National Ambient Air Quality Standards. These standards were established by the Environmental Protection Agency (EPA) under the Clean Air Act (CAA).

(2) Industrial demand from brownfield and greenfield expansions

There looks to be a new industrial revolution powered by abundant, domestic natural gas, with input costs among the lowest in the world

The most momentous change on the demand side could be the re-industrialization of America and Canada based on dramatically lower cost of feedstock and fuel than is available anywhere in the world, with the possible exception of Qatar. For industries with large physical plants, such as metals, machinery and much of the manufacturing sector, natural gas consumption typically exceeds 30% and in some cases 50% of their respective total energy demand. Over the long run, the abundance of natural gas and the just-in-time production would reduce price volatility and place a long-term cap on prices. Fuel substitution, especially with coal and petroleum, and a reduction in the per-unit expenditure on gas would lower the overall cost of operation and improve competitiveness. Below we highlight this impact on several industries.

Figure 31. Natural Gas as a Share of Total Energy Consumption by Sector



Source: EIA, Citi Investment Research and Analysis
Note: For the Chemical sector, the share includes dry natural gas only and does not include natural gas liquids or petrochemical feedstock.

benefiting sectors ranging from petrochemicals to steel

The petrochemical industry is a direct beneficiary of the boom in natural gas and natural gas liquids (also known as liquefied petroleum gases) production. Using gas as a feedstock for basic chemicals lends an edge to US producers, as naphtha, a crude oil refined product, is typically the feedstock used by overseas producers. Given the steep price advantage US gas has over crude oil and its derivatives, the relative abundance of gas in North America compared with the tightness in global oil market is inducing higher capacity utilization and facilitating expansions in the US Expansions would increase gas demand structurally. Dow Chemical, for one, is proceeding with its plan to restart an ethylene cracker shut in 2009. See the next section for an in-depth discussion on the petrochemical sector.

The steel sector could see additional growth as it migrates some of its facilities to rely more on low-cost natural gas, and as the oil and gas boom provides a positive feedback to the tubular steel sector. First, lower fuel costs, including the use of gas for the reheating and rolling procedures, certainly improve the sector's cost competitiveness. But migrating the steel-making process from using high-cost metallurgical coal to an alternative steel-making process would increase its cost competitiveness as well.

The alternative method combines the use of Direct-Reduced Iron facilities with Electric Arc Furnaces. Using low-cost natural gas as a reducing agent in making steel leads to a reduction in feedstock spending. Second, the shale gas drilling boom is also feeding a cycle of increased production between the hydrocarbon producers and the tubular steel industry. Surging activities in drilling require an increasing amount of drill pipe, rippling from upstream to tubular steel makers and steel companies. The $650 million new tubular steel plant in Youngstown, OH, built by France's Vallourec and Mannesmann, among the largest steel tube makers globally, is an example of such a revival.

to construction, mining and agriculture through natural gas vehicles, and in the production of fertilizers

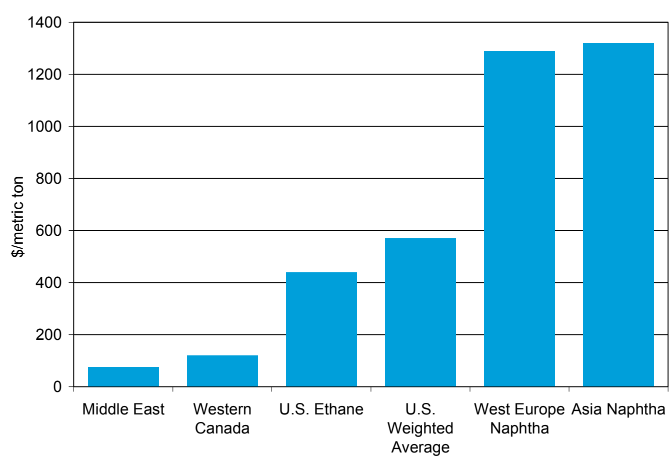
Even sectors that rely more on liquid fuels, such as construction, mining and agriculture, could become more reliant on natural gas. Across sectors, natural gas vehicles (NGVs) could begin to replace some conventional diesel- or gasoline-burning vehicles. Although most of the attention has been on converting the heavy duty truck fleet, smaller vehicles, such as pickup trucks, are being targeted as well. In March, 2012, GM and Chrysler announced plans to manufacture pickup trucks powered by natural gas. See the "Natural Gas Vehicle" section below for details.

The agricultural sector would be another beneficiary of the natural gas boom due to its use of fertilizers. Natural gas accounts for the majority of the cost of producing ammonia fertilizer, where gas is used to make ammonia. Higher gas production and lower prices have contributed to the return of activities. Orascom Construction bought and reopened a large ammonia plant in Beaumont, TX. CF Industries also restarted its large Donaldsonville, LA plant and has planned over $1 billion in investments to expand ammonia production capacity over the next four years. Saskatchewan's Potash Corp is investing in the restart of an ammonia plant shut in 2003.

Chemicals: Taking advantage of growing feedstock supply

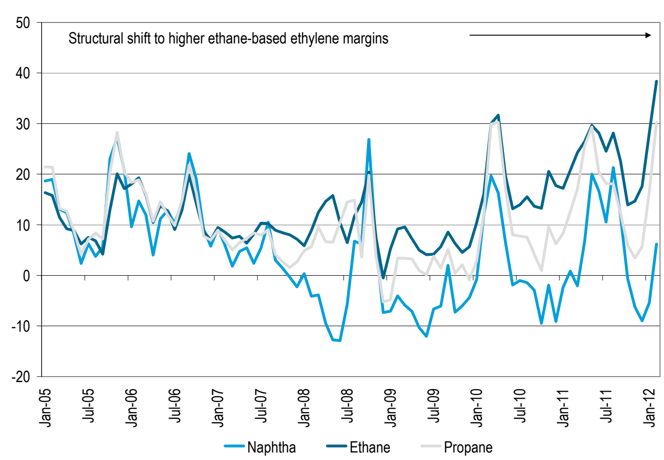
With excellent profitability amid a gradual recovery following a steep recession in 2008-09, cheap natural gas and associated ethane have been a game changer for the US petrochemical industry. US ethane-based ethylene producers have moved to the lower end of the global cost curve, after only the Middle East and Canada, and are currently enjoying record margins. By comparison, naphtha-based ethylene producers in Europe and Asia are at a competitive disadvantage.

Figure 32. Global Ethylene Cost Curve, January 2012



Source: Citi Investment Research and Analysis, CMAI

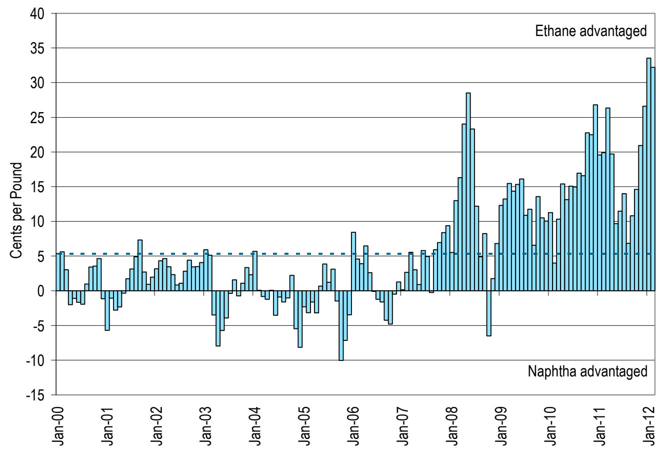
Figure 33. US Ethylene Margins by Major Feedstock



Source: Citi Investment Research and Analysis, CMAI

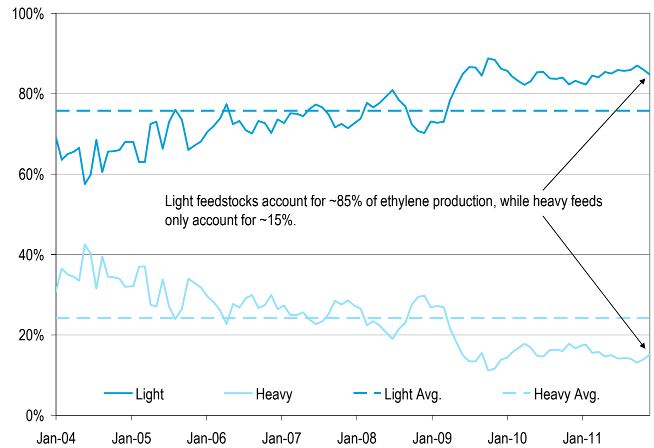
Given the significant margin advantage that ethane provides relative to naphtha, the US petrochemical industry has undergone a renaissance of sorts. Since the advent of horizontal drilling, the petrochemical industry has steadily invested in additional feedstock flexibility to process more NGLs, essentially shifting their feedstock mix to process incremental ethane. Approximately 85% of US ethylene production is based on NGLs compared to an average of ~75% since 2004. By comparison, heavy feedstocks like naphtha only account for 15% of US ethylene production.

Figure 34. Ethylene Margin Delta: Ethane – Naphtha



Source: Citi Investment Research and Analysis, CMAI

Figure 35. US Ethylene Production Sources (2004-2011)



Source: Citi Investment Research and Analysis, CMAI

Future ethylene capacity expansions should take several forms. Some producers are restarting previously idled crackers, including Dow Chemical. Others are de-bottlenecking plants and adding additional light feedstock flexibility, a list that includes numerous petrochemical companies such as LyondellBasell. Capacity growth over the next few years primarily consists of Brownfield expansions, although several new crackers have been announced by companies including Dow and Shell for the latter part of this decade.

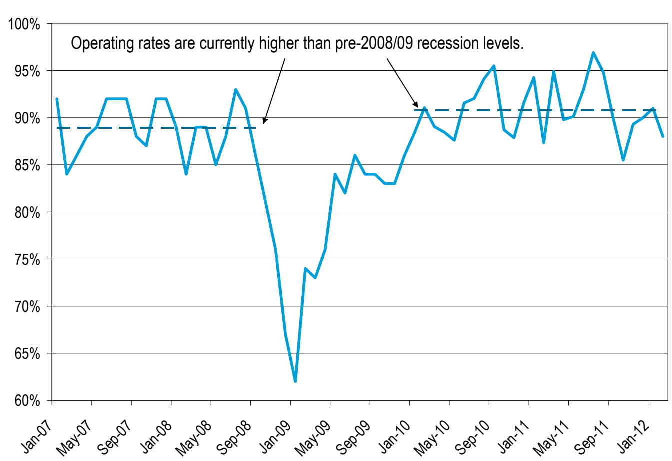
Figure 36. Planned US Ethylene Capacity Expansions, million pounds

Incremental Ethylene Capacity (mm lbs)	Location	Plant	2011	2012	2013	2014	2015	2016	2017
New Crackers									
Chevron	Cedar Bayou, TX							3,300	
Dow	Gulf Coast								3,300
Shell	Marcellus								2,500
Formosa	Point Comfort, TX							1,760	
Sasol	Lake Charles, LA								2,650
Restarts									
Dow	Taft, LA	#2			850				
Debottlenecks / Feedstock Conversions									
Westlake - de-bottleneck & feedstock flexibility	Lake Charles, LA	#1			235				
Westlake - de-bottleneck	Lake Charles, LA	#2					235		
Williams - expansion	Geismar, LA					600			
LyondellBasell - expansion	La Porte, TX					850			
LyondellBasell - de-bottleneck	Morris, IL and Clinton, IA				100				
LyondellBasell - de-bottleneck	Channelview, TX			500					
Ineos - de-bottleneck	Chocolate Bayou, TX			254					
Nova - increase utilization by 10%	Joffre, Alberta						620		
Other de-bottlenecks			-	200	200	200	200	200	200
Incremental Ethylene Capacity (mm lbs)			**860**	**954**	**1,385**	**1,650**	**1,055**	**5,260**	**8,650**
US Nameplate Ethylene Capacity (mm lbs)			**59,465**	**60,419**	**61,804**	**63,454**	**64,509**	**69,769**	**78,419**
% of US Capacity				1.6%	2.3%	2.7%	1.7%	8.2%	12.4%
Global Nameplate Ethylene Capacity (mm lbs)			**325,251**	**329,123**	**344,837**	**359,028**	**366,433**	**378,294**	**389,643**
% of Global Capacity			0.3%	0.3%	0.4%	0.5%	0.3%	1.4%	2.3%

Source: Citi Investment Research and Analysis, Company Reports, CMAI

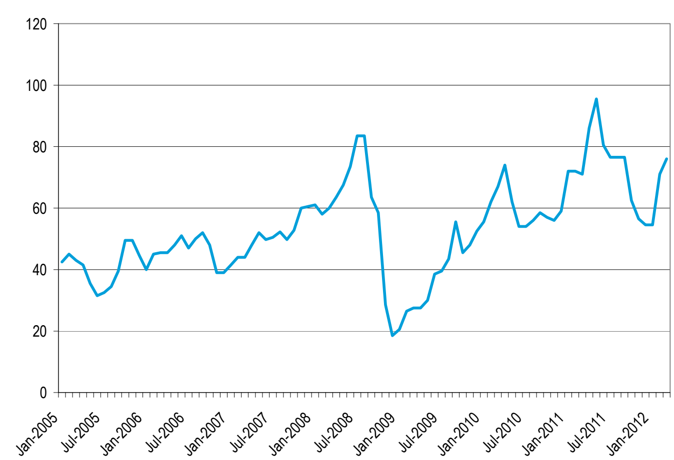
An ethylene feedstock advantage is also supporting high utilization rates for US producers due to advantaged exports. The US currently exports ~20% of polyethylene (PE) production and nearly 40% of PVC production. The chlor-alkali production process is very energy intensive and US producers benefit from lower power costs due to cheaper gas. The US export window to ethylene short regions like Latin America is expected to remain open. Although the industry has yet to see a dearth of new PE project announcements, we think future PE capacity expansions are likely.

Figure 37. US Ethylene Nameplate Operating Rate



Source: Citi Investment Research and Analysis, CMAI

Figure 38. Contract US Propylene Prices, cents per pound



Source: Citi Investment Research and Analysis, CMAI

Increased ethane cracking in the ethylene industry has limited the production of co-products like propylene and butadiene, which are produced in greater quantities from heavier feedstocks like naphtha. As a result, prices for co-products such as propylene have increased considerably over the past three years, sparking interest in on-purpose production facilities. For example, Dow Chemical plans to build two on-purpose propylene plants (propane to propylene) on the Gulf Coast for startup in 2015 and 2018. Similarly, LyondellBasell is expanding propylene capacity at one of its ethylene crackers to take advantage of a short propylene market in the US.

Cheaper natural gas has also made US methanol production more economical. Consequently, Canadian methanol producer Methanex recently announced plans to relocate an existing methanol plant from Chile to the US Gulf Coast in 2014. Next year LyondellBasell plans to restart a methanol plant on the Gulf Coast that was idled in 2003 because of high natural gas prices.

Fertilizer manufacturers, particularly ammonia producers, are also mobilizing to take advantage of cheaper natural gas. Approximately 85% of the cash cost of producing ammonia is based on natural gas prices. As a result, Potash Corp is restarting an idled ammonia plant on the US Gulf Coast and is also expanding two other existing ammonia plants.

(3) Rising demand in the residential and commercial sector

Fuel-switching and reduced vacancy rates could drive further demand in the residential and commercial sector

Demand in the residential and commercial sector could rise beyond its long-run growth rate as a result of fuel-switching and the reduction in vacancy rates. Given the large swing in seasonal demand in the sector, any structural increase would also boost the peak demand for gas.

Similar in concept to the fuel switching in the power generation sector, natural gas as a home heating fuel has become more economic than heating oil since the fall in gas prices in 2009. Replacing a boiler using heating oil with one that uses natural gas could reach breakeven in just a few years as a result of low fuel costs. Utilities are offering incentives to consumers for replacements, while a modification in the home heating oil specification from high sulfur to low sulfur is also motivating the change. That's because ultra low sulfur diesel is harder to make than currently higher sulfur heating oil and should raise home heating bills sharply. Some regions with a lack of access to gas pipelines previously could be connected to the gas supply network as infrastructure improves, enabling further gains in natural gas demand.

A reduction in vacancy rates in both residential and commercial buildings could increase demand further. As the housing overhang is worked off, space heating and cooling needs should rise from the minimum level. The minimum could be a nominal demand level that prevents damage to the structure and piping of a well-maintained building, or the minimum could be zero demand for buildings that have been off the market for so long that all heat, water and power have been shut off. The reoccupation of these vacant units would push demand back up to normal demand levels rapidly.

Further, as the housing market improves and the backlog of vacant homes and offices is worked off, the spur in construction activities would not only increase construction-related energy demand, including natural gas, but also raise the number of natural-gas consuming devices installed in new buildings. The improved availability and relatively lower cost of natural gas could shift consumer choices to gas from other fuels. This demand increase would be structural and long-lasting, as a replacement of these devices would require overcoming the cost hurdle and the "hassle" factor.

(4) LNG exports

As North America becomes a burgeoning hydrocarbon exporter, LNG exports could play a significant role

Other incremental gains would come from LNG exports, but the implications are transformational, both domestically and globally. North America could act as the swing supplier due to its proximity to Europe, South America and Asia. Further, if the wide price discount between gas in the US and overseas were to persist, then the US could maintain its re-found role as a base-load gas exporter. Gas exports from Alaska, shut down a year ago, are now resuming, and total gas exports from the continental US could perhaps rise to as much as 5-Bcf/d by the end of the decade, although some 15-Bcf/d of export terminals are now being planned. Regulatory scrutiny and pressure from special interests that desire to keep gas prices low in the US could present hurdles in the approval of more terminals. Liquefaction terminals on the west coast of Canada, principally at Kitimat, British Columbia, would draw on gas reserves in northeastern BC and western Alberta to supply the Pacific Basin market. In addition, as noted above, LNG exports from Alaska could move beyond its small Kenai facility and could provide between 2- and 4-Bcf/d of gas sourced from the North Slope – the same gas originally slated for shipment to the Lower 48 States. In all, North America could indeed be in an enviable position as a gas export hub due to its location and abundance in gas reserves. Below we briefly survey the LNG market in Asia, South America and Europe, as well as developments of LNG export terminals in the US

with strong demand likely to continue and grow in Asia

Much stronger recent demand growth in Asia amid tight supply could keep prices closer to oil parity for a longer period than once expected, and this wide and potentially persistent price differential between Asian gas prices with North America would make US Gulf Coast exports of gas to Asia competitive. Demand growth from China and India is already happening, on top of the steady demand from long-standing importers, such as South Korea and Taiwan. These demand gains are expected to far outpace supply growth in the region in the next few years. Chinese demand is growing at a rate of 3-Bcf/d year-on-year – a goal derived from the country's 12th Five Year plan. Elsewhere in Asia, Thailand is also expected to increase its gas imports, while traditional gas exporters, such as Indonesia and Malaysia, are resorting to gas imports to satisfy domestic needs, even when they continue to honor LNG export contracts.

although later in the decade, Australian, East African and other supplies could begin to catch up

Gas supply could start catching up to demand only in the later part of the decade, starting when Australian LNG projects start coming online. Other supply sources, such as turning massive new East African gas discoveries into LNG exports to Asia, could add to supply in a similar timeframe. Gas exports from Alaska, Canada and the continental US would also materialize in about the same period (post-2015), possibly easing the tightness in the Asian LNG market.

