Louisiana – The Status of the State

A Report on the Impact of Energy Activity on the State's Economy

For: GNO, Inc. Spring 2014
By: Eric N. Smith

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Executive Summary

Many people have been using the word “renaissance” recently when referring to the Gulf Coast economies generally and to Louisiana’s energy economy, specifically. While this seems out of sync with the strained budgets of both the State and the many municipalities, most energy economists see a strong performance since the 2008 recession and a relatively bright future for the state and the region.

1) Over the last five years, with the advent of new extraction technology, there has been a fundamental change in the way we access hydrocarbons, both oil and gas, in this country.

2) As a result of the fracking revolution, the U.S. now enjoys the status of being a low cost source of both natural gas and light sweet crude oil used for transportation, power generation and petrochemical manufacturing.

3) Moreover, because of the rig intensive nature of shale operations and the difficulty of replicating the US onshore drilling fleet, as well as the pervasiveness of our existing and forecasted hydrocarbon transportation infrastructure, our hydrocarbon cost advantage should be with us for a generation.

4) The cost advantage will continue to be a fundamental driver for growth of both existing production capacity and downstream manufacturing operations, as well as a driver for the addition of a number of new production facilities using both current and new technologies.

5) Existing technologies run the gamut of refining, particularly low sulfur diesel and heating oil; petrochemical manufacturing operations, including new Ammonia, Methanol and Ethylene plants; and Chlor-Alkali expansions.

6) New technologies allow plants to be centered on the use of the DRI (Direct Reduction Iron) process to produce pig iron without the use of coke. This is a new industry for Louisiana and the United States. In addition, the use of state-of-the-art GTL (Gas to Liquids) technology will allow for the conversion of a portion of the new natural gas supply into high quality diesel fuel and other refinery products -- another first for the state.

7) Beyond new and existing technologies, we will also see improvement in our export posture, both for Liquefied Natural Gas (LNG); refined products, such as gasoline, diesel and jet fuel; and for petrochemicals such as plastic resins. This has positive implications for our port facilities which are expected to see a marked increase in loadings of refined products and petrochemical intermediates destined for export markets. Evidence of this new traffic can be found in the utilization rates, and consequent increases in charter rates, for the world’s LNG tanker, refined products tankers and chemical tanker fleets. While it is

unlikely that many of these vessels will be built in the United States, new vessels will be added to the international fleet and they, along with the existing vessels, will make increasing calls in Louisiana to pick up cargoes. We should also expect to see additional ship arrivals, both as a result of the widening of the Panama Canal as well as the need to import vital raw materials such as the iron ore (from Brazil) for the new Direct Reduction Iron (DRI) facilities.

Finally, we expect to see increased domestic marine shipments, particularly of refined products. Unless the rules change, these vessels will be built in the United States, crewed and flagged, and will bring potential business to Louisiana shipyards.

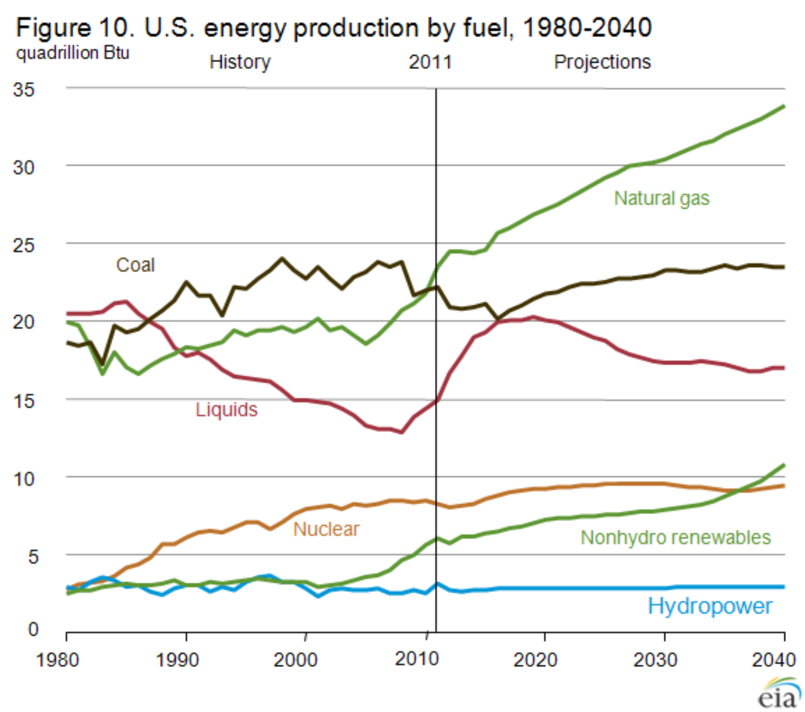
In short, the reasons why Louisiana evolved as a major energy center the first time, things like available hydrocarbon supplies, plentiful fresh water, relatively inexpensive power generation, wide ranging pipeline infrastructure, and navigable rivers with numerous port facilities, are all lined up to support the renaissance of Louisiana's industrial complex. This will not just to feed US consumption, but also support demand in the rest of the world as well. In addition, this time around we have a critical mass of well-trained upstream, midstream, and downstream workers. This is not meant to imply that we have a "surplus" of such workers. We will need to do a massive job of training new operators in order to maintain and grow the relevant workforce. However, we do start with a critical mass of trained workers that are not present in other potential energy states.

While there are always setbacks, particularly at the State and Federal policy level, for example the delays in approving the Keystone XL pipeline or the heated debate about the possible impacts of fracking technology, the economic fundamentals for the Gulf Coast in general, and Louisiana in particular, look strong. Existing refineries and petrochemical plants are running near capacity with expansions underway, funded by both domestic participants as well as by new international firms anxious to take advantage of our infrastructure and our fundamental energy cost advantages.

Current Overview of US Energy Industry-

All Sectors

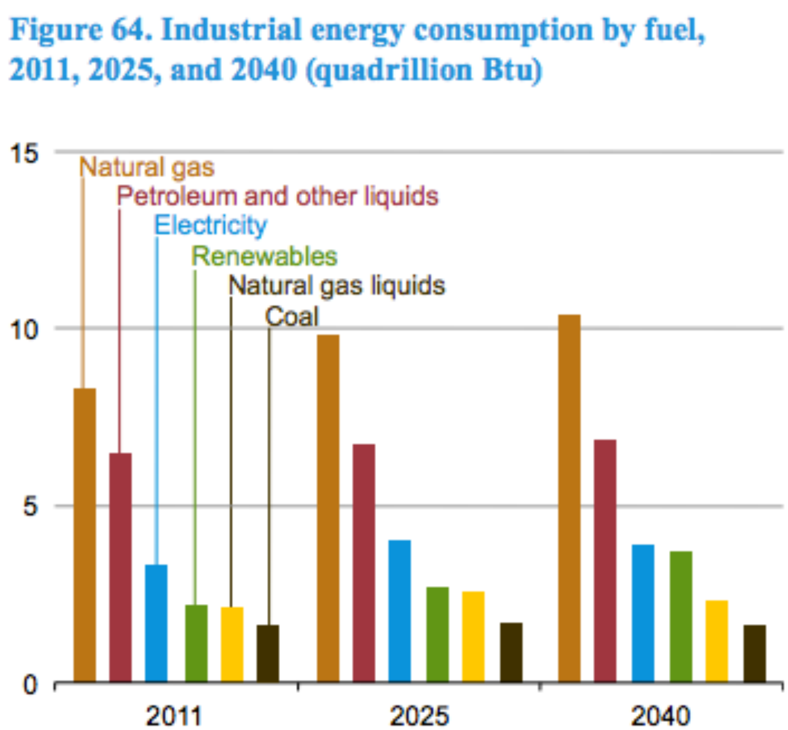
At the national level, the patterns for total energy production illustrate the dominant position of natural gas, with gas continuing to grow long term. Liquids growth is apparent through 2020 but then begins to decline even as coal remains flat. Nuclear and Hydro are also both stagnant with non-hydro renewables exhibiting good growth throughout the period, surpassing nuclear output late in the plan period.



An Energy Information Agency (EIA) report on Crude Oil production, downloaded 3-20-13, shows total U.S. annual crude production has increased from 5,077,000 barrels per day in 2007 to a level of 6,488,000 barrels per day in 2012. US Production actually increased further to 7,455,000 barrels per day for the year 2013. With stable consumption, the increase has resulted in corresponding declines in US imports, particularly of foreign light sweet crude. For the year 2014, there is another increase forecasted, of 935,000 bbl/day, to a total estimated crude production of 8,390,000 barrels/day. However, it is important to note that this aggregate growth masks the fact that we have seen significant decreases in crude production in some states and at best stable production in many others. Still, even with declines in certain regions like the West Coast, absolute national production is increasing nicely, most obviously in North Dakota and in Texas.

The anticipated long term effects on the industrial sector are summarized in the following Energy Information Agency (EIA) chart. On a British Thermal Unit (BTU) basis, natural gas continues to grow, while renewables and natural gas liquids also grow, but from lower base levels. The EIA also expects “Petroleum and other liquids”, the feed stocks for refined products primarily used in the transportation sector, to continue to grow, both for domestic consumption as well as for export. Higher liquids consumption has positive implications for natural gas demand as virtually all US refineries use natural gas to provide process heat necessary for the refining process. In fact, lack of access to gas for process heat has caused the shutdown of at least two “island” refineries, St. Croix and in Aruba and threatened a third, the Come-By Chance refinery in Eastern Canada.

These facilities supplied the East Coast of the United States with refined products. However, the need to consume part of the liquids product stream in order to produce heat and power caused their closure. 6,000 cubic feet of gas contains the same BTUs as one barrel of oil. Logically, one barrel of oil should cost 6 times the natural gas cost; gas at $4.00/thousand cubic feet should equate to oil at $24/barrel. With oil at $100/barrel, the ratio is over 25:1. This means that oil-based BTUs are now roughly four times the cost of gas-based BTUs. This resultsin closures of refineries in economies that cannot afford job losses.



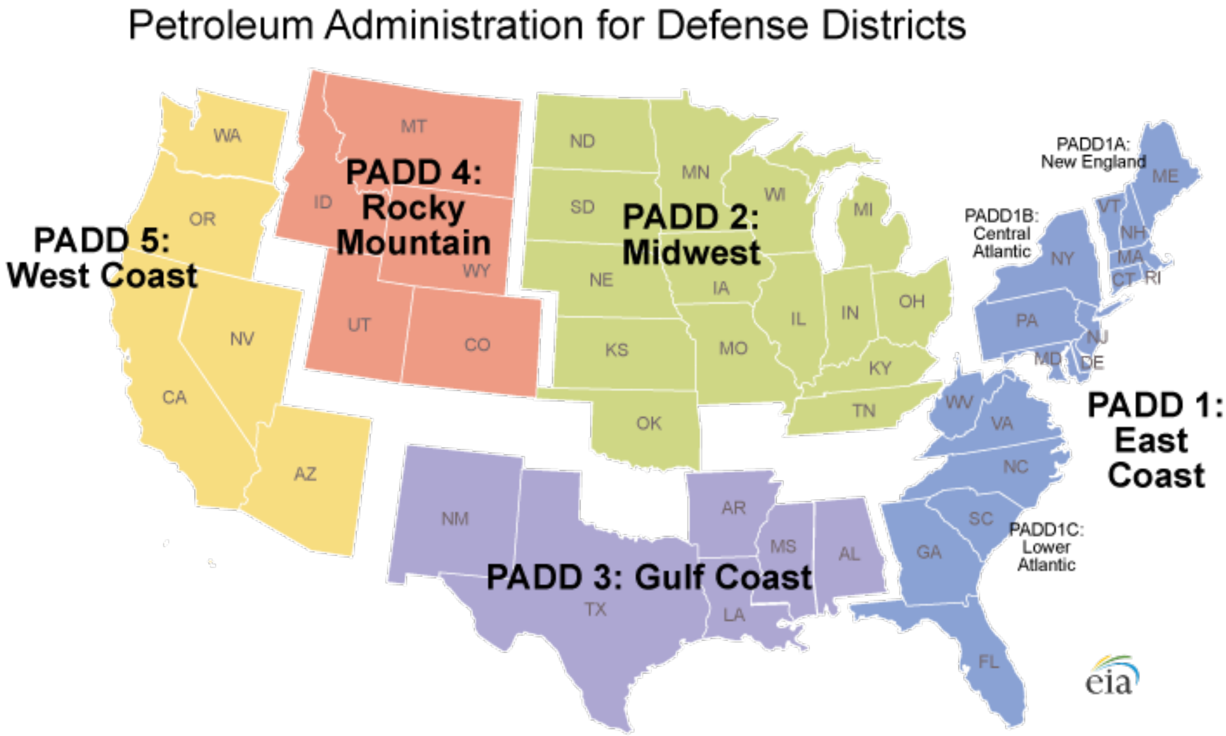
Source: EIA 2011 Annual Energy Outlook

Petroleum and other liquids production continues to grow, both as a result of deep water offshore production coming on stream after the interruptions caused by the Macondo spill in 2010, as well as by onshore shale oil developments, most notably the Bakken in North Dakota, as well as the Eagle Ford and Permian basins in Texas.

In addition, Natural gas liquids (NGLs), co-produced with natural gas in the “wet” gas shale developments, such as the Eagle Ford, South West Marcellus and Granite Wash, are also making significant contributions to the US liquids energy balance, on the order of two million bblper day. While a portion of this production is used directly in the manufacture of plastics and elastomers (synthetic rubber), a large share finds its way into the gasoline pool, once it has been converted into alkylate, a high octane component blended into gasoline. Per the graph, NGLs exhibit growth, peaking in 2025. This is in contrast to Natural Gas which continues to grow and becomes the major provider of energy to the Industrial sector in the United States. Two other sources, Nuclear and Hydropower, are anticipated to remain flat, while non-hydropower renewables, such as ethanol and bio-diesel, continue to grow but from a much lower base. Helped by significant fiscal subsidies, this latter category has already bypassed hydropower, in 2000, and is anticipated to surpass Nuclear power late in the forecast period. Finally, Coal recovers a bit from its recent precipitate decline but is not able to sustain growth in the face of significant environmental challenges and competition from natural gas in the electric power sector.

PADDS

The EIA uses PADDs, or Petroleum Administrative Defense Districts, to account for energy production in various regions of the United States. These districts were originally defined in WWII under Franklin Roosevelt and his energy expert, Harold Ickes, to aid in the allocation of scarce petroleum resources needed to support the Allied war effort.



The Gulf Coast states, along with New Mexico and Arkansas, make up PADD 3, which is and has been the heartland of US energy production, refining and petrochemical manufacturing for a number of years. Energy products and raw materials historically flow from PADD 3 into other areas of the country, most notably into the Midwest - PADD 2 and to the East Coast - PADD 1. At the heart of PADD 3 are Louisiana, Texas and the Gulf Federal Offshore, also known as the Outer Continental Shelf. Crude Oil, Natural Gas, Natural Gas Liquids (NGLs), and a host of refined products and petrochemical intermediates flow North and East out of PADD 3 via pipelines, marine vessels, trucks and rail lines, all headed to these highly populated areas for further processing into a myriad of consumer products. Almost half of the US refined products and petrochemical products produced in the US emanate from PADD 3 with Louisiana having 3,246,020 bbl./day or 18.6% of total US refining capacity.

From 2007 to 2012, PADD 1 - the East Coast and PADD 4 - the Rocky Mountain Region, have both increased crude production. The East Coast - PADD 1, grew by 5,000 barrels/day to a still relatively low level of 25,000 barrels/day while PADD 4 - the Rocky Mountain region, grew from 368,000 to 447,000 barrels /day. The majority of that latter growth occurred in Colorado.

The largest region, PADD 3, increased from 2,820,000 barrels/day in 2007 to a level of 3,798,000 barrels/day in 2012, or an increase of 34.7% during the period. Growth was led by Texas, which almost doubled from 1,072,000 barrels/day to 2,000,000 barrels/day in 2012. To put that in context, that exceeds production from a number of oil exporting countries.

The other big source of growth in PADD 3, Federal offshore production, remained flat between 2007 and 2012, with production in the earlier period at 1,282,000 barrels/day vs. 1,267,000 barrels/day in 2012. Recent production in May of 2013 was 1,213,000 barrels/day while the recent peak was 1,735,000 bbl./day in August of 2009. Certainly some of the offshore decline being seen today can be traced back to interruptions in development resulting from the Macondo spill in April of 2010. Another reason for stagnation has been a lack of success when looking for new liquids production in the shallow water Gulf of Mexico (GOM). While deep water oil production has been increasing, declines in existing shallow and intermediate depth production have been blunting the deep water gains.

Louisiana has also seen a decline from 211,000 barrels/day in 2007 to 193,000 barrels/day in 2012, while May of 2013 registered production of 203,000 barrels/day. Despite Louisiana's stagnant output, the adjacent federally administered Outer Continental Shelf (OCS) is still a major production source for the US and Louisiana has hopes for continued recovery of both the deep water offshore regime as well as for new onshore development in the Tuscaloosa Marine Shale north of Lake Pontchartrain. However, on a statewide basis, we have barely been able to keep pace with depletion in existing onshore and shallow water Gulf of Mexico production.

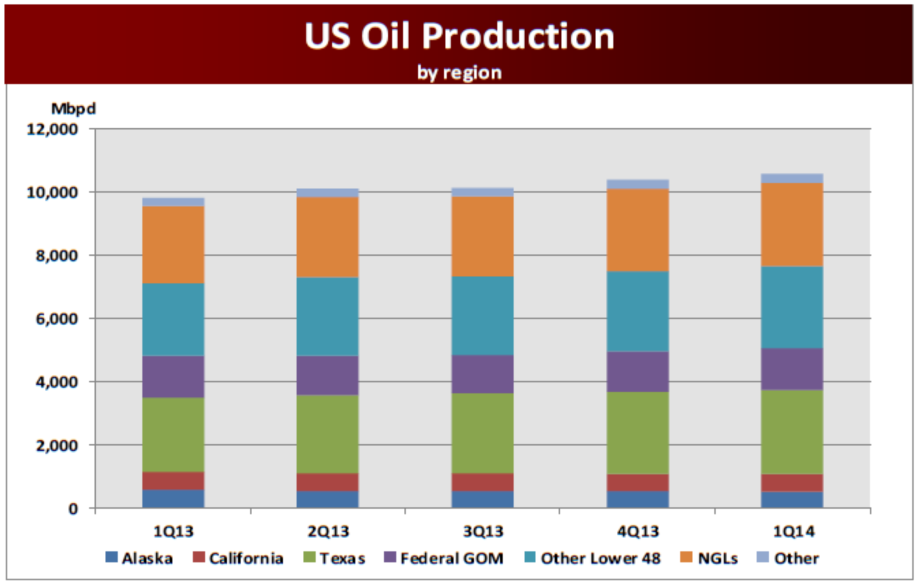
As mentioned, Texas has increased from 1,072,000 bbl./day in 2007 to 2,000,000 bbl./day in 2012 with EIA reporting a rate of 2,525,000 barrels/day in May of 2013, largely a result of increased output in both the Eagle Ford Shale play in East Texas and additional shale developments in the Permian basin in West Texas. As the following chart illustrates, PADD 3 continues to grow and, as of 2012 represented 3,798,000 bbl./day or 58.5% of all domestic crude oil production. If we look at May 2013 numbers, that percentage increases to 59.2%. From a policy standpoint, Louisiana needs to capture a significant portion of this new production to support Louisiana's refining and petrochemical infrastructure. Our Achilles heel is that this is all light sweet crude and our complex refineries have a limited capacity to process this type of crude. Absent the ability to process this crude, Louisiana and Texas will be faced with the need to continue importing heavy sour crudes but without the ability to export the excess domestic sweet crude.

Another area experiencing significant growth, albeit from a lower base, was PADD 2 - the Midwest, where production more than doubled from 478,000 barrels/day in 2007 to 1,115,000 barrels/day in 2012. Most of that growth was a result of expanded production in

North Dakota, which grew from 124,000 bbl./day in 2007 to 663,000 barrels/day in 2012. Production continues to grow with May of 2013 reporting 810,000 barrels/day. North Dakota is home to the Williston basin and the Bakken Shale. Also helping PADD 2 performance was Oklahoma, which improved from 175,000 in 2007 to 244,000 in 2012. As the following chart illustrates, growth in PADD 2 has been steady and dramatic.

Finally, PADD 5 - the West Coast, declined with 2007 production of 1,390,000 barrels/day dropping to 1,111,000 barrels/day in 2012. Alaska and California, the major producers in PADD 5, have both seen significant declines in production. Alaska dropped from 722,000 barrels/day in 2007 to 526,000 barrels per day in 2012 (515,000 in May of 2013) while California dropped from 599,000 barrels/day to 531,000 barrels/day in 2012 with May 2013 production also at 531,000 barrels/day. California peaked in February 1986 with production of 1,109,000 barrels/day. Alaska has seen recent production decline from 722,000 barrels/day in 2007 to 526,000 barrels/day in 2012 and to 515,000 barrels/day in May of 2013. The Alaska decline is all the more notable given its peak production of 2,086,000 barrels/day, which occurred in March of 1988. Sad to say, TAPS, the Trans-Alaska Pipeline is now operating at about 25% of peak output.

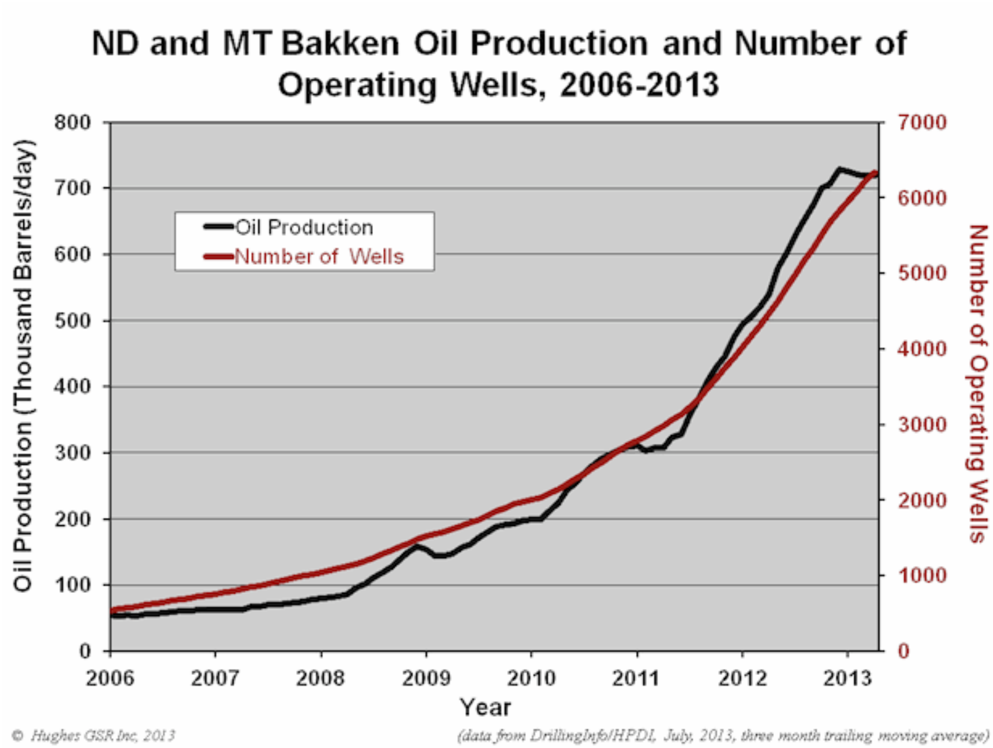
Graphically, we can see the short term forecast of total US production in the following chart from the International Energy Agency (IEA) which shows the massive contributions to production associated with relatively few plays concentrated in a few US locations. While our own Gulf of Mexico is a significant player, matching the combined output of California and Alaska, it is still only about half the output of Texas. The other important item to note is the sizable contribution made by NGLs, which are produced as co-products with natural gas.

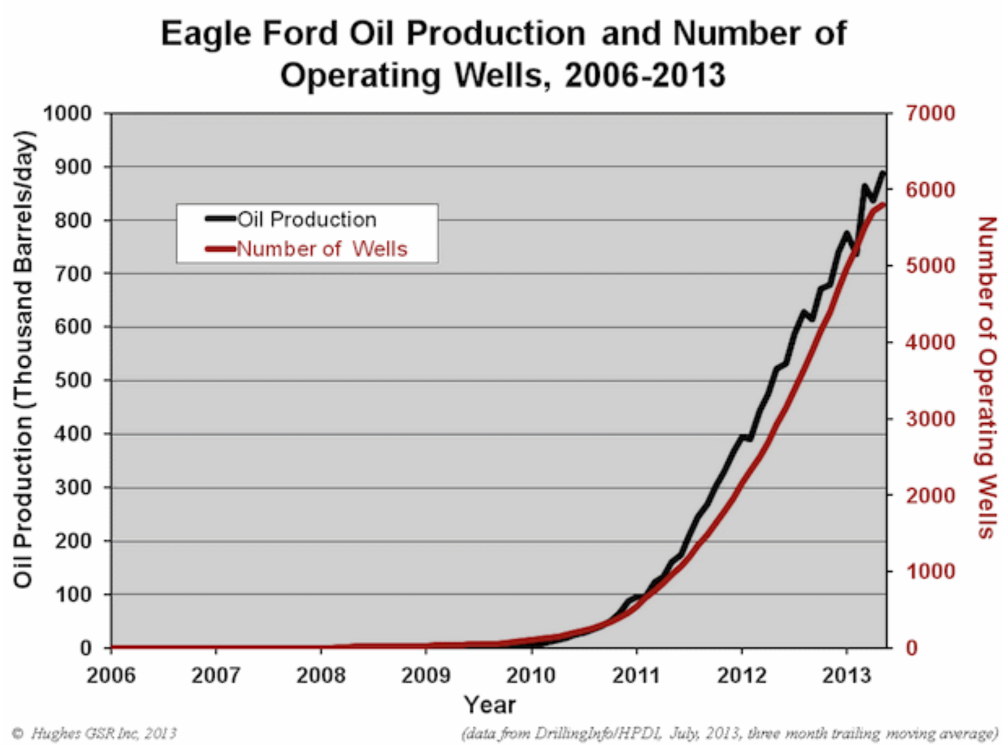


SOURCE: IEA Oil Market Report.

The cumulative growth in oil production from the Bakken and Eagle ford shale has come at a price and that is the number of wells required to generate, maintain, and grow the increasing production. As can be seen below, it has required over 6,300 wells in the Bakken and almost the same number of wells to support Eagle Ford shale production. In the Bakken case, production was above 700,000 bbl. per day while in the Eagle Ford shale it was above 800,000 bbl. per day. Drilling that many wells has required about half of the US inventory of drilling rigs or 25% of the world's inventory of drilling rigs. This is one of the arguments people make against the sustainability of continued growth from shale production in the US and the export of that capability internationally. There are barely enough rigs, crews, and service personnel available to support such drilling intensity in the US much less in the rest of the world.

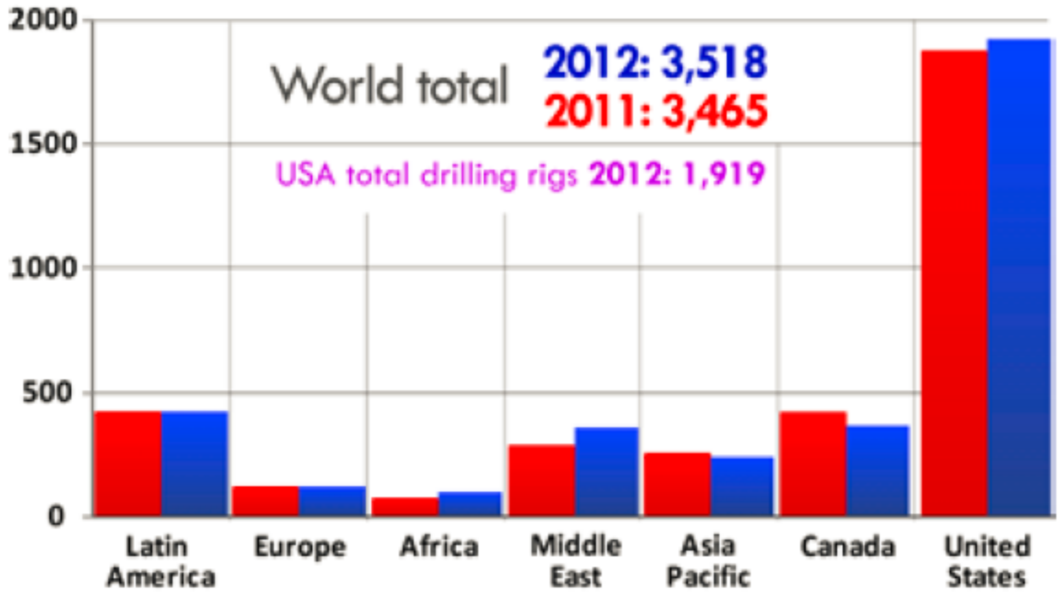
The following charts cover the Bakken and Eagle Ford fields and demonstrate that oil production and the number of operating wells correlate relatively closely. As time passes, an even higher proportion of the rig fleet will be needed just to maintain production rather than to create production growth.


ND and MT Bakken Oil Production and Number of Operating Wells, 2006-2013
Oil Production
Number of Wells
Oil Production (Thousand Barrels/day)
Number of Operating Wells
Year
© Hughes GSR Inc, 2013
(data from DrillingInfo/HPDI, July, 2013, three month trailing moving average)


Eagle Ford Oil Production and Number of Operating Wells, 2006-2013
Oil Production
Number of Wells
Oil Production (Thousand Barrels/day)
Number of Operating Wells
Year
© Hughes GSR Inc, 2013
(data from DrillingInfo/HPDI, July, 2013, three month trailing moving average)

The next chart highlights the rig census worldwide and the concentration of rigs in the United States. While there has been some increase in the worldwide rig count in 2012, most of the improvement has been in the United States.

Figure 7. Worldwide active drilling rigs count (2012 average)



Of the U.S. drilling rigs, roughly 90 percent were equipped for horizontal drilling, an essential component in shale development. In 2011, nearly 95 percent of U.S. horizontal and vertical wells were fractured[40] compared with less than 10 percent outside the United States.

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While typical worldwide shale maps highlight the widespread geographic locations of shale deposits, the lack of available equipment, trained crews, and infrastructure will limit the rate at which those deposits can be developed. While there is ongoing work at several international locations, including in northeast China, these trials are in the earliest of stages. Moreover, once fields are discovered, there will still be the issue of transportation infrastructure needed to get the gas to locations where it can be monetized. In the case of the United States, much of the infrastructure, ranging from pipelines to fractionation plants and steam crackers were already in existence.

The following table provides a "snapshot" of the number of rigs committed to major shale concentrations in the United States. This chart is provided by Raymond James and uses publically available data from Baker Hughes. The top three shale regions account for 890 or 50% of the 1,778 active rigs in the United States.

The other key takeaway is the relative lack of drilling activity in dry gas shale plays. Note that Haynesville shale, here in North Louisiana, is only supporting 41 rigs while the Barnett, between Dallas and Fort Worth in Texas is only supporting 28 rigs, and the Fayetteville in Arkansas is only supporting 11 rigs. The differences between these locations and the Permian/Eagle Ford regions in Texas and the Bakken region in North Dakota can be summed up with one phrase, "wet shale vs. dry shale".

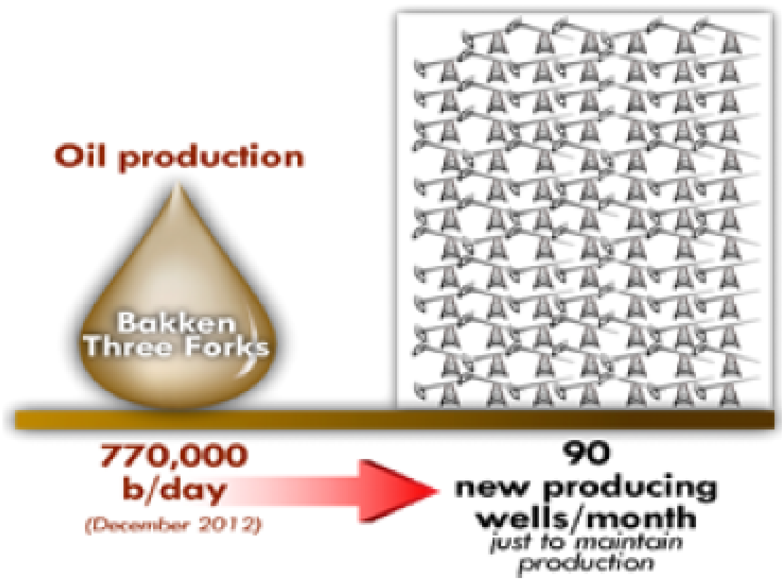
U.S. Rig Count Breakdown

	8/9/2013	8/2/2013	W/W Δ	YTD Δ	YTD % Δ	Y/Y Δ	Y/Y % Δ
Total Count							
U.S. Rig Count	1778	1782	(4)	16	1%	(153)	-8%
By Basin*							
Permian	452	447	5	-4	-1%	-45	-9%
Eagle Ford	259	262	(3)	10	4%	-7	-3%
Bakken	179	178	1	-12	-6%	-32	-15%
Marcellus	81	81	0	-8	-9%	-12	-13%
Mississippi Lime	60	60	0	-16	-21%	-13	-18%
Granite Wash	66	69	(3)	10	18%	-3	-4%
Haynesville	41	41	0	2	5%	0	0%
DJ Basin	44	44	0	9	26%	5	13%
Barnett	28	28	0	-7	-20%	-12	-30%
Cana Woodford	31	32	(1)	-4	-11%	-16	-34%
Uinta	26	26	0	-1	-4%	-9	-26%
Utica	35	35	0	5	17%	16	84%
Powder River Basin	27	27	0	1	4%	3	13%
Pinedale	20	20	0	0	0%	-1	-5%
San Joaquin Basin	22	22	0	6	38%	-13	-37%
Fayetteville	11	11	0	-2	-15%	-3	-21%
Piceance Basin	16	14	2	5	45%	4	33%
Arkoma Woodford	2	1	1	-2	-50%	-6	-75%
Other	378	384	(6)	24	7%	-9	-2%
Drill For							
Oil	1385	1388	(3)	67	5%	(47)	-3%
Dry Gas	126	124	2	(12)	-9%	(28)	-18%
Wet Gas	260	264	(4)	(41)	-14%	(81)	-24%
Thermal	7	6	1	2	40%	3	75%
Trajectory							
Horizontal Oil	800	812	(12)	8	1%	(18)	-2%
Horizontal Gas	265	261	4	(55)	-17%	(77)	-23%
Horizontal	1065	1073	(8)	(47)	-4%	(96)	-8%
% Horizontal	60%	60%	0%	-3%		0%	

Source: Baker Hughes, Inc, Raymond James research
Includes all trajectories

Further highlighting the issue of drilling intensity is the following graphic presentation showing that as total production increases, the requirement for replacement drilling also increases so that a significant number of rigs and corollary equipment, like fracking spreads, need to be devoted to simply maintaining existing production levels. While these wells are relatively quick to drill and complete, the sheer number of required wells needed to maintain steady production rates is impressive. Just consider one of the leading shale oil plays, the Bakken - Three Forks play: maintaining production requires ninety new producing wells to be brought on stream **per month** in order to maintain the current production level of 770,000 bbl./day of production. As absolute production continues to increase, the need for this maintenance drilling continues to escalate because of the relatively short period before production declines occur. This chart is included in the recent (June, 2013) report by Leonardo Maugeri who is a Fellow at the Belfer Center for Science and International Affairs, a unit of the Kennedy School at Harvard University. The report, "The Shale Oil Boom: A US Phenomenon".

Figure 2. Drilling intensity: The case of Bakken-Three Forks



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The decline rates for shale plays are significantly steep. This table, also courtesy of Leonardo Marguri in his recent Belfer Center article entitled, "The Shale Boom: A U.S. Phenomenon" details the anticipated decline rates in three major basins. Bear in mind that the decline in each period is calculated based on the amount of reserves remaining at the end of the prior year. His estimates show the percentage decline forecasted over a five-year period for each of the big three wet shale plays. The cumulative effects, for example in the Bakken - Three Forks area, is that by the end of the third year, 74% of all of the oil that will ever be produced from a given well has already been produced.

Table 1. Estimated decline rates of the Big Three U.S. shale oil plays

Play	Year 1	Year 2	Year 3	Year 4	Year 5
Bakken-Three Forks	43%	35%	30%	20%	20%
Eagle Ford	55%	40%	30%	20%	20%
Permian Basin	50%	40%	30%	20%	20%

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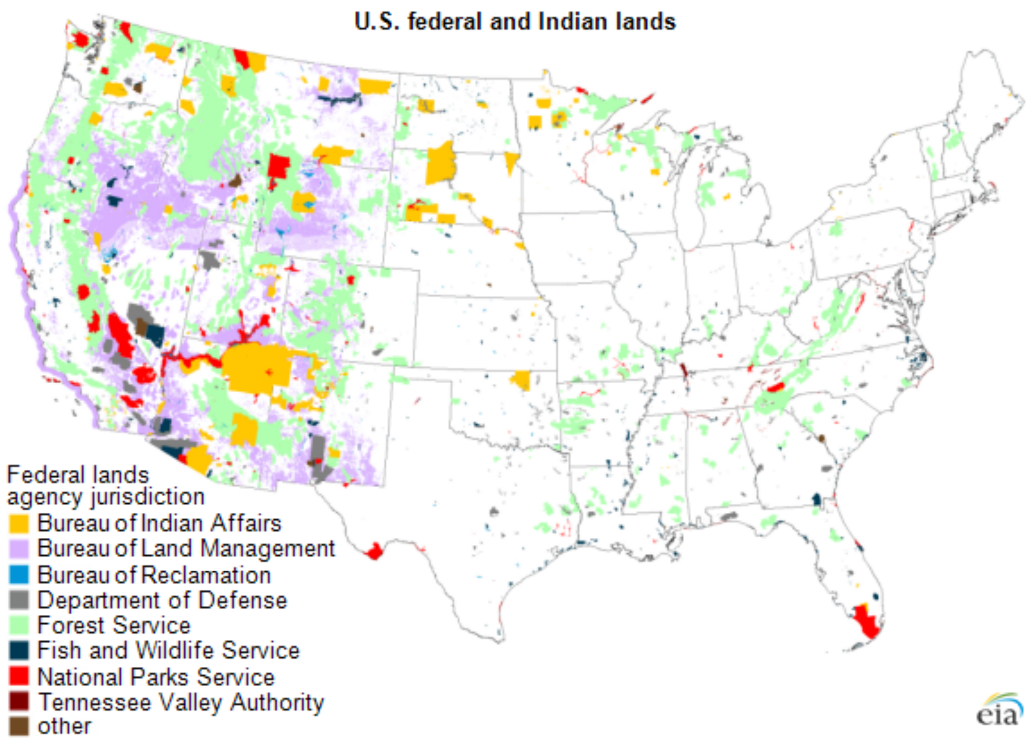
Leonardo Maugeri argues in his article that the United States will be the only large shale gas and oil-producing nation for at least a generation. His primary reason is that the extreme drilling intensity necessary to commercialize shale plays requires the commitment of half of the world's supply of drilling rigs just to develop and maintain production in the United States plays. There are simply not enough drilling rigs, completion equipment and pressure pumping equipment, to say nothing of trained crews, to allow any other individual foreign shale play to be developed in parallel with the efforts in the United States, regardless of the size of the proved reserves. While other countries will eventually add drilling equipment and narrow the gap, the United States starts with a huge home court advantage.

Production of fossil fuels from Federal controlled land onshore

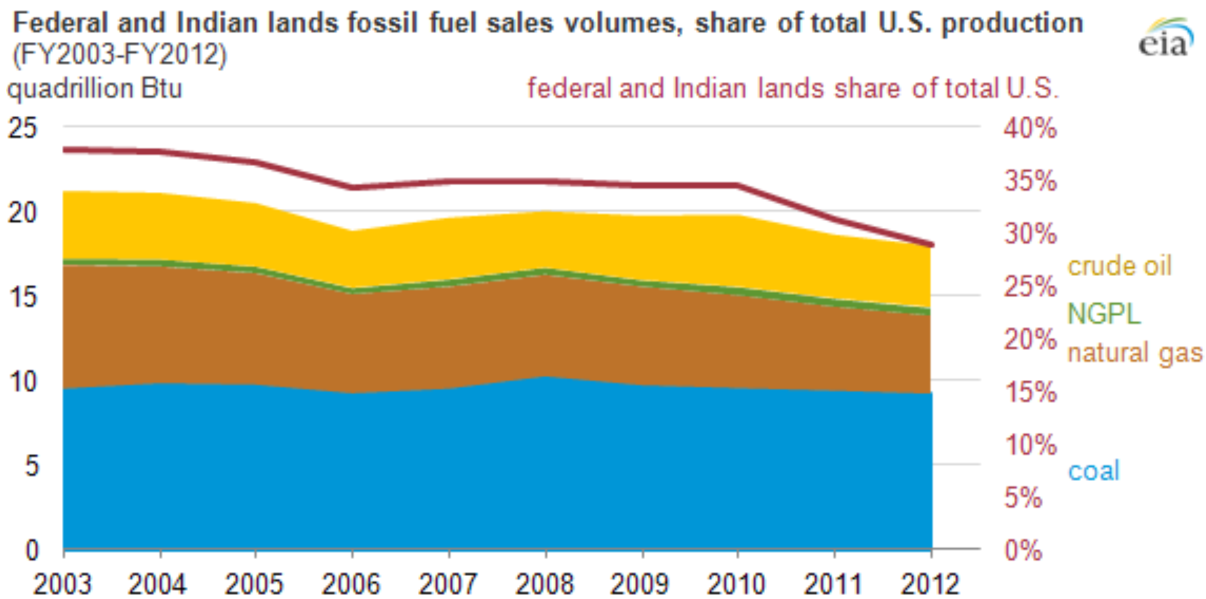
It may be worth noting that all of the increases in United State fossil fuel production have occurred primarily in areas not directly controlled by the US government. As this EIA chart points out, from an onshore perspective, federally controlled lands are disproportionately located in PADDs 4 and 5 and are regulated by eight major federal agencies. Not surprisingly, western states are complaining.



