Paper #1-13

NATURAL GAS LIQUIDS (NGLs)

Prepared for the

Resource & Supply Task Group

On September 15, 2011, The National Petroleum Council (NPC) in approving its report, *Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources*, also approved the making available of certain materials used in the study process, including detailed, specific subject matter papers prepared or used by the study's Task Groups and/or Subgroups. These Topic and White Papers were working documents that were part of the analyses that led to development of the summary results presented in the report's Executive Summary and Chapters.

These Topic and White Papers represent the views and conclusions of the authors. The National Petroleum Council has not endorsed or approved the statements and conclusions contained in these documents, but approved the publication of these materials as part of the study process.

The NPC believes that these papers will be of interest to the readers of the report and will help them better understand the results. These materials are being made available in the interest of transparency.

The attached paper is one of 57 such working documents used in the study analyses. Also included is a roster of the Task Group for which this paper was developed or submitted. Appendix C of the final NPC report provides a complete list of the 57 Topic and White Papers and an abstract for each. The full papers can be viewed and downloaded from the report section of the NPC website (www.npc.org).

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NPC NGL STUDY

Assuming dry gas supply grows from 60 to 110 Bcf/d by 2035: estimated NGL production, processing and refining constraints, supply and demand dynamics for ethane, propane, n butane, isobutane, and natural gasoline.

NGL Supply and Demand through 2035

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Executive Summary

Shale Revolution Will Stimulate Significant Increases in NGL Supplies

Over the past five years, the North American natural gas industry has experienced a "shale revolution." Advancements in horizontal drilling and well-completion technologies applied to low-permeability, natural gas formations – shales and tight sands - have unlocked huge reservoirs of natural gas supply from Western Canada, to the Gulf Coast to Appalachia. It is a revolution of productivity and abundance, which has already yielded extraordinary natural gas production growth, lower natural gas prices and reduced natural gas imports. Ultimately this revolution has the potential to drive natural gas production well beyond historic levels and to fundamentally shift the dynamics in other energy markets which compete with, or are closely related to, natural gas.

This is particularly true for natural gas liquids (NGLs). NGLs have traditionally been considered a byproduct of natural gas production. The five NGLs—ethane, propane, normal butane, isobutane and natural gasoline (pentanes+)—are produced when natural gas is processed for delivery to market. As shale natural gas production continues to expand, it has a direct impact on the supply of NGLs. Whether the infrastructure and market for NGLs can absorb these increasing volumes and how the new supplies will impact demand for NGLs and related products are key questions facing producers and consumers of these important petrochemical products.

North American Natural Gas Production Growing towards Historical High

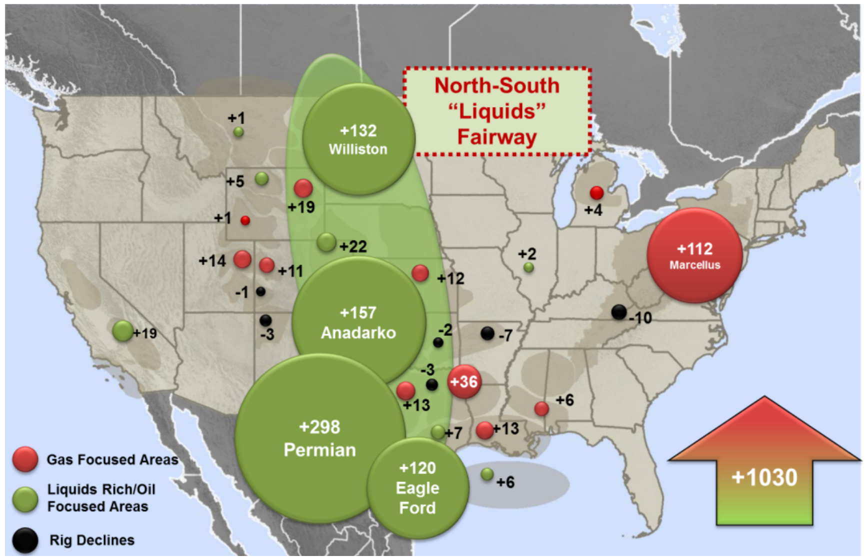
The shale revolution has the potential to drive natural gas production to unprecedented levels. Since 2007, average annual gas production in North America has increased 5.6%, going from 66.6 Bcf/d up to 70.4 Bcf/d in 2010. The U.S. accounts for more than 75% of this supply. If sufficient additional demand develops, it has been estimated that natural gas supply could be developed up to 100 Bcf/d to 125 Bcf/d by 2035, an increase of 40-75% over 2010. Such a huge increase would have important implications for both natural gas and NGL markets.

The impact of increasing natural gas production on NGL supplies is a function of three factors: (1) the amount of natural gas that is processed to remove the NGLs; (2) the amount of NGLs that are contained in the natural gas that is processed; and (3) the processing technique used to remove the NGLs. Increases in the first factor are primarily being driven by the shale revolution. The second factor is associated with the physical composition of natural gas as it is produced at the wellhead.

Natural gas production at the wellhead is typically composed of a number of hydrocarbon and other compounds. The largest hydrocarbon component of most natural gas is methane. But wellhead gas, also known as "wet gas" or "gross gas production," contains NGLs. NGLs are generally in gaseous form at the wellhead and are extracted from natural gas by chilling to very low temperatures to produce liquid hydrocarbons—hence the name "natural gas liquids". In some situations, NGL extraction is required to produce a natural gas stream that can meet pipeline or industrial specifications. In other cases, when the price of NGLs is higher than that of natural gas, NGLs are extracted for economic reasons.

Not all natural gas contains enough NGLs to require processing. This "dry" natural gas can be delivered directly to pipelines after the removal of water and other impurities. The term "dry" natural gas also refers to the natural gas which flows out of natural gas plants after it has been processed and the NGLs have been removed.

The natural gas production referenced in the first paragraph of this section refers to dry gas. To yield 70.4 Bcf/d of natural gas in 2010, 83 Bcf/d of gross natural gas was produced at the wellhead. The natural gas that was processed also yielded 2,420 Mb/d of NGLs. If dry natural gas production increases to 110 Bcf/d by 2035, it is likely that gross gas production will increase to about 130 Bcf/d in that year, generating about 3,900 Mb/d of NGLs, an increase of 61% compared with 2010. This is in addition to the approximately 692 Mb/d of NGLs produced by refineries. Such an increase in NGL production would exceed the current capabilities of existing NGL infrastructure, including natural gas processing, fractionation, ethylene cracking, and export capacity. However, it is likely that the market would respond to the challenge of NGL supply increases with additional investment. If so, NGL markets and their downstream customers would gain significant advantages in domestic and global markets.



Note: Source of data is RigData and BENTEK, and is valid only for the U.S. as of March 11, 2011

Figure 1. Active Rig Additions since Recent Low - May 2009, Lower 48 (March 2011)

Rising oil and NGL values relative to natural gas have resulted in exploration and production activity in 2010 shifting significantly to oil- and liquids- rich plays such as the Permian, Anadarko, Williston, Eagle Ford, Niobrara, and other basins. Rig activity has shown significant movement toward these wet plays. Figure 1 shows rig additions per play since May 2009, which marked a low point in rig count since 2005. Rig activity has also shifted to plays that have higher-BTU gas. The higher the BTU of the produced gas, the more NGLs it can yield. The BTU content of the gas is measured by gallons of NGLs produced per thousand cubic feet of gas processed, or "gallons per Mcf," commonly referred to as GPM. A higher GPM indicates a higher BTU content.

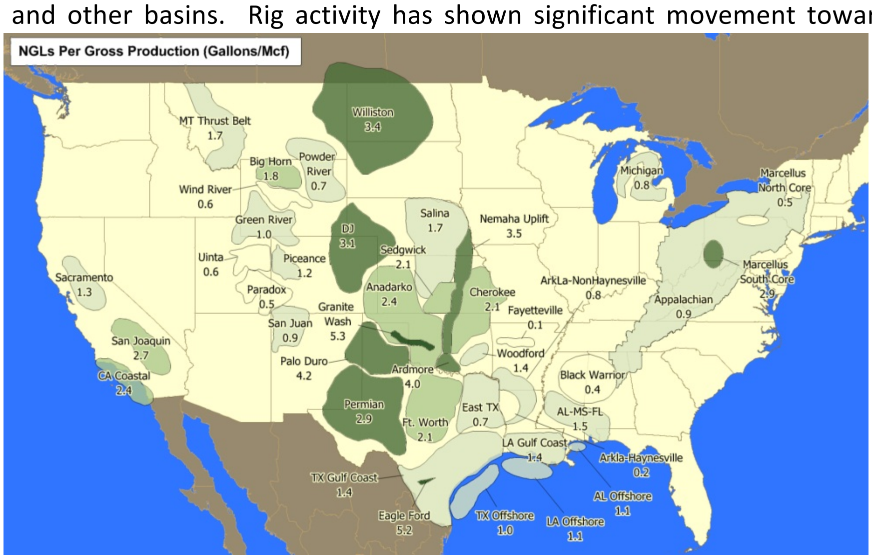


Figure 2. GPM by Basin - U.S.

Figure 2 shows the GPM for U.S. gas- producing basins. The darker the green color is, the higher the BTU content of the gas. The Granite Wash play has the highest GPM at 5.3, followed by the Eagle Ford at 5.2. In 2010, the average GPM for North America was 1.25.

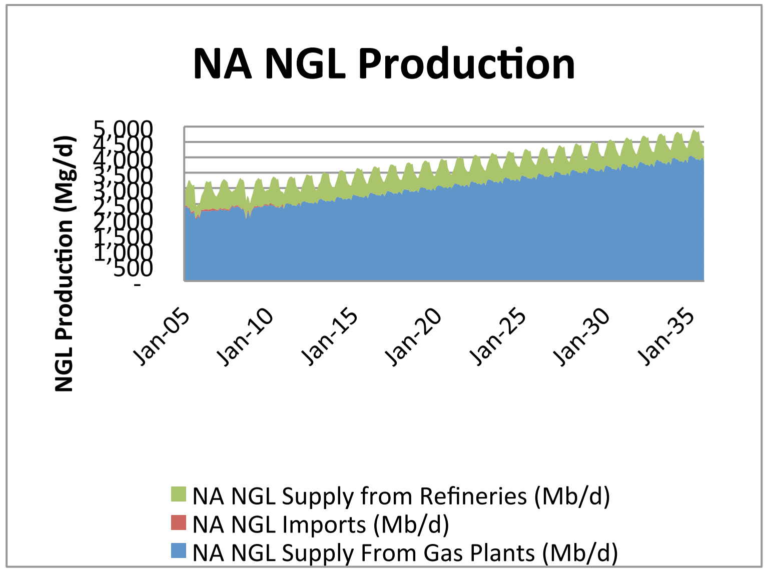


Figure 3. North American NGL Production through 2035

NGL Production Likely to Grow Significantly

Figure 3 shows North American NGL production projections through 2035. Growth in gross gas production and subsequent gas processing will drive increases in NGL production. Total NGL supply in North America is forecast to grow from 3,135 Mb/d in 2010 to 4,668 Mb/d in 2035. NGL production from gas processing is forecast to grow 61% from 2,420 Mb/d in 2010 up to 3,900 Mb/d in 2035, while NGL production from refineries was held constant at an annual average of 692 Mb/d. Imports of NGLs into North America are small, averaging about 30 Mb/d, and are likely to be displaced completely by late 2011.