Japan's increased LNG demand should continue while its nuclear sector remains challenged beyond the short term

Although the impact of the Fukushima nuclear accident in March 2011 is long-lasting and global, its immediate impact was to quickly tighten the previously loose global LNG supply-demand balance. To put it into perspective, within Japan (the largest LNG importer by far), imports of LNG in January 2012 rose by 28.5% year-on-year to 8.15 metric tons, or 12.5-Bcf/d, even though average temperatures were about same year-on-year at 41F. Demand could rise by 3-Bcf/d in 2012 on top of its average demand of 9.2-Bcf/d in 2010 for as long as nuclear units are offline. Japan was highly reliant on nuclear for power generation and operated its 49GW nuclear fleet at just under 70% utilization. But with Kansai electric bringing its Takahama facility offline at the beginning of 2012, operating nuclear capacity fell to just over 2GW nationally. Local opposition to any restarts and the extended period needed for inspection before any potential repowering of nuclear plants could mean that this elevated demand will persist. The loss of nuclear entirely would effectively translate into a need to replace more than 30GW of nuclear generation.

Assuming the 7% decline in power demand in the rest of 2011 after the earthquake stays in place, Japan would still require just over 20GW of generation capacity to fill the gap left by nuclear. If 70% of this generation is replaced by gas, then this implies that 3-Bcf/d of natural gas could be needed to satisfy this fuel demand. Economic recovery and power demand growth would have to be offset in part by conservation and generation from other fuels, otherwise gas demand would continue to rise.

Globally, the once-expected nuclear renaissance has failed to materialize in many developed countries in the aftermath of the Fukushima accident, while developing countries are carefully reconsidering their planned build-out of nuclear power units. Germany decided to phase out nuclear generation yet again after a reversal only a few years earlier. The promise of clean energy from nuclear sources was clouded by the accident resulting in other nations either slowing or halting their nuclear build-out. With coal both high in price and in emissions, and renewables still being developed, gas has become the cleaner fuel of choice for power generation.

Australian LNG exports beginning mid-decade could remain less competitive relative to North American LNG from the Gulf Coast

By the middle of the decade, LNG exports principally from northwestern Australia could finally come online to supply the market, but the cost escalation being seen in Australian LNG projects does affect their competitiveness. Some analysts think that breakeven prices could reach $12/MMBtu or more, or at a slope of 0.145 on $80/bbl Brent oil prices. In contrast, North American LNG from the Gulf Coast, priced at $4 to $6/MMBtu at Henry Hub, would be very competitive at between $10 and $12.9/MMBtu delivered to Asia. In fact, two of the four foundation customers of Cheniere Energy's Sabine Pass liquefaction terminal are GAIL of India and Kogas of South Korea. The latter is known for being very conservative in signing long-term contracts satisfying its baseload gas requirements. Both companies also appear to want North American supply with a link to Henry Hub (US) prices in order to pressure traditional suppliers to move away from the traditional link to oil prices.

Using the BG-Cheniere deal as an example, project economics for Sabine Pass – and for other North American LNG export projects – are based on the current low US feed stock gas price delivered at the liquefaction plant. With liquefaction costs of about $2.25/MMBtu, a fuel surcharge to fuel the liquefaction of about 15% of the underlying gas prices in the $4 to $6/MMBtu range, and transport costs of about $1.0 to 1.5/MMBtu, breakeven economics require a price of $7.85 or higher delivered to Europe. With transport costs more than $2 higher to Asia, the delivered breakeven for Asia is $10.10 on a $4 US gas price.

Figure 39. Estimated Cost of Delivered LNG to Europe and Asia from Cheniere's Sabine Pass Project

	Europe		Asia	
($/MMBtu)	**Low**	**High**	**Low**	**High**
Henry Hub Gas	4.00	6.00	4.00	6.00
Fuel (15%)	0.60	0.90	0.60	0.90
Liquefaction	2.25	2.25	2.25	2.25
Shipping	1.00	1.50	3.25	3.75
Delivered Cost	7.85	10.65	10.10	12.90
Equivalent to the Austrian LNG procured at JCC price (USD/bbl) of			66	85

Source: Cheniere, Oil and Gas Journal, Citi Investment Research and Analysis

Domestic impediments in the development of South America's own substantial gas resources should mean North American gas exports remain attractive

Gas demand growth in South America should also remain robust, making North American gas exports appealing there as well. Offsetting peak demand periods between North and South America allows lower cost gas to meet peak winter demand in South America. Regulatory impediments that discourage indigenous gas production in South America could continue to support robust growth of gas imports into the area, particularly into gas-rich Argentina. Price intervention by governments, by keeping prices low, encourages demand growth but disincentivizes upstream development, despite large reserves in Venezuela and Brazil, as well as discoveries of shale gas resources in Argentina, for example. The growth of power generation also adds to gas demand. Hydropower supplies over 50% of electricity in the region, but new power demand is being met by gas. Nevertheless, if price controls were relaxed and upstream activities rose later in the decade, importing gas from North America would lose some of its appeal.

North American gas exports are appealing compared to oil-indexed Russian gas, but further Gazprom developments could challenge the economics of US LNG exports to Europe

Exports to Europe, based on netbacks from National Balancing Point, or NBP, prices, a benchmark price in Northwest Europe, may not be the most attractive. But North American exports would be appealing compared with Russian gas sold at oil-indexed prices especially on a spot basis. Yet, as Gazprom develops its Yamal Peninsula and a possible Southern Corridor bringing gas from Azerbaijan via Turkey, perhaps by 2017, these supply increases could threaten the economics of US LNG supply to Europe, especially if it results in lower European natural gas prices at a time when US gas prices rise.

US East Coast LNG exports would benefit from proximity to the Marcellus and Europe

Besides Gulf Coast LNG terminals, East Coast LNG exports, perhaps at Cove Point in the Mid-Atlantic region of the US, could take advantage of its proximity to the Marcellus, one of the largest gas fields globally, and the shorter distance to Europe than exporting from the Gulf of Mexico. A liquefaction terminal on the East Coast would have a more direct impact on forming a natural gas highway between Europe and North America. Previously, the Trans-Atlantic LNG bridge was provided by LNG cargoes coming from Africa, the Caribbean or the Middle East, where the East Coast of the US or Northwest Europe would compete for spot cargoes depending on their respective demand needs. However, with the advent of the shale gas boom, the U.S could have the ability to ship gas to Europe from the East Coast, constituting a link between the two regions.

though the West Coast could face greater political opposition

Terminals on the West Coast could face more political and grassroots opposition even if current drilling restrictions in California are overcome. Less probable is the building of pipelines transporting gas to the edge of the Pacific Ocean. Current pipeline networks would have to be extended and expanded to the coast, though such development might affect environmentally fragile areas, again potentially subject to opposition.

If one standard LNG liquefaction train comes online every year, this could entail about a 0.5-Bcf/d demand increase annually starting in 2015, assuming that utilization is under 100% throughout the year due to periodic maintenance of the liquefaction train. However, LNG exports are also subject to political pressure induced by competing industries that use gas as fuels or feedstock. Political opposition and pressure from some industrial segments that benefit from low natural gas prices could limit the number of export terminals approved. We examine in detail those issues in the section on regulatory risk.

Cheniere's Sabine Pass terminal in Louisiana is the farthest along of all LNG export terminal projects

Of the six liquefaction terminals in the continental US that are in the planning process, Cheniere Energy's Sabine Pass terminal in Louisiana has already signed up four foundation customers — the farthest along of all LNG export terminal projects. The first two customers, BG and Gas Natural Fenosa, are global midstream players that supply gas by arbitraging price differentials between locations. Freeport LNG in Texas might not be far behind. Figure 40 lists other terminals under consideration.

Figure 40. Operating, planned or proposed LNG liquefaction terminals

Project	Companies	Location	Capacity mtpa	Capacity Bcf/d	Year
Canada					
Kitimat	Apache/EOG/EnCana	Kitimat, BC	10.0	1.3	2015
BC LNG	LNG Partners/Haisla	Kitimat, BC	1.8	0.2	
Kitimat LNG Exports	Kogas/Mitsubishi/CNPC/ Shell	Kitimat, BC	13.8	1.8	
Progress/Petronas	Petronas/Progress Energy	BC	7.4	1.0	
Prince Rupert	BG				
US					
Cove Point Export	Dominion	Lusby, MD	7.8	1.0	2016
Cameron LNG Export	Sempra	Hackberry, LA	13.1	1.7	
Freeport LNG Export	Freeport/Macquarie	Freeport, TX	21.5	2.8	2016
Gulf Coast LNG Export	Gulf Coast LNG	Brownsville, TX	21.5	2.8	
Sabine Pass Export	Cheniere	Cameron, LA	16.0	2.1	2015
Corpus Christi Export	Cheniere	Corpus Christi, TX	14.0	1.8	
Kenai LNG	ConocoPhillips	Kenai, AK	1.5	0.2	1969
Lefthand Bay	Shell	AK			
North Slope Gas	Alaska Gasline Port Authority	Valdez, AK			
Total			**129.1**	**16.8**	

Source: Platts, Citi Investment Research and Analysis

(5) Natural Gas Vehicles

The wildcard could be surprisingly strong gas demand from natural gas vehicles, driven first by conversion of fleet vehicles

Natural Gas Vehicles (NGVs) could be the wildcard that provides a surprisingly strong boost to gas demand. The market share of NGVs, primarily as a substitute for diesel-burning heavy duty trucks or other bus fleets, could rise to 1% in the initial year, but escalate by 3% in market share each year by the middle of the decade as retrofits and new sales of NGVs accelerate. By 2015, NGVs could have 9% of the market share, representing a small 0.2-m b/d of diesel demand in the heavy duty truck segment, yet the energy conversion could put gas demand at about 1.1-Bcf/d in 2015. As the infrastructure becomes more developed later in the decade, it is possible that, at growth rates mentioned above, gas demand could reach 3.3-Bcf/d, substituting 0.57-m b/d of diesel.

which enjoy several technological and price advantages over electric vehicles

One of the appealing features of NGVs is the ability to use conventional spark-ignited (for gasoline) or compression-ignited (for diesel) engines, subject to some modifications, unlike electric-vehicles (EVs). In EVs, battery technology remains the costliest component, as well as the most significant technological and infrastructure hurdle. NGVs can be powered by either compressed natural gas (CNG) or liquefied natural gas (LNG)[8], both of which cost less than gasoline. Based on Clean Energy Fuel's calculations[9], fuel costs could be reduced by more than 40%, where the cost of CNG would be about $2.32/gallon, comparable to $4.05/gallon's worth of diesel. Natural gas' more homogenous composition, with fewer impurities such as sulfur as in petroleum-based fuels, would translate into less engine corrosion and maintenance, lowering the operating cost of a vehicle as well.

[8] CNG is made by compressing natural gas at high pressure (3600psi) to less than 1% of its volume. Gas is used directly in spark-ignited or diesel engines. LNG is made by condensing natural gas to liquid form at -260F, or -162C, reducing its volume to about 1/600th of its size at normal temperature and pressure. LNG is stored in double-walled stainless steel tanks. LNG is vaporized before injection into engines.

[9] From the website of Clean Energy

Hurdles remain, but they are mainly a market sizing issue that happens to have favorable economics on its back, rather than technological issues that require breakthroughs at an uncertain time. The market sizing issue is mainly a chicken-and-egg problem of needing more refueling stations for NGVs to proliferate, while more NGVs have to be on the road to justify more refueling stations. There are about 1000 CNG refueling stations across continental US, and 80 in Canada, but only about half are open to public. Home installation of refueling kits could cost several thousand dollars.

In light of the cost competitiveness of natural gas as a transport fuel and its possible emergence as a dominant alternative, firms along the value chain of NGVs are getting involved more actively, including major consumers, car makers, infrastructure providers, gas producers and conglomerates:

Already, shipping companies and municipal buses are adopting natural gas vehicles into their fleets

Shipping companies with dedicated depots are converting their vehicle fleets to natural gas, such as UPS and DHL and a rapidly expanding their medium-haul distribution networks. Municipal buses are also early adopters of natural gas as a fuel.

- Navistar and Clean Energy Fuels (CLNE) announced a joint venture offering natural gas-powered trucks and a rollout of refueling infrastructure. Navistar, a manufacturer of trucks and diesel engines, would sell CNG or LNG-powered heavy duty vehicles and service them through its network of dealerships; CLNE would build out a natural gas refueling network. In the first phase, it plans to build 150 LNG fueling stations, where 98 sites have been identified and 70 could begin operating by the end of 2012. It has already just about that many fueling stations in China.
- Natural gas producers, such as Apache and Chesapeake Energy, are turning over part of their vehicle fleet to use natural gas and are active supporters of NGV venture companies. Even the light and medium duty truck segment could be developed, not just heavy duty trucks.
- GM and Chrysler announced in March 2012 their planned roll-out of natural-gas powered pickup trucks by mid-2012.
- General Electric and Chesapeake Energy announced in an agreement that GE would provide more than 250 modular compression stations in 2H'12

Canadian gas production

Meanwhile, Canada could see its gas glut relieved mid-decade, allowing production to reverse declines

The overall Canadian gas production decline could continue until the middle of the decade, before LNG terminals at Kitimat, British Columbia could come online in 2015 to relieve the gas glut in Western Canada. A gas glut in Western Canada, the dominant producing region where over 97% of the gas is produced in the country, would constrain production growth to match demand growth, unless and until gas export terminals are developed, and when US demand exhibits the strong growth starting in the middle of the decade. The much tighter balance in the latter half of the decade could help gas production rise by 4 to 6-Bcf/d between now and 2020. Three major drivers contribute to the level of Canadian gas production: domestic demand, particularly with oil-sands processing being a growth driver; US gas supply/demand, especially with the shale gas boom backing up the gas that the US traditionally imports from Canada, similarly causing a gas glut in Western Canada; and LNG exports as a major relief valve of this glut. The steady decline in drilling activities at conventional gas plays has been evident since the latter half of last decade. With the shale gas boom in the US stranding gas supply in Western Canada, as well as Canada's own shale gas discoveries at the Horn River and Montney shales in northeast British Columbia and western Alberta, conventional gas production is squeezed and the decline would continue. Substituting this conventional decline is the development of shale gas resources.

Strong US natural gas production growth has pushed out Canadian gas, but mid-decade demand resurgence and gas export would relieve the gas glut

With strong production from US shales and associated gas production from liquids-producing wells, net exports of Canadian gas to the US have fallen from nearly 10-Bcf/d in early 2000s, to 7-Bcf/d in 2010 and an estimated 5- to 5.5-Bcf/d in 2012. Low gas prices that have plagued the US market, along with Canadian gas that is supposed to be exported getting backed up to Alberta or BC, have combined to force Canadian gas prices at the benchmark AECO hub in Alberta to below \$2.0/MMBtu in early 2012. But demand, excluding LNG exports, is only expected to rise by about 0.3- to 0.4-Bcf/d per year due to a combination of population and economic growth (which contribute about 0.1-Bcf/d per year on average) as well as gas demand for oil sands processing (contributing at between 0.2- to 0.3-Bcf/d). The decline in pipeline gas exports to the US has so far outpaced the rise in domestic Canadian demand such that Canadian gas is stranded. The resulting low prices are discouraging production. The Kitimat LNG export terminal, with a capacity of 10 million metric tons per annum (mtpa), or 1.3-Bcf/d, could help to relieve the gas glut. Thereafter, production growth would track the growth of Canadian LNG exports (when other liquefaction terminals come online), domestic demand increases and the tightening supply-demand balance in the US.

What factors could change the production trajectory?

The level of gas production is likely to be determined by: (1) the level of drilling activities using rig counts as proxies, (2) the proportion of dry gas coming out of “liquids” producing wells, and (3) the decline rate of existing production.

Although rig counts are hard to predict, expect rigs to be allocated away from dry gas plays to liquids-rich plays

It is difficult to predict where the rig count could be in most situations, let alone where the rig count might be in a number of years into the future, given ongoing changes in technology and the economics of drilling and production. But it is expected that for the next couple of years producers will continue to favor allocating capital to liquids-rich plays due to their superior economics over dry gas plays, unless and until futures prices rise back toward \$5/MMBtu. Structurally higher demand could drive this price rise, eliminating some of the coal-to-gas switching. The ability to allocate capital across the oil and gas spectrum could be the balancing mechanism that keeps gas production from surging again, where low gas prices would yet again motivate producers to flee gas drilling for oil/liquids drilling.

while mature shale gas plays see the drilling-to-production process become more akin to a manufacturing process, given better known geology and learning-by-doing

More mature shale gas plays, such as Haynesville, Fayetteville, Barnett and others, would continue to produce. The probability of hitting dry holes in the shale era is much lower, since drilling is targeted at the source rock and that geology became much better-known after the first sets of wells were drilled. As such, with a higher degree of certainty, the process from drilling to production has become more like a manufacturing process as drilling rigs and fracturing crew/equipment are deployed.

The volumes of associated gas from liquids-rich plays are an important contributor to production growth

The next driver of dry gas production is coming from associated gas production from liquids plays. These are by no means minor. On aggregate, associated gas production could constitute 40 to 50% of hydrocarbon production from these liquids-producing wells. Indeed, in Chesapeake Energy’s investor presentation, its forecast of associated gas production out to 2020 makes up about 40 to 50% of its hydrocarbon production from liquids-producing wells. In line with the rise of natural gas liquids of 1.5-m b/d by 2020, as in our projection in the oil section, associated gas production could rise by about 6- to 7-Bcf/d between now and 2020.

while decline rates see a flattening out without a sharp fall below the economic limit, although reworking or refracturing may be needed to boost or sustain production, with associated additional costs

Finally, the decline rate could determine whether production indeed flattens out in the out years, so that not much new production would be needed to replace declines, or whether production would continue to fall sharply so as to make existing shale gas production uneconomic. If this is the case, much new drilling would be needed to fill the gap left by production decline. At the moment, history provides us clues to the decline profile of shale gas. Vertical shale gas wells taking gas from the Devonian shale have been producing gas for over 50 years, with a relatively flat production profile after the initial decline. However, this shale was not subject to the type of hydraulic fracturing as has been the case over the past few years. More recently, many shale gas wells in the Barnett have also been producing since in the mid-2000s, and the production decline has also flattened out without a sharp fall to below the economic limit. Given how production at other plays are still relatively new, longer-term production data would be needed to give us more of a clue, but so far the production history from longer-producing wells point to steadier production later in a shale well's life. Nevertheless, wells may have to be reworked or re-fractured to boost or sustain production, which also involves the added cost for the process. The cost that would have to be amortized over the life of the well would increase the breakeven production cost.

And Alaskan gas could see production growth driven by LNG export demand

In Alaska, production growth could reach 2-Bcf/d or as much as 4-Bcf/d between now and 2020, driven by LNG export demand. Previous proposals of moving the stranded gas in the North Slope in Alaska via the Alaska gas pipeline down to Canada and the Lower 48 states would have unlocked the 4-Bcf/d of production potential, but the high cost of building the pipeline, sizable tariffs involved in transporting the gas and the subsequent boom in shale gas production made these proposals uneconomic. Instead, if gas prices in Asia remain elevated and close to oil parity despite new LNG supplies coming online in Australia and later in East Africa, this new source of Alaskan LNG would be economic, even though new gas pipelines would have to be built from the North Slope to southern Alaska. However, the uncertainty lies partly in the timeline to get projects off the ground. To get an LNG liquefaction facility built, various stages of planning, regulatory approvals, environmental assessments, negotiations with import entities overseas, front-end engineering design and final investment decisions could take a number of years. Constructing a pipeline from the North Slope to the southern coast of Alaska, say Valdez, at over 800 miles away over difficult terrain, could involve the most time and resources. Construction of a new pipeline and liquefaction terminal could take 4 to 6 years, in addition to time spent on pre-approvals, planning and contract negotiations with importers. Taken together, an export terminal might become ready in the early part of next decade, but could be earlier. Completion could come in phases, instead of having multiple trains all at once.

Could the Marcellus be the next price benchmark?