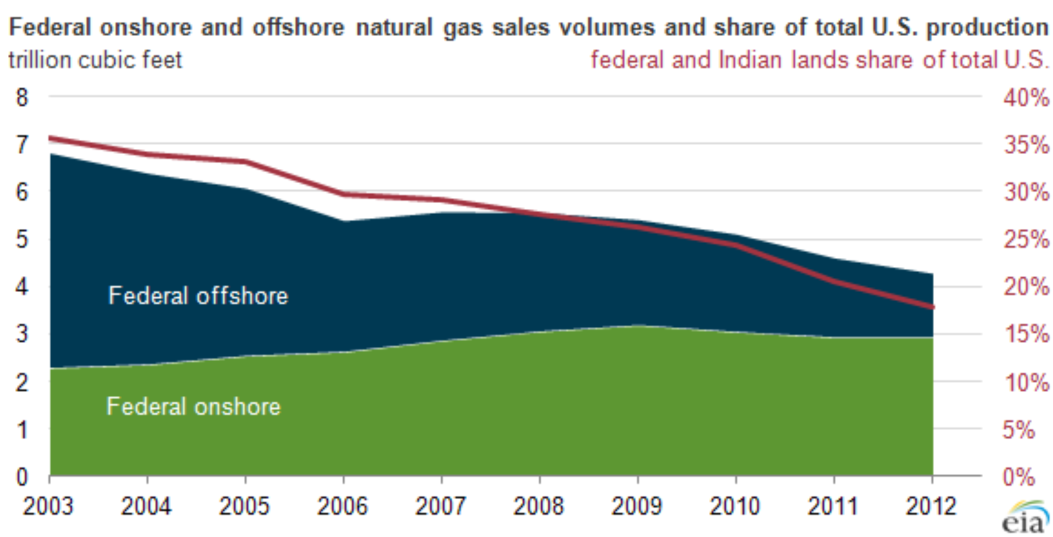
The effects of the drop in federally controlled production have been most pronounced in the natural gas sector, followed by the petroleum sector and then with coal activity. On a btu basis the drop in share has been from 38% in FY 2003 to a 27% in FY 2012. (The Federal fiscal year runs from October 1st to September 30th).

Because most of the federally controlled onshore sites are in the West, some elected officials in these areas are objecting to the economic consequences of what they perceive as a disproportionate imposition of new restrictive federal regulations on their production activity. The result can be to drive new energy development to areas where production from federally controlled land is minimal. The burden of new federal rules to control fracking on federal leases consequently shale gas and oil production is seen as challenging by officials. The source of this challenge is that this function is already subject to regulation by the individual states.

The following chart from the EIA details the long term decline in federally controlled site production.



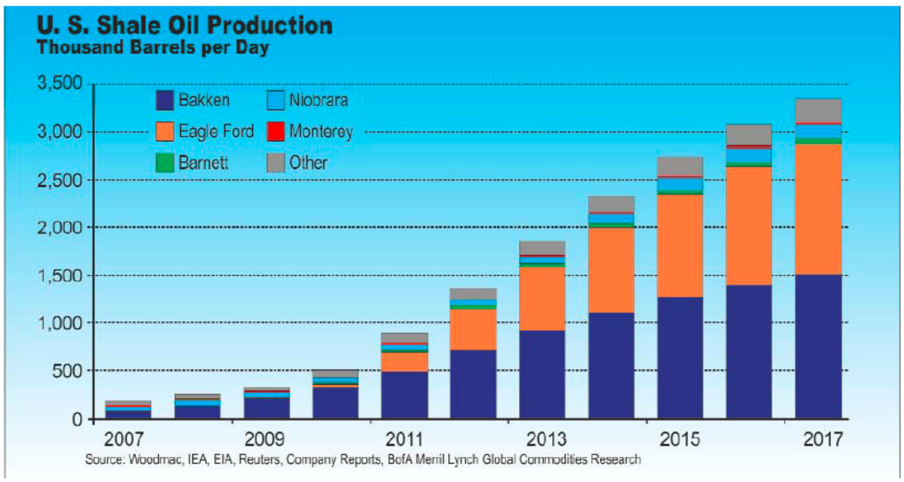
In terms of the natural gas sector, the aggregate federal decline has been from approximately 37% of total production in FY 2003 to a level of 18% in FY 2012 with Federal offshore production declining in absolute terms from two thirds to one third. Federal onshore production increased from approximately one-third to two-thirds of the lower aggregate.



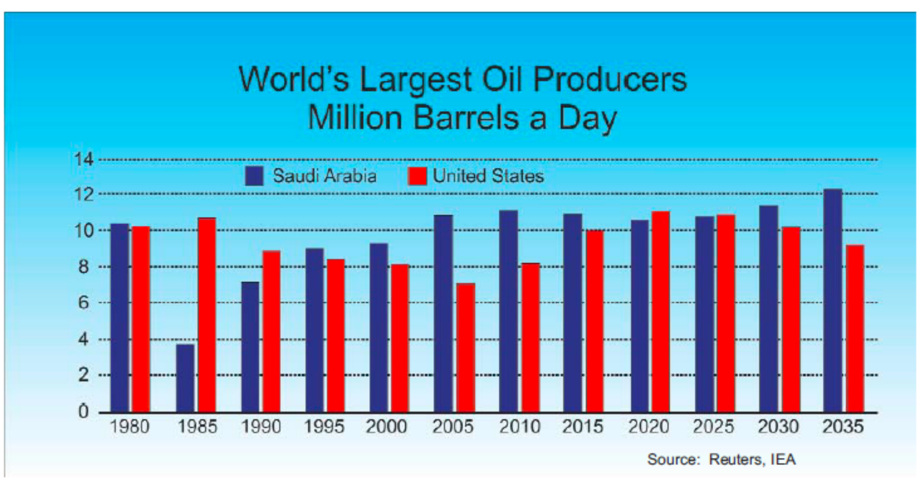
Certainly, some of the decline in production has been the result of natural decline in more mature, federally administered, conventional fields. However, additional waning has been attributed to regulatory red tape and uncertainty encountered in attempting to discover and develop new fields, of any type, in federally administered areas. Furthermore, regulatory reactions to adverse events, like the federal drilling moratorium after the Macondo spill, and the subsequent halt and slowdown of issuing drilling permits, have had damaging impacts to energy production.

Bakken Shale Oil

In the last six years, with the advent of shale oil and gas production in the United States, major supplies of new light sweet crude oil have been created. The following two charts from *The Consultant*, a publication of the engineering firm, W.S. Nelson and Company, points out that the majority of near-term gains in crude production in the United States are expected to come from even more growth in the so-called "wet shale" plays with the Bakken in North Dakota and Eagle Ford shale in Texas accounting for the bulk of the growth.

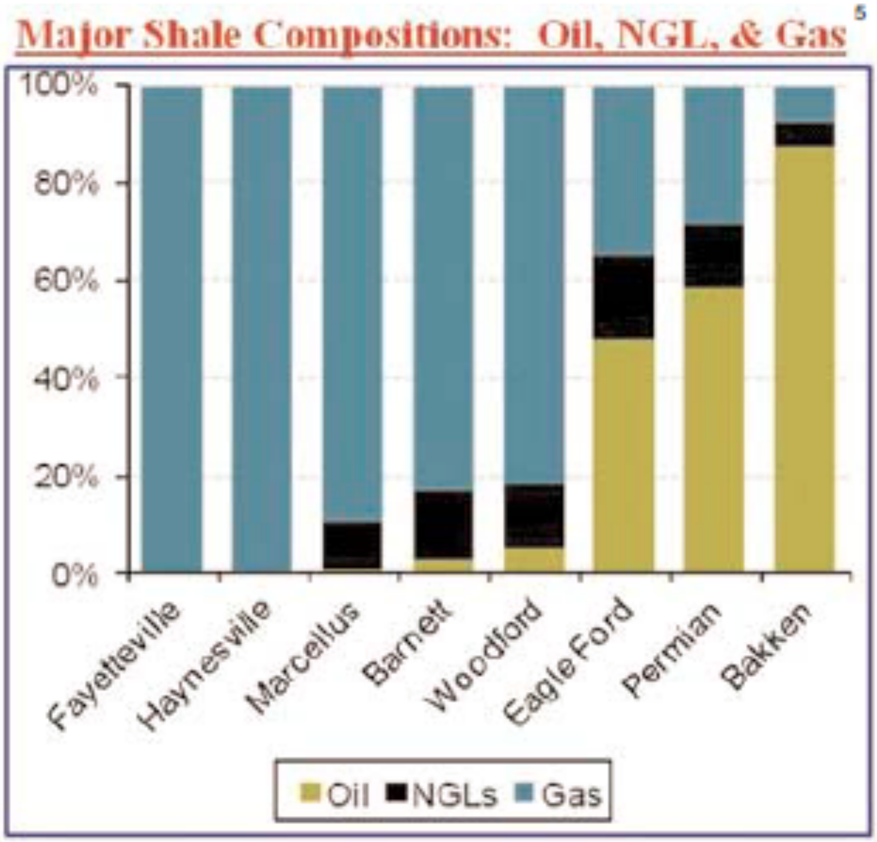


This rapid growth in production, even assuming continuing declines in conventional production, should allow the US to surpass Saudi Arabia, by 2020. However, by 2025 Saudi Arabia should be back on top.



[3] 5 Hidden Oil Shale Plays for 2013," www.seekingalpha.com (accessed January 2, 2013)

Of all of the shale plays, Bakken production is most heavily weighted towards liquids and NGLs. This is also a feature of the Eagle Ford and Permian Basin shales in Texas. All three of these plays continue to enjoy high rates of drilling while the so-called dry gas shale plays, such as those in Fayetteville and Haynesville, are experiencing reduced drilling activity.



The crude from the Eagle Ford, Permian and Bakken formations can most profitably be used by refineries in the interior of the United States, the so-called "simple" refineries which are not equipped to process heavier, more viscous, and more sulfur laden crudes commonly consumed by "complex" refineries located along the Gulf Coast.

Historically, the Gulf Coast has generally preferred to ship locally produced light, sweet crudes inland and to import heavy sour crudes for its own use. Light sweet crudes produced along the Gulf Coast, or that were imported into US Gulf Coast crude oil terminals, move inland to supply the Midwest (PADD 2) refineries. The rationale is that, while refining heavy sour crudes on the Gulf Coast requires more capital intensive "complex" refineries, the heavily discounted prices associated with heavy sour crudes more than makes up for the additional processing cost.

On the East Coast, the requisite sweet crudes have typically been imported through marine terminals located at or near existing refineries. Due to refinery shut downs, many of the former refinery sites have actually been converted to refined product import terminals. Those refineries that remain now supply less than one third of the area's requirements of three million bbl./day of products. The balance is imported from Eastern Canada or from Europe and, via the Colonial pipeline, from the Gulf Coast.

As output of domestic sweet crude has increased, the pipeline infrastructure required to transport crude has suffered bottlenecks with the result that the price of West Texas Intermediate, the marker crude for US inland production including Bakken crude, dropped well below the price of Brent Crude, the marker crude that determines coastal crude prices in the Atlantic Basin, including crudes delivered to the East Coast (PADD 1) and Gulf Coast (PADD 3).

With the arrival of the new light sweet crudes coming out of the Bakken as well as out of other shale plays, such as the Eagle Ford and Permian in Texas, there has been a massive rebalancing of existing pipelines and other transportation infrastructure. One positive result, for consumers, of the imbalance between takeaway capacity and new production has been depressed prices for the newly produced, but stranded, sweet crude. The lower domestic crude prices not only helped inland refineries to compete but also acted to accelerate the conversion from imported sweet crudes to domestic crude. Now, some of the Gulf Coast sweet crudes formerly being sent to PADD 2 are actually being used in coastal refineries rather than being shipped to PADD 2 refineries. Also, some of the pipelines that moved sweet coastal crude inland have now been "reversed" to allow surplus Bakken crude to flow south to the Gulf Coast.

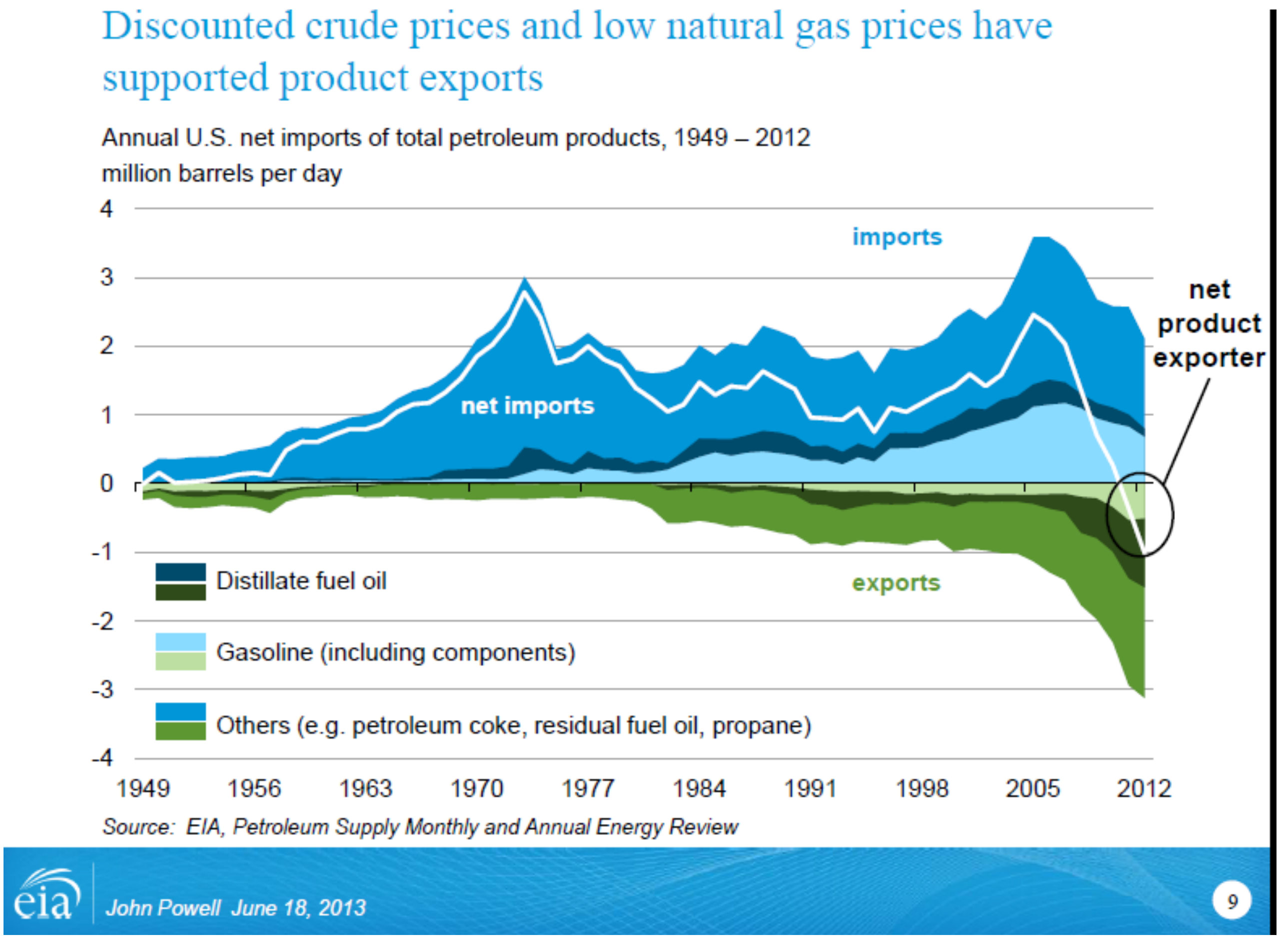
Finally, several new pipelines have been built, including the purely domestic sections of the Keystone XL system, with the intent of relieving the bottlenecks created by the sudden increase in crude oil production emanating from the Bakken and other shale oil basins. These modifications and enhancements allow even more sweet crude to arrive on the Gulf Coast, further displacing imported sweet material.

The continued price disparity, lessened by the modifications mentioned, between West Texas Intermediate and Brent marker crudes, has also allowed for the emergence of crude oil "unit" trains. These trains, containing up to 115 cars and four or more engines, can move up to 70,000 barrels of crude from locations in North Dakota to refinery locations in the Midwest and Eastern Canada as well as to refineries one the Gulf Coast and East Coast. Using rail is more expensive and less safe than using pipelines, but so far, the shortage of pipeline alternatives and the added flexibility of rail shipment have allowed for a rapid increase in rail car shipments of crude, on the order of a 57% increase between 2011 and 2012. Of course, this new transportation option necessitates new rail equipment and specialized rail transfer facilities at both the beginning and end of the new routes. Here in Louisiana, the biggest such facility is in St. James Parish while a smaller facility in New Orleans East has recently been completed. One side benefit for Louisiana is a boom in building new rail tanker cars at facilities in the Shreveport area.

Another new transportation initiative involves moving Bakken crude via pipeline and rail to Corpus Christi and Houston onshore terminals and from there, via tanker vessels, either directly to refineries or alternatively to “LOOP”, also known as the Louisiana Offshore Oil Port. Upon arrival at LOOP, crude is delivered offshore then transported via subsea pipeline to the Cloverly storage terminal, south of Houma and nearby Port Fouchon. From there, the crude moves through pipelines to various refineries. Using LOOP normally allows the importers of crude to use larger, more economic, tankers such as Very Large Crude Carriers (VLCCs) and Ultra Large Crude Carriers (ULCCs), which cannot enter the shallow Mississippi River or Houston Ship Channel due to draft limitations. In the domestic case, the offloading buoys had to be modified to accept the smaller domestic tankers, which can transit Gulf Coast ports and channels.

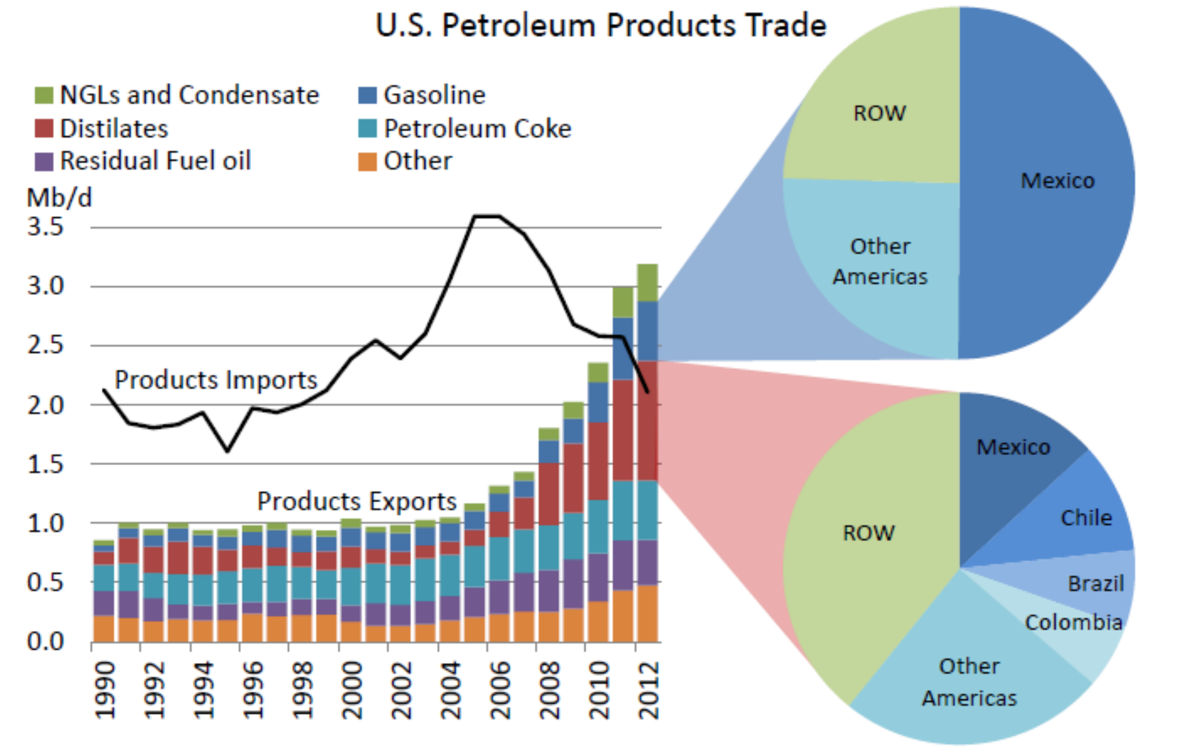
Import/Export Status

The United States will continue to be net importers of crude oil for some period of time. However, the country is already a net exporter of refined products as shown in this recent EIA chart. In 2012, the United States crossed over to being a net exporter of finished products with imports of refined products, shown above the abscissa, declining since 2005 while exports of refined products demonstrate an accelerating trend since 2005. Note that the accelerating exports are concentrated in the areas of NGLs (Natural Gas Liquids), chiefly propane, as well as distillates and heavier products. The white line highlights the crossover to being a net exporter of refined products.



In terms of the ultimate destinations of our new exports, the predominant market for gasoline is Mexico and Latin America while the distillate exports are more distributed. However, Latin America and Mexico are still taking a majority of the exports. Consciously expanding the Rest of World (ROW) share should be a priority.

Changing trade flows

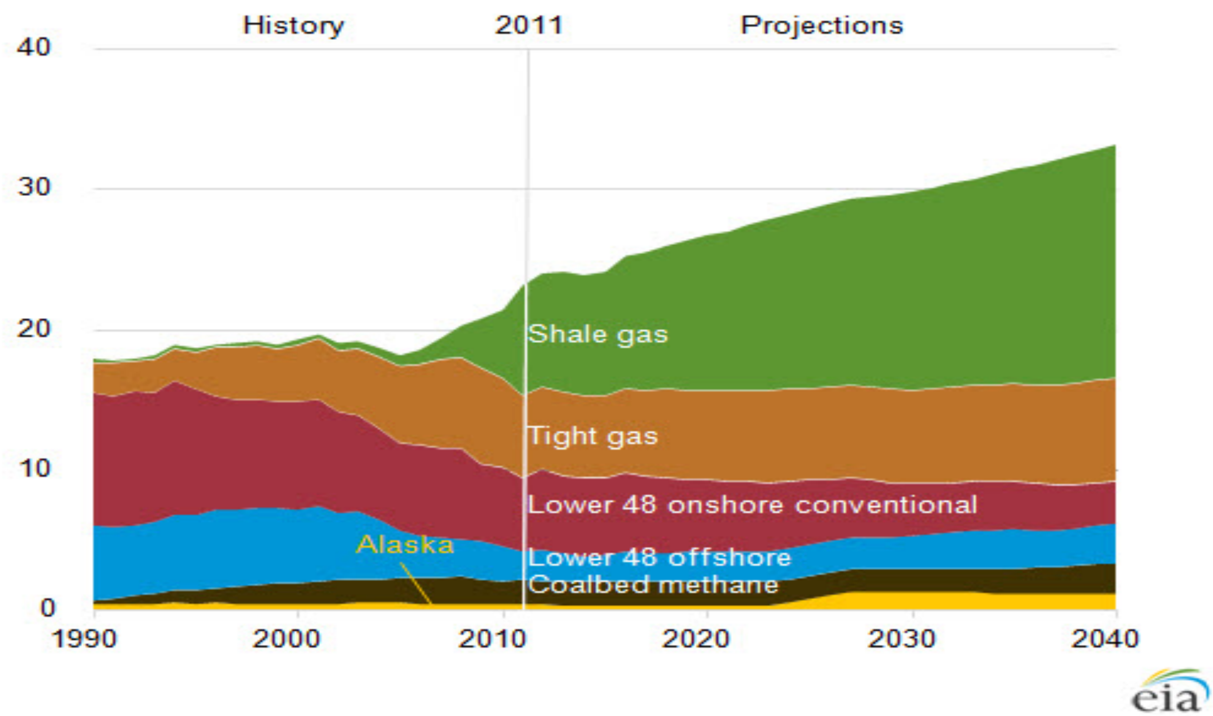


Data source: EIA. Gasoline includes finished gasoline and blending components.

Shale Gas

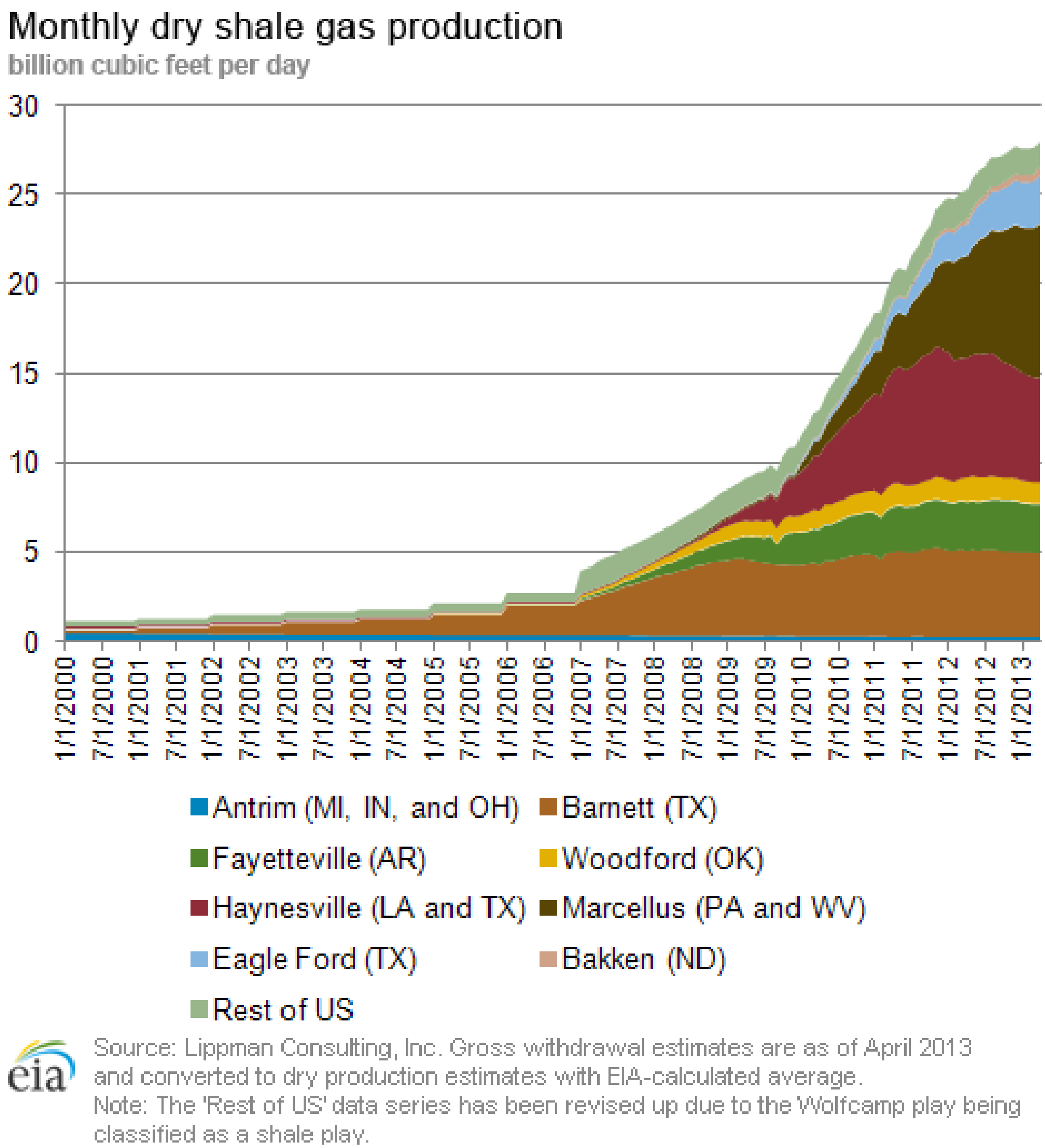
We now move on to a discussion of Natural Gas and Natural Gas Liquids. The next chart illustrates the rapid growth in shale gas over the last decade, coupled with declining production of conventional gas in the lower 48 states, both onshore and offshore. Much of the natural gas produced in Alaska is re-injected due to the desire to increase oil production as well as the lack of any viable pipeline capacity to move this gas to the population centers of the lower 48 states. Since 1969, some Alaska gas from the Cook Inlet area has been converted to LNG and shipped to Japan from the Kenai Peninsula. However, the depletion of existing gas fields, coupled with the lack of pipeline capacity from the North Slope, has hampered efforts to maintain gas supply to the plant as well as to competing local communities in Alaska.

Figure 91. Natural gas production by source, 1990-2040 (trillion cubic feet)



Alaskan gas as, well as lower 48 conventional gas production and coal bed methane, are all expected to grow slowly -- if at all -- due to their inability to compete with lower priced shale gas supplies. The next chart illustrates the rapid growth that has taken place in the various shale plays with most of that growth occurring since 2007. One note of caution, several of the early shale plays such as the Fayette, Barnett and Haynesville, here in Louisiana, are showing declining production, a result of the dry nature of the gas produced and continuing low prices for dry gas. The Fayetteville in Arkansas is down from 14 in August of 2012 to 8 rigs as of February 28, 2014. The Barnett is down from 40 rigs to 24 rigs in the same period and the Haynesville is relatively stable with 43 working rigs on February 28, 2014 versus 41 in August of 2012.

However, should there be a modest increase in gas prices, say to the $5 to $6 range, production levels in these now dormant plays could recover nicely.



We have also seen steady growth in annual US natural gas consumption driven by the shale gas revolution. The source of growth from the demand side is from the increasing use of gas-fired power plants as well as increased demand for gas and gas liquids by existing petrochemical plants and refineries. We mention US refineries because of their dependence on low cost natural gas for the process heat they need for the refining process as well as due to their use of NGLs as feed stocks.

Natural gas based process heat is a distinct advantage in the Atlantic basin market. Refineries without this capability, for example the “island” refineries at St. Croix and Aruba, have been shut down due to the high cost of using part of their high cost liquid input as fuel to provide heat and power for the refinery. The higher cost of Atlantic basin Brent crude compared to WTI (West Texas Intermediate) has also adversely impacted these vulnerable facilities.

Another opportunity and challenge for natural gas is the anticipated development of a bulk export market. This market expands in two ways. First, we anticipate major pipeline exports to Mexico with the gas being used to support Mexican power generation and industrial development. Because Mexico pays North American prices for the gas, the same effects that help US manufacturing will also help Mexican manufacturers as they compete in world markets.

Secondly, the addition of liquefaction and expansion of at least four, and probably more, LNG import terminals to export service could allow for exports of LNG to international clients beyond the reach of pipeline service. A range of challenges have hindered this expansion: 1) continued public opposition to hydrocarbon usage via hydraulic fracking and 2) concern that the US will lose the international competitive advantage it currently holds due its captive source of low cost natural gas and gas liquids. This particular trepidation is two-fold. First is the possibility of a diminution in the supply of domestic gas with a consequent price rise that may erode profit margins. The second concern is that low cost gas exports can find their way to international chemical suppliers located outside of the US, further reducing their competitive advantage.

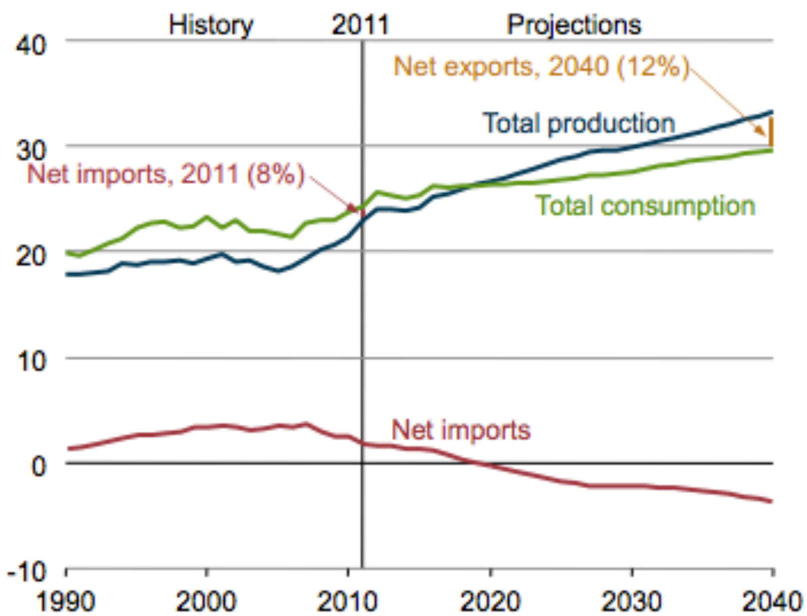
Though the amount of gas involved will not result in meaningful changes in world supply or in large increases in domestic gas prices, the economic impacts on jobs and revenues, positive and negative, are worth exploring.

In the intermediate term, some forecasters attribute greater export volumes via new pipeline routes to Mexico than to LNG export facilities. As for Louisiana’s position, we are better served by the aggressive development of LNG exports as the existing and new pipelines serving Mexico from the US will cross the border in Texas. To date, three LNG export facilities have received full approval. The first and largest facility is under construction at Sabine Pass on the Louisiana-Texas border. The second is located at Freeport, Texas, south of Houston. The third is one of the original LNG import facilities in the US and is located in Lake Charles, Louisiana.

Another twenty proposals, for both conversions and new construction are awaiting approval by Federal regulators. Gaining timely approval to export LNG to “non-FTA” countries is being delayed with the setbacks attributed to politics faced by the administration. The reason non-FTA countries are important is that the major countries importing LNG fall into this category. Japan alone imports about one third of the world’s supply of LNG and is a non-FTA country. Of interest is the fact that the third facility mentioned above intends to carve out a niche market supplying only FTA clients located in Latin America.

The following chart, again from the EIA, forecasts the switch to being a net exporter of natural gas, both as LNG and pipeline gas, to occur within this decade as natural gas marketers succeed in gaining regulatory approvals as well as in constructing new export infrastructure.

Figure 89. Total U.S. natural gas production, consumption, and net imports, 1990-2040 (trillion cubic feet)



Source: EIA Annual Energy Outlook 2013 May, 2013.

Lastly, there is significant debate about the potential for price rises in natural gas going forward. The author agrees with the argument that prices will rise, but only to the point where the full costs of producing dry gas, the marginal supply source, from shale are reached. At that point, the rapid response characteristics of shale gas projects will result in new production and relatively stable gas prices in the $4 to $6 range.

When scarcity causes prices to exceed the upper end of that range, coal will again displace gas in power generation, resulting in a drop in gas demand, gas price declines, and the cessation of new gas drilling.

When gas prices drop below $4, coal consumption will be displaced and gas demand for power generation will increase, causing prices to again increase to the point that operators will be comfortable drilling new wells. Indeed, the equilibrium pattern reflects the current state of gas production in the US shale plays. There appears to be about an eighteen-month lag between cessation of drilling and a decline in production followed by an uptick in gas prices and a resumption of drilling.

One complication to this simple economic model results from a very logical tactic of operators, who, in a low price environment, switch from dry gas drilling (for example in the Haynesville or Barnett shale,) to “wet” gas drilling as seen in the Eagle Ford shale or in the southwest Marcellus shale. “Wet Gas” is simply the material produced from certain shale fields where significant quantities of natural gas liquids and condensate are produced as co-products with the dry natural gas.

Operators with the ability to drill in both types of formations (dry or wet) preferentially drill wells in the wet gas plays when natural gas prices are low and NGL prices are high. If the NGLs associated with these latter plays sell for higher prices and the associated methane co-produced from the wet gas sells at a lower price, the higher NGL prices allow the operators to sell methane at prices as low as $3 per mcf while still producing an average price for the composite well head gas price that is above the hurdle rate, approximately $4, necessary to justify drilling new wells. This tactic works well until the market for NGLs is saturated at which point NGL prices drop and operators are left with no option except to stack rigs and wait until natural gas and/or NGL prices improve.

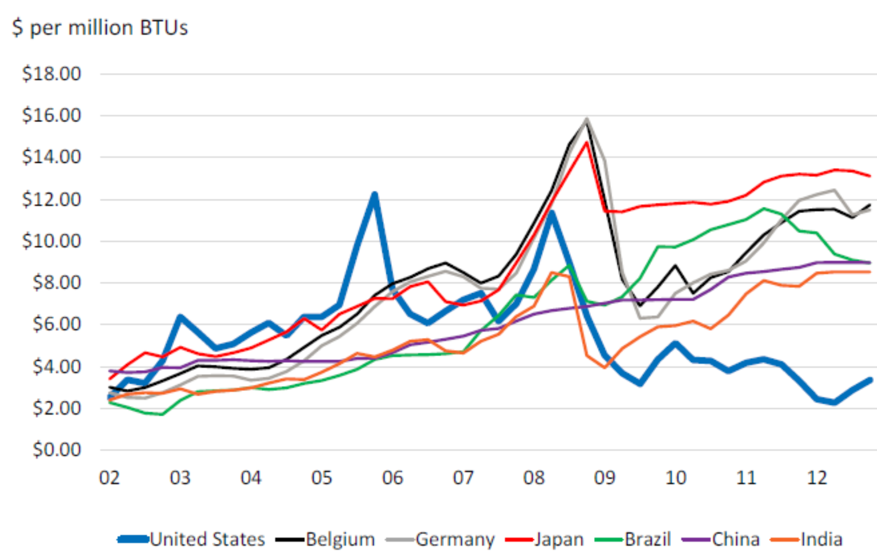
Both events occur when demand exceeds supply for these commodities. Likely causes for positive changes in gas demand include new power generation capacity coming on stream as well as the growth of LNG export markets. NGL volumes will increase as downstream conversion and plastics manufacturing infrastructure comes on stream and as exports of LPGs increase.

New infrastructure is being constructed, ranging from new pipelines and rail systems to new NGL fractionators, steam crackers, and downstream polymerization capacity; they collectively will allow for an increase in the volume of NGLs and the products derived from them.

Beyond the domestic market, the advent of shale gas has also allowed for the re-emergence of exports of US petrochemicals based on natural gas and natural gas liquids.

The United States, shown below by the thick blue line, has gone from a position of having relatively high natural gas prices, in 2005 and 2006, to having relatively low prices today. That price advantage translates into a preference for using natural gas based chemistry for manufacturing a variety of petrochemicals versus. using Gasoil (Naphtha), a product of the refining operation. It happens that most of the world's non-US petrochemical capacity is based on the latter process while infrastructure in the United States is based on the former.

FIGURE 4
TRENDS IN NATURAL GAS PRICES ACROSS THE WORLD



Sources: EIA, Petrobas, IMF, World Bank, various national statistical agencies

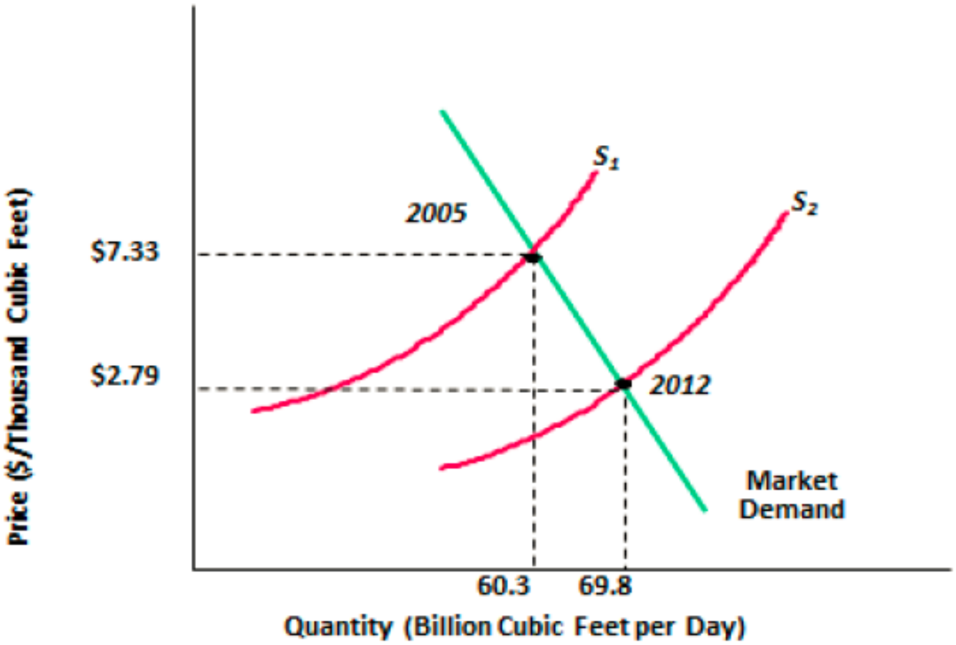
We discuss the prospects for the export of chemical intermediates later in the paper, but for now we just need to recognize that having low prices for natural gas, gas liquids, and utilities such as electricity has allowed for a rebirth of US petrochemical manufacturing and particularly of export markets for those products.