Current NGL Infrastructure Inadequate to Handle NGL Growth

The current NGL infrastructure (processing, fractionation, and ethylene cracking) capacity may not be large enough or sufficiently interconnected to handle the potential NGL production growth. Current natural gas processing capacity in the U.S. is 66 Bcf/d, yet gross U.S. gas production is forecast to grow to more than 90.5 Bcf/d (of the 110 Bcf/d projected total for North America). Further, the shale gas revolution has shifted gas production regions, and processing plants that are currently underutilized may not be close enough to production regions expected to grow. For example, growing NGL production in the Marcellus play located in the northeastern U.S. requires additional processing capacity to keep pace, while processing plants along the U.S. Gulf Coast have 30 to 50% of open capacity. To date, there have been announcements for an additional 7.8 Bcf/d of processing capacity in the U.S, an increase of 12%. In Canada, on the other hand, gross gas production is declining, and as a result NGL production is also falling. Canadian gas processing capacity is not problematic for the foreseeable future. Canadian export gas is more likely a destination U.S. gas that requires processing and/or fractionation.

Current U.S. fractionation and cracking capacity will also be exceeded at the forecast NGL growth rate. However, there have been a number of announcements of new processing, fractionation, and cracking capacity to meet the growing needs, and it is likely that infrastructure will continue to be developed to address growth in NGL production.

Market Implications

The tremendous growth in natural gas production in North America has resulted in significant NGL production growth. NGL production growth will come from both legacy plays where infrastructure is mature and from newer plays where infrastructure is in its infantile stages. For example, NGL production out of the Eagle Ford is poised for growth because of the existing infrastructure. In contrast, NGL production from the Marcellus will create additional challenges since the northeast region lacks infrastructure to bring the NGLs to market. The midstream sector will need to evolve and grow quickly in order to manage and capitalize on the NGL growth. If the midstream sector does not response quickly enough, production growth will be constrained. However, midstream infrastructure can grow only so quickly, and given the number of new plays developing, it is likely that some plays will develop at much faster rates than other plays. North America is already expected to see significant infrastructure investment and growth along all points of the NGL value chain. Significant gathering, processing, fractionation, and cracking capacity is under construction or has been announced. Ethane is poised to be the dominant feedstock for the petrochemical industry for the foreseeable future. While this results in lower input costs for manufacturing of ethylene and ethylene derivatives, co-products such as propylene experience a shortfall in supply. Meanwhile propane demand is anticipated to drop as heating demand declines in response to households switching to natural gas. The propane export market should therefore be robust. The heavier NGLs (butane and pentane+) experience difference dynamics. North American could be supply long on butane as it gets pushed out of the motor gasoline pool due to increased ethanol blending and flat to declining motor gas demand. Natural gasoline could experience demand growth driving by the oil sands sector's need for diluent.

Along with the growth in natural gas, the associated natural gas liquids market is rapidly changing and evolving, from the upstream to the downstream. The pace of growth will vary by basin as the market responds to the increased supply and resultant demand.

Background

NGL Supply/Demand Balance

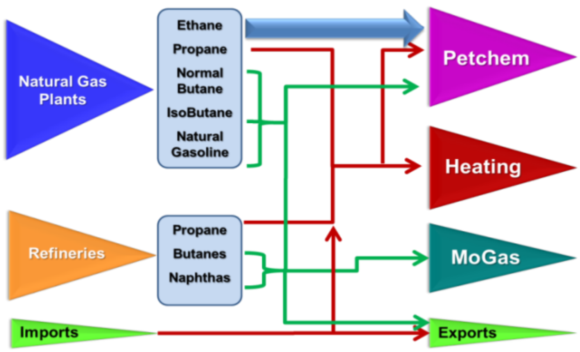


Figure 4. NGL Supply/Demand Chain

Figure 4 is a simplified representation of the NGL supply chain. NGLs are produced by both natural gas processing plants and petroleum refineries. Natural gas processing plants separate dry gas (i.e., methane) from wellhead gas production, or wet gas (natural gas containing quantities of NGLs—i.e., ethane, propane, normal butane isobutane, natural gasoline), while refineries produce NGLs as a byproduct of refinery distillation and cracking processes. Each successive NGL has an additional carbon molecule and different chemical properties. For example, ethane is C_2H_6, propane is C_3H_8, butane is C_4H_{10}, and natural gasoline is C_5H_{12}. NGLs are used by the petrochemical industry as feedstock to produce a variety of plastic products, for heating in the case of propane, as components in the motor gasoline pool ("motor gasoline"), and are exported in some cases. Figure 5 shows the five-year average supply/demand balance for NGLs in the U.S.

Each component of the NGL barrel has a unique supply/demand profile. For ethane, over 90% of supply comes from natural gas processing plants; the remainder comes from refineries. Demand for ethane is almost exclusively from petrochemical plants, known as steam crackers or ethylene crackers. These units transform ethane into ethylene, which is an essential component for production of a variety of plastic products. The primary demand factors for ethane are ethylene/propylene prices, steam cracking capacity, exports, and the relative value of the dollar. Ethane is unique from other NGLs because it is uneconomic and operationally challenging to export outside North America. Therefore, demand for ethane is constrained to North America.

Approximately 60% of propane comes from natural gas processing plants, and 40% comes from refineries. Petrochemical demand consumes 35% of the propane supply, while 65% is consumed by domestic home heating demand. The primary demand factors for propane are weather, ethylene/propylene prices, and export economics.

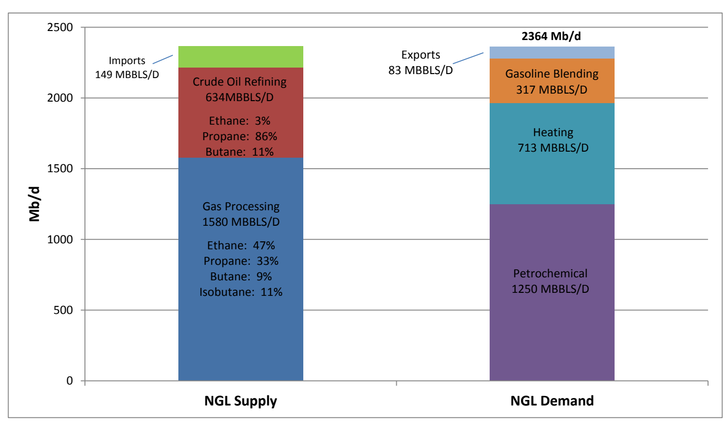


Figure 5. U.S. NGL Supply/Demand Balance (5-yr Ave, EIA Data)

There are two forms of butane, normal butane and isobutane. For normal butane ("n-butane"), 45% comes from natural gas processing plants, and 55% comes from refineries. The lighter the crude, the more n-butane that is produced compared to heavier crude. About 10% of n-butane is used by petrochemical while 90% is refiner/blender demand. The motor gasoline market, ethylene/propylene prices, and import/export economics all impact the demand for n-butane. For isobutane, 60% is derived from natural gas processing plants and 40% from refineries. Commercial

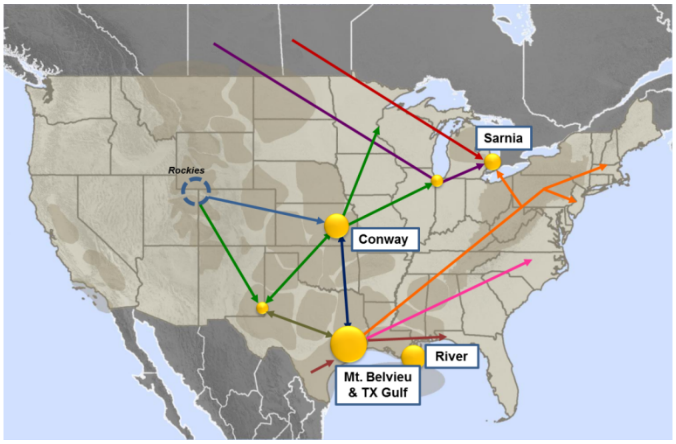


Figure 6. Major NGL Pipeline Corridors and Fractionation Centers

isomerization involves converting butane into mixed butane, which is then fractionated into isobutane, high- purity isobutane, and residual normal butane. The primary uses of isobutane are production of propylene oxide, isooctane and alkylate for motor gasoline. Ninety-five percent is consumed for alkylation, a process for the manufacture of a high octane motor gasoline component. The balance of isobutane is used for refrigerant/aerosol markets. The demand for isobutane is governed by the motor gasoline market and import/export dynamics.

Natural gasoline, which primarily comprises pentane with some hexane and heaver hydrocarbons, is supplied 80% by natural gas processing plants and 20% by refineries in the form of naphtha and condensates. Demand for natural gasoline is 30% petrochemical and 70% refiner/blender. The motor gasoline market, ethylene/propylene prices, and naphtha market impact the demand for natural gasoline.

NGL Infrastructure

Figure 6 shows the major NGL pipeline corridors and fractionation centers while Figure 7 shows the existing natural gas processing capacity in the U.S. Current gas processing capacity is 65.7 Bcf/d while current fractionation capacity is 3,000 Mb/d. If NGL production grows to 4,668 Mb/d by 2035, current and planned processing capacity may be exceeded in the next few years.

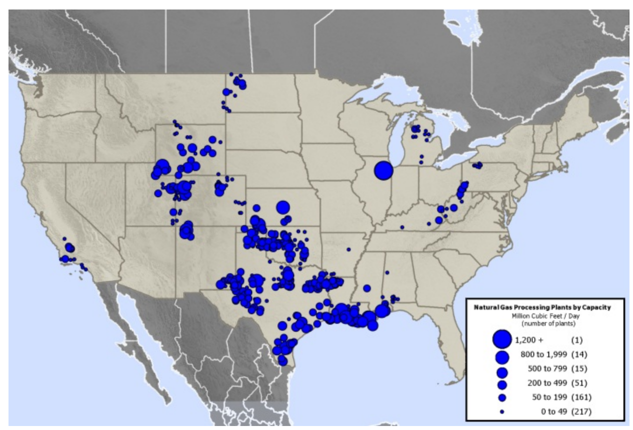


Figure 7. U.S. Gas Processing Capacity

Fractionation

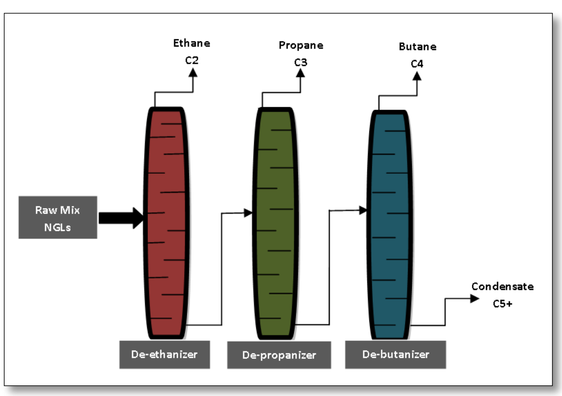


Figure 8. Diagram of NGL fractionation Process

Once the NGLs are extracted from the natural gas stream, these mixed NGLs, otherwise known as Y-grade or raw mix, are sent to a fractionator to be split into individual purity products. Approximately 68% of capacity is located in Texas and Louisiana. Additionally, there are several projects that will expand fractionation capacity by 438,000 b/d by 2014.

Figure 8 shows a simplified diagram of the NGL fractionation process. A fractionation facility uses a sequence of towers whereby temperatures and pressures are regulated so that the boiling point will be reached by only one product in each tower. Mixed NGLs first enter the de-ethanizer tower, where only the ethane is allowed to boil and escape through the top of the tower. The remaining NGLs fall to the bottom of the tower and are heated slightly on their way to the next tower where the next-lightest hydrocarbon (propane), which has the next-highest boiling point, is boiled out the top.

Once the propane comes out the top of the tower as a gas, it is cooled so that it condenses back to a liquid and is sent to a temporary holding tank in preparation for transport to market. Fractionation is only needed for NGLs that are extracted from natural gas. Much of the production from refineries does not need fractionation because it is already separated into individual components.

Transportation and Storage

NGL Pipelines

Some NGL pipelines carry mixed NGLs to fractionation facilities. Other NGL pipelines transport purity products, many times in batches, from fractionators or storage facilities to end users or related storage. In the current fast gas growth environment, NGL available pipeline capacity is limited; therefore truck and rail become viable options. The Bakken Shale play in North Dakota is a perfect example of an area that faces NGL takeaway constraints via pipeline, so producers in this region utilize truck and rail services. Though a large portion of the NGLs produced in the Bakken are consumed locally, the remainder is transported to the market using the BNSF rail system, or via trucking companies. NGL production is expected to continue to increase in the Bakken, reaching levels high enough to justify the capital investment required to build a pipeline. Consequently, two NGL pipelines have been proposed that would take NGLs from the Bakken to market.

Truck/Railroad Transport

Due to its high vapor pressure, ethane is not typically transported by truck or rail. However, heavier NGLs are commonly transported via truck or railroad. These methods of transport are normally more costly than pipeline, and therefore less preferred

Cargo Ships

Hundreds of ships carry propane and butane between different ports around the world. Currently ethane is not transported by ship, but this may change. One midstream company is proposing a project that would use LNG marine vessels to transport Marcellus ethane from the Northeast U.S. to the Gulf Coast region via the Delaware River and the Atlantic Ocean.

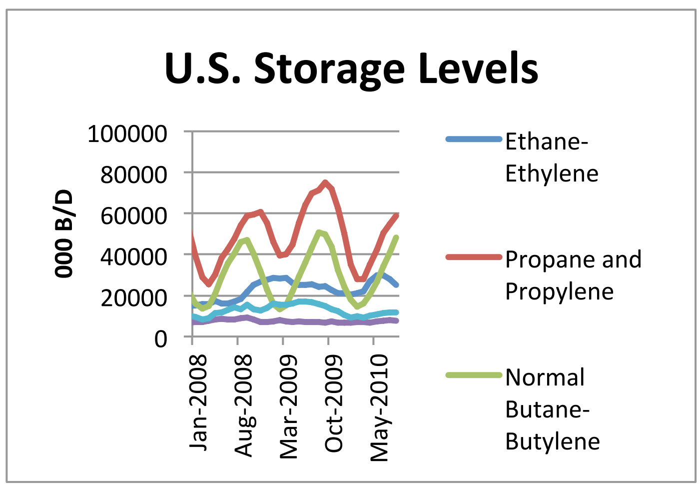


Figure 9. Propane and butane demand are seasonal, leading to higher fluctuations in storage.

Storage

Figure 9 shows the storage levels over time in the U.S. for each of the NGLs. While NGL storage is seasonal for propane and normal butane, it is relatively steady for ethane, isobutane and pentanes plus. Since demand for propane as a heating fuel is seasonal like natural gas, propane stocks build during the warmer months and are drawn down in colder months.

Refineries produce more butane than they consume in the summer, and the opposite is true during the winter. Sufficient storage capacity for NGLs balances the market and allows it to cope with seasonality or supply/demand disruptions

Refining and Petrochemical Overview

Because of the complex interaction (see Figure 10) between the primary producers, fractionation plants and the consumers of NGLs (refineries, petrochemical facilities, and industrial and residential), there are a large number of supply and demand options available which make the analysis of a shifting market complex. The economic objective for refining is to maximize profitability by choosing a feedstock and product mix that maximizes refining gross margin. Similarly the economic objective of base chemicals is to provide the desired mix and volume of chemicals at the lowest cash cost possible (Cash Cost = Feedstock + Operating cost – Co-products). Even in the absence of integration with chemical manufacturing, refinery optimization is a multifaceted undertaking. In the more complicated case with chemical plants, refineries are depicted as making three classes of products: transportation products (gasoline, jet, diesel, etc.), fuel products (utilized for combustion heat and include NGLs, fuel oils, and petroleum coke) and a third smaller group of more specialized products that don't fit in the first two groups.

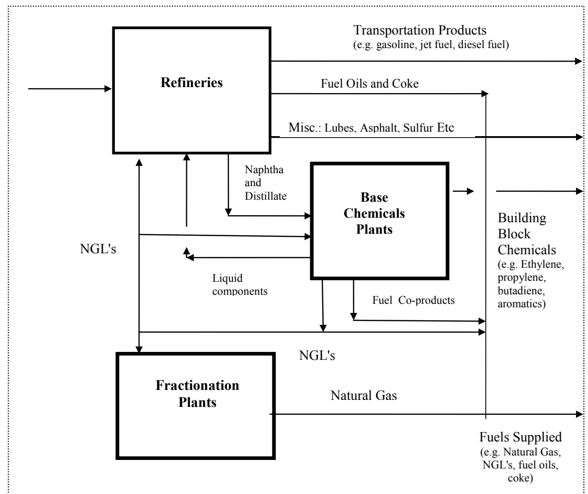


Figure 10. Integrated Refining and Petrochemical Industry

Given high North American crude prices relative to natural gas prices, liquid feedstock becomes more expensive, causing shifts in refinery behavior, including:

- Shift to less expensive feedstock
- Optimize production to increase yield of transportation products
- Increase base chemical derived from gas

Other changes will include:

- Fractionation plants will push as much product as possible into the transportation market and provide an outlet for co-products (NGLs).

- The consumer market may shift fuel consumption from crude oil-derived products to natural gas-derived products. For example, natural gas vehicles may become part of the transportation sector, which would displace crude oil demand.

Complicating this planning in the U.S. is expected growth in renewable and biofuels volumes that are mandated in the Renewable Fuel Standards. If it is assumed that the renewable and biofuel growth will occur, then in combination with the expected efficiency changes for key consumers, the product demand can be estimated. Based on the EIA 2011 AEO reference case, demand of petroleum-based transportation products will be flat.

Against this expected flat demand, options to change processing conditions, invest in new facilities, and even introduce different process technology options, can be tested. The complexity of the number of options available and product specifications dictates that less complex simplified analyses often overlook key considerations that invalidate the simplified results. This issue is made more complex in that refineries vary widely in process configuration, logistics, potential crude sources and product requirement. For example, a West Coast refinery producing almost all its gasoline to conform with California specifications and having no surrounding chemical infrastructure may respond to changing economics very differently from a Gulf Coast refinery with the ability to produce gasoline against less stringent gasoline specifications and with a surrounding base chemical infrastructure. The following observations are relevant based on the industry practices today in the NGL sector:

- Normal butane is isomerized to isobutane when needed to economically alkylate excess refinery olefins and produce a valued gasoline blending component.
- As the differential between the value of transportation products and fuel products widens, additional refinery investment to build additional cokers to upgrade fractions that would otherwise be sold as heavy fuel oil. A byproduct of the coking process is additional olefins (butylenes and propylene) that are available for alkylation to gasoline. However, in a scenario where the demand growth for hydrocarbon-based transportation products is flat, additional coker capacity additions may result in further rationalization of total refining industry capacity (less economic refineries shut down), and thus, it is difficult to project the net effect of this activity on refining sector NGL demand.
- Base chemical producers (steam crackers) manufacture light olefins from a variety of feeds, some of which are derived from wellhead gas and some of which are heavier liquids (naphtha and gas oils) derived from crude oil. The industry has evolved to highly value flexibility to selecting from among various feeds. A higher differential between NGL feeds and naphtha and gas oil cracking will further favor the NGL derived feedstock as primary feeds.

Outlooks for NGL

Natural Gas Production

For purposes of this analysis, unconstrained dry natural gas production is projected to increase from 74 Bcf/d in 2010, to 110 Bcf/d by 2035. This represents a roughly 48%, or 36 Bcf/d increase. The high crude-to-gas ratio has incentivized exploration and production (E&P) companies to develop oil and liquid rich plays. Assuming that the crude-to-gas price ratio holds current levels in the medium-term, the GPM should remain at current levels or possibly increase slightly over time. Figure

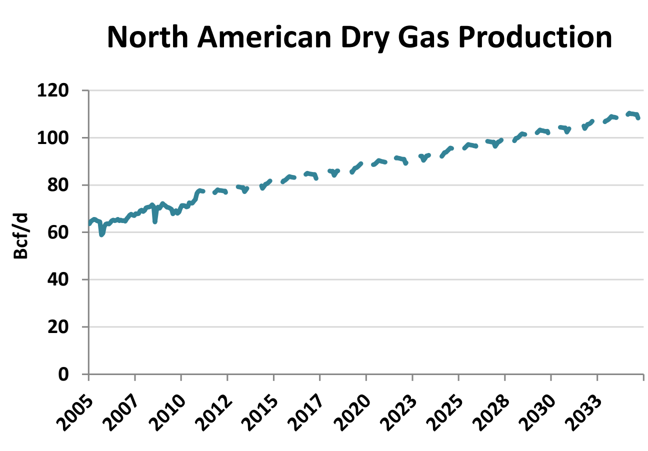


Figure 2 North American Dry Natural Gas Production

11 shows the projected dry natural gas production for North America.

From 2011 through 2016, existing midstream infrastructure is accounted for in the projection, and therefore provides a constraint on the rate of growth of gas production. The midstream infrastructure constraints include natural gas processing plants, transportation, fractionation, and consumption. From 2017 through 2035, it is assumed that connectivity, transportation and midstream infrastructure will be built in a sufficient amount to prevent bottlenecks and not constrain growth. In this context, we will examine the increases in capacity that will be required to avoid constraining the market.

Ethane

As shown in Figure 12, ethane production is expected to increase dramatically through 2035, primarily in the U.S. If North American dry natural gas production grows by 36 Bcf/d by 2035, ethane production is expected to increase by 47% or 527,000 b/d, to over 1.6 million b/d.

Demand for ethane is 100% from the petrochemical sector. Base chemical producers (i.e. steam crackers) manufacture light olefins from a variety of feeds, some of which are derived from wellhead gas and some of which are heavier liquids (naphtha and gas oils) derived from crude oil. The petrochemical industry has evolved to highly value flexibility of selecting from among various feeds. Two factors make the U.S. an attractive global provider of ethylene: ability to access demand centers, and competitive prices for cheap feedstock. As long as U.S. ethane prices stay attractive relative to global chemical costs, it will be profitable to invest in U.S. petrochemical plants through reconfiguring feed slates, expansions, and new builds.

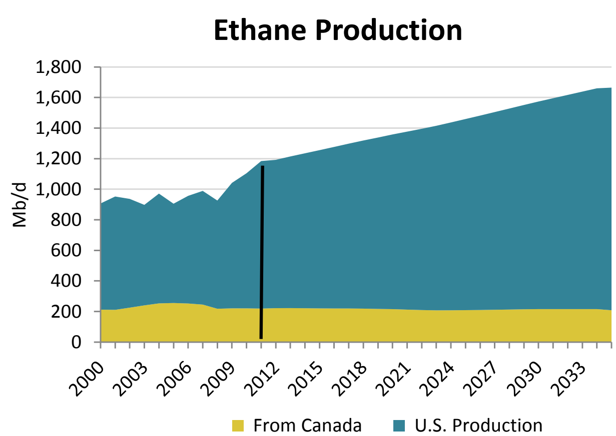


Figure 3 North American Ethane Production

Steam Cracker Demand Increasing

Ethane consumption from steam crackers has reached a record high, exceeding 873,000 b/d in December 2010. Ethane has had a prolonged advantage over other feed stocks because of the increased supply which has applied downward pressure on the price. Since petrochemical plants are going to use as much of the cheapest feed slate as possible, U.S. crackers have been running as much ethane through their units as possible. However, with utilization rates at max sustainable levels, the U.S. Chemical Industry is exploring its options to increase ethane consumption.

Expansion Projects

There was considerable feedstock switching in 2008 and 2009 as a result of broad re-configuring of steam crackers to handle lighter feed stocks. In 2010, two mothballed crackers were brought back online:

- Eastman restarted its HCC-3A cracker in Longview, TX and was producing on-spec ethylene as of Dec. 16. This 200 Mlbs/yr unit can consume approximately 5,000 b/d of NGLs.
- CP Chemical restarted its Sweeny 22 cracker. This 590 MMlbs/yr unit can consume approximately 15,000 b/d of NGLs, when 90% utilized.

From now until the end of 2017 companies are expected to provide more capacity to crack ethane. This will be done three ways:

Feed slate switching

Roughly 200,000 b/d ethane capacity could be made available by reconfiguring feed slates at existing facilities to handle lighter feeds, though some of those are less likely to happen. We anticipate an increase of roughly 115,000 b/d ethane demand from crackers to be added over the next six years if market economics don't drastically change. This type of work will most likely occur during a planned maintenance turnaround. This type of switching will occur before any new capacity is added to existing facilities because it easier, cheaper, and can be done fairly quickly. It is also important to note that the overall capacity of these crackers will decrease slightly with a switch to lighter feeds.

These are the projects expected to contribute to the increase in feedslate switching, though no formal announcements have been made:

2011 Projects:

- Formosa Plastics' Point Comfort O2 unit in Point Comfort, TX. This 1,800 MMlbs/yr unit is currently running at 95% utilization with a feedslate of 38% E/P mix, 31% propane, 31% naphtha. A maintenance outage is scheduled for Sept 2011.
- Shell Chemical's Deer Park OP3 unit in Deer Park, TX. This 1,840 MMlbs/yr unit is currently running at 95%utilization with a feedslate of 55% ethane, 20% propane, 5% butane, 15% naphtha. A maintenance outage is scheduled for 4Q2011.

2012 Projects:

- BASF's Port Arthur, TX Ethylene unit located on the TX Gulf Coast. This 2,060 MMlbs/yr unit is currently operating at 78% utilization, and has 100% naphtha feed slate. This plant is expected to re-configure its feed slate by the first half of 2012, and is expected to be a very significant change to their feedstock since is only uses naphtha currently.

Date Unknown:

- Dow Chemical's Oyster Creek Chemical LHC8 unit in Freeport, TX. This 2,200 MMlbs/yr unit is running at 95% utilization, and has a feed slate of 35% E/P mix, 50% propane, 15% naphtha. This is a definite candidate, but their last turnaround was in 2009, so it will be a while unless they come down early to make this switch.
- Formosa's Point Comfort O1 unit in Point Comfort, TX. This 1,500 MMlbs/yr unit is currently running at 92% utilization with a feed slate of 32% E/P mix, 37% propane, 37% naphtha. This could happen in tandem with it #2 unit in Sept. 2011, but I'm not sure.

- Chevron Phillips Chemical is advancing a feasibly study to construct a world-scale ethane cracker and ethylene derivatives at one of its existing facilities in the U.S. Gulf Coast region.

Capacity Debottlenecking/Expansions

In addition to reconfiguring feedslates, petrochemical plants are expected to add roughly 50,000 b/d ethane demand with unit expansions. As a rule of thumb, $100 million would increase a unit by 200 MMlbs/year, and these projects would typically pay off within 15 years. Most projects have yet to be formally announced, however, expansions are expected at the following facilities:

- Williams Geismar Olefins Unit - expansion. This 1350 MMlbs/yr unit is currently running at 100% utilization with a feed slate of 92% ethane, 8% propane.
- Westlake's Lake Charles site– debottlenecking. The #1 unit is a 1,250 MMlbs/yr unit that is currently operating at 100% utilization with a feed slate of 100% ethane. The #2 unit is a 1,150 MMlbs/yr unit that is operating at 100% utilization with 65% ethane, 35% propane.
- Formosa's Point Comfort site – expansion or NEW BUILD. O1 is a 1,500 MMlbs/ yr unit that is operating at 92% utilization. This is one of the units listed above in the feed slate switch, as it has heavier feeds. O2 is a 1800 MMlbs/yr unit is also listed above for a feed slate switch.

As shown in Figure 13, U.S. steam cracking capacity, which represents ethane demand, will not expand fast enough to balance the ethane production, which could lead to an oversupply situation. In order to utilize the growing ethane production, expansions of crackers, feedslate switching by the petrochemical industry, debottlenecking at existing crackers, and new ethane pipelines to move ethane to underutilized crackers are necessary to increase ethane cracking capacity in North America. In approximately 2016 new cracking capacity will be needed to handle the increased production of ethane from gas plants. However, underutilized cracking capacity exists in Canada that, if utilized, may be able to balance the supply/demand until 2017 at which time capacity is expected to be maxed out. Midstream additions have been announced which would bring ethane from the U.S. to Canada. An ethane pipeline from the Bakken shale, in North Dakota to Alberta has been proposed, as well as some proposed projects to bring ethane from the Marcellus shale in Pennsylvania to crackers in Sarnia, Canada. One or both of these pipeline projects can be expected to be completed by the end of 2013, and would provide for the U.S. to export up to 60,000 b/d of ethane to underutilized crackers in Canada.

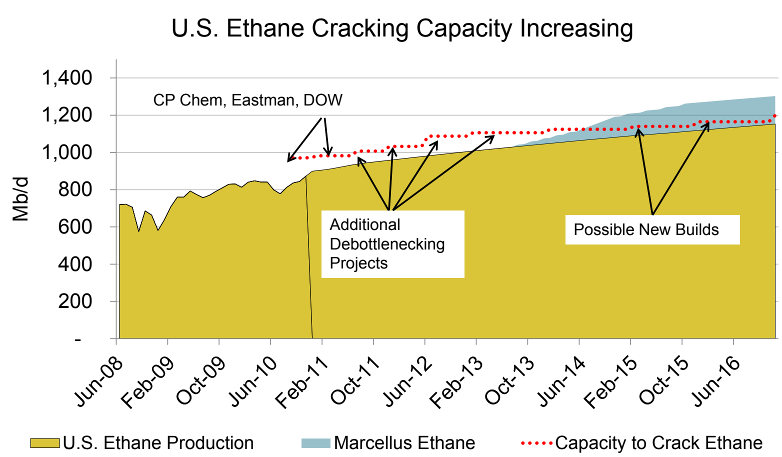


Figure 13 U.S. Ethane Supply/Demand Balance Forecast

New Pipelines

NOVA Chemicals has entered an agreement with Hess Corp. and Mistral Energy to purchase and transport ethane production from Hess' Tioga Gas Plant in North Dakota via a proposed pipeline to Alberta, Canada. Nova Chemicals will purchase 100% of the ethane produced at the Tioga gas plant under a long term agreement. Mistral will construct, own and operate the proposed Vantage Pipeline to transport ethane from Hess' Tioga gas plant into Nova's existing Joffre petrochemical complex in Alberta. The initial pipeline capacity is planned to be approximately 45,000 b/d of ethane, and will be expandable to approximately 60,000 b/d to handle future ethane supply from Williston Basin producers. The pipeline is expected to start up in the third quarter of 2012. MarkWest revised their Marcellus Mariner Project, which would take ethane from Pennsylvania eastward to Delaware in order to load it onto vessels to be shipped to the Gulf. The revision to this project would also give shippers the option of sending their ethane westward to Sarnia, Ontario.

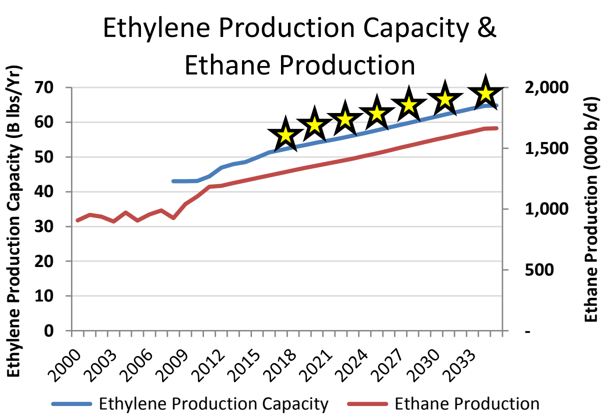


Figure 4 Ethylene Capacity and Ethane Production

New Steam Crackers

Ethane has had a prolonged advantage over other feed stocks because of the increased supply which has helped keep prices at a desirable level for use as feed stock at U.S. petrochemical plants. The U.S. could see 75,000 b/d of ethane demand from new construction by the end of 2017. Since it takes four to five years to build a steam cracker, a new unit would not be online any earlier than 2016-2017. Any new cracker would be built for export design and not for domestic consumption (which means a different design in the plant to make a product capable of exporting). As long as U.S. ethane prices stay attractive relative to global chemical costs, it will be economical for U.S. petrochemical plants to reconfiguring feed slates, pursue expansions, and create new infrastructure. Figure 14 shows that as North American ethane production increases to over 1.6 million b/d by 2035, ethylene cracking capacity (a.k.a. steam cracking) will need to increase at the same pace in order for supply and demand to balance. Each star in Figure 14 located along the ethylene capacity line indicates a world scale cracker that needs to be built in North America to keep supply and demand balanced. The forecast for ethane supply and demand suggests that a new cracker needs to be built, with 1,850 MMlbs/yr capacity, and 100% ethane as the feedstock, every three years to keep pace with the increased ethane production. As specified in the section above, various projects will be completed which will provide incremental increases at existing facilities. The increased ethane consumption capacity, as well as the assumption that at least one ethane pipeline will be completed and exports from the U.S. to Canada so increase each 60 M b/d, a new cracker is not needed until 2017.

If sufficient ethylene cracking capacity is not constructed, ethane will be rejected upstream at gas processing plants and sent with the natural gas stream. For every cracker in Figure 15 that does not get built, approximately 50,000 b/d of ethane will need to be rejected by natural gas processing plants, causing natural gas production to increase and additional 137 MMcf/d. Further, if no additional cracker capacity is constructed after 2016, approximately 350,000 b/d of ethane will be rejected and result in an increase in natural gas production of 960 MMcf/d. Global ethylene demand in 2010 was a little over 264 billion lbs/yr, so if seven crackers are constructed, they would represent 4.9% of 2010 world demand.

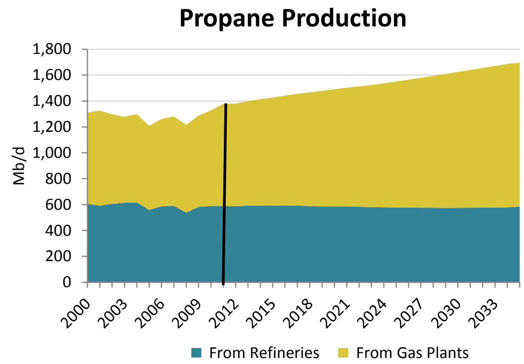


Figure 15 Propane Production by Source

Propane Supply

Figure 16 shows projected propane production from refineries and gas processing plants. Propane production is projected to increase from 1,328 Mb/d in 2010 to 1,696 Mb/d (28%) by 2035. In 2010, propane from refining accounted for 589 Mb/d while propane from gas processing accounted for 739 Mb/d. For reasons explained in the following section, it was assume propane production from refineries will remained unchanged throughout the forecast period. Meanwhile, gas processing derived propane is projected to grow to 1,111 Mb/d, which represents a 50% increase.

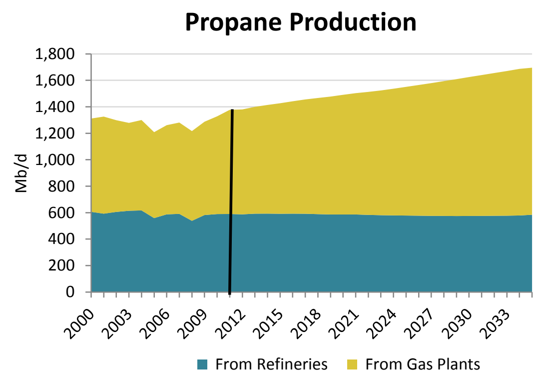


Figure 16 N.A. Propane Production by Source

Figure 17 shows propane production spilt between the U.S. and Canada. Propane production in the U.S. is projected to grow while Canadian production is shown to be flat. Canada accounts for 15% of current propane production, but by 2035 it accounts for 10%.

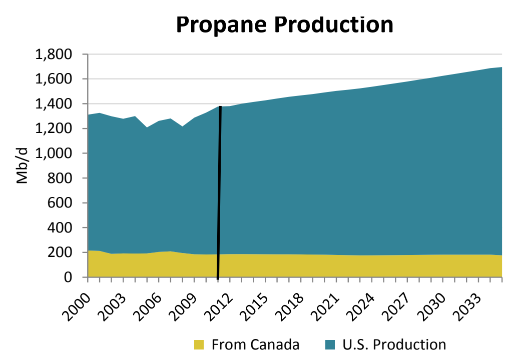


Figure 17 N.A. Propane Production by Country

Propane from Refineries

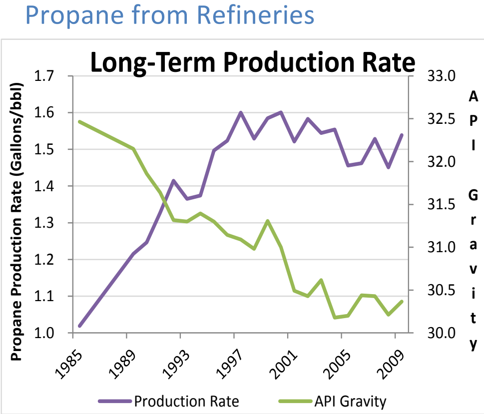


Figure 18 Long Term Propane Production Rate

Current expectations are that light crude production is naturally declining, and heavier crude production from the oil sands of Canada is increasing. As a result overall crude inputs to U.S. refineries are expected to become heavier as indicated by a

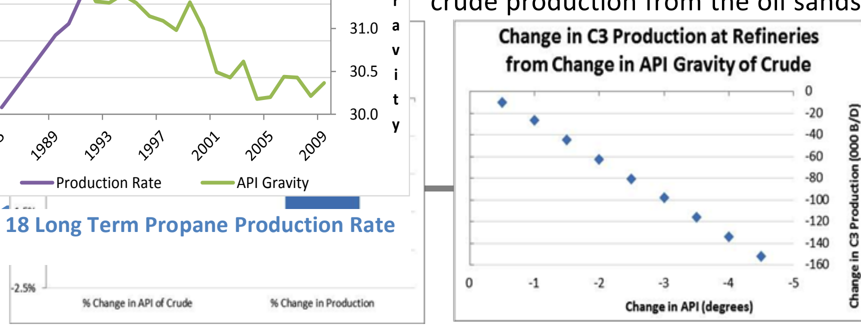


Figure 19 Propane Analysis

decreased API gravity (Figure 17). The effects of heavier crude impact propane/propylene production at refineries. In the short-term, the heavier the barrel of crude is, the lower the propane/propylene production. But, when conversions are done at refineries and cokers are added, propane/propylene production rates increase. That being said, horizontal well technology is unlocking new sources of sweet crude in the Permian, Williston, Eagle Ford, Granite Wash, Niobrara, and other plays. A growth in domestic light crude production would decrease the amount that is imported from overseas.

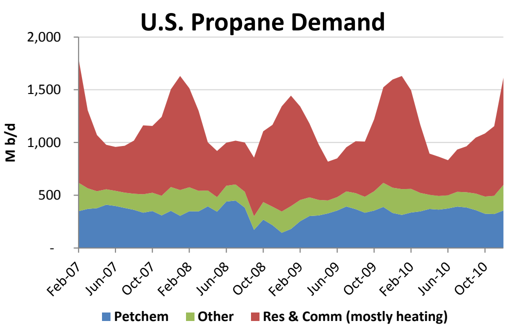


Figure 20 U.S. Propane Demand

Typically, light crude oil has API gravity higher than 30 degrees, whereas heavy crude can be below 22 degrees. Using monthly EIA data from Jan. 2005 for propane/propylene production rate, (measured by gallons of propane/propylene produced per barrel of crude refinery input), a standard OLS regression was run against the gravity of the crude oil being refined (measured by API). The p-value for the coefficient on API gravity is well below .0001 meaning there is a very high probability that the API gravity of the crude being refined affects the amount of propane/propylene being produced. That the change in API gravity is indicative of the change in propane production is a reasonable conclusion because lighter crude has more light ends like propane and butane. The chart on the left in figure 19 shows that for every 1% decrease in API gravity of crude oil, propane/propylene production at refineries decreases by nearly 2%. The chart on the right hand side of Figure 19 shows the resulting effect of API changes on actual production of propane/propylene. For every 1-degree decline in API gravity, there will be roughly a 35,000-b/d decline in propane production. But when conversions are done and cokers are added, more propane/propylene is produced as bigger molecular chains are broken into smaller chains. As shown on the graph to the left, as many conversions at refineries were done between 1985 and 1997, even though the API gravity of the crude was declining, the propane/propylene production rate was increasing. So in a simplified example, a refinery produces less propane/propylene as the barrel gets heavier, because there is less to distil, but when a conversion is made to better deal with the heavier crude, the resulting increase in production from the coker can more than offset the decreased production from the distiller.

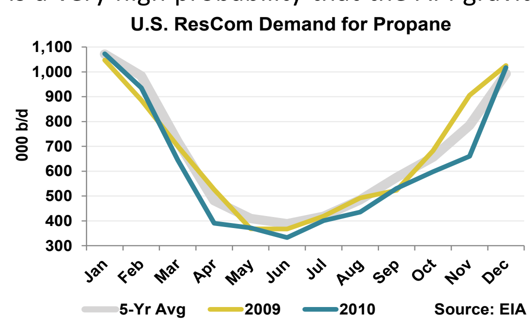


Figure 21 U.S. ResCom Demand for Propane

As the differential between the value of transportation products and fuel products widens, additional refinery investment to build additional cokers to upgrade fractions that would otherwise be sold as heavy fuel oil. A byproduct of the coking process is additional olefins (butylenes and propylene) that are available for alkylation to gasoline. However, in a scenario where the demand growth for hydrocarbon-based transportation products is flat, additional coker capacity may result in further rationalization of total refining industry capacity (less economic refineries shut down), and thus, it is difficult to project the net effect of this activity on refining sector NGL demand.

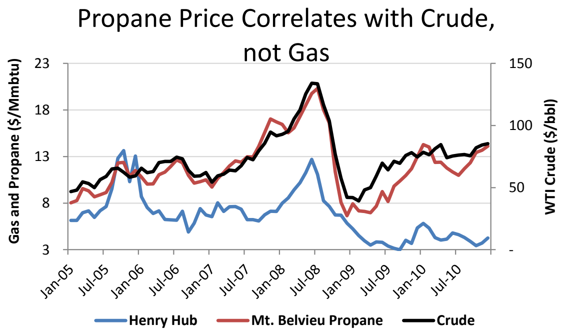


Figure 22 Propane-Crude Price Relationship

Demand

As shown by the red-shaded area in Figure 20, propane demand for residential and commercial use is very seasonal and makes up a large portion of overall demand. Most of this demand is for heating and is directly related to the temperature. The colder the winter is, the more propane consumed to produce heat in homes and businesses.

As shown by the green line in Figure 21, ResCom demand was generally lower in 2010 compared to 2009, and compared to the 5-year average. Since temperature has such a large influence on demand, it is appropriate to calculate demand per degree and analyze the rate of demand rather than demand itself.

Crude prices have been and are expected to continue to be high relative to natural gas prices. Since propane prices correlate strongly to crude oil and are only influenced slightly by the price of natural gas, propane prices have been high relative to natural gas prices (see Figure 22). Since propane and natural gas compete as a heating fuel, a high crude-to-gas price ratio can be expected to lead to fuel substitution in the medium- or long-run timeframe as shown in Figure 23.

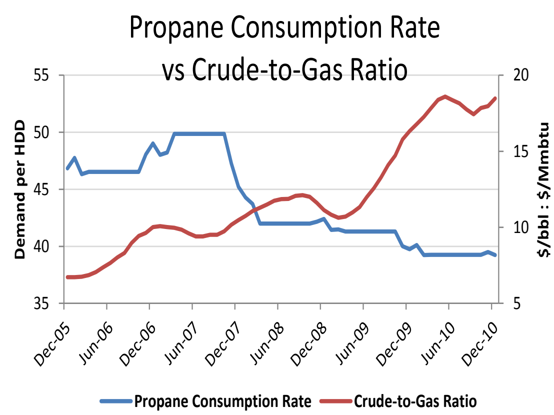


Figure 5 Propane Consumption Rate vs. Crude-to-Gas Ratio

The higher the price of propane relative to other heating fuels, specifically natural gas, the more likely consumers will switch fuels if that option is available. In the short-run, the option is not available in many cases based on the large up-front cost of switching. But in the medium- and long-term, switching could take place as current customers may switch fuels, and new customers that have the option and have not yet invested in one fuel or the other will choose natural gas over propane.

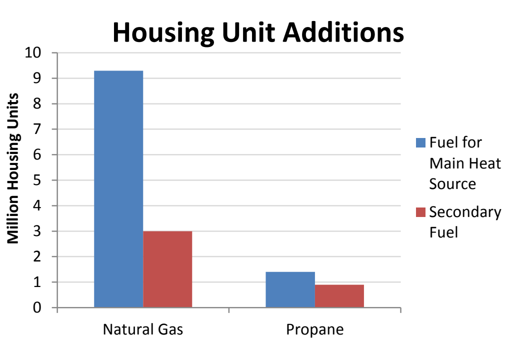


Figure 24 Housing Unit Additions

According to EIA results in its *Residential Energy Consumption Survey,* the number of housing units in the colder parts of the U.S., which does not include hot-humid or marine climate regions, increased from 64.3 million in 2005 to 88.3 million in 2009. The number of homes using natural gas increased by 10.7 million compared to only 3.9 million additions for propane. Propane, however, had a larger percentage gain (Figure 24), pointing to the possibility of propane expanding its market share. However, data from 2007-2010 which includes the ramp-up in crude prices relative to natural gas, shows that switching from propane to natural gas may be occurring.

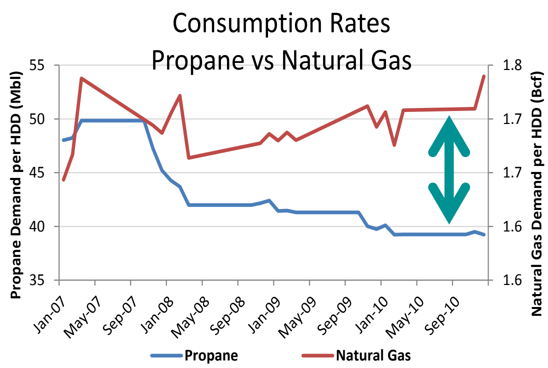


Figure 25 Consumption Rates: Propane vs. Natural Gas

To examine the amount of switching that has taken place over the past few years, we must take temperature out of the equation. By calculating demand per degree, we can see how normalized

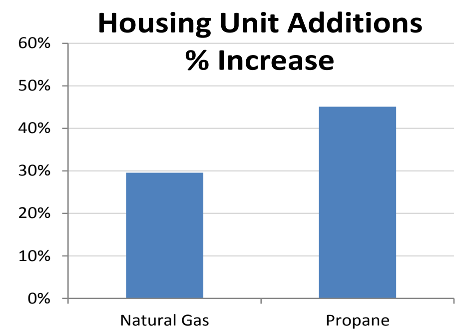


Figure 26 Housing Unit Additions % Increase

demand has changed with the evolution of higher propane-to-natural gas prices. The blue line in both graphs below represents the consumption rate of propane per temperature degree measured in thousand barrels per HDD and smoothed with a 12-month moving average. Figure 25 shows the consumption rate starting to decrease in late 2007, while at the same time the crude-to-gas ratio moved higher. Some of this decline in the consumption rate can be attributed to efficiency gains and conservation related to the economic downturn. But, the red line in Figure 26 shows that while the consumption rate for propane as a heating fuel has declined, the consumption rate for natural gas has remained fairly flat. The divergence of these two consumption rates, as represented by the green arrow in Figure 26, may be an indication that fuel switching from propane to natural gas as a heating fuel has begun to take place as crude prices soar relative to natural gas.

Demand or Exports Must Increase to Balance the Market

The average of the 10 months of largest LPG exports, including propane and butane, by Canada to countries other than the U.S. is 110,000 b/d. However, the last time Canada exported more than 50,000 b/d to non-U.S. countries was in April, 2004 . Because it was so long ago, it is doubtful that 110,000 b/d of export capacity still exists. Assuming Canada does not build new capacity to export propane by ship, there will continue to be product moving across the border into the U.S., even if the U.S. is oversupplied. Propane movements from Canada to the U.S. are expected to decrease from 98 Mb/d in 2010, to 74 Mb/d in 2035 as shown in Figure 27. In order to balance supply/demand for propane in the short- to mid-term, net-imports are likely to decline significantly, driven by increased exports from the U.S. For this to be possible, more ship export capacity will

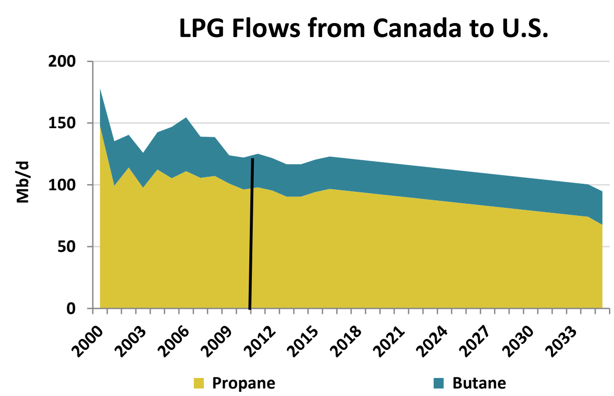


Figure 27 LPG Flows Declining from Canada to U.S.

need to be built. Enterprise announced plans to nearly double its export capacity at its Houston Ship Channel facility, from approximately 120,000 b/d to 240,000 b/d by the end of 2012. This increased capacity should be enough until 2016 when additional capacity will be needed. As shown in Figure 28, an additional 190 Mb/d of export capacity will be needed by 2035 if domestic demand does not increase substantially.

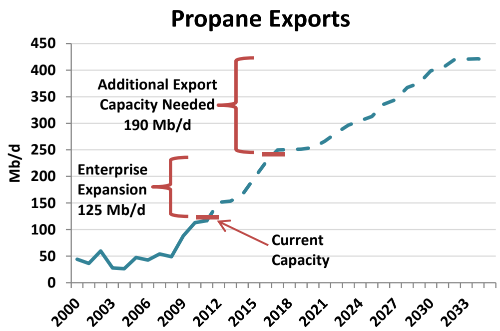


Figure 28 Propane Exports

The other option is for demand from petrochemical and other sectors such as motor fuel to increase significantly to soak up the excess propane. If petrochemical demand were to increase enough from 2010 levels, to consume the extra propane, 3 new crackers with 1,850 MMlbs/yr capacity, and 100% propane as the feedstock would need to be constructed by 2035 to soak up the extra 190 Mb/d of production.

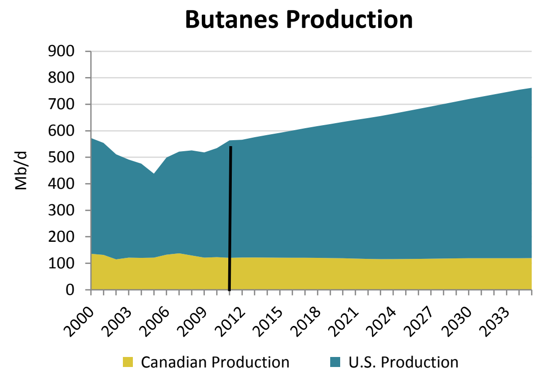


Figure 6 Butane Production by Country

Butanes

Figure 29 and 30 show butane production. Production of normal and isobutane from gas plants is expected to increase by 250 Mb/d in 2035 compared to 2010 levels, while consumption from traditional sources is expected to remain relatively flat. Most of the butanes produced in North America end up in the gasoline pool in one form or another. Increased production may cause summer stock levels to exceed winter blending demands. In this case, the price of butane will decline, and could reach a level that makes it a competitive feedstock for petrochemical steam crackers. Otherwise, non-traditional demand would need to increase, like a butylene dehydrogenation facility, or exports would need to increase.

Butane Demand for Making Isooctane Not Expected to Increase

Commercial technology exists to convert normal butane to isobutane, then to isobutylene for dimerization to isooctane for blending into motor gasoline, but the lack of wide commercial practice of the technology suggests the economics are marginal in today's market. Enterprise has a dedicated isooctane manufacturing facility that was converted from MTBE manufacture, and thus had significant sunk capital before undertaking the venture. There is a possible scenario where butanes become sufficiently over supplied and underpriced so that the economics would support investing new capital to expand capacity of this many step process of producing isooctane from normal butane. However, there must be a refinery customer base with a clearly defined need for low emissions, high octane blending components which is not common because refineries are

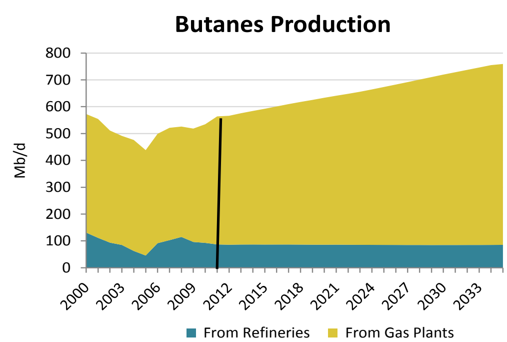


Figure 7 Butane Production

blending more ethanol into the gasoline pool which is a high octane component (Ethanol has an (R+M)/2 octane of 113).

When isobutylene was made available because refineries discontinued MTBE production (isobutylene plus methanol) in response to environmental concerns, conversion of existing MTBE facilities for dimerization was evaluated versus alkylation. In many cases alkylation was preferred because one could react the available isobutylene with isobutane to make roughly 1.7 volumes of alkylate per volume of isobutylene reacted. Dimerization yields a much lower volume of 1:1 and the resulting olefinic product is a less desirable gasoline blending component. Alkylate is also preferred to dimerization because it is clean and has a lower octane so it does not get displaced by ethanol.

Only a Small Increase in Demand Expected from Alkylation

Some normal butane is isomerized to isobutane when needed to economically alkylate excess refinery olefins and produce a valued gasoline blending component. Refinery grade propylene is sold into the chemical market when in close proximity to fractionation, transport and storage systems (PADD 3). However, in other regions, propylene and isobutane have been traditional alkylation feeds.

Due to changing gasoline regulations over the past decade, there has been a strong incentive to increase alkylate production, but alkylation capacity at refineries has been relatively flat. Catalytic crackers, the source of light refinery olefins, are typically run against one of several hard constraints that make a significant change in product outturn difficult to achieve. Thus, incremental volumes of refinery olefins, such as propylene for alkylation are difficult to generate.

Table 1 EIA Refinery Alkylation Capacity

Ex EIA data base	2000	2010	Annual Growth Rate, %/yr
Refinery Alkylation Capacity, MM bbl/cd	1.185	1.249	0.5

Refining capacity is expected to be flat to declining, as is the petroleum based gasoline demand. The EIA 2011 Reference case projects operable refining capacity to decrease from 17.6 MM b/d to 16 MM b/d as utilization of operable capacity increases from 86% to 91%. This scenario likely supports little investment to increase gasoline volume. However, normal recapitalization may lead to a marginal increase in alkylation capacity in operating refineries as long as gasoline regulations favor alkylate as a blend stock. In summary, absent a significant change in gasoline economics or regulations, there is little expected incremental capacity growth for consuming isobutane in refining.

Future U.S. Gasoline Regulation Could Push Refinery Demand Lower

Once a certain threshold of ethanol mixed in the motor gasoline pool is reached, vapor of the mixture does not continue to increase. Therefore increasing the ethanol % of motor gasoline pool beyond that threshold will not displace butane in the context of high vapor pressure constraints. But until that threshold is reached, increased vapor pressure from ethanol limits the amount of butane that can be blended because it also has a high vapor pressure.

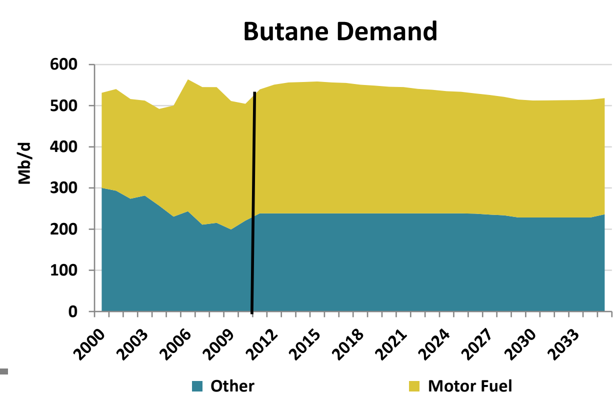


Figure 8 Butane Demand

In Oct. 2010 the U.S. Environmental Protection Agency (EPA) granted a waiver that effectively allows for the increase of the maximum blending limit of ethanol into gasoline from 10% to 15% for approved vehicles. A significant provision in the October waiver is the elimination of the exemption that allowed the vapor pressure of conventional gasoline with 10% ethanol to exceed that of an ethanol-free blend by 1 PSIG during the summer season (typically May 1 to Sept 15). The EPA opined in their proposed rule that complications associated with producing conventional gasoline blend stock for both 10% and 15% ethanol contents "could be avoided by refiners producing a lower RVP blend stock for E-10 as well." Thus, a transition to produce and market E-15 gasoline could effectively lead to a 1 PSIG vapor pressure reduction in the summer months for an undetermined portion of the gasoline pool.

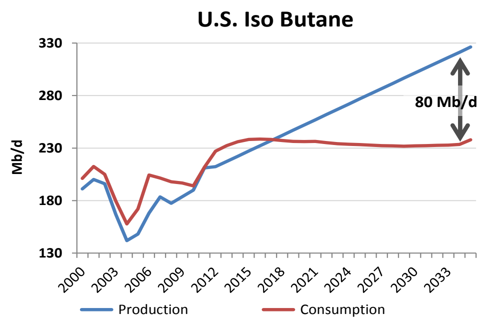


Figure 9 U.S. Isobutane Supply and Demand

A previous EIA study in 2002 for 9.0 PSIG gasoline showed that without the exemption, in order to drop the RVP by 1 PSIG, it would take a 3.2% reduction in butanes and pentanes as blend stock volume. The actual reduction would be dependent on individual refinery configuration and the markets to which their product is directed. Consider the scenario where a 1 PSIG vapor pressure reduction is required for 5.75 MMb/d of conventional gasoline (100% of the U.S. volume) during 50% of the year. If normal butane was the only blend stock removed in order to lower the vapor pressure of the gasoline pool, it would equate to a 50 Mb/d reduction in demand for butanes by refineries.

Isomerization Capacity Expected to Decline

Isomerization facilities convert normal butane to isobutane. As shown in Figure 32, isobutane production at gas plants is expected to exceed consumption. If isomerization units remain operating at 2010 levels, by 2022 there will be an excess of approximately 20 Mb/d and by 2035, 80 Mb/d of isobutane in the U.S. It can be expected that as sufficient naturally occurring isobutane is produced at gas plants to meet consumption rates, isomerization of normal butane into isobutane will become uneconomic and capacity utilization of these units will decline by 80 Mb/d by 2035.

Where will all the Butane Go?

Similar to propane, Canada will continue to export butanes to the U.S. to balance the market north of the border. Since propane and butane exports from Canada to the U.S. are likely to decline to less than 100 Mb/d by 2035 (see Figure 33). Pipeline infrastructure that is currently used for this purpose can be put into some other kind of service as the volumes may be too low to justify allocating capacity to these products. Therefore, these movements will likely happen by sending propane and butanes with the heavy crude as a diluent to

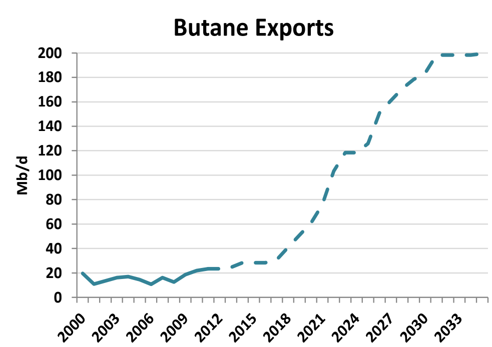


Figure 10 LPG Flows Declining from Canada to U.S.

the U.S.

But with production increasing significantly and demand remaining flat, the U.S. will not need butane from Canada and it will only work to exasperate the over-supply situation in the U.S. To avoid over-supply, demand or exports need to increase by 177 Mb/d over the next 25 years. A higher differential between NGL feeds and naphtha and gas oil cracking will further favor the NGL derived feedstock as primary feeds, and for refineries that are closely integrated with chemical plants through existing infrastructure such as that existing on the Gulf Coast, butanes could become a greater portion of the steam cracker feed slate. However, since we expect lighter NGLs such as ethane and propane to be favored feedstocks over butane, demand by the petrochemical sector is not expected to increase. If it did, 3 new crackers with 1,850 MMlbs/yr capacity, and 100% butane as the feedstock would need to be constructed by 2035 to soak up the extra supply from gas plant production. Other options such as a butylene dehydrogenation unit could increase demand by converting butane to butylene, which should be in short supply if crackers will be cracking lighter feedstocks such as ethane and propane.

If demand remains fairly flat while production increases, butane exports will need to increase from 23 Mb/d in 2010 to 200 Mb/d by 2035.

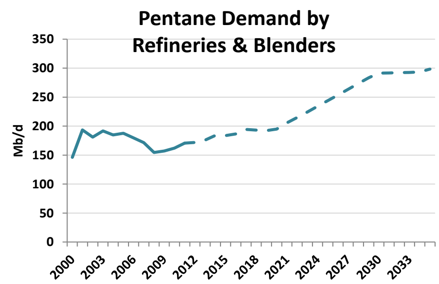


Figure 11 Pentane Refineries and Blender Demand

Natural Gasoline

Natural gasoline is consumed largely by refineries year-round as a component of the motor gasoline pool. Since natural gasoline (mostly pentanes with some hexane and heavier hydrocarbons), is similar in composition to light condensate, it is expected to remain priced similarly and can displace crude up to a certain degree. For this reason it is not expected that increased production from gas plants will be enough to have an effect on this heaviest of the NGLs. As shown in Figure 34 demand for natural gasoline by refineries and blenders will need to increase to 300 Mb/d by 2035. This still will only represent 2% of crude inputs to refineries, which are expected to average 14.5 MMb/d in 2035.

Natural gasoline is used to dilute bitumen produced from oil sands in order to decrease viscosity and allow the bitumen to flow in a pipe. This is referred to as a “diluent.” Demand for natural gasoline used for Canadian tar sands diluent (is expected to increase over the coming years. However, as specified in the butane section of this paper that demand may only increase marginally as we expect increased use of propane and butanes as diluent. Even if demand for natural gasoline as diluent increases, it can be considered a closed loop system. If the U.S. exports more natural gasoline to Canada and Canada mixes it with the heavy crude and sends it back to the U.S. then it can be considered the same as if it never left in the first place.

Even though domestic demand of crude related products for motor gasoline is expected to remain flat, there is a scenario where we could keep running refineries at a high rate and export excess motor gasoline. The U.S. has some of the most complex and efficient refineries in the world. So in a society that emphasizes maximizing energy while minimizing environmental impact, the flexibility, complexity and efficiency of U.S. refineries will make them competitive in the world market and encourage motor gasoline exports.

Another possible scenario is that natural gasoline production could be very high and put downward pressure on price, making it the preferred feedstock for steam crackers. It could become preferred over ethane because ethane has a medium and long-term price floor which is the price of natural gas, but natural gasoline does not have a price floor because processing plants don't have the option to reject heavier NGLs. They must be recovered in order to lower the BTU content and dew point of the gas stream to pipeline specifications. In this scenario, petrochemical facilities would shift to a heavier feedslate and consume more natural gasoline in steam crackers. So in the long-term, natural gasoline price should remain strong, because if there is an over-supply situation which drives the price down, and demand by refineries remains stagnant, petrochemical demand and exports can be expected to increase to balance the market.

Conclusions

Over the past five years, the North American natural gas industry has experienced a "shale revolution." Advancements in horizontal drilling and well-completion technologies applied to low-permeability, natural gas formations – shales and tight sands - have unlocked huge reservoirs of natural gas supply from Western Canada, to the Gulf Coast to Appalachia. It is a revolution of productivity and abundance, which has already yielded extraordinary natural gas production growth, lower natural gas prices and reduced natural gas imports. Ultimately this revolution has the potential to drive natural gas production well beyond historic levels and to fundamentally shift the dynamics in other energy markets which compete with, or are closely related to, natural gas.

This is particularly true for natural gas liquids (NGLs). NGLs have traditionally been considered a byproduct of natural gas production. The five NGLs—ethane, propane, normal butane, isobutane and natural gasoline (pentanes+)—are produced when natural gas is processed for delivery to market. As shale natural gas production continues to expand, it has a direct impact on the supply of NGLs. Whether the infrastructure and market for NGLs can absorb these increasing volumes and how the new supplies will impact demand for NGLs and related products are key questions facing producers and consumers of these important petrochemical products.

The tremendous growth in natural gas production in North America has resulted in significant NGL production growth. NGL production growth will come from both legacy plays where infrastructure is mature and from newer plays where infrastructure is in its infantile stages. For example, NGL production out of the Eagle Ford is poised for growth because of the existing infrastructure. In contrast, NGL production from the Marcellus will create additional challenges since the northeast region lacks infrastructure to bring the NGLs to market. The midstream sector will need to evolve and grow quickly in order to manage and capitalize on the NGL growth. If the midstream sector does not response quickly enough, production growth will be constrained. However, midstream infrastructure can grow only so quickly, and given the number of new plays developing, it is likely that some plays will develop at much faster rates than other plays. North America is already expected to see significant infrastructure investment and growth along all points of the NGL value chain. Significant gathering, processing, fractionation, and cracking capacity is under construction or has been announced. Ethane is poised to be the dominant feedstock for the petrochemical industry for the foreseeable future. While this results in lower input costs for manufacturing of ethylene and ethylene derivatives, co-products such as propylene experience a shortfall in supply. Meanwhile propane demand is anticipated to drop as heating demand declines in response to households switching to natural gas. The propane export market should therefore be robust. The heavier NGLs (butane and pentane+) experience difference dynamics. North American could be supply long on butane as it gets pushed out of the motor gasoline pool due to increased ethanol blending and flat to declining motor gas demand. Natural gasoline could experience demand growth driving by the oil sands sector's need for diluent.

Along with the growth in natural gas, the associated natural gas liquids market is rapidly changing and evolving, from the upstream to the downstream. The pace of growth will vary by basin as the market responds to the increased supply and resultant demand.

Glossary

Associated gas: Associated or casing head gas is raw natural gas that has become dissolved in oil accumulations and is produced as a by-product along with crude oil. If the gas is in contact, but not in solution with crude oil, it called associated free gas. Associated gas is typically rich with heavier NGLs.

Condensate: Condensate or "lease condensate" refers to a specific portion of the NGL stream. Some of the heavier NGL components (i.e., isobutane and natural gasoline) exist as a gaseous state only at underground pressures. These molecules will immediately "condense" to a liquid state when brought to atmospheric conditions, hence the name condensate.

Cryogenic expander process: The cryogenic expansion process is one of the primary techniques (the other being lean oil absorption) used for methane separation, that is, the actual separation of methane (i.e., natural gas) from NGL components, which is the last step in natural gas processing. Cryogenic expansion involves the rapid cooling of natural gas via expansion to approximately negative 120 degrees Fahrenheit. At this temperature, ethane and the other NGL components condense out of the natural gas stream, while methane remains in its gaseous form. Most modern processing plants use the cryogenic expander process to extract NGLs.

Dry natural gas: Natural gas is classified as "dry" or "wet" depending on the amount of NGLs present. Dry or lean natural gas contains less than 1 gallon of recoverable NGLs per Mcf of gas (GPM) and is composed primarily of methane. The amount of NGLs contained in the natural gas stream can vary depending upon the region, depth of wells, proximity to crude oil, and other factors.

Ethane: Ethane is typically the second-largest component of natural gas (methane is the largest). It is primarily used as a feedstock for ethylene production by the petrochemical industry. Thus, the demand for ethane is tied closely to ethylene production, which, in turn, is tied to demand for plastics, or more broadly speaking, the health of the overall economy.

Ethane extraction: Natural gas processors will choose to extract (i.e. separate) ethane from the natural gas stream when processing economics are favorable (i.e. when ethane is worth more as a distinct product than as part of the natural gas stream).

Ethane rejection: A natural gas processor will likely choose, if given the option, to reject ethane (i.e., leave it in the natural gas stream) rather than extract it, when the processing margin (specifically the ethane margin) turns negative or uneconomic (i.e., below a plant's fixed operating costs). If the processor is unable to reject ethane under this scenario, the company would likely incur a loss. To note, the remainder of the NGL stream (i.e., propane+) is still processed. Most modern processing plants have the ability extract heavier NGL components, but leave ethane in the natural gas stream when processing economics are unfavorable.

Ethylene: Ethylene is a building block for polyethylene, which is the most popular plastic in the world. Ethylene is the simplest olefin produced by the petrochemical industry.

Fractionation: Fractionation is the process that involves the separation of the NGLs into discrete NGL purity products (i.e., ethane, propane, normal butane, isobutane, and natural gasoline).

Gallons of recoverable NGLs per Mcf (GPM): GPM refers to the amount of NGLs contained in the natural gas stream and is dependent upon the region, depth of wells, proximity to crude oil, and other factors.

Frac Spread: The margin between NGL and natural gas prices

HPIB: high-purity isobutylene. Used in the manufacturing of tires, lubricants, and other petroleum basin products

Light feedstock. Light feedstock is commonly defined as hydrocarbon feeds derived from natural gas sources (i.e., ethane, propane, and butane); however, it can also refer to light naphtha. Light feedstock produces lighter olefins including ethylene, propylene, and butadiene.

Natural gas liquids (NGL): NGLs are extracted from the raw natural gas stream into a liquid mix (consisting of ethane, propane, butane, isobutane, and natural gasoline). The NGLs are then typically transported via pipelines to fractionation facilities.

Midstream Sector: the processing, storage and transportation sector of the petroleum industry

Olefin: An olefin is any unsaturated chemical compound containing at least one carbon double bond. The petrochemical industry produces three primary olefins: ethylene, propylene, and butadiene.

Processing margin: The processing margin is the difference between the price of natural gas and a composite price for NGLs on a BTU-equivalent basis.

Propane: Propane is one of the five primary natural gas liquids (NGLs). Propane is a byproduct created during the processing and separating of natural gas liquids from natural gas to meet pipeline standards, or during the crude oil refining process.

Raw NGL Mix. Raw NGL mix or "y" grade refers to the heavier NGL components that are extracted via natural gas processing. The resulting NGL mix is commingled product consisting of ethane (depending on whether ethane rejection took place), propane, butane, isobutane, and natural gasoline. It is not until fractionation, the next step in the NGL value chain, that the raw NGL mix is further separated into individual NGL components.

Residue Gas: Is dry gas, after removing liquids (after shrink). A component of gross production.

Steam cracker: A steam cracker is a petrochemical plant that uses either light feedstock (i.e., ethane, propane, LPGs) or heavy feedstock (i.e., heavy naphtha, gas oil), depending on plant configuration and economics to create ethylene, propylene, and other petrochemicals. In order to create these petrochemicals (e.g., ethylene), saturated hydrocarbons need to be broken down (or cracked) into smaller, unsaturated hydrocarbons in a process known as stream cracking. Steam cracking is accomplished by heating the hydrocarbon feedstock diluted with steam in a furnace to approximately 650-850 degrees Celsius. Subsequently, the mixture is rapidly cooled to 400 degrees Celsius to stop the reaction. Water is then injected to further cool the mixture; thereby creating a condensate, rich in ethylene and various quantities of other byproducts (depending on the type of feedstock).

Straddle Plant: A gas processing plant located on or near a gas transmission line, and used to process gas by removing the liquids (NGLs) from sales gas, and returns the sales gas to the pipeline

Upgrading: A process that makes the oil more viscous and allows it to flow.