Independent Statistics & Analysis
U.S. Energy Information Administration

Technical Options for Processing Additional Light Tight Oil Volumes within the United States

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Preface

U.S. oil production has grown rapidly in recent years. U.S. Energy Information Administration (EIA) data, which reflect combined production of crude oil and lease condensate, show a rise from 5.6 million barrels per day (bbl/d) in 2011 to 8.7 million bbl/d in 2014. Increasing production of light crude oil from low-permeability, or tight, resource formations in regions like the Bakken, Permian Basin, and Eagle Ford, often referred to as light tight oil (LTO), accounts for nearly all the net growth in U.S. crude oil production.

EIA's March 2015 *Short-Term Energy Outlook* (STEO) forecasts U.S. crude oil production averaging 9.3 million bbl/d in 2015 and 9.5 million bbl/d in 2016, well above the 2014 average level but only moderately above production during December 2014. EIA's *Annual Energy Outlook* (AEO) projects further production growth, but its pace and duration remain uncertain, as shown by the significant differences in both the timing and level of the highest volume of U.S. crude oil production between the Reference case and the High Oil and Gas Resource case.

Recent and forecast increases in domestic crude oil production have sparked discussion on the topic of how rising crude volumes might be absorbed. As EIA noted nearly two years ago, relaxation of restrictions on U.S. exports of crude oil is only one among several ways to accommodate growing near-term flows of domestic production (EIA, *This Week in Petroleum*, “Absorbing increases in U.S. crude oil production,” May 1, 2013). Recognizing that some options, such as like-for-like replacement of import streams, are inherently limited, the question of how a relaxation in current limitations on crude exports might affect domestic and international markets for both crude oil and products continues to hold great interest for policymakers, industry, and the public. In response to multiple requests, EIA is developing analyses that shed light on this question, including earlier reports on U.S. crude oil production by type (EIA, *U.S. crude oil production forecast – analysis of crude types*, May 29, 2014), gasoline price determinants (EIA, *What drives gasoline prices?*, October 30, 2014) and changes in U.S. crude oil imports to accommodate increased domestic production (*This Week in Petroleum*, “Crude oil imports continue to decline,” January 23, 2014).

This report examines technical options for processing additional LTO volumes within the United States. Domestic processing of additional LTO would enable an increase in petroleum product exports from the United States, already the world’s largest net exporter of petroleum products. Unlike crude oil, products are not subject to export limitations or licensing requirements. While this is one possible approach to absorbing higher domestic LTO production in the absence of a relaxation of current limitations on crude exports, domestic LTO would have to be priced at a level required to encourage additional LTO runs at existing refinery units, debottlenecking, or possible additions of processing capacity. The cost of such adjustments or capacity additions, together with the perception of market and policy risks surrounding potential investments, will determine the extent to which LTO might need to be discounted to spur those investments.

The analysis of technical options for additional domestic LTO processing discussed in this report, together with the previous analyses cited above, provide a foundation for further analyses of the market outlook and the effects of a possible relaxation of existing restrictions on U.S. crude oil exports.

Executive Summary

With the growth in U.S. production of light tight oil (LTO) in recent years, domestic refiners have been processing greater LTO volumes. To date, increased runs of domestic LTO have mainly been facilitated by a reduction of light crude oil imports, particularly to refineries on the U.S. Gulf Coast (USGC) and the East Coast. In addition, refinery utilization rates have increased, and some imports of heavier crude types have also been displaced in some U.S. regions.

The sharp decline in oil prices in recent months may slow domestic LTO production growth in the immediate future. However, there is significant potential for further growth in domestic LTO production. This is particularly the case in scenarios with favorable resource availability, technology development, and oil prices that rise above their level in early 2015, even if they remain below the range sustained from 2011 through mid-2014. For this reason, there is considerable interest in how additional volumes of domestically produced LTO might be accommodated.

This paper focuses on technical options for processing more LTO within the United States. With the rise in domestic production of petroleum products and a general decline in U.S. petroleum product use since 2005, the United States, until recently the world's largest net importer of petroleum products, is now the world's largest net exporter of these products. There are no limitations on U.S. trade in petroleum products. Trends in U.S. consumption of petroleum products such as gasoline and diesel fuel reflect prices determined on global product markets, fuel economy and alternative fuel policies, and demographic and economic drivers. Because petroleum product use is not significantly affected by the level of U.S. refining activity, additional processing of crude oil in the United States would likely increase net exports of petroleum products.

The relaxation of current limitations on exports of crude oil, another possible way to accommodate additional LTO production volumes, is not considered in this report. However, the discussion of technical options for additional domestic processing provided here points to several key issues that will be addressed in forthcoming analysis that considers how markets might evolve with or without changes in current limitations on crude oil exports. These questions include:

- How large is the opportunity to further increase the utilization of existing refining assets to process more LTO, and what are the economic costs associated with such increased utilization?
- What is the actual opportunity for LTO to displace non-similar grades of imported crude oil?
- At what rates of return and payback periods would investments in additional processing capacity become attractive, given the risks associated with future changes to policy, prices, and production?
- How might the costs associated with processing more LTO in domestic facilities be reflected in prices paid to LTO producers? How would any price discount affect projected LTO production?

There are several different ways that U.S. refiners could process additional volumes of LTO. Beyond their varying associated costs, the options have different implications for overall U.S. petroleum product output volumes and their composition. Once the growth in throughput volume from no- or low-cost import substitution or debottlenecking options has been fully realized, further increases in LTO processing would require significant investments in new processing facilities. Refiners would likely prefer low-cost investment options to larger and more-expensive facilities given market, timing and policy risks associated with large-scale investments.

Limited- or no-investment-cost options

The cheapest and simplest option for U.S. refiners to process more domestic LTO production is to replace imported volumes of similar light crude oil types. However, opportunities for additional "like-for-like" substitutions are limited given the significant backing-out of light crude imports that has already occurred since 2010. Refiners are likely to increasingly consider other options, such as displacing volumes of non-light crude oil imports, increasing refinery utilization rates, or making limited investments in debottlenecking existing refinery infrastructure.[1]

Crude import displacement

Imports of light crude oil into the United States have decreased significantly in recent years, with light crude imports to the USGC almost fully eliminated. As these light crude oil imports have been displaced, refiners looking to process additional domestic LTO production with existing capacity have reduced imports of comparatively heavier crude types. This can result in a lighter overall crude oil input slate to U.S. refineries, which can lead to operational inefficiencies, particularly at refineries designed to process heavier crude oil types.

To offset some of the impact of the lighter crude inputs on refinery operations, refiners can purchase additional volumes of heavy crude oil imports for blending, as medium crude oil imports are displaced.[2] The extent to which refiners can do this is limited by the amount of medium crude oil available for backing out, as well as the availability of heavy crude types that can be used for blending. Additionally, although total production volumes would be unaffected by this blending process, the slate of petroleum products may be altered.

Another technical option would be to process LTO in refineries that are optimized to process heavy crude slates, accepting the inherent operational inefficiencies. While there would be no large investment cost, the opportunity cost could prove to be very large, even if LTO was available domestically at a significant discount to comparable global crudes. One consideration is that many of the heavy crude types currently processed in complex Gulf Coast refineries have few alternative markets. For this reason, markets may respond to potential

[1] Debottlenecking refers to the practice of modifying existing equipment to remove restrictions on throughput. Usually, such projects can be carried out at significantly lower cost than building whole new units or facilities.

[2] EIA data through December 2014 indicate a 24% decrease in medium crude oil imports (crudes with an API gravity of equal to or above 27 and below 35) into the United States over the last three years, from an average of 3.3 million barrels per day (bbl/d) in 2011 to an average of 2.5 million bbl/d in 2014. The data indicate particularly large decreases in the Gulf Coast (31% or 0.5 million bbl/d) and East Coast (33% or 0.2 million bbl/d) Petroleum Administration for Defense Districts over this period.

competition from discounted LTO through more competitive pricing of such crudes that serves to either prevent or substantially curtail their displacement from complex USGC refineries. Under such circumstances, the addition of new processing capacity for LTO, discussed below, may prove to have a lower opportunity cost than "LTO for heavy" displacement, even though it entails a significantly higher investment cost.

Increased utilization of existing processing capacity

Increased capacity utilization has also provided U.S. refiners with a relatively simple way to process additional domestic LTO production volumes, with no additional investment in new processing capacity. However, this has largely already occurred, with crude oil refinery inputs reaching record levels last year.[3] The additional domestic LTO production that refiners can process by increasing capacity utilization rates is limited.

Increased refinery utilization rates have already enabled U.S. petroleum product production and net exports to increase, and further increases in capacity utilization would cause these exports to rise above current levels. Unlike crude oil exports, which are currently restricted and subject to licensing requirements, U.S. trade in finished petroleum products is not restricted.[4]

Capacity debottlenecking

As U.S. refinery utilization rates have increased, refiners have made relatively low-cost investments in equipment modifications to remove restrictions on throughput, also known as crude unit debottlenecking. So far, debottlenecking investments have largely been to replace the gathering trays and condenser units needed to collect the greater volumes of lighter distillation products at the top of an Atmospheric Distillation Unit (ADU) column resulting from processing additional LTO. Because the opportunities for such investments are limited, so too is their potential impact on the amount of additional LTO that U.S. refiners will be able to process. Like increased capacity utilization, capacity debottlenecking would lead to increased petroleum product output, which would largely translate into higher net petroleum product exports.

Capacity expansion options

A range of technical expansion options might be considered once the limited- to no-cost options described in the previous section either are no longer available or if the expected margins (revenues less input and operating costs) available from processing additional domestic LTO volumes are more than sufficient to justify costs and risks associated with new capacity additions. Investment decisions are also likely to reflect factors such as scale, location, crude type availability, construction timelines, market risk, policy risk, and the expected value of petroleum product output slates.

Possible expansion projects include those that increase only ADU capacity, those that increase only secondary processing capacity, and integrated projects that include both ADU and secondary units. Within each category, there are tradeoffs between cost and location. Projects to build greenfield[5] facilities outside of existing refinery locations include costs that are not included in projects to build brownfield [6] facilities located at existing refineries. Greenfield projects are assumed to include additional costs for production area setup, auxiliary

[3] Gross inputs to U.S. refineries reached a record 16.9 million barrels per day (bbl/d) in July 2014.

[4] Net exports of finished petroleum products averaged 2.1 million bbl/d in 2014, composed of 2.8 million bbl/d of gross finished product exports and 0.6 million bbl/d of gross finished product imports.

[5] Built on a site with no existing infrastructure in place.

[6] Built on a site with existing infrastructure in place.

equipment, and other utilities that would already be available for facilities built at an existing refinery. However, greenfield project costs could be less than assumed in this paper for a project located in an industrial area with some available auxiliary equipment and on a surface that has already been prepared for unit construction. Brownfield construction costs might be understated, since even for a project that is built at an existing refinery, it is unlikely that all necessary utilities and other facilities will be available on-site. In addition to financial costs, greenfield and brownfield projects differ in terms of their construction timelines. The risk of a greenfield project is generally greater because its longer lead time increases the likelihood that market changes affecting a project's profitability will occur before construction is finished.

There is also a tradeoff between scale and risk. For projects of a given type, larger-scale projects generally have lower unit costs due to well-known economies of scale.[7] However, the lower unit costs of larger units must be weighed against the potentially substantial risks associated with their higher absolute cost and longer lead times, which increase exposure to changes in the cost and availability of crude oil inputs and changing conditions in petroleum product markets.

Potential changes in policies are another source of risk for capacity expansion options. One major policy risk is the possibility that current restrictions on U.S. crude oil exports will be relaxed or eliminated, which could significantly lessen the future value of additional domestic processing capacity.

Some have argued that policy and market risks would pose an absolute and insurmountable barrier to significant investment in additional domestic processing capacity. Although such a view seems extreme, investors may require a high rate of return over a short timeframe when considering such investments. Table ES-1 illustrates how the per-barrel processing margin required to motivate investment in various refinery expansion projects changes when perceived risk causes potential investors to seek a higher expected rate of return (18% rather than 12%) over a shorter payback period (10 rather than 25 years). A sufficient difference, or spread, between petroleum product prices that are determined on global markets and the price at which crude oil is available to domestic processors could make investments in additional processing capacity attractive even in the face of considerable policy and market risk.

The size of the spread required to motivate investment in additional processing capacity could in turn determine the extent to which domestic LTO would need to be discounted relative to comparable global crudes. The discount for domestic LTO needed to spur additional investment in processing capacity at U.S. refineries would change if assumptions are modified regarding the current limitations on crude oil exports and expected growth in domestic LTO resource availability. The difference in price between domestic LTO and global crude oil would in turn have implications for the level of LTO production, which is one key question to be addressed in considering effects of a possible relaxation of current limitations on crude oil exports.

Expanding only distillation capacity

Investments in units that provide only additional distillation capacity have costs significantly below those of facilities that include secondary processing units that can be used to turn naphtha and other distillation products into finished products like motor gasoline and jet fuel. The unfinished product streams from distillation-only facilities can be sold directly as petrochemical feedstock in domestic or export markets. They

[7] The cost advantage obtained due to size, output, or scale of operation.

can also undergo further processing, either on-site or at another domestic or foreign refinery, into finished products.

Splitters and stabilizers offer refiners a less-expensive option for expanding crude oil distillation capacity than building new refineries or adding ADU columns. Splitters and stabilizers, several of which are now under construction or in the engineering, permitting, or planning phases, are typically designed to distill the very light streams that are largely produced in the Eagle Ford region in south Texas. They will operate less efficiently when processing relatively heavier crudes, including crudes produced in the Bakken region in North Dakota and eastern Montana. Although splitters and stabilizers can process crudes with API gravity well below API thresholds that are often cited as representing condensates, doing so will result in decreased throughput levels and increased output of heavier, unfinished petroleum products.

Because the availability of very light streams is relatively less affected by current limitations on crude oil exports, the supply of feedstock for splitters and stabilizers is less subject to market and policy risk than that of other options. Splitters and stabilizers would also benefit from less market risk because their smaller size requires less upfront investment than larger distillation units.

A 20,000-barrel-per-stream-day[8] (bbl/sd) brownfield stabilizer is the least expensive option for expanding distillation capacity, in both overall and per-barrel terms. The limited separation provided by such units would mean that while investing less, operators would also receive smaller processing margins compared to higher-cost projects offering potentially higher processing margins.

A project to build a 50,000-bbl/sd greenfield splitter facility would require more investment than a stabilizer, but less than most other distillation expansion options. Although building the facility as a greenfield project means that it would include production area setup, auxiliary equipment, and utility costs, it also means that it would not have to be located at an existing facility. This would provide flexibility to locate the project in an area that may have better access to markets and lower crude oil transportation costs than the location of existing refineries.

By comparison, a 50,000-bbl/sd brownfield splitter would require significantly less upfront capital to build, as it would not require the construction of any other additional equipment already available at an existing refinery site. However, the feasibility of building a brownfield splitter at an existing refinery would be dependent on the proximity of this refinery to supply sources and the market.

Because of their smaller size and cost, splitter and stabilizer projects can be built with less of a commitment to process large volumes of crude oil over the life of the investment. This is important in light of the market and policy risks previously discussed. A refiner would be significantly more exposed to this risk if they added a 250,000-bbl/sd ADU column to an existing refinery. However, they would also benefit from significantly greater economies of scale.

Secondary processing capacity investment options

Secondary processing units receive their feedstock from the ADU for upgrading to higher-value products. These units are not themselves a technical constraint for refineries to process additional LTO, but could be

[8] The maximum volume that a distillation facility can process in a 24-hour period under optimal conditions with no allowance for downtime.

useful in processing additional volumes of naphtha into motor gasoline. Refiners can build new secondary processing units to accompany many of the distillation capacity expansions described in the previous section.

This paper considers two options for secondary processing capacity, continuous catalytic reformer (CCR) units or isomerization units. Although CCR units have a significantly lower per-barrel cost than isomerization units, they are designed to process heavier intermediate naphtha that is distilled at temperatures that are equal to or greater than 180 degrees Fahrenheit (°F). Despite its higher cost, an isomerization unit could still be an attractive investment for a refinery that receives a relatively high volume of lighter intermediate naphtha that is distilled at temperatures below 180°F.[9]

Expanding both distillation and secondary processing capacity

Expanding ADU capacity by building new, fully equipped facilities that include secondary processing units would enable U.S. refiners to process additional crude oil volumes into finished petroleum products. These finished petroleum products could be either sold to domestic consumers or exported for more revenue than the unfinished naphtha produced from a distillation-only capacity expansion. Refiners would weigh the benefit of this additional revenue against the relatively higher cost of these projects compared to other options described in this paper.

A hydroskimmer refinery consists of an ADU to distill light crude oil (sometimes referred to as a topping unit) and a modest set of secondary processing units. The basic design of a hydroskimmer refinery's topping and secondary units makes it less expensive and better-suited for processing domestic LTO production than other fully equipped facilities. A hydroskimmer's topping unit is smaller than the standard ADU at a full refinery. Its secondary units would only include hydrotreaters and a reformer, not heavier processing units like crackers and cokers. The hydroskimmer's limited capacity would limit both cost and exposure to market and policy risk.

A 100,000-bbl/sd brownfield hydroskimmer would be the least expensive option for expanding both ADU and secondary unit capacity. It would not include the costs for production area setup, auxiliary equipment, or utilities that would be included if the hydroskimmer were built as a greenfield project. An industrial area that has already received some site preparation, with costs somewhere between the brownfield and greenfield options, is another siting possibility for a new hydroskimmer refinery. Therefore, the cost differences in Table ES-1 for a greenfield and brownfield unit represent a range of costs.

Building an entirely new 250,000-bbl/sd greenfield refinery is the most expensive option for expanding both distillation and secondary processing capacity. It has the highest equipment costs, and because it is a greenfield project, would also have higher costs for production area setup and auxiliary equipment. However, it would yield the most additional revenue for a refiner, because it would have the greatest capacity to produce finished petroleum products. As with all other projects listed, its cost in terms of upfront investment would have to be weighed against this greater additional revenue.

[9] This refers specifically to C_5 and C_6 molecules, and not C_8 molecules, which can be isomerized after being distilled at higher boiling temperatures.

Table ES-1. Summary costs for capital investment options at refineries

Option	Advantages	Disadvantages	Processing capacity (Mbbl/sd)	Construction time (years)	Overnight cost: Total ($MM)	Overnight cost: Volumetric input ($/bbl/sd)	Amortized capital cost: 12% annual interest and 25-year amortization ($/bbl)	Amortized capital cost: 18% annual interest and 10-year amortization ($/bbl)
No investment options								
Increase refinery capacity utilization	Allows for additional LTO processing at zero cost	Limited by available unused refinery capacity	0	0	$0		$0	$0
Back out medium and heavy imports	Allows refiners to take advantage of available LTO volumes at a minimal cost	Operational inefficiencies, reduced crude oil input and production volumes	0	0	$0		$0	$0
Debottlenecking	Allows for additional LTO processing at a minimal cost	Can only provide a limited amount of additional capacity	Minimal	<1				Minimal
Purchase less domestic light tight oil production	Zero cost, no operational inefficiencies	Shut-in U.S. LTO production volumes, capped growth in petroleum product output	0	0	$0		$0	$0
Distillation-only capacity investment options								
Brownfield stabilizer	Additional ADU capacity at an existing facility; lower per-barrel amortized capital cost than any other option	Constrained by crude type; high unprocessed and unseparated naphtha volumes	20	1.5	$30	$1,390	$0.63	$1.16
Brownfield splitter	Additional ADU capacity at an existing facility	Constrained by crude type; high unfinished naphtha volumes; limited locational flexibility	50	1.5	$100	$2,060	$0.94	$1.73
Greenfield splitter	Additional ADU capacity; locational and operational flexibility	New facility; constrained by crude type; high unfinished naphtha volumes	50	1.5	$140	$2,830	$1.30	$2.39
Brownfield atmospheric distillation column	Additional capacity at an existing facility; economies of scale	Policy risk; high unprocessed, unfinished product volumes could require additional investment	250	2	$370	$1,500	$0.70	$1.31

Table ES-1. Summary costs for capital investment options at refineries (cont.)

Option	Advantages	Disadvantages	Processing capacity (Mbbl/sd)	Construction time (years)	Overnight cost: Total ($MM)	Overnight cost: Volumetric input ($/bbl/sd)	Amortized capital cost: 12% annual interest and 25-year amortization ($/bbl)	Amortized capital cost: 18% annual interest and 10-year amortization ($/bbl)
Secondary processing-only capacity investment options								
Brownfield isomerization unit	Low cost; increased volume of higher-octane motor gasoline	Only ideal for naphtha processed at temperatures below 180°F	20	1.5	$110	$5,250	$2.38	$4.37
Brownfield continuous catalytic reformer unit	Low cost; increased volume of higher-octane motor gasoline	Only ideal for naphtha processed at temperatures equal to or greater than 180°F	50	2	$150	$3,000	$1.40	$2.61
Combined distillation and secondary processing capacity investment options								
Brownfield hydroskimmer refinery	Additional capacity at an existing facility; some economies of scale; finished products	Limited volumes, relatively high cost; limited locational flexibility	100	3	$530	$5,280	$2.64	$5.06
Greenfield hydroskimmer refinery	Additional capacity; some economies of scale; finished products	Limited volumes, relatively high cost	100	3	$720	$7,170	$3.59	$6.87
Full greenfield refinery (ultra-light)	Additional capacity; low impact on existing facilities; finished products	High capital costs, market and policy risk	250	3	$3,390	$13,540	$6.78	$12.98

Sources: U.S. Energy Information Administration, Independent Project Analysis, Inc.

Note: Mbbl/sd = thousand barrels per stream day, or the maximum volume that a distillation facility can process in a 24-hour period under optimal conditions with no allowance for downtime; $/bbl = dollars per barrel; $/bbl/sd = dollars per barrel per stream day; MM = million. Overnight cost is the cost of a project with no interest incurred, or the lump sum cost of a project if it were completed overnight. Amortized capital cost is the revenue per barrel processed needed to pay the cost of the project over a 25-year period with a 12% annual interest rate, or over a 10-year period with an 18% annual interest rate, with the facility operating at a utilization rate of 85% of full stream-day capacity.

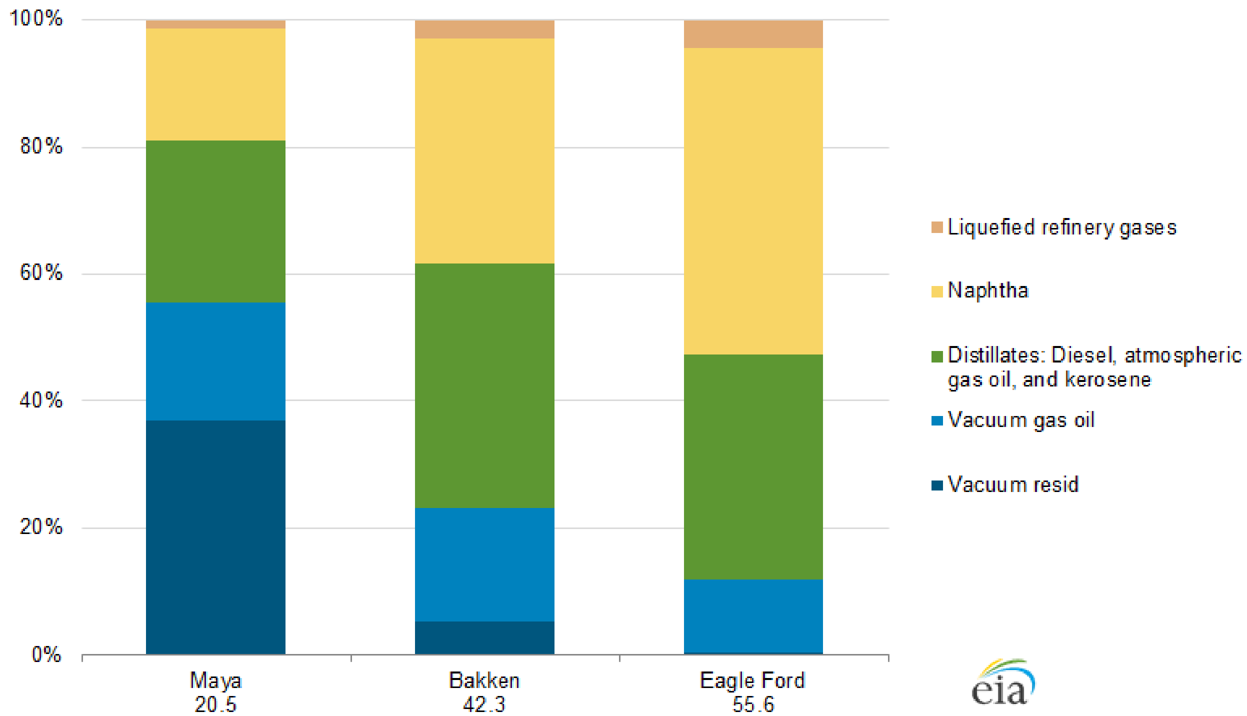
Technical Options for Processing Additional LTO Volumes

Assuming the continued growth of domestic LTO production in a scenario where current U.S. crude oil export restrictions remain in place, there are a number of ways that additional LTO volumes could be processed in domestic facilities.

Context and background

The mix of petroleum products resulting from petroleum refining reflects both the crude oil input stream and the equipment used for processing. For example, when light oil is run through an ADU, there are higher yields of light and medium intermediate products, like naphtha, liquefied refinery gases, kerosene, and distillate, compared with refinery runs of heavy crudes. Additionally, distillation of light crude oil yields a relatively low volume of heavy intermediate products like vacuum residual fuel and vacuum gas oil. Figure 1 compares distillation yields from 20.5-API gravity Maya crude oil imported from Mexico, 42.3-API gravity Bakken crude oil, and 55.6-API gravity Eagle Ford crude oil.

Figure 1. Proportional atmospheric distillation yields from three crude oil types



Source: U.S. Energy Information Administration calculations with Chevron Crude Assay Library data.

Refiners generally seek a combination of crude inputs and product output that maximizes the margin between the value of the products produced and their input and other operating costs. Once built, refinery units are a largely sunk cost. However, prior to their construction refiners try to assess whether or not the addition of a particular type of unit is likely to increase margins by an amount sufficient to justify the investment.

Limited- or no–investment-cost options

In recent years, U.S. refiners have been able to improve their margins by processing increased LTO volumes without making significant infrastructure investments. The cheapest and most feasible of the limited- or no-cost options is to decrease imports of similar-quality crudes, such as Bonny Light from Nigeria and Brent crude oil from the United Kingdom. Data indicate that this has been occurring, particularly on the U.S. Gulf Coast (USGC).[10] Although most of the USGC refineries were designed to process heavy crude, they historically received small volumes of light imports, which have increasingly been replaced by volumes of Permian and Eagle Ford LTO production.[11] These refineries have now virtually eliminated light crude imports,[12] indicating that other options must now be considered before investing in additional capacity to process LTO production. These include:

- Displacing relatively heavier crude oil types
- Increasing refinery utilization rates
- Debottlenecking crude oil processing units

To an extent, a number of these options have already been realized. The following section discusses each of them, and the degree to which they can allow U.S. refiners to respond to increased domestic LTO production without making larger-scale capacity investments.

Displacing heavier crude oil inputs that are still being imported

With light crude oil imports virtually eliminated, USGC refineries have increasingly made more refining capacity available to process domestic LTO production by reducing imports of medium crude oil types.[13] USGC imports of these medium crude types decreased from an average of 1.7 million barrels per day (bbl/d) in 2011 to an average of 1.2 million bbl/d in 2014.

The ability of USGC refineries to replace medium imports with domestic LTO production is limited by the higher ADU yield of light-end streams from LTO than from medium API crudes. Because many of these refineries are designed to process heavier medium API crude, the ADU is limited by the amount of light components that can be distilled. One option for USGC refineries to avoid reaching the limit on capacity for light distillation streams is to import greater volumes of heavy crude oil to blend with domestic LTO production. This allows USGC refineries to receive greater volumes of domestic LTO with a minimal change in the average API gravity of their crude oil feedstock, and a limited increase in lighter distillation yields.

However, the ability to replace medium crude oil imports with a combination of domestic LTO and heavy foreign imports is limited by the amount of medium crude oil that can be displaced, the availability of heavy imports, and the ability to chemically combine heavy and light crude oil types to produce distillation yields that

[10] U.S. Energy Information Administration, "Recent decline in Gulf Coast crude oil imports mainly affects lighter grades," *This Week in Petroleum*, October 30, 2013.

[11] U.S. Energy Information Administration, "Crude oil imports continue to decline," *This Week in Petroleum*, January 23, 2014. http://www.eia.gov/petroleum/weekly/archive/2014/140123/twipprint.html

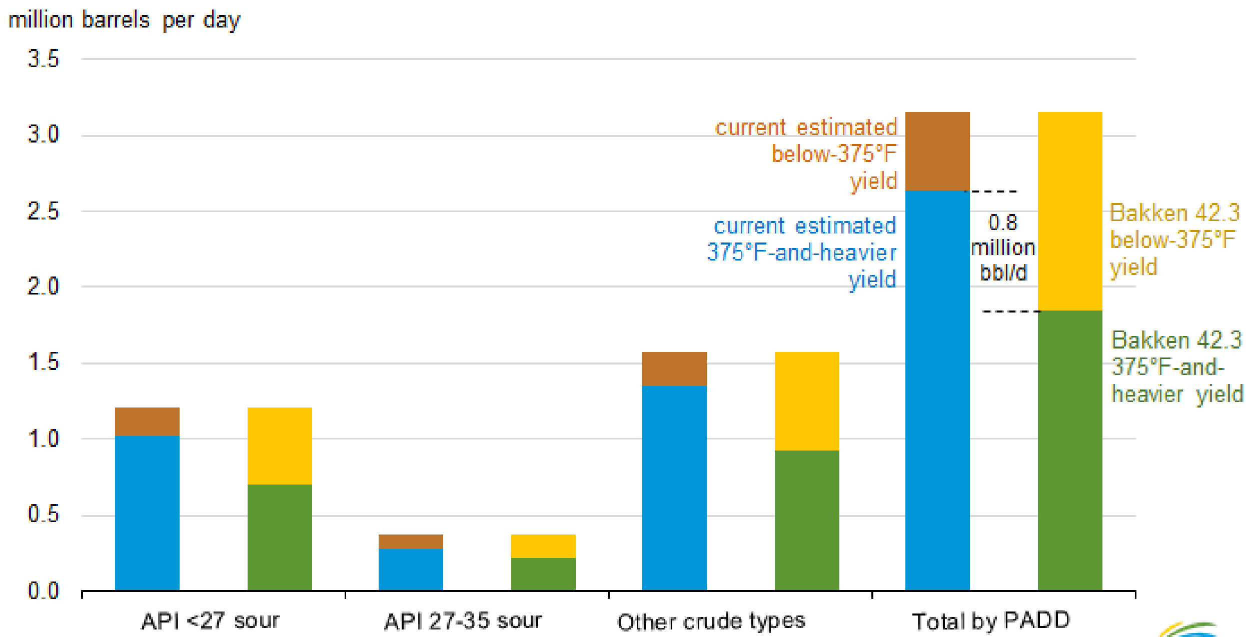
[12] U.S. Energy Information Administration, "EIA tracking tool shows light-sweet imports to Gulf Coast virtually eliminated," *Today in Energy*, February 10, 2015. http://www.eia.gov/todayinenergy/detail.cfm?id=19931

[13] For the purposes of this paper, medium crude oil has an API gravity of equal to or greater than 27 and less than 35.

are similar to those of a medium crude type.[14] USGC imports of medium crude oil decreased to an average of 0.9 million bbl/d in the fourth quarter of 2014, less than half of the 1.9 million bbl/d average in the first quarter of 2009. This limits the remaining amount of medium crude oil available to be replaced with a blend of heavy imports and domestic LTO. Additionally, increased demand for heavy crude oil may raise its price to the point where this option is no longer economically feasible, especially if decreased demand for medium crude oil causes medium-grade prices to weaken.

Recognizing that refiners need not use all available processing units, there are also technical options for more drastic shifts in input streams to process additional LTO. For example, refineries optimized to run very heavy crude oil through cokers and other deep conversion units could reduce utilization of those units and instead run light crude oil if that is the most profitable option.

Figure 2. Change in estimated yield distribution from replacing all crude oil imports into PADD3 (Gulf Coast) with Bakken 42.3 crude oil



Source: U.S. Energy Information Administration.
Note: Below-375 °F distillation product yields are estimated by matching assay data for crude oil types that are most similar to each imported crude type, and accounting for each imported crude type's respective PADD 3 refinery input volumes.

However, the direct replacement of all imports with domestic LTO would be problematic in many respects. For example, it would lead to a significant increase in the yield of light intermediate streams distilled at temperatures below 375°F. Without some investment in new processing capacity, many refineries would likely have to reconfigure their equipment and reduce throughput levels to handle this increase in light distillation yields. Figure 2 shows that if the 3.2 million bbl/d of total crude imports into the USGC in January 2015 were

[14] A large amount of blending between heavy and light crudes can cause distillation yields of very heavy and very light streams, more quickly straining capacity at the upper and lower portions of an ADU.

replaced by Bakken crude oil with an API gravity of 42.3, there would be an additional 0.8 million bbl/d of lighter intermediate streams distilled at below 375°F, creating significant challenges downstream of the ADU.

Also, since many of the heavy crude types currently processed in complex Gulf Coast refineries have few alternative markets, prices for those crudes may respond to potential competition from discounted domestic LTO. Heavy crude oil prices could decline enough to either prevent or substantially curtail their displacement from complex USCG refineries. Under such circumstances, the addition of new processing capacity for LTO, discussed below, may become more feasible than LTO-for-heavy crude displacement, even though capacity expansions would entail a significantly higher investment cost.

Table 1 summarizes some implications of using refineries to process the input streams that they were designed for versus other crude types.

Table 1. Combinations of heavy and light crude oil processed at heavy and light crude refineries

	Refinery designed to process	
Crude oil type	**Heavy crude oil**	**Light crude oil**
Heavy	High capacity utilization, high yield of petroleum products that typically yield high revenue.	Potential low capacity utilization, high yield of residual fuel oil that typically yields low revenue.
Light	Potential low capacity utilization, but high margins. Possible shutdown of heavy processing units.	High capacity utilization, potentially high margins if light crude oil feedstock is cost-competitive.

Source: U.S. Energy Information Administration.

Increasing refinery utilization rates

Without a major investment, refineries could also increase the amount of domestic LTO production that they process if they were able to raise their utilization rates.

However, like displacement of light or medium imports, increased capacity utilization is an option that many USGC refineries have already carried out. In July 2014, total throughput at both U.S. and USGC refineries reached record levels,[15] and capacity utilization rates in both reached their highest level since 2005. Although utilization rates have decreased since July, they remain high, with limited available capacity to receive additional LTO volumes without making any additional investments.

Debottlenecking crude oil processing units

In order to limit the capacity constraint at the top of a refinery's ADU column, an issue discussed above, refiners could invest in ADU debottlenecking. To do this, a refiner might replace the trays and condensers at the top of the ADU. Doing so allows refiners to collect increasing amounts of light-end intermediate streams that result from processing a lighter crude oil slate. Because this option does have a small cost, refiners would likely consider it once it is no longer economically advantageous to replace medium imports with LTO and heavy crude blends, and they no longer have enough available capacity to increase throughput. However, this option has already been carried out by many U.S. refineries, and is limited by the fact that replacing trays and condensers only adds a marginal amount of additional capacity, compared with the larger-scale investments described in the next section.

[15] U.S. Energy Information Administration, "U.S. refineries running at record levels", *This Week in Petroleum*, July 23, 2014. http://www.eia.gov/petroleum/weekly/archive/2014/140723/twipprint.html

Issues surrounding capacity expansion decisions

This report considers a range of expansion options that might be considered once the limited- to no-cost options described in the previous section are either no longer available, or if the expected margins (revenues less input and operating costs) available from processing additional domestic LTO volumes are more than sufficient to justify costs and risks associated with new capacity additions. Investment decisions are also likely to reflect factors such as scale, location, crude type availability, construction timelines, market risk, policy risk, and the expected value of petroleum product output slates. There are relationships among these considerations, for example, the tradeoffs between risk and scale.

U.S refiners opting to expand their LTO processing capacity are likely to find smaller-scale and lower-cost options the most attractive. The smallest-scale and lowest-cost option available is the addition of a brownfield stabilizer unit to an existing refinery. This option has the advantage of allowing refiners to process increased domestic LTO production with minimal exposure to the effects of decreased crude oil supply or petroleum product demand. However, other more expensive options described in this section might be more attractive to some refiners.

Market and policy risk

There are both market and policy risks associated with investments in expanding crude oil processing capacity. On the market side, the ability to make a return on investment from new refining capacity would be jeopardized if domestic LTO production growth does not continue at levels that enable pricing of LTO inputs that processors find attractive. Another area of market risk involves the amount of revenue that refineries can make from selling their petroleum product output. There is uncertainty surrounding how overseas demand for motor gasoline, particularly in Central America and South America, would respond to a significant rise in U.S. motor gasoline exports. If international motor gasoline prices decrease significantly, it could make distillation and secondary processing expansions uneconomical. Similarly, a decrease in the international naphtha price could make distillation-only expansions a significantly less attractive option for U.S. refiners.

Beyond these market risks, capacity investment projects are also subject to policy risk. In this case, these policy risks could result in a decrease of LTO supply or a reduction in petroleum product demand. The returns on such an investment could also be jeopardized by an increase in supply of non-LTO crude oil, which could more economically be processed at existing refineries in the United States and the rest of the world. This would result in lower petroleum product prices, and limit the return on investment in building capacity to produce domestic LTO.

A major policy risk of an investment in processing technology to take advantage of LTO supply availability might be the relaxation of current restrictions on U.S. crude oil exports.[16] Such a change in policy could cause the price of domestically produced LTO to increase, reducing the *ex post* economic returns to capacity added to process it into petroleum products. A relaxation of U.S. crude export restrictions could also cause the world crude oil price and the price of petroleum products in the United States and overseas to decrease, further decreasing the return on investments in capacity to process additional domestic LTO volumes at U.S. refineries.

[16] See Federal Regulations, Title 15: Commerce and Foreign Trade, §754.2: Crude Oil

Recognizing market and policy risks, investors may require a high annual interest rate over a short timeframe when considering investment in added capacity to process domestic LTO. For purposes of this study, perceived risk is assumed to cause potential investors to seek a higher expected annual interest rate (18% rather than 12%) over a shorter payback period (10 rather than 25 years). While these assumptions are adopted for all expansion projects, their impact is most significant for larger-scale, costlier projects, for which risks are generally highest.

Economies of scale

The scale of a facility affects its unit cost of production (i.e., price per unit volume), as well as its exposure to market risks. Large-scale projects will have higher overall capital outlays and, as a result, higher risk exposure. However, they also have lower unit production costs compared with similar smaller facilities, due to well-known economies of scale.[17] This phenomenon is based on the observation that as the size of an object increases, its volume increases by the cube of its radius, while the surface area increases by the square of its radius, often referred to as the "square-cube law." For capital projects, the throughput of a facility is related to volume while the costs are more closely related to its surface area. For example, if a spherical storage tank at a facility were to have its radius doubled, the cost of the materials that constitute the tank envelope would increase by four times, while the capacity of the tank would increase by eight times. The resulting 'scale factor' as described by the square-cube law in this example is 0.67, or an increase in cost that is two-thirds of the increase in capacity.[18],[19]

The lower unit costs of higher-capacity units must be weighed against the potentially substantial risks associated with their higher absolute cost and longer lead times. Both of these factors increase exposure to changes in the cost and availability of crude oil inputs and changing conditions in petroleum product markets. The inverse is true for similar facilities with a smaller capacity and shorter lead times.

Level of processing

Projects that result in low levels of crude oil processing, such as stabilizers and splitters, have lower costs due to a reduced level of equipment complexity. Although small-scale projects generally have higher unit costs because they do not benefit from economies of scale, stabilizer and splitter expansions can cost less per unit processed than larger projects because they are limited to building simple distillation units. The only larger distillation project that has a comparable cost per unit of volume processed to that of a splitter or stabilizer is a 250,000-bbl/d brownfield ADU column, largely because this unit also provides only initial distillation capacity.[20]

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[17] The cost advantage obtained due to size, output, or scale of operation.

[18] The scale factor is the exponent, 'b' that describes how costs change relative to the change in the volume or throughput of a process unit or facility. The specific equation is $C = C_o(Q/Q_o)^b$, where C and C_o are the cost of two different facilities that differ only by size, and Q and Q_o are the respective sizes of those two facilities.

[19] In practice, the cost and scale of a facility do not change at exactly the rates described above. Certain equipment items may reach practical limits of scale due to having complicated internal structures or due to limitations on capabilities to manufacture this equipment. EIA assumes a scale factor of 0.8 for refinery facilities based on reviews of empirical research. See, for example, L.B. Evans, A. Mulet, A.B. Corripio, and K.S. Chretien, "Costs of pressure vessels, storage tanks, centrifugal pumps, motors, distillation and absorption towers," *Modern Cost Engineering II*, Chemical Engineering Magazine, McGraw-Hill, New York (1984), pp. 140-146, 177-183; and Moore, Frederick T., "Economies of Scale: Some Statistical Evidence," *Quarterly Journal of Economics* (May 1959), pp. 232-245.

[20] The brownfield ADU column's unit cost is below that of a brownfield splitter, which provides some naphtha separation, but greater than that of a brownfield stabilizer, which provides only basic separation of naphtha and light gases.

However, while providing limited to no processing capacity beyond initial crude oil distillation will significantly lower a project's cost per unit of volume, it will also limit the value of its petroleum products. Minimally processed naphtha and other intermediate streams have value because they can be blended into motor gasoline, diesel, and other petroleum product pools after additional processing. Without this additional processing, the demand for these streams is generally limited to petrochemical producers, and other refiners that profit by purchasing these unfinished streams at a lower price than the finished petroleum products that they will be blended with. A refinery that contains more expensive and sophisticated equipment to process crude oil beyond simple distillation will have more demand for its output, a greater portion of which can likely be sold directly to end users. A simple comparison of cost and scale is thus not sufficient to determine which option will be most desirable to an existing refiner; the amount of additional revenue from selling finished or more processed petroleum products will also be a significant consideration. Refiners will also likely consider the longer lead time required for projects with a greater degree of post-distillation processing capacity, which increases the likelihood that market changes affecting their profitability will occur before construction is finished.

Other considerations

Location and availability of crude oil feedstock are among other considerations for investing in capacity expansion. Although greenfield projects have higher cost than similar projects that are done at an existing refinery, they also have the advantage of building at a location with potentially greater access to crude oil feedstock and/or end users. For example, while the Midwest could offer refiners advantageous access to Bakken LTO production, the Texas Gulf Coast offers advantageous access to light and very light streams from the Eagle Ford. While refineries in both regions can access petroleum product pipelines to take their finished products to end users, the Gulf Coast has more immediate access to export terminals, which can reduce costs and improve margins for a refinery that is built there.

Additionally, certain projects can only efficiently process particular feedstocks. Limitations on options regarding feedstock sourcing reduce the market power a facility has and exposes them to the risk of changes in feedstock costs. For example, stabilizers are primarily designed to distill the very light streams that are largely produced in the Eagle Ford in south Texas. Heavier crude oil feedstock will have large volumes that are essentially unprocessed, limiting the value for which it can be sold above its purchase price. As a result, changes in the price of very light streams from the Eagle Ford will affect the profitability of a stabilizer or splitter project, while full refinery, ADU, or hydroskimmer profitability will be much more affected by changes in the supply and demand of domestic LTO produced in the Bakken and Permian formations.

Capacity expansion options

Expanding only distillation capacity

It can be less expensive for refiners to add capacity to process additional domestic LTO volumes by building distillation units without the capacity to convert unfinished naphtha into finished products than by building facilities that do have such units. The drawback is that this unfinished naphtha is a lower-valued product stream than the finished petroleum products.

There are a number of options for expanding only distillation capacity, with costs that vary as a result of both scale and location.

Brownfield stabilizer (20,000 bbl/sd)

A 20,000-bbl/sd brownfield stabilizer is the least-expensive option for expanding distillation capacity, in both overall and per-barrel terms.

The brownfield stabilizer would have an overnight cost[21] of approximately $30 million, or $1,390 per barrel per stream day (bbl/sd).[22] This would result in amortized capital cost[23] of $0.63 per barrel ($/bbl) when assuming a 12% annual interest on investment and a 25-year investment payback period, or $1.16/bbl assuming 18% annual interest over a 10-year investment payback period, with both scenarios assuming that the facility processes crude oil at 85% of full stream-day capacity over the payback period.

Stabilizers only remove very light gases and liquids from the crude oil stream, reducing its volatility to the point where it can be transported on a pipeline. For that reason, stabilizers are often built on a crude oil production lease, but can also be built at refineries. Because naphtha-range products are not separated from the remainder of the crude stream, the processed stream would have to be sold to petrochemical manufacturers, reprocessed to separate naphtha, or sold to refineries for further processing into finished products. These refineries could be in the United States or overseas. A recent regulatory clarification from the U.S. Department of Commerce Bureau of Industry and Security (BIS) allows export of processed condensate from stabilizer facilities.[24] Martin Midstream had planned a splitter project in Corpus Christi, but the company has indicated interest in modifying this project to include only a stabilizer following the BIS clarification.[25]

A stabilizer built in a refinery would most likely be intended to permit additional LTO processing in the refinery itself, rather than producing processed streams for export. Considerations in the economics of a stabilizer would include transportation infrastructure such as available pipelines, storage terminals, and export terminals. Although the stabilizer's smaller capacity and lower construction cost provides less exposure to market and policy risk, there is some risk that the revenue received from selling its minimally processed naphtha to overseas markets is affected by changes in unfinished product prices.

Stabilizers, in the context of this paper, would be designed to process very light streams like those produced in the Eagle Ford region in south Texas. Such a unit could also process heavier input streams without significant change in unit throughput, but the resulting intermediate stream would require a significantly greater amount of processing to be refined into finished products.

Brownfield splitter (50,000 bbl/sd)

Processing LTO in a 50,000-bbl/sd brownfield splitter would also lead to an increase in unfinished naphtha

[21] Overnight cost is the cost of a project with no interest incurred, or the lump sum cost of a project if it were completed overnight.
[22] The cost of a facility divided by the number of barrels processed in one 24-hour day at full operating capacity.
[23] The revenue required per barrel of crude oil processed at a facility (or intermediate streams if the facility is secondary-capacity-only) to pay off the total project cost plus the required annual interest on investment by the end of a project's determined payback period.
[24] U.S. Department of Commerce, Bureau of Industry Security, "FAQs – Crude Oil and Petroleum Products", December 30, 2014, http://www.bis.doc.gov/index.php/policy-guidance/faqs?view=category&id=114#subcat171.
[25] "Martin: Splitter plan 'continues to evolve'," *Argus (*July 31, 2014). http://www.argusmedia.com/Events/Argus-Events/Americas/Condensate-and-Naphtha/Splitter-plan-continues-to-evolve.

volumes. Like the brownfield stabilizer, it could be built with minimal preparation costs if it was located at an existing refinery or terminal. The brownfield splitter's larger capacity would provide for some economies of scale, but also more exposure to market and policy risks at a higher upfront capital cost than a brownfield stabilizer.

The brownfield splitter would have an overnight cost of approximately $100 million, or $2,060/bbl/sd. This would result in an amortized capital cost of $0.94/bbl, assuming a 12% annual interest on investment and a 25-year investment payback period, or $1.73/bbl, assuming 18% annual interest over a 10-year investment period, with both scenarios assuming that the facility processes crude oil at 85% of full stream-day capacity over the payback period.

A brownfield splitter's relatively higher cost is not only due to its larger capacity, but also due to its complexity, which allows it to separate the input stream into unfinished intermediate streams that can be sold for greater revenue. The output from a typical splitter might include fuel gas, light naphtha, heavy naphtha, distillate, and a small amount of residual fuel oil. Like the brownfield stabilizer, a brownfield splitter's access to an export terminal would be an important economic consideration. Table 2 lists new splitter projects. Many of these projects are located at existing refineries near export terminals, including all of those located in Corpus Christi and Port Arthur, Texas.

Greenfield splitter (50,000 bbl/sd)

Building a 50,000-bbl/sd greenfield splitter would be significantly more expensive than building a similar-sized brownfield splitter. Because the greenfield splitter would not be located at an existing refinery or terminal, it would require investments in production area setup and auxiliary equipment that are not included in the cost of a brownfield project.

A greenfield splitter would cost approximately $140 million, or $2,830/bbl/sd. This would result in an amortized capital cost of $1.30/bbl, assuming a 12% annual interest on investment and a 25-year investment payback period, or $2.39/bbl assuming 18% annual interest over a 10-year investment payback period, with both scenarios assuming that the facility processes crude oil at 85% of full stream-day capacity over the payback period.

The costs assumed in this report for a greenfield splitter and stabilizer are likely higher than the actual costs, since the project does not have to be fully greenfield. A greenfield splitter and stabilizer could be located at an industrial site where some investment has already been made in site preparation and auxiliary equipment. For example, because the Kinder Morgan projects in Galena Park, Texas (Table 2) are being built on an industrial site, they will benefit from already having access to pipelines transporting very light Eagle Ford streams, among other in-place infrastructure. Building splitters at industrial sites would be attractive to refiners that do not operate full refineries near export terminals where brownfield splitters can be built.

Table 2. New splitter projects in the United States

Project	Capacity (Mbbl/sd)	State	Cost ($MM)	Completion	Status
Total/BASF - Port Arthur	75	Texas	300[e]	2000	completed
Kinder Morgan - Galena Park	50	Texas	180	2015	under construction
Kinder Morgan - Galena Park	50	Texas	180	2016	under construction
Kinder Morgan - Galena Park	50	Texas	200[e]	2017	proposed
Marathon - Canton	25	Ohio	180	2015	under construction
Marathon - Catlettsburg	35	Kentucky	150	2016	FEED
Buckeye/Trafigura – Corpus Christi	50	Texas	200	2016	proposed
CCI – Corpus Christi	100	Texas	500	2016	FEED
Targa - Houston Ship Channel	35	Texas	115	2017	FEED
Magellan – Corpus Christi	50	Texas	250[e]	2017	proposed
Magellan – Corpus Christi	50	Texas	200[e]	2018	proposed
Phillips 66 – Sweeny	75	Texas	242	2018	proposed
Total splitter projects	645		2,697		
Completed or under construction	200		840		
FEED	170		765		
Proposed	275		1,092		

Source: U.S. Energy Information Administration, compiled from industry sources as of January 2015.
Note: Mbbl/sd = thousand barrels per stream day; MM = million; [e] = Estimated costs, when stated costs not available from news reports or company filings; FEED = Front-end engineering design.

Brownfield atmospheric distillation unit (250,000 bbl/sd)

If a refiner wanted to make a significant commitment to processing additional volumes of domestic LTO production and was willing to make a large upfront capital investment in order to benefit from greater economies of scale, it would likely consider building a brownfield atmospheric distillation unit (ADU) of significant capacity (250,000 bbl/sd). Both this unit's large scale and the fact that it does not provide any secondary processing capacity contribute to its very low cost per unit of volume processed. However, it also means that this project is very exposed to market and policy changes that result in a decrease of LTO supply, an increase in non-LTO crude supply, or a reduction in petroleum product demand. Because the new ADU produces unfinished intermediate steams, it may provide only a limited amount of additional revenue per barrel of crude oil processed. If there were either low demand for naphtha from the petrochemical industry or high demand for petroleum products from domestic or overseas consumers, there could be advantages in investing in secondary units to process the large volumes of unfinished intermediate streams from a brownfield ADU into finished products.[26]

The brownfield ADU would have an overnight cost of approximately $370 million, or $1,500/bbl/sd. This would result in an amortized capital cost of $0.70/bbl assuming a 12% annual interest on investment and a 25-year investment payback period, or $1.31/bbl assuming an 18% annual interest on investment and a 10-year investment payback period, with both scenarios assuming that the facility processes crude oil at 85% of full stream-day capacity over the payback period.

[26] Options for standalone secondary processing or hydroskimmer and full refinery projects are considered below.

Secondary processing capacity investment options

Secondary processing units receive feedstock primarily from the ADU for upgrading into finished products. The lack of sufficient secondary unit processing capacity to process all of the light product streams does not necessarily constrain the throughput of the distillation process, but it could limit the amount of unfinished light product streams that could be processed into valuable finished products like motor gasoline, jet fuel, or diesel fuel. Refiners can build new secondary processing units to accompany many of the distillation capacity expansions described in the previous section.

This paper considers two options for secondary processing capacity, isomerization and continuous catalytic reformer (CCR) units.

Brownfield isomerization unit (20,000 bbl/sd)

Isomerization units process very light hydrocarbons distilled at temperatures below 180°F.[27] Isomerization units primarily convert low-octane, straight-chained molecules such as pentane (C_5) and hexane (C_6) into branched molecules. Doing so significantly increases their octane ratings,[28] and allows the transformed molecules to increase the octane level of the motor gasoline pool they are blended into (an octane premium) rather than decreasing its octane level (an octane penalty).

The brownfield isomerization unit would have an overnight cost of approximately $110 million, or $5,250/bbl/sd. This would result in an amortized capital cost of $2.38/bbl, assuming a 12% annual interest on investment and a 25-year investment period, or $4.37/bbl assuming 18% annual interest over a 10-year investment payback period, with both scenarios assuming that the facility processes crude oil at 85% of full stream-day capacity over the payback period.

Brownfield continuous catalytic reformer (CCR) unit (50,000 bbl/sd)

Although CCR units have a significantly lower per-barrel cost than isomerization units, they are designed to process heavier naphtha that is distilled at temperatures between 180°F and 400°F. Like an isomerization unit, a reformer increases the octane rating of straight-chained naphtha molecules by converting them into branched molecules. It can also convert them into cyclic and aromatic molecules.

The CCR would have an overnight cost of approximately $150 million, or $3,000/bbl/sd. This would result in an amortized capital cost of $1.40/bbl assuming a 12% annual interest on investment and a 25-year investment period, or $2.61/bbl assuming 18% annual interest over a 10-year investment payback period, with both scenarios assuming that the facility processes crude oil at 85% of full stream-day capacity over the payback period.

Expanding both distillation and secondary processing capacity

New, fully equipped distillation facilities that include secondary processing units would enable U.S. refiners to process additional crude oil volumes, and convert these higher distillation volumes into finished petroleum products. These finished petroleum products would generate greater revenue than the unfinished naphtha produced at a distillation-only capacity expansion, and could either be sold to domestic consumers or exported. However, like the other options previously discussed, this option faces significant policy risk since the lessening of crude oil export restrictions would likely raise the price of LTO to domestic refiners. It also

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[27] This refers specifically to C_5 and C_6 molecules, and not C_8 molecules, which can be isomerized after being distilled at higher boiling temperatures.

[28] The octane rating for pentane increases from 62 to 90 when it is converted from straight-chained pentane to branched iso-pentane. The octane rating for hexane increases from 25 to 92 when it is converted from straight-chained hexane to branched iso-hexane.

faces significant risk from market factors impacting the LTO and non-LTO production, and petroleum product prices.

Although there is significant upside to processing LTO into higher-value finished products, there is also a greater degree of risk from both crude oil supply and petroleum product demand. These risks are augmented by the fact that projects to provide both distillation and secondary processing capacity have a longer lead time, taking three years to build compared to two years or less for all of the distillation-capacity-only expansions. This increases the level of uncertainty about what crude oil and petroleum product markets will look like once construction is finished. Lastly, refiners would also weigh the benefit of additional revenue from adding both distillation and secondary processing capacity against the higher costs that come with having more sophisticated secondary processing equipment.

Hydroskimmer refinery

A hydroskimmer refinery (also known as a topping-reforming refinery) consists of an ADU to distill light crude oil and a modest set of secondary processing units, including a reformer. The basic design of a hydroskimmer refinery's topping and secondary units make it less expensive and better-suited for processing domestic LTO production than a complex refinery that contains more processing units. A hydroskimmer would contain an ADU and secondary units like hydrotreaters and a reformer, but not heavier processing units like crackers and cokers, or isomerization and other treatment units. The hydroskimmer's limited upgrading complexity would limit both its cost and its risk exposure when compared to a full refinery.

A hydroskimmer's cost per unit of volume processed is higher than that of larger and simpler distillation-only units. However, a hydroskimmer's hydrotreater and reformer units allow it to produce diesel fuel, kerosene, and reformate and natural gasoline for blending with motor gasoline. The motor gasoline blending components from a hydroskimmer have a greater market value than the unfinished naphtha from a distillation-only unit. These motor gasoline blending components provide the hydroskimmer refinery with a relatively greater stream of revenue than distillation-only expansions, despite greater exposure to changes in domestic and world petroleum product demand.

A 100,000-bbl/sd brownfield hydroskimmer would be the least-expensive option for expanding both ADU and secondary unit capacity. It would not include the costs for production area setup, auxiliary equipment, or utilities that would be included if the hydroskimmer were built as a greenfield project. The overnight cost of a 100,000-bbl/sd brownfield hydroskimmer is approximately $530 million, or 5,280/bbl/sd. This would result in an amortized capital cost of $2.64/bbl assuming a 12% annual interest on investment and a 25-year investment payback period, or $5.06/bbl assuming 18% annual interest over a 10-year investment payback period, with both scenarios assuming that the facility processes crude oil at 85% of full stream-day capacity over the payback period.

The cost of a greenfield hydroskimmer refinery is higher than the brownfield because of the costs associated with site preparation. A greenfield hydroskimmer refinery would have an overnight cost of approximately $720 million, or $7,170/bbl/sd. This would result in an amortized capital cost of $3.59/bbl assuming a 12% annual interest on investment and a 25-year investment payback period, or $6.87/bbl assuming 18% annual interest over a 10-year investment payback period, with both scenarios assuming that the facility processes crude oil at 85% of full stream-day capacity over the payback period.

An industrial area where some site preparation has already occurred is another siting possibility for a new hydroskimmer refinery. Therefore, the costs for a greenfield or brownfield unit, shown in Table ES-1, represent a range. Currently, Valero is building topping units at its existing refineries in Houston and Corpus Christi, respectively (Table 3). These units are principally designed to process very light Eagle Ford streams into naphtha and jet fuel, as well as some volumes of diesel fuel and motor gasoline.[29]

Table 3. New hydroskimmer projects in the United States

Project	Capacity (Mbbl/sd)	State	Cost ($MM)	Completion	Status
Valero – Houston	90	Texas	400	2016	under construction
Valero – Corpus Christi	70	Texas	350	2016	under construction
Total hydroskimmer	160		750		

Source: U.S. Energy Information Administration, compiled from industry sources as of January 2015.
Note: Mbbl/sd = thousand barrels per stream day; MM = million.

Full greenfield refinery

Building an entirely new 250,000-bbl/sd greenfield refinery is the most expensive option for expanding both distillation and secondary processing capacity, as well as the most expensive option overall. It has the highest equipment costs, and because it is a greenfield project, would also have higher costs for production area setup and auxiliary equipment. A greenfield refinery's 250,000-bbl/sd capacity means that it has the greatest amount of exposure to market and policy risks that impact both LTO supply and petroleum product demand.

However, a full greenfield refinery would yield the most additional revenue for a refiner, because it would have the greatest capacity to produce finished petroleum products. As with all the other projects listed, its cost in terms of upfront investment and its higher risk exposure would have to be weighed against the additional revenue-generating potential from producing finished products. In addition, the risk of building such a facility would be relatively limited by the fact that its wide array of sophisticated secondary processing equipment would allow it to produce a more diverse pool of finished products, limiting the degree to which its profitability is impacted by changes in the demand for any individual petroleum product.

Although the fact that a new refinery would have to be fully greenfield will increase its construction cost, it also provides for flexibility in terms of where it can be built. While there could be advantages to building a full greenfield refinery on the Gulf Coast, where it could access production from the Permian Basin and benefit from its proximity to overseas petroleum product markets, it could also be built in the Midwest or Rocky Mountain regions, where it could benefit from greater access to Bakken production.

A fully greenfield refinery would have an overnight capital cost of approximately $3,390 million, or $13,540/bbl/sd. This would result in an amortized capital cost of $6.78/bbl assuming a 12% annual interest on investment and a 25-year investment payback period, or $12.98/bbl assuming 18% annual interest over a 10-year investment payback period, with both scenarios assuming that the facility processes crude oil at 85% of full stream-day capacity over the payback period.

[29] Valero Investor Presentation, January 2015. http://valero.investorroom.com/download/VLO+IR+2015+Jan+FINAL+1-2-15.pdf.

Appendix: Estimation of Construction Costs

This appendix details the EIA refinery construction cost estimates for facilities built to process light crude oil, condensate, intermediate streams, or some combination of these. Methodologies and general assumptions are presented first, followed by a description of baseline brownfield cost estimates for standard refinery processing units. Next, greenfield capital costs for a new refinery designed for processing heavy and ultra-light crude oil types are discussed, followed by a discussion of greenfield splitter capital costs, and the cost of building a greenfield hydroskimmer refinery.

General methodology and assumptions

Baseline project cost estimates include the cost of each unit's base capacity, after it is adjusted according to the project configuration. Each project configuration was determined through a refinery-yield-based, profit-optimization analysis based on a fixed crude oil assay, or distribution of intermediate distillation streams.[30],[31] Three specific crude oil types were used in designing the refinery options:

- Crude oil with an API gravity of 19.9
- Crude oil with a 45.2 API gravity
- Crude oil with a 55.6 API gravity

The capacity adjustments based on these crude types are used to determine each project's "overnight cost," or the cost before interest. This includes not only construction costs, but also the cost of acquiring initial catalyst feed for those units that require it, and any applicable greenfield construction costs for production area setup and auxiliary equipment.[32] Each project's volumetric overnight cost is equal to the overnight cost divided by the full stream-day capacity, or the number of barrels of crude oil that a facility can process assuming full operations over a 24-hour period. The volumetric overnight cost is measured in dollars per barrel per stream day ($/bbl/sd).

The amortized capital cost per barrel is the average amount that must be made per barrel of crude oil processed to pay the project cost plus the interest accrued over a project's payback period. The total project cost is higher than the overnight cost because it includes interest that is paid during the construction phase. Construction loans are assumed to be made in three tranches, following a 20/30/50 draw schedule, with 20% of the loan drawn in period one, 30% in period two, and 50% in period three. The period after which a new tranche of the loan is drawn and interest is paid on any previous tranches is adjusted for the length of the project's construction timeline. For example, a three-year project to build a full greenfield refinery for the second of the three streams identified above will have its three tranches drawn and compounded in one-year intervals, while a two-year project to build a splitter optimized for the third of the three streams identified above will have its three tranches drawn and compounded in eight-month intervals. The annual interest rate remains the same for both projects, but the accumulated interest for the splitter is one-third less than if it were done over three years, because each tranche accumulates in eight monthly installments instead of 12.

[30] *Perry's Chemical Engineer's Handbook*, E. Ackers, D. Green, and R. Perry, McGraw-Hill Publication, 8th ed., 2007.
[31] *Plant Design and Economics for Chemical Engineers*, M. Peters, K. Timmerhaus, and R. West, McGraw-Hill Higher Education, 4th edition, 1990.
[32] Initial catalyst feed, project area setup, and auxiliary equipment costs are assumed to be equal to 5%, 12%, and 25% of the base overnight cost for each unit, respectively.

Using the total project cost, the amortized capital cost per barrel is derived by assuming that project expenses are repaid at a required annual interest rate over a project's payback period. For illustrative purposes, this section presents the amortized capital cost that is calculated assuming a 12% annual interest rate and a 25-year payback period for all projects. Accrued interest is added to the total project cost to derive the amortized capital cost, which is determined on a per-barrel basis by dividing by the number of barrels of crude oil that a facility would process over the payback period if it were operating at a utilization rate equal to 85% of its full stream-day capacity. The 85% utilization rate is assumed in order to account for both scheduled downtime and any additional downtime required for maintenance.

Table 4 (Appendix). U.S. refinery expansion options for handling increasing light tight oil volumes

Option	Project type	Processing capacity type	Processing capacity (Mbbl/sd)	Overnight total cost ($MM)	Overnight volumetric cost ($/bbl/sd)	Amortized capital cost ($/bbl)
1 - Greenfield refinery (ultra-light)	greenfield	distillation and secondary	250	$3,390	$13,540	$6.78
2 - Single atmospheric distillation column	brownfield	distillation	250	$370	$1,500	$0.70
3 - Splitter	greenfield	distillation	50	$140	$2,830	$1.30
4 - Splitter	brownfield	distillation	50	$100	$2,060	$0.94
5 - Stabilizer	brownfield	distillation	20	$30	$1,390	$0.63
6 - Continuous Catalytic Reformer unit	brownfield	secondary	50	$150	$3,000	$1.40
7 - Isomerization unit	brownfield	secondary	20	$110	$5,250	$2.38

Sources: U.S. Energy Information Administration, Independent Project Analysis, Inc.
Note: Mbbl/sd = thousand barrels per stream day, or the maximum volume that a distillation facility can process in a 24-hour period under optimal conditions with no allowance for downtime; $/bbl = dollars per barrel; $/bbl/sd = dollars per barrel per stream day; MM = million. Overnight cost is the cost of a project with no interest incurred, or the lump sum cost of a project if it were completed overnight. Amortized capital cost is the revenue per barrel processed needed to pay the cost of the project over a 25-year period with a 12% annual interest rate, with the facility operating at a utilization rate of 85% of full stream-day capacity

Baseline – Brownfield refinery unit costs

EIA developed a cost baseline for refinery processing units that might exist in a typical USGC 250,000-bbl/sd refinery that processes an average USGC crude oil assay. The overnight or pre-interest costs of the refinery processing units are based on estimates developed by Independent Project Analysis, Inc. (IPA). EIA commissioned a study from IPA to validate the costs used for various refinery units modeled in EIA's Liquid Fuels Market Module and for analytic purposes. The IPA costs were limited to refinery additions and did not include production area setup, the cost of auxiliary expenses, or start-up costs such as the purchase of initial catalyst feed. EIA then added other units and adjusted capacities to be consistent with a typical 250,000-bbl/sd refinery to protect IPA's proprietary information. The cost for each unit that is added as part of a brownfield project at an existing refinery is shown in Table 5.

Table 5 (Appendix). Brownfield project total costs

	Construction	Nameplate	Overnight cost	
	duration	capacity	Total	Volumetric
Description	Months	Mbbl/sd	2013 $MM	2013 $/bbl/sd
Atmospheric crude distillation	24	250	$370	$1,500
Vacuum crude distillation	24	140	$150	$1,100
Naphtha hydrotreater unit	30	60	$110	$1,940
Kerosene hydrotreater unit	18	50	$140	$2,940
Hydro-desulfurization	18	50	$160	$3,440
Fluid catalytic cracking unit	30	60	$150	$2,630
Hydrocracking unit	24	40	$280	$7,270
Delayed coker unit	24	60	$440	$7,380
Continuous Catalytic Reformer unit	24	50	$140	$3,000
Alkylation unit	18	15	$230	$15,960
C_5/C_6 isomerization unit	18	20	$100	$5,250
Aromatic extraction unit	24	20	$610	$30,550
Integrated sulfur removal (capacity LT/SD)	30	1,000	$210	$220
Splitter	18	50	$100	$2,060
Naphtha stabilizer (no stripper)	18	20	$30	$1,390
Gas plant and hydrogen unit	24	40	$200	$5,250

Sources: U.S. Energy Information Administration, Independent Project Analysis, Inc.
Note: Mbbl/sd = thousand barrels per stream day; MM = millions; $/bbl/sd = dollars per barrel per stream day, or the total cost divided by the number of barrels produced in one 24-hour day of operating at full capacity. Overnight cost is the cost of a project with no interest incurred, or the lump sum cost of a project if it were completed overnight.

Greenfield refinery capital cost estimate

EIA developed comparative capital cost estimates for two crude oil types to assess the upper bounds for the cost of building an entirely new refinery. The lower bound came from the construction of a refinery designed to process Bakken 42.3 API gravity crude oil, with no additional units to convert residual fuel oil into additional petroleum product volumes. The upper bound came from a refinery designed to process Maya 19.9 API gravity crude, with all units needed for secondary processing of its residual fuel oil into additional petroleum product volumes. Because of the variation in refinery designs, it is unlikely that every processing unit in Table 6 would be found in every refinery, as this study assumes, based on the processing units detailed in Figures 3 and 4.

Table 6 (Appendix). Greenfield refinery total project costs

	Heavy Crude		Ultra-Light Crude	
	Built capacity	Overnight cost	Built capacity	Overnight cost
Description	**Mbbl/sd**	**2013 $MM**	**Mbbl/sd**	**2013 $MM**
Atmospheric crude distillation	250	$370	250	$370
Vacuum crude distillation	110	$130	N/A	--
Naphtha hydrotreater unit	50	$100	100	$170
Kerosene hydrotreater unit	70	$180	100	$240
Hydro-desulfurization	30	$110	40	$140
Fluid catalytic cracking unit	90	$210	40	$110
Hydrocracking unit	70	$430	N/A	--
Delayed coker unit	40	$320	N/A	--
Continuous Catalytic Reformer unit	50	$140	50	$140
Alkylation unit	20	$290	20	$290
C_5/C_6 isomerization unit	20	$100	20	$100
Aromatic extraction unit	20	$610	20	$610
Integrated sulfur removal (capacity LT/SD)	1,400	$280	100	$30
Naphtha stabilizer and stripper	40	$90	50	$100
Gas plant and hydrogen unit	40	$200	20	$110
Auxiliary equipment	250	$890	250	$610
Production area setup	250	$430	250	$290
Initial feed and catalyst loading	250	$180	250	$70
Total overnight cost		**$5,050**		**$3,390**
Accrued interest during construction		$1,100		$740
Total project cost ($MM)		**$6,140**		**$4,120**
Volumetric ($/bbl/sd)		**$24,570**		**$16,490**
Amortized capital cost ($/bbl)		**$10.10**		**$6.78**

Source: U.S. Energy Information Administration.
Note: Mbbl/sd = thousand barrels per stream day; $/bbl/sd = dollars per barrel per stream day, or the total cost divided by the number of barrels produced in one 24-hour day of operating at full capacity; $/bbl = dollars per barrel; MM = million. Overnight cost is the cost of a project with no interest incurred, or the lump sum cost of a project if it were completed overnight. Construction interest is based on a 12% annual interest rate, with 20% of the loan drawn in year one, 30% in year two, and 50% in year three. The volumetric cost is based on total project cost divided by the number of barrels of crude oil processed assuming full operations over a 24-hour period. Amortized capital costs based on 12% annual interest over 25 years, with the facility operating at a utilization rate equal to 85% of full stream-day capacity.

For processing ultra-light crude oil, the vacuum crude distillation, hydrocracking, and delayed coker units are not required, decreasing the project cost by $880 million compared to that of the heavy crude refinery. A significant ($100 million) cost reduction also occurs from reducing the size of the fluid catalytic cracking unit by more than half when running an ultra-light crude oil. The requirement for integrated sulfur removal is significantly reduced, lowering the cost by another $240 million. The lower project cost for the light crude refinery decreases accrued construction interest by $360 million. However, there are other cost increases that occur when designing a refinery to process ultra-light crude oil. These include $70 million for doubling the naphtha hydrotreater capacity and $60 million for increasing the size of the kerosene hydrotreater by slightly over 40%. Also, the cost of hydro-desulfurization for the light crude refinery increases by $30 million.

Splitter greenfield capital cost

A splitter produces four product streams from a 55.6 API gravity input stream: fuel gas, light naphtha, heavy naphtha, and distillate (Figure 5). Splitters can provide feedstock for the chemical industry in the United States or for export. The design selected is flexible enough to accommodate inputs from both natural gas and crude oil facilities. Splitters can also be used to remove light intermediate streams from heavier input streams, such as light tight oil, before sending the heavier fractions to refiners. This helps reduce bottlenecks at the crude distillation units. For the purpose of this analysis, additional assumptions included the following:

- The splitter is designed to process Eagle Ford 55.6 crude oil.
- No units are required for sulfur removal.

EIA estimates that a 50,000-bbl/sd greenfield splitter plus stabilizer would have an overnight cost of approximately $140 million, or $2,830 per barrel per stream day (bbl/sd). This would result in an amortized capital cost of $1.30/bbl assuming a 12% annual interest rate and a 25-year payback period, and that the splitter operates at 85% of its full stream-day capacity. This cost is not directly comparable to the greenfield refinery cost because the splitter would be designed to process Eagle Ford 55.6 crude oil, whereas the greenfield refinery would be designed to process Bakken 42.3. In addition, the splitter contains no secondary processing units, and would be built over two years instead of three.

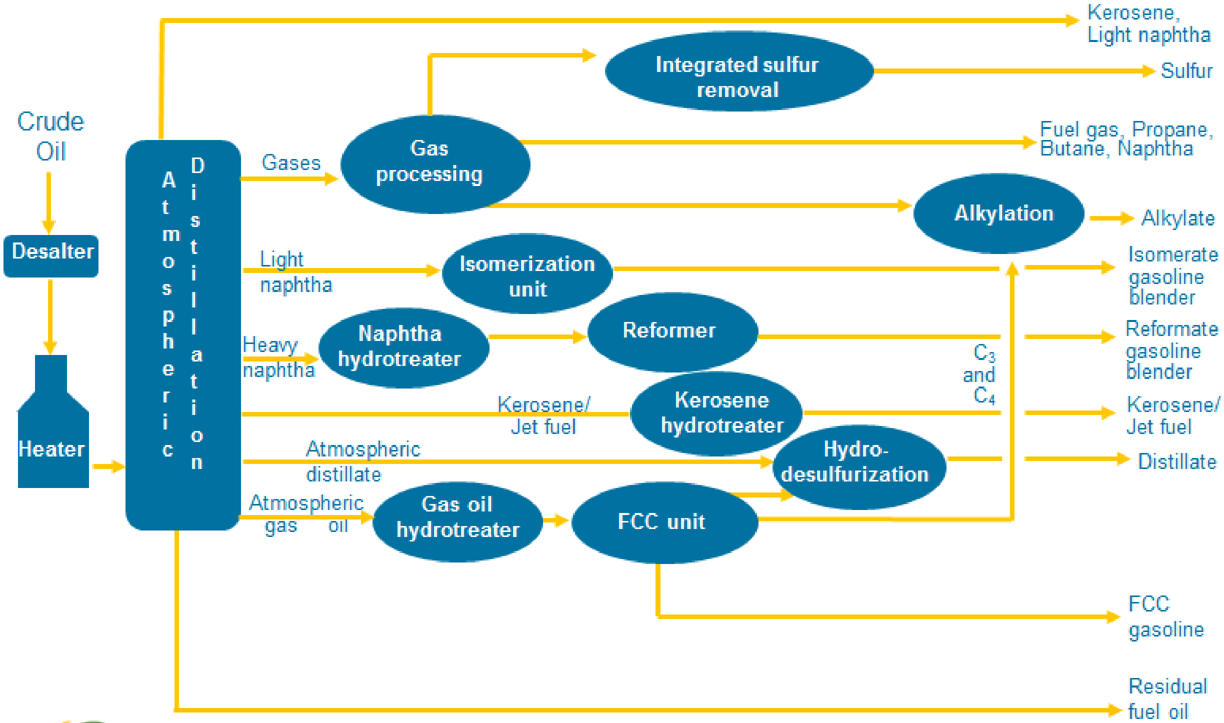
Hydroskimmer greenfield and brownfield capital costs

A hydroskimmer (also known as a topping reforming refinery) produces the same four product streams as a splitter, but includes secondary units that provide additional refining to produce reformate and light naphtha for motor gasoline blending, as well as kerosene jet fuel and diesel fuel (Figure 6). The hydroskimmer is designed to process a similar feedstock as the ultra-light-crude greenfield refinery. Its 100,000-bbl/sd capacity is less than a full refinery or a splitter, and it includes some but not all of the secondary processing units contained at a full refinery. In addition to its distillation tower, a hydroskimmer includes:

- heavy naphtha hydrotreater unit
- light naphtha hydrotreater unit
- kerosene hydrotreater unit
- diesel hydrotreater unit
- naphtha reformer unit
- gas processing unit

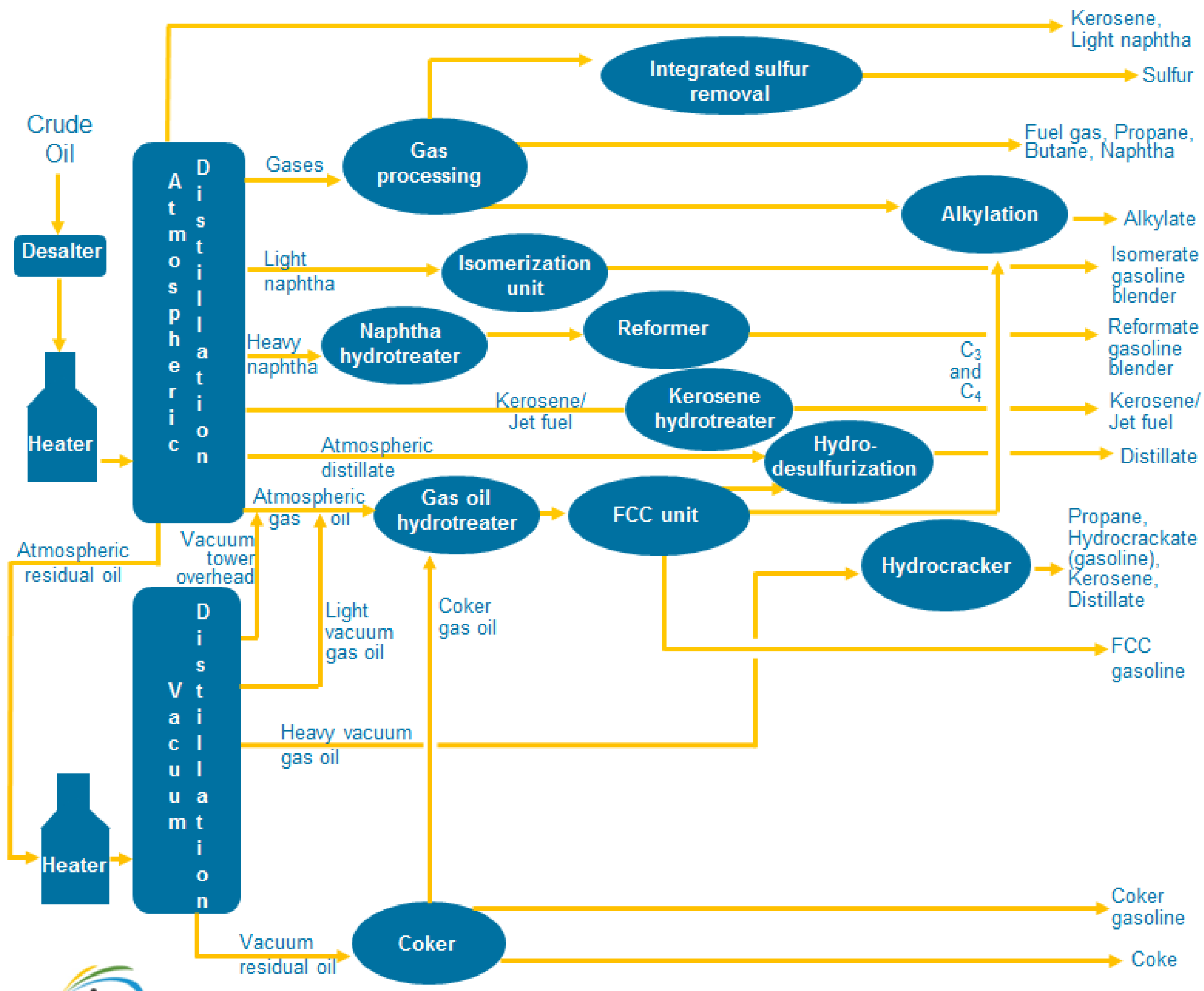
EIA estimates that a 100,000-bbl/sd greenfield hydroskimmer refinery would have an overnight cost of approximately $720 million, or $7,170/bbl/sd. This would result in an amortized capital cost of $3.59/bbl assuming a 12% annual interest rate over a 25-year payback period, and that the greenfield hydroskimmer operates at 85% of its full stream-day capacity. EIA estimates that a 100,000-bbl/sd brownfield hydroskimmer refinery would cost $530 million ($5,280/bbl/sd) or $2.64/bbl assuming a 12% annual interest rate over a 25-year payback period, and that the brownfield hydroskimmer operates at 85% of its full stream-day capacity.

Figure 3 (Appendix). Units at a refinery designed to process light crude oil



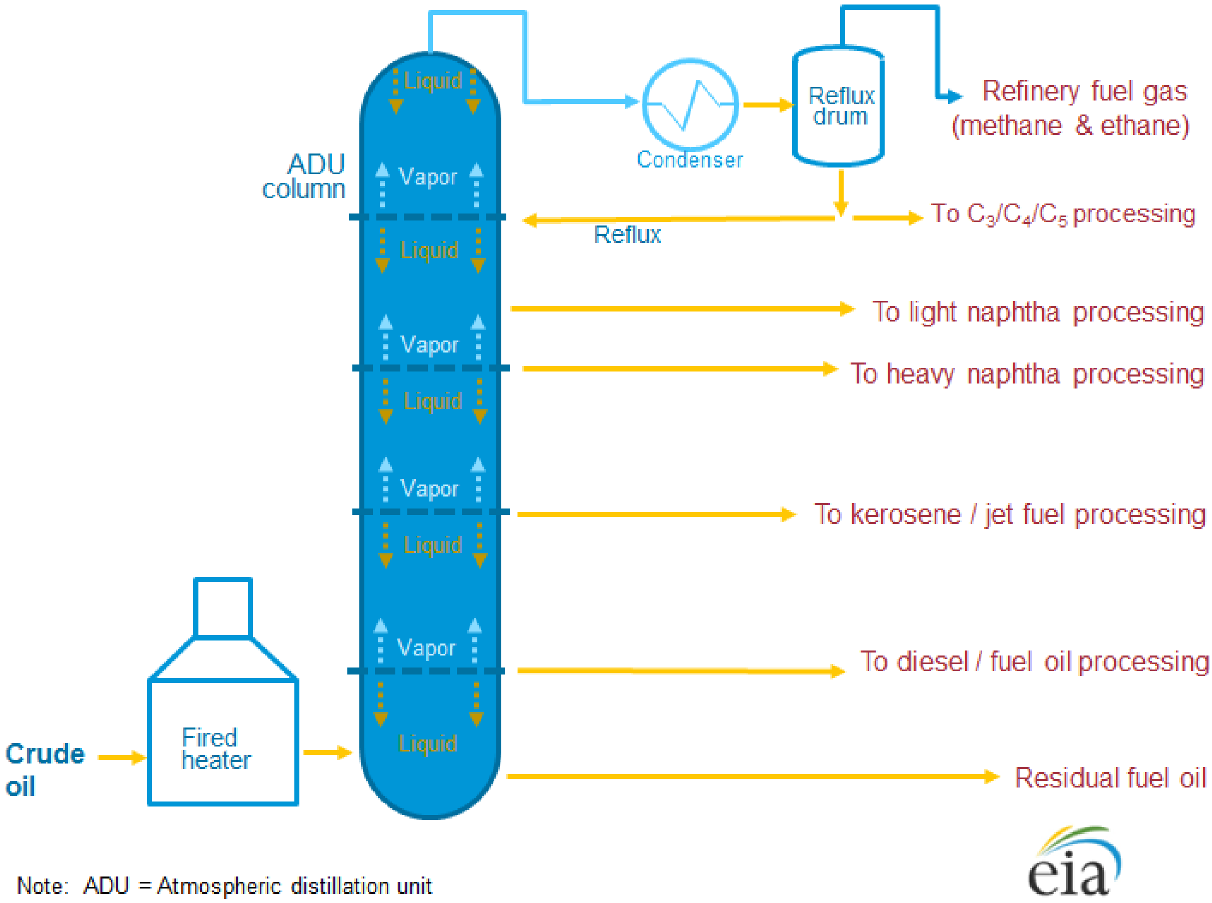
Source: U.S. Energy Information Administration.

Figure 4 (Appendix). Units at a refinery designed to process heavy crude oil



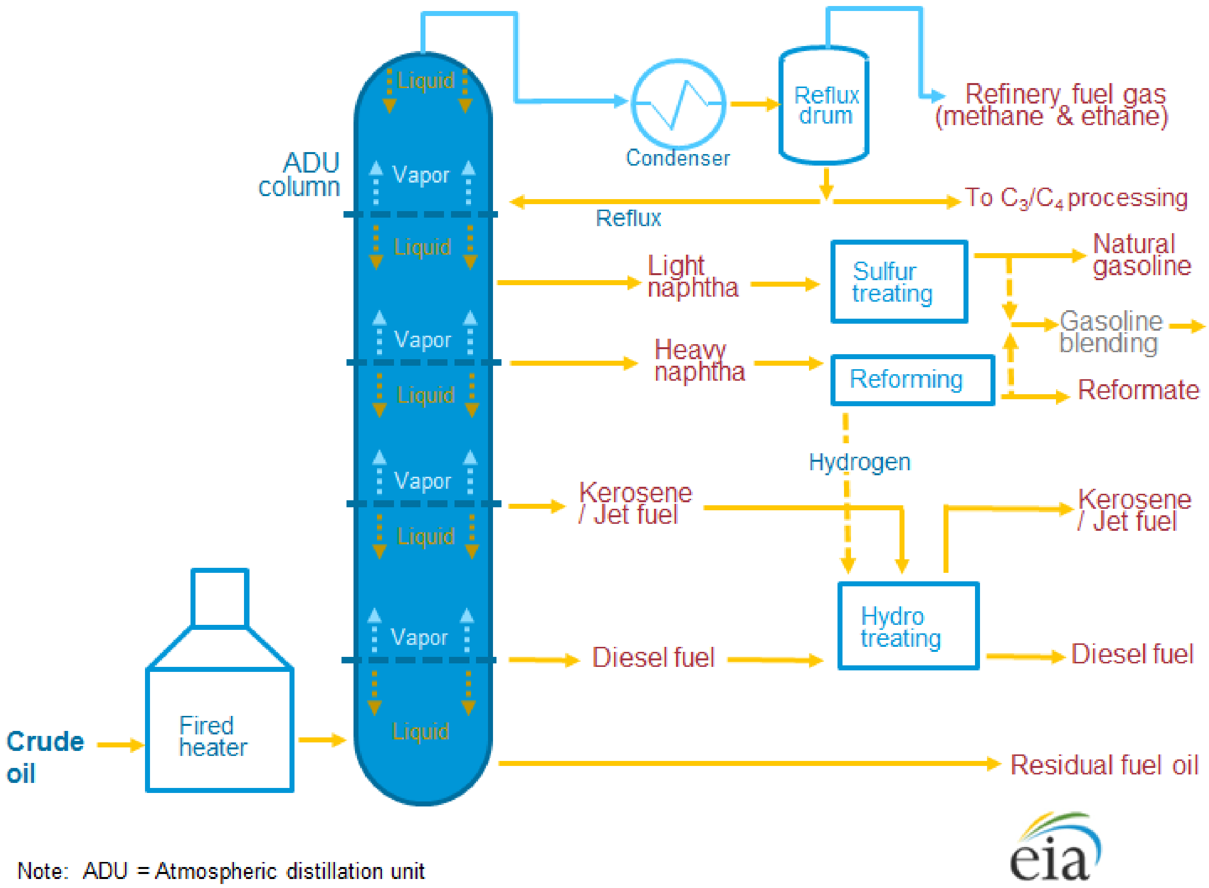
Source: U.S. Energy Information Administration.

Figure 5 (Appendix). Splitter design



Note: ADU = Atmospheric distillation unit
Source: U.S. Energy Information Administration

Figure 6. (Appendix). Crude hydroskimmer design



Note: ADU = Atmospheric distillation unit
Source: U.S. Energy Information Administration