Note on the following chart the effect of shale production on US gas prices starting in 2005 along with the peak and subsequent falloff as a result of the recession of 2008. While all gas prices associated with conventional production and imports into the other European and BRIC (Brazil, Russia, India and China) countries have begun to recover, the US price continued to trend down until 2012, resulting in one of the lowest gas prices in the world. This low price is the proximate cause of the rejuvenation of US petrochemicals production and exports as well as the cause of a flurry of announcements and permit applications surrounding LNG exports.

While gas prices have definitely been affected by events like Hurricane Katrina in 2005 and the market crash of 2008, the trend since the advent of shale gas in 2005 has been towards lower prices.

The effect of the lower gas price on US natural gas demand can be illustrated with the following basic supply-demand chart provided by the American Chemistry Council. Note the price and volume of natural gas in 2005. At the point where the red curve "S1" intersects the green market demand curve, the natural gas price was $7.33/mcf and the resultant volume delivered to customers was 60.3 billion cubic feet/day or 22 trillion cubic feet per year. This date coincides with the beginning of commercial shale gas production. We then fast forward to 2012 and the intersection of "S2" and the green demand curve where the price has now dropped to $2.79 and the resultant volume has climbed to 69.8 billion cubic feet per day or 25.5 trillion cubic feet per year. Recent forecasts for the year 2013 actually exceed both this volume estimate as well as this price level. This likely indicates a shift in the slope of the market demand curve from the fixed slope used in this simple model.

FIGURE 3
THE ADVENT OF SHALE GAS RESULTED IN MORE, LESS COSTLY SUPPLY OF US NATURAL GAS

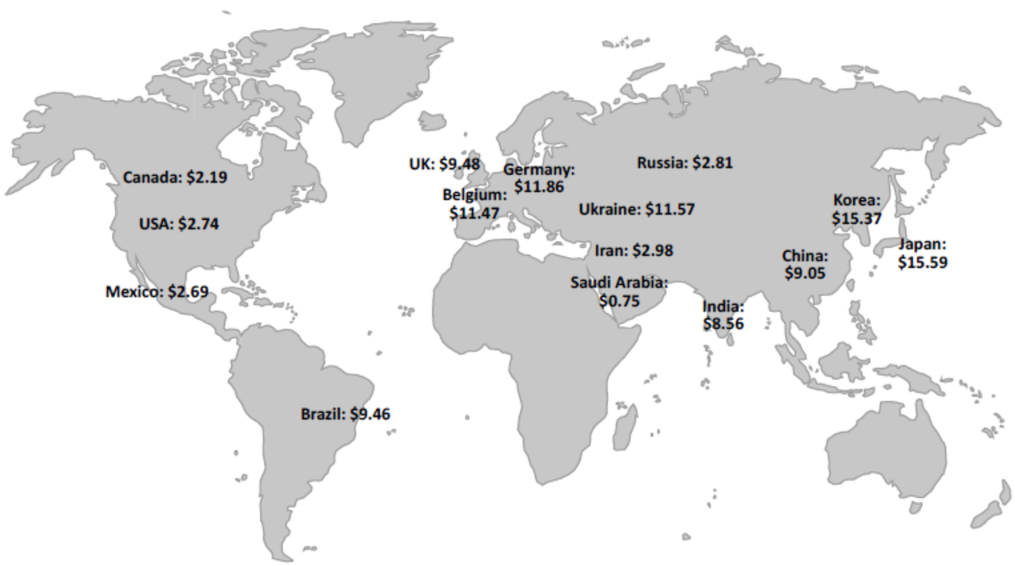


Source: American Chemistry Council –"Shale Gas. Competitiveness, and New US Chemical Industry Investment: An Analysis Based on Announced Projects"-Many, 2013

Going forward we expect gas consumption to continue to increase despite some upward adjustment in the price of dry gas. This will be caused by the shrinking contribution to the total revenue stream of shale gas producers from the NGL content of wet gas. We expect gas prices to be in a range between $3 to $6, with the lower prices occurring when gas is in surplus. At that point, rigs will be laid down and storage inventories will begin shrinking, in part because utilities are shifting to gas as a lower priced alternate to coal. As this increasing demand makes itself felt, the gas price will increase into the $6 area and new drilling will take place while power producers will begin to shift back to coal, the now lower priced alternative. The rapid decline curve for shale gas actually helps with the adjustment process as developed shale gas depletes much faster than would have been the case with conventional gas.

A quick snapshot comparison of international gas prices is seen in the following chart, courtesy of the American Chemical Council. It details the wide spread of prices seen in the rest of the world, ranging from approximately $11/mcf in Western Europe to a high in the $15-$16 range for Korea and Japan. While Saudi Arabia does have lower prices ($.75) that gas generally does not participate in the international market, being retained as a strategic feed stock by SABIC (Saudi Arabian Basic Industries Corporation).

FIGURE 5
AVERAGE 2012 NATURAL GAS PRICES BY NATION
($ per million BTUs)



Note: Prices generally reflect domestic wellhead/hub prices or imported prices via pipeline. Some nations (e.g., Japan and Korea) import LNG. Thus, the higher prices. Other nations import LNG if it's a minor share of demand but these prices aren't generally reflected in the above.

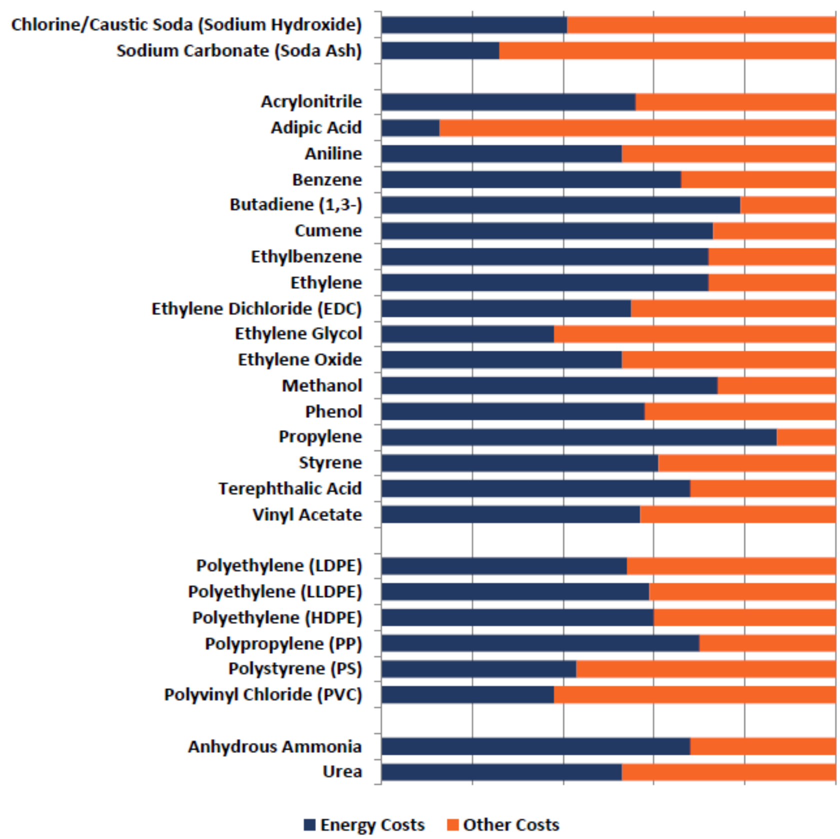
Source: American Chemistry Council –"Shale Gas. Competitiveness, and New US Chemical Industry Investment: An Analysis Based on Announced Projects"-May, 2013

The close correlation of prices in North America (The US, Canada and Mexico) is a result of pipeline infrastructure connecting the three countries, while the higher but correlated pricing in Western Europe is based on pipeline imports of gas from Russia and North Africa. The latter model also reflects long term gas prices formally linked to oil prices. Similarly, long term contracts support the even higher prices seen in Korea and Japan which rely almost exclusively on imported LNG for their natural gas supply.

It follows that petrochemicals produced using natural gas indexed to oil or direct use of the refinery intermediate gasoil will result in higher cost petrochemical products.

In the next chart, the American Chemical Council details the proportion of the manufacturing costs of various commodity chemical intermediates resulting from energy inputs, both for feed stock as well as for the fuel, used to create process heat and electrical power. Not surprisingly, many of the chemicals with a high proportion of cost related to energy are favorites of the Gulf Coast manufacturing complex in Louisiana and Texas.

FIGURE 9
FUEL, POWER AND FEEDSTOCK COSTS AS A PERCENT OF TOTAL COSTS FOR SELECTED CHEMICAL PRODUCTS



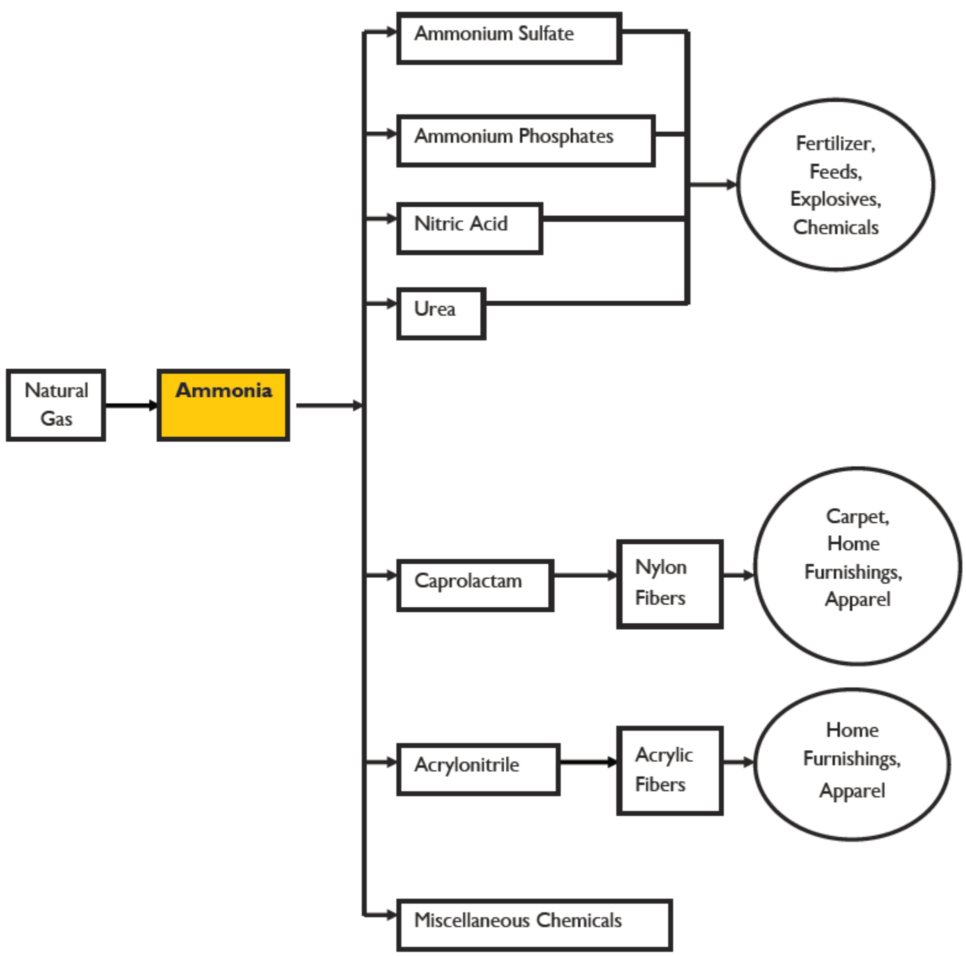
Proximity of hydrocarbons at affordable prices, in addition to transportation infrastructure, a trained labor pool, and a critical mass or other chemical manufacturing sites, account for these chemicals being produced in Louisiana and Texas. While the names may be difficult to pronounce, the finished products produced from these intermediates are recognizable staples for US and world consumers. For example, Butadiene is a basic building block for synthetic rubber and other elastomers used in things like automobile tires; Cumene and Terephthalic acid are major ingredients in Nylon used to produce auto tire casings, synthetic carpets, and the tricot fabrics used in lingerie. Anhydrous Ammonia and Urea are produced from natural gas and are staples in the production of synthetic fertilizers as well as nylon. Ethylene is a key building block for a whole variety of molded plastic items produced from Polyethylene and PVC. The three flowcharts that follow show the variety of finished products generated by just three of these petrochemical raw materials.

Ammonia

This first chart starts with natural gas (CH4) which can be converted into ***Ammonia*** (NH4) and can then be used to produce a variety of synthetic fertilizers here in Louisiana. Alternatively, it can be combined with organic chemicals to produce nylon and acrylic polymers which can then be converted into a variety of synthetic fibers useful for clothing, home furnishings, and transportation applications. While we do not produce these particular finished fibers in Louisiana, we do produce feed stocks that are shipped out of state for final conversion.

Appendix 4: Simplified Chemical Value Chains

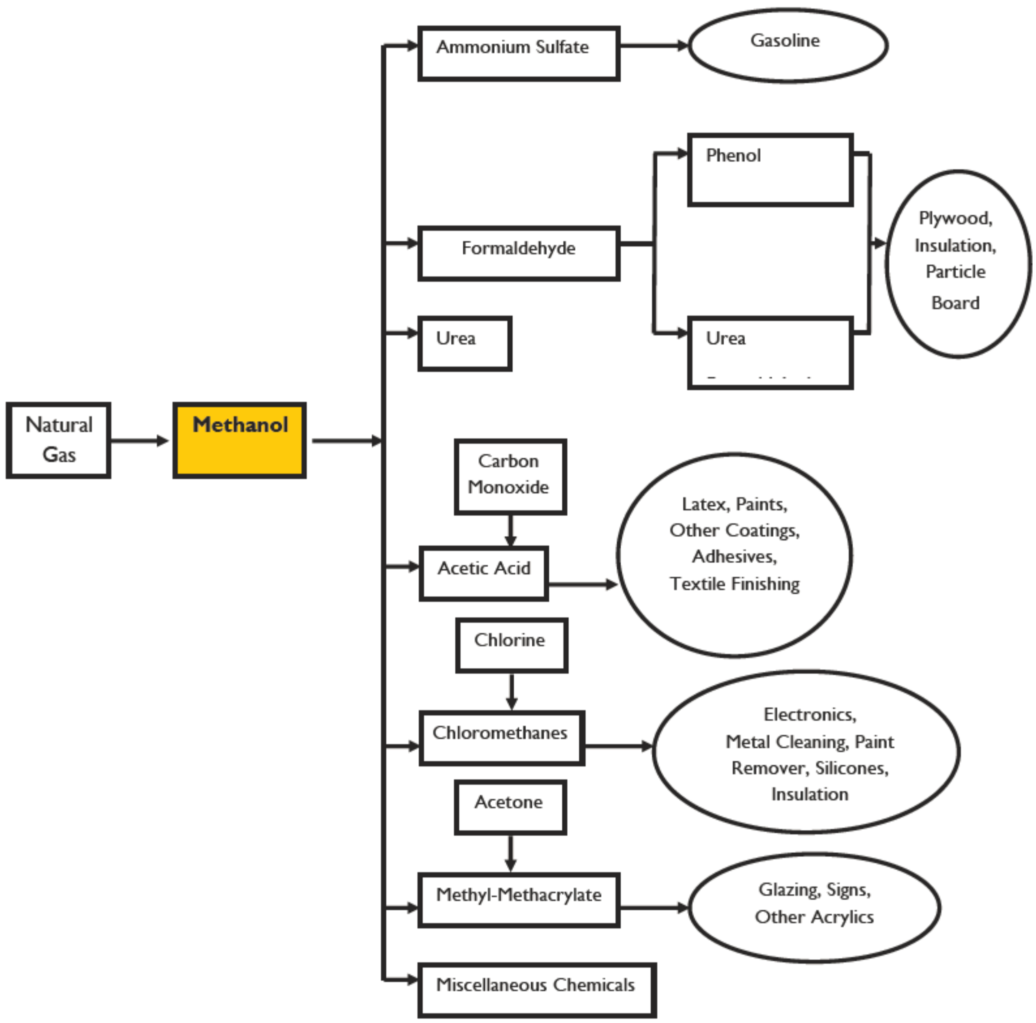
Ammonia



Methanol

Methanol (CH3OH), also known as “Wood Alcohol” is another chemical intermediate which is produced from Natural gas (CH4). This material is used to produce gasoline additives, combined with carbon monoxide (CO) to produce resins used in adhesives and various coatings such as latex paints, and combined with chlorine and used to produce silicones and insulation. It can also be combined with acetone to produce methyl-methacrylate, which is used in glazing windows, producing signs and a host of other applications.

Methanol

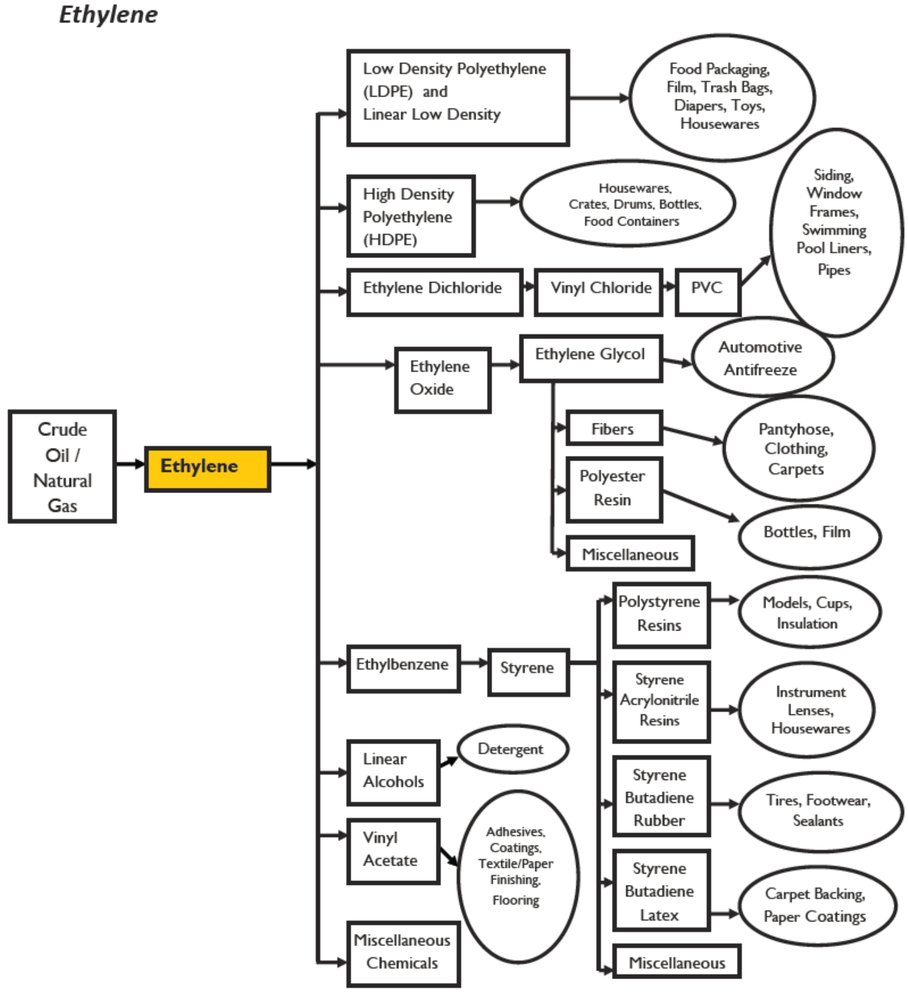


Ethane/Ethylene

***Ethane (C2H6*), a gaseous byproduct in natural gas production, is converted to its olefin form (C2H4) in steam crackers once it is separated out of the gas stream, and then polymerized into various grades of polyethylene. Ethylene can also be combined with chlorine (CL2), also produced in Louisiana, using electric power and brine (H2O and NACL) to produce poly vinyl chloride or PVC plastic. Polyethylene and PVC are two of the most popular plastics used in packaging and disposable containers. Ethane (C2H6) can also be converted to Ethanol (C2H5OH), however, most production today is focused on renewable raw materials as a result of EPA mandates.

The same feed stocks can also be converted into polyester, yet another plastic with good strength and dyeing properties that is used, much like nylon, for the production of synthetic fibers used in tires, clothing, and carpeting, or into polystyrene, another plastic used to produce a variety of molded consumer products.

Ethylene



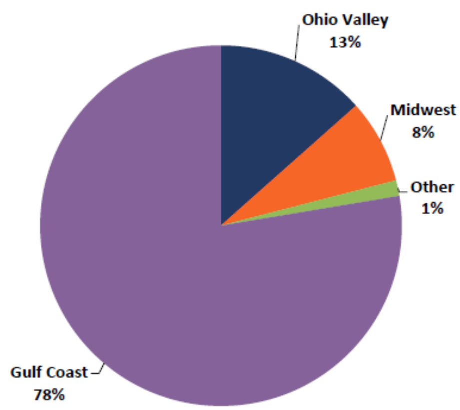
All of these intermediates are produced in a number of variants intended for different end use applications. Typically, they are shipped out of state in rail cars for final conversion, packaging, and distribution.

Not shown in these flow charts are the extraordinary interconnections between the various production facilities along the Gulf Coast where the chemical and thermal by-products of one plant contribute raw materials and process heat for another. Beyond the benefits of low energy and raw material costs, the existence of significant material and energy linkages provides an attraction for existing and newly arriving chemical producers that would be impossible to replicate at a green field location in another state.

Forecasted Capital Expenditures

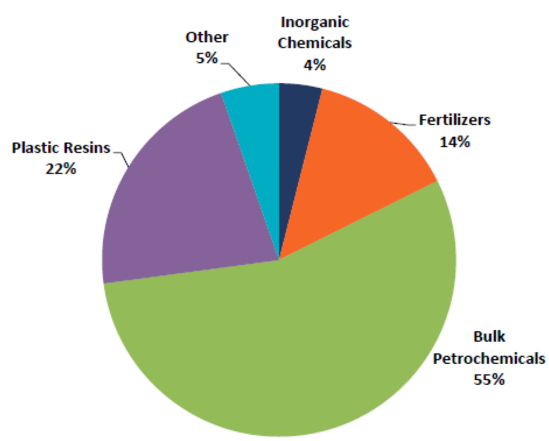
According to a recent report by the American Chemical Council, capital expenditures for both new petrochemical plants and the expansion of existing sites will be felt disproportionately along the Gulf Coast with 78% of the anticipated spending to occur in our region, far more than in all other regions combined.

FIGURE 16
NEW CHEMICAL INDUSTRY CAPITAL INVESTMENT BY REGION



The makeup of this spending will favor bulk petrochemicals and plastics intermediates with fully 91% of the capital expenditures being spent on products dominated by Gulf Cost manufacturing. Not surprisingly, Fertilizers at 14%, Plastic Resins at 22%, and Bulk Petrochemicals at 55% make up most of the forecasted output. Inorganic chemicals, such as chlorine and nitrogen, will account for about 4%.

FIGURE 15
COMPOSITION OF NEW CAPITAL INVESTMENT BY CHEMICAL INDUSTRY SEGMENT

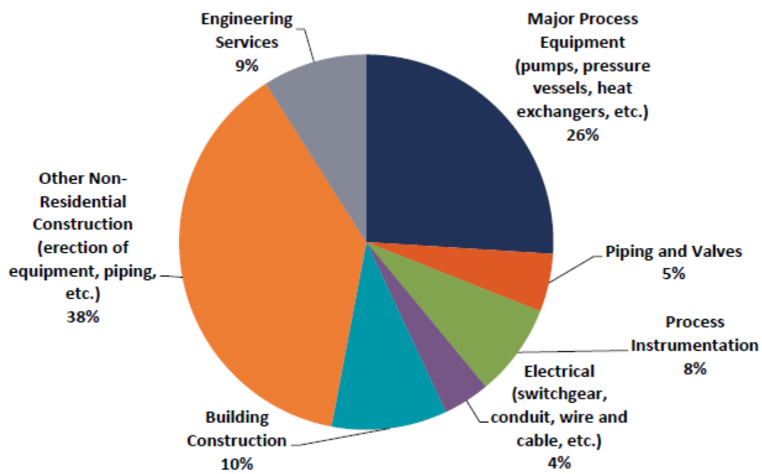


Source: American Chemistry Council –"Shale Gas. Competitiveness, and New US Chemical Industry Investment: An Analysis Based on Announced Projects"-May, 2013

The American Chemical Council estimates that we can expect to see spending on these plants peak in 2015 after a significant rise in 2013 and 2014 to a spending level of $14.5 billion in 2015. The following decline occurs as identified projects complete construction. We anticipate that new unidentified projects will slow this apparent decline considerably.

Finally, it is worth noting the actual makeup of the forecasted spending over the next few years. Below we can see that over half of the expenditure will be associated with building and construction, erection of equipment, piping, provision of engineering services, etc.

FIGURE 14
COMPOSITION OF NEW CAPITAL INVESTMENT BY ASSET TYPE



Source: American Chemistry Council –"Shale Gas. Competitiveness, and New US Chemical Industry Investment: An Analysis Based on Announced Projects"-May, 2013

We would expect Louisiana suppliers to be well represented in these three categories. While our participation in the provision of actual industrial equipment will be less pervasive, we should be able to penetrate some of those categories as well. In Louisiana, Louisiana Economic Development (LED) is tracking approximately $65 billion of existing products in the planning and construction phase with over $20 billion of that spending expected to be awarded to Louisiana based service providers.

Louisiana Energy Employment

At the state level, using information provided by Ramona Robichaux and Mark Jones of the Louisiana Workforce Commission (LWC), I examined key energy categories in terms of employment. We did this for both the state overall as well as for the specific parishes in Greater New Orleans which include Jefferson, Orleans, Plaquemines, St. Bernard, St. Charles, St. James, St. John the Baptist, St. Tammany, Tangipahoa, and Washington parishes. As the following table indicates, there are 4.6 million people in the state with 1.5 million people in the civilian labor force. They earned an average annual wage of $42,450 during 2012, equivalent to a weekly wage of $816.

Population and Employment	**Louisiana**	**Period**
Population	4.6 million	2011
Average Annual Employment	1.5 million	2011
Annual Per Capita Personal Income	$42,450	2011
Per Capita weekly income	$816	2011

Source: Eric Smith and the Louisiana Workforce Commission

Based on selected NAICS codes, our target group of energy-related employees totaled 104,346 for the State of Louisiana. This group earned a total of $8.7 billion in 2011, or an annual average of $83,676, equivalent to an average weekly wage of $1,609. That is almost double the state average of $816. The NAICS categories chosen and the relevant statistics for each category follow:

Annual Data for Calendar year 2011 by NAIC Code for Energy Sector

NAICS Category	**# of empl**	**Wages ($mm)**	**Avg. ann.**	**Wkly wages**	**% diff.**
211 Oil and Gas Extraction	8,504	$1,012	$118,963	$2,288	180.40%
213 Support Activities for Mining	40,620	$3,139	$77,272	$1,486	82.10%
22 Utilities	14,320	$878	$61,344	$1,180	44.60%
324 Petroleum and Coal Products Mfg.	11,128	$1,140	$102,426	$1,971	141.50%
325 Chemicals Manufacturing	23,255	$2,130	$91,597	$1,761	115.80%
326 Plastics and Rubber Products	3,689	$186	$50,441	$970	18.90%
486 Pipeline Transportation	2,830	$246	$86,875	$1,671	104.80%
Subtotal	**104,346**	**$8,731**	**$83,676**	**$1,609**	**97.20%**
Other Private Employment	1,404,578	$55,322	$39,387	$757	-7.20%
Total 2011 La. Private Employment	**1,508,924**	**$64,053**	$42,450	**$816**	**0.00%**
Energy as a Percent of Totals	**6.90%**	**13.60%**			

Average energy wages were 97% higher than the average wage earned by all private employees. Within the energy category, the highest weekly energy wage rate was for the oil and gas extraction area at $2,282 or 180% higher than the average employee. The lowest wage rate for the energy sector, for Plastics and Rubber Manufacturing, was $970/week, still 18.9% higher than the average. Stated another way, of the 1.5 million privately employed workers in the state in 2011, energy workers represented 6.9% of the census but earned 13.6% of the wages paid.

For the moment, let's limit the analysis to what we will call broadly, the petroleum sector. This data from 2011 accounts for a total of 63,082 state workers earning a total of $5.5 billion annually or $1,688 on a weekly basis.

Employment and Annual Wages Paid

in Petroleum related Industries

2011

Sector	**Employment**	**Annual Wages**	**Average Weekly**
			Wages Paid
Oil and Gas Extraction	8,504	$1,011,771,904	2,288
Support Activities for Mining	40,620	3,138,788,640	1,486
Petroleum Refining	11,128	1,140,530,976	1,971
Pipelines	2,830	245,904,360	1,671
Total	63,082	$5,536,995,880	1,688

Source: www.Laworks.net Go to LMI section

The group with the highest weekly pay was the 8,504 oil and gas extraction workers who earned weekly wages of $2,288 or a total of $1.0 billion in 2011. However, there were also 40,620 upstream support personnel who earned a total of $3.1 billion or an average weekly rate of $1,486. While lower than the upstream group, there were almost five times as many workers earning three times the aggregate payroll earned by the extraction workers. Another $1.1 billion, roughly equal to upstream employees, in annual payroll was provided by Petroleum Refining, which had 11,128 direct employees earning $1,971 a week. Finally, we had 2,830 pipeline workers who averaged $1,671/week and brought home $246 million. In aggregate, these subsectors accounted for 63,082 workers and a total payroll of $5.5 billion.

Now, let's take a look at our other major contributor, the Chemical, Plastics and Rubber products sector. Here we have a total of 26,944 employees earning a total of $2.3 billion in 2011 or an average weekly wage of $1,653, not far from the average for the Petroleum group of $1,688/week.

Employment and Annual Wages Paid

in Chemical Plastics and Rubber related Industries

2011

Sector	Employment	Annual Wages	Average Weekly Wages Paid
Chemicals	23,255	$2,129,506,860	1,761
Plastics and Rubber	3,689	186,073,160	970
Total	26,944	$2,315,580,020	1,653

Source: www.Laworks.net Go to LMI section

The large subsector is Chemicals Manufacturing where 23,255 employees earned a collective annual income of $2.1 billion, which equates to a weekly average wage of $1,761. The Plastics and Rubber sector was smaller, but still had 3,689 employees who earned an average weekly wage of $970.

Together, the two major energy subsectors, Petroleum and Chemicals, provided 90,026 jobs with a collective annual payroll of $7.9 billion and an average weekly wage of $1,677. (It is important to note that we have not included a number of utility, shipbuilding, fabrication, transportation, and other services that also support both of our major subsectors.)

Another table from the Louisiana Workforce Commission (LWC) details just manufacturing employment in Louisiana, which totaled 139,688 persons in 2011. Included in the table are the Refining, Chemicals, Plastics and Rubber Manufacturing, but not the Oil and Gas Extraction, E&P Support Services Utilities or Pipeline transportation sectors. The included manufacturing groups equate to 38,072 jobs or 27.3% of the total manufacturing jobs in the state.

Table 3
Chemical Employment Relative to Other Louisiana Manufacturing Sectors: 2011

Manufacturing	**139,688**
Food manufacturing	16,323
Beverage and tobacco product manufacturing	2,401
Textile mills	325
Textile product mills	694
Apparel manufacturing	373
Leather and allied product manufacturing	83
Wood product manufacturing	5,818
Paper manufacturing	7,203
Printing and related support activities	3,223
Petroleum and coal products manufacturing	11,128
Chemical manufacturing	**23,255**
Plastics and rubber products manufacturing	**3,689**
Nonmetallic mineral product manufacturing	5,727
Primary metal manufacturing	2,725
Fabricated metal product manufacturing	16,846
Machinery manufacturing	15,381
Computer and electronic product manufacturing	2,037
Electrical equipment and appliance manufacturing	1,140
Transportation equipment manufacturing	16,375
Furniture and related product manufacturing	1,002
Miscellaneous manufacturing	3,942

Source: www.Laworks.net/Downloads/LMI/2011statewide

Another measure of the impact of the relevant manufacturing sectors on Louisiana's economy requires a look at the value added in Louisiana. Again, the following table from 2010 does not include the upstream sector, but does include manufacturing categories such as Refining, Chemical, Plastics and Rubber products. Together, these categories represent $41.5 billion or 72.6% of the total $57.1 billion of Louisiana value added by manufacturing in 2010.

Table 7
Value Added by Manufacturing Sector in Louisiana: 2010

	Value Added: Millions	% of Total
Manufacturing Total	$57,120.9	100.0
Chemical manufacturing	*22,027.4*	*38.6*
Petroleum and coal products manufacturing	18,890.0	33.1
Food manufacturing	4,307.0	7.5
Paper manufacturing	2,614.7	4.6
Fabricated metal product manufacturing	2,165.4	3.8
Transportation equipment manufacturing	2,009.7	3.5
Machinery manufacturing	1,453.5	2.5
Nonmetallic mineral product manufacturing	724.4	1.3
Wood product manufacturing	*625.5*	*1.1*
Plastics and rubber products manufacturing	536.8	0.9
Primary metal manufacturing	403.2	0.7
Miscellaneous manufacturing	284.5	0.5
Printing and related support activities	216.5	0.4
Beverage and tobacco product manufacturing	205.5	0.4
Electrical equipment and appliance manufacturing	204.3	0.4
Computer and electronic product manufacturing	180.1	0.3
Furniture and related product manufacturing	D	D
Textile mills	D	D
Textile product mills	D	D
Apparel manufacturing	D	D
Leather and allied product manufacturing	D	D

Source: http://factfinder2.census.gov/faces/tableservices/jst

It is a relatively safe statement that energy manufacturing is the dominant subsector for value added manufacturing in Louisiana.

Multiplier Effects

Our final foray into quantifying the formidable economic impact of the energy industry on Louisiana has to do with quantifying multiplier effects. These measure the indirect impact of specific energy sectors beyond the directly quantifiable jobs and wages. The multiplier accounts for other indirect jobs that depend upon the direct jobs in any category.

The following analysis borrows on work done by Dr. Loren Scott who generated the petroleum related information as part of a report commissioned by the Louisiana Mid-Continent Oil and Gas Association (LMOGA) entitled *"The Energy Sector: Still a Giant Economic Engine for the Louisiana Economy".*

Information on the Chemical, Plastics and Rubber sectors was also provided by Dr. Scott from a report commissioned by the Louisiana Foundation for Excellence in Science, Technology and Education, a unit of the Louisiana Chemical Association. The latter report is entitled *"The Economic Impact of the Chemical Industry on the Louisiana Economy".*

In order to perform this analysis, it was necessary to utilize Input/Output (I/O) tables which measure both the direct and indirect effects of spending by a targeted industry while also including induced effects resulting from spending by the employees of both of the sector under study as well as the indirect jobs associated with the target sector's suppliers.

One way to think of these categories is that, in addition to hiring operators for its plants, a refining company also purchases a variety of supplies and maintenance services from a host of third party contractors, all of whom have their own employees. (In fact, some refineries and chemical plants have more "contract" employees on site than they do permanent employees.) This is particularly true during periodic turnarounds when the entire facility is shut down and overhauled.

For an Input-Output analysis, the people hired by those subcontractors are considered indirect employees of the refining sector. Employees of both the refiners and their service contractors spend their paychecks on consumer products and services. Each of the consumer products vendors or businesses also employs a workforce. We call this third category, these employees of companies who provide consumer products and services to the families of both the direct and indirect employees, "induced" employees.

Upstream effects

Using 2009 data, we note the following direct, indirect and induced sales, earnings and jobs created by activity in the upstream Oil and Gas Extraction sector.

Direct and Multiplier Effects of Oil and Gas Extraction Sector: 2009

Category	Business Sales (Millions)	Earnings (Millions)	Jobs
Agriculture, forestry, fishing, and hunting	$132.3	$22.0	1,032
Mining	$21,456.0	$4,356.0	40,976
Utilities	$705.5	$142.2	1,705
Construction	$1,024.7	$383.1	10,643
Manufacturing	$2,309.7	$436.3	8,010
Wholesale trade	$797.0	$252.3	4,754
Retail trade	$1,136.5	$394.2	17,024
Transportation and warehousing	$656.6	$207.1	4,735
Information	$508.6	$113.3	2,448
Finance and insurance	$960.2	$262.0	6,081
Real estate and rental and leasing	$3,985.4	$385.3	9,205
Professional, scientific, and technical services	$1,378.7	$629.4	11,323
Management of companies and enterprises	$1,095.8	$452.8	7,880
Administrative and waste management services	$471.3	$205.0	10,039
Educational services	$141.8	$58.3	2,521
Health care and social assistance	$1,208.6	$567.3	15,544
Arts, entertainment, and recreation	$120.1	$46.4	2,071
Accommodation	$155.1	$46.8	1,710
Food services and drinking places	$460.3	$145.8	10,088
Other services*	$570.0	$176.3	7,061
Households		$13.1	1,503
Totals	**$39,274.3**	**$9,294.9**	**176,352**

Source: Louisiana Input-Output Table, Bureau of Economic Analysis, U.S. Department of Commerce, Washington, D.C.

We note a total of 176,352 jobs. These jobs were tied to business sales of $39.2 billion and earnings of $9.3 billion. Of the total, 40,976 or 23.2% of the indirect jobs were in the mining sector (these are the jobs identified earlier in the upstream support sector.)The multiplier was 20.7 (176,352/8,504) or 19.7 additional jobs for every direct job in the oil and gas extraction category.

Next, we reviewed the refining sector. Here the I/O table produced the following results:

Direct and Multiplier Effects of the Refinery Sector in Louisiana: 2009

Category	Sales	Earnings	Jobs
Agriculture, forestry, fishing, and hunting	$78.4	$13.1	623
Mining	0	0	0
Utilities*	$877.3	$163.3	1,973
Construction	$594.3	$222.0	6,175
Manufacturing	$24,941.9	$2,977.9	26,121
Wholesale trade	$1,003.5	$317.8	5,987
Retail trade	$968.7	$335.2	14,527
Transportation and warehousing*	$1,166.8	$328.7	6,360
Information	$370.1	$82.7	1,797
Finance and insurance	$635.6	$169.8	3,886
Real estate and rental and leasing	$2,248.6	$182.9	5,238
Professional, scientific, and technical services	$759.7	$363.5	6,612
Management of companies and enterprises	$709.6	$293.9	5,110
Administrative and waste management services	$444.1	$189.4	9,455
Educational services	$115.4	$47.9	2,072
Health care and social assistance	$990.5	$465.8	12,732
Arts, entertainment, and recreation	$95.8	$37.0	1,658
Accommodation	$121.9	$37.0	1,340
Food services and drinking places	$398.4	$126.3	8,758
Other services*	$550.7	$169.8	6,600
Households		$10.9	1,235
Totals	**$37,071.2**	**$6,534.8**	**128,259**

Source:Louisiana Input-Output Table, Bureau of Economic Analysis, U.S. Department of Commerce, Washington, D.C.

Note that in this analysis, we ascribe zero jobs to the mining sector as anything else would result in a double counting of employees included in the extraction sector. In addition to a total of 128,259 jobs, this sector was responsible for sales of $37 billion and for household earnings of $6.5 billion. With the refining sector accounting for 11,128 direct jobs, the result is a multiplier of 11.5 meaning the refining sector is creating 10.5 additional jobs for every direct job in the sector. This relatively high multiplier can be accounted for in part by the enormous number of jobs associated with refinery contract employees as well as a large number of other 3rd party suppliers.

Finally, in the case of the pipeline sector, the I/O table reveals 5,606 total jobs in the direct, indirect and induced categories. Again, we leave the Mining sector blank in order to avoid double counting upstream oil and gas extraction workers.

Direct and Multiplier Effects of the Pipeline Sector in Louisiana: 2009

Category	Output	Earnings	Jobs
Agriculture, forestry, fishing, and hunting	$2.6	$0.4	20
Mining	0	0	0
Utilities*	$17.2	$3.5	41
Construction	$29.6	$11.1	308
Manufacturing	$109.3	$17.5	286
Wholesale trade	$26.8	$8.5	160
Retail trade	$32.4	$11.2	486
Transportation and warehousing*	$451.5	$97.7	1,288
Information	$14.2	$3.1	67
Finance and insurance	$29.4	$8.0	180
Real estate and rental and leasing	$51.9	$3.3	159
Professional, scientific, and technical services	$59.1	$27.3	493
Management of companies and enterprises	$6.9	$2.9	50
Administrative and waste management services	$38.0	$18.8	931
Educational services	$3.8	$1.6	68
Health care and social assistance	$32.1	$15.1	413
Arts, entertainment, and recreation	$3.0	$1.2	52
Accommodation	$3.9	$1.2	43
Food services and drinking places	$12.1	$3.9	267
Other services*	$21.3	$6.6	253
Households		$0.3	40
Totals	**$945.2**	**$243.1**	**5,606**

In addition to 5,606 total workers, we find related sales of $945 million and additional household income of $243 million. We also find a relatively low multiplier effect of 2.0 meaning that each of our 2,830 direct workers created only one additional indirect or induced worker. The largest single indirect category was the group of 1,288 employees in the transportation and warehousing category.

When we combine these effects, we note a total of 310,217 jobs exist as a result of jobs in the petroleum sector.

Summary of Input-Output Results Across Industries: 2009

Industry	Direct and Multiplier Effects on:		
	Sales (millions)	Household Income (millions)	Jobs
Oil & Natural Gas Extraction	$39,274.3	$ 9,294.9	176,352
Refineries	37,071.2	6,534.8	128,259
Pipelines	945.2	243.1	5,606
Totals	**$77,290.7**	**$16,072.8**	**310,217**

Source: Louisiana Input-Output Table

56.8%, or over half of the total are tied to extraction, although the downstream refining sector is responsible for another 41%.

In summary, when we include the data from Oil and Natural Gas Extraction, Refining, and Pipeline employment we generate 310,217 Louisiana jobs, $77.3 billion in sales revenue, and $16.1 billion in household income that can be traced back to the 22,462 direct jobs identified in the oil and gas extraction, refining and pipeline sectors. This produces an aggregate multiplier effect of 13.8 with 12.8 additional workers for every direct job analyzed. This admittedly high multiplier can be partially explained by the large number of third party workers employed by both the upstream and refining sectors. Collectively, they include over 60,000 employees. Moving those employees from the numerator to the denominator would reduce the multiplier from the double-digit levels seen in this analysis.

Chemicals, Plastics and Rubber Sector

The above analysis excluded the Chemicals, Plastics and Rubber manufacturing businesses. Using a more recent 2010 data base, but the same methodology, we now focus on the multiplier effects related to this second set. Using data on Chemical Manufacturing as well as Plastics and Rubber Manufacturing as inputs, we developed details for the direct, indirect, and induced jobs that come about in other sectors because of Chemical, Plastics, and Rubber manufacturing activities.

Table 9

Distribution of Business Sales, Household Earnings and Jobs Benefits

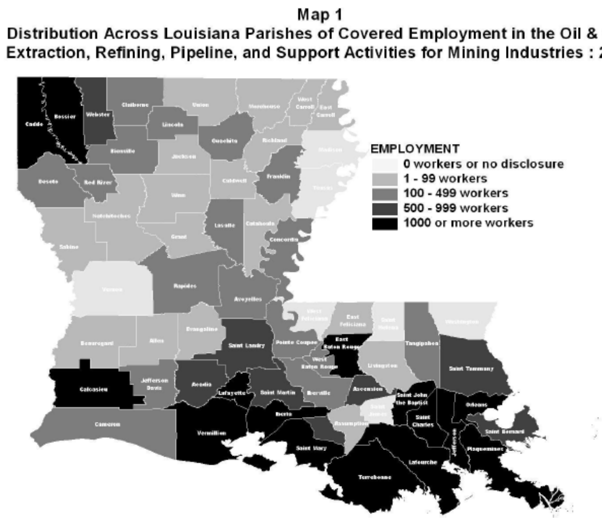
Industry	Sales	Earnings	Jobs
Agriculture, Forestry, Fishing, And Hunting	$162.3	$36.1	1,514
Mining	$2,281.1	$342.4	3,367
Utilities	$1,540.6	$237.4	2,886
Construction	$310.7	$110.4	2,767
Manufacturing	$36,525.3	$4,466.4	52,279
Wholesale Trade	$1,715.1	$556.6	9,673
Retail Trade	$1,125.4	$415.0	16,868
Transportation And Warehousing*	$1,315.8	$381.1	7,724
Information	$390.5	$77.2	1,671
Finance And Insurance	$701.0	$172.3	4,050
Real Estate And Rental And Leasing	$1,851.8	$155.1	7,722
Professional, Scientific, And Technical Services	$791.1	$360.4	6,839
Management Of Companies And Enterprises	$645.0	$294.4	4,668
Administrative And Waste Management Services	$502.7	$210.5	9,001
Educational Services	$156.2	$77.0	2,983
Health Care And Social Assistance	$1,228.8	$570.3	15,104
Arts, Entertainment, And Recreation	$108.8	$40.8	1,504
Accommodation	$152.2	$40.9	1,436
Food Services And Drinking Places	$412.6	$133.7	8,216
Other Services	$635.1	$255.4	7,572
Total	**$52,551.9**	**$8,933.5**	**167,843**

Source: Authors' calculations from I/O table

In this second phase, we identify 167,843 jobs in the subject categories. Not surprisingly, the most affected category is manufacturing which includes a total of 52,279 jobs. The next biggest category is the retail sector where 16,868 jobs are tied to the chemical, plastics and rubber industries. This is closely followed by the healthcare and social assistance sectors which add another 15,104 jobs. The result for this latter group is a job multiplier of 6.2 (167,843 total jobs/ 26,944 direct jobs). Stated another way, each job in the Chemical, Plastics and Rubber industries carries with it another 5.2 jobs in other sectors of the Louisiana economy. Adding our two major sectors together, the Petroleum and Chemical jobs, we have 478,060 direct, indirect and induced jobs tied to energy activity. This represents approximately 32% of Louisiana’s 1,509,000 employees in the private sector.

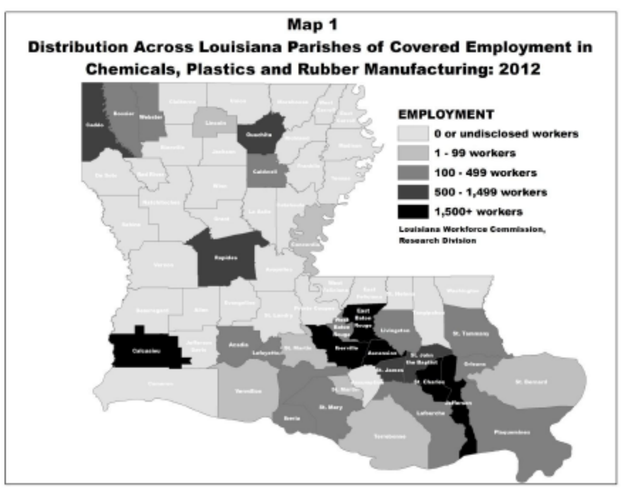
Geographic Locations of Energy Activity

Louisiana jobs in 2010, those that are related to Oil and Gas Extraction, Refining, Pipeline, and Mining Support are heavily concentrated in Southeast Louisiana. However, additional concentrations are also seen in the Lake Charles and Shreveport areas.



Source: Louisiana Workforce Commission

A second map, this one based on 2012 data, gives geographic concentrations for Chemicals, Plastics and Rubber activity. We see the same pattern, but the concentration in the Southeast is less pronounced.



Source: Louisiana Workforce Commission

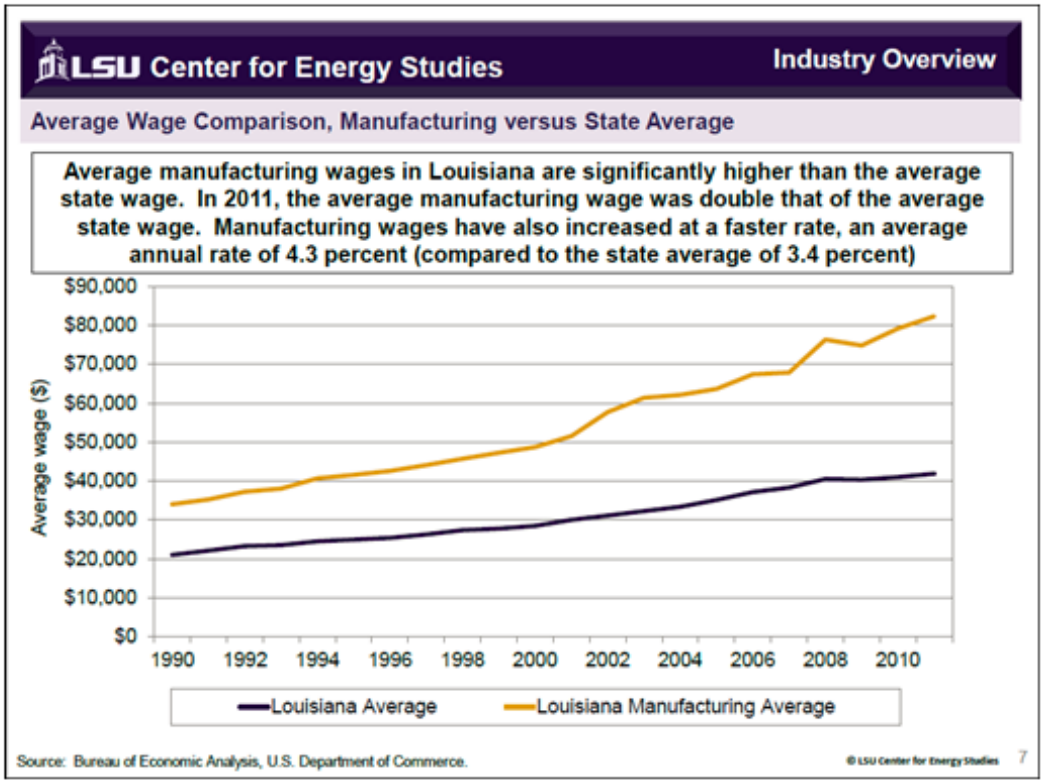
Relative Wage Levels within Louisiana

In terms of the relative wage level for energy manufacturing jobs, the following chart from our colleagues at LSU's Center for Energy Studies, using data from 2011, makes the point that we are fortunate to have steadily increasing manufacturing wages in the state with an increasing gap between manufacturing wages and non-manufacturing wages in the same time period.

What the chart does not highlight is that the energy sub-component of the manufacturing sector posts even higher average wages, wages that are 46% higher than the average manufacturing wage which in turn is 47% higher than the average non-energy manufacturing wage.

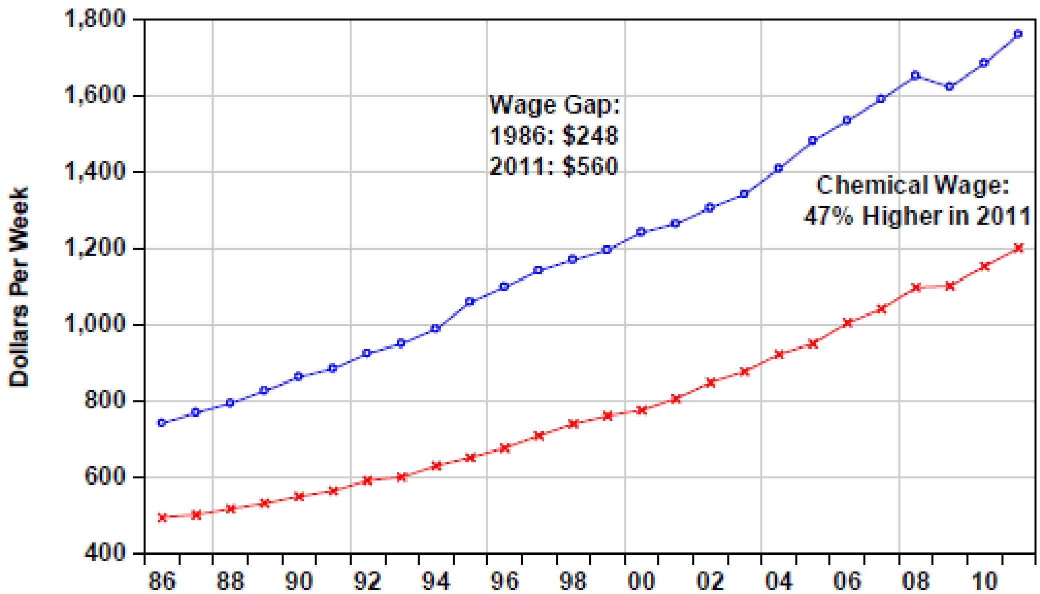
We believe this is primarily a result of the higher skill levels required to work as an operator in a modern, highly automated and capital intensive, refinery or petrochemical plant. Junior Colleges like Nunez, located in Chalmette, provide invaluable training for the next generation of skilled operators for these plants. Virtually all of the students who graduate with an Associate degree from these education programs have jobs when they graduate. Both the state and industrial partners coordinate their efforts to make sure that Louisiana's industrial training programs are creating a relevant workforce. This means educating not only replacements for the existing operator pool but also producing enough new operators to staff all of the expansion facilities currently being planned and erected in Louisiana. Indeed, anecdotal evidence is that these programs have become critical infrastructure in attracting new manufacturers to the state

The following table points out the long standing spread between manufacturing and non-manufacturing wages.



The Energy and Chemical sub-segments are significantly higher than the average manufacturing wage. As an example we submit this chart, which details the widening spread between chemical industry weekly wage and all manufacturing jobs. We also believe that the weekly wage rates for the chemical industry, over the long term, will continue to grow at a high rate owing to the expected ramp up in economic activity generally and of hydrocarbon based activity in particular.

Figure 3: Chemical Industry Weekly Wages Compared to Manufacturing Weekly Wages-Louisiana



Source: www.Laworks.net/Downloads/LMI

Note that in every year since 1986, chemical wages have been well above the average wage for manufacturing in Louisiana. The gap between the two categories has widened from $248/week in 1986 to $560/week in 2011. However, the percentage difference has remained relatively constant in the 47% to 50% range.

Should anyone doubt the significance of energy related employment to Louisiana, they only need to consult the employment statistics available at the Bureau of Economic Analysis of the US Department of Commerce or those available from the Louisiana Work Commission. Upon doing so, they would find that, of the 147,000 manufacturing jobs in the state, the chemical industry accounts for 16% while the Petroleum and Coal products group (aka Refining) accounts for 8% and the Rubber and Plastics groups cover another 2%. Combined, these three groups account for 26% of our total manufacturing employment and an even higher percentage of our manufacturing payroll. These groups earn the highest average manufacturing wages in the state, by a large margin.

The significantly higher wage for these jobs, in a very capital-intensive industry group, present tremendous opportunities for economic development. These companies and their employees broaden the income and property tax base significantly.

In 2011, the Manufacturing weekly wage at $1,201 (approximately $62,452 on an annual basis) was 47% higher than the statewide average wage of $816 ($42,432 annual basis). The Chemical manufacturing wage, at $1,761 ($91,572 annual), was 46.6% higher than the average manufacturing wage and the Petroleum and Coal Products Manufacturing (Refining) weekly wage, at $1,971, was 64% higher than the average manufacturing wage. Again, this table, consistent with the earlier manufacturing sector tables, does not include Petroleum Extraction or the related service support group and transportation subsectors.

Table 5
Average Weekly Wages Statewide & in Louisiana's Manufacturing Sector: 2011

Statewide	**$816**
Manufacturing	**1,201**
Food manufacturing	720
Beverage and tobacco product manufacturing	812
Textile mills	763
Textile product mills	601
Apparel manufacturing	493
Leather and allied product manufacturing	1,077
Wood product manufacturing	801
Paper manufacturing	1,310
Printing and related support activities	690
Petroleum and coal products manufacturing	1,971
Chemical manufacturing	**1,761**
Plastics and rubber products manufacturing	**970**
Nonmetallic mineral product manufacturing	913
Primary metal manufacturing	1,143
Fabricated metal product manufacturing	1,070
Machinery manufacturing	1,164
Computer and electronic product manufacturing	1,180
Electrical equipment and appliance manufacturing	1,135
Transportation equipment manufacturing	1,151
Furniture and related product manufacturing	622
Miscellaneous manufacturing	724

Source: www.Laworks.net/Downloads/LMI/2011statewide

Greater New Orleans Region Energy Labor Profile

Using Regional Labor Market (RLMA) data for 2011, published by the Louisiana Workforce Commission, we are able to detail certain categories of employment for each of the ten parishes in Greater New Orleans. The aggregate shows that this region has a total of 39,527 locations, employing 566,307 people and paying annual wages of $26 billion. This results in an average weekly wage of $861 in the region, marginally higher than the statewide average of $816.

Areas of special interest from the New Orleans area are those NAICS codes perceived to be high in energy content. We include NAICS code 11, which includes oil and gas extraction, NAICS code 22 which covers utilities, including both electric power and major pipeline infrastructure, and NAICS codes 31-33 which includes refining as well as chemical manufacturing. In total, these codes total 48,628 jobs in the region, which earned a total of $3.7 billion or an average weekly wage of $1,463/week.

The importance of these jobs varies depending on which parish is being examined. For example, St. Charles has large positive effects from Petroleum and Coal Products (Refining) and Chemical Manufacturing while Jefferson, Orleans and Plaquemines have major contributions from Oil and Gas Extraction as well as Support Activities for Mining. St. John the Baptist has a mixture of Chemicals, Refining and Upstream support activities while St. James seems almost completely focused on Chemical Manufacturing. Utilities are present in a number of parishes, however, they have a relatively larger share of employment in Tangipahoa and Washington Parishes.

Reviewing the same data on a percentage basis really highlights the differences between parishes. We can get a better idea of the relative profile of energy employment by looking at annual employment data for each of the sub-segments and average annual payroll. For example, we can note the relatively strong role played by Utilities in Tangipahoa and Washington parishes.

The following tables detail Jefferson, Orleans and St. Charles parishes, revealing the number of companies, the average annual headcount, the annual payroll, and average weekly wage rates. We were able to have the Louisiana Workforce Commission create a special analysis using 2012 information based on specific NAICS three digit codes. This allowed us to accumulate core energy employees by parish. However, the final two lines of each table revert to RLMA data for 2011. This is done solely to provide context.

Annual Jefferson Parish Energy Labor Profile for 2012

Parish	Labor Category	# of units	Average Employees	Total Wages	Avg. wkly Wage
Jefferson	Oil and Gas Extraction	19	294	43,748,023	2,862
Jefferson	Support Activities for Mining	54	1369	135,073,060	1,897
Jefferson	Utilities	26	503	41,752,909	1,596
Jefferson	Petroleum & Coal Products Mfg.	6	104	6,141,055	1,138
Jefferson	Chemical Manufacturing	18	644	54,188,831	1,618
Jefferson	Plastics & Rubber Products Mfg.	22	1145	73,198,857	1,229
Jefferson	Pipeline Transportation	4	206	22,086,047	2,065
Jefferson	TOTAL ENERGY	148	4,265	376,188,782	1,696
Jefferson*	Non-Energy	13,593	187,921	8,185,157,354	838
Jefferson*	Total	13,741	192,186	8,561,346,136	857

*Source: Louisiana LWC 7/24/13, *RLMA 2011 report*

Jefferson Parish's energy category covers 148 economic units and 4,265 individuals who were paid $376 million during 2012 and averaged $1,696 per employee per week. In Jefferson, refinery workers were earning wages that were 35.8% higher than the average for all non-energy workers in the parish while Chemical workers were 93% higher than the non-energy group.

Jefferson absolute wages were highest for Exploration and Production (E&P) Support services, at $135 million, followed by plastics and rubber manufacturing at $73 million and Chemical manufacturing at $54 million. The highest average weekly wage, at $2,862, was earned by Oil and Gas extraction. This was followed by the average weekly wage of $2,065 earned by the 206 Pipeline Transportation workers. The 13,593 non-energy firms in Jefferson parish earned an average wage of $838 a week, less than one half the $1,696 earned by the energy workers. As a parish, the annual payroll for 192,186 workers was $8.6 billion or an average weekly rate of $857.

A comparable table for Orleans Parish reveals the following:

Annual Orleans Parish Energy Labor Profile for 2012

Parish	Labor Category	# of units	Average Employees	Total Wages	Avg. wkly Wage
Orleans	Oil and Gas Extraction	31	1390	261,810,623	3,623
Orleans	Support Activities for Mining	30	929	98,217,205	2,032
Orleans	Utilities	24	269	24,381,950	1,746
Orleans	Petroleum & Coal Products Mfg.	3	****	****	****
Orleans	Chemical Manufacturing	14	205	15,831,427	1,485
Orleans	Plastics & Rubber Products Mfg.	4	****	****	****
Orleans	Pipeline Transportation	1	****	****	****
Orleans	Sub TOTAL Detailed segments	97	2793	400,241,205	2,756
Orleans	Subt. Non-detailed for confidentiality	8	265	29,184,243	2,121
Orleans	TOTAL ENERGY	105	3,057	429,425,448	2,701
Orleans	Non-Energy	10,861	170,929	8,266,367,704	930
Orleans	Total*	10,966	173,986	8,695,793,152	961

*Source: Louisiana LWC 7/24/13, *RLMA for 2011*

Orleans Parish had fewer total energy employees than Jefferson Parish. However, there are relatively more employees in the higher wage areas of “Oil and Gas Extraction” and “Support activities for Mining”. Furthermore, these employees were paid higher average wages than their colleagues in Jefferson Parish. The result is that Orleans actually has a higher annual energy payroll total of $429.4 million, but with fewer employment locations (105) and fewer total employees (3,057) than found in Jefferson Parish (148 and 4,265 respectively).

This could be the result of Orleans Parish being host to fewer, larger, regional and head office locations while Jefferson Parish hosts more numerous smaller operations, for example the offices of smaller independent E&P companies and various specialist engineering service providers. All energy workers, according to our definition, averaged $2,701 a week or a 190% premium to Non-Energy workers in the parish who averaged $930 a week. Appendix “A” includes a detailed report for all 10 parishes included within the Greater New Orleans territory as well as a full listing of all parishes in the state with energy employees.

When we look at St. Charles Parish we see a different profile than with Orleans or Jefferson parishes. We believe this pattern results from locational bias. The E&P sector involves a number of white collar jobs, which tend to be located in urban areas, while the Refining and Chemicals area are dominated by a need for large amounts of land, access to navigable water as well as pipeline highway and rail services. In St. Charles Parish, we note a relatively minor contribution from the upstream sector and a dominant position held by Refining and Chemicals manufacturing. There are 17 firms in these two industrial categories and they support 3,810 jobs with a total payroll of $429.3 million, roughly equivalent to the entire E&P payroll in Orleans Parish. In the case of St. Charles, the total energy/manufacturing payroll exceeds $521.7 million, larger than either the Orleans or Jefferson parish segments.

Annual St. Charles Parish Energy Labor Profile for 2012

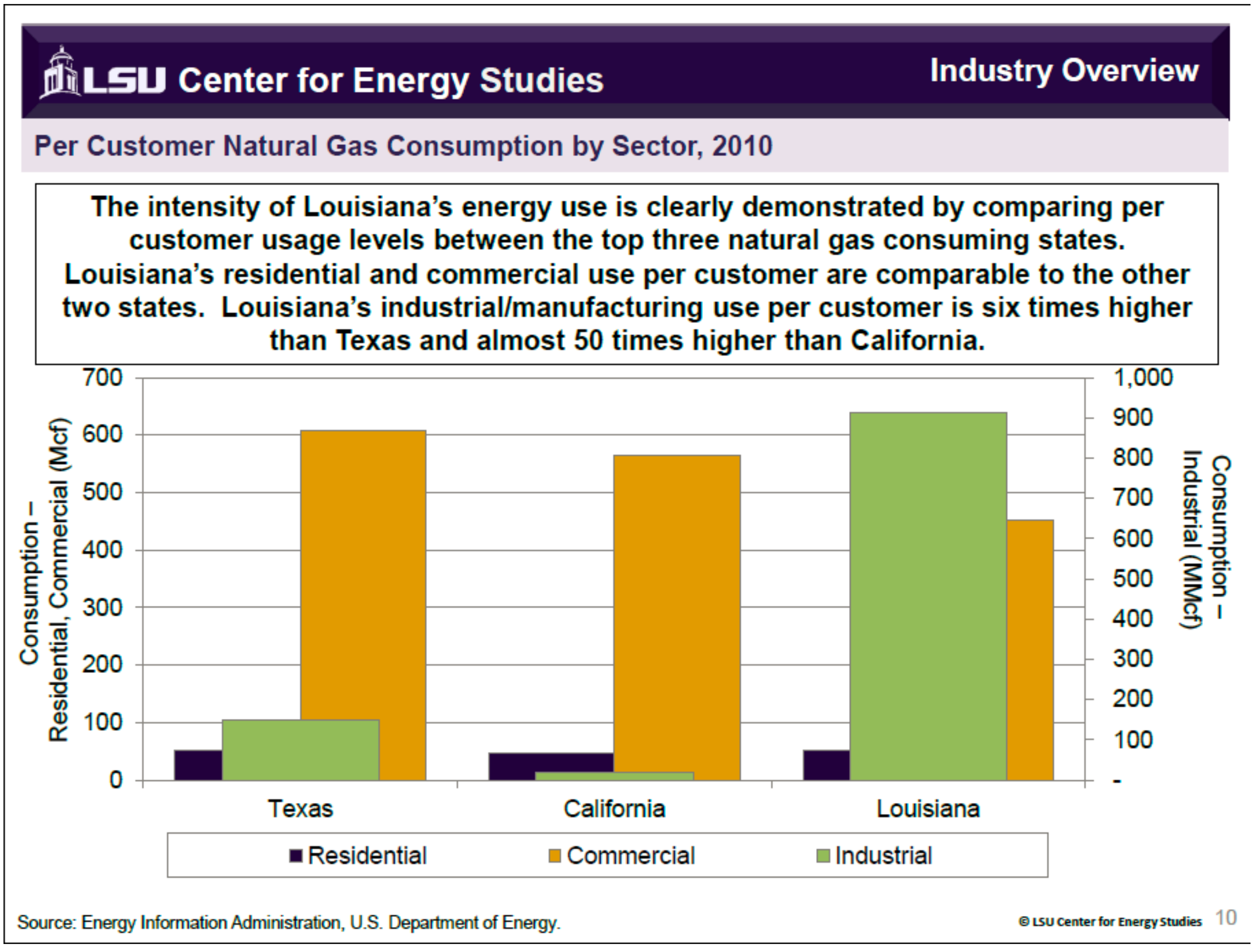
Parish	Labor Category	# of units	Average Employees	Total Wages	Avg. wkly Wage
St. Chas	Oil and Gas Extraction	2	****	****	****
St. Chas	Support Activities for Mining	4	77	5,396,991	1,342
St. Chas	Utilities	11	****	****	****
St. Chas	Petroleum & Coal Products Mfg.	8	1563	192,912,070	2,373
St. Chas	Chemical Manufacturing	9	2247	236,378,226	2,023
St. Chas	Plastics & Rubber Products Mfg.	0			
St. Chas	Pipeline Transportation	1	****	****	****
St. Chas	Sub TOTAL Detailed segments	21	3,887	434,687,287	2,151
St. Chas	Not detailed for confidentiality	14	818	86,963,718	2,044
St. Chas	TOTAL ENERGY	35	4,705	521,651,005	2,132
St. Chas	Non-Energy*	1,123	18,624	845,234,967	872
St. Chas	Total	1,158	23,329	1,366,885,972	1,127

Source: Louisiana LWC 7/24/13, *RLMA for 2011

The average weekly wage for energy jobs in St. James Parish, at $2,132 is in the middle between Orleans at $2,701 and the average energy weekly wage of $1,696 seen in Jefferson Parish. St. Charles serves to highlight the strong performance possible in a parish focused on refining and petrochemical manufacturing. It also serves to point out the effects of synergy between units in the closely coordinated petrochemical and refining infrastructure. Details for other Greater New Orleans parishes are in Appendices A & B.

Natural Gas

Including offshore natural gas produced in adjacent federal waters, Louisiana is the second largest producer of natural gas in the United States and the third largest consumer of natural gas given its use by industry both as a fuel and as a feedstock. Texas is first in both categories, while California is second in natural gas consumption. Louisiana is always in the top three in terms of industrial consumption per capita.



Louisiana's industrial use of natural gas per customer is six times greater than Texas and 50 times greater than California. Our industrial base uses this gas as a source of process heat, for the generation of steam and electricity, and as a chemical feedstock. Louisiana also has 125,000 miles of pipeline for moving gas, crude oil and refined products throughout the state.

Refining

US refineries, about half of which, on a capacity basis, are located in Texas and Louisiana, utilize natural gas to create the process heat required for the refining process. Louisiana is second to Texas in terms of US refining capacity. Countries without domestic access to inexpensive natural gas have to either import natural gas or burn part of the refinery product stream in order to generate necessary process heat. The result is that, in a world of low gas prices and higher petroleum prices, US refineries have an innate cost advantage versus much of the international refining sector.

Two examples showcasing the result of not having access to natural gas are the Hess Refinery in St. Croix and the Valero refinery in Aruba. Both of these island refineries were, until recently, major suppliers of refined products to the US Eastern Seaboard states. Now, both are permanently shut down. Their costs of crude were competitive, but their costs for process heat were not. The same cost advantage also explains the rapid growth in US exports (largely from Texas and Louisiana) of distillate products with Europe and Latin America as major destinations.

In addition to a cost and capacity advantage, the Gulf Coast refineries also have a scope advantage. These are “complex” refineries meaning that they possess more integrated processing units and are able to handle relatively poorer (and cheaper) grades of crude oil. In fact, they prefer heavier, more viscous crudes, which naturally contain higher amounts of sulfur. Many of the refineries on the eastern seaboard as well as in the Midwest, Rockies, and West Coast are “simple” refineries meaning they lack the necessary equipment to remove sulfur compounds and to convert the more viscous crudes to usable products. Instead, they rely on more expensive light sweet crude to produce refined products. The Gulf Coast refineries were designed to operate using imported low cost heavy “sour” crudes, from Mexico, Venezuela, West Africa and elsewhere. At the same time, the locally produced crude, Louisiana Light Sweet, was “exported” within the United States to the Midwest to earn higher prices and to support their local primarily “simple” refineries.

This situation is changing with the advent of two alternate crude sources:

1) Canadian heavy “tar sands” crude produced either by surface strip mining or by in situ steam assisted gravity drainage (SAGD). The actual product is known as “Dil bit” (Diluted Bitumen), a blend of heavy Tar aka Bitumen, which is almost a solid at room temperature, and a Condensate which a liquid byproduct of natural gas production. The blend is liquid enough to be transported, either in pipelines or in rail tanker cars. If intended for pipelines, the “Dil Bit” is a 70/30 blend of tar and Condensate. If intended for rail, the blend is 85/15.

2) The development of the Bakken shale in North Dakota, the Eagle Ford shale in south Texas, and the Permian shale, in West Texas. All three of these sources produce light sweet domestic crude, usually in combination with natural gas and condensate.

The initial solution was to move the sweet Bakken crude to the Midwest and East Coast “simple” refineries, displacing imports as well as domestic production, such as Louisiana Light Sweet Crude (LLS), while moving the heavy, sour, Canadian sourced “Dil Bit” to Gulf Coast complex refineries where it could displace imported heavy sour crudes.

These massive sourcing changes require new pipelines, such as the Keystone XL line from Canada to the Gulf Coast, as well as the reversal of some of the sweet crude pipelines, which formerly fed Louisiana Light Sweet (LLS) and West Texas Intermediate crudes, as well as imported sweet crudes to Midwest refineries.

Because of the delays in pipeline construction, we have seen a remarkable ramp up in the use of unit trains and multi modal transportation to move the shale crudes to refineries that can use light sweet crudes. One caveat: there is a limit to the amount of sweet crude that these simple refineries can absorb. As a result, surplus light sweet shale crudes have been moving to the complex refineries along the Gulf Coast. Here in Louisiana, we have two major rail terminals, one in St. James Parish and the other in New Orleans East, which receive unit trains made up of four engines and up to 115 rail tank cars. Each of these trains contains up to 70,000 barrels of shale sourced crude. Upon arrival, they are offloaded to either storage tanks, pipelines or to river barges for ultimate delivery to Gulf Coast refineries.

However, because of their design, there is a limit to the amount of these types of crudes that can be processed on the Gulf Coast. The United States could end up with a surplus of un-refined sweet crude that would need to be exported. However, crude and condensate exports are illegal based on a federal law passed during the 1970s that forbids such exports. (Condensate is a mixture of light liquid hydrocarbons co-produced with methane in wet shale gas.) Canada is exempted from the prohibition, which explains the context of the recent train derailment and fire in Ontario involving US-sourced Bakken crude. On occasion, the US President has exempted other shipments of US-sourced crude with the most notable, recent example involving the use of Strategic Petroleum Reserve (SPR) crudes to mitigate the effects of logistics problems in the rest of the world during the “Arab Spring” uprising in Libya in 2011.

Louisiana refineries can process 3,246,020 bbl./day of crude oil or 18.6% of US capacity. There are three concentrations of refineries in the state. The largest group includes major integrated refineries located along the Mississippi River between Belle Chasse and Baton

Rouge. A second concentration of refineries exists in the southwest of the state, near Lake Charles. Yet a third group of smaller, specialized refineries are located northwest, around Shreveport. The latter group includes a number of facilities that produce heavier blending stocks used for manufacturing lubricants.

Petrochemical Plants

An analogous situation exists for our petrochemical units. This results from their use of processes which convert natural gas and natural gas liquids (NGLs) into various plastics and rubber products.

Most of the rest of the world utilizes a crude derivative liquid hydrocarbon, known as “gasoil” or “naphtha”, as a feedstock. This material is co-produced from natural gas well and is also generated during refinery activity. It is heavier than gasoline but lighter than kerosene and its price is tied to crude oil.

On a BTU (British Thermal Units) equivalent basis, the price of a barrel of oil should be six times the cost of 1,000 cubic feet of natural gas. However, oil/naphtha is now roughly twenty five times the current cost of natural gas ($100 oil/$4 natural gas) in the United States. Europe sees a price ratio of roughly 10:1 ($100/$10) and Asia is roughly at BTU parity of 6:1 ($100/$16). This explains the actions of companies like the German firm BASF which is building new petrochemical units in the United States or the South African firm SASOL which is building the first US commercial scale GTL (Gas to Liquids) plant here in Louisiana. The relocation costs are high, but not so high as to wipe out the substantial electric power and raw material cost advantage. We have lower electric power costs than most of the US as well as Germany and South Africa, in large measure because our low priced natural gas also supplies our Louisiana power plants.

One major caveat, these firms are “betting the farm” on the assumption that natural gas prices will remain in a fairly narrow band and that as prices rise, they will remain substantially below international prices for natural gas. Once these plants are built, it will take decades of operation before the companies will be able to consider moving to another more cost advantaged site.

Our own experience with petrochemicals and other energy intensive industries reflects what can happen when a basic energy feedstock rises above international levels. It wasn’t so long ago that Louisiana watched helplessly as methanol plants and fertilizer plants, not to mention an aluminum smelter, were all shut down and, in some cases, moved to foreign locations based on our then higher natural gas price.

Resource Mega Trends

Conventional Production

Conventional exploration, development and production of natural gas is in decline. For example shallow water gas production in the Gulf of Mexico has been severely impacted by the arrival of onshore shale gas.

Shallow Water Natural Gas Production

Here in Louisiana, we have seen a steady decline in offshore production of natural gas from shallow water areas. The problem is that shallow water gas cannot compete with unconventional gas produced from “wet gas” shale like in the Eagle Ford basin in Texas, or even the dry gas shale basins like the Haynesville in North Louisiana or the Fayetteville in Arkansas. Dry gas is usually defined as having a very low percentage of NGLs or Condensate as a constituent of the gas at the well head before any processing. Wet gas usually has high double digit percentages ranging from 20-50% present in the wellhead gas.

Some conventional offshore gas production will continue, but it will be in the form of associated gas emanating from deep water oil fields. That gas will be produced because it is associated with oil production, but the production of shallow water dry gas from gas only wells is on the wane. Any new drilling in shallow water is now focused on finding overlooked deposits of conventional oil, not gas.

The impact of this decline is not only being felt by the operators, but also by the related services industry as companies owning older specialized equipment that can only work in shallow water have consolidated operations and scrapped equipment. We expect more of this shallow water fleet rationalization to continue. Onshore, the recent formal closure of the McDermott facility in Morgan City is a direct result of the long term decline in shallow water exploration and production. The services offered by that yard were focused on building so called “bottom founded” platforms for exploiting shallow water oil and gas fields. Bottom founded structures literally are supported by the seafloor with legs extending above the water’s surface to support the production facilities. With the demise of that production, this specialized fabrication site is now obsolete.

While some of the skilled workers may be able to transition to deep water activity, that yard, located on a shallow inland waterway, has lost its economic viability. In a similar way, some of the shallow water drilling rigs, derrick barges, pipe lay equipment and supply boats, may continue to eke out a living by maintaining existing facilities, moving to international markets, or undertaking the mandated plugging and abandonment of remaining shallow water structures. However, the bulk of these fleets will find themselves marooned just as much as the McDermott Yard has been marooned and isolated by a long-term change in market fundamentals.

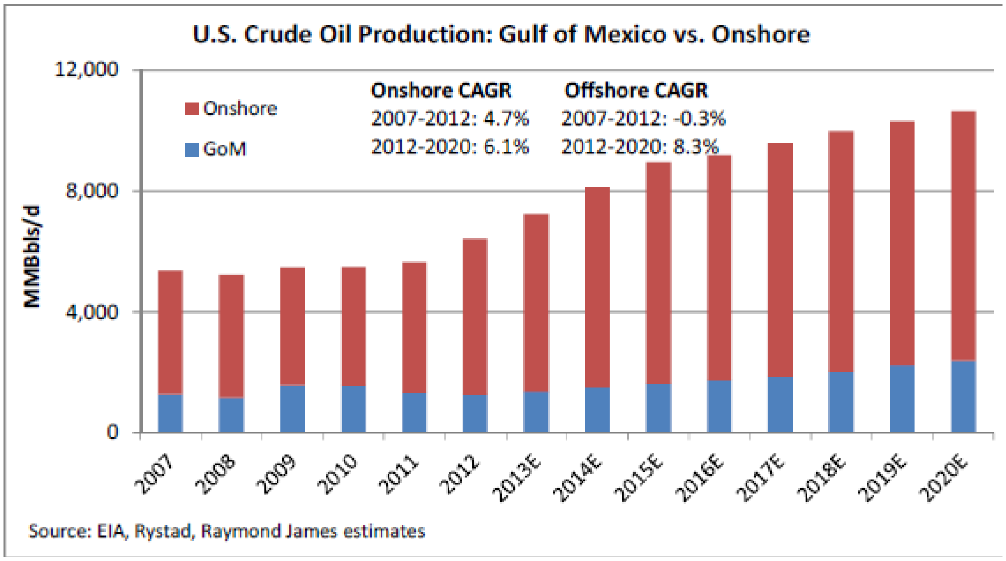
Deep Water Natural Gas Production

Under US regulations, offshore oil cannot be produced without monetization of any associated gas which is co-produced. As a result, efforts to produce deep water oil from conventional reservoirs result in the production and monetization of associated natural gas. As the oil production increases, so will this associated gas. However, while deep water oil production, and hence associated gas production, is growing, it is not growing fast enough to offset the steep decline in shallow water gas production. In federal waters, gas production has declined from over six trillion cubic feet per year, as recently as 2007, to a current level of less than 1.5 trillion cubic feet per year. The United States consumes approximately 25 trillion cubic feet a year, therefore the Gulf Coast only represents 6% of US natural gas consumption versus 25% as recently as 2007.

Deep water Oil Production

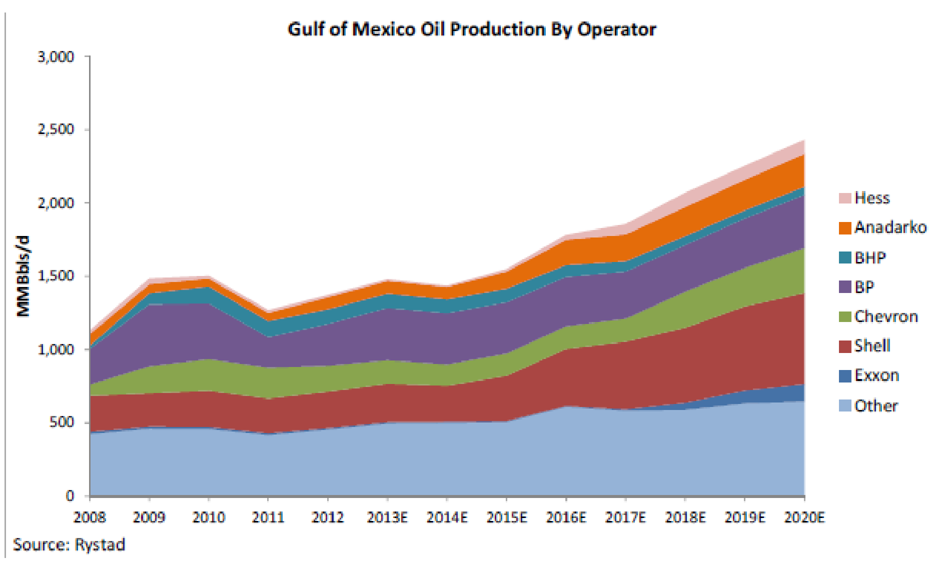
On a more positive note, deep water oil discoveries and production are increasing. This is certainly true here in the Gulf Coast. After the multiyear set back associated with the Macondo incident and the ensuing moratoria and “permitorium”, deep water drilling has returned to a level of activity that was ongoing on April 20, 2010, the date of the Macondo spill. Unfortunately, two years of exploration and development activity was lost and the production represented by those undrilled wells is haunting us both now and in the future.

However, we have a number of large scale projects which will be coming on stream despite the delays. As the chart shows, we expect heavy growth in the onshore oil shale plays, but we cannot ignore significant growth in the deep water offshore activity. It is true that offshore shrank at a compounded decline rate of -.3% during the period from 2007 until 2012 while onshore crude production grew at a CAGR of 4.7% during the same period. It is also expected that onshore production will continue to grow at a CAGR or 6.1% between 2012 and 2020. However, Raymond James and Rystad Consulting believe that offshore deep water oil will grow even faster, at an 8.3% rate between 2012 and 2020.



Source: Raymond James – Energy "Energy Stat: Don't Ignore the GOM's Future Role in Growing Domestic Oil Supply March, 2-13

Actual and forecasted growth for seven of the larger oil companies active in the deep water Gulf is shown on our next chart. This level of concentration is unheard of in the onshore oil production region and exists because of the barriers of cost and complexity associated with drilling and producing in deep water. Most independents do not participate in the deep water plays. Just combining two majors, Shell and BP, accounts for 43% of production the deep water production. This concentration, plus the extended timeframe associated with deep water developments and the performance associated with the Miocene plays that will represent two thirds of the anticipated new production, suggest that the future of the Gulf really is in deep water oil plays.



Source: Raymond James – Energy "Energy Stat: Don't Ignore the GOM's Future Role in Growing Domestic Oil Supply March, 2-13

Specific projects coming on stream presently and in the next two years, for example Chevron's deep water developments at Bigfoot, Blind Faith, Jack/St. Malo, and Tahiti are responsible for a significant portion of the forecasted growth in deep water production.

Chevron is not alone in finding the deep water US Gulf attractive. The following table illustrates that multiple major integrated oil companies ,as well as large iIndependents, are active in this area.

Major Deepwater Production Efforts in the Gulf of Mexico

Project	Major Owner/ Operator	Reserves (mmboe)	Well Count	Peak Production Oil (bopd)	Peak Production Gas (MMcf/d)	Develop-ment Cost (USD Bil)
Atlantis	BP	635	20	200,000	180	2
Big Foot	Chevron	100	—	—	—	—
Bigger Pompano	BP	—	40	60,000	90	—
Blind Faith	Chevron	>100	—	65,000	55	0.9
Constitution	Anadarko	110	6	40,000	75	0.6
Greater Chinook	Petrobras	—	—	80,000	—	—
Holstein	BP	—	15	100,000	90	—
Hoover-Diana	ExxonMobil	300	6	80,000	200	1.2
Horn Mountain	BP	>150	10	65,000	68	0.6
Independence	Anadarko	—	21	—	1000	2
Jack/St. Malo	Chevron	>500	12	120,000-150,000	37.5	—
Mad Dog	BP	200-450	16	up to 100,000	up to 60	1.5
Marlin	BP	—	—	up to 400,000	up to 250	0.5
Na Kika	BP	300	12	110,000	100	1.5
Perdido	Shell	—	—	100,000	200	4
Tahiti	Chevron	400-500	8	125,000	70	3.5
Thunder Horse	BP	1500	25	5,881	5,881	5,881
Ursa	Shell	400	14	up to 150,000	up to 400	1.5
Total		4,695-5,045	205	2,095,000	2,876	24.8

Sources: Company Reports, Morningstar Estimates

The good news is that oil is still selling at over $100/barrel and Asian shipyards continue to deliver new $700 million ultra-deep water drilling vessels, with approximately 150 in the world wide fleet and another 90 scheduled for delivery over the next three years.

However, the wells these vessels drill are not cheap. A deep water well takes at least ninety days to drill, costs between $120 and $180 million, and multiple wells are needed to develop a field. Just the "all in" rate for the new drilling vessels can be $1 million a day with the basic charter hire coming in at $6-700,000 per day with the balance being made up of the myriad services required to safely drill and complete the well. Beyond drilling and completing the well, operators also need to consider the full capital costs of developing the entire field. Expensive subsea wells need to be tied back to floating production systems that can cost multiple billions of dollars alone and requires the whole system to be tied back to the shoreline with expensive pipelines that can easily average $5 million a mile. If your new field is 150 miles offshore, the crude pipeline alone can cost $750 million. Fortunately, it is rare that one needs to go all the way to the coastline before finding existing under-utilized pipeline infrastructure that can be used. Of course any associated natural gas will also need to be piped to shore, used on site, or re-injected. Given today's drilling costs, injection wells are not popular in the deep water gulf.

While the successful deep water field will produce lots of oil over a long life time, it has to be able to compete with other viable sources of crude oil, including onshore shale oil where individual wells are an order of magnitude cheaper and surface facility costs are much more modest. Right now, a new well in North Dakota can be drilled for $10-12 million. The resulting crude can be moved by rail or pipeline to waiting refineries. Today, a significant portion of the Bakken crude produced is moving by rail because of the absence of oil pipelines. Meanwhile, much of the gas is being flared. Low gas prices do not justify the installation of gas gathering and processing systems in the fields and the State of North Dakota does not require that the gas be monetized.

Competing sources of North American crude supply include Tar Sands crude produced in western Canada. Right now this Bitumen is higher in unit cost than deep water oil and fetches a lower price than the sweet crudes produced either in the Bakken Shale or in the deep water offshore developments. However, both of these sources are seeing stable or reducing unit costs while costs in the deep water arena are increasing. *Oil and Gas Journal* reported that, according to Ziff Energy's annual report, average unit operating costs for oil and gas production in the deep water Gulf of Mexico increased by 45% during 2010-2012. Actual aggregate costs were $3.37 in 2010, $4.97 in 2011 and $4.83 in 2012. The study covered twenty four deep water assets owned by a total of six companies and produced 736,000 barrels of oil equivalent (boe) a day or close to one half of deep water production. "BOE" is a measurement which converts gas production to virtual barrels on a BTU basis. The virtual barrels and the actual barrels are then added together.

The real test will come in a prolonged recession when oil prices begin falling. We would expect to see the high cost tar sands crudes drop out first. Production and transportation costs are such that prices below $90/barrel result in losses. Prices would need to drop to the $50-60 range for deep water producers to see losses, but Bakken crude can probably be produced and delivered at prices below that and still show a profit. That means that deep water production is vulnerable, but not as vulnerable as tar sands crude.

Onshore Unconventional Oil Production

Onshore, older oil basins, such as the Permian basin in West Texas and New Mexico, are seeing their own rebirth as the shale source rock that originally supplied the crude that accumulated in conventional geologic traps is now being accessed directly using two extraction techniques, horizontal drilling and fracking. Horizontal drilling involves using a steerable drill bit and motor to extend a vertical wellbore into a horizontal well bore. Using this technique, much more of a shallow shale sediment section can be exposed to the well bore. After the well has been drilled and cased (lined with steel pipe that is cemented in place), the well is perforated and then fracked so that the gas or oil can travel through the wellbore to the surface. Fracking involves pumping water at very high pressures (15,000 to 20,000 pounds per square inch) which causes small interconnecting cracks to form throughout the shale deposit. Along with the water, small concentrations of various chemicals are included as well as somewhat larger quantities of "proppant". Proppant is simply small sand particles, or manufactured ceramic spheres, which lodge in the cracks and prevent them from closing once the water pressure is turned off.

These new sources are considered unconventional plays since they are dependent on unconventional extraction techniques. The same argument can be made about our own Haynesville shale in northwest Louisiana. Also in the Shreveport area, hydrocarbons from the shallower Cotton Valley formation have been producing for decades, a conventional formation that was dependent on underlying shale deposits as a source of hydrocarbons. The Haynesville is considered an unconventional play because it uses unconventional extraction technology while the related Cotton Valley play is clearly a conventional play. One piece of good news is that the produced hydrocarbons can and do use the same above ground infrastructure. Pipelines and processing plants built to support the earlier Cotton Valley play clearly help the unconventional production get to market.

Beyond the shale plays, we are also seeing growth in the use of "Tertiary Oil Recovery" techniques. Primary recovery occurs when reservoirs have their own sources of pressure, either gas based or water driven. Additional oil can be recovered using a variety of secondary techniques, most commonly a "Water flood" wherein water is injected under pressure around the perimeter of a field to carry remaining oil to a centrally located wellbore. Finally, tertiary techniques are used in which various chemicals are injected to recover oil that was not capable of being moved by the water flood. The most common of these tertiary techniques in Louisiana involves the injection of liquid CO2. Here in Louisiana, Denbury Resources has been the pioneer in exploiting this technology in order to produce more oil from existing fields that had been abandoned after the first 30-50% of the crude oil had been removed.

Starting in Mississippi, near the Jackson Dome which is a natural source of CO2, Denbury has gradually moved into central Louisiana and southeastern Texas, completing the so-called Green pipeline to transit CO2 from Jackson to the area around Beaumont. This pipeline differs markedly from our existing pipeline infrastructure due to the high pressure

(2,000 psi) necessary to contain the CO_2 during transit. More recently, they have acquired assets in the west to support the use of tertiary recovery in mature oil fields in that area.

CO_2 tertiary recovery even has a “green” side in that it represents a viable market for CO_2 produced in certain power plants and petrochemical operations. It is the only CO_2 sequestration method that exists where CO_2 is viewed as anything but an additional cost and regulatory burden. If your power plant, refinery or fertilizer plant has sufficient quantities of high pressure relatively clean CO_2, Denbury Resources will build a pipeline connection to pick up the CO_2 and pay you for the CO_2.

Once the additional oil has been produced, CO_2 can be sequestered in the now fully depleted oil field reservoirs.

Onshore Natural Gas Liquids

As mentioned earlier, the future growth of onshore natural gas as well as of onshore oil production is inextricably tied to the horizontal drilling and sequential fracking of shale deposits. In terms of natural gas, the low prices of shale gas and hence all gas, has meant that most operators have preferentially sought to develop “wet gas” fields, such as the Eagle Ford shale in Texas, as opposed to “dry gas” fields such as the Haynesville shale in northwest Louisiana. Right now we are running approximately 40 rigs in the Haynesville. Two years ago we were running over 150. The reason for the decline is that it simply costs more than $3.50 per thousand cubic feet (mcf) to produce gas in the Haynesville which does not see any upward leverage from the sale of gas liquids. Conversely, much of the production in the Eagle Ford shale in Texas receives the benefit of a high price for the separated liquids. This allows the Eagle Ford shale operator to profit even if he needs to sell the dry gas portion for $3.50 per mcf or less.

The actual difference in profitability between the two types relates to the amount of NGLs contained in the produced gas at the wellhead. Natural Gas Liquids include Ethane, Propane and Butane. These gases, along with Methane, the major ingredient in natural gas, are co-produced in wet gas wells. If the high value NGLs are separated and sold, the operator can earn a much higher aggregate price than by selling the combined flow at the lower Methane price. After separation, the NGLs subsidize a low price for the Methane (dry gas) that goes into the interstate pipeline system.

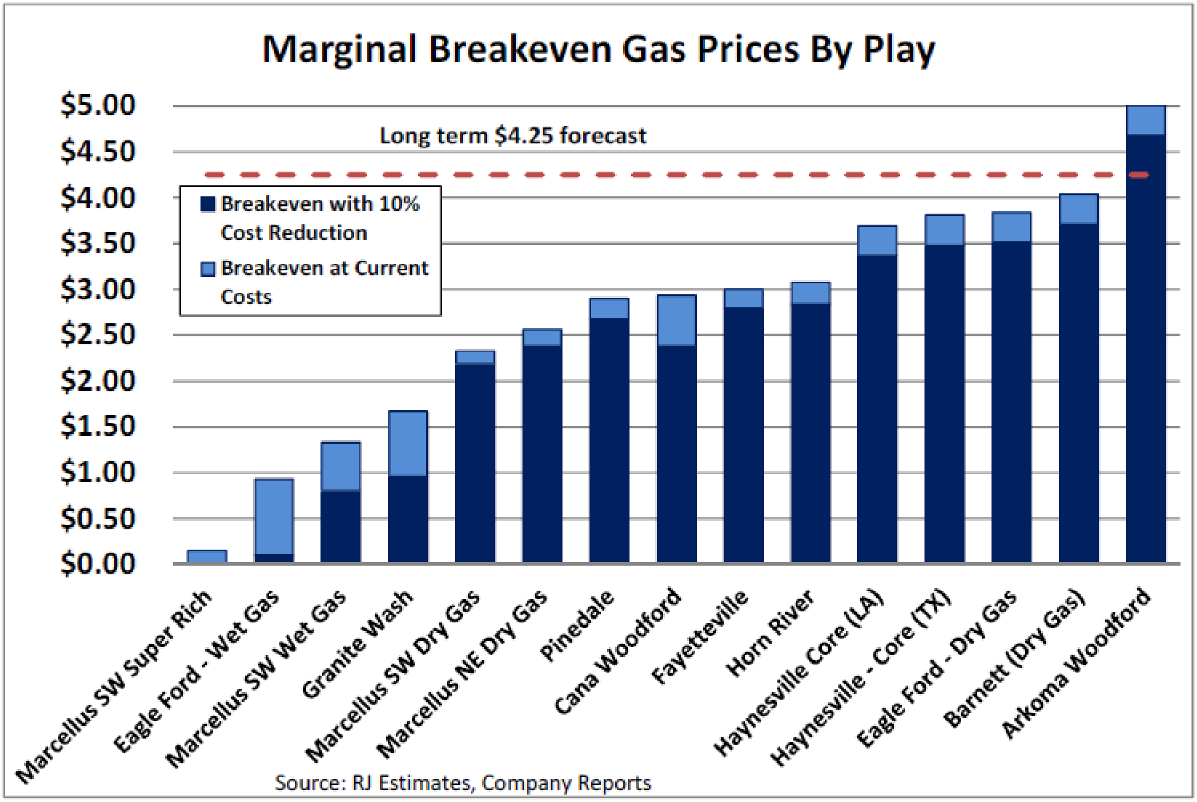
Unfortunately, copious production of wet gas has resulted in the saturation of the domestic NGL markets. While pipeline quality natural gas markets are growing, as a result of the conversion of power generation from coal to natural gas, the use of natural gas in existing petrochemical infrastructure, the potential use of additional natural gas as a transportation fuel, and finally, the export of natural gas in the form of liquefied natural gas (LNG); growth in domestic natural gas liquids (NGL) markets is limited by the capital and time required to expand downstream NGL consuming infrastructure.

First, the produced NGLs need to be separated from the pipeline quality gas. Then the resultant "Y" grade mixture of NGLs needs to be fractionated into the individual compounds (ethane, propane and butane). These segregated gases then need to be processed in steam crackers in order to convert them into unsaturated olefins which are chemically active versions of the underlying NGLs. Finally, these olefins need to be utilized in various process plants to produce polymers and synthetic rubbers for the downstream markets. While there is a world market for these resulting materials, the cost, in capital and time, to expand downstream NGL related capacity is daunting.

Another major use of NGLs is at refineries. These gaseous materials can be combined into longer hydrocarbon chains, which, as liquids at atmospheric pressure, can be used to expand the amount of refined product produced by the refiners. Today approximately two million barrels per day of NGLs are used in this fashion. To the degree that international export markets exist for Liquefied Petroleum Gas (LPGs), exports from Gulf Coast marine terminals are increasing, with the only limit being the availability of the LPG tankers.

US Shale Gas Production

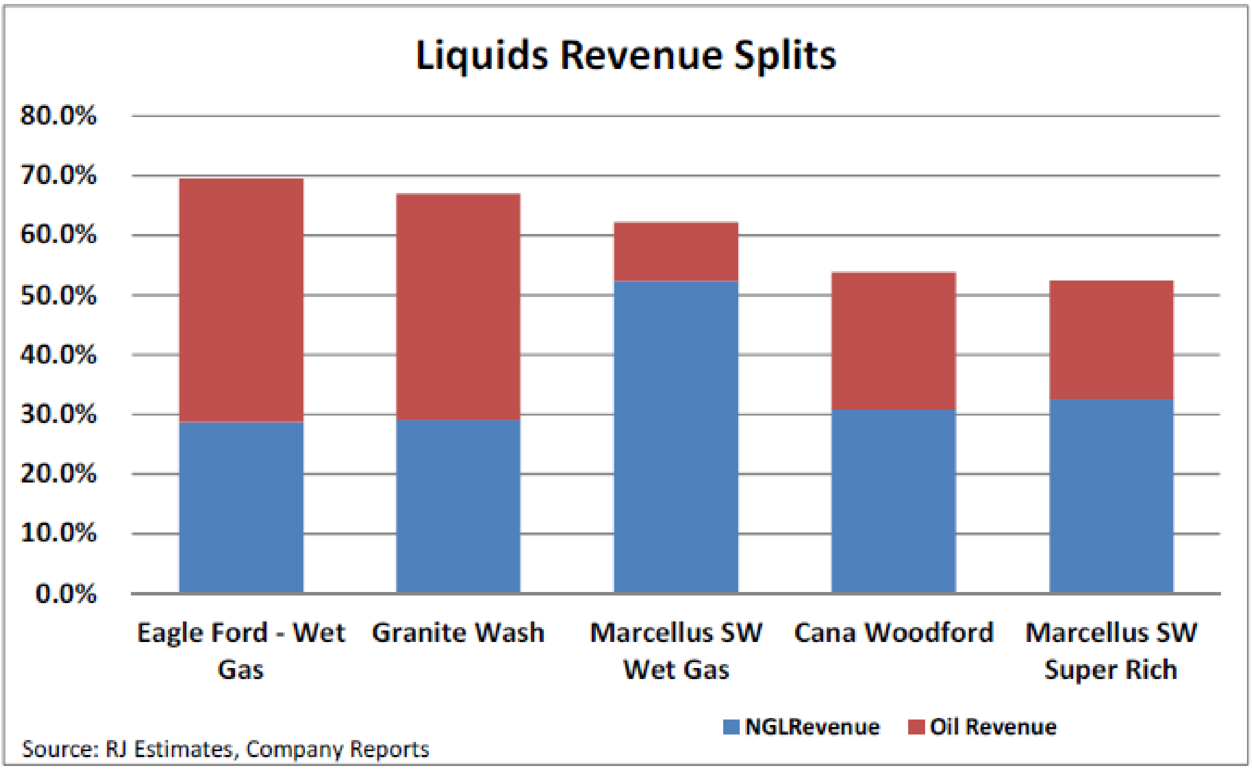
Our next chart, courtesy of the research firm Raymond James, illustrates the breakeven price for shale gases produced from various shale plays around the United States. It is important to note that this is a marginal cost breakeven meaning we are not considering sunk costs and overhead costs, but are including completed well costs and lifting costs. The Raymond James analysis includes the effect of a 10% improvement in costs to show the effect on breakeven of the learning curve. Using this admittedly simple discriminator, we see that virtually all current shale plays can break even or make money at prices below $4.00/mcf and actually earn a decent return at prices of $4.25/mcf and above. The bad news is that it may take a while to achieve such price levels as dry gas (95% methane) currently sells in the $3.50/mcf range.



Source: Raymond James Equity Research "Energy Stat: What is the Breakeven Cost for Natural Gas Plays"-June, 2013

One other major consideration when looking at shale gas plays is the proclivity of operators to prefer drilling in "wet gas" fields as opposed to "dry gas" fields. This preference is driven by revenue disparity. As discussed earlier, it is a result of the historically higher selling prices of oil and NGLs entrained along with methane in wet gas. While there are definite costs incurred in separating out the oil and NGLs and separately transporting them to market, the revenue improvement allows operators to drill new wet gas wells and continue to sell the dry gas portion of the production at relatively low prices as long as there is a significant premium associated with selling the entrained oil and NGLs. However, low dry gas prices make drilling new dry gas wells, for example in the Haynesville or Barnett shale, profoundly uneconomic.

It should be no surprise that several of the basins with the lowest breakeven costs are also basins where wet gas drilling predominates. A good example is the Eagle Ford wet gas where the breakeven is approximately $1.00 for the residual dry gas being produced after the extraction and sale of the higher priced NGL components. No dry gas field can be profitably drilled at such a low cost. One cautionary word: the resultant flood of new NGL production from wet gas fields has actually caused the price of NGLs to decline, lessening the positive benefits for new wet gas development. For example, the Eagle Ford Wet Gas example below derives 70% of its revenue from entrained liquids and only 30% from methane. Of the 70%, almost 30% is associated with NGLS while Oil and Condensate revenue account for 40%. The following comparison makes this point graphically.



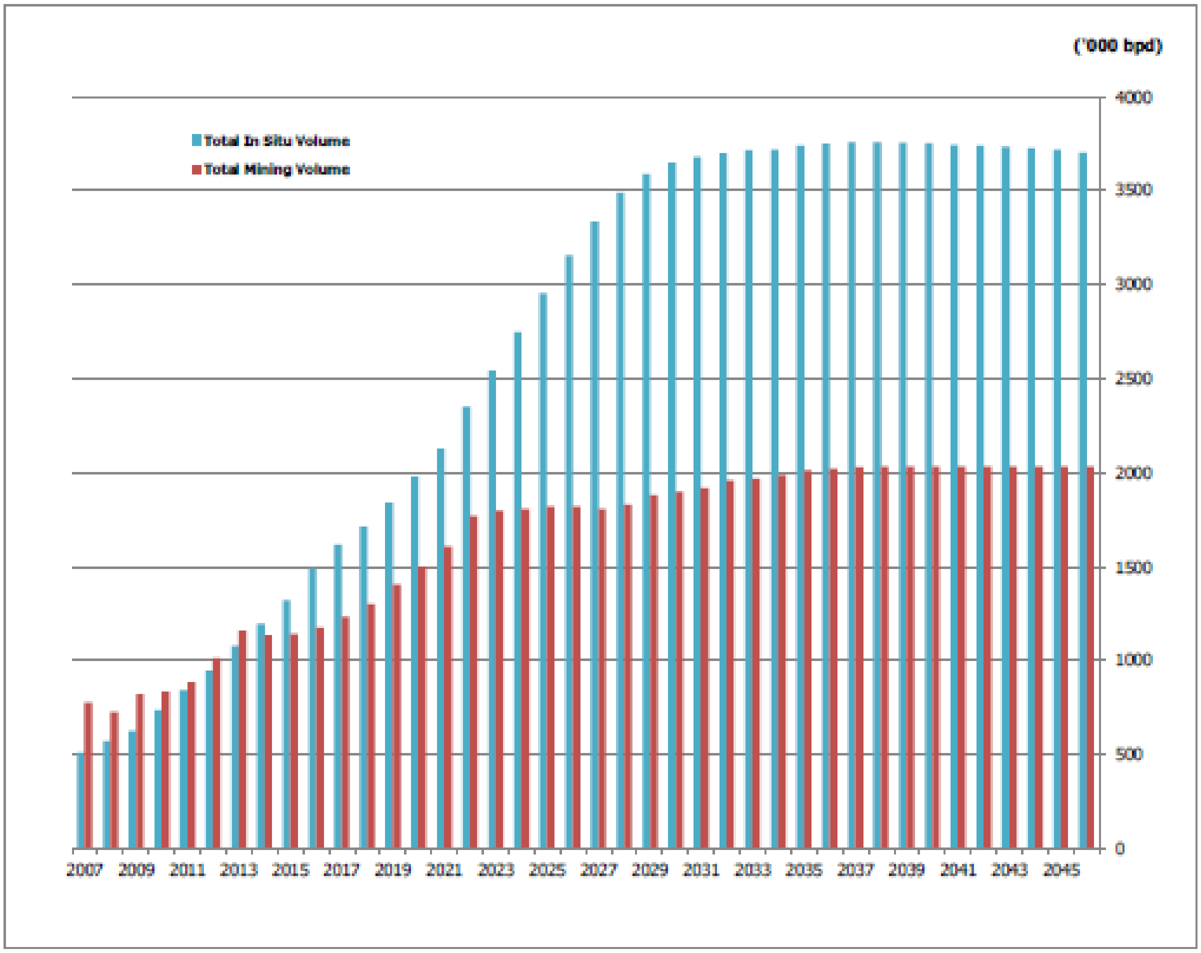
Source: Raymond James Equity Research "Energy Stat: What is the Breakeven Cost for Natural Gas Plays"-June, 2013

Tar Sands Crude

At the other end of the North American spectrum the market has seen increased production of heavy sour crudes in Alberta, a province in Western Canada. These crudes, which are extracted as bitumen using strip mining or in situ SAGD (Steam Assisted Gravity Drainage, are practically a solid at room temperature. Strip mining resembles open pit coal mining where the overburden is removed, the sand laden with tar is removed and processed to separate out the petroleum fraction, and then the cleansed sand as well as the overburden is returned to the exhausted pit. SAGD technology requires that two horizontal wells be drilled. Then steam is injected into the upper bore. The steam reduces the viscosity of the tar to the point where it flows down to the lower well bore and is then brought to the surface with pumps. The major advantage is that there is minimal surface disruption and damage. The major problem is that it consumes larger amounts of energy in producing the steam. In either case, the tar, when processed and diluted with condensate, can be transported via both pipeline and rail. This is fortunate because there are no markets for bitumen (tar) based crudes in Western Canada, just as there is little local market for light sweet Bakken Crude in North Dakota where much of the diesel to run the drilling rigs actually needs to be brought in from refineries outside of the state.

As we note on the following page, using charts supplied by CERI (Canadian Energy Research Institute), tar sands production, by both surface mining and in situ production, is slated to increase from a little over 2,000,000 bbl./day to a level of almost 5,800,000 bbl./day in 2037. However, the growth curve for in situ production is much higher with the result that 3,800,000 bbl./day or about two thirds of production in 2037 will use in situ methodology. This system is viewed as being more energy efficient and ecologically friendly as there is no need to remove forests and overburden in order to access the bitumen deposits. However, the costs of extraction, including the energy needed to heat the in situ bitumen to the point where it can be pumped from the tar sand matrix, will remain high making this one of the more expensive crudes around.

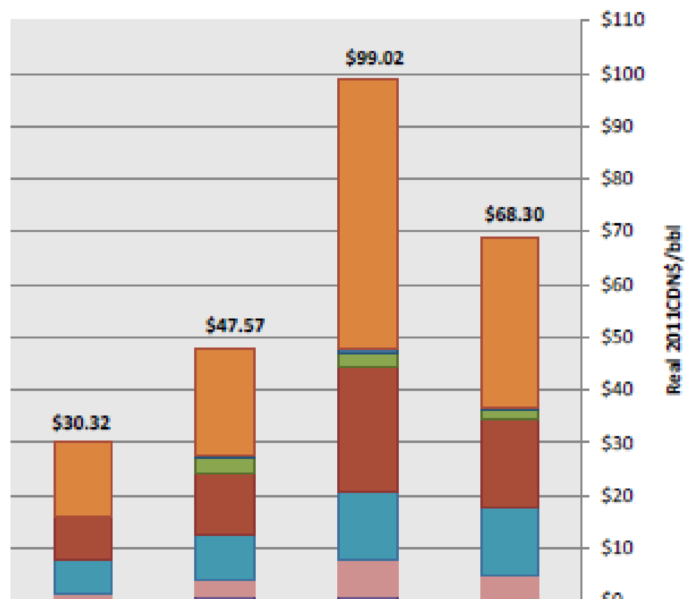
Figure 2: Bitumen Production by Extraction Type



Source: CERI, CanOils

A brief review of costs for Canadian Tar Sands Crude proves enlightening. The costs, assuming a 10% return on capital for mining and upgrading tar sands crude, range from $48 to $68/bbl. However, when upgrading costs are included, the aggregate costs are just short of $100/bbl. The bulk of the costs in each case are associated with the capital equipment and energy costs needed to support the process.

Figure 1: Field Gate Bitumen and Synthetic Crude Oil (SCO) Supply Costs



	Primary Recovery 10% ROR (a)	SAGD 10% ROR (a)	Mining & Upgrading 10% ROR (a)	Mining 10% ROR (a)
Fixed Capital (Initial & Sustaining)	$14.31	$19.87	$51.03	$32.00
Operating Working Capital		$0.45	$1.01	$0.69
Fuel (Natural Gas)		$3.23	$2.55	$1.60
Other Op. Costs (Fixed, Variable, Elec)	$8.38	$11.44	$23.62	$17.00
Royalties	$6.40	$8.83	$12.89	$12.76
Income Taxes	$1.23	$2.98	$7.20	$4.31
Emissions Compliance Costs		$0.73	$0.65	$0.40
Abandonment Costs		$0.03	$0.07	$0.05

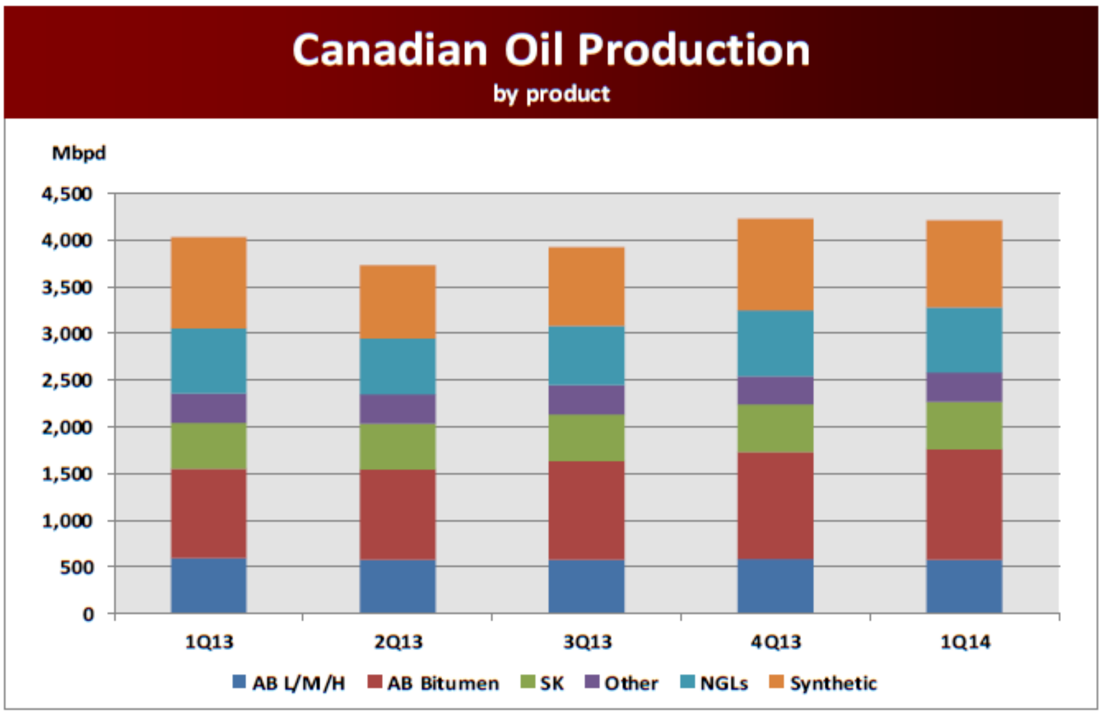
[a]return on investment is included. Source: CERI

Despite production of conventional crudes from offshore Eastern Canada, Canadian onshore production will continue to be dominated by tar sands crude assuming that suitable methods are developed to move that crude to domestic, US and international refineries equipped to utilize that crude.

To that end, Canada is simultaneously pursuing the Keystone XL pipeline to the Gulf Coast, a proposed pipeline to Canada's West Coast to support exports to China, and a recently announced pipeline conversion and extension to Canada's East Coast which will allow

Canada to support existing Canadian refineries as well as provide for the export of Canadian heavy crude to other international markets.

Our last chart on Canadian production provides a near term forecast of Canadian production, which now exceeds 4 million barrels per day. Of that total, over 600,000 bbl. per day are in the form of NGLs coming from Canada's own shale fields while almost one million barrels are in the form of "synthetic" crude, which is modified and diluted Bitumen. Over 1.2 million barrels are in the form of Bitumen itself.



SOURCE: IEA Oil Market Report.

Given the options available to Canada and the United States, the most logical destination for the heavy Canadian crudes is the collection of "complex" refineries along the Gulf Coast, primarily in Texas and Louisiana. These refineries have been already modified to accept low quality heavy, sour imported crudes. Shipments to Canada's own refineries on the East Coast will require refinery modifications to allow them to process the heavier sour crude, while exports to China will face high transportation costs as well as modifications of the refineries in China. The Gulf Coast facilities are equipped to handle similar crudes, which are currently being imported from a variety of locations, primarily from Venezuela, Mexico and West Africa.

The solution for moving this crude from Canada to the Gulf Coast is the Keystone XL pipeline. As a result of continued debates about environmental impacts, the construction of the portion of this pipeline that crosses the US-Canadian border has been repeatedly delayed. A partial solution has been to rely on the same sort of unit trains mentioned earlier to bring diluted heavy crude to the Gulf Coast for conversion into marketable products.

Continued delays in the implementation of the trans-border portion of the Keystone XL pipeline may result in the construction of one or both of those two alternate pipelines mentioned above which will move the heavy crude to Canada's west coast for export to China or to its east coast for refining and possible export to Atlantic basin markets.

An additional impact of the delayed pipeline may be to continue US reliance on heavy international crudes that may eventually cause a glut of light sweet crude oil that will arrive on the Gulf Coast but which, in large quantities, are unsuitable for use by Gulf Coast refineries. This results because the pipeline is designed to move both Bakken crude and Canadian heavy crude to the Gulf Coast. One partial solution to that problem will be yet more capital expenditures to modify these complex refineries to allow them to absorb more sweet crude. Alternatively we could become exporters of sweet crude while we continue to import heavy crudes. Currently, the export of any crude from the United States, other than certain exports to Canada, is illegal.

The relevant law dates to the 1970s and the Carter Administration when the government was desperate to retain as much North American crude as possible to alleviate shortages caused by the Arab Oil Embargo of 1973. While some exceptions have been made, for example crude shipments to Canada or especially permitted drawdowns and exports of sweet crude from the Strategic Petroleum Reserve during international crises like Libya in 2011, the regular export of sweet crude from the United States will require Congress to change the law.

As this Commerce chart illustrates, the effect of increasing domestic production has been and will continue to be, a drop in crude imports. However, with continued growth in crude production and without meaningful increases in demand or in refinery processing capacity, the day is quickly coming when the United States will need to authorize crude oil exports or artificially constrain efforts to produce more domestic crude.

Existing and Planned Assets in Greater New Orleans.

Louisiana has a great inventory of electric power plants, refineries, gas processing plants and numerous petrochemical plants all suitable for converting natural gas, natural gas liquids, and crude oil into a wide variety of chemical intermediates as well as some finished products. Within the Greater New Orleans region, we have thirteen major chemical plants, both inorganic and organic, along with five major refineries and one plastics facility.

The five refineries include Chalmette Refining, a JV between Exxon and PDVSA located in St. Bernard Parish, a Valero refinery and the large Shell Motiva facility in St Charles Parish, another JV, this one with Saudi Aramco. We also have the Phillips 66 refinery, located in Plaquemines Parish, and the Marathon Ashland Petroleum refinery, in St. John the Baptist Parish. The Phillips, Motiva and Marathon facilities are particularly noteworthy due to their size and their demonstrated ability to export refined products.

We also have thirteen chemical plants including one Chlor-Alkali plant, owned by Occidental Chemical, located in St. James Parish. The plant uses electricity to convert locally produced brine into gaseous chlorine and sodium hydroxide, also known as Caustic. There are three industrial gas plants, in Orleans, Jefferson and St. Charles parishes, owned by Air Products, Cornerstone Chemical, and Air Liquide-America. These gas plants produce industrial gases such as hydrogen and oxygen that are used in refinery and petrochemical operations.

Next, we have three plants producing inorganic chemicals. These are located in St. John the Baptist, Jefferson and St. James parishes and are owned by NALCO, Cornerstone Chemical and Noranda Alumina.

Orleans Parish has a single plant, owned by Southern Recycling, producing plastics materials and resins; while Dow Chemcial, Americas Styrenics and Dupont have plants in St. Charles, St. James and St John the Baptist parishes. These latter three plants all produce various organic chemicals.

We have two synthetic fertilizer plants, one each in St. Charles and St. James parishes. The first of these plants, owned by Monsanto Envirochem Systems, produces nitrogen-based fertilizer while the second, owned by Mosaic Fertilizer, is focused on phosphate based fertilizers. Finally, we also have an Intralox facility in Jefferson Parish that produces plastics products.

Dow Chemical, mentioned above, recently restarted an ethylene cracker in Hahnville that had been idle since 2009. They also announced a $1 billion plus investment spread across three parishes. New steam cracker capacity will be built at an existing Dow site in Plaquemine, Louisiana, while two new polyolefin plants will be built in Iberville and West Baton Rouge parishes. The latter two plants will produce high performance polyethylene and synthetic rubber using feed stocks from the Plaquemines facility.

Other recently announced expansions include new methanol capacity being erected in Ascension parish, CF industries is building a new nitrogen based fertilizer plant in Donaldsonville, while Dyno-Nobel is doing a feasibility study for an ammonia production facility in Waggaman.

In St. James parish, Mosaic, mentioned earlier, has begun work on a new ammonia plant. In Plaquemines parish SE Tylose, a sister company to Shintech, is building a plant to manufacture materials used in latex paints and water based coatings.

Beyond these plants, there are the multibillion dollar investments in three new LNG liquefaction plants, two of which have received approval and are proceeding with design and construction activities.

Louisiana Exports

Louisiana's worldwide exports increased 3.4% in the first six months of 2013 compared to the same period in 2012. The overall value of Louisiana's exports totaled $29 billion, breaking all previous records held by the state for this same period.

Louisiana's principal export markets through the second quarter were Mexico ($3.26 billion), China ($2.58 billion), and Singapore ($1.53 billion), followed by Japan, Canada, Brazil, the Netherlands, Panama, Egypt, and France. Chile and Colombia were edged out of Louisiana's Top 10 export markets in the first half of 2013 by France and Panama, who were previously ranked 16th and 18th respectively over the same period last year.

The strongest Q2 growth in Louisiana export markets were Panama (up 112.37%, an increase of $484 million,) Singapore (up 44.25%, an increase of $469 million,) and France (up 34.16%, an increase of $187 million.) In contrast, the largest declines in exports were represented by the Netherlands (down 38.66%), Egypt (down, 17.04%), China (down 16.83%), and Japan (down 15.61%).

In terms of the products being exported, the following table and chart illustrate the massive position held by petroleum and petrochemical products. Together they represent the majority of all Louisiana exports.

Louisiana Exports by Industry
(US$ NAICS Database)

Code	Description	Q2 2012 YTD	Q2 2013 YTD	% Q2 2012-Q2 2013
	TOTAL ALL INDUSTRIES	28,051,367,133.00	29,011,816,303.00	3.42
324	Petroleum And Coal Products	10,392,027,961.00	11,742,934,220.00	13
111	Agricultural Products	7,813,490,396.00	6,272,465,845.00	-19.72
325	Chemicals	4,258,900,977.00	4,406,966,784.00	3.48
311	Food And Kindred Products	2,106,092,703.00	2,589,685,845.00	22.96
333	Machinery, Except Electrical	847,172,001.00	1,591,091,830.00	87.81
212	Minerals And Ores	732,638,742.00	469,071,563.00	-35.98
331	Primary Metal Manufacturing	317,171,154.00	338,447,042.00	6.71
312	Beverages And Tobacco Products	281,733,445.00	325,008,535.00	15.36
332	Fabricated Metal Products, Nesoi	295,012,943.00	311,048,252.00	5.44
336	Transportation Equipment	225,858,305.00	271,135,612.00	20.05

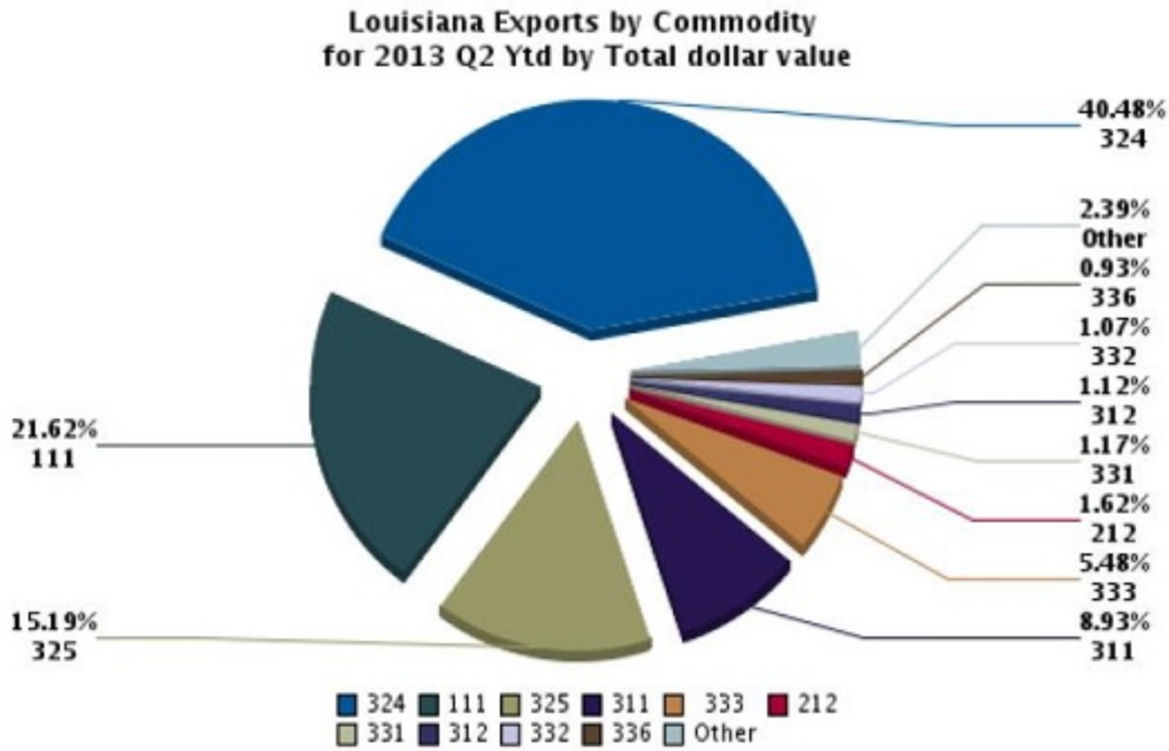
Source: World Trade Center New Orleans August, 2013

At $11.7 billion for the second quarter of 2013, Petroleum and Coal Products (Refined Products) is our number one export and represents 40.5% of the total. Primary markets for these products were Mexico, Singapore, and the Netherlands, followed by Gibraltar (UK) and France. Notably, Louisiana's exports of Petroleum and Coal Products increased substantially to Latin American markets such as Peru (up 233.24%), Ecuador (up 172.50%) followed by Panama (up 73.88%) and Mexico (up 66.80%). Petroleum and Coal Exports were up 13% over the comparable quarter a year earlier. In addition to higher exports of petroleum products, coal exports also increased driven by exports to Europe, primarily for power generation.

The number two category, Agricultural Products, passes through the local port, but, like steel and consumer durables are not really produced locally. Still, the related area Food and Kindred Products comes in as number four in the lineup.

Chemicals, at the number three position with $4.4 billion in exports, represents 21.6% of total second quarter exports. Here, the stimulus has been the relatively recent availability of lower cost natural gas and natural gas liquids feed stocks compared to those available to other chemical manufacturing countries. Sector exports were up 3.5% over the same quarter a year earlier.

Together, these two categories accounted for 62.1% of the exports through Louisiana port facilities. The following pie chart, generated by the World Trade Center of New Orleans, who also provided the data immediately above, gives the details for these as well as the balance of our Louisianan export profile. The prior chart contains a key to the NAICS codes used in the chart.



Source: World Trade Center New Orleans August, 2013.

Exports Looking Forward

Going forward, we expect to see continued growth in both categories. We also expect to see Louisiana and Texas chemical exports increase disproportionately versus the rest of the country given our regional focus on organic chemistry.

In addition, we also expect to see increasing imports, most notably in terms of Iron ore to feed the NUCOR DRI plant. We understand that the iron ore to be used, magnetite, will be imported from Brazil.

An Agence France-Presse article dated August 21, 2013, highlights a Boston Consulting Group study which states that a more productive US factory sector, enjoying cheaper energy and relatively lower wages, will pull production from leading European countries, Japan and China. Within six years that production will capture $70 billion to $115 billion in annual exports that would have come from those countries by 2020.

Together with "re-shored" manufacturing from China, where rising wages are undermining its competitiveness, the shift could add from 2.5 million to 5 million jobs in the United States which is steadily becoming one of the lowest-cost countries for manufacturing in the developed world. The study goes on to say that by 2015, average manufacturing costs in the five major advanced export economies -- Germany, Japan, France, Italy and Britain -- will be 8% to 18% higher than those in the United States. By that time US labor costs will be 16% lower than in Britain, 18% below Japan's, 34% below Germany's and 35% below labor costs in France and Italy. Moreover, the report underlined, the US workforce has much greater flexibility than its industrial rivals.

The second key advantage in the United States is the sharp fall in energy prices due to the boom in shale gas production. As the Agence-France-Press article states, "Cheap domestic sources of natural gas translate into a significant competitive advantage for a number of U.S.-based industries."

All of those new exports between now and 2020 will require port facilities such as the Gulf Coast ports of Louisiana and Texas. In addition to the international shipments, we should also see increased brown water traffic associated with moving both raw materials and finished products to and from the ports.

Louisiana Transportation Infrastructure

Pipelines

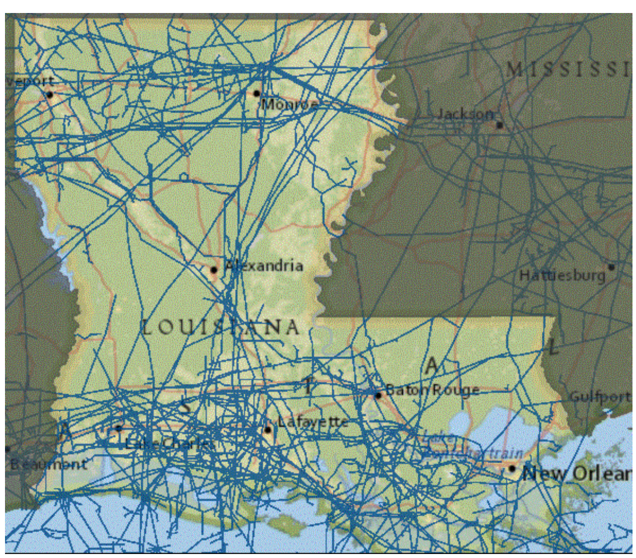
A second closely related industry to oil and gas extraction is the pipeline industry. Because pipelines are effectively hidden from view, Louisianans are little aware of the massive amount of oil and gas products that move underground in this state.

Consider these figures:

There were 87,764 miles of pipelines in onshore Louisiana in 2010. These pipelines carry crude oil, natural gas, petrochemical products, LPG/NGL, gasoline, jet fuel, and other refined products. In 2010, there were also 37,000 miles of active and proposed pipelines in offshore Louisiana, outside the state's jurisdictional boundaries.

These 124,764 miles of pipelines are the ones for which reasonable data are available because they are subject to state or federal regulation. These are not pipelines transporting chemicals with no petroleum base. There are various other materials such as carbon dioxide and hydrogen, which are also moved by pipeline but are not included in these totals.

Perhaps two of the most strategic product pipeline systems are the Plantation and Colonial pipelines. These allow the export of gulf coast refined products to the densely populated eastern seaboard of the United States.



The “Plantation” system primarily covers the southeastern states up to Maryland while the “Colonial” system moves product from the Houston Ship Channel, across Louisiana and a number of other states, and ends up in Linden, New Jersey. The Colonial system includes fifteen major terminals along its route and starts out moving 2.5 million bbl. /day out of the refining states and into the seaboard consuming states.

Of the total, 1.9 million barrels are diverted along the route, prior to the pipeline reaching its northern terminus in Linden, NJ. At that point it supplies a maximum of 600,000 bbl. per day to the New York area. Unfortunately, the northeast consumes 3 million bbl. per day. Local refiners produce less than 1 million bbl. per day with the result that the region, in addition to importing 1 million barrels/day of either domestic or international crude to support the local refineries, has to import another 1.4 million bbl. per day of refined product through marine terminals. The major sources of this imported product are the Irving refinery in Eastern Canada and various refineries in Europe.

Europe requires more diesel than it can produce. It produces both diesel and gasoline in a relatively fixed proportion. It consumes the diesel and exports surplus gasoline to the northeast United States. The unfilled European diesel demand is then met with various imports including imports from the Gulf Coast.

Solutions to the significant undersupply of petroleum products in the North East include:

1) Refining more fuel locally, using sweet shale crudes delivered by rail.

2) Expanding the capacity of the Colonial products pipeline. This would allow additional domestic products to be shipped from the Gulf Coast.

3) Bringing in more domestically refined product, again from the Gulf Coast, using new Jones Act compliant vessels, or

4) Instituting yet more unit trains to move refined product from the Gulf Cost to the Northeast. This would be in addition to the unit trains needed to move crude to the remaining northeast refineries.

The first option is being pursued by adapting closed refineries so that they can receive unit trains of crude from the Bakken shale in North Dakota. This can perhaps cover 2-300,000 bbl. per day. However, in addition to crude, the closed refineries need major capital expenditures in order to meet current environmental restrictions. There is also an issue of how many unit trains will be allowed to transit into an area with the highest population density in the United States.

The second option, and perhaps the least expensive on a unit basis, is to expand the capacity of the existing Colonial pipeline. This option faces significant regulatory hurdles even assuming the use of existing right of way. The system has been sold out since the early part of the decade and the easy incremental expansions (adding additional pumps and debottlenecking terminals) have all been done. Hence, the next phase will require new pipeline "laterals" in addition to the two lines that already exist. Laterals are essentially new parallel pipeline segments, which are laid alongside the existing lines within the existing right of way. Such pipeline additions will cost in the billions and will require users to commit to significant take or pay, multiyear contracts.

The third option also will be costly and will require significant investment in small tankers or integrated tug barges. These will also require new long term take or pay contracts. The fact that the United States has a cabotage law (The Jones Act) which requires that vessels used in coastwise trade be US owned, built, crewed, and flagged when moving merchandise from point to point within the United States effectively doubles the cost of the marine option. The good news is that numerous marine terminals that already exist in the Northeast, currently serving the international crude and refined product import markets. These existing terminals could accept marine based shipments of domestic refined products.

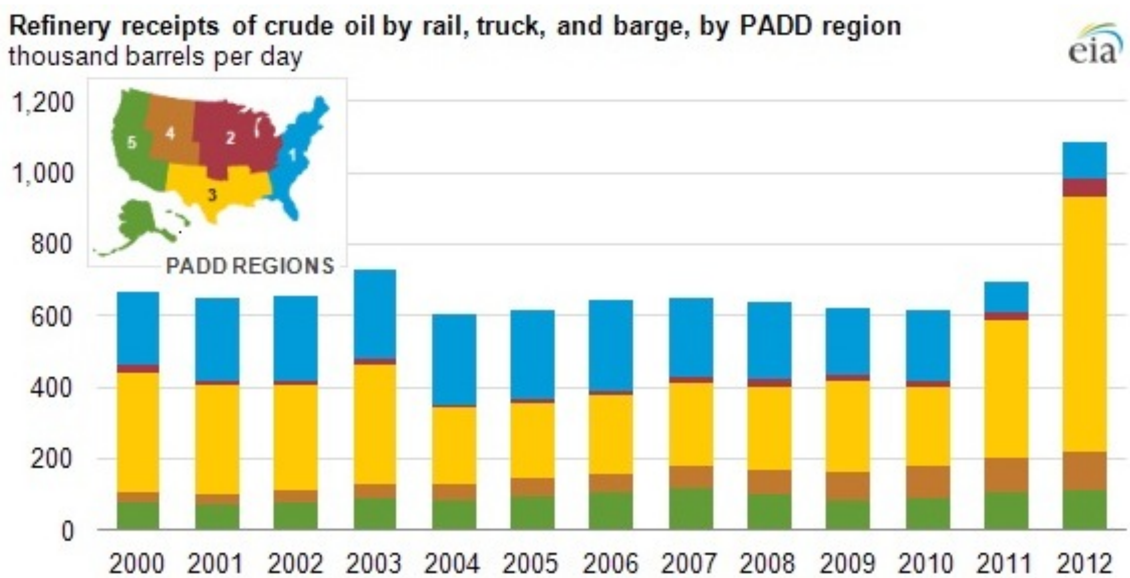
The fourth and final option is to use refined product unit trains. This would require new transfer terminals on both ends of the route plus the ability to route these long and relatively slow trains over existing rail rights of way in the most densely populated portions of the country. If such trains can handle 70,000 barrels each, the entire shortfall could be handled albeit with twenty train deliveries per day. Assuming a 72-hour trip each way, which includes maximum speeds of 45 mph, rest stops for crew changes every 8 hours, and a 24-hour turn around at each end, this would imply that a round trip would take seven days. The United States would need 140 trains, each over a mile in length and each using four engines and 115 tank cars every day of the year. It would also require perhaps as many as ten very large rail terminals on both ends, capable of handling two trains per day. To put this in perspective, unit trains moving coal east out of Wyoming have never exceeded eighty trains per day. Clearly, unit trains could help the situation but can only be a part of the solution.

Unit Trains

As the above argument points out, unit trains are not without their complications. However, when used in less densely populated areas where existing rail and petroleum handling infrastructure already exists, they can make a lot of sense. Unit trains will always be more costly than pipeline transportation, on the order of two to three times the price per barrel of large diameter interstate pipelines. They will also be more accident prone, although the resultant accidents should result in more limited spillage. However, they are also much more flexible with standardized engines and rail cars, existing rights of way, and terminals that should cost on the order of $30 million each. The terminals will take one to two years to construct. The long lead time item will be the locomotives and the rail cars themselves with current lead times on the order of three years. Certain merchant refiners, such as Valero, have already placed orders for captive rail car fleets and are building their own receiving terminals at their refineries. They believe the added transportation costs can be made up by the added flexibility of accessing geographically different sources of crude.

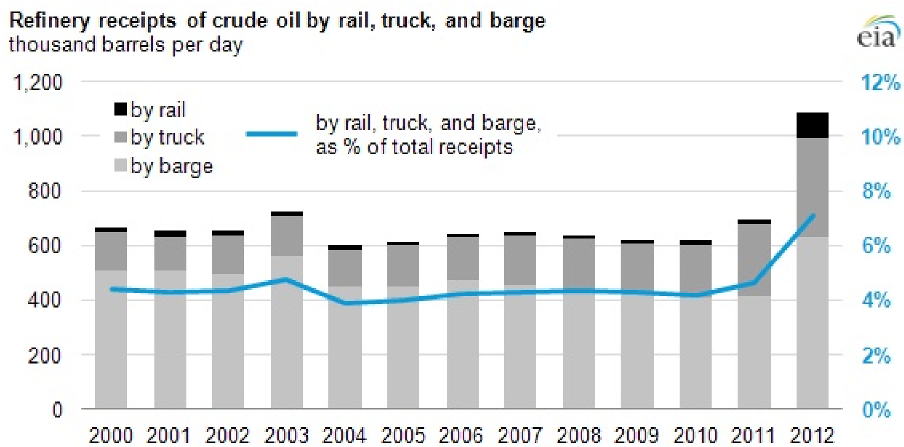
In a recent head to head comparison, a pipeline proposed by Kinder Morgan and designed to deliver crude to California refiners, was not successful because the California refiners were willing to pay a premium in order to have the flexibility to source crude oil from multiple sources. The potential customers included both Valero and Tesoro refineries.

In this recent EIA chart, highlighted in an article by the Oil and Gas Financial Journal, refineries in PADD 3 have been the major beneficiaries of the increased use of non-pipeline deliveries of crude oil over the last three years. While we would expect the absolute level to be substantial, the increases seen since 2010 are dramatic evidence of market penetration by railroads devoted to getting non-conventional crude oil delivered to where it can be converted into salable products despite the limitations inherent in the existing transportation network.



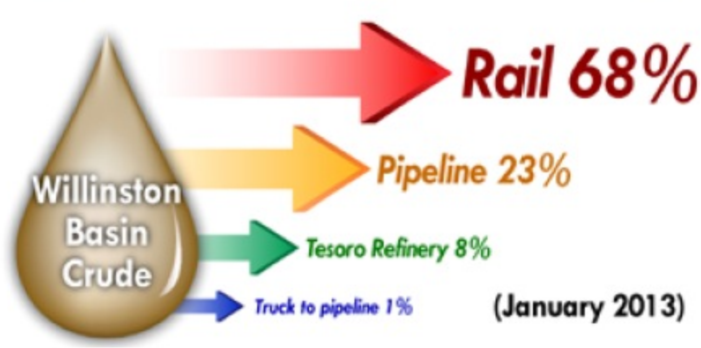
Source: Energy Information Agency (EIA) and Oil and Gas Financial Journal

The next chart, also from EIA and O&GFJ, illustrates that the major source for non-pipeline deliveries to refineries is by barge, followed by truck, with rail still small, but growing. Bear in mind that this chart does not account for deliveries of domestic crude via tanker, a recent development. Also of note is the limited use of alternate transportation to deliver crude to the remaining refineries in the Northeast. Arguments have been made that even with an expedited approval of the Keystone XL pipeline and the completion of other interstate crude oil pipelines, the rail option will continue to thrive. The author believes that will be the case. He also believes that domestic rail and marine tanker deliveries will also grow.



In terms of crude oil leaving the Bakken area, total transportation in 2007 was about 200,000 bbl. per day and all of it was by pipeline. In 2012, total capacity was approximately 1.1 million bbl. per day with 430,000 of the total using pipelines. EIA's forecast for 2014 is for a total take away capacity of 1.9 million bbl. per day with pipelines representing about 900,000 bbl. per day and railroads representing the balance. We note that in January of 2013, the Tesoro Refinery accounted for 8% of Bakken exports while rail moved 68% or more than two thirds of the crude while pipelines moved 23%.

Figure 6. Willinston Basin crude exports by channel (January 2013)



Belfer Center for Science and International Affairs | Harvard Kennedy School

LNG-Import/Export

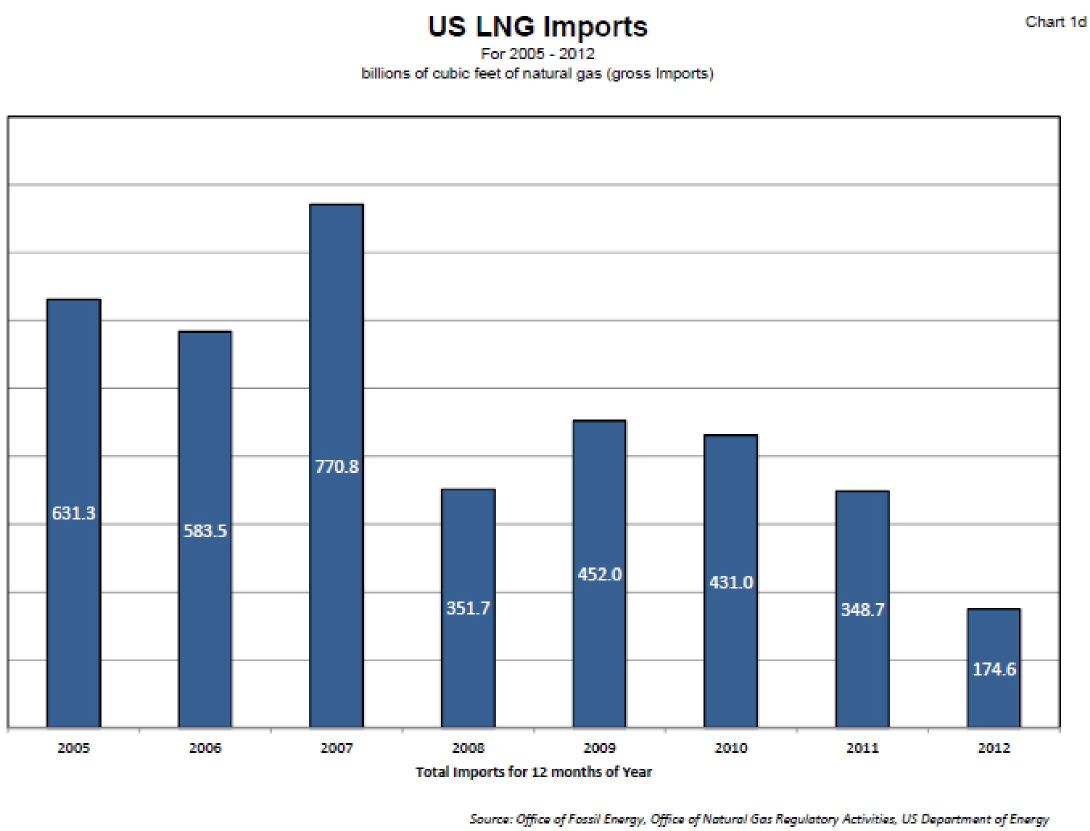
Liquefied Natural Gas or “LNG” has a fascinating history, which we cannot really delve into in this paper. The economic rationale for liquefying natural gas rests on the tremendous reduction in volume that occurs when one converts six hundred cubic feet of gas at atmospheric pressure and a temperature of sixty degrees Farenheit into a cryogenic liquid, also at atmospheric pressure, occupying one cubic foot. The energy contained in each is the same. If there is no way to build a pipeline to deliver gas, say from Nigeria to Europe, it can be converted to a liquid, loaded on special ships, and transported to the intended destination. Once the ship arrives, the gas is heated up to forty degrees Farenheit and returns to its original gaseous state ready to be distributed to various residential, commercial, industrial and utility customers. Farenheit

There is no question that significant energy and capital is required in compressing and cooling the gas until it undergoes the phase shift from a gas to a liquid at -260 degrees Farenheit. Significant capital is required to develop the field, build the liquefaction plant, the loading terminal, a fleet of specialized vessels, and a receiving terminal/re-gasification unit. However, if an economy needs the gas badly enough and there is no other practical alternative, then LNG makes sense. Obviously, the farther apart the locations, the more capital that is required for the vessels dedicated to moving the LNG between the two ports. Typically the ships cost approximately $230 million each and the average route will need ten vessels in order to assure continuous gas supply. The liquefaction facility is the most expensive unit and can cost $2-4 billion depending on the capacity required. Finally, the re-gasification terminal will cost in excess of $1 billion. The net effect is to roughly double the value of the gas over its value immediately prior to liquefaction. These large permanent liquefaction installations also require proved and developed natural gas reserves, on the order of nine tcf large enough to feed the installed infrastructure for a period of twenty to thirty years. This latter requirement is in itself a major hurdle as there are many medium size gas fields available, but relatively few giant gas fields.

Recently, two events have improved the potential for additional LNG transport infrastructure. The first is the emergence of surplus natural gas supplies in the United States due to the shale gas phenomenon discussed elsewhere in this paper. The second is the emergence of floating liquefaction units, which can sequentially exploit multiple smaller reserves.

With surplus gas supplies in the United States, we have idled existing LNG import terminals within our borders. Plans to reuse these idle import units by converting them to LNG liquefaction and export facilities are moving forward currently. Three units are authorized for conversion and another twenty-one units, both existing and green fields, awaiting full authorization. The existing facilities already have much of the required infrastructure in place including cryogenic LNG storage tanks, pipeline access, and the specialized dock facilities needed to load LNG transport vessels. The changes required include reversing the direction of the natural gas pipelines connecting the terminals to the pipeline grid and the addition of liquefaction capabilities.

While this is still an expensive conversion, having existing import infrastructure lowers the time and the cost of a conversion to about half the cost of a green field liquefaction facility. The following chart from Zach Allen of Paneurasian, a consultancy, shows that imports of LNG into the United States have been on the decline, with one exception, since 2005. The anomalous year is 2007, which was the boom year just before the economic recession of 2008 which caused a sudden drop off in LNG demand in 2008.



Over the last four years, the decline has been steady. Remember that 2005 marks the beginning of the shale revolution in the United States. As shale output has increased, it has displaced all higher priced supplies, starting with LNG imports, but also including Gulf of Mexico conventional gas production. Most of the import terminals are on standby status with only minimal amounts of LNG being delivered, just sufficient supplies to maintain the cryogenic temperature of the facilities. Typically that amounts to about one cargo per year.

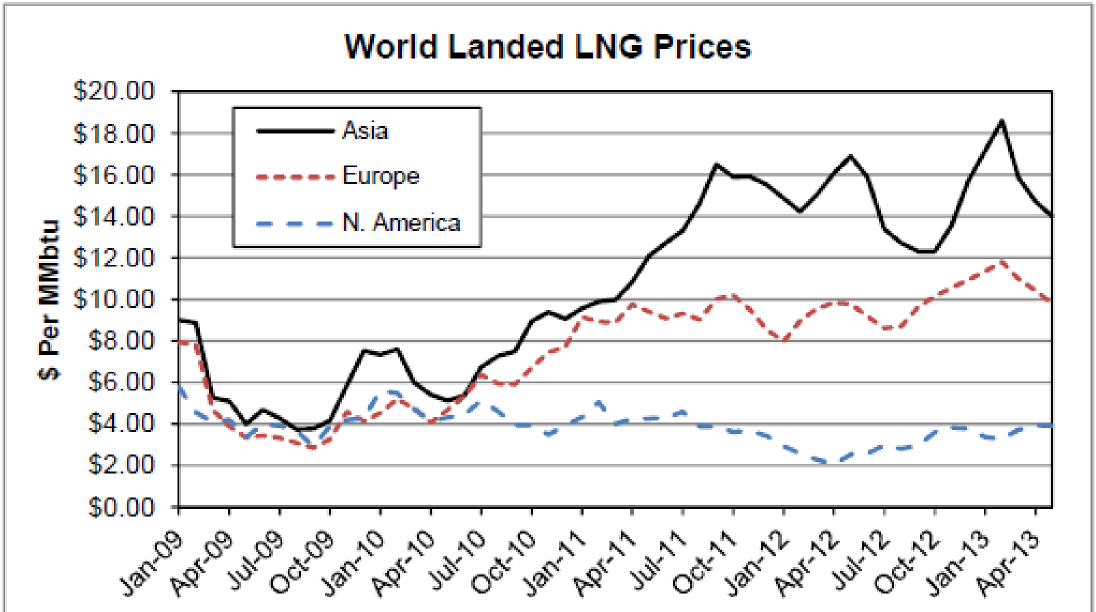
As the LNG in the tank and pipelines slowly heats up and is converted to boil off gas, that gas does enter into the United States pipeline system.

One other major consideration, beyond the costs of utilizing LNG as a transportation fuel involves the relative pricing mechanisms for natural gas in various parts of the world. In the United States, natural gas developed as a separate market from crude oil and refined products. Here, gas pricing depends largely on gas-on-gas competition or in the power context, gas vs. coal. As a result, United States gas prices are low relative to other parts of the world. In the United States, a whole group of power generation and process industries grew up based on using gas.

In the rest of the world, the power and petrochemical industry evolved differently with gasoil, also known as naphtha -- a refinery byproduct, being the starting point for their petrochemical industry. For the most part, foreign power generation relied on hydro, coal and nuclear units. To the degree that natural gas is used for power generation, it was seen as a premium fuel that was largely reserved for peak demand response and is associated with residential and commercial consumption. As the following table, from Raymond James, illustrates, these latter countries price natural gas based on its BTU (British Thermal Unit) content compared to crude oil. As a result, the classic 6:1 ratio, where 6,000 cubic feet of natural gas is equivalent of one barrel of oil, meant that $100 oil equates to $17/mcf natural gas. The de-coupled US price of gas remains in the $4 range compared to the $100 bbl of oil resulting in an effective price ratio of 25:1. Btu equivalency is logical but it does result in a gas price that is four times higher than the prevailing price in the US market.

Europe has been able to mitigate the economic damage to some degree through re-negotiating contracts with their major supplier, Russia. As a result, they now have effective prices of $10-11/mcf. Asia has been less successful and now enjoys the highest natural gas prices in the world at about $14-16/mcf. The following chart details the historical prices for the three regions. Most recently, the Asian countries have been investing in US and Canadian gas plays with the intent of circumventing the serious price disadvantage that results directly from the way they have indexed their gas prices to their cost of crude oil.

The following table provided by Raymond James, is based on data from the Federal Energy Regulatory Commission, lists details on these various plants as well as expected timing for commercial production.



Source: Raymond James research, Waterborne LNG

The next table lists the announced plant conversions as well as a couple of new green field plants that have been proposed in order to allow US exports of LNG. To date, three of these units, the facility at Freeport Texas as well as the Sabine Pass facility in Louisiana, the largest such unit in the United States, and the Lake Charles facility, also in Louisiana, have been approved for export to non-FTA approved countries. While a number of other units have been approved for sale to FTA countries, those countries do not have much demand for LNG when compared to the non-FTA category.

North American Liquefaction Plants							
Project	Location	Est. Capacity (Bcf/d)		Est. Cost	Status	Targeted	Owner/Applicant
		Initial	Max. Target	($ MM)		Startup	
Kenai	Alaska	0.19	0.19	NM	In operation	Producing	ConocoPhillips
Douglas Channel	BC, Canada	0.1	0.3	$3,500	CNEB-approved	2015	BC LNG Export Cooperative
Sabine Pass	Louisiana	1.0	2.0	$12,000	Under construction	Late 2015	Cheniere
Plaquemines	Louisiana	0.2	1.1	?	DOE-approved	2016	Cambridge Energy (CE FLNG)
Elba Island	Georgia	-	0.2	$1,100	DOE-approved; under FERC review	2016	Kinder Morgan, Shell
Kitimat	BC, Canada	0.7	1.4	$5,500	CNEB-approved	2017	Chevron, Apache
Cameron LNG	Louisiana	-	1.7	$6,000	DOE-approved; under FERC review	2017	Sempra, Mitsui, Mitsubishi, NYK
Cove Point	Maryland	-	0.8	$3,400 - $3,800	DOE-approved; under FERC review	2017	Dominion
Lavaca Bay FLNG	Texas	0.4	1.1	?	DOE-approved; under FERC review	2017	Excelerate Energy
Oregon LNG	Oregon	-	1.3	$6,000	DOE-approved; under FERC review	2017	LNG Development Co.
Main Pass Energy Hub	Louisiana	-	3.2	$14,000	DOE-approved	Mid-2017	McMoRan Exploration, United LNG
Corpus Christi	Texas	-	1.5	?	DOE-approved; under FERC review	Late 2017	Cheniere
Freeport	Texas	0.6	1.9	$4,000	DOE-approved (incl. non-FTA); under FERC review	Late 2017	Freeport LNG, Zachry, Dow Chemical, Osaka Gas
Lake Charles	Louisiana	-	2.0	$9,500	DOE-approved; under FERC review	Early 2018	Energy Transfer, BG Group
Pacific Northwest	BC, Canada	1.7	2.6	$10,000	Project description stage	2018	Petronas
Gulf Coast	Texas	-	2.8	?	DOE-approved	2018	Gulf Coast LNG Export
S. Texas LNG Export	Texas	-	1.1	?	Under DOE review	2018	Pangea LNG (North America)
Gulf LNG	Mississippi	-	0.3	$1,000	DOE-approved	2018	El Paso, GE Energy Financial Services
Goldboro LNG	NS, Canada	0.7	1.4	$5,000	Preliminary project design	Late 2018	Pieridae Energy Canada
LNG Canada	BC, Canada	-	3.2	?	CNEB-approved	TBD	Shell, Kogas, Mitsubishi, PetroChina
Jordan Cove	Oregon	-	0.9	$7,500	DOE-approved; under FERC review	TBD	Veresen
Golden Pass	Texas	-	2.2	$10,000	DOE-approved	TBD	Qatar Petroleum, ExxonMobil
Waller Point	Louisiana	-	0.2	?	DOE-approved	TBD	Waller LNG Services
Magnolia LNG	Louisiana	0.5	1.1	$2,200	Under DOE review	TBD	Liquefied Natural Gas Ltd.
Alaska LNG	Alaska	-	3.5	?	Preliminary project design	2024	ExxonMobil, ConocoPhillips, BP, TransCanada
Total			38.0				

Source: FERC, EIA, Waterborne LNG, company reports. Assumes 1 mtpa = 0.1433 Bcf/d unless specific Bcf/d figure is given by company.

Higher probability completion before the end of the decade, subject to regulatory approval

One example of the conversion approach is the Sabine Pass facility of Cheniere energy. According to the Federal Energy Regulatory Commission (FERC) July 2013 report, engineering is now 72% complete, procurement is 65% and overall project progress is 40.2% complete against a budgeted 38.3%. Final completion is still anticipated as February 2016 for train #1 and June 2016 for train #2. The second Louisiana site, at Lake Charles, recently awarded the initial engineering contract.

Sabine Pass Train 1 Area 131N (Propane Condenser) 7-23-13-FERC

The business models for these modified plants, as well as for other plants built to import LNG, are based on so called “take or pay” contracts. In such contracts, large natural gas marketers, who are typically not equity holders in the terminal, reserve portions of the processing capacity of the plants under multiyear contracts. They are then obligated to pay for this reserved capacity whether or not it is actually utilized. When it is used, they also pay additional volumetric costs for receiving, liquefaction, storage and loading of the LNG onboard transport vessels under contract to the gas suppliers/marketers. These take or pay contracts are sufficiently rigorous to support the multi-billion dollar project financing packages used to build new or to modify existing terminals. Beyond the costs of building the plants, there is also significant time and money required in order to garner the necessary permits to export LNG from the United States.

While there are no limitations on the export of refined products or products produced using domestic natural gas, export of crude oil or natural gas in the form of LNG requires approval of the executive branch of the US government. Permission is required regardless of whether or not there is a surplus or shortage of such products in the US economy. For example, strenuous objections have been voiced, not only by environmentalists, but also by certain companies in the petrochemical sector about allowing LNG exports. These companies see a significant commercial advantage versus their international competitors due to low domestic gas prices and they are concerned that exports will cause an increase in domestic prices causing their current cost advantage to narrow.

The Gulf Coast is home to a concentration of LNG import terminals with two in Texas, several in South West Louisiana and one in coastal Mississippi. Other terminals exist on the East Coast, at Elba Island outside of Savannah, in Chesapeake Bay near Baltimore, as well as in Boston. There is also one terminal in eastern Canada that primarily supplies New England with natural gas. Several new units have been proposed for the west coast, in both the United States and in Canada. Mexico also has two terminals, one on each coast.

Beyond the large onshore facilities mentioned above, the last five years has also seen the emergence of Floating Liquefied Natural Gas (FLNG) import terminals. These terminals provide all of the services associated with an onshore facility, but have the advantage of smaller scale as well as mobility once a given gas customer no longer needs an LNG supply. As a result, they can exploit smaller gas customers, for example, island based economies interested in improving local air quality.

Even more recently, the industry has approved the construction of floating export liquefaction facilities. Two are currently under construction. These floating facilities are able to access and process smaller gas reserves than the immovable onshore plants. In addition, they have the advantage of being able to be assembled in developed shipyard facilities without the need for major onsite construction activity in remote locations. Shell is sponsoring a large liquefaction facility of this type for use in Australia while Excelerate of the United States is planning a smaller facility for a coastal Texas location near Corpus Christi, Texas.

Finally, the market is also beginning to build new small scale onshore liquefaction plants for use by companies interested in converting transportation users from diesel to natural gas. In addition to significant improvements in emissions, the LNG for transportation is significantly less expensive on a BTU equivalent basis.

Lessons Learned from the Past

One prime lesson we hope everyone has learned is that economies run in cycles. The energy industry is not immune from this pattern. As we look at the current renaissance in petro-chemicals, it is worth noting that the current euphoria is quite similar to that which we saw in the 1970s when there seemed no end to the expansion of the then growing petrochemicals business along the Gulf Coast.

Eventually, the rest of the world caught up and with rising US natural gas prices, many of those plants curtailed production or closed. In certain cases, the plants themselves were disassembled and moved to foreign countries with lower raw material and/or labor costs. Some of those same plants, including two Methanol plants in Argentina, are now being disassembled and re-erected in Louisiana while other Louisiana plants that didn't move are being expanded and modernized. It may be that we will have a twenty to twenty five year run this time, but eventually the competitive advantage will shift again. The answer to this sort of cyclic risk is to diversify and to avoid being dependent on one product, one feed stock or one technology.

Another lesson learned is that Louisiana has been primarily involved in the extraction of crude oil and natural gas and the conversion of those materials into bulk chemical intermediates. To the degree possible, we should focus on moving further down the value chain. Rather than selling basic plastic resins or elastomers, we should concentrate on attracting plants that convert these materials into items that are recognizable by the ultimate consumer. This not only means that we develop local customers for our existing chemical intermediates, but we also develop new employment opportunities to help reduce our state's unemployment rate. While our rate at ~7.2% is not terrible, it could certainly improve. Plants that specialize in converting bulk chemicals into specialty chemicals or better yet, into finished consumer products, tend to be labor intensive and not as capital intensive as the upstream plants. Focusing on moving several of these facilities to our area should be an economic development priority.

Finally, we need to acknowledge that tensions between industry and local communities and environmental interests groups are pervasive, and have resulted in a long history of litigation. Strategies to mediate the polarization that now exists should be explored so as to continue to be able to retain and attract companies that are investing in our energy industry. To the degree possible, we want those companies to remain in Louisiana and to expand here rather than in other locations. We also want them to bring in their suppliers and direct customers.

Future Prospects for Energy

Energy's future has to be assessed as being bright because of the positive impact of new technologies that make possible the economic extraction of oil and gas from shale deposits. Southeast Louisiana is particularly blessed because of the commingling of a number of positive trends that have been outlined in this paper. We should have a great future over the next ten to twenty years based on our E&P, Refining, Petrochemical, and Transportation advantages.

However, that does not mean that there are no clouds on the horizon.

Many of today's upstream energy executives separate their business risks into two categories. They refer to these as "subsurface risk" and "above ground risk". The first category includes all of the traditional risks they face in exploring for and developing oil and gas reserves. The second includes the risks associated with regulations and policy.

An increased regulatory environment designed to enhance safety and mitigate environmental impacts has the potential to discourage the energy and manufacturing sectors from continuing to invest in the economy. As the country grapples with a fragile job market and strives for energy security, and while the renewable energy sector is still in its most nascent stages, continued growth of the petroleum and petrochemical markets are warranted and Louisiana has an opportunity to play a leading role.

New Energy Markets for Louisiana

DRI Units

Direct Reduction Iron or “DRI” units are a new approach to producingiron without the need to use conventional blast furnaces in order to produce pig iron, a necessary precursor and the main raw material used for steel production. Instead of using Coke, a derivative of metallurgical coal, to reduce iron oxide ore to elemental iron, DRI units use natural gas for the reduction, resulting in iron production that is more environmentally friendly, less expensive to produce and which requires a much smaller manufacturing footprint. While the technology has been available for over twenty five years, it has been limited in its deployment to places like Trinidad and Tobago because of the dual needs for good water transportation as well as reliable supplies of the appropriate ore and reasonably priced natural gas.

The innovative steel company NUCOR is well along in the construction of the first DRI plant in the United States and it will be here in Louisiana. With commercial success, they plan a second phase expansion and are also planning on subsequent downstream expansions, which will convert the produced pig iron into higher value steel products. This is a good example of the combination of good physical infrastructure, strong recruiting efforts and advantageous energy costs bringing a major new energy intensive industry to south Louisiana.

GTL Units

Gas to Liquids technology was pioneered by SASOL, a South African company whose antecedents go back to successful efforts in Germany to produce synthetic petroleum products from coal. During WWII, Germany was able to produce the majority of its aviation gasoline from coal using a process that first converted the coal into a mixture of carbon monoxide and hydrogen and then reassembled those building block molecules into the required liquid hydrocarbons used in blending aviation gasoline. These Coal to Liquids (CTL) plants were completely destroyed by Allied bombing in the last year of WWII.

Later, during the apartheid era in South Africa, the United Nations, in an effort to break the will of the white minority in South Africa, imposed sanctions that prevented the country from receiving crude oil needed to provide transportation fuel for its population. South Africa’s apartheid government responded by building new coal fired steam locomotives in lieu of the diesel electric locomotives used by the rest of the world’s railways. The sanctions also inspired SASOL to build the first modern CTL (coal-to-liquids) plants and later, at least one GTL (Gas to Liquids) plant. Both the CTL and the GTL plants used technology derived from the German experience.

More recently, Sasol and Shell are planning new GTL plants for Louisiana in order to produce premium blending components for transportation fuels using low cost domestic natural gas as the raw material. As long as a significant difference between the cost/btu of gas and crude oil continues to exist, these plants will be able to make money and, in the case of Shell, provide a natural hedge against escalating crude oil prices. While the international price for crude oil fluctuates on a daily basis, the trend has been for prices to remain in the $100 range while the dynamics of the domestic natural gas market seem to indicate range bound pricing between $4 and $6/mcf. That approximately 25:1 to 16:1 ratio would seem to support the development of this technology which basically uses $4 gas to produce $100 oil products.

Biofuels

Biofuels, for most people, means corn based ethanol blended in a 90:10 ratio with conventional gasoline. To a lesser degree, bio diesel fuel blends, such as those used by our local RTA, contain no more than 5% renewable diesel fuel produced primarily from soybean oil. While R&D efforts are ongoing, for example to produce advanced ethanol fuels from non-food cellulosic materials and to produce second generation bio diesel fuels made from algae, these efforts are still shy of being fully commercial.

Based on strong lobbying efforts and a desire to diversify away from conventional hydrocarbon based transportation fuels, the United States and other countries have mandated the use of renewable ethanol and bio-diesel in the transportation sector. While the programs have been politically popular in the Midwest and with the current administration, the economic fundamentals of increased use of renewable ethanol and bio-diesel remain challenging. The current products, when available, drive up the costs of a whole variety of food products, as a result of displacement. It also drives up the average cost of conventional transportation fuels through a variety of adverse impacts.

As fuel, ethanol is costly, lacks energy density, has severe blending problems with conventional gasoline, and can cause damage to older engines when used in concentrations above 10%. In addition, ethanol, regardless of its source, requires a segregated fuel distribution system with the result that blending cannot occur at the refinery but must take place just prior to delivery to the local gasoline station. Ironically, there are also a number of studies that argue that all of the intensive agriculture as well as all of the added truck based transportation used in producing ethanol actually results in more CO2 being released with corn based ethanol than with conventional gasoline.

While much publically funded effort has gone into efforts to produce a second generation cellulosic ethanol so as to mitigate the fuel versus food complaints, these efforts have not resulted in meaningful cellulosic ethanol production. Today, in the United States, the bulk of the ethanol used in transportation is derived from corn while sugar cane based “advanced” ethanol supplies are imported from Brazil until we have domestic cellulosic ethanol production available.

While there are continuing efforts to improve the ethanol product and to diversify the agricultural raw material, the long term ability for renewable ethanol to compete without subsidies and mandated production requirements is not good. Some efforts are going into producing other alcohols, such as bio-butanol, which would have better blending and energy density properties. However, it would still have the same issues with dispersed production. Regrettably, the second and third generation ethanol products intended as gasoline substitutes are nowhere near commercial application at dosage levels above ten percent.

On the Biodiesel front, the first algae-based bio diesel plant is just beginning operations in New Mexico. In the meantime, soybeans, also a food product, will be the main sources of bio-diesel production. Certainly, some progress is being made, but the agricultural nature of the feed stocks has been a detriment to their wide spread adoption. Also, bio-diesels suffer from the effects of cold weather on their viscosity.

As of May 2013, the EIA believes that biodiesel production in May reached 111 million gallons versus 106 million gallons in April. The Midwest, PADD 2, represents about 67% of US production. May production equates to about 1.3 billion gallons per year. Overall, there are 116 operating plants in the US with nameplate capacity of 2.2 billion gallons per year, so utilization is not great. In terms of feedstock, soybeans accounted for 54% with a ratio of 7.6 pounds of soybeans needed to produce one gallon of biodiesel.

Current feed stocks, things like soy bean oil in the United States and rapeseed oil or palm oil in international markets, are competing directly with food markets, driving up the price of these materials in the developing world. Longer term, the use of algae to produce synthetic diesel shows promise. The first semi-plant is just now starting up in New Mexico. While algae may eventually contribute a partial solution, it will still require huge amounts of fresh water and land in order to be a meaningful contributor to our distillate fuel needs. For those who would argue the case for industrial process plants to grow algae and thereby reduce land requirements, there will then be the challenge of providing intensive artificial light to substitute for sunlight. That will require significant electrical power to promote the growth of the oil bearing algae.

We believe that algae based product could represent a long term potential for Louisiana, given our well watered alluvial plain as well as our low cost electricity and no shortage of CO_2. However, the emphasis should be on the term “long”. At the moment, there are no commercial facilities producing algae based diesel. The time line is more in terms of decades than in years.

LNG as the New Transportation Fuel

Given the growth in natural gas production, several new transportation applications have been spawned. In each case, the driver has been lower fuel costs, somewhat offset by the need to invest in new vehicles and new fueling infrastructure. The areas include large over the road trucking, marine transportation, and railroad locomotives.

In terms of truck usage, successful operations are already in place. These operations depend on central refueling locations for vehicles that periodically return to the same location. Examples would be local delivery trucks, public transportation vehicles, and refuse haulers. In each case, a single refueling facility is able to resupply the vehicles during scheduled daily periods of inactivity. This market will continue to grow.

However, excitement is now focused on long distance over the road routes where a series of refueling operations can be located approximately four hundred miles apart in order to allow long haul trucking operations to use LNG as a fuel. In addition to refueling infrastructure the LNG tractors need modified diesel engines that can run on either diesel or LNG. Typically, these engines are designed to start out using diesel and to then convert to LNG once the engines have warmed up. The auxiliary diesel supply also provides a backup in case of emergencies such as the loss of a scheduled LNG refueling stop.

The following snapshot illustrates a currently operating LNG fueled diesel tractor, one of several owned by Illinois based Dillon Transport Inc.

While externally similar to a standard tractor, the cryogenic saddle tanks are larger to account for the necessary insulation and the lower energy density of LNG. They also incorporate supplemental diesel fuel capacity. Of course the engines are also different in being equipped to handle dual fuels. The truck economics are fairly straightforward with fuel economy offsetting higher capital costs. The economics of the refueling infrastructure is a bit more complex unless the trucks are part of an integrated trucking operation with existing distribution hubs that can serve as refueling sites. Dillon is adding one hundred new tractors per year and will have converted their entire fleet within five years.

A second application involves marine transportation. This originally started in Europe but is now being implemented along the Gulf Coast by Harvey Gulf Marine with heavy encouragement and support from Shell. In this case, large supply boats servicing deep water offshore platforms will be supported by a fleet of LNG fueled supply vessels operating out of Port Fourchon, Louisiana. These vessels will be able to operate up to eleven days without refueling. Actual refueling will occur during the typical port turnaround while the vessel is being re-supplied with materials for transport to the offshore platforms. In addition to the LNG, the vessels will also have tanks for diesel fuel which can be used in emergencies but which is primarily intended for delivery to the platforms in the Gulf. The first six vessels in this new fleet are under construction, not in Louisiana but at least along the Gulf Coast, at TY Shipyards in Gulfport. There are also options for another four units are part of the construction program.

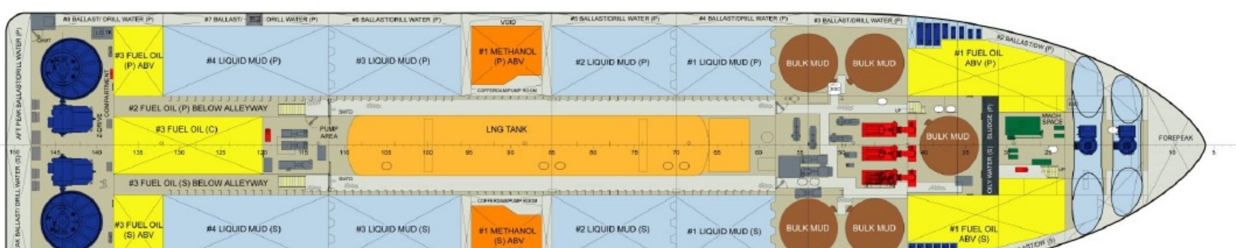
Beyond use with Offshore Support Vessels (OSVs), there are also extant applications with ferries and other small coastal vessels. As far as blue water applications, portions of the LNG transporter fleet have been fueled by boil off gas from the LNG tanks although most operators now prefer to utilize conventional diesel propulsion systems. Here in the United States, the AKER Shipyard in Philadelphia has recently contracted to build two "LNG Compatible" merchant ships. These units will be easily convertible from diesel to LNG once refueling facilities become available.

A total of six OSV vessels are under construction with options covering four additional units. Each vessel actually has three LNG fueled power plants on board. These units generate electricity which is then used to power the twin thrusters at the rear of the vessel as well as the twin tunnel thrusters located near the bow. All four thrusters are controlled by dual dynamic positioning computers which allow the boat to maintain complete control over its course and position, including holding position while delivering cargo to deep water offshore facilities.

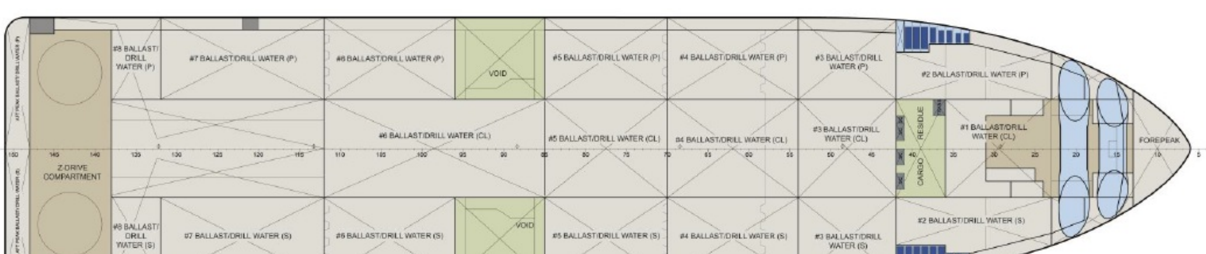
Dynamic positioning systems utilize satellites, wind speed and direction sensors, ocean current sensors and proximity sensors to allow these vessels to hold position next to a deep water drilling unit or a floating production facility without needing to anchor or tie up to the other vessel. These first ten vessels are being built by TY Shipyards, a unit of Trinity Yachts located in Gulfport, Mississippi.

Below, is a rendering of the new OSVs being built for Harvey Gulf Marine. The vessels will be used to service Shell's deep water drilling and production facilities.

The plan clearly show the central cryogenic LNG storage tank as well as various other tanks used to store diesel, liquid and bulk mud, and methanol for use offshore. Note also the four thrusters, two tunnel thrusters at the bow, and two azimuth thrusters at the stern. The three diesels are shown in red.



HOLD PLAN



TANK TOP PLAN

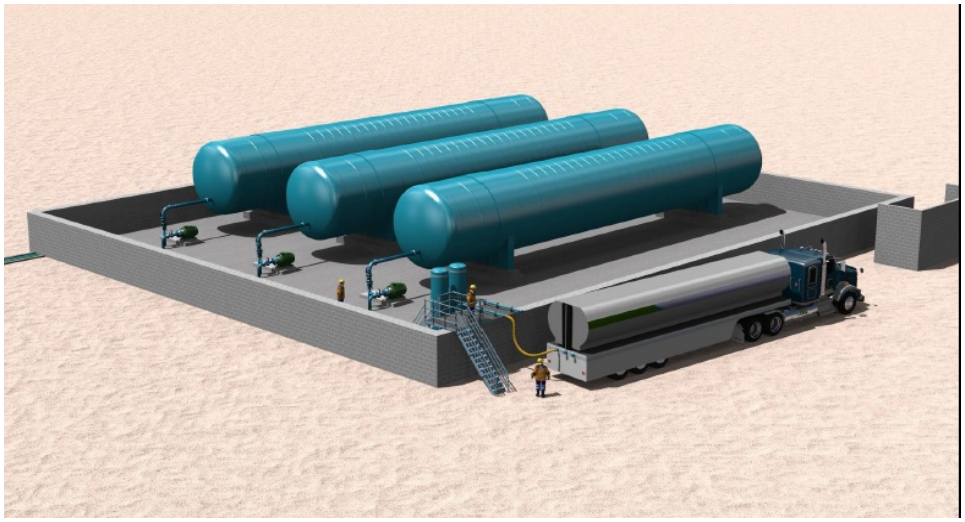
Currently, firm construction plans cover six hulls with four additional options. While the cryogenic fuel tanks for the first three hulls were provided by Chart Industries, starting with hull #4, the 67,000 gallon tanks will be provided by Lockheed-Martin, from the Michoud facility in New Orleans East.

Beyond the OSV construction, Shell is also investigating the construction, with Edison Chouest, of LNG barges, which will allow for the bunkering of LNG as well as vessel resupply of the Port Fourchon facility.

Bunkering involves the transfer of fuel from one vessel to another while vessel resupply involves bringing the vessel to a stationary onshore fueling location.

LNG will actually be produced at Shell's facility in Geismar, Louisiana. It will then be initially trucked to a shore side facility in Port Fourchon, Louisiana. The next rendering is of that marine fueling facility, which is being installed at Harvey Gulf Marine's operations base in Port Fourchon. In addition to being able to refuel marine vessels, the site will also have the capability of supplying LNG to over-the-road vehicles.

Beyond the local liquefaction activity at the Shell Chemical complex in Geismar, Louisiana (250,000 tons per year), Shell is also building additional LNG production facilities in Sarnia, Ontario, to supply marine traffic on the great lakes, as well as a third production facility in Alberta. The latter facility will supply truck stops, E&P operations and eventually railroads.



Another onshore application involves railroad locomotives. These dual diesel-electric locomotives utilize large displacement V-12 engines in the 2,500-4,000 horsepower range. They are actually variants of the engines used for the marine equipment mentioned above. As in the marine case, the motivation is to reduce fuel costs as well as to limit pollution. Two large rail operations, Burlington Northern of the United States and CN of Canada, have working prototypes in operation and are developing plans to convert portions of their rail fleets. General Electric, a major manufacturer of locomotives is cooperating in the tests. The mode of operation for these units will be equivalent to that used by the long haul trucking operations. Two diesel electric locomotives will be linked to a single LNG tender. Potential applications include providing the necessary power to move those 115 car unit trains from North Dakota to the Gulf Coast.

Beyond these mobile applications, stationary applications are also being implemented.

For example, a number of drilling contractors are converting portions of their onshore drilling rig fleets to dual fuel capability. Each rig uses at least one diesel engine that is comparable in horsepower and displacement to those used in the marine vessels and locomotives. Once the wells are drilled, the pressure pumping units, which are part of the fracking spread will also utilize LNG as a fuel source. In both cases, the goals are fuel economy and reduced emissions. Once a field is partially developed, the drilling units will be able to use locally produced natural gas and the skid mounted LNG fuel infrastructure can then be moved to a new immature field location.

While absolute LNG consumption in all of these segments is small at present, it is slated to grow over the next ten years as the fueling infrastructure is put in place, as the costs of new construction versus existing engine conversions become standardized, and as the operational benefits of using low cost natural gas in lieu of diesel become more pronounced. Because natural gas burns more completely and has less inorganic ash, lower maintenance costs are expected in addition to the direct benefit of lower fuel costs.

We would hope that Louisiana, with its existing LNG infrastructure and its significant truck, rail and marine vessel infrastructure will be able to capitalize on these new applications.

Competitive Markets for Growth in Greater New Orleans

As of 2011, the Greater New Orleans region included a total of 566,307 employees. Total wages in the region totaled $26 billion in 2011. This equates to an average weekly wage of $881. These and the following details are drawn from the LWC RLMA report.

In every case, energy employees in each parish earned higher average weekly wages than other non-energy employees. Within the energy group, the manufacturing sector generally provided the biggest aggregate payrolls while the Mining (upstream E&P) sector provided the highest average weekly wages. One exception to this rule was Orleans parish where the absolute payroll for Mining exceeded that for manufacturing. However, manufacturing dominates in parishes such as Jefferson, St. Charles and St. James parishes.

This would suggest that an intermediate term growth goal should be to focus on Refining and Petrochemical manufacturing. These firms are faced with significant increases in the utilization of existing petrochemical operations plus extra growth resulting from expansions and new energy intensive operations now locating in Southeast Louisiana to take advantage of our relatively low natural gas and NGL costs. In addition, our relatively low cost electric power, a result of a favorable mix of nuclear and natural gas powered generation, our skilled labor force, and our advantageous shipping options including blue water and brown water marine transportation, top quality rail facilities and excellent pipeline infrastructure. These pipelines carry crude oil, refined products, natural gas, and NGLs, but also include other gases such as hydrogen, nitrogen and CO2. As we add to the manufacturing base, we will also necessarily add to our transportation infrastructure, particularly in the pipeline and rail segments.

In general, we will see major growth in intermediate gas processing plants, steam crackers and new polyolefin units designed to convert raw NGLs to new polymers such as polyethylene as well as new elastomers. While these don't represent new technologies, they do build on our existing petrochemical capabilities while taking advantage of our strategic advantages in power and raw material costs.

We should do everything possible to expedite enhancements to the transportation matrix while also encouraging new product capabilities such as the NUCOR pig iron plant and the SASOL Gas to Liquids facility.

The big challenge, as always, will be to encourage additional vertical integration in the refining and petrochemical process industries. We need to add additional value to our raw materials beyond simply producing petrochemical intermediates. Not only will this add value to our bulk chemicals, but it will disproportionately add to the skilled employee base associated with manufacturing.

Historically, downstream users of bulk plastics and elastomers have preferred to set up their finishing facilities closer to their ultimate end user markets. As a result, many polymer plants and synthetic fiber plants, and plastic molding facilities of all types are located along the Atlantic Seaboard in states like, North and South Carolina, Virginia, Tennessee and Delaware. We believe that, with a concentrated effort, we could attract some of these "downstream" consumer-oriented businesses to Louisiana. Rather than manufacturing polymer chips and shipping them East in rail cars, we could be producing the products that are being consumed by the ultimate consumers. It is an industry maxim that the closer you get to the consumer, the lower the fixed capital cost of the plants and the more people intensive the production becomes. In the quest for more high paying jobs, we cannot afford to overlook this option.

Expansion Trends over the next five years

We expect to see continued growth in the upstream markets, both onshore and offshore.

We expect deep water oil plays to strengthen as that segment continues to recover from the Macondo spill of 2010. Despite setbacks like the closure of the McDermott yard in Morgan City, the closure of the Avondale shipyard, and the bankruptcy of several smaller independent oil and gas operations, the need for offshore crude development continues to grow and the support structure along the Gulf Coast will need to adapt to deep water as the “new normal”.

We need to view the closure, in the McDermott case, as a result of the disappearing need for bottom founded structures used in shallow water, the original target market for that yard. The current need is for yards capable of building deep water floating structures such as the new Williams “Gulfstar” project, this major deep water production facility will be completely built in the United States. Rather than yards located up shallow water bayous, we need to have deep water access.

In the case of Avondale, the yard was completely focused on building of military vessels. The resultant cost structure is simply too expensive and inappropriate for constructing commercial vessels and offshore floating structures. If the yard can be re-tooled for deep water oil and gas construction, it may yet be able to contribute to our regional economy. Given the actual and forecasted use of Floating Production, Storage and Offloading vessels (FPSOs) in the Gulf, as well as the continued construction of production decks for other floating production units along the Gulf Coast, that might be an initiative worth pursuing.

Elsewhere, the continued growth of the deep water OSV fleet is exemplified by the new LNG fueled vessels and the new fuel manufacturing facilities being built by Shell, at Geismar, and the new fueling facility being built by Harvey Gulf Marine at Port Fourchon. We need targeted programs to capture those building programs now to support new build and repair shipyards like those operated by Bollinger Marine and Edison Choest as well as numerous other facilities around coastal Louisiana. While the LNG fueling is in its infancy, Louisiana has a long history of building and operating offshore support vessels. This new technology seems to be a natural initiative for coastal Louisiana to undertake. Unfortunately, both the vessels for this initial foray are all being built outside of the state.

In addition, by 2018, we should be seeing growth in the export of LNG from existing import terminals that are now being modified to handle exports. Two of the three plants approved for non-FTA sales are located in Southwest Louisiana, one at Sabine Pass and the other at Lake Charles. Sabine Pass is approximately 40% complete and is slated for commissioning in 2016. Southern Union, at Lake Charles, is just starting the construction process with the award of a Forward Engineering Estimating and Design (FEED) contract to Technip, the largest French Engineer, Procure and Construct (EPC) firm. This latter project involves a new liquefaction plant with total export capacity of fifteen million metric tons per annum using three identical liquefaction trains. These trains will use technology supplied by Air Products, a long time participant in Louisiana's chemical industry. In addition they will use virtually all of the existing LNG import facilities.

We should also see continued growth in conventional refined products, both for domestic and international consumption, at least until we reach 100% utilization of existing refining capacity. At that point we will face the need to expand refining capacity to process increasing quantities of light sweet crudes and condensate becoming available from North Dakota and from the wet shale gas plays of Texas and Pennsylvania. This will take place in addition to any adjustments associated with handling increasing supplies of heavy sour crudes coming down from Canada that will be displacing imports of heavy sour crudes from West Africa, Venezuela and Mexico.

Adding to these plants, we should also see continued growth in the production of petrochemical products from both new and existing plants that will convert natural gas and NGLs into petrochemicals for both domestic and international consumption.

Major growth over the next five years will also result from the completion of many of the new petrochemical and other energy consuming plants that are in the construction stage. Petrochemical shipments are increasing as the US captures a larger share of the world wide chemical intermediates and bulk plastics markets. Again these plants may be capacity limited as a result of permitting difficulties, particularly receiving air permits from the EPA. Already several new steam crackers and polyethylene plants in coastal Texas are experiencing difficulties in receiving permits, particularly from the EPA. So far plants announced for Louisiana, include a $1 billion plus Dow Chemical investment in Iberville and West Baton Rouge parishes, covering new synthetic rubber and polyethylene plants, in addition to the upgrade of Dow's ethylene production capacity in Plaquemines parish. Dow recently restarted an existing ethylene cracker in Hahnville, Louisiana that had been idle since 2009. Several other relevant plants are in construction including Methanol plants, ammonia plants, and synthetic fertilizer facilities.

Beyond the plants and refineries, we also note a number of new pipelines and pipeline enhancements being built to move the new shale based NGL production to our Gulf Coast manufacturing complex. Examples include plans by Kinder Morgan and Mark West Utica EMG to convert a pipeline to move natural gas liquids between the Northeast and Louisiana. Enterprise Products has separate plans to bring NGLS sourced from the Marcellus Shale in Pennsylvania to the steam crackers located along the Gulf Coast in Louisiana and Texas. Finally, Bluegrass Pipeline Partners, a partnership between Williams

Companies and Boardwalk Pipeline Partners, is designing a new line to move NGLs from the Marcellus and Utica shale to those same Gulf Coast crackers.

In addition, we have already seen new pipelines being installed to deliver additional refined products from Valero's refinery in Destrehan to a terminal interconnect with the Colonial pipeline which services the entire Eastern Seaboard of the United States. Other pipelines are being modified in order to deliver additional US-based crude from the Texas hub, which will be receiving sour crude from Canada.

Also in the transportation arena are the new rail terminals which are being constructed and expanded to handle both the heavy sour crudes as well as the burgeoning production of light sweet shale based crudes from North Dakota, East and West Texas, and from Pennsylvania.

New Technology Plants:

Perhaps the most unusual plant that will be coming on stream before 2018 is the Nucor DRI pig iron plant, which will rely on imported iron ore and domestic natural gas for its two major feed stocks. The iron ore will arrive in bulk carriers, which will represent new activity for the Port of South Louisiana while the natural gas will arrive via pipelines. DRI stands for "Direct Reduction Iron" and is a new method for producing iron that does away with the need for coke as a reducing agent. Instead, natural gas acts as both a source of heat and as the reducing agent. In addition to phased expansions of the new NUCOR facility, a second plant will be producing finished steel tubular products to support continued shale gas and oil drilling and production operations.

NUCOR first pioneered the DRI process, using imported iron ore and indigenous natural gas, in Trinidad and Tobago. Having proved the process, they are now moving to a location that is closer to their ultimate steel markets. The DRI process is much cleaner than conventional blast furnaces which utilize coke to convert iron ore to pig iron, occupy a smaller "footprint" than conventional plants, and have a lower cost per ton of iron produced. The technology has been known for about thirty years, but the requisite supply of plentiful natural gas at affordable prices is a fairly recent development.

A second technology new to the state will be the Sasol Gas to Liquids plant, which will utilize natural gas to produce transportation fuels. This is a new technology application for the US as well as for Louisiana. An outgrowth of Sasol's experiences in South Africa with Coal to Liquids and Gas to liquids facilities, the new plant will be able to convert standard natural gas into premium transportation fuels that can compete in today's market for refined products. The combination of available petroleum infrastructure, a trained workforce, reliable supplies of natural gas, and existing port infrastructure make Louisiana a natural location for the first United States plant utilizing this exciting new technology.

All of these new capital investments will enhance the value of marine traffic on Louisiana's waterways as export markets for refined products and petrochemicals continue to grow and as we require heightened import capabilities, for example to handle the iron ore that will be delivered to the NUCOR plant, probably magnetite from South America.

We are even seeing the use of smaller tankers to deliver crude oil, condensate and NGLs between Texas terminals and Louisiana refining and manufacturing locations. Even LOOP, the Louisiana Offshore Oil Port, has gotten into the act, helping to bring shale crude into Louisiana refineries. Beyond moving raw materials between Texas and Louisiana, we also expect to see additional marine traffic headed to the East Coast to supplement pipeline deliveries of refined product. Perhaps this new manufacturing initiative will be able to bring back the use of blue water, US flagged cargo vessels. We certainly hope so.

Potential for new Value Added Opportunities

As an indication of the size of the chemical market in the United States and in Louisiana, we offer the following two tables again, courtesy of Dr. Loren Scott. As can be seen, the US value of shipments was $889.8 billion in 2010. At that time, Louisiana was #3 in terms of Chemical shipments at $58.2 billion with Texas holding the #1 position at $157.1 billion followed by California at $58.9 billion. Given the excellent performance of the Chemicals

Top 5 States in Value of Chemical Industry Shipments: 2010

Region	Value of Shipments*	% of U.S. Total
U.S.	$889.8	100.0%
Texas	157.1	17.7
California	58.9	6.6
Louisiana	*58.2*	*6.5*
North Carolina	52.1	5.9
Illinois	48.7	5.5

Source: Annual Survey of Manufactures: Geographic Area Series, 2010 Annual Survey. http://factfinder2.census.gov/faces/tableservice/jsf. *Billions of dollars

industry over the intervening two and a half years, we would not be surprised to see Louisiana overtake California in the next year or two.

Source: Dr. Loren C. Scott-"Louisiana Chemical Industry Economic Impact" December, 2012

Louisiana's chemical shipments total was composed of $37.4 billion in basic chemicals along with a least $13 billion in more advanced chemical products and chemical intermediates.

Makeup of Louisiana's Chemical, Plastics & Rubber Sector: 2010

Sector	Value of Shipments*
Total	$58.2 Billion
Basic chemicals	$37.4 Billion
Resins, synthetic rubber, artificial synthetic fibers & filaments	$7.4 Billion
Pesticides, fertilizers & other agricultural chemicals	$4.6 Billion
Plastics products manufacturing	$0.8 Billion
Rubber products manufacturing	$0.3 Billion

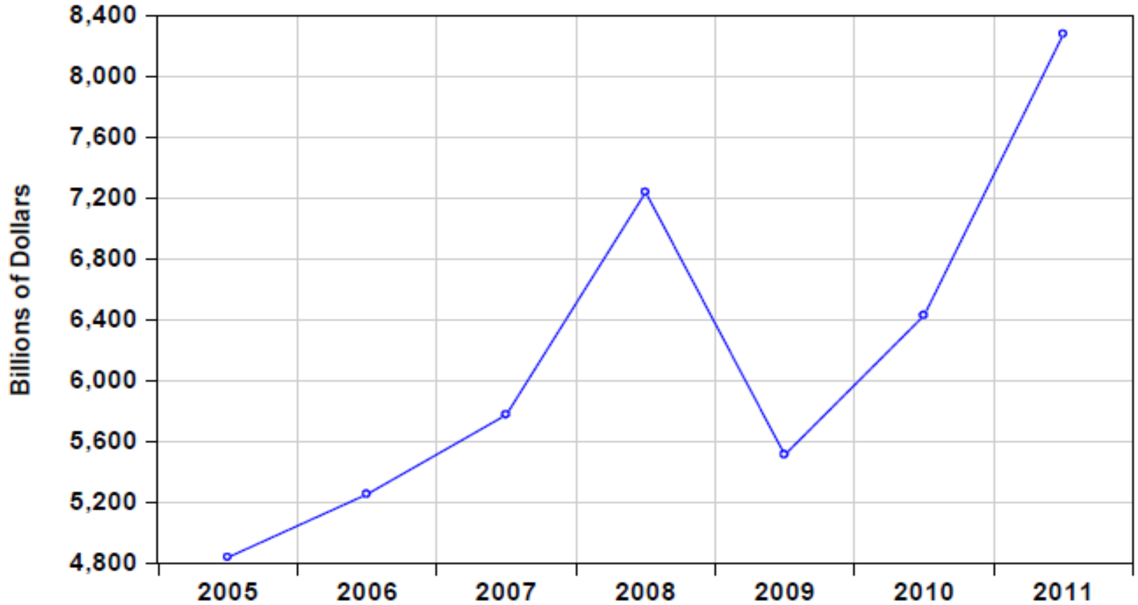
Source: Annual Survey of Manufactures: Geographic Area Series, 2010 Annual Survey. http://factfinder2.census.gov/faces/tableservice/jsf. *Numbers do not sum due to disclosure rules.

Source: Dr. Loren C. Scott-"Louisiana Chemical Industry Economic Impact" December, 2012

As the above chart illustrates, Louisiana has a strong position in basic chemicals ($37.4 billion) as well as in plastics and rubber products and in agricultural chemical products. To the degree that we can add value by moving commodity chemical products further downstream before they leave the state, we should do so.

The portion of chemical shipments that represented exports for Louisiana has grown to $8.3 billion in 2011 from a recent low point of$5.5 billion in 2009 following the recession of 2008 and an even lower $4.8 billion level seen after the disruptions associated with hurricane Katrina. Growth should continue given our fundamental advantages of 1) using low priced natural gas as the primary fuel for our plants and 2) having petrochemical manufacturing plants that are designed to use natural gas and NGLs (in lieu of Naphtha) as primary chemical feed stocks allow us to capture more of the export market.

Fig. 1: Chemical Exports From Louisiana



Source: http://tse.export.gov

Source: Dr. Loren C. Scott-"The Economic Impact of the Chemical Industry on the Louisiana Economy" December, 2012

Chemical employment in 2011 is now at 23,525 along with 3,689 people employed in the Plastics and Rubber manufacturing category. Together these 27,214 people represent 19.5% of our total manufacturing census of 139,688 in 2011.

Glossary

bbl - Barrels, in the energy context this abbreviation refers to 42 gallon barrels which are the standard unit of account for liquid hydrocarbons.

Bottom Founded Platforms – In offshore oil and gas fields, production structures which rest directly on the sea floor are referred to as "bottom founded". The other major category are floating structures which may be moored to the seafloor but which are not supported by the sea floor, relying on natural buoyancy for their support.

BRIC – Is an abbreviation for Brazil, Russia, India and China. The collective term is used when referring to these countries where production and/or consumption of oil products are growing most rapidly.

BTU - or British thermal unit is a measure of the energy content of any particular material. One BTU is the amount of heat needed to raise the temperature of one pound of water by one degree Fahrenheit, equal to approximately 1055 joules.

CERI – The Canadian Energy Research Institute is the Canadian equivalent of the US Energy Information Agency and provides statistical data on energy demand and supply for Canada.

Cotton Valley – refers to a long developed field located near Shreveport, La. roughly coincident with the Haynesville shale gas field which is thought to have been the source rock for the shallower conventional Cotton Valley formation.

CTL - or Coal to Liquids is a process that reduces coal to a mixture of hydrogen and Carbon monoxide before reassembling these building blocks into liquid hydrocarbons. The process is based on the Fischer-Tropsch reaction which was developed and used by Germany during WWII to produce aviation gasoline from Coal.

DRI - or Direct Reduction Iron refers to the ability to use pipeline quality natural gas to convert particular iron ores into pig iron, the starting point for all iron based alloys. The benefits of the process over conventional iron ore reduction are a much smaller and cleaner plant in terms of footprint and emissions.

Dry Gas – This term refers to gas wells where the well head gas is almost entirely methane with very little NGL content. After having various impurities removed, dry gas can go directly into the interstate pipeline system.

EIA - Energy Information Agency is a unit of the US Department of Energy and is responsible for providing periodic statistical information concerning energy supply and demand, in all forms, for the United States. They also provide limited information on each of the states and territories as well as on a number of foreign countries. Finally, they also provide periodic forecasts of expected energy supply and demand as well as custom reports for the US Congress covering particular energy issues being addressed by congress.

Ethane – is a two carbon hydrocarbon that is a by-product of natural gas.

Ethanol – is the official name of an alcohol which contains a two carbon atoms. In addition to being a mandated component of gasoline, it is also a prime intermediate for the production of a number of petrochemical based products. Ethanol can be produced from both fossil and renewable raw materials.

Ethylene – is a derivative of ethane that has had two hydrogen atoms removed via a process called “steam cracking”. It is much more chemically active and is the source of a variety of plastic materials.

FERC – Federal Energy Regulatory Commission is the unit of the Department of Energy that regulates interstate pipelines as well as electric power transmission facilities. In addition it is also required to approve the construction of LNG import and export terminals.

FLNG – Floating Liquefied Natural Gas refers to gas liquefaction plants that are built on vessels that can be moved to the location of either onshore or offshore natural gas fields. Historically, all LNG liquefaction plants have been permanent installations built onshore near the gas field. By building the plant in a shipyard rather than in remote locations, costs can be reduced. In addition, multiple smaller stranded gas fields can be exploited.

Fracking – refers to the process of injecting water, proppants and various enabling chemicals into a well bore in order to create micro-fractures in the targeted rock. Once the water pressure is removed, the proppants hold the fractures open and allow natural gas or crude oil to travel to the wellbore and thence to the surface.

GTL - or Gas to Liquids a process that reduces natural gas to a mixture of Hydrogen and Carbon monoxide before reassembling these building blocks into liquid hydrocarbons. The process is based on the Fischer-Tropsch reaction which was first developed and used by Germany during WWII to produce aviation gasoline from Coal. Later, it was improved and used in South Africa by Sasol to produce liquid fuels from both coal and natural gas.
GOM - Gulf of Mexico

Horizontal Drilling – is a technique of diverting the wellbore 90 degrees from the vertical position in order to penetrate relatively thin sediments of carboniferous rock. Extending up to two miles from the vertical wellbore, horizontal drilling allows much higher production rates by exposing a much longer section of the wellbore to the hydrocarbon producing rock.

IEA – International Energy Agency, the statistical arm of the OECD. Functioning like the US based EIA, the IEA provides the same statistical and economic services for the Organization of Economically Developed Countries.

Laterals – is a term used when referring to new pipelines that are installed parallel to existing lines in existing rights-of-way in order to boost total capacity. A number of new laterals have been built in order to accommodate new shale oil and gas production.

LNG or Liquefied Natural Gas is Methane gas that has been chilled to -260 degrees Fahrenheit at which point it becomes a colorless liquid. The advantage in doing this is that the volume is reduced ~600 times compared with the natural gas at standard pressure and temperature. This makes it possible to ship the material economically.

LOOP – The Louisiana Offshore Oil Port consists of a major platform located in Federal Waters south of Port Fourchon, La. Three floating buoys allow VLCC (Very Large Crude Carriers) and ULCCs (Ultra Large Crude Carriers) to offload crude oil which is then moved to shore via a 48 inch pipeline to a point 25 miles inland at Clovelly, Louisiana, where the crude is temporarily stored in 8 underground salt caverns. These vessels are not capable of entering US conventional ports because their draft exceeds the water depth available in our regular ports. From there, the crude moves through a pipeline network that connects Clovelly to many of the major refineries along the Gulf Coast.

LPG – or Liquefied Petroleum Gas refers to Ethane Propane, and Butane which are able to be shipped and stored as liquids under moderate pressures and without refrigeration. The most familiar version is Propane in cylinders used to provide fuel to barbeque pits. However, the material is also used in refineries and in petrochemical processes.

mcf – or thousand cubic feet, this is a stand volumetric unit of measurement for gases including natural gas. It assumes standard temperature and pressure conditions.

Methanol – is the official name of an alcohol which contains a single carbon atom. An older term for the same material is "wood alcohol". It is a prime intermediate for the production of a number of petrochemical based products.

mmcf – or million cubic feet, this is a stand volumetric unit of measurement for gases including natural gas. It assumes standard temperature and pressure conditions.

Natural Gas Condensate – is co-produced with natural gas and becomes a liquid at ambient conditions. Condensate contains molecules with 4, 5 or 6 carbon atoms. Condensate can be used to denature ethanol or can be used in gasoline blends. However, it typically has a relatively low octane number and requires the use of other high octane number materials in order to produce gasoline usable in modern automobiles.

NGLs Natural Gas Liquids are produced with methane from oil and gas wells, both onshore and offshore. These materials include Ethane, Propane and both isomers of Butane. Normally, because of their higher heat content, NGLs are extracted from the gas produced at the wellhead before the residual gas is introduced into the pipeline system. National specifications dictate the maximum and minimum energy content of pipeline quality natural gas.

OCS – Outer Continental Shelf refers to the waters surrounding the US that are administered by the Federal Government. In Louisiana those waters extend from three miles out to 200 miles from the shoreline.

OECD -The Organisation for Economic Co-operation and Development (OECD) is an international economic organisation of 34 countries founded in 1961 to stimulate economic progress and world trade. Most OECD members are high-income economies and are regarded as developed countries. The OECD's headquarters are at the *Château de la Muette* in Paris, France.

OSVs – refer to Offshore Supply Vessels which are the boats that transport various dry and liquid supplies from shore bases to offshore drilling and production locations.

PADD – Petroleum Administration for Defense Districts. The US is divided up into 5 major PADD units with PADD 1, the East Coast, being further divided into 3 sub districts. Originally created to facilitate energy allocations during WWII, the divisions continue to be used to present regional differences related to energy supply and demand. Louisiana is included in PADD 3.

ROW – Is an abbreviation for “Rest of World”.

SAGD – or Steam Assisted Gravity Drainage is a process that uses heat, provided by steam, which is introduced into a tar sands deposit via an injection well. The added heat reduces the viscosity of the surrounding tar and allows for it to flow downward through the sand to a second horizontal well where it can be collected and pumped to the surface.

Shale- is a type of carbon rich sedimentary rock that underlies a significant portion of the US. It is the source rock for much of the crude oil and natural gas that has been produced from shallower conventional traps over the last 160 years. Basically, the hydrocarbons slowly migrate up from the shale through the earth until they reach a layer of non-permeable rock which traps the hydrocarbons. Shale rock is characterized by having low porosity and low permeability. Here in Louisiana, the best known shale, the Haynesville shale, contains dry natural gas and is located in the extreme northwest of the state. The best known shale oil deposit is located in the Williston basin in North Dakota and is called the Bakken shale.

SPR- Strategic Petroleum Reserve is a series of underground salt caverns located in Texas and Louisiana where the US stores an emergency supply of both sweet and sour crude oil. As of December 21, 2012, the inventory was 694.9 million barrels (110,480,000 m^3). This equates to 36 days of oil at current daily US consumption levels of 19.5 million barrels per day (3,100,000 m^3/d). At recent market prices ($102 a barrel as of February 2012) the SPR holds over $26.7 billion in sweet crude and approximately $37.7 billion in sour crude (assuming a $15/barrel discount for sulfur content. The price paid for the oil is $20.1 billion (an average of $28.42 per barrel).

The United States started the petroleum reserve in 1975 after oil supplies were cut off during the 1973-74 oil embargo, to mitigate future temporary supply disruptions. According to the World Factbook, the United States imports a net 12 million barrels (1,900,000 m^3) of oil a day (mmbd), so the SPR holds about a 58-day supply. However, the maximum total withdrawal capability from the SPR is only 4.4 million barrels (700,000 m^3) per day, so it would take over 160 days to utilize the entire inventory.

Strip Mining – is a process which uses established mining techniques to remove top soil and overburden to arrive at shallow deposits of tar sand. The tar sand is then excavated using mechanical shovels and transported in dump trucks to processing plants which separate the sand and the tar prior to diluting the tar for shipment to refineries.

Tertiary Oil Recovery – refers to the use of liquid carbon dioxide, polymers or other materials to change the physical behavior of liquid hydrocarbons to allow them to move through low permeability rock. Tertiary recovery occurs after primary production is complete and after secondary recovery, which use water, has been utilized to remove additional crude oil from mature reservoirs.

WTI – Is an abbreviation for West Texas Intermediate which is the marker crude for most US crude oil that is produced onshore. The prices of other crudes produced in the US are sold at a discount or premium to WTI.

Wet Gas – This term is used to refer to natural gas which contains a higher percentage of natural gas liquids than are allowed to be moved through the US interstate pipeline system. Although the natural gas liquids are required to be removed, they have a higher value to the refining and petrochemical industry than does the natural gas itself. As a result, during periods of low natural gas prices, wet gas fields are preferentially developed in order to generate the revenue levels necessary to financially justify drilling the well.

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Appendix A - LWC Annual Energy Profile for 2012 for GNOI Parishes

Parish	Labor Category	Units	Average Employees	Total Wages	Wages % of GNOI	Avg. wkly Wage	Wage % of Parish
Jefferson	Oil and Gas Extraction	19	294	43,748,023	0.2%	2,862	0.50%
Jefferson	Support for E&P	54	1369	135,073,060	0.5%	1,897	1.60%
Jefferson	Utilities	26	503	41,752,909	0.2%	1,596	0.50%
Jefferson	Refining	6	104	6,141,055	0.0%	1,138	0.10%
Jefferson	Chemical Mfg.	18	644	54,188,831	0.2%	1,618	0.60%
Jefferson	Plastics & Rubber Mfg.	22	1145	73,198,857	0.3%	1,229	0.90%
Jefferson	Pipeline Transportation	4	206	22,086,047	0.1%	2,065	0.30%
Jefferson	Sub TOTAL	149	4265	376,188,782	1.4%	1,696	4.40%
Jefferson	no detail-confidential	0	0	0	0.0%		0.00%
Jefferson	TOTAL ENERGY	149	4265	376,188,782	1.4%	1,696	4.40%
Jefferson	Non-Energy	13592	187921	8,185,157,354	31.5%	838	95.60%
Jefferson	Total	13741	192186	8,561,346,136	33.0%	857	100.00%
Orleans	Oil and Gas Extraction	31	1390	261,810,623	1.0%	3,623	3.00%
Orleans	Support for E&P	30	929	98,217,205	0.4%	2,032	1.10%
Orleans	Utilities	24	269	24,381,950	0.1%	1,746	0.30%
Orleans	Refining	3	****	****		****	
Orleans	Chemical Mfg.	14	205	15,831,427	0.1%	1,485	0.20%
Orleans	Plastics & Rubber Mfg.	4	****	****		****	
Orleans	Pipeline Transportation	1	****	****		****	
Orleans	Sub TOTAL	99	2793	400,241,205	1.5%	2,756	4.60%
Orleans	no detail-confidential	8	264	29,184,243	0.1%	2,125	0.30%
Orleans	TOTAL ENERGY	107	3057	429,425,448	1.7%	2,701	4.90%
Orleans	Non-Energy	10859	170929	8,266,367,704	31.8%	930	95.10%
Orleans	Total	10966	173986	8,695,793,152	33.5%	961	100.00%
Plaquemines	Oil and Gas Extraction	17	765	90,203,195	0.3%	2,268	10.80%
Plaquemines	Support for E&P	27	936	62,052,694	0.2%	1,275	7.40%
Plaquemines	Utilities	4	359	34,577,190	0.1%	1,852	4.10%
Plaquemines	Refining	2	****	****			
Plaquemines	Chemical Mfg	6	118	7,442,179	0.0%	1,213	0.90%
Plaquemines	Plastics & Rubber Mfg.	1	****	****			
Plaquemines	Pipeline Transportation	3	38	3,908,210	0.0%	1,978	0.50%
Plaquemines	Sub TOTAL	57	2216	198,183,468	0.8%	1,720	23.70%
Plaquemines	no detail-confidential	3	460	56,954,873	0.2%	2,381	6.80%
Plaquemines	TOTAL ENERGY	60	2676	255,138,341	1.0%	1,834	30.50%
Plaquemines	Non-Energy	775	11897	582,069,435	2.2%	941	69.50%
Plaquemines	Total	835	14573	837,207,776	3.2%	1,105	100.00%

Parish	Labor Category	Units	Average Employees	Total Wages	Wages % of GNOI	Avg. wkly Wage	Wage % of Parish
St. Bernard	Oil and Gas Extraction	2	****	****			
St. Bernard	Support for E&P	2	****	****			
St. Bernard	Utilities	4	60	5,277,773	0.0%	1,692	1.10%
St. Bernard	Refining	7	709	85,757,561	0.3%	2,326	17.50%
St. Bernard	Chemical Mfg.	3	4	238,659	0.0%	1,147	0.00%
St. Bernard	Plastics & Rubber Mfg.	0.75	****	****		****	
St. Bernard	Pipeline Transportation	3	22	2,346,061	0.0%	2,051	0.50%
St. Bernard	Sub TOTAL	17	795	93,620,054	0.4%	2,265	19.10%
St. Bernard	no detail-confidential	5	13	1,254,868	0.0%	1,856	0.30%
St. Bernard	TOTAL ENERGY	22	808	94,874,922	0.4%	2,258	19.40%
St. Bernard	Non-Energy	776	9996	394,262,335	1.5%	759	80.60%
St. Bernard	Total	**798**	10804	489,137,257	1.9%	871	100.00%
St. Charles	Oil and Gas Extraction	2	****	****		****	
St. Charles	Support for E&P	4	77	5,396,991	0.0%	1,348	0.40%
St. Charles	Utilities	11	****	****		****	
St. Charles	Refining	8	1563	192,912,070	0.7%	2,374	14.10%
St. Charles	Chemical Mfg.	9	2247	236,378,226	0.9%	2,023	17.30%
St. Charles	Plastics & Rubber Mfg.						
St. Charles	Pipeline Transportation	1	****	****		****	
St. Charles	Sub TOTAL	21	3887	434,687,287	1.7%	2,151	31.80%
St. Charles	no detail-confidential	14	818	86,963,718	0.3%	2,044	6.40%
St. Charles	TOTAL ENERGY	35	4705	521,651,005	2.0%	2,132	38.20%
St. Charles	Non-Energy	1123	18624	845,234,967	3.3%	873	61.80%
St. Charles	TOTAL	1158	23329	1,366,885,972	5.3%	1,127	100.00%
St. James	Support for E&P	2	****	****			
St. James	Utilities	1	****	****			
St. James	Refining	4	****	****			
St. James	Chemical Mfg.	6	646	65,850,595	0.3%	1,960	14.90%
St. James	Plastics & Rubber Mfg.						
St. James	Pipeline Transportation	2	****	****			
St. James	Sub TOTAL	6	646	65,850,595	0.3%	1,960	14.90%
St. James	no detail-confidential	11	669	83,342,658	0.3%	2,396	18.80%
St. James	TOTAL ENERGY	17	1315	149,193,253	0.6%	2,182	33.70%
St. James	Non-Energy	397	6448	293,184,620	1.1%	874	66.30%
St. James	TOTAL	414	7763	442,377,873	1.7%	1,096	100.00%

Parish	Labor Category	Units	Average Employees	Total Wages	Wages % of GNOI	Avg. wkly Wage	Wage % of Parish
St. Jn the Bapt.	Oil and Gas Extraction	2	****	****			
St. Jn the Bapt.	Support for E&P	5	498	31,491,151	0.1%	1,216	4.30%
St. Jn the Bapt.	Utilities	3	****	****			
St. Jn the Bapt.	Refining	3	932	107,964,251	0.4%	2,228	14.90%
St. Jn the Bapt.	Chemical Mfg.	11	830	77,708,663	0.3%	1,800	10.70%
St. Jn the Bapt.	Plastics & Rubber Mfg.	1	****	****			
St. Jn the Bapt.	Pipeline Transport						
St. Jn the Bapt.	Sub TOTAL	19	2260	217,164,065	0.8%	1,848	29.90%
St. Jn the Bapt.	no detail-confidential	6	126	9,764,592	0.0%	1,490	1.30%
St. Jn the Bapt.	TOTAL ENERGY	25	2386	226,928,657	0.9%	1,829	31.20%
St. Jn the Bapt.	Non-Energy	875	12613	499,465,057	1.9%	762	68.80%
St. Jn the Bapt.	TOTAL	900	14999	726,393,714	2.8%	931	100.00%
St. Tammany	Oil and Gas Extraction	16	****	****			
St. Tammany	Support for E&P	27	599	68,486,445	0.3%	2,199	2.20%
St. Tammany	Utilities	18	253	17,212,352	0.1%	1,308	0.60%
St. Tammany	Refining	2	****	****			
St. Tammany	Chemical Mfg.	15	246	16,795,650	0.1%	1,313	0.60%
St. Tammany	Plastics & Rubber Mfg.	5	52	1,344,657	0.0%	497	0.00%
St. Tammany	Pipeline Transportation	2	****	****			
St. Tammany	Sub TOTAL	65	1150	103,839,104	0.4%	1,736	3.40%
St. Tammany	no detail-confidential	20	829	151,155,570	0.6%	3,506	5.00%
St. Tammany	TOTAL ENERGY	85	1979	254,994,674	1.0%	2,478	8.40%
St. Tammany	Non-Energy	7182	75107	2,792,918,997	10.8%	715	91.60%
St. Tammany	TOTAL	7267	77086	3,047,913,671	11.7%	760	100.00%
Tangipahoa	Oil and Gas Extraction	1	****	****			
Tangipahoa	Support for E&P	5	78	5,239,122	0.0%	1,292	0.40%
Tangipahoa	Utilities	13	287	16,927,225	0.1%	1,134	1.20%
Tangipahoa	Refining	3	****	****			
Tangipahoa	Chemical Mfg.	4	8	359,386	0.0%	864	0.00%
Tangipahoa	Plastics & Rubber Mfg.	3	****	****			
Tangipahoa	Pipeline Transportation						
Tangipahoa	Sub TOTAL	22	373	22,525,733	0.1%	1,161	1.50%
Tangipahoa	no detail-confidential	7	537	24,416,168	0.1%	874	1.70%
Tangipahoa	TOTAL ENERGY	29	910	46,941,901	0.2%	992	3.20%
Tangipahoa	Non-Energy	2643	40749	1,408,050,690	5.4%	665	96.80%
Tangipahoa	TOTAL	2672	41659	1,454,992,591	5.6%	672	100.00%

Parish	Labor Category	Units	Average Employees	Total Wages	Wages % of GNOI	Avg. wkly Wage	Wage % of Parish
Washington	Oil and Gas Extraction						
Washington	Support for E&P	3	****	****			
Washington	Utilities	5	101	6,532,695	0.0%	1,244	2.00%
Washington	Refining	1	****	****			
Washington	Chemical Mfg.						
Washington	Plastics & Rubber Mfg.	1	****	****			
Washington	Pipeline Transportation	3	17	1,515,454	0.0%	1,714	0.50%
Washington	Sub TOTAL	8	118	8,048,149	0.0%	1,312	2.40%
Washington	no detail-confidential	5	105	5,310,176	0.0%	973	1.60%
Washington	TOTAL ENERGY	13	223	13,358,325	0.1%	1,152	4.00%
Washington	Non-Energy	763	9699	319,200,660	1.2%	633	96.00%
Washington	TOTAL	776	9922	332,558,985	1.3%	645	100.00%
GNOI	Oil and Gas Extraction	90	2449	395,761,841	1.5%	3,108	1.50%
GNOI	Support for E&P	84	4487	405,956,668	1.6%	1,740	1.60%
GNOI	Utilities	94	1832	146,662,094	0.6%	1,540	0.60%
GNOI	Refining	128	3308	392,774,937	1.5%	2,284	1.50%
GNOI	Chemical Mfg.	86	4948	474,793,616	1.8%	1,845	1.80%
GNOI	Plastics & Rubber Mfg.	38	1197	74,543,514	0.3%	1,197	0.30%
GNOI	Pipeline Transportation	19	283	29,855,772	0.1%	2,031	0.10%
GNOI	Sub TOTAL	463	18503	1,920,348,442	7.4%	1,996	7.40%
GNOI	no detail-confidential	79	3821	448,346,866	1.7%	2,256	1.70%
GNOI	TOTAL ENERGY	542	22324	2,368,695,308	9.1%	2,040	9.10%
GNOI	Non-Energy	38985	543983	23,585,911,819	90.9%	834	90.90%
GNOI	TOTAL	39527	566307	25,954,607,127	100.0%	881	100.00%
	Energy as a Percent of Totals		**3.9%**	**9.1%**			

Appendix B - LWC Annual Energy Profile for 2012 for GNOI Parishes

PLANT NAME	COUNTY	SIC4	SIC4_NAME	EMPL.	Pct Empl.	Pct of GNOI
WALLE CORP	JEFFERSON	2759	Commercial Printing, Nec	150		
CORNERSTONE CHEMICAL CO	JEFFERSON	2813	Industrial Gases	500	2.3%	
CORNERSTONE CHEMICAL CO	JEFFERSON	2819	Industrial Inorganic Chemicals, Nec	450	2.0%	
INTRALOX INC	JEFFERSON	3089	Plastics Products, Nec	310	1.4%	5.7%
GULF ENGINEERING CO INC	JEFFERSON	3443	Fabricated Plate Work-Boiler Shops	100		
STEWART & STEVENSON SVCS INC	JEFFERSON	3511	Turbines & Turbine Generator Sets	95		
LAITRAM MACHINERY CO	JEFFERSON	3535	Conveyors & Conveying Equipment	800		
PELLERIN MILNOR CORP	JEFFERSON	3582	Commercial Laundry Equipment	850		
WILLIAM T JOHNSON INC	JEFFERSON	3911	Jewelry, Precious Metal	32		
	JEFFERSON – Total	**9**		**3287**	**14.8%**	
	JEFFERSON – Energy	**3**				
SOUTHERN FOODS GROUP LP II	ORLEANS	2026	Fluid Milk	150		
ALOIS J BINDER BAKERY INC	ORLEANS	2051	Bread & Other Bakery Products	30		
BUNNY BREAD LLC	ORLEANS	2051	Bread & Other Bakery Products	140		
SILOCAF OF NEW ORLEANS INC	ORLEANS	2095	Roasted Coffee	400		
FOLGER COFFEE COMPANY	ORLEANS	2095	Roasted Coffee	400		
LIGHTHOUSE FOR THE BLIND	ORLEANS	2392	House furnishings	117		
ORLEANS CUSTOM MILLWORK LLC	ORLEANS	2431	Millwork	15		
ACE BAYOU CORP	ORLEANS	2511	Wood Household Furniture	50		
TIMES PICAYUNE PUBLISHING CORP	ORLEANS	2711	Newspapers: Publishing/Printing	500		
M PRESS	ORLEANS	2752	Commercial Printing, Lithographic	55		
AIR PRODUCTS AND CHEMICALS INC	ORLEANS	2813	Industrial Gases	100	0.5%	
SOUTHERN RECYCLING LLC	ORLEANS	2821	Plastic Materials & Resins	90	0.4%	

KALENCOM CORPORATION	ORLEANS	3171	Women's Handbags & Purses	80		
OWENS & SONS INC	ORLEANS	3273	Ready-Mixed Concrete	25		
FALK RENEW PRAGER	ORLEANS	3599	Industrial Machinery, Nec	75		
HUNTINGTON INGALLS INDUSTRIES	ORLEANS	3731	Ship Building & Repairing	7000	31.6%	
MIGNON FAGET LTD	ORLEANS	3911	Jewelry, Precious Metal	40		32.4%
	ORLEANS – Total	**18**		**9332**	**42.1%**	
	ORLEANS – Energy	**3**				
ALLIANCE REFINERY	PLAQUEMINES	2911	Petroleum Refining	450	2.0%	
EBI ELEVATING BOATS LLC	PLAQUEMINES	3731	Ship Building & Repairing	200	0.9%	
	PLAQUEMINES Total	**2**		**650**	**2.9%**	**2.9%**
	PLAQUEMINES Energy	**2**				
DOMINGO SUGAR CORP	ST. BERNARD	2062	Cane Sugar Refining	500		
VALERO ENERGY CORP	ST. BERNARD	2911	Petroleum Refining	200	0.9%	
CHALMETTE REFINING LLC	ST. BERNARD	2911	Petroleum Refining	650	2.9%	
	ST. BERNARD Total	**3**		**1350**	**6.1%**	**3.8%**
	ST. BERNARD Energy	**2**				
AIR LIQUIDE AMERICA CORP	ST. CHARLES	2813	Industrial Gases	12	0.1%	
DOW CHEMICAL	ST. CHARLES	2869	Industrial Organic Chemicals, Nec	2000	9.0%	
MONSANTO ENVIRO-CHEM SYSTEMS	ST. CHARLES	2873	Nitrogenous Fertilizers	700	3.2%	
MOTIVA ENTERPRISES LLC	ST. CHARLES	2911	Petroleum Refining	659	3.0%	
	ST. CHARLES Total	**4**		**3371**	**15.2%**	**15.2%**
	ST. CHARLES Energy	**4**				
OCCIDENTAL CHEMICAL CORP	ST. JAMES	2812	Alkalies & Chlorine	152	0.7%	
NORANDA ALLUMINA LLC	ST. JAMES	2819	Industrial Inorganic Chemicals, Nec	490	2.2%	
AMERICAS STYRENICS	ST. JAMES	2869	Industrial Organic Chemicals, Nec	140	0.6%	
MOSAIC FERTILIZER LLC	ST. JAMES	2874	Phosphatic Fertilizers	301	1.4%	
	ST. JAMES Total	**5**		**1314**	**5.9%**	**4.9%**
	ST. JAMES Energy	**4**				

NALCO COMPANY	ST. JOHN THE BAPTIST	2819	Industrial Inorganic Chemicals, Nec	130	0.6%	
DU PONT E I DE NEMOURS AND CO	ST. JOHN THE BAPTIST	2869	Industrial Organic Chemicals, Nec	550	2.5%	
MARATHON ASHLAND PETROLEUM LLC	ST. JOHN THE BAPTIST	2911	Petroleum Refining	455	2.1%	
ARCELOR MITTALL LAPLACE LLC	ST. JOHN THE BAPTIST	3312	Blast Furnaces & Steel Mills	400		5.1%
	ST. JN THE BAPTIST-Total	**5**		**1665**	**7.5%**	
	St. JN THE BAPTIST-Energy	**3**				
CMC CAPITOL STEEL SLIDELL	ST. TAMMANY	3441	Fabricated Structural Metal	44		
	ST. TAMMANY-Total	**1**		**44**	**0.2%**	
	ST. TAMMANY-Energy	**0**				
MANDA PACKING CO LLC	TANGIPAHOA	2013	Sausages & Other Prepared Meats	175		Pct of GNOI
ELMER CANDY CORP	TANGIPAHOA	2064	Candy & Confectionery Products	300		
PAUL DAVIS INC	TANGIPAHOA	2421	Sawmills & Planning Mills	42		
ROSS AND WALLACE PAPER PDT INC	TANGIPAHOA	2674	Uncoated Paper & Multiwall Bags	60		
DAILY STAR	TANGIPAHOA	2711	Newspapers: Publishing/Printing	34		
AMERICAN SPORTSWORKS	TANGIPAHOA	3799	Transportation Equipment, Nec	50		
BRITT KENNEDY SIGNS INC	TANGIPAHOA	3993	Signs & Advertising Specialties	35		
	TANGIPAHOA Total	**7**		**696**	**3.1%**	
	TANGIPAHOA Energy	**0**				
INTERNATIONAL PAPER	WASHINGTON	2631	Paperboard Mills	450		
	WASHINGTON Total	**1**		**450**	**2.0%**	
	WASHINGTON Energy	**0**				

	Total Plants	Total Jobs
Totals in GNOI	**55**	**22159**
Total Energy	**21**	**15527**
Percentage involving Energy	**38.2%**	**70.1%**

38.2% of the firms in these parishes are involvec in energy while 70.1% of the employees in these parishes are involved in energy.

Appendix C - LWC Annual Energy Profile for 2012 for GNOI Parishes

PLANT NAME	COUNTY	SIC4	SIC4_NAME	EMPL	% of Oth	% Engy
LOUSIANA RICE MILL	ACADIA	2044	Rice Milling	70.00		
PHOENIX FORGE COMPANY	ACADIA	3498	Fabricated Pipe & Pipe Fittings	250.00		
		2 0		320.00	0.7%	
BLUE RUNNER FOODS INC	ASCENSION	2033	Canned Fruits, Vegetables, & Jams	25.00		
NEESE INDUSTRIES INC	ASCENSION	2394	Canvas & Related Products	40.00		
GONZALES WEEKLY CITIZEN INC	ASCENSION	2721	Periodicals: Publishing/Printing	25.00		
AIR LIQUIDE AMERICA CORP	ASCENSION	2813	Industrial Gases	3.00	0.0%	
AIR PRODUCTS AND CHEMICALS	ASCENSION	2813	Industrial Gases	9.00	0.0%	
OCCIDENTAL CHEMICAL CORP	ASCENSION	2813	Industrial Gases	400.00	0.9%	
HONEYWELL INTERNATIONAL INC	ASCENSION	2819	Industrial Inorganic Chemicals, Nec	280.00	0.6%	
E I DU PONT DE NEMOURS & CO	ASCENSION	2819	Industrial Inorganic Chemicals, Nec	25.00	0.1%	
WESTLAKE VINYLS COMPANY LP	ASCENSION	2821	Plastic Materials & Resins	250.00	0.5%	
LION COPOLYMER LLC	ASCENSION	2869	Industrial Organic Chemicals, Nec	100.00	0.2%	
INNOPHOS	ASCENSION	2869	Industrial Organic Chemicals, Nec	30.00	0.1%	
SHELL OIL COMPANY	ASCENSION	2869	Industrial Organic Chemicals, Nec	500.00	1.1%	
RUBICON LLC	ASCENSION	2869	Industrial Organic Chemicals, Nec	437.00	1.0%	
PCS NITROGEN INC	ASCENSION	2873	Nitrogenous Fertilizers	200.00	0.4%	
CF INDUSTRIES INC	ASCENSION	2873	Nitrogenous Fertilizers	300.00	0.7%	
CF INDUSTRIES INC	ASCENSION	2873	Nitrogenous Fertilizers	186.00	0.4%	5.9%
PAX INC	ASCENSION	3443	Fabricated Plate Work-Boiler Shops	90.00		
FURNACE AND TUBE SERVICE INC	ASCENSION	3443	Fabricated Plate Work-Boiler Shops	125.00		
		18		3025.00	6.6%	

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ALLEN CANNING CO	AVOYELLES	2033	Canned Fruits, Vegetables, & Jams	50.00		
LOUISIANA HOOP CO INC	AVOYELLES	2448	Wood Pallets & Skids	37.00		
		2 0		87.00	0.2%	
BOISE CASCADE CORP	BEAUREGARD	2631	Paperboard Mills	850.00		
MEADWESTVACO CORPORATION	BEAUREGARD	2861	Gum and Wood Chemicals	159.00		
		2 0		1009.00	2.2%	
HOUSE OF RAEFORD FARMS INC	BIENVILLE	2015	Poultry Slaughtering & Processing	950.00		
MICHAEL L HAWKINS LOGGING CO	BIENVILLE	2411	Logging	28.00		
GRAPHIC PACKAGING INTL INC	BIENVILLE	2674	Uncoated Paper & Multiwall Bags	120.00		
HAYNES INTERNATIONAL INC	BIENVILLE	3325	Steel Foundries, Nec	120.00		
		4 0		1218.00	2.7%	
CUSTOM PRINTED PRODUCTS	BOSSIER	2679	Converted Paper Products, Nec	120.00		
CALUMET LUBRICANTS CO	BOSSIER	2911	Petroleum Refining	117.00	0.3%	0.3%
		2 1		237.00	0.5%	

LAND O LAKES INC/PURINA FEEDS	CADDO	2048	Prepared Foods & Feed Ingredients	65.00		
SHREVEPORT TIMES	CADDO	2711	Newspapers: Publishing/Printing	200.00		
CHEMTRADE REFINERY SVS INC	CADDO	2819	Industrial Inorganic Chemicals, Nec	30.00	0.1%	
UOP LLC	CADDO	2865	Cyclic Crudes & Intermediates	300.00	0.7%	
CERTAINTEED CORPORATION	CADDO	2952	Asphalt Felts & Coatings	115.00	0.3%	
CALUMET LUBRICANTS CO	CADDO	2992	Lubricating Oil & Greases	300.00	0.7%	1.6%
LIBBEY GLASS INC	CADDO	3229	Pressed & Blown Glass, Nec	1082.00		
SHAW GROUP	CADDO	3498	Fabricated Pipe & Pipe Fittings	200.00		
FRYMASTER CORPORATION	CADDO	3589	Service Industry Machinery, Nec	622.00		
GE COMMERCIAL TRANSFORMER	CADDO	3612	Transformers	200.00		
		10 4		3114.00	6.8%	
P P G INDUSTRIES INC	CALCASIEU	2812	Alkalies & Chlorine	1300.00	2.8%	
AIR LIQUIDE AMERICA CORP	CALCASIEU	2813	Industrial Gases	8.00	0.0%	
LOUISIANA PIGMENT CO	CALCASIEU	2816	Inorganic Pigments	400.00	0.9%	
TESSENDERLO KERLEY INC	CALCASIEU	2819	Industrial Inorganic Chemicals, Nec	16.00	0.0%	
GRACE DAVISON	CALCASIEU	2819	Industrial Inorganic Chemicals, Nec	325.00	0.7%	
CERTAINTEED CORPORATION	CALCASIEU	2821	Plastic Materials & Resins	68.00	0.1%	
FIRESTONE POLYMERS LLC	CALCASIEU	2822	Synthetic Rubber	300.00	0.7%	
SASOL NORTH AMERICA INC	CALCASIEU	2869	Industrial Organic Chemicals, Nec	400.00	0.9%	
CITGO PETROLEUM CORPORATION	CALCASIEU	2911	Petroleum Refining	1600.00	3.5%	
ALCOA INC	CALCASIEU	2911	Petroleum Refining	180.00	0.4%	
PHILLIPS 66	CALCASIEU	2911	Petroleum Refining	770.00	1.7%	
CALCASIEU REFINING CO	CALCASIEU	2911	Petroleum Refining	90.00	0.2%	

RAIN CII CARBON LLC	CALCASIEU	2999	Petroleum & Coal Products, Nec	65.00	0.1%	
BASELL USA	CALCASIEU	3089	Plastics Products, Nec	175.00	0.4%	12.4%
		14 14		5697.00	12.4%	
BERRY PLASTICS	CLAIBORNE	2671	Laminated Packaging Paper & Film	200.00		
		1 0		200.00	0.4%	
BASF CORP	CONCORDIA	3365	Aluminum Foundaries	48.00		
		1 0		48.00	0.1%	
INTERNATIONAL PAPER COMPANY	DE SOTO	2631	Paperboard Mills	450.00		
		1		450.00	1.0%	
FLOWERS BKG CO BATON ROUGE LLC	EAST BATON ROUGE	2051	Bread & Other Bakery Products	100.00		
LOUISIANA COCA-COLA BTLG LTD	EAST BATON ROUGE	2086	Bottled & Canned Soft Drinks	525.00		
ARCHITECTURAL WOOD PRODUCTS	EAST BATON ROUGE	2431	Millwork	28.00		
C & C CABINET WORKS INC	EAST BATON ROUGE	2434	Wood Kitchen Cabinets	25.00		
GEORGIA-PACIFIC CORPORATION	EAST BATON ROUGE	2621	Paper Mills	875.00		
CAPITAL CITY PRESS LLC	EAST BATON ROUGE	2711	Newspapers: Publishing/Printing	200.00		
MORAN GROUP COMPANIES INC	EAST BATON ROUGE	2752	Commercial Printing, Lithographic	100.00		
UOP LLC	EAST BATON ROUGE	2819	Industrial Inorganic Chemicals, Nec	52.00	0.1%	
LA-MAR-KA INC	EAST BATON	2819	Industrial Inorganic Chemicals, Nec	25.00	0.1%	

	ROUGE					
RHODIA INC	EAST BATON ROUGE	2819	Industrial Inorganic Chemicals, Nec	300.00	0.7%	
EXXON CORPORATION	EAST BATON ROUGE	2821	Plastic Materials & Resins	1300.00	2.8%	
LION COPOLYMER HOLDINGS LLC	EAST BATON ROUGE	2822	Synthetic Rubber	300.00	0.7%	
SCHERING-PLOUGH VETERINARY	EAST BATON ROUGE	2834	Pharmaceutical Preparations	60.00	0.1%	
NOVOLYTE TECHNOLOGIES	EAST BATON ROUGE	2869	Industrial Organic Chemicals, Nec	100.00	0.2%	
FORMOSA PLASTICS CORP LA	EAST BATON ROUGE	2869	Industrial Organic Chemicals, Nec	300.00	0.7%	
DELTECH CORP	EAST BATON ROUGE	2869	Industrial Organic Chemicals, Nec	80.00	0.2%	
HONEYWELL INTERNATIONAL INC	EAST BATON ROUGE	2869	Industrial Organic Chemicals, Nec	162.00	0.4%	
EXXON MOBIL CORPORATION	EAST BATON ROUGE	2911	Petroleum Refining	3000.00	6.5%	
EXXON MOBIL CORPORATION	EAST BATON ROUGE	2911	Petroleum Refining	3000.00	6.5%	
LEADER GLOBAL TECHNOLOGY	EAST BATON ROUGE	3053	Gaskets, Packing & Sealing Devices	35.00	0.1%	
INDUSTRIAL PLASTICS & MCH INC	EAST BATON ROUGE	3089	Plastics Products, Nec	38.00	0.1%	19.1%
STUPP CORP	EAST BATON ROUGE	3317	Steel Pipe and Tubes	210.00		
XENETECH USA INC	EAST BATON ROUGE	3555	Printing Trades Machinery	15.00		
INDUSTRIAL PARTS SPC LLC	EAST BATON ROUGE	3599	Industrial Machinery, Nec	53.00		
LAMBERTS ORTHOTICS & PROSTH	EAST BATON ROUGE	3842	Surgical Appliances & Supplies	9.00		

H & H LURES INC	EAST BATON ROUGE	3949	Sporting & Athletic Goods, Nec	50.00		
		26		10942.00	23.9%	
		14				
CABOT CORP	EVANGELINE	2895	Carbon Black	85.00	0.2%	
CAMERON INTERNATIONAL CORP	EVANGELINE	3533	Oil/Gas Field Machinery & Equipment	450.00	1.0%	1.2%
		2		535.00	1.2%	
		2				
HUNT FOREST PRODUCTS INC	GRANT	2435	Hardwood Veneer & Plywood	275.00		
		1		275.00	0.6%	
		0				
BRUCE FOODS CORP	IBERIA	2033	Canned Fruits, Vegetables, & Jams	100.00		
MORTON INTERNATIONAL INC	IBERIA	2819	Industrial Inorganic Chemicals, Nec	166.00	0.4%	
CARGILL INC	IBERIA	2899	Chemical Preparations, Nec	200.00	0.4%	0.8%
HONIRON	IBERIA	3523	Farm Machinery & Equipment	100.00		
BREAUXS BAY-CRAFT INC	IBERIA	3732	Boat Building & Repairing	40.00		
		5		606.00	1.3%	
		2				
GEORGIA GULF CORPORATION	IBERVILLE	2812	Alkalies & Chlorine	486.00	1.1%	
AIR LIQUIDE AMERICA CORP	IBERVILLE	2813	Industrial Gases	5.00	0.0%	
OLIN CORPORATION	IBERVILLE	2819	Industrial Inorganic Chemicals, Nec	150.00	0.3%	
TOTAL PETROCHEMICALS USA INC.	IBERVILLE	2869	Industrial Organic Chemicals, Nec	240.00	0.5%	
DOW CHEMICAL CO	IBERVILLE	2869	Industrial Organic Chemicals, Nec	2000.00	4.4%	
MEXICHEM FLOUR	IBERVILLE	2869	Industrial Organic Chemicals, Nec	79.00	0.2%	

TAMINCO	IBERVILLE	2869	Industrial Organic Chemicals, Nec	75.00	0.2%	
SYNGENTA CROP PROTECTION INC	IBERVILLE	2879	Pesticides & Agricultural Chemicals	610.00	1.3%	8.0%
		8		3645.00	8.0%	
		8				
ROCKTENN CP LLC	JACKSON	2621	Paper Mills	500.00		
		1		500.00	1.1%	
		0				
LEEVAC SHIPYARDS INC	JEFFERSON DAVIS	3731	Ship Building & Repairing	250.00	0.5%	0.5%
		1		250.00	0.5%	
		1				
MILK PRODUCTS L P	LAFAYETTE	2026	Fluid Milk	162.00		
FLOWERS BAKING CO OF LAFAYETTE	LAFAYETTE	2051	Bread & Other Bakery Products	150.00		
LANGLINAIS BAKING COMPANY INC	LAFAYETTE	2051	Bread & Other Bakery Products	40.00		
SAMSON ROPE TECHNOLOGIES	LAFAYETTE	2298	Cordage & Twine	107.00		
AWNING & SUPPLY CO INC	LAFAYETTE	2591	Drapery Hardware, Blinds & Shades	25.00		
THE DAILY ADVERTISER	LAFAYETTE	2711	Newspapers: Publishing/Printing	200.00		
EXPRESS PRINTING AND FORMS	LAFAYETTE	2752	Commercial Printing, Lithographic	20.00		
GULF SOUTH PRINTING & SPC	LAFAYETTE	2752	Commercial Printing, Lithographic	25.00		
RTL INC	LAFAYETTE	3111	Leather Tanning & Finishing	34.00		
SOUTHERN STRUCTURES INC	LAFAYETTE	3448	Prefabricated Metal Buildings	170.00		
MACHINE SPECIALTY & MFG INC	LAFAYETTE	3463	Nonferrous Forgings	82.00		
SCHOELLER-BLECHMANN ENERGY	LAFAYETTE	3532	Mining Machinery & Equipment	75.00	0.2%	
TAYLORS OILFIELD MANUFACTURING	LAFAYETTE	3533	Oil/Gas Field Machinery & Equipment	70.00	0.2%	
TOOLS	LAFAYETTE	353	Oil/Gas Field	37.00	0.1%	

INTERNATIONAL CORP		3	Machinery & Equipment			
REAMCO INC	LAFAYETTE	3533	Oil/Gas Field Machinery & Equipment	20.00	0.0%	
MCCOY DRILLING AND COMPLETION	LAFAYETTE	3561	Pumps & Pumping Equipment	150.00	0.3%	
NATIONAL ALL WELL ROCCO	LAFAYETTE	3599	Industrial Machinery, Nec	38.00	0.1%	
HUNTING OIL FIELD SERVICES	LAFAYETTE	3599	Industrial Machinery, Nec	175.00	0.4%	
TOTAL INSTRUMENTATION AND CTRL	LAFAYETTE	3823	Process Control Instruments	184.00	0.4%	1.6%
		19		1764.00	3.9%	
		8				
JOHN DEERE THIBODAUX INC	LAFOURCHE	3523	Farm Machinery & Equipment	500.00		
BOLLINGER SHIPYARDS INC	LAFOURCHE	3731	Ship Building & Repairing	612.00	1.3%	1.3%
		2		1112.00	2.4%	
		1				
FLAKE BOARD AMERICA LTD	LINCOLN	2493	Reconstituted Wood Products	125.00		
INDUSTRIAL INSUL GROUP LLC	LINCOLN	2819	Industrial Inorganic Chemicals, Nec	120.00	0.3%	0.3%
SAINT GOBAIN-CONTAINER LLC	LINCOLN	3221	Glass Containers	360.00		
		3		605.00	1.3%	
		1				
PARISH READY MIX INC	LIVINGSTON	3273	Ready-Mixed Concrete	30.00		
DELTAK MANUFACTURING INC	LIVINGSTON	3443	Fabricated Plate Work-Boiler Shops	36.00		
SHAW SUNLAND	LIVINGSTON	3498	Fabricated Pipe & Pipe Fittings	401.00		
		3		467.00	1.0%	
		0				
PILGRIMS PRIDE	NATCHITOCHES	2015	Poultry Slaughtering & Processing	660.00		

TRAVIS TAYLOR	NATCHITOCHES	2411	Logging	25.00		
INTERNATIONAL PAPER CO	NATCHITOCHES	2621	Paper Mills	400.00		
		3 0		1085.00	2.4%	
LOUISIANA COCA-COLA BTLG LTD	OUACHITA	2086	Bottled & Canned Soft Drinks	300.00		
GRAPHIC PACKAGING	OUACHITA	2631	Paperboard Mills	1300.00		
GEORGIA-PACIFIC CORPORATION	OUACHITA	2653	Corrugated & Solid Fiber Boxes	250.00		
GANNETT CO. INC	OUACHITA	2711	Newspapers: Publishing/Printing	150.00		
BERRY PLASTICS GROUP INC	OUACHITA	3081	Unsupported Plastics Film & Sheet	350.00	0.8%	0.8%
PLYMOUTH TUBE CO	OUACHITA	3312	Blast Furnaces & Steel Mills	110.00		
		6 1		2460.00	5.4%	
DEGUSSA ENGINEERED CARBONS LP	POINTE COUPEE	2895	Carbon Black	90.00	0.2%	0.2%
		1 1		90.00	0.2%	
ROY O MARTIN	RAPIDES	2491	Wood Preserving	56.00		
PQ CORP	RAPIDES	2819	Industrial Inorganic Chemicals, Nec	10.00	0.0%	0.0%
AFCO INDUSTRIES INC	RAPIDES	3354	Aluminum Extruded Products	135.00		
DRESSER INDUSTRIES INC	RAPIDES	3491	Industrial Valves	399.00		
		4 1		600.00	1.3%	
SAPA EXTRUSIONS LLC	RICHLAND	3354	Aluminum Extruded Products	300.00		
		1 0		300.00	0.7%	

BOISE CASCADE LLC	SABINE	2436	Softwood Veneer & Plywood	200.00		
WEYERHAEUSER COMPANY	SABINE	2436	Softwood Veneer & Plywood	200.00		
		2		400.00	0.9%	
		0				
DOW CHEMICAL	ST. HELENA	2819	Industrial Inorganic Chemicals, Nec	40.00	0.1%	0.1%
		1		40.00	0.1%	
		1				
VENTURA FOODS LLC	ST. LANDRY	2079	Shortening,Cooking Oils & Margarine	183.00		
VENTURA FOODS	ST. LANDRY	2079	Shortening,Cooking Oils & Margarine	216.00		
EUNICE NEWS INC	ST. LANDRY	2711	Newspapers: Publishing/Printing	28.00		
ALON USA ENERGY INC	ST. LANDRY	2911	Petroleum Refining	200.00	0.4%	0.4%
		4		627.00	1.4%	
		1				
STERLING SUGARS INC	ST. MARY	2062	Cane Sugar Refining	100.00		
COLUMBIAN CHEMICALS CO	ST. MARY	2895	Carbon Black	105.00	0.2%	
CABOT CORP	ST. MARY	2895	Carbon Black	160.00	0.3%	
SUPERIOR FABRICATORS INC	ST. MARY	3441	Fabricated Structural Metal	20.00		
MC DERMOTT INC	ST. MARY	3533	Oil/Gas Field Machinery & Equipment	250.00	0.5%	
CONRAD INDUSTRIES INC	ST. MARY	3731	Ship Building & Repairing	500.00	1.1%	2.2%
		6		1135.00	2.5%	
		4				
PEARL INC	TERREBONNE	2091	Canned & Cured Fish & Seafoods	75.00		
INDIAN RIDGE SHRIMP CO	TERREBONNE	2092	Fresh or Frozen Fish & Seafoods	40.00		
GULF ISLAND FABRICATION INC	TERREBONNE	3441	Fabricated Structural Metal	650.00		

WEATHERFORD INTERNATIONAL	TERREBONNE	3533	Oil/Gas Field Machinery & Equipment	400.00	0.9%	
MAIN IRON WORKS INC	TERREBONNE	3731	Ship Building & Repairing	140.00	0.3%	1.2%
		5		1305.00	2.8%	
		2				
OMEGA PROTEIN INC	VERMILION	2077	Animal & Marine Fats & Oils	150.00		
		1		150.00	0.3%	
		0				
CALUMET LUBRICANTS CO	WEBSTER	2911	Petroleum Refining	50.00	0.1%	0.1%
CLEMENT INDUSTRIES INC	WEBSTER	3715	Truck Trailers	50.00		
		2		100.00	0.2%	
		1				
AIR GAS SPECIALITY GASSES INC	WEST BATON ROUGE	2813	Industrial Gases	26.00	0.1%	
SHINTECH LOUISIANA LLC	WEST BATON ROUGE	2821	Plastic Materials & Resins	120.00	0.3%	
RICHARDSON SID CARBN ENRGY CO	WEST BATON ROUGE	2895	Carbon Black	79.00	0.2%	
EXXON MOBIL CORPORATION	WEST BATON ROUGE	2911	Petroleum Refining	9.00	0.0%	
PLACID REFINING CO LLC	WEST BATON ROUGE	2911	Petroleum Refining	200.00	0.4%	
BASF CATALYSTS LLC	WEST BATON ROUGE	3365	Aluminum Foundaries	80.00		
TRINITY MARINE PORT ALLEN	WEST BATON ROUGE	3731	Ship Building & Repairing	300.00	0.7%	1.6%
		7		814.00	1.8%	
		6				

KPAQ INDUSTRIES LLC	WEST FELICIANA	2621	Paper Mills	200.00		
		1		200.00	0.4%	
		0				
WEST FRASER INTERNATIONALINC	WINN	2421	Sawmills & Planning Mills	200.00		
WEYERHAEUSER COMPANY	WINN	2436	Softwood Veneer & Plywood	150.00		
ARCLIN USA INC	WINN	2819	Industrial Inorganic Chemicals, Nec	40.00	0.1%	0.1%
		3		390.00	0.9%	
		1				
Total Facilities and labor in Other Parishes		175		45802.00	100.0%	59.8%
Total involving Energy		88		27377.00		
Percentage involving Energy		50.3%		59.8%		

50.3% of the firms in these parishes involve energy while 59.8% of the employees in these parishes are also involved in energy.

Appendix D - Annual Data for Calendar year 2012 by NAIC Code for State Energy Sector

NAICS Code		# of Jobs	Wages Paid	Avg. Annual wage	Weekly wage	Wage compared to non energy
211	Oil and Gas Extraction	8504	1,011,658,609	118,963	2288	202.00%
213	Support activities O&G	40620	3,138,769,329	77,272	1486	96.20%
22	Utilities	14320	878,456,648	61,345	1180	55.80%
324	Petroleum and Coal Products Mgf.	11128	1,140,356,225	102,476	1971	160.20%
325	Chemicals Manufacturing	23255	2,130,099,481	91,597	1761	132.60%
326	Pastics and Rubber Products	3689	186,075,342	50,441	970	28.10%
486	Pipeline Transportation	2830	245,855,470	86,875	1671	120.60%
	Subtotal for Energy	104346	8,731,271,104	83,676	1609	112.40%
	Other non- Energy	1404578	55,321,511,782	39,387	757	0.00%
	Total Private Employment	1508924	64,052,782,886	42,449	816	7.80%
	Energy as a % of Total	6.90%	13.6%			