The Marcellus is well positioned to become a parallel gas price benchmark, given its low cost and closeness to supply and demand centers

If Marcellus production were to keep increasing, given its vast resource base, low cost and proximity to major demand centers in the US, could a separate gas price benchmark emerge, in parallel with the traditional Henry Hub benchmark in Louisiana? It is an idea that has been advanced in the industry, including by Michelle Foss at the University of Texas, Austin[10]. This would be similar to what has happened in the oil market, where Brent, West Texas Intermediate (WTI), Dubai, Urals and, to a lesser extent, Cinta have come to define benchmark oil prices in Europe, North America, Middle East, Former Soviet Union and Southeast Asia, respectively. And in the US and Canada in any event there are already other pricing hubs, including AECO in Canada.

It can reach major Northeast demand centers, though new pipeline infrastructure development could be crucial

The Marcellus region occupies prime real estate in the overall gas supply geography. Its proximity to major Northeast demand centers certainly gives it an advantage in reaching historically higher premium markets of New York, Philadelphia, Washington, DC and Boston and nearby areas. However, contingent on the development of more pipeline infrastructure to debottleneck production, the sizeable gas production from the Marcellus may finally bring down prices in these locations in ways that would link prices in the Northeast to price points beyond the US. Marcellus production growth already displaces imports from Canada into New York, with a re-routing of gas into Eastern Canada bringing gas prices in the region under the sphere of influence of the Marcellus. Further pipeline development could break through to New England, the last region in the US that has been remained outside of the gas glut, with a history of heavy reliance on LNG.

And LNG exports to Europe could form closer linkages with the NBP price hub

Most important, LNG export terminals perhaps at Cove Point in Maryland, and other locations along the Northeast, could bring Marcellus gas to Europe, forming a bilateral price link between the Northeastern US and Northwest Europe, where NBP is the price hub. It is almost akin to the development of the Interconnector pipeline between the UK and Belgium. The Interconnector was instrumental in bringing gas, as well as the price impact of UK's NBP, to continental Europe. Similarly, with LNG exports from the Marcellus, although the distance would be much greater, the price signal established in the US Northeast could be transmitted more rapidly to Europe. The ability for US LNG exports to respond to expected demand increases or decreases in Europe within days, rather than weeks as with Middle Eastern LNG, could be the key in forming closer linkages between Trans-Atlantic gas prices.

[10] "The Outlook for U.S. Gas Prices in 2020: Henry Hub at $3 or $10", Michelle Michot Foss, PhD, December 2020, Oxford Institute for Energy Studies.

Yes, But
Politics and Policies Look Likely to Point to Second-Best Solutions

The complex and integrated nature of natural resource development makes it an area especially rife for politics that can both serve to buttress as well as challenge its growth. Whilst the story of North American 'energy independence' is one of incredible potential and possibility that could alter the geopolitical landscape from the Middle East to the Mid-Continent — public policy might well be the most critical factor in determining whether the current steep supply trajectory remains robust for many decades to come or if it fizzles out; trumping both technology and geology.

Rampant hydrocarbon production growth brings up a myriad of political obstacles, with political trade-offs hotly contested between bitter rivals

The myriad of policy implications relating to hydrocarbon production growth involve entrenched political trade-offs that have the potential to significantly slow if not halt the development of deepwater wellheads, tar sands, tight oil, and NGL supplies that could otherwise nearly double to almost 27-m b/d in the next decade. For example, Canada could see over 3-m b/d of growth impeded by the geopolitics of pipeline development, environmental policy and resource nationalism. The US faces these same obstacles in addition to perhaps even more deeply rooted environmental concerns and interstate politics. Mexico, too, could risk little flexibility on constitutional change, hence limiting output growth of Pemex shale and deepwater plays to perhaps 50% or even less of their potential.

United States

The politics of energy are front and center in a year full of key elections worldwide, not least the one in the US

In a year chock full of key elections across the OECD and developing world with four of the five UN Security Council member states potentially incurring a leadership change, perhaps none will be as closely watched as that for the presidency of the United States. And the politics of energy are already front and center on the campaign trail and within the White House. To be sure, President Obama made it a focal point of his State of the Union speech this year when citing the importance of American 'energy security' and lauding the '100 year supply' of natural gas in the US that could potentially 'add 600,000 new jobs' over the next decade. But he also chided the country's dependence on oil and long-standing subsidies to the industry in the same address, calling for a 'comprehensive energy solution' and a doubling-down on a clean energy mandate. He has subsequently been more open in encouraging oil development and has come a long way from his anti oil-industry rhetoric following the Macondo well blowout disaster of April 2010. But the fact remains that active oil rig counts and domestic oil production have increased nearly every month President Obama has been in office; and behind the scenes policy actions (which generally look supportive for hydrocarbon extraction and development) might tell us more about the direction of US energy growth than campaign rhetoric.

with oil and gas tax breaks under siege

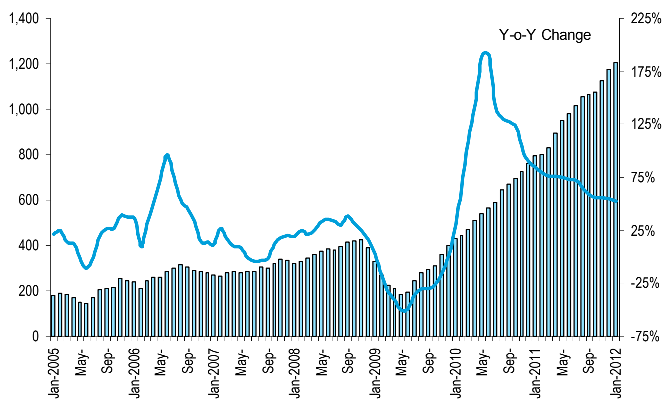
The Administration's 2013 budget proposal released on 13th February intends to unwind tax breaks for oil and gas companies including the elimination of certain write-offs for upstream E&P expenses and what the Administration considers wasteful and outdated energy subsidies while looking to increase funding for natural gas research. The White House budget office estimates it could raise nearly $40 billion in revenue over the next decade with the elimination of these tax treatments and has the support of the OECD, which is looking to reduce fossil fuel subsidies in G-20 members to curb GHG emissions by at least 10%.

But subsidy unwinds need not constitute a burden for a US industry with $1.7 trillion market cap and a nearly equal amount in annual revenue. Nor should the job creation and positive revenue implications of accelerated hydrocarbon development be ignored (see Assessing the Economic Consequences later in the report).

and regulatory and environmental concerns at the Federal and local levels

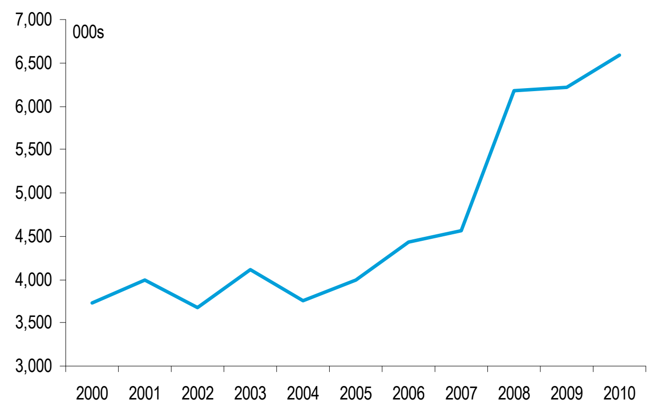
Rather, it is the potential of resource nationalism or regulatory/environmental (both federal and local) concerns that matter. With political gridlock in Washington precariously high, it remains unlikely that a comprehensive energy policy will be achieved in the near future. Industry and congressional opponents have already expressed disdain over White House plans. Thus, the intersection of politics and policy as related to US hydrocarbon production is likely to settle between 'Drill, Baby Drill' and 'Find Alternatives Now' and the political obstacles could loom larger for crude oil than they do for natural gas (although it could be just as well likely that politics are so entrenched that it becomes an either/or proposition, especially when considering the integrated nature of upstream exploration and production activity). And while the geopolitics of energy is typically an OPEC phenomenon, the politics driving North America's energy island and its crude glut are clearly local.

Figure 41. US Active Oil Rig Count



Source: Baker Hughes, Citi Investment Research and Analysis

Figure 42. US Employment in Oil/Gas Extraction and Pipeline Transportation Industries

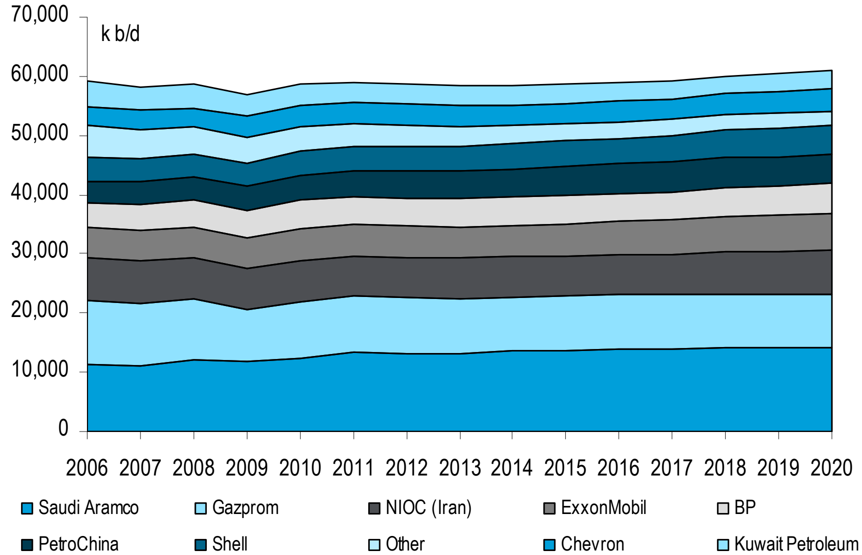


Source: Haver Analytics, Citi Investment Research and Analysis

Resource nationalism and environmental issues in the US

Resource nationalism is the first potential pitfall on the US road to energy development, albeit somewhat minor. In traditional political parlance, resource nationalism is the event where a sovereign would take control of natural resources within its borders for political and strategic reasons. This is particularly common in emerging market economies and OPEC nations where state-controlled NOCs dominate the means of energy production, exports and allocation; be it a net producer (i.e. Saudi Arabia) or a net importer (i.e. China). It can also come as a complete surprise to market players as it did in Venezuela in 2007, when a hostile state government crowded out private upstream entities such as ExxonMobil and ConocoPhillips, offering the two firms an ultimatum of either joining the Chavez government as a minority partner in the Orinoco basin or facing the threat of full nationalization of their local assets. More recently, it can be seen in mineral-rich African states including South Africa and Ghana, which are actively targeting foreign mining consortiums for a larger share of resource extraction profits or shared stakes. Although at first glance it would appear the US (with a privatized stable of IOCs and history of free market capitalism) should be immune to such centralized state control, there are more subtle 'nationalistic' political forces that could pose challenges to its energy exports and development.

Figure 43. Largest Global Oil and Gas Producer Entities



Source: Rystad UCube, Citi Investment Research and Analysis

Petrochemical, industrial and transportation sectors could increasingly look to block exports of natural gas to maintain an input cost advantage against global competitors

The two posits that could drive resource nationalism in the US relate to protecting domestic industries that are energy intensive and heavy natural resource users as well as national security interests. The first bucket would include the petro-chemical, industrial and transportation sectors that collectively make up nearly 15% of the S&P 500 market capitalization weighting. With 10% of US natural gas usage attributable directly to the chemical industry (industrial demand accounts for about a third of US natural gas consumption or more than 21-Bcf/d and chemicals account for about a third of industrial demand), it is no surprise that chemical companies have and would benefit from an energy glut in the US. But this should not appear to be a credible enough factor to stop supply exploration and perhaps would only pose a ‘don’t export’ threat in the future should domestic energy producers look to ship products to richer markets at the expense of local consumer supply (i.e. Asian markets, where the bulk of energy and raw material demand growth is projected over the next two decades). If, as we expect, there will be an increase in natural gas prices around mid-decade due to a surge in demand, there could well be tangible actions limiting LNG exports due to their implications for domestic prices.

while crude export controls and the Jones Act also pose constraints to crude oil moving abroad or between US ports, respectively

The second concern would be more immediate and pertinent to national security and the extent to which non-US flagged vessels would be allowed to ship out of the Gulf Coast and the extent to which the US would want to double-down on its resource ties with Canada. Already existing laws make it restrictive to export oil or gas produced in federal waters or on federal lands or shipped through pipelines laid under federally mandated rights of way. Canada is already the United States’ primary energy trading partner with the US importing nearly 2.9-m b/d in total petroleum from its northern neighbor, nearly double the 1.2-1.5-m b/d of daily intake from Saudi Arabia (often its second or third largest crude trading counterparty along with Mexico). With the US engaged in two wars in the greater Middle East until the recent troop withdrawals and exit strategies, the political benefits of curtailing America’s dependence on the region’s exports are politically clear although the concerns of importing ‘dirty’ Canadian oil may weigh on this trend.

And the numbers show that the US is already emerging as a major net refined product exporter

Evidence of America's energy emergence can be seen in the numbers. For the first time in over 60 years, the US was a net exporter of refined crude oil products in 2011 at around 420-k b/d. The EIA expects this trend to continue at net 350-k b/d in 2012 and net 320-k b/d in 2013 as the share of US demand for total liquid fuels coming from imports continues to shrink; a phenomenon that began in 2005. Thus the EIA projections look to be extremely low and product exports are likely to remain well above the 1-m b/d with which 2011 ended. With the technology already in place for efficient extraction, hydrocarbon supply in the US and West Canada is on a steady path to outpace domestic demand growth, perhaps leading to the US eventually becoming a net petroleum and LNG exporter, especially in light of a projected structural decline in gasoline consumption. Evacuating resources more efficiently within the US and to external markets thus seems inevitable from the investment and producer side of the ledger making the politics regarding marine transport and pipeline infrastructure good areas to examine energy politics in play.

Figure 44. Keystone Pipeline Proposed Extension

Source: Company filings

Pipeline infrastructure build out has been slowed or halted by US politics — not by technology or economics

With the robust growth of PADD II and West Canadian supply (North Dakota output up 60% y-o-y to 546-k b/d at the start of 2012 and perhaps targeting 1-m b/d by the middle of this decade), there is a clear need to evacuate output. With about 1.9-m b/d of pipeline capacity into Cushing, Oklahoma from US Gulf Coast (USGC) and about 1-m b/d from Cushing to the USGC (not yet taking into account the net impact of Seaway reversal of ~150-k b/d in 2Q'12), TransCanada's proposed 1,700 mile Keystone XL pipeline through the US heartland has made logistical sense to help reduce this congestion and build stronger strategic energy ties between the two countries. Notably enough, it was US politics not cost or technology that halted the $7 billion deal earlier this year.

Despite some environmental concerns in the North, polls throughout the process suggested three-quarters of Canadians are in favor of the project, which was heavily pushed by the Harper Administration. But a combination of environmental concerns of Keystone's path through the seven-state-linked Ogallala aquifer, and political gamesmanship in Washington between Congress and the President nixed the project on the US side, which remains open to resubmission but would require a further environmental impact study (EIS), likely pushing any approval well beyond this year's election. While initially supportive of the proposal, the White House and Department of State eventually balked when Republicans attached it as a rider to the payroll tax cut extension.

The approval of the Keystone XL pipeline project has been a particularly contested process

President Obama also faced sharp criticism from environmental groups, not just on the pipeline itself, but on the very concerns of importing any of Canada's 'dirty' oil. Recent statements have been revealing, with the Executive Director of the Sierra Club, one of the most prominent environmental groups in the US, noting " the effort to stop Keystone is part of a broader effort to stop the expansion of the tar sands it is based on choking off the ability to find markets for tar sands oil." The issue is also more complex than donkeys and elephants. To be sure, entrenched Democratic leadership in Montana was quite supportive while leading Republican policy makers in Nebraska opposed it. But TransCanada recently informed the US Department of State of its plan to file a new cross-border permit for Keystone XL from the Montana border to Steele City, Nebraska, with an alternate route through the state. A Cushing to USGC line would be built separately, due in 2H'13 perhaps at the earliest.

Pipeline infrastructure is central to American hydrocarbon development and is the cheapest way to transport crude. It also is the 'greenest' way to transfer hydrocarbons, especially with a US land link to Canada vis-à-vis receiving tanker shipments from abroad. While the specific case of a cross-border pipeline such as Keystone XL also had a 'national security' element that the White House could have used to push forward, it was the politics of environment in an election year that appears to have driven the decision. While the two-stage rerouted Keystone deal likely gets done by 2014, and the uncertainty surrounding it did help open up the Seaway reversal, it is clear US policies will need to support further infrastructure expansion for crude transport in light of growing domestic production. Stalling its expansion would greatly hinder new production growth and the possibility of increasing US exports of products, LNG and eventually crude, policy permitting.

Figure 45. Estimated Transportation Costs for Crude (Cushing to Gulf Coast)

	$/bbl
Truck	12-17
Rail	7-9
Barge	4-5
Pipeline	1-3

Source: Citi Investment Research and Analysis

The fact remains that several hundred thousand miles of pipeline already crisscross the US mid-continent, including side-by-side with Ogallala aquifer. While the original Keystone XL proposal would have been the first to run through the Nebraska Sand Hills, nearly 21,000 miles of natural gas and hazardous liquid pipelines already exist in Nebraska alone, according the PHMSA reports. With 'water protection' a clear concern for fracking of gas wells as well (see Natural Gas production section), protection of aquifers must be made in conjunction with new pipeline proposals in order to mollify environmental concerns.

Exports of crude of US origin would currently require a Presidential waiver, as any domestically produced oil passing through pipelines granted Federal right-of-way is restricted from export under the Minerals Leasing Act, and exports of deepwater Gulf of Mexico-produced oil are blocked under the Outer Continental Shelf Leasing Act. In both cases, a Presidential waiver is required before the Bureau of Industry and Security (BIS) at the Commerce Department may issue an export license. Again, this falls to a political process and is likely to be contentious and will pit loud political voices on each side of the divide.

The Jones Act, again, relates to this. The act is an early 20th century law that restricts the movement of cargo and goods between US ports to American 'flagged' vessels as a way to support US shipbuilding and the marine transport industry. Such cabotage laws are common throughout many countries although critics argue it can add significantly to the cost of shipping. Use of non-US flag vessels could cut nearly 50% of the non-Jones Act basis, from a Houston to New York shipment on a 300-k bbl cargo size to alleviate any gasoline shortage on the US East coast. Policies to reduce port congestion could also help as last year's strategic petroleum reserve (SPR) release showed the drawdown speed was in fact much slower at just over 700-k b/d at the most. Other times in the past — most notably after Hurricane Katrina during the first Gulf War, strategic petroleum reserves were released — and the US Maritime Administration waived this restriction for the oil and gas 'emergency', thus allowing a greater fleet to transport to the US East Coast. Further easing of the Jones Act and waivers as well as port expansion appear to be natural follow-on policies as more crude is evacuated from West Canada and Bakken through PADD II to the Texas and Louisiana Gulf Coast.

The Keystone XL controversy has often been portrayed as a binary choice between environmental protection on the one hand, and job creation on the other

Perhaps no other government agency has felt more political heat than the US Environmental Protection Agency (EPA), an organization the current opposition party simply labels a "jobs killer." Additionally, while hardly the most powerful lobby in Washington, environmental concerns typically ensure their voices are heard when it comes to critical decisions (e.g. Keystone XL). But while there are a slew of actual policy initiatives related to reducing US GHG emissions (and the current White House does have a penchant for renewable sources) on the whole, these largely voluntary bullets don't appear very restrictive for the oil and gas production side (rather, more immediate regulatory uncertainty concerns appear more impactful for power and utilities). Outside of the EPA, there are other agencies involved with carbon capture and tax incentive policies to reduce GHGs but these, too, seem benevolent although the emissions rule (discussed in the Natural Gas section) is likely the biggest factor in seeing if the demand side will pull supply. Additionally (and more relevant specific to production), the White House has supported several meaningful policies just this year including the historic deepwater drilling agreement with Mexico (see section on Mexico) and the Department of Interior's announcement of enhanced exploration in shallow waters of the Arctic this summer. Secretary Salazar noted earlier this month, "Alaska's energy resources — onshore and offshore, conventional and renewable — hold great promise and economic opportunity for the people of Alaska and across the nation" with the Administration asserting its support for safe and science-based exploration in the region.

Regulatory risks

The regulatory risks to shale gas and oil production largely relate to two key technologies

Technological improvements in a number of areas in petroleum engineering truly propel the growth of shale gas and oil production. But knowledge and experience over years of drilling have made such rapid growth possible.

Many years of vertical well drilling have provided geologists with a plethora of well-log data about the geology of various locations, enabling the rapid identification of areas with high probable and possible reserves, and providing some clues to the composition of hydrocarbons in the reservoir or source rock. Well-logging and various tests associated with rock and hydrocarbon identification remain key to finding areas with high original oil or gas in place. These are also the very same reasons that could make the production growth from shale rocks elsewhere in the world slower than the US, because of the relative lack of data on the underlying geological formation and hydrocarbon contents.

horizontal drilling and hydraulic fracturing

Horizontal drilling and fracturing processes are exhibiting further advancements, even when production has moved away from the "sweet-spots" of various plays. While horizontal drilling enables the well-bore greater exposure to the hydrocarbon-rich areas, or net pay, which are typically horizontal due to the sedimentary process, better placements put the well-bore more squarely in the middle of the net pay, enabling even better drainage of hydrocarbons from the rock formation.

and progress with multi-stage hydraulic fracturing methods as well as longer laterals is driving improved productivity

Focusing only on the number of fractures made, multi-stage hydraulic fracturing enables more micro-fractures to be created deeper in the shale. (We examine the water and emission issues related to shale drilling and fracturing below.) These fractures increase the flow rate of hydrocarbons into the well-bore, translating into high production. High initial production rates generally exhibited by these shale wells are partly a result of the steep pressure gradient between the shale down below and the ground on top. But fractures allow gas and oil molecules to flow more easily out of shale rocks, which in fact are source rocks of hydrocarbons that "feed" traditional, conventional oil and gas reservoirs made of the less densely packed sandstone.

Longer laterals, or well-bores extending deep into the shale, also increase the surface area exposed to the shale rich in oil and gas.

Figure 46. US EPA Short-term GHG Reduction Key Initiatives

Initiative	Objective
Clean Energy-Environment State Partnership	Voluntary - partnership with states to develop clean energy
Climate Leaders	Industry-government partnership to garner GHG reduction commitments
Combined Heat and Power (CHP) Partnership	Voluntary - reduce environmental impact of power gen
ENERGY STAR	Voluntary - labeling program to promote energy efficient products
EPA Office of Transportation and Air Quality Voluntary Programs	Improve air quality and pollution reduction including green vehicle guides and information packets
Green Power Partnership	Expand use of green power
High GWP Gas Voluntary Programs	Limit use of synthetic PFCs and HFCs
Methane Voluntary Programs	Collaboration between state, local and federal and US industries to deter methane emissions
WasteWise	Voluntary - efficient waste reduction and recycling programs

Source: EPA, Citi Investment Research and Analysis

Emissions

The hydrocarbon production process sees several sources of emissions

We can put hydrocarbons into three categories, loosely speaking, and look at their emission potential: (1) the hydrocarbon that remains in the rock formation, (2) the hydrocarbon that is extracted and burnt, and (3) the hydrocarbon that is leaked as fugitive emissions. For the first group, other than the portion that would flow into the wellbore and move above ground over time as part of the production process, the rest should remain in the rock formation and pose few emissions issues. For the second group, the full cycle emission would be considered, with much of the emission coming from the burning process that transforms potential energy into heat that heats the boiler and turns the steam turbine in a power plant. In this respect, combined cycle gas-fired generators are more efficient and emit about half the carbon as that of coal-fired units. However, despite the efficiency, the carbon dioxide would still be emitted into the air. This is what is meant by the contribution to atmospheric CO2 concentration. Hence, if the carbon emission target were to be set at a level that requires a larger cut than what the emission reduction brought on by gas units over coal could achieve, then somehow the excess carbon emission would have to go away. Maybe CCS is the answer; maybe not.

Hence, it depends on the emission target and when that target would have to be met — whether it is far enough away in the future. For the third group, the fugitive emission is something that is not transformed into energy but is instead released into the air. Capturing that would be key, given the outsized impact of methane in a 20-year GWP scenario, though less so in a 100-year GWP scenario.

An analysis of this issue by Professor Howarth of Cornell University drew substantial attention to the issue of methane leakages and other emissions related to shale gas drilling and production. His paper put emission from shale gas as greater than that from coal. However, research by scientists from US national laboratories back the conclusions that the full cycle emission from the use of shale gas is generally lower than the use of coal.

Finally, it appears that methane leakages from gas well completion and pipeline could be captured with simpler technologies. However, mitigating emissions from coal units would require Carbon Capture and Storage (CCS), which is not commercial yet in a large scale.

Regulatory risks to hydraulic fracturing: water

Water use in fracking is one of the key issues of contention, and has three main aspects — adequacy of water, disposal of waste water, and the integrity of aquifers

Hydraulic fracturing ("fracking"), or the use of pressurized water, sand and chemicals in order to 'fracture' deep underground shale formations in order to more easily access gas and fluids, has been around for six decades. But its enhanced use has let to a large policy debate on how safe the procedure is and if the energy benefits outweigh the costs. Three issues dominate discussion: the adequacy of water, the disposal of waste water, and the integrity of aquifers. This has led to an ongoing moratorium of fracking in New York State as well as calls for further oversight for a largely unregulated technology that (combined with horizontal drilling) has the ability to unlock US energy independence. One generally agreed issue is that best practices involving concrete funnels can protect aquifers when they surround the tubulars through which fracking fluids and extracted hydrocarbons flow.

The use of water in fracking remains relatively modest compared to other uses

On the whole, the use of water in fracking remains a modest proportion of water use compared to other industries such as agriculture. Nevertheless, fracking is a water-intensive process. The EPA estimates that 1.2 to 3.5 million gallons of water is used to frack a well, depending on the well type. As an example, the EPA's estimate for water used for gas production in the Barnett shale was estimated to be 9.5 billion gallons; 1.7% of the 554 billion gallons of freshwater demand in the area by all users. The agency also projects that Barnett shale groundwater use could increase from around 3% of total groundwater use today to 7-13% by 2025, thought this could be offset by a fall in number of wells completed over time. Emerging best practices in recycling water used for fracking could see the process become less water-intensive over time, although the efficacy of this technique also varies by geology of each shale play.

Figure 47. Estimated Water Needs for Fracking of Horizontal Wells at Various Shale Plays

Shale Play	Formation Depth (ft)	Porosity (%)	Organic Content (%)	Freshwater Depth (ft)	Fracturing Water (gal/well)
Barnett	6,500-8,500	5-Apr	4.5	1,200	2,300,000
Fayetteville	1,000-7,000	8-Feb	10-Apr	500	2,900,000
Haynesville	10,500-13,500	9-Aug	0.5-4	400	2,700,000
Marcellus	4,000-8,500	10	12-Mar	850	3,800,000

Source: EPA, Citi Investment Research and Analysis

Developing regulations on water in fracking comes down to two key areas — the chemical composition of fracking fluids, and the treatment of water

Hydraulic fracturing and water are at the center of a number of regulations, although, in a nutshell, it comes down to the chemical composition of hydraulic fracturing fluids, and treatment of water. Although a number of regulations and regulatory bodies, such as the Environmental Protection Agency (EPA), the Interior Department and various state governments, would be involved, it does appear that, without major accidents or environmental disasters happening, hydraulic fracturing would still go ahead and the industry does not expect a dramatic cost increase. The key point is that the EPA has assured states that it would not issue a moratorium. In addition, both the current Obama Administration and many in Congress do not oppose to hydraulic fracturing's role in developing this vast resource of oil and gas in shale rock.

Water is the very component in hydraulic fracturing that makes the current shale gas and oil boom possible by creating fractures in oil and gas-bearing shale rock thousands of feet below ground. Water is affected in the whole process: the vast amount of water drawn from underground aquifer or other surface water bodies, how the injection process works, impact of fracturing, leakages or spills of produced or flowback water to the ground after fracturing down in the formation, and the treatment of this water afterwards. Although other fracturing techniques, such as foam fracturing, propane and others are available, convenience and cost still seem to make hydraulic fracturing the dominant method for creating fractures in rock formations. As for water recycling, some of this fracturing fluid made of water would stay in the formation. In conventional hydrocarbon production, water drive or water flooding is used to push the oil or gas out, but some of the water stays behind. Hence, overall, rather than recycling 100% of the water pumped into the formation, recycling as much of the fluid coming back to the surface as possible would still be helpful in reducing water use.

The result of an EPA study on the impact of fracking on drinking water resources, which could see an initial report out in 2012, could have a significant impact on future regulations on fracking

The EPA is currently conducting a study on the impact of hydraulic fracturing on drinking water resources. Its conclusions could affect how the Administration and Congress draft other regulations on fracturing, how state and local governments in the US approach water issues related to oil and gas production, as well as the global response to this technique (given the expected details involved and how it would influence industry standards). An initial report would come out later in 2012, with another detailed report coming in 2014.

The treatment and disposal of waste water is key

Setting regulations on the treatment of waste water is key a part of the overall regulatory effort. Guidelines derived from the Clean Water Act set standards for discharges of industrial waste water based on Best Available Technologies, similar to emission regulations. A direct, on-site discharge of waste water from oil and gas production into waters of the United States is currently prohibited. Besides some form of recycling or reuse of this water in the injection process, water disposal is often sought. Water could be disposed in injection wells or into sewage treatment plants, depending on location, costs and state regulations. And risks are not just limited to underwater reservoirs and wells. Communities have also been impacted by 'above-ground' contamination from residual industrial activity, transport and storage. Opponents point to this tangential risk a direct causality of fracturing.

as well as the use of diesel and other chemicals in fracturing fluids

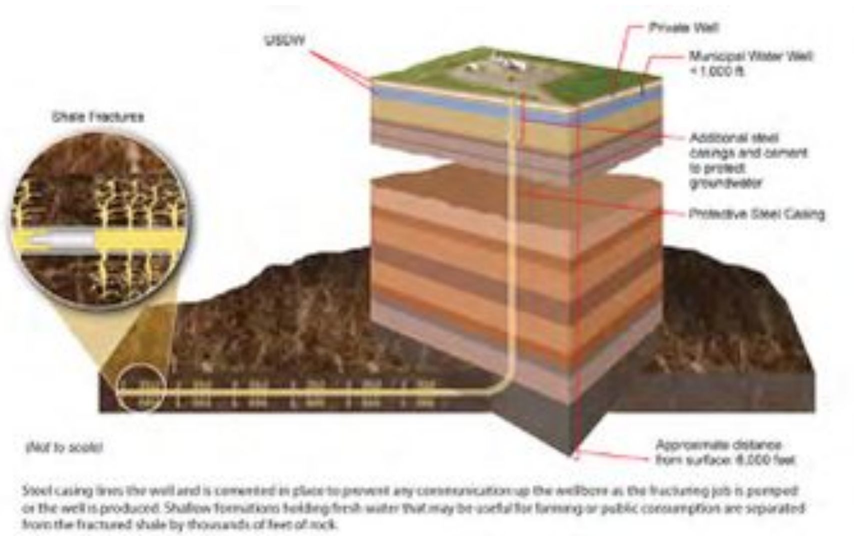
The interplay between two key parts of the regulation should be closely watched: the chemical composition of fracturing fluids and the siting of injection wells. The Underground Injection Control (UIC) program of the Safe Drinking Water Act (SDWA) regulates the siting, construction and operation of injection wells. Although the Energy Policy Act of 2005 did not include hydraulic fracturing for oil and gas production to require UIC permits, the use of diesel in the fracturing fluid is regulated by the EPA. At the center of the regulatory debate, it is the definition of diesel, which is used in many but not all fracturing fluids as a solvent additive. A broad definition, which includes BTEX compounds, or benzene, toluene, ethylbenzene and xylene, would give the EPA broad authority over hydraulic fracturing.

and the EPA could require companies to disclose the chemical composition of the fracture fluid — viewed by some in the industry as a trade secret

Further, EPA is beginning a ruling-making process, an authority granted under the Toxic Substances Control Act (TSCA). The EPA could require companies to disclose the chemical composition of the fracture fluid. Although a number of companies have begun disclosing the composition and advocated others in the industry to do so, the composition and making of the frack-fluid in determining its effectiveness is still viewed by some in the industry as a trade secret — similar in nature to how Coca Cola is made. An advance rule-making process should be announced later in 2012.

Besides the EPA, the Interior Department is also drafting regulations over hydraulic fracturing performed on public land. While it does not affect drilling and completion on private land, the proposed rule would present another step that the industry would have to comply.

Figure 48. Hydraulic Fracturing Schematic



Source: US Department of Energy, NETL

State level regulations on top of Federal regulations could add further to operating costs

Besides Federal regulations, new regulations from Pennsylvania, Ohio and West Virginia, among others, would add to the cost of operation. The governor of Pennsylvania recently signed into law in February, 2012, regulations where drillers have to pay local impact fees for each well drilled over the first 15 years of the life of the well. Proceeds of the fee, if imposed at the discretion of the local government, would go toward funding road repairs, environmental clean-up and plugging abandoned wells. The fee could range from $40,000 to $60,000 in the first year of the well, falling to about $5,000 to $10,000 in the final five years. Other compliance costs include about $100,000 per fracturing job, $30,000 for cementing per well and $0.15 to $0.25/gallon for waste water treatment. In addition, producers would have to follow guidelines on the disclosure of chemical compositions of fracturing fluids, air emissions from the well, in addition to well spacings and distance from water sources and buildings. Ohio's governor has also discussed the possibility of raising the severance tax of oil and gas and implementing an environmental impact fee. In addition, Ohio's Department of Natural Resources has halted the approval of new injection wells after earthquakes were detected that were believed to be related to waste water disposals into injection wells. West Virginia's governor likewise called a special session of the state's legislature to pass the Natural Gas Horizontal Wells Control Act, with provisions for local environmental impact fee.

Regulatory risks: seismic activity

Other than potential water (and air) contamination, seismic activity is another area of concern, seen as potentially linked to fracking, and disposal of waste water

Environmental assessments have pushed policymakers to focus on the two main risks: potential water (and air) contamination — both above and below ground — as well as seismic activity. Most recently, the US EPA found fracking to be the "likely" cause of water contamination in the small town of Pavillion, Wyoming. This news has been frequently touted by interests against the use or expansion of fracking. However, the EPA's multi-year study was not fully conclusive and unlikely to restrict activity although it opens up the door for new and updated regulations. A second regulatory report suggests a link between fracking and an earthquake in the Fayetteville shale play in Arkansas, as well as one in Ohio. Government regulations, including those proposed in California, are now beginning to target these issues through environmental standards and disclosure requirements on fracking fluids. Since the EPA may not legally impose water quality regulations on operators, they have instead suggested rules requiring "green" technology for wastewater and measures to control air pollution from the fracking process. This carries over to the spillover effect of industrial activity above ground. The Energy Institute of the University of Texas researched the Barnett, Marcellus and Haynesville plays and concluded in February this year that actual fracking of shale had no explicit connection to water contamination. The water, sand and chemical hybrids used in fracking are similar to those used in traditional drilling operations. The research echoed sentiment of the industry; citing contamination issues linked to spills on land, storage and jettisoning wastewater. The UT report was in stark contrast to the EPA studies released in late 2011 and critics have argued against the efficacy of such a report from an institute partially 'funded' by energy firms. But the public is what matters, and to lift fracking moratoriums and garner greater support, the industry and regulators must ensure clear mandates to keep the water system safe and to secure wells, storage and transport options above ground as well.

Regulations in California and New York

And regionally, regulations in California and New York could see major impacts on activity in the Monterey/Santos basin and the Marcellus shale, respectively

Regulation in California and New York is also a major factor influencing the pace of shale liquids production going forward in the Monterey/Santos basin and potentially oil sands imports in the former and gas well drilling in the Marcellus shale in the latter. The California bill for fracking legislation, proposed in February 2011 and which could pass this year or the next, calls for regulation of fracking by the DOGGR and disclosure of chemicals used in the fracking process, increasing reporting obligations on producers. Meanwhile, the California regulators' permitting process was slow through 2011, with only 14 of 199 applications granted by October, such that by the end of the year, the governor of California made leadership changes at the regulatory division with the build-up of the backlog of well and injection permits. As an offsetting factor to the pace of activity in Monterey, the glut in US midcontinent crude drove WTI to move to a discount to ANS-based California crude in March 2011, spurring further drilling. Initial attempts to curb the use of high carbon intensity crudes, too, might look to fade. Last December's California Air Resources Board (CARB) meeting to discuss the Low Carbon Fuel Standards (LCFS) regulation that targeted oil sands and 'dirtier' crudes is facing challenges that it exempts its own California heavy crude.

New York also remains a policy challenge, particular to gas supply with a moratorium on fracking still in effect; risk of water contamination is a major political issue for local communities, including the Governor's office. Such interests are discussing alternative energy and base load sources through high power transmission lines from Canadian plants. But with the dual concern of Indian Point (which provides about ~20% of New York's energy) and a moratorium on fracking, an overly active policy ban on such sources could see New York City and State energy needs unable to be efficiently met.

With over six million air-conditioning units in the city, lack of power generation (and the lack of smart grid system) could exacerbate the risk of rolling blackouts during peak demand. On the whole, anti-fracking sentiment in New York could put a damper on future growth and spread, where judges have upheld community bans on grass drilling and anti-fracking sentiment has become a part of the Occupy Wall Street movement.

Canada

Western Canadian oil sands production also faces potential future constraints from insufficient pipeline takeaway capacity, like the US midcontinent, but the major proposed project – Keystone XL – has faced significant opposition

The growth of oil sands production in West Canada shares an affinity to the Bakken phenomenon in needing evacuation routes. Indeed long before anyone dreamed of the extent of the supply surge from tight formations in the US, the flow of surging Canadian production emphasized the need for pipelines to be built to the US Gulf Coast. But with the State Department and Obama Administration's (temporary) 'veto' of Keystone XL to better connect supply cross-border to the US Gulf Coast, nationalistic pressures have risen in Canada to accelerate exit strategies to its Western Coast (notwithstanding TransCanada's most recent announcement). Indeed from the perspective of long-term netbacks for Canadian producers, it is now clear that taking advantage of demand growth in the Pacific Basin is far more important today than access to the US Gulf Coast market with dwindling US demand. But the Canadian permitting process remains onerous, including permitting reviews by various First Nations owning land rights and environmental objections about 'dirty crude' and the potential for spills in Vancouver and elsewhere in British Colombia. Such considerations are crucial to regional firms producing oil sands and cover a broad range of concerns from water use, waste, emissions and land use according to both independent sources and the Canadian Association of Petroleum Producers (CAPP).

Figure 49. Evacuation Routes West

Source: The Affairs of Canada, National Resources Canada

The Energy Policy Institute of Canada has recommended that the aboriginal consultation process would need to be revised in order to avoid project delays or nixed approvals – that sometimes arrive months into the analysis process currently. A step to ensure this would be to have the Crown more actively consult with locals prior to the permitting application process, setting strict timelines for a review. Additionally, better coordination among the state and provincial officials in dialogue with the Aboriginal Affairs and Northern Development (AANDC — a Canadian government department responsible for supporting aboriginal issues and statutes and legal protections) might help improve strained relations. CAPP has also looked to impose stricter standards on oil sands output and environmental impacts, including CO2 sequestration systems added on to processing plants, land reclamation initiatives (Syncrude Canada Ltd.'s Gateway Hill received a final reclamation certificate government — potentially the first of many) as well as water-use efficiency measures to reduce fresh water/bbl use through higher recycle rates and new technologies (Imperial Oil Resources' Cold Lake operation used 3.5bbl water per barrel of crude extracted in 1985 but uses only 0.5 bbl today). On the whole, Canada's Harper Administration has been supportive of new output, however, and to date there has not been a significant policy related 'shut-in' of production. Shut-ins and deep discounting have occurred, however, due to infrastructure constraints.

But activist movements after the Keystone XL denial by the US (since resubmitted as two separate lines by TransCanada) have focused on stopping the Northern Gateway pipeline that would move crude West. Self-regulatory and government initiatives might not suffice, with the politics firmly opposed to 'dirty' tar sands. The First Nations are central to Canadian history as early settlers of the region with a current population of about 700,000 and with full ownership to land rights and right-of-way rights.

Similar to Native Americans in the US, these groups suffer disproportionately from income inequality and other social stigmas. With sympathy and natural alignment with the environmental caucus, there is a minority but loud voice in Canada that is not only against pipelines, but also against oil sands.

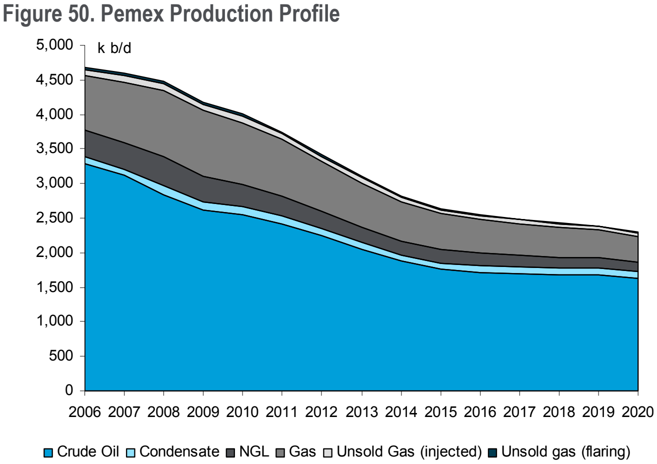
Mexico's energy policy: Is it time for a change?

Meanwhile, Mexico has seen its energy sector development stymied by a zealous nationalism which has seemed inadequate, particularly in recent years, as production volumes have declined sharply

Mexico, the proud southern neighbor of the US, has a storied history in the oil sector that has more recently proved to be a case of lost potential as opposed to one of glorious industry. In 1938, during the tail end of the Great Depression, President Cardenas decided to nationalize privately controlled oil assets of all foreign entities operating within its borders. In a moment of pre-Che Guevara-esque triumph, picketing oil workers seeking better pay and social welfare found an ally in Mr. Cardenas as his government took control of fields and facilities from US and British operators, citing legal grounds under the 1917 constitution; rules that remain sine qua non to the energy policy debate today. With assets in hand, Petroleos Mexicanos (Pemex) was born soon after President Cardenas' actions. Today the firm continues to be one of the world's largest NOCs and remains a strong source of nationalistic pride for the Mexican people.

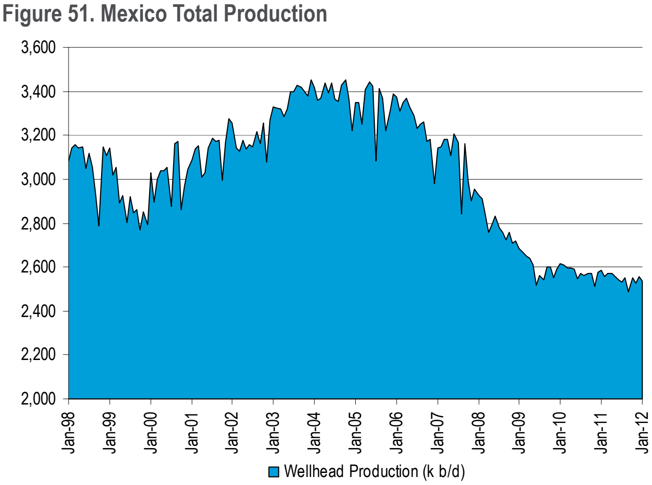
As such, with the 1st July 2012 Mexican presidential election drawing near, questions related to the direction of opening up the country's oil and gas sector may also greatly impact the North American energy story, particularly as it relates to the state-owned Pemex, a firm whose only North American rival in size would be ExxonMobil. Expected to produce nearly 3.5-m b/d (oil equivalent) in oil and gas in 2012, the Mexican NOC spends $25 billion annually in capital expenditures that are slated to exceed $30 billion by 2015. While Mexico's total crude oil production of about 2.6-m b/d has declined nearly 1-m b/d in the past decade, this assessment appears to have stabilized since 2009 in part due to the increased capex in Mexico which has boosted production ex-Cantarell, where production growth since 2005 has averaged about 8% per annum. Total Mexican production had been pulled lower by the sharper-than-expected decline at Cantarell, which was in the past a legacy of limited spending on reservoir management during early years of production. More alarming than the decline rate of years past, perhaps, is that the EIA's 2010 IEO forecast that Mexico could become a net oil importer by decade's end with net imports increasing to 1-m b/d in 2035; quite disconcerting as the country is typically the second or third largest exporter of crude oil to its Northern neighbor. But this outlook has the potential to meaningfully change should Mexico's leadership look to stave off the country's sub-par production profile.

Figure 50. Pemex Production Profile



Source: Rystad UCube, Citi Investment Research and Analysis

Figure 51. Mexico Total Production



Source: EIG, Citi Investment Research and Analysis

The current Mexican constitution prohibits the development of Mexican Gulf reserves in conjunction with foreign counterparties, and constitutional changes could be challenging

The primary policy issue deals with Mexico's inability to partner with US IOCs (and other international oil and gas firms) that would be necessary for the country to efficiently extract its resources. In short, the current Mexican constitution prohibits the development of Mexican Gulf reserves with foreign counterparties. So new policy initiatives to open up its energy sector to large multinational partnerships would require a constitutional change and could be challenging. But on the whole, this likely makes the process slow rather than completely impossible. With Pemex projecting over 29 billion barrels of crude oil equivalent resources in the southern deepwater Gulf of Mexico, and petroleum revenues providing nearly 10% of Mexico's GDP according to the Baker Institute, it appears Mexican policymakers would be incentivized in developing its natural resources, especially to avoid becoming a net importer; also boosted by its close relationship with the US that depends upon the Mexican oil trade. The likelihood of constitutional change is further buttressed by logical constraints. Pemex has limited upstream experience in deepwater drilling more than 5,000-7,000 feet, likely requiring the expertise of foreign IOCs from both a technology and strategic risk management purview (unlike Petrobras for example, which is also a Latin American player, but the world leader in deepwater technology). But the history of failed Mexican energy reform full of false hope and the oil industry is a large source of nationalistic pride in the country, alluding to what will hardly be an 'easy' reform.

But there are some signs that Mexican energy policy and politics could be moving in the direction of reform

Nevertheless, some energy policy and politics thus far seem to be moving in the right direction. Earlier this year, Mexico's government and the United States' Department of Interior inked a cross-border oil and gas development deal potentially opening up 1 to 1.5 million acres to deepwater drilling in the Southern Gulf of Mexico. The deal's finer points still require approval from lawmakers from both nation's local legislatures but the proposal has set guidelines on a joint environmental and regulatory framework that opens the door to attracting cross-border partnerships. Mexico also has large unconventional oil and shale gas plays, most notably its Sabinas and Burgos basins, the latter with 0.4 billion bbls of proven hydrocarbon reserves that may also benefit from foreign joint ventures. Two leading presidential candidates including front-runner Mr. Pena Nieto of the Institutional Revolutionary Party (PRI) and Ms. Josefina Vazquez Mota of the National Action Party (PAN) thus far appear supportive of reforming Mexico's upstream energy sector although Mr. Andres Obrador of the PRD party could pose larger hurdles for opening and enhancing the current system. While the likelihood is that of expanded cooperation between the US and Mexico, to date there has not been a meaningful physical partnership related to inland development projects or the significant opportunities in shared deepwater drilling. And only with the proper policy and resource partnerships might Mexico's current 2.9-m b/d of oil and liquids production reverse its downward trend and grow by 1.6-m b/d to 4.5-m b/d by the end of this decade.

North America: Residual "Supplier" to Global Markets

No other region of the world is having as significant impact on global markets as North America. The rapid growth of production combined with the decline in US consumption is as effective as a producer adding 700-k b/d per year to global balances. For a number of years, the main thrust will be in a reduction in crude oil imports combined with increased petroleum product exports. By the end of the decade, net oil exports from Canada outside of North America and some gross exports from the US are on the horizon along with incremental exports from Mexico. If Venezuela turns around current obstacles to production growth and if Brazil fulfills its potential, the Western Hemisphere as a whole will in many respects represent the new Middle East.

The transformation of the North American oil supply landscape pressures existing transportation infrastructure as well as driving hydrocarbon exports

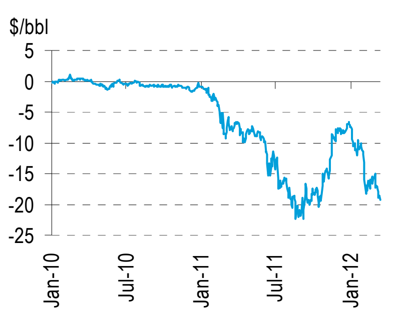
The massive reshaping of the North American oil supply picture sets into motion forces that put pressure on existing transportation infrastructure within North America, as well as trade flows in and out of the North American continent. The future looks different from the picture one might have envisioned only a few years ago. Instead of growing dependence on imported oil and gas to feed continuous domestic demand growth in the face of declining homegrown sources, the picture is of abundant supply unlocked by technological advances that are overwhelming existing pipeline infrastructure, causing blowouts of price spreads that depend on lumpy logistical capacity additions before they can be arbitraged away. US refineries, changing their diets from lighter crudes to heavier crudes, decrease their demand for light crudes — much like the kind that is produced from shale plays, narrowing light-heavy differentials.

although restrictions on crude exports or movements between US ports present obstacles

Combined with a growing surplus over declining domestic consumption, the dynamics above create incentives to export, but this bumps into anachronistic legislation that restricts exports of crude oil of US origin for the defunct reason of short supply, as well as the Jones Act, which requires crude and petroleum products be shipped on US flag vessels between US ports.

The US has already become a net exporter of petroleum products since last year, and whether exports of crude are also permitted is a key question for the price of the landlocked US crude benchmark relative to waterborne crudes. Without the ability to export, US crude oil could become as disconnected from world markets as US natural gas.

Figure 52. WTI-Brent spread has experienced blowouts as rampant production spills over infrastructure constraints

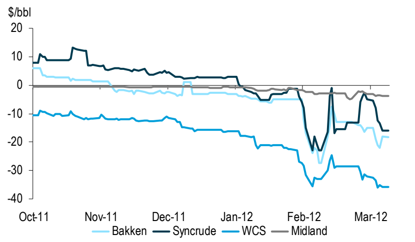


Source: Bloomberg

The symptoms of these dynamics are seen in the trials and tribulations of the WTI-Brent spread, and underlying and related differentials between WTI, WCS, Bakken, Syncrude, LLS and Brent. After WTI-Brent's blowout in February 2011 to $10/bbl levels as the Libyan conflict began and as Cushing stocks were building, it blew out further in 2H'11 to well over $20, before retreating again in November 2011 to $7-$9 levels, triggered by the news of the reversal of the Seaway pipeline, and exacerbated by short-covering and an OPEC producer hedging program. As this was happening in late-2011, Cushing stocks had been drawing down as refinery runs, particularly in the US mid-continent PADD II region, were at full-out utilization rates of 98% at times. Since then, February 2012 has seen the spread push out to close to $20/bbl. To be sure, recent upward pressures on Brent have played a part, with technical problems returning to the much-maligned North Sea Buzzard field, and force majeure declared on Nigerian production again as sabotage and security issues disrupted pipelines. Further, Brent-related crudes also saw upward pressures, with Urals boosted by precautionary replacement buying for Iranian barrels with US and EU sanctions to bite come July, while Iran has threatened to self-impose a preemptive export ban on the EU, recently announcing that it would stop shipments to the UK and France.

Geopolitics aside, a biting winter came to Europe, boosting heating oil demand, but also disrupting Black Sea shipments of crude. But the widening of the WTI-Brent spread remains primarily a story set within the North American context.

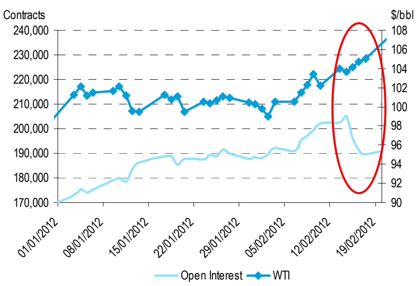
Figure 53. Bakken, syncrude, WCS and Midland physical cash differentials to WTI



Source: Bloomberg

A mild winter has allowed more crude to be produced or to move into the US midcontinent, testing pipelines and refineries already close to capacity. In the winter of 2011, well freeze-offs, and later spring flooding, halted or slowed Bakken production. Winter production slowdown remains a potential seasonal factor in the WTI-Brent differential going forward, but not at the moment. Combined with a period of few problems with Canadian upgraders of bitumen, and you are left with flows into the US midcontinent that have challenged already congested logistics. This congestion is appearing at various pressure points of the crude glut corridor from Western Canada to the US Gulf Coast — not just Cushing. Bakken, Western Canadian Select and Edmonton syncrude cash differentials blew out dramatically at end-January, exacerbated by stockpiling at Cushing and purging of the pipeline before the Seaway reversal, which is slated for April 1, indicating bottlenecks before crude even reaches Cushing.

Figure 54. Short covering in WTI drove the recent widening of the WTI-Brent spread



Source: Bloomberg, CIRA

The volatility in the spread is being exacerbated by the popularity of it as a trade by hedge funds and other non-physical players. The mid-February rally in the 'arb' is a perfect example of the type of volatility that can result from the crowded nature of the trade. The sharp fall-off in open interest in WTI futures on ICE is a strong indication that the rally in the 'arb' was a result of short-covering, because although WTI volumes on NYMEX remain much higher than on ICE (in January 2012 total NYMEX WTI open interest was 3.7x that on ICE), ICE is where the liquidity in WTI-Brent resides. Open interest in WTI has also fallen on NYMEX, but not as steeply as on ICE.

Growing North American supply is challenging the logistical system for moving sources of supply to major refining centers and it looks likely that for the next 5-10 years infrastructure or political bottlenecks will make it impossible for WTI to reach equilibrium price levels with global waterborne crude streams. There are several degrees of freedom for crude transportation infrastructure to evacuate the major sources of North American crude supply: Western Canadian oil sands, the Bakken and other shale plays, Permian basin shale liquids and going forward, growth from Gulf of Mexico deepwater, with Cushing, Oklahoma, and increasingly, the US Gulf Coast, as crude glut hotspots. These options are their implications are described in more detail in our 27 February 2012 note, "End Game".

Pipeline and other crude transportation infrastructure looks to be challenged well into the decade, struggling to keep up with surging supplies, with westward solutions perhaps by 2017

Western Canadian oil sands production could be exported eventually through the US Gulf Coast, and flows can be diverted westwards to the Pacific, although these projects aren't likely to start until 2017 at the earliest. These are Kinder Morgan Energy Partners' Trans Mountain pipeline, with a planned expansion of capacity from 280-k b/d to 600-k b/d, going west to central British Columbia, Vancouver or Washington State; or Enbridge's Northern Gateway, which would end up in Kitimat, BC, with a capacity of 525-k b/d.

… and some eastward capacity potentially by 2013

Eastward and southward pathways are predominantly via Enbridge's mainlines at least until Keystone XL and other expansion projects are completed. Enbridge has two planned projects which could provide relief in late 2012 or early 2013. The Line 5 expansion would add 50-k b/d to current capacity of 490-k b/d from Wisconsin to Ontario, perhaps as soon as late 2012. The Line 9 reversal and extension could see 240-k b/d reversed to move crude from Sarnia, Ontario to refining centers in Montreal and Ohio; there is independently the possibility of the line reversal linking Montreal to Portland, Maine, allowing volumes to be delivered via tanker or barge to destinations along the Atlantic seaboard.

Figure 55. Selected Major US and Canadian Pipelines, Existing and Proposed

Source: CAPP

After the veto by US President Obama early in 2012 of the building of the Keystone XL line to the US Gulf Coast, nationalistic pressures have risen in Canada to accelerate exit strategies West, but the Canadian permitting process remains onerous, including permitting by various First Nations owning land rights and environmental objections at Vancouver.

Currently, Enbridge's mainline pipeline system is the only major route with significant spare capacity from Canada into the US; the troubled Keystone XL would be the main potential addition

Meanwhile, Enbridge's Canadian and US Lakehead mainline system appears to be permitted for 2.5-m b/d of capacity, but carried just over 1.5-m b/d of Western Canadian crude to the US over 2011, or around 17% of US crude imports. Thus, there should be room to expand capacity on existing routes south into the US without further approvals, with the route currently ending in Chicago. By comparison, TransCanada's existing Keystone pipeline is transporting almost 500-k b/d, close to current capacity of 590-k b/d.

Figure 56. Enbridge Canadian and US Lakehead Mainline System – reported crude throughput

2010					2011				
Q1	Q2	Q3	Q4	Total	Q1	Q2	Q3	Q4	Total
1,602	1,457	1,565	1,594	**1,554**	1,515	1,629	1,468	1,537	**1,537**

* Throughput volume represents mainline deliveries ex-Gretna, Manitoba and is exclusive of western

Source: Enbridge, Citi Investment Research and Analysis

The reversal of the Seaway pipeline helps ease flows between Cushing and the Gulf Coast starting 2Q'12, and a further additional chunk of capacity added in 2013, but even this likely provides relatively brief respite

As for pipelines out of Cushing and down to the Gulf Coast, the Seaway reversal is the most significant, and soonest, relief available, with 130- to 150-k b/d of flows likely to start perhaps as early as April 1 from Cushing to Freeport, Texas on the Gulf Coast, earlier than the June 1 date initially announced. (Uncertainties about that start-up as well as the eventual expansion of Seaway just add to spread trading volatility ahead.) Further expansions of Seaway capacity to a nameplate 400-k b/d could come in 4Q'12 or 1Q'13, although slightly lower volumes than nameplate are likely depending on crude grade and batching issues. Enbridge are planning to twin the Seaway pipeline by late-2014, as well as twin the Spearhead pipeline from Chicago to Cushing as part of its Flanagan South project.

The Cushing-to-Gulf Coast leg of the Keystone XL could potentially start up by late 2013

Notably, TransCanada is now planning to reapply for the US Presidential Permit that was denied this January for Keystone XL, with customer commitment still in place; the company projects potential start-up for early 2015. The southern leg of the Keystone XL, between Cushing and the Gulf Coast, is to be built separately, and earlier, and would not require a Presidential Permit; this could begin operations in late-2013, adding perhaps +500-k b/d.

And a reversal of Longhorn could ease some flows from the Permian basin to Cushing, in mid-2013

Additionally, Magellan's Texas Longhorn pipeline currently carries refined products from Houston to El Paso, but is being reversed and converted to crude service, likely by mid-2013. This would divert Permian basin crude away from Cushing, with an initial capacity of 135-k b/d, with potential peak capacity of 220-k b/d.

Local Bakken pipelines and rail capacity is seeing fast growth

Local Bakken takeaway capacity by pipeline and rail is being built at a rapid pace, with around 470-k b/d of takeaway pipeline capacity in the Williston Basin. Local rail takeaway capacity has also stepped up, and could reach 640-k b/d of takeaway capacity in 1Q'12. Crude-by-rail continues to play a role as a more flexible but more expensive transportation option, with the North Dakota Pipeline Authority estimating end-2011 crude-by-rail levels at ~130-k b/d. Meanwhile, early-2012 petroleum railcar freight volumes as reported by the American Association of Railroads show a 150- to 200-k b/d increase over the same period last year, and it is likely that much if not most of this is attributable to crude-by-rail out of North Dakota.

Refinery upgrades to process heavier crudes reduces demand for light crudes to the tune of around 420-k b/d less perhaps by early 2013, leaving an even greater surplus of WTI-like crudes in the US midcontinent

Within this broad picture, dietary changes of US midcontinent and Gulf Coast refineries impact the heavy-light crude spread. Refinery upgrade projects to process heavier crudes put further pressure on light WTI-like crudes. The WRB Wood River refiner upgrade was completed end-2011 and decreased demand for light crude by 130- to 150-k b/d. Marathon Detroit's upgrade project is expected to be complete by mid-2012, accounting for another 70- k b/d of lost light crude demand. The heavy crude processing capacity increases by 80-k b/d after the installation of its 28-k b/d coker and 36-k b/d diesel hydrotreater, with a 70-day turnaround to integrate the units. BP Whiting's "modernization project" is expected to be complete by early-2013, and leaves another 230-k b/d of light crude without a home, for a total of ~420-k b/d over the next two years. The heavy-light spread should continue to tighten with these upgrades, combined with growth of US light crude.

Figure 57. US Refinery Upgrades to Process Heavier Crudes Leaves ~420-k b/d of Light Crude without a Home in PADD II by 2013

		Before		After		Delta	
k b/d	date	light	heavy	light	heavy	light	Heavy
WRB Wood River	end-2011	200	100	70	260	-130-150	160-180
Marathon Detroit	mid-2012	80	20	10	100	-70	80
BP Whiting	early-2013	300	100	70	330	-230	230

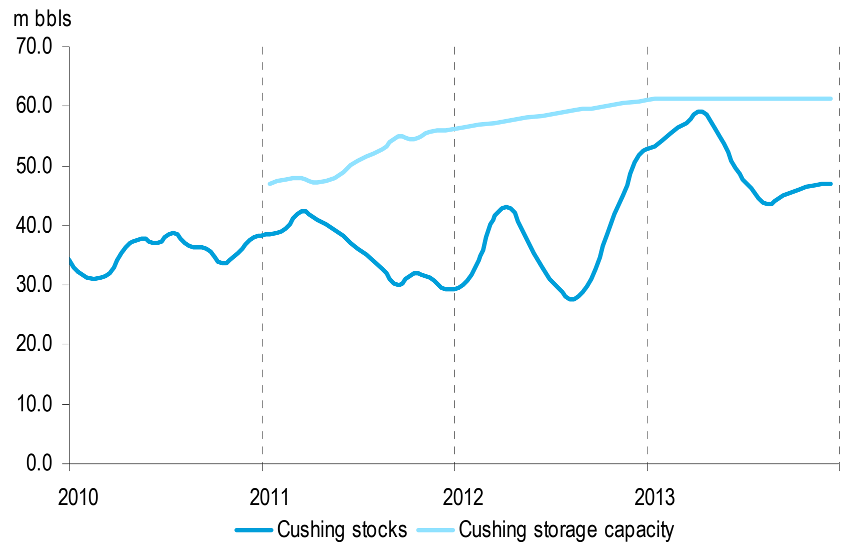
Source: Company websites, Reuters, Citi Investment Research and Analysis

2012 could see another two WTI-Brent blowouts in 2Q'12 and late 3Q'12 while 2013 could face severe challenges, particularly if the southern leg of Keystone XL runs into problems

These dynamics point to particularly severe price volatility in 2012 and 2013, with midcontinent Canadian and US production growing faster than any other previous year, and with liquids evacuation logistics growing in fits and starts, with Seaway, Longhorn, a bunch of new pipelines out of the Bakken, Enbridge's Line 9 reversal and a bump up in Seaway capacity at year-end having a yo-yo impact on prices with surging storage punctuated and reversed periodically by lumpy new exit routes by pipe and rail. Three spread blowouts could occur in 2012, one now, which could be moderated as refiners return from seasonal maintenance; one in the run-up to a reversed Seaway opening at 150-k b/d probably late in Q2; and another in Q4, assuming BP Whiting will undergo deep maintenance then, just as Seaway prepares to triple its flow capacity.

Little significant takeaway capacity had been scheduled for 2013, although TransCanada's plans to build the southern leg of Keystone XL between Cushing and the Gulf Coast provide some easing of Cushing congestion perhaps by the end of that year. The mid-2013 reversal of Longhorn could also help somewhat, but a continued surge in US and Canadian output could make 2012's expected spread volatility a precursor of more volatility and even wider spreads in the following years as logistical constraints look to be bumped up against time and time again.

Figure 58. Cushing Dynamics Point to Blowouts in 2Q'12 and Throughout 2013



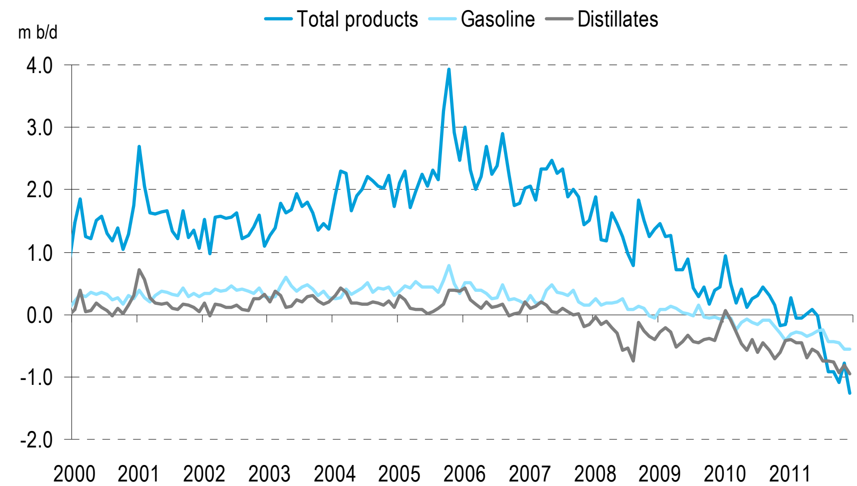
Source: Citi Investment Research and Analysis

Beyond importing less and less crude oil, the US is becoming an increasingly major net petroleum product exporter

The US is already showing signs of being a burgeoning petroleum product net exporter since 2010, but 2011 has seen this trend solidify.

Abundant domestic crude output is keeping the PADD III's 8.5-m b/d of refinery capacity (of which 7.5-m b/d is on the Texas and Louisiana coastal areas) well supplied, even with current bottlenecks. In December 2011, PADD III produced some 3.3-m b/d locally, importing 4.7-m b/d, but only consuming 5.1-m b/d; this surplus drove 2.7-m b/d of products exports. Of this, distillate exports hit a record 1.1-m b/d in December 2011, with the largest average exports over the year going to the Netherlands (an average of 145-k b/d), Mexico (100-k b/d), Chile (80-k b/d), Colombia (50-k b/d) and Brazil (40-k b/d). Gasoline exports hit over 600-k b/d, with a record 626-k b/d in November 2011, with the largest volumes by far going to Mexico, averaging 277-k b/d over the year. December exports of residual fuel oil (465-k b/d), jet kerosene (130-k b/d) and petroleum coke (575-k b/) were at or near highs, and also account for significant portions of growing US product exports.

Figure 59. US Net Petroleum Imports have become Firmly Negative – the US is Solidifying its Position as a Growing Net Petroleum *Exporter*



Source: EIA, Citi Investment Research and Analysis

Given a potential overhang of an additional +9.8-m b/d of crude production in the US and Canada, while US oil consumption simultaneously falls by as much as 2-m b/d by 2020, petroleum product exports should continue to rise, while pressures to export crude oil should also increasingly mount. This faces political and legal issues in the US, which are discussed below.

Figure 60. Refinery Closures or Maintenance end-2011 to 2012

Refinery	Capacity	Date
US East Coast closures		
ConocoPhillips Trainer, PA	185	Nov 2011
Sunoco Marcus Hook, PA	178	Dec 2011
Sunoco Philadelphia	335	July 1 if not sold
	698	
Europe closures		
Petroplus Antwerp	110	Jan 2011
Petroplus Petit Couronne	154	Jan 2011
Petroplus Cressier	73	Jan 2011
Lyondell Berre L'Etang	105	Dec 2011
	442	
At risk		
At risk: Petroplus Coryton	172	
At risk: Petroplus Ingolstadt	106	
Caribbean closures		
Hovensa St. Croix	350	Mid-Feb
Valero Aruba	118 of 235	Since Oct
Turnarounds		
PDVSA Isla Curacao (planned turnaround)	335	Apr-Jun

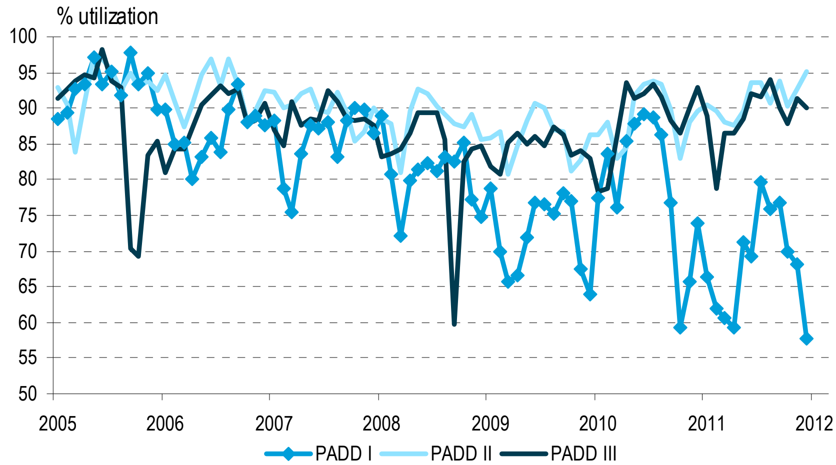
Source: IIR, FGE, CIRA

While product net exports should continue to rise over the long term, a caveat is that the US is likely to be *importing* gasoline this summer, for current, specific fundamental reasons. Global supply disruptions, notably the continued tensions between Iran and the US and Israel, have physically tightened markets as US sanctions have began to bite, and EU sanctions look to start in July, while market positioning by investors has also skewed to the upside. Meanwhile, various political and technical disruptions across the world — in Sudan and the newly formed South Sudan, Yemen, Syria, Nigeria, the Black Sea, and the North Sea — have provided further bullishness in Brent-related crudes. This has challenged refining margins, particularly for simple refiners, causing a chain of closures in the Atlantic Basin since end-2011. These refinery closures or economic shutdowns, from the Petroplus refineries in Europe, to the Sunoco and ConocoPhillips Philadelphia area refineries, to the Caribbean, have tightened gasoline markets on the US East Coast. At the same time, summer specification gasoline is harder to make, and Latin American demand remains strong, especially given its own refinery turnarounds and outages. Given that record prices for gasoline could be a damaging issue for President Obama's re-election campaign this year, the prospect of issuing Jones Act waivers to move products from US Gulf Coast to the East Coast is improving, which would help ease gasoline supplies somewhat. But gasoline import pull from abroad is likely to increase significantly otherwise.

There looks to be a brighter future for (PADD II and PADD III) US refiners. Even as East Coast refineries have been challenged by unfavorable waterborne prices for Brent and related crudes, US midcontinent refiners should continue to enjoy favorable economics due to abundant, local crude supplies, with growing demand from Latin America, Europe and other petroleum export markets. PADD II and PADD III refinery utilization rates have been running at high levels – particularly PADD II refiners, with infrastructure bottlenecks keeping WTI cheap and thus margins high – but PADD I refiners, typically buying Brent and other light, sweet crudes such as from West Africa, have suffered from relatively high waterborne crude prices.

Both the integrated and the independent refining model should work in the US midcontinent and Gulf Coast, but are broken in PADD I and PADD V. International, export refineries that are product short should work (such as in Singapore, Taiwan and South Korea) while Europe is in trouble, as it has no local crude supply, continues to face refinery overcapacity, and suffers from being both long gasoline but short middle distillates.

Figure 61. Refinery Utilization in PADD I has Suffered, while Soaring in PADD II and PADD III



Source: EIA, Citi Investment Research and Analysis

As takeaway infrastructure eases later this decade, the crude glut moves down to the Gulf Coast, to be joined by local Eagle Ford and deepwater production growth, particularly if crude exports remain restricted

With Gulf Coast volumes from the Eagle Ford increasing, as well as from deepwater Gulf of Mexico later in the decade, a crude glut looks to emerge on the US Gulf Coast. Beyond growing petroleum product exports, there are likely to be economic incentives to export both Canadian and US-based crude streams. Canadian crude should be the first to be exported from the US to earn higher netbacks elsewhere — if this is permitted as is currently the case, unless there is a move to block it (see further discussion on US crude export controls below). Once Pacific takeaway exists – with Trans Mountain and Northern Gateway potentially ready in 2017, or with further delays some time later — there should be a push for higher Alberta netbacks in the Pacific. And unless Canadian pipelines eastward are bolstered (which as yet are not planned), light sweet crude will have several layers of bottlenecks, starting with an export bottleneck on the US Gulf Coast, if the US does not allow exports. At the same time, with Mars-quality deepwater output growing and restricted from export, a well-supplied Gulf Coast puts pressure back on Canadian supply to stay north and move west; but if westward pipelines are congested, this surging deepwater Gulf of Mexico production would force Canadian crude to be exported from the Gulf Coast, perhaps even competing with Mexican — and obviously, Venezuelan crudes — and face deep discounts in the Atlantic Basin in order to reach foreign destinations. With landlocked Canadian and US supplies, this situation of multiple bottlenecks between Western Canada, Cushing and the Gulf Coast could be messy, with blowouts of $20-$30 for WTI-Brent, we estimate.

"Short supply" controls on crude exports fall under the jurisdiction of the Bureau of Industry and Security at the Department of Commerce

The Department of Commerce currently imposes export controls on domestically-produced crude oil.

A license is required for the export of crude oil to all destinations, including Canada. Only in limited circumstances has Commerce approved applications to export crude oil, consistent with the regulations of the Bureau of Industry and Security (BIS), which sometimes has required a Presidential waiver/finding before the export can be authorized. But the reason for export controls — short supply in the US — is becoming somewhat of an anachronism, as the situation now being faced is of abundant supply.

Export of Canadian crude is currently relatively easily approvable under current rules, as it is "crude of foreign origin", but political wranglings could change this, going forward

Under current rules, exports of Canadian crude, as crude of foreign origin, are already under statute, and so should be approvable with relatively little trouble. "Commingling" with crude of US origin would not be allowed under these rules, but de minimis quantities should be fine, within reason — so Canadian crude running through pipelines and storage that have held crude of US origin should be fine. But new rulings from Congress or a Presidential finding on the matter could change the leniency on exports of foreign crude. Already, there has been proposed legislation in Congress that would seek to ban exports of Canadian crude from the Keystone XL pipeline, as instigated by environmental groups that, like those in Europe, want to reduce production of crude from oil sands because of their high greenhouse gas emissions content.

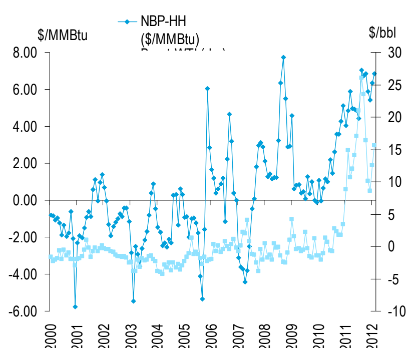
On the other hand, effectively all US-produced crude oil is restricted from export, and would require a Presidential waiver on a case-by-case basis

Exports of crude of US origin would currently require a Presidential waiver, as any domestically-produced oil passing through pipelines granted Federal right-of-way is restricted from export under the Minerals Leasing Act, and exports of deepwater Gulf of Mexico-produced oil are blocked under the Outer Continental Shelf Leasing Act. In both cases, a Presidential waiver is required before the Bureau of Industry and Security (BIS) at the Commerce Department may issue an export license. Again, this falls to a political process and is likely to be contentious. The ability to export crude remains a key question for the relationship between North American crude and waterborne crude. If exports are allowed, LLS-Brent could settle at a long-term "equilibrium" of -$2 to -$4/bbl, taking into account the transport arbitrage and the embedded premium on Brent as North Sea production continues to slide. Add to that the transport differential between Cushing and the USGC and the differential between WTI and Brent could grow to as much as -$4 to -$6/bbl.

and shipping crude from the US Gulf Coast to East or West Coast ports would require a Jones Act waiver

And shipping crude from the US Gulf Coast to ports on the East or West Coast falls under the Jones Act, which would require that the goods be carried on US flag vessels, constructed in the US, owned by US citizens, and crewed by US citizens and permanent residents. There are practically no US flag vessels available for these purposes. Waivers would need to be issued, but this could also face problematic politics.

Figure 62. Brent-WTI could go the same way as NBP-HH



Source: Bloomberg, CIRA

Thus, a fully free regime for US crude oil exports looks extremely unlikely

US Gulf Coast production combined with growing inland production would need to seek increasing markets within the continental US. This would mean pumping oil up the 1.2-m b/d capacity Capline, or moving oil from the USGC to refineries on the East and West Coasts. If, as was the case when Alaskan North Slope crude was in surplus on the US West Coast, the oil needs to be transported on US flag vessels, a truly depressed crude oil market could emerge in the US. What's recently occurred in the US natural gas market would likely spill over to the oil market. Light sweet crude would no longer be trapped without exit, inland in PADD II, but would be trapped by law within the continental US. These circumstances could add another $4-5 to the WTI-Brent spread, which would find a floor at perhaps $8/bbl and no theoretical ceiling, other than potential eroding economics for future US production.

Economic Consequences of Energy 2020

Assessing the economic consequences

Our new supply and demand outlook has potentially dramatic consequences on the US and global economies

The changing outlook for domestic energy production and consumption unleashed by the supply revolution and new demand efficiencies discussed throughout the report has wider ramifications beyond changing the domestic energy landscape.

In particular, they have potentially transformative impacts on the US and global economies including reducing international energy prices, stimulating US economic output, growth, and job creation, and reducing over time historic US current account deficits, all else equal. A more detailed discussion of our counterfactual analysis is provided in the appendix.

To summarize our main findings, we estimate that the cumulative impact of new production, reduced consumption, and associated activity may increase real GDP by 2 to 3%, creating from 2.7 million to as high as 3.6 million net new jobs by 2020. Furthermore, the current account deficit could shrink by 2.4% of GDP, a 60% reduction in the current deficit, by 2020. This may also cause the dollar to appreciate in real terms by +1.6 to +5.4% by 2020.

Overall, these estimates, if accurate, suggest that the energy sector in the next few decades may drive an extraordinary and timely revitalization and reindustrialization of the US economy, creating jobs and bringing prosperity to millions of Americans just as the national economy struggles to recover from the worst economic downturn since the Great Depression. It would not only improve incomes and create jobs, but also improve national energy security and reverse perennial current account deficits, long a source of angst for policymakers.

New production

New technologies to extract hydrocarbons from deepwater, oil sands, and shale rock have dramatically raised the supply outlook

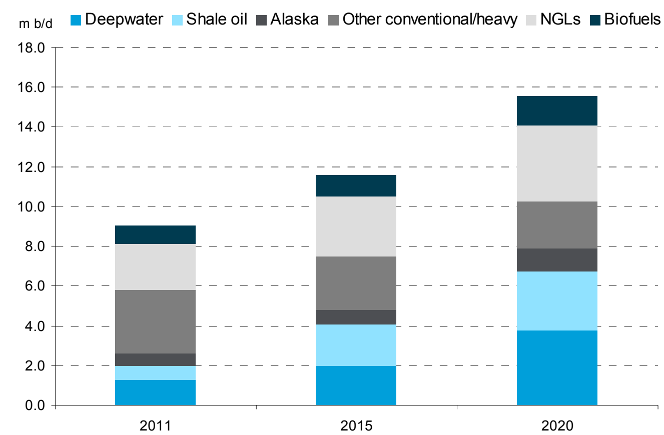
The new outlook for hydrocarbon production is continent-wide, and is transforming energy supply balances for the United States, Canada and Mexico. However, we concentrate only on the US-specific new production when discussing the economic consequences for the US economy, though we acknowledge that new production in Canada and Mexico would likely spill over and benefit the US as well.

Oil production growth in US may come from conventional, deepwater, heavy oil, and oil sands/shale, while new gas production may come from both conventional and unconventional sources. Finally, there is also the associated growth in liquids production.

On the oil side, we assume some +6.6-m b/d of growth in US-specific production occurring in our alternative scenario as compared to the base case — +2.5-m b/d from deepwater sources, another +2.3-m b/d from shale oil, +0.5-m b/d from Alaska, +0.6-m b/d from biofuels, and +1.5-m b/d from liquids, offset by declines elsewhere. By comparison, current US domestic crude oil production amounts to 5.8-m b/d and NGLs of 2.3-m b/d; hence, we are assuming domestic oil and liquids production would increase by more than a third by 2020. This increase would amount to some 7 to 8% of current global production.

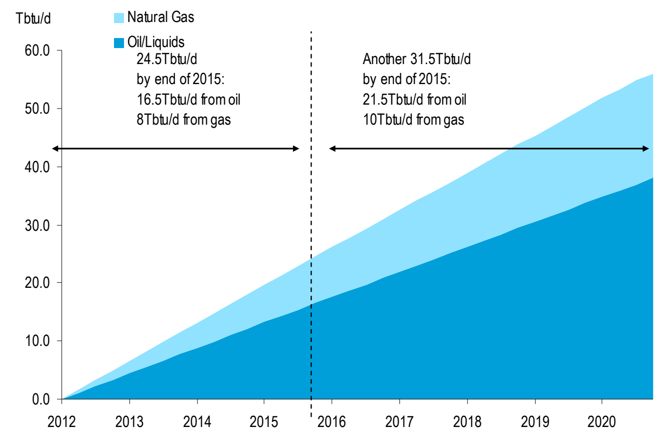
Furthermore, we are assuming domestic dry gas production rises from 62-Bcf/d in 2012 to 66-Bcf/d by the end of 2015 and 76-Bcf/d by the end of 2020. As global dry gas production amounts to some 307bcf/d, this increase of +14-Bcf/d from 2011 to 2020E is roughly 6% of global production.

Figure 63. Sources of U.S. Oil, Gas, and Liquids Production from 2011 to 2020E



Source: Citi Investment Research and Analysis

Figure 64. New Production Impact in Tbtu/d from 2011 to 2012E



Source: Citi Investment Research and Analysis

In energy terms, this wave of hydrocarbon adds 24.5 trillion BTU worth of energy per day (Tbtu/d) to domestic energy production from 2011 to 2015E and another 31.5Tbtu/d by 2020E, which we extrapolate linearly over the time period. This results in a cumulative 56Tbtu/d of new energy production from 2011 to 2020E.

In a world of high energy prices, the potential economic activity generated by this wave of new hydrocarbon production is extraordinary, and should strongly boost national output, increase incomes, create wealth, stimulate consumption and create jobs. But on top of the direct economic benefits of this production bonanza, there are also the added benefits down the value chain, in areas such as refined products and petrochemicals.

Already, the US producers of ethylene, polyethylene and propylene have benefited greatly from the influx of cheap natural gas and associated ethane, helping the US petrochemical industry become cost-competitive compared to their naphtha-based peers across the Atlantic. Other hydrocarbon and energy-intensive industries such as fertilizer and steel production also should benefit strongly from the production revolution, leading to extra marginal economic output and job creation.

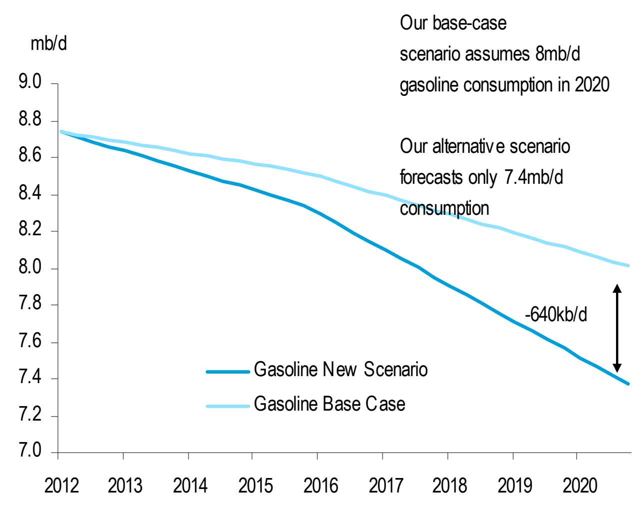
Reduced consumption

Demographic changes and new substitution and conservation technologies are also shaving the demand outlook

On top of the impact from new production, new trends are driving (no pun intended) sharply lower projections for consumption demand from the transportation, industrial, and power generation sector.

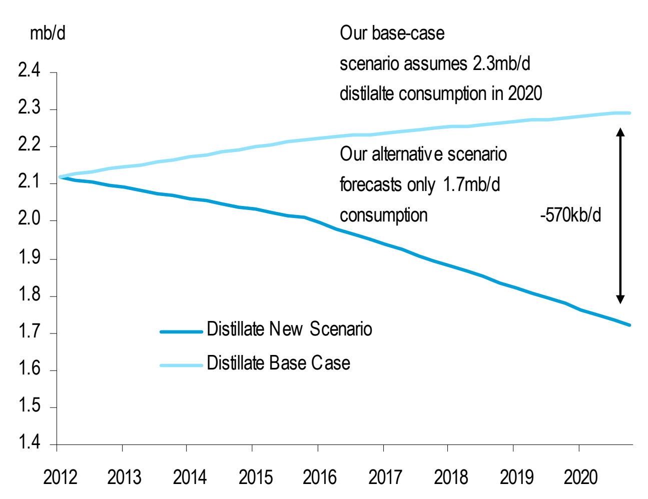
Some of this is caused by demographic changes and relocation from suburban to urban environments, meaning fewer families with driving-age individuals and fewer cars per driver, leading to weaker demand for gasoline. However, better technologies applied in improving vehicle mileage standards, industrial efficiency gains in extracting more liquids out of given crude oil feedstock, and substitution into gas, both in the transportation and industrial sector, should drive lower demand for both gasoline and distillates.

Figure 65. Gasoline Demand Base Case and New Scenario



Source: Citi Investment Research and Analysis

Figure 66. Distillate Demand Base Case and New Scenario



Source: Citi Investment Research and Analysis

Not only does this provide direct economic savings to consumers and firms in the form of less consumption, but also frees up wealth and income for other consumption and investment, with second- and third-round positive impacts for economic growth, employment, and the current account.

Of the -2-m b/d of demand declines projected to 2020 in an earlier chapter, we assume some -800-k b/d of demand declines would have occurred regardless, due to demographic and other non-technology-driven factors mentioned above. On the other hand, some -1.2-m b/d of this would be from technology, whether efficiency gains, conversions to natural gas vehicles, or other mechanisms.

By 2015, we assess some -150-k b/d of reduced gasoline demand and another -210-k b/d of reduced distillate demand compared to our base case scenario. By 2020, gasoline demand would be reduced by -640-k b/d and distillate by -570-k b/d for a cumulative reduced consumption profile of some -1.2-m b/d for the US by 2020, a reduction of roughly 6.3% of current consumption.

International energy prices

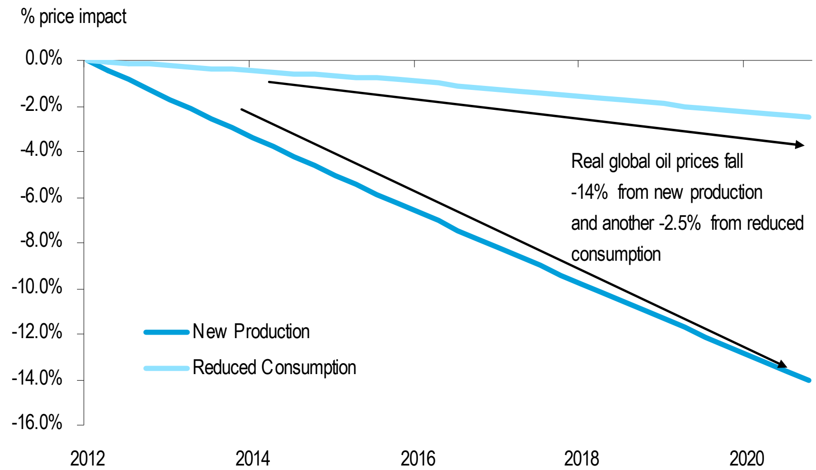
Greater domestic supply and lower demand would naturally lead to lower global energy prices, all else equal

The most immediate economic consequence of these new supply/demand scenarios would be their impact on the economy through the channel of international energy prices. Higher supply and lower demand would both work to lower the international equilibrium price of oil and other energy products. But how exactly would one quantify this impact?

This depends on the assumed price elasticity of supply and demand, defined as the ratio of the percentage change in either oil demand or supply in response to a unit percentage change in oil prices. For example, a price elasticity of demand at 0.5 or 50% would suggest that a 10% increase in global oil prices would be accommodated by a 5% decrease in demand.

The challenge is that price elasticities of supply and demand are both hard to estimate and may vary over time. Estimates for the US price elasticity of demand within one year are very low, around 0.03 to 0.05. Taken literally, an elasticity of 0.05 would imply that a 10% increase in global production would require a 10% divided by 0.05 or a 200% decrease in oil prices! However, short-term elasticities are better used in the context of some unexpected sudden change in demand or supply that requires immediate adjustment through price-driven demand destruction or new incentivized supply instead of inventories.

Figure 67. Real Oil Price Impact From New Production and Reduced Consumption, 2012E-20E



Source: Citi Investment Research and Analysis

But our alternative scenarios for new demand and supply considered above are slow moving and should be well anticipated in advance by the time the actual impact occurs. Hence, it is more appropriate not to use short-term but long-term elasticities, whose estimates are closer to 0.3 to 0.5.

Given the long-term projections for global demand in the Energy Information Administration's 2011 International Energy Outlook, this new production would amount to some 7% of additional global production. Hence, using a conservative price elasticity of 0.5, we estimate that by 2020, global real oil prices would be roughly -14% lower than they otherwise would have been due to the surge of oil and liquids production and exports from the US.[11]

Furthermore, using the same elasticity, real prices would fall by another -2.5% thanks to reduced consumption in the US, resulting in an overall reduced price difference of -16.1% between our base case and our alternative scenario, stemming from the confluence of both new production and reduced consumption.

The economic benefits from reduced global oil prices should have mixed impacts on US economic growth. On the one hand, it means lower oil costs for consumers, with broadly positive effects for growth, jobs, and the current account. On the other hand, this also reduces the revenue earned from each new barrel of oil produced.

[11] To simplify the analysis, we disregard the economic impact of US new gas production through possibly lower natural gas prices, assuming that any fall in US-based gas prices would be largely offset by new export capacity, keeping domestic gas prices roughly equivalent to that in the base case scenario.

National output and real GDP growth

We estimate that real GDP may be 2 to 3.3% higher than it otherwise would have been given these new technologies

The figure below charts the consequences of the new production/consumption profile on real Gross Domestic Product by comparing between the two counterfactual scenarios. The direct value added in new oil and gas production we estimate at roughly $274 billion (in 2005 $) or 1.4% of real GDP, $240 billion from oil and liquids and $34 billion from natural gas, assuming the declines in global oil prices discussed above.

On top of this, there are the multiplier effects that occur as firms make new orders for machinery and other goods and services, hire new workers who in turn increase consumption and spending on other goods, and thereby generate virtuous cycles of new economic activity.

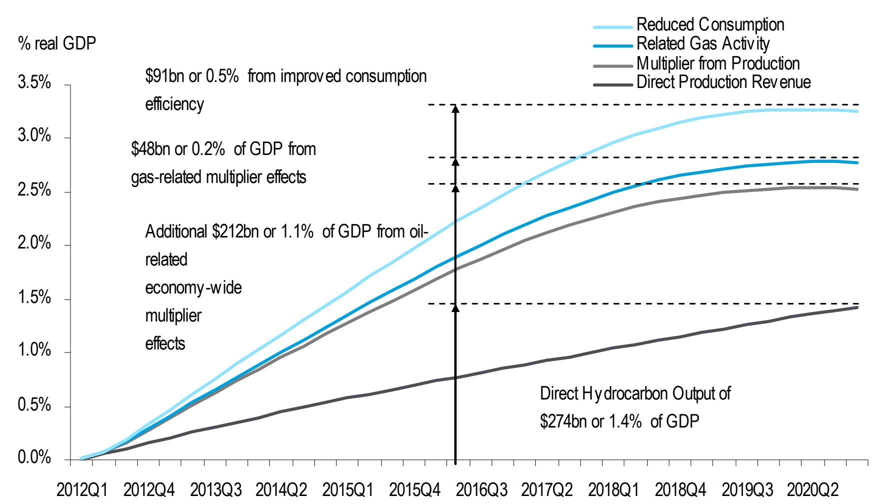
On top of the direct new hydrocarbon output, the increased wealth drives multiplier effects that aggregate through the economy

Our estimates suggest this may stimulate an additional $100 billion to $200 billion more economic activity from the additional oil-driven income alone, depending on the model used. Furthermore, multipliers from gas-related production stimulate another $48 billion in new income in petrochemicals, steel, fertilizer, and other activity not included in the original impact stemming just from new hydrocarbon production.

Finally, some $91 billion in new economic activity could be stimulated because of freed incomes from consumers enjoying more disposable income due to improved efficiency and therefore lower demand for gasoline and distillate.

Cumulatively, we estimate the combined impact of new production for oil+gas+liquids, related economic activity in non-hydrocarbon manufacturing, and finally improved efficiency adds somewhere between +2.0% and +3.3% or about $370 billion to $624 billion (in 2005$) to annual real GDP.

Figure 68. Cumulative Impact on US Real GDP, 2012E to 2020E

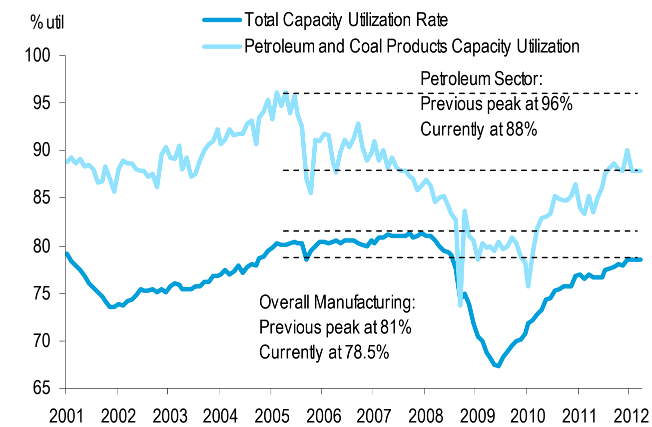


Source: Citi Investment Research and Analysis

In terms of growth, at the point of maximum economic impact, the new scenario adds some +0.5 to +0.6% to real GDP growth and remains strongly positive to 2015. However, post-2015, as incremental new production slows and the economy adjusts to new levels of income, the impact on real GDP growth also falls.

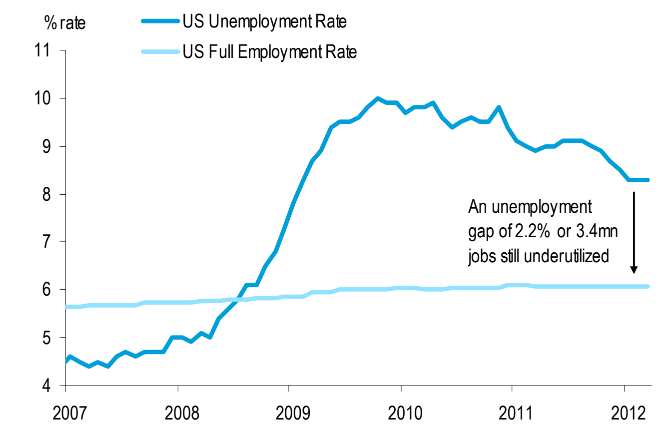
Overall, these are large numbers. The multiplier, which calculates the overall economic GDP impact compared to the initial direct stimulus in output from new production alone, is anywhere from 1.3 to 1.7, on the high end of traditional estimates of the multiplier.[12] This may suggest that our +3.3% real GDP impact estimate number may be optimistic. On the other hand, the US economy is still emerging from recession with significant spare capacity in its manufacturing.

Figure 69. US Overall and Petroleum Manufacturing Spare Capacity



Source: Federal Research, Citi Investment Research and Analysis

Figure 70. US Labor Market Unemployment and Capacity



Source: US Bureau of Labor Statistics, OECD, Citi Investment Research and Analysis

Furthermore, there is substantial capacity slack remaining in the petroleum and coal product sector. While absolute rates of utilization are near 90% compared to the 78% utilization rate in the manufacturing sector as a whole, the gap to the previous peak in the 2000s is wider in the petroleum sector (see Figure 69). This suggests substantial gains to output can be achieved from each additional dollar in hydrocarbon output.

Job creation and reduced unemployment

We estimate that 2.2 to 3.6 million more jobs might be available than there otherwise would have been given these new technologies

Similar to the impact on real GDP, the new scenarios for production and consumption not only creates new jobs directly in the hydrocarbon extraction sector but also through broader job creation as aggregate output surges through the multiplier effect.

We estimate that some +550,000 new jobs would be directly created in the oil and gas extraction sector by 2020. Furthermore, some +2.2 million to +2.3 million new jobs would be created directly from the resulting economic stimulus effects of new production by 2020.[13] On top of that, some +785,000 new jobs are created as the improved efficiency in the US consumer profile frees up consumer incomes for other spending and job-creating economic activity. This cumulatively creates some +3.6 million new jobs, reducing the national unemployment rate by roughly -0.8% by 2015 and by -1.1% by 2020.

[12] Estimates of the overall multiplier in the US vary, but range from 1 to 1.7 depending on the type of stimulus.

[13] Our estimates of the number of jobs created from new hydrocarbon production alone using our US macroeconomic model and an alternative model created by Macroeconomic Advisors are remarkably close, +2.8mn jobs from our model vs. +2.7mn jobs from the MA model.

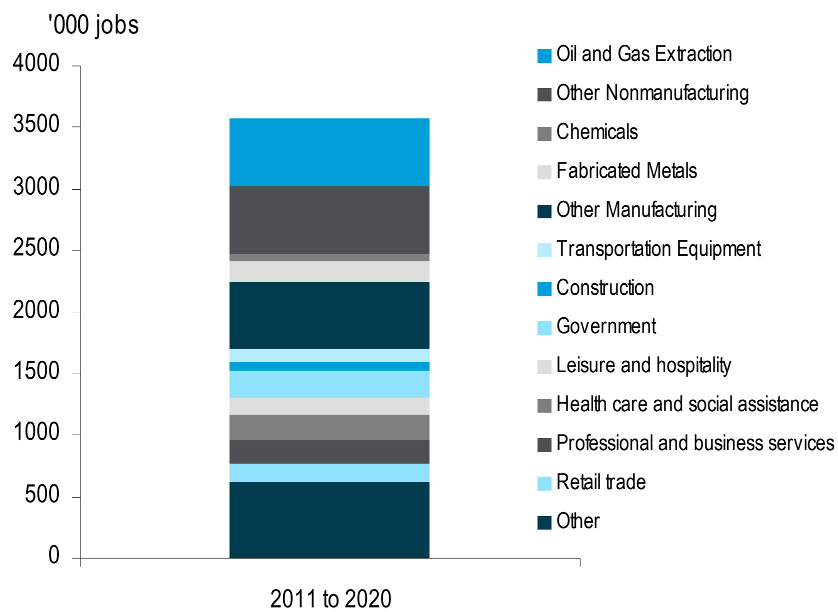
Beyond direct hiring in the hydrocarbon and related sector, the virtuous cycles of economic activity generate jobs in all sectors

Breaking down the job creation by business sector, the most immediate impact is again the +550,000 job creation in the oil and gas extraction sector. Despite the hydrocarbon sector being relatively less labor intensive than other non-manufacturing industrial sectors on average, the initial exploration and capital investment phase should be significantly more labor intensive. As we forecast new production to continue to arise through 2020, the extraction sector should remain a substantial contributor to job growth.

Also, another +1.1 million jobs would be generated in the manufacturing sector, notably for machinery, transportation equipment, fabricated metals, paper products, and chemicals. These sectors benefit not only from the overall economic expansion but also from cheaper energy input costs. The manufacture of petrochemicals, steel and fertilizer is notably intensive in the use of petroleum and/or natural gas, and should benefit disproportionately from the increased output of hydrocarbons.

Furthermore, as the economic benefits of the oil/gas production surge ripple through the economy through increased overall spending and consumption, another +1.3 million jobs would be created in the non-industrial goods and services sector. We expect that health care, retail trade, leisure and the government should continue to be areas for significant job creation (see Figure 71). The detailed breakdown of the job creation impact by business sector is provided in the technical appendix.

Figure 71. Impact on Job Creation, 2011 to 2020E



Source: Citi Investment Research and Analysis

Again, the aggregate +3.6 million job creation figure is substantial and should be considered a high-end estimate. However, the high degree of slack in the labor market suggests rapid job creation can be achieved with relatively little stimulus.

Currently, the US unemployment rate of 8.3% contrasts with levels considered to be the “natural” rate of unemployment anywhere from 5.2% estimated by the CBO to 6.1% estimated by the OECD. Even using the higher number, this still leaves a gap of 2.2% or 3.4 million workers underutilized (Figure 70), which does not count the millions of discouraged workers who have dropped out of the labor force.

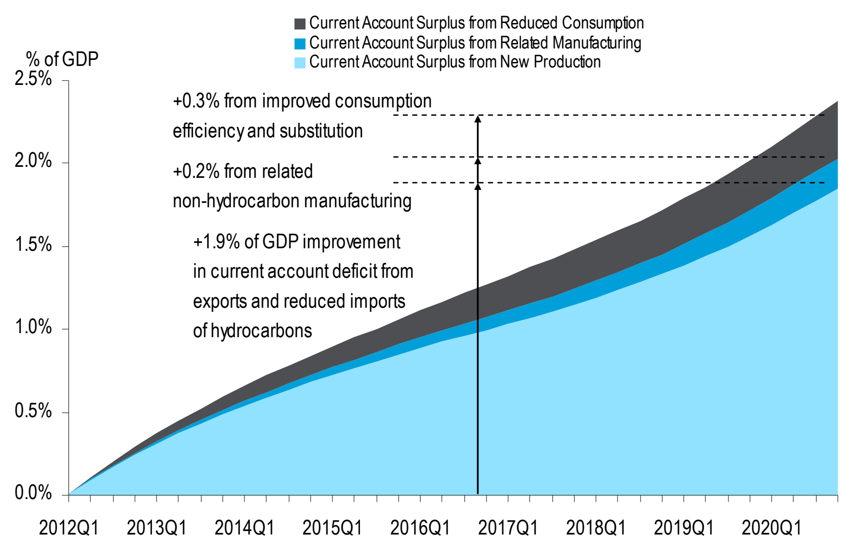
Current accounts and the US dollar

New production and reduced consumption may also have dramatic effects on the national current account

Perhaps the most intriguing consequence of the new energy demand and supply profiles for the US would be their potential impact on the US current account deficit. The US has perennially run a large negative current account deficit, peaking at -6% of GDP in 2005. As of the end of 2011, it is running at about -$496bn annually or -3.2% of GDP. By comparison, in December 2011, the US was importing on net about 7.4-m b/d of crude oil and petroleum products, dragging down the US trade deficit to the tune of -$270bn on an annualized basis or 1.7% of GDP, more than half of the total deficit.

Cumulatively, some -$471 billion (in 2005 $) may be shaved off the current account deficit or about 2.4% of the hypothetical GDP in 2020. About 1.9% percentage points of this 2.4% cumulative impact stems from the reduction of imports and the boost in exports of hydrocarbons from new oil and gas production, with the remainder coming from reduced consumption from new technologies, and exports of related manufactured products.[14] This more than offsets increases in net imports in the non-oil and gas sector.

Figure 72. Impact on US Current Account, 2011 to 2020E



Source: Citi Investment Research and Analysis

While the effect of current account imbalances on the US dollar has been historically weak, our simulations suggest the improved current account picture may help the US dollar to appreciate anywhere from +1.6% to +5.4% in real terms, potentially helping reverse a historical long-term decline in the US dollar since the 2000s.

[14] The MA model suggests just oil-related production alone would improve the US current account by +1.2% of GDP.

Economic consequences in perspective

The scale of the potential economic consequences is staggering, raising visions of a minor Industrial Revolution

At this point, it may be useful to step back and consider the sheer scale of the potential economic consequences in perspective: We are contemplating hundreds of billions of dollars of new output, three or four million new jobs, a current account deficit slashed by half or more, and a strengthened dollar firmly reasserted as the reserve currency of choice. Not to mention the potential strengthening of U.S. federal and state government finances, the national security implications of improved energy independence, a resurgence of the nation's technological and manufacturing competitiveness, the social implications of new wealth and job creation, and many other silver linings.

It is difficult to square these rosy visions with the current reality of a nation still struggling to shake off the aftermath of the 2008 Great Recession, with millions still unemployed, economic recovery still uncertain, worries over ballooning fiscal debts, a hollowing out and loss of manufacturing competitiveness, tremendous angst and hand-wringing over volatile oil prices and dependence on oil imports, deep social divisions, and political paralysis. But if our analysis is accurate, then in only eight short years, this situation may be turned upside-down and economists, policymakers and the nation as a whole may confront new "problems" around managing a vast hydrocarbon windfall and preventing "Dutch Disease."

Of course, this vision should not blind us to the fact that these numbers are only estimates based on a "good-case" scenario for technological and geological breakthroughs powering future hydrocarbon production and reduced consumption, a vision that may falter from regulatory impediments and other risks as discussed above. And even if North America or the US were to become a net exporter of oil and hydrocarbons, the integrated nature of the global oil and gas market and imbalances between the domestic consumers and producers of hydrocarbons means price spikes and volatility will always bring with it economic dislocation and costs.

Nevertheless, the coming generation of Americans and its leaders may be privileged to witness a remarkable resurgence of the American economy and industry, led by its energy sector, but spreading to the rest of the manufacturing sector and beyond, a potential minor Industrial Revolution. As Clint Eastwood remarked in his trademark gravely voice on a much-discussed 2012 Super Bowl commercial, "Yeah. It's halftime, America. And our second half is about to begin."

Conclusions

Transformations abound, but what do they mean for global stability?

Deep divisions between competing interest groups could challenge robust supply growth in North America, but are also unlikely to entirely block this

The implications of robust supply growth in North America are profound. They include the potential for a radical re-industrialization of the US, based on energy intensive industry and a surge in employment growth not only around enhanced drilling and industrial growth but in a host of other industrial and services sectors. Both of these factors are likely to result in significant objections from environmental groups concerned with the emissions associated with more hydrocarbon production, transportation and processing. Rarely in recent years have democratic processes in North America or elsewhere been able to process conflicting concerns let alone lead to consensus decisions based on trade-offs between conflicting objectives, dearly held by competing political groups. But it is unlikely that the push toward greater production will be entirely blocked.

The consequences of North American hydrocarbon output (and lower demand) on the US current account and federal budget could be major, positive and long-lasting

Equally if not more significant are the other consequences of higher domestic output and lower demand, particularly in the United States. The US has been confronting two massive imbalances — the persistent dual deficits of the current account and budget. We have not focused any attention on the potential reduction in the federal budget deficit that could result from a persistent surge in hydrocarbon production, but we have on its twin, the current account. The largest single factor in the persistent US current account deficit has been combined crude oil and petroleum product imports. The latter has already come to a sudden end, and the US now looks likely to remain a growing net petroleum product exporter for decades to come.

Hydrocarbon exports would play a significant role in this transformation — *if* regulations allow for them

The Canadian and US mid-continents have reduced whatever shortfall in crude oil supplies existed in years past in their own regions. They are within eye shot of becoming surplus, helping to support increasing petroleum products exports from the US Gulf Coast. The result for the US is a strong divide between the US mid-continent, from the Canadian border to the US Gulf of Mexico, where product exports will soon be followed by crude oil exports *if* regulations will allow it. But the US East and West Coasts are likely to remain both crude oil and product short and unless new pipelines are built to bring products to these coastal areas or unless changes in the protectionist Jones Act are underway, the US will be continuing to export oil products and natural gas derivatives to other countries from Louisiana and Texas and import similar products in coastal regions.

although even a reduction of imports itself could be significant — a contrast with China, which looks likely to increase its dependence on oil imports

Even so, the US will be narrowing the current account deficit progressively, with the oil and petroleum product elements reducing the share of oil imports in the deficit massively, probably by more than 80-90%. And meanwhile, the resurgence in energy intensive industries will be moving in the same direction — reducing imports and promoting exports. Whether the current account moves to surplus or to a narrow deficit is less relevant than what this change means. Among its meanings is a structural strengthening of the US dollar by 2020 if not long before that. The current account has been one of the major vulnerabilities confronting the role of the US in the global economy and with the coming profound changes in the current account is an array of accompanying new strengths for the US, strengths that look to be elusive for major rivals, including China, in the years ahead, given the likely increases in China's dependence on oil imports and the low probability that China's level of regulatory control or transparency will enable the country to rival the US globally in financial terms in the decades ahead.

As North America becomes the new Middle East, this poses a challenge to the future role of OPEC

But other implications are also profound. The US, Canada and potentially Mexico will together be sustaining their role as base load incremental suppliers to the world market. As a result they will pose a dual challenge to OPEC. On the one hand, OPEC countries will be unlikely to increase output at the same rate as the three North American countries combined. On the other hand, unlike OPEC members, the North American trio, each a member of the OECD, are unlikely to try to protect prices by limiting output. If more non-OPEC oil is developed in the latter half of the decade, particularly in deep waters, the potential loss of influence by OPEC is significant. No wonder OPEC producers are looking so closely at what is unfolding in North America.

And natural gas exports could weigh increasingly heavily on global markets, eroding the appetite for oil-linked prices

With respect to natural gas, continued growth of supplies in North America, particularly as North America becomes an incremental exporter of LNG, is likely to weigh increasingly heavily on global markets. This is especially likely toward the end of this decade when new base load supplies from Australia and West Africa start to rival in size exports from the Middle East, especially Qatar. These new suppliers to markets will be vying for access to the most rapidly growing markets — China and India — where the appetite for oil-linked natural gas is waning rapidly. North American natural gas exports, from Alaska, Canada and the US Gulf Coast could well prove critical in pushing the natural gas world to a revolutionary new pricing regime.

Near-term supply tightness likely masks the significant geopolitical consequences of the emergence of North America as the new Middle East

Finally, there are significant geopolitical consequences of the supply push from North America. These are likely to be camouflaged over the next two or three years, as markets continue in all probability to be tight despite the persistent growth of North American supply. This tightness is likely to stem from lagging production growth elsewhere in both OPEC and non-OPEC countries, persistent demand growth in emerging markets, and a particular dilemma being confronted in major oil exporters in OPEC. These countries are seeing domestic demand increasing rapidly, while they are unlikely to be able to increase supply rapidly enough to meet this demand. This means that their exportable surpluses will be contracting at a time when their budgetary requirements are rising for a host of factors related to last year's MENA and Arabian uprisings. The result is probably tighter markets ahead.

but as supply eases towards 2020 and global prices weaken, the US will need to reflect deeply on its resurgent ability — but waning willingness — to play its traditional , major role at the center of the global energy order

But by the end of the decade, with investments coalescing in offshore output in the Gulf of Mexico, offshore West and East Africa, India, the Caspian and various places in Asia, markets look likely to turn significantly looser. And when that happens, North American petroleum (including products and LNG) exports will likely be rising. Thus, virtual energy independence is likely to come to fruition at a time of weakening prices. It is unclear what the political consequences of this might be in terms of American attitudes to continuing to play the various roles adopted since World War II — guarantor of supply lanes globally, protector of main producer countries in the Middle East and elsewhere. A US economy that is less vulnerable to oil disruptions, less dependent on oil imports and supportive of a stronger currency will inevitably play a central role globally. But with such a turnaround in its energy dependence, it is questionable how arduously the US government might want to play those traditional roles.

Technical Appendix

Notes on the economic methodology

Providing accurate estimates of economic consequences is conceptually challenging and methodologically perilous, given the complexities and large feedback loops inherent in the US and global economy. The nature of this analysis, which requires a counterfactual assessment of what the world might have looked like if this revolution in energy supply and demand did not occur, is necessarily speculative.

Nevertheless, to provide some guidance as to economic consequences of such a dramatic phenomenon, we attempt to simulate two scenarios using a large-scale computable general equilibrium (CGE) model of the US economy.

The first scenario is our the “base-case” or “business-as-usual” scenario, assuming standard decline rates for US hydrocarbon production as well as more modest declines in consumption. This is to be compared to an alternative scenario in which we assume instead the much more dramatic surge in US hydrocarbon production and declines in consumption discussed in the text.

Our estimates of the economic consequences for growth, unemployment, the current account, and so on are derived by calculating the difference in the simulated paths for these economic variables between our counterfactual base case and our new alternative scenario.

The main advantage of this methodological approach, in particular using a large-scale CGE model, is that it can take into account multiple causality loops that may be important. For example, on top of the direct increase in output from higher hydrocarbon production, the oil/gas wealth would raise consumer incomes, stimulating further virtuous cycles of new spending on goods and services, higher production, and growth (known as the multiplier effect). On the other hand, this stimulation of the US economy may also cause inflation to heighten, leading the Federal Reserve to hike interest rates faster than it otherwise would have to cool down the economy. These potentially significant second-round and third-round effects can be captured in our approach.

The disadvantage is that even the most sophisticated macroeconomic model likely fails to capture important features in something as complex as the US economy. Also, the style of our CGE model is distinctly “Keynesian,” in the sense that explicit consumption, savings, and investment functions are estimated using all available data that can go as far back as 1945. This introduces features such as a relatively low marginal propensity to consume and a positive propensity to save that may not accurately reflect current and future US conditions. Normally, they are better recommended for use in short-term forecasting within a few quarters rather than the almost decade-long horizon we are considering.[15]

[15] As a robustness check, we also ran a similar exercise using not our own US CGE macroeconomic model but that provided by Macroeconomic Advisors, a leading economic consultancy. Our numbers are surprisingly similar to that resulting from the MA Model, lending some confidence in our estimation results.

And, in the interest of simplicity and tractability, we ignore many potentially important dynamics that may occur if these projections come to fruition, distorting our estimates. For example, we assume that government fiscal spending remains identical in both scenarios, when larger tax windfalls may cause the government to raise spending instead. We do allow for changing monetary policy using an estimated Taylor Rule.

In particular, these assumptions should caution us as to overestimating the impact on the current account. According to standard economic accounting, the current account is equal to national savings, both private and public, minus national investment, again both private and public.

Our counterfactual analysis critically does not assume differences in the national investment required between the base case and the alternative scenario, as we desired to assess the economic consequences in the framework of a technological boost to total factor productivity in the hydrocarbon sector. Also, our CGE model assumes marginal propensities to consume less than one, based on the cumulative postwar US experience but one which may not reflect recent behavior. Furthermore, we assume that government spending does not change in the two scenarios, when in practice, government savings may decline as they raise spending in response to higher tax income. All of these would bias the impact on the current account upward.

Other research (see "How Much Is This Going To Hurt? New Evidence on Global Adjustment to Oil Shocks," published 13 March 2012) suggest that the US non-oil current account typically moves in the opposite direction to movements in the oil-related current account though with a lag. While the report focused on the reaction to a surge in oil prices, it may also be interpreted to suggest that the hydrocarbon windfall may vanish within five years from a combination of lower private and public savings, higher spending on non-oil imports, and higher investment.

Nevertheless, the nature of this counterfactual analysis in the context of a general equilibrium requires sweeping assumptions to maintain tractability and cohesion. We maintain that this exercise may nevertheless help provide ballpark numbers of the economic consequences, a useful starting point for further discussion and more refined analysis.

Breakdown of the Job Creation Estimates

Figure 73. Job creation impacts of Energy 2020

Employment Sector	Thousands of Jobs
Total	**3577**
Total Industrial	2257
Total Nonmanufacturing	1109
Oil and Gas Extraction	549
Other Nonmanufacturing	561
Total Manufacturing	1148
Petroleum Refineries	24
Paper Products	56
Chemicals	53
Stone, Clay, and Glass	40
Primary Metals	17
Iron and Steel Mills and Products	13
Alumina and Aluminum Products	4
Fabricated Metals	178
Machinery	88
Computers and Electronics	55
Transportation Equipment	108
Other Manufacturing	528
Non-Industrial Non-Agricultural Goods and Services	1301
Construction	69
Utilities	5
Wholesale trade	58
Retail trade	153
Transportation and Warehousing	47
Information	27
Financial Activities	79
Professional and business services	193
Educational Services	37
Health care and social assistance	208
Leisure and hospitality	135
Other services	65
Federal government	24
State and local government	199
Agriculture, Forestry, Fishing, Hunting	19
Agriculture Salaried	12
Agriculture Self-Employed	7

Source: Citi Investment Research and Analysis

IMPORTANT DISCLOSURES

NOW / NEXT

Key Insights on the Shifting of Energy Supply and Demand

INFRASTRUCTURE

Growing dependence on imported oil and gas to feed continuous domestic demand growth in the face of declining homegrown sources. / Abundant supply is being unlocked by technological advances, which combined with a decline in US consumption driven by demographic changes, policies on fuel efficiencies and the mass-commercialization of new technologies, means a decrease in crude oil imports and increased petroleum products exports.

NATURAL RESOURCES

Coal and oil-derivatives are the main inputs for the industrial & transportation sectors in the US. / America and Canada will be re-industrialized based on dramatically lower cost feedstock than is available almost anywhere in the world – a result of the shale gas production boom – leading to higher employment and GDP.

POLICY

The complex and integrated nature of natural resource development makes it an area especially rife for politics that can both serve to buttress as well as challenge it's growth. / While the story of North American energy independence is one of incredible potential and could alter the geopolitical landscape, public policy might well be the most critical factor in determining whether the current steep supply trajectory remains robust or fizzles out.