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Small Refineries and Oil Field Processors: Opportunities and Challenges

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Summary

The last refinery constructed in the United States opened in 1977. Since the mid-1980s, some 150 have closed as part of an industry-wide consolidation. Over the same time, the remaining refineries expanded their operational capacity by 23% to keep up with increasing demand. Current U.S. refining capacity appears to satisfy if not exceed demand as the increasing export of refined petroleum products would seem to suggest. Notwithstanding the current surplus capacity, opportunities for new refineries appear to have emerged as the result of the rise in production of U.S. light-sweet crude oil from unconventional resources such as North Dakota's Bakken and Texas' Eagle Ford formations. These new resources have revitalized some refinery operations that formerly depended on imported light crude oil, thereby making the smaller refineries more competitive with large refineries that process more widely available heavy-sour crude oil. Rising domestic crude oil production has not only led U.S. refineries to export their petroleum products, but has led some oil producers to attempt to bypass refining and export crude oil condensates directly. However, Department of Commerce regulations currently restrict crude oil exports. Whether condensates fall under a refined product classification or crude oil remains an unresolved issue, and one that Congress may choose to take up. Congress may also consider whether small businesses face inherent disadvantages in entering an industry dominated by large complex refinery operators.

While some arguments remain for new refinery construction, some argue that economic and regulatory barriers hinder new construction. Small refining enterprises may suffer certain economic disadvantages in an industry driven by the economy of scale. Furthermore, opportunities may depend on geographic location, regional markets, and source of crude oil. The barriers from regulatory requirements remain less clear. Export restrictions certainly affect potential product markets that could support new refining capacity. Whether these markets would spur new refinery construction is a separate question.

The history of refinery expansions suggests that environmental requirements do not generally pose a significant barrier to refinery construction, but local challenges vary (e.g., locations with currently unhealthy air quality). Small refineries face many of the same economic, market, and environmental factors that affect large refineries, but they may also benefit from exemptions in complying with certain federal regulations. As with any industrial facility involving potential air emissions, water use, and waste generation, certain environmental permitting and regulatory requirements apply to the construction and operation of refineries. The specific requirements, and the degree of difficulty or ease in meeting them, will depend not only on the nature of the project, but perhaps more importantly on the location of the project.

Small business opportunities in refining may strongly depend on a number of factors, including regional demand for refined products, available crude oil supplies, and unique regional environmental regulations, among others. A "small business" in the oil refining business is defined differently in different statutes. In addition, some fuels are easier to produce than others are. While evaluating opportunities is beyond the scope of this report, some key opportunities have recently emerged. Perhaps the most discussed potential opportunity for constructing a small topping or hydroskimming refinery is in the mid-continent region (North Dakota, Colorado) to process these new sources of light sweet crude. Other opportunities may lie in installing condensate splitter and stabilizer plants to handle North Dakota and Texas expanding production of light sweet crude oil and condensate.

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Introduction

The last new refinery to open in the United States finished construction in 1976. That record is about to fall with the construction of a small refinery scheduled to open late this year in North Dakota. Since the mid-1980s, though, some 150 or more refineries closed. However, the refineries that remained open expanded their operational capacity to keep up with the increasing demand for refined petroleum products. Current U.S. refining capacity (roughly 18 million barrels per day) appears to satisfy if not exceed demand as the increasing export of refined petroleum products would seem to suggest. The refining industry even shows signs of expanding to take advantage of less expensive U.S. crude oil and export more products. The perception remains, nevertheless, that the United States needs new refineries but economic and regulatory barriers stand in the way of their construction. Thus far, the industry has managed to negotiate regulatory hurdles in expanding refinery capacity, an option preferred over new construction and driven by the economy of scale.

In general, new entrants into refining may find steep competition with existing operators. However, for some “teapot” refineries, the door is wide open, and the cost of admission is comparatively little when processing light-sweet crude oil or condensate, whether in the mid-continent or elsewhere. Some may argue that there may be only a short window of opportunity to get in and then get out. A change in crude oil prices could quickly disadvantage them.

Small refineries do face many of the same economic, market, and environmental factors that affect large refineries, but they may also benefit from exemptions in complying with certain federal regulations. Further, some federal policies have had the effect of displacing petroleum products in the market place, and introduced refineries to direct challenges, such as the Renewable Fuel Standard.

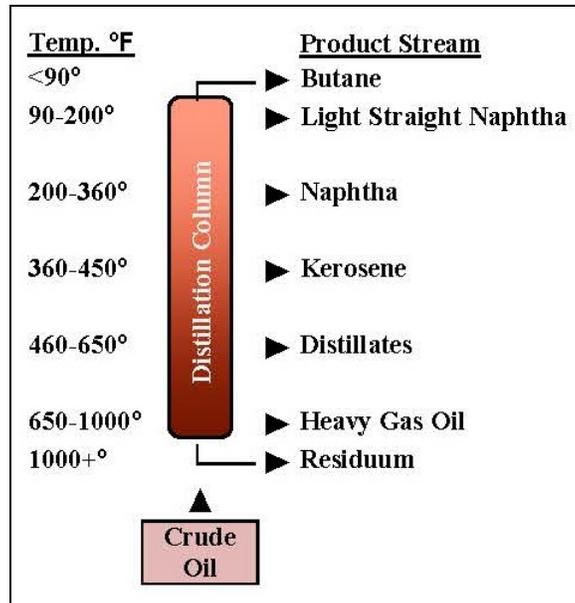
We begin this report with a brief discussion on the state of refining in the United States, paying particular attention to regulatory criteria that define refining (as this has taken on new significance), the threshold between small and large refineries, and potential opportunities for small businesses. In the discussion on “Economic Challenges”, we examine the pace of refinery construction and capacity expansion, and the profitability of operating refineries. Current economic challenges for the industry also include competition from ethanol and biodiesel producers, many of which are considered small businesses; the potential displacement of refined petroleum products by these alternative fuels, as mandated by the Renewable Fuel Standard; and the erosion in demand for refined petroleum products, due to both consumer and government-mandated trends toward increased automotive fuel efficiency.

Like any other industrial facility, refineries are subject to certain environmental laws that regulate their construction and operation. In the discussion on Environmental Permitting and Regulatory Requirements, we summarize some of the major environmental requirements associated with refinery construction and operations, few of which are unique to refineries compared to any industrial operation with similar potential emissions. This discussion focuses on air emissions control requirements, often regarded as the most significant challenge in permitting the expansion of existing refineries or constructions of new refineries.

Background

By CRS’s recent count, some 115 refineries/refinery complexes process roughly 18 million barrels per day (Mb/d) of crude oil in the United States.¹ All have atmospheric distillation in common, which involves heating crude oil in a furnace then condensing it in an atmospheric distillation tower (or crude unit)—the tall, narrow columns that give a refinery its distinctive skyline (see **Figure 1**).

Figure 1. Generic Crude Oil Distillation Column



Source: Prepared by CRS.

Notes:

Refinery Type	Processes	Increasing Complexity ▼
Topping	Atmospheric distillation to separate crude oil into constituent petroleum product, produces naphtha, and middle distillate fuels, and resid, but no gasoline	
Hydroskimming	Atmospheric distillation, naphtha reforming and desulfurization process to run light sweet crude and produce gasoline	
Cracking	Adds vacuum distillation and catalytic cracking process to run light sour crude to produce light and middle distillate	
Coking	Adds resid destruction to run medium/sour crude oil	

Refineries vary in complexity, and can include, for the purposes of this report, stabilizers, condensate splitters, simple topping plants and hydroskimmers to more complex cracking and ultimately coking plants. Coking has become an increasingly important capability of the U.S.

¹ CRS Report R41478, *The U.S. Oil Refining Industry: Background in Changing Markets and Fuel Policies*, by Anthony Andrews et al.

refining industry with nearly three-quarters of the fuel-producing refineries having some capacity to convert heavy crude oils into refined products.

Beginning in the late 1970s, U.S. refineries began facing a dwindling supply of light-sweet crude oils favored for making motor fuels. Many refineries began switching to increasingly available heavy-sour crude oils, and began adding “cracking” and “coking” processes to convert petroleum “resid” into high value motor fuels. The resid that remained after atmospheric distillation found earlier use as low value “ship’s bunker fuel” and as boiler fuel in electric power plants. Cracking and coking processing upgrades came at considerable investment costs. Coking dates back to the late 1920s, but became the defining characteristic of the U.S. refinery during the 1980s and 1990s. U.S. refineries have the capacity to convert some 2.5 Mb/d of petroleum resid into higher value motor fuels. In other words, refineries increased motor fuel production without having to increase nameplate capacity by adding cracking and coking units.² Several Midwest refineries have recently added coking/conversion capacity to take advantage of the increasing supply of heavier crude oils from Canada’s oil sands projects.

The increasingly available light sweet crude oils produced from unconventional shale resources, like North Dakota’s Bakken formation and the Texas Eagle Ford formation, are changing U.S. refining prospects and have revitalized some refinery operations that formerly depended on imported light crude oil. Some have raised questions and concerns about the role of condensates in the market. The domestic market for condensate is somewhat limited, however, and “lease” condensate (a term applied to Outer Continental Shelf production) is subject to current export restrictions.³

Processing Condensates in the Oil Field

Condensates are volatile light hydrocarbons in the range of ethane, propane, butane, iso-butane, and iso-pentane (natural gasoline) associated with crude oil.⁴ The elevated pressures in oil and gas reservoirs keep condensates in a condensed liquid-state. However, the drop in pressure at the surface can cause condensates to “flash” or vaporize when transferred to the stock tanks. To avoid flashing, the crude oil stream is directed through a separator or “splitter” that separates the condensates into various product streams. A splitter operates as a series of stages, each calibrated to release a particular condensate product based on its characteristic temperature and pressure.⁵ The process has similarities to refining, but at temperatures in the range of 100°F to 250°F, and under controlled pressures. In the generic three-stage splitter shown in **Figure 2**, progressively heavier volatiles are separated with each stage ending with degassed crude oil entering the stock tank.

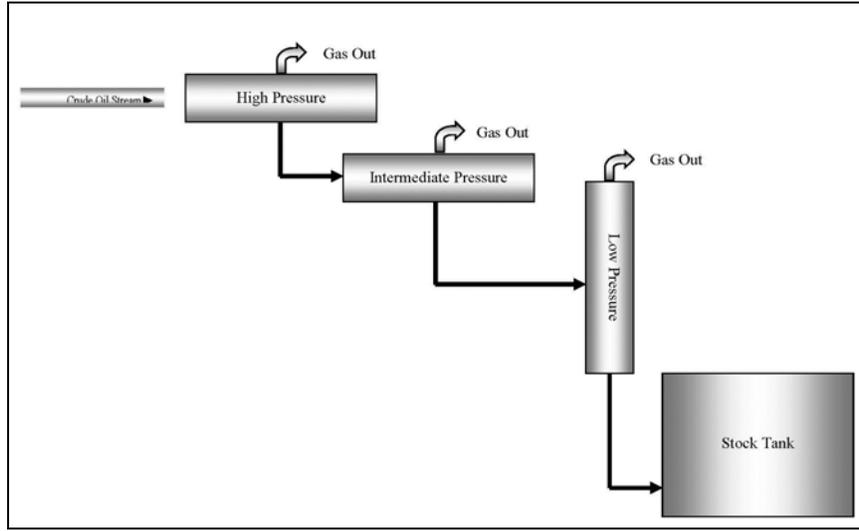
² Nameplate capacity refers to the throughput capacity in barrels per day of a refinery’s atmospheric distillation tower.

³ Christian Berthelsen and Lynn Cook, “U.S. Set to Export First Oil Since ‘70s,” *Wall Street Journal, Eastern edition* (New York, NY), June 25, 2014; and “Energy Industry Buzzes at Oil Export Opening,” *Wall Street Journal*, July 15, 2014. For more information on oil exports, see CRS Report R43442, *U.S. Crude Oil Export Policy: Background and Considerations*, by Phillip Brown et al.

⁴ Propane and butane are also referred to as liquefied petroleum gas (LPG).

⁵ Ken Arnold and Maurice Stewart, *Surface Production Operations, Volume 1, Design of Oil-Handling Systems and Facilities* (Houston, Texas: Gulf Publishing Company, 1995), p. 33.

Figure 2. Three Stage Separator



Source: Prepared by CRS from *Surface Production Operations, Vol. 1, Design of Oil-Handling Systems and Facilities*.

Notes: Crude oil is flashed at an initial pressure and then flashed at successively lower pressures two times before entering stock tank. Condensates flashed will depend on the crude oil, and the operating temperature and pressures of the splitter.

Condensate	Formula	Use
Methane	CH ₄	Heating, transportation fuel
Ethane	C ₂ H ₆	Petrochemical feedstock
Propane	C ₃ H ₈	LP Gas heating/transportation fuel
Butane	C ₄ H ₁₀	LP Gas heating/transportation fuel
Iso-butane	C ₄ H ₁₀	Propellant, solvent, refrigerant
Iso-pentane	C ₅ H ₁₂	Natural gasoline/blending

Small Refineries: How They Are Defined and What They Do

From the small business perspective, several legislated provisions define small refineries, but inconsistently. According to the U.S. Small Business Administration (SBA), only refiners that employ fewer than 1,500 employees and produce less than 125,000 barrels per calendar day may qualify for a federal small business contract.⁶ By CRS count, 27 refineries make up 50% of U.S.

⁶ “NAICS code 324110—For purposes of Government procurement, the petroleum refiner must be a concern that has neither more than 1,500 employees nor more than 125,000 barrels per calendar day total Operable Atmospheric Crude Oil Distillation capacity. Capacity includes owned or leased facilities as well as facilities under a processing agreement or an arrangement such as an exchange agreement or a throughput. The total product to be delivered under the contract must be at least 90 percent refined by the successful bidder from either crude oil or bona fide feedstocks.” U.S. Small Business Administration, “Table of Small Business Size Standards Matched to North American Industry Classification System Codes,” http://www.sba.gov/sites/default/files/files/Size_Standards_Table.pdf.

refining capacity. Almost half of the U.S. refineries (some 50 or more) produce less than 125,000 b/d, but in total they make up only 21% of total refining capacity (roughly 18+ Mb/d).

Both Title XV (Ethanol and Motor Fuels) of the Energy Policy Act 2005⁷ and Title II (Energy Security Through Increased Production of Biofuels) of the Energy Independence and Security Act of 2007⁸ defined a small refinery as having less than 75,000 b/d in average aggregate daily crude oil throughput.

EPA regulations temporarily exempted small refineries and small volume refineries, which have a capacity below 155,000 b/d, from complying with the Renewable Fuel Standard (RFS) through 2010.⁹ The Clean Air Act regulations set 65,000 b/d as the small business threshold for complying with vapor recovery provisions.¹⁰

Finally, the North American Industry Classification Codes (NAICC) identifies the construction costs for small oil and gas structures at below \$33.5 million. However, the smallest refinery currently under construction, a 20,000 b/d refinery in North Dakota, reportedly will cost \$350 million.¹¹ Smaller oilfield equipment used to treat crude oil before it reaches a refinery (e.g., oil and gas separators, splitters, and stabilizers) may line up close to NAICC costs given the mobile and temporary application of the equipment. For example, a “skid-mounted” 2,500 b/d crude oil condensate stabilizer operating in the Texas Eagle Ford shale play cost roughly \$400,000 (exclusive of tanks, pipelines, and pumps) in 2012.¹² A permanent 60,000 b/d condensate stabilizer plant might cost upwards of \$80 million.

Small business opportunities in refining may strongly depend on a number of factors, including regional demand for refined products, available crude oil supplies, regional price differences, and unique state environmental regulations, among others. In addition, some fuels are easier to produce than others are. The unique “boutique” fuel requirements for some regions can affect the decisions of individual companies to produce, distribute, and market them. While evaluating opportunities would exceed the scope of this report, some key factors have emerged as of late. The frequency that refinery-ownership changes hands suggests that buying an existing refinery offers the most straightforward opportunity to expand capacity quickly. This has been the case for refineries serving regional markets as well as those operating in the major refining centers of the Gulf Coast and the West Coast. The availability of light sweet crude oil in the mid-continent region (North Dakota, Colorado) presents some opportunities for constructing a small topping or hydroskimming refinery. A greater opportunity may lie in installing condensate splitter and stabilizer plants to handle the excess condensate production in North Dakota now being flared,¹³ or in Texas. Hess Corp. has applied an even simpler “heater treater” to strip out the light-end

⁷ P.L. 109-58, and codified in 40 C.F.R. 80.1101 (g). “Small refinery, for this subpart only, means a refinery for which the average aggregate daily crude oil throughput for calendar year 2006 (as determined by dividing the aggregate throughput for the calendar year by the number of days in the calendar year) does not exceed 75,000 barrels.”

⁸ P.L. 110-140.

⁹ 40 C.F.R. 80.1142—What Are the Provisions for Small Refiners Under the RFS Program?

¹⁰ 42 U.S.C. 7625—Vapor Recovery for Small Business Marketers of Petroleum Products.

¹¹ Rachael Seeley, “MDU Expands North Dakota Presence with Greenfield Refinery,” *Unconventional Oil and Gas Report*, May/June 2014.

¹² Personal communication with Bill Bowers, Valerus Inc., July 8, 2014. See “Eagle Ford Complete Well Pad Solution,” <http://www.valerus.com/knowledge-center/>.

¹³ Russell Gold and Chester Dawson, “Firms Leave Oil from North Dakota Fracking Prone to Explosion,” *Wall Street Journal*, July 8, 2014, pp. B1, B2.

hydrocarbons by heating oil to between 80 and 120°F for the oil production from the North Dakota Bakken formation.¹⁴

As many as 20 other refining projects (with a total capacity of more than 900,000 b/d) are proposed or are in various stages of development.¹⁵ These projects range from splitting and stabilization plants for processing crude oil condensate to “teapot” or mini-refineries. It is uncertain how many projects may actually be completed.

Economic Challenges

Oil companies can meet increasing/decreasing demand for petroleum products, such as gasoline, in three basic ways. They can build or idle refineries, expand or reduce capacity or capacity utilization rates of existing refineries, or they might choose to export or import petroleum products. These three alternatives allow the industry considerable flexibility in meeting changing short-term demand requirements while still allowing for the implementation of their long-term strategy. Within this framework, any individual refining company can either buy or sell a refinery to change its market position; however, this alternative is not available to the industry as a whole. In general, the industry will choose how to meet demand requirements based on which strategy is the most profitable.

No new complex refineries have been constructed in the United States since the Grayville, LA, facility that opened in 1977. Over 150 refineries have closed since 1982, representing some 1.6 Mb/d in lost refining capacity. However, capacity expansion in existing refineries countered the loss, bringing it up to the current 18+ Mb/d capacity—a 23% increase since the mid-1980s.¹⁶ Between January 2013 and January 2014, refining capacity increased by another 101,000 b/d, the result of investments at existing refineries.

Since 2008, the United States has moved from being a net importer of 1.36 Mb/d of petroleum products to being a net exporter of 1.39 Mb/d in 2013. This shift from net importer to net exporter in less than five years suggests that the United States does not suffer from a shortage of refining capacity. While domestic demand was met, capacity existed to supply foreign markets.

These data suggest that the refining industry has chosen to reduce the number of refineries, increase the capacity of existing refineries, and use foreign markets to meet domestic demands for various petroleum products when it is high and to optimize capacity utilization rates when domestic demand is reduced.

Refining Profitability

Over the period 2006 through 2009, as shown in **Figure 1**, refiners’ profits generally declined. This may be attributed to several factors, including high oil prices that peaked in 2008, coupled

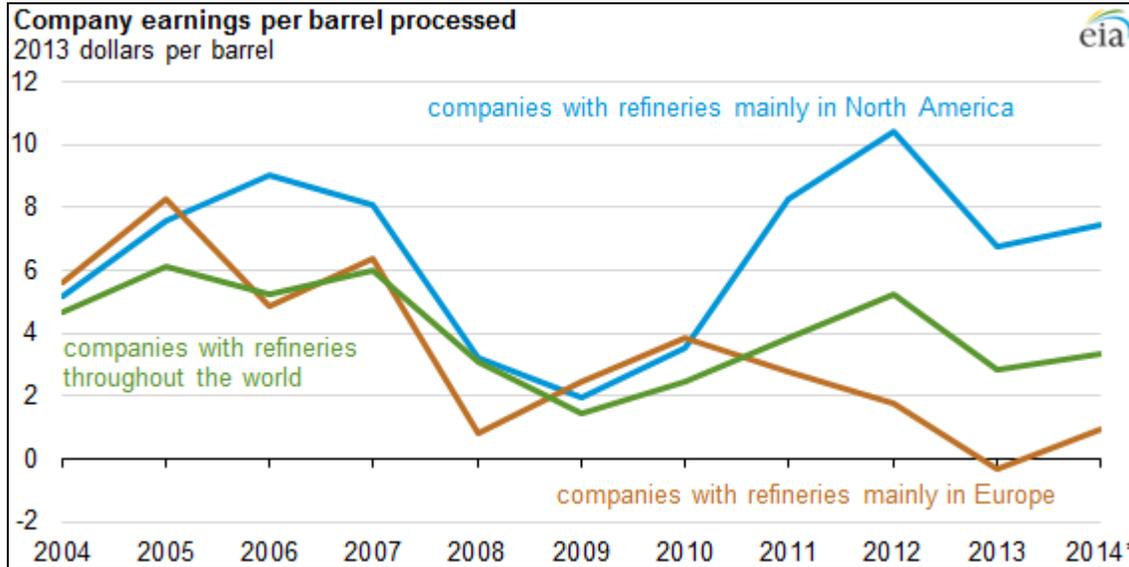
¹⁴ Russell Gold and Chester Dawson, “Firms Leave Oil from North Dakota Fracking Prone to Explosion,” *Wall Street Journal*, July 8, 2014, pp. B1, B2.

¹⁵ Christian Bethelsen and Lynn Cook, “U.S. Set to Export First Oil Since ’70s,” *Wall Street Journal*, June 25, 2014.

¹⁶ 14.4 Mb/d in 1985 vs. 17.7 Mb/d in 2014; see U.S. Energy Information Administration, Number and Capacity of Petroleum Refineries, http://www.eia.gov/dnav/pet/pet_pnp_cap1_dcu_nus_a.htm.

with weak demand due to the recession that began in December of 2007. **Figure 1** also shows that North American refiners' profits increased from 2009 through 2012, because of recovering demand and discounted crude oil supplies that resulted from expanded production from U.S. tight oil deposits. Profits decreased, and then turned upward, from 2012 through the first quarter of 2014. The profit volatility over time shown in **Figure 3** is common for the refining industry.

Figure 3. North American Refinery Profitability



Source: U.S. Energy Information Administration; <http://www.eia.gov/todayinenergy/detail.cfm?id=16571>.

Notes: * 2014 estimated.

Uncertainty with respect to industry profitability is an important reason why the decision to build a new refinery in the United States has not been taken. Desirable multi-billion dollar investment projects should offer companies predictable profits in the end, reflecting the long-run time frame for refinery investment and operation. Generally, North American refinery earnings per barrel processed have been positive.

Refining Capital Investment

The refining industry undertakes capital investment for a variety of reasons, including expanding existing or creating new production facilities, implementing new or enhanced technology, regulatory compliance, and adapting existing refineries to available crude oil streams. With the exception of investments to insure compliance with environmental and other regulations, other activities may be considered to be competing for capital resources. When profitability declines or regulations tighten, the resource pool available for capital investment is reduced. **Table 1** shows the capital budget expenditures of the refining industry.

U.S. refining capital investment peaked in 2008, reflecting rapidly increasing world demand for petroleum products. A 22% decline in capital investment from 2008 through 2009 was followed by a further 50% decline from 2009 through 2010. More recently, the surge of petroleum product exports, coupled with investments to take advantage of new supplies of discounted light, sweet crude oil have seen investments increase. An example of the importance of new light, sweet crude oil supplies is the construction of a new refinery in Dickenson, ND, that is scheduled to open in

December 2014. This new refinery, with a capacity of 20,000 b/d, is a direct result of the expansion of oil production in the Bakken fields. In addition, it has been reported that as many as five additional small refineries might be constructed in North Dakota.¹⁷

Table I. U.S. Refining Industry Capital Budget Expenditures

2005-2013	
Year	\$ Billion
2005	7.2
2006	9.0
2007	8.3
2008	13.0
2009	10.1
2010	5.3
2011	9.2
2012	13.0
2013*	12.9

Source: *Oil and Gas Journal*, March 7, 2011; *Oil and Gas Journal*, March 4, 2013.

Notes: * 2013 Estimated.

One part of the capital investment decision is the time and cost of permitting a new site. Many observers have raised this issue with respect to the lack of refinery construction in the United States. One reported example of permitting issues purportedly associated with refinery construction delays is the Arizona Clean Fuels Refinery, which planned to refine Mexican crude oil in Arizona for use in the western United States.¹⁸ Interest in constructing this approximately \$3 billion facility began in 1998 and took seven years and reportedly millions of dollars of cost for permitting, and has yet to be constructed. However, the project has also experienced financing difficulties, local zoning changes, and legal challenges.¹⁹

For capital investment in new refineries to be desirable, certain market conditions should prevail. An important prerequisite is an expectation of growth in demand, especially in the transportation fuels, gasoline and distillates. The availability of stable, affordable crude oil supplies, and certainty with respect to the regulatory environment, are also important.

While growing demand for petroleum products is a key element in refining profitability, the U.S. demand for gasoline declined by about 5% from 2007 through 2013. Although this fall in demand was likely tied to the recession, and might be considered temporary, other factors may continue to reduce demand, or at least demand growth. Among these factors are rising Corporate Average Fuel Economy (CAFE) Standards, which are set to increase to roughly 50 miles per gallon by 2025. Full implementation of these standards could reduce the U.S. demand for motor fuel by 12

¹⁷ *Oil Daily*, July 3, 2014, pg.1.

¹⁸ PADD: Petroleum Administration for Defense District. PADD 5 includes Alaska, Washington, Oregon, California, Nevada, Arizona, and Hawaii.

¹⁹ The refinery plans appear to be on hold, with no press releases since March 2009.

Mb/d, as discussed next.²⁰ These savings represent oil that the domestic refining industry will not be required to process over the next decade, reducing the need for new capacity.

The growth in the use of bio-based ethanol as a component of gasoline has also contributed to reduced demand for crude oil per gallon of gasoline. To a lesser extent, this is true for biodiesel and diesel fuel as well. In addition, the potential growth in alternative fuel vehicles, including hybrid and electric vehicles and natural gas-fueled vehicles, could further demand growth.

While the growing U.S. crude oil and natural gas production from unconventional resources would seem to assure the refining industry that a reliable source of domestic feedstock would be available, several problems have developed. The quality of very light sweet crude oil supplies is in one sense very high. However, larger and more complex refineries have positioned themselves to take advantage of lower quality heavy sour crude. For them, light sweet crude represents an opportunity that will depend on a competitive price advantage it offers in refining. Having made considerable investments in crack and coke heavy feedstock, these refiners now face the decision to bypass their conversion capacity and shift to light crude. This processing re-orientation spells increased competition for smaller refineries that had forgone investment in upgrades and continued to process diminishing light crude supplies.

Refinery and fuel environmental regulations are covered in the next section of this report. However, it can be noted that given any level of refining industry capital investment, tightening regulations may impute a cost to any refiner that wishes to remain in operation.

Vehicle and Fuel Regulatory Requirements

Two key vehicle and fuel regulatory standards—the coordinated Corporate Average Fuel Economy (CAFE)/Green House Gas (GHG) vehicle emission standards and the Renewable Fuel Standard (RFS)—have likely affected the refining industry by reducing the consumption of petroleum fuels.²¹ Compliance with the RFS may also increase the costs for some refiners, as well as present other challenges.

Corporate Average Fuel Economy (CAFE)/GHG Vehicle Emission Standards

The federal government has regulated vehicle fuel economy since 1978 and, more recently, aligned these efforts with new GHG vehicle emission standards in a joint national program aimed at reducing petroleum consumption and GHG emissions from the transportation sector.²² As required by the Energy Policy and Conservation Act of 1975 (EPCA),²³ the National Highway Traffic Safety Administration (NHTSA) sets Corporate Average Fuel Economy (CAFE) standards

²⁰ The White House, “Obama Administration Finalizes Historic 54.5 MPG Fuel Efficiency Standards,” press release, August 28, 2012, <http://www.whitehouse.gov/the-press-office/2012/08/28/obama-administration-finalizes-historic-545-mpg-fuel-efficiency-standard>.

²¹ EPA Tier 3 sulfur standards are discussed in the section “Environmental Permitting and Regulatory Requirements.”

²² For a more detailed discussion on fuel economy standards, see CRS Report R42721, *Automobile and Truck Fuel Economy (CAFE) and Greenhouse Gas Standards*, by Brent D. Yacobucci, Bill Canis, and Richard K. Lattanzio.

²³ P.L. 94-163

for passenger cars and light trucks. These standards were raised under the Energy Independence and Security Act of 2007 (EISA),²⁴ and, subsequently, coupled with vehicle GHG standards as administered by the Environmental Protection Agency (EPA) through its authority under the Clean Air Act and subsequent amendments.²⁵

Fuel consumption and greenhouse gas (GHG) emissions from motor vehicles are closely linked. The vast majority of vehicle GHG emissions result from the burning of petroleum products, so reducing vehicle fuel consumption is the most direct means of reducing emissions. For these reasons, the Obama Administration has issued joint rules on vehicle fuel economy and GHG emissions for model year (MY) 2012-2016 passenger cars and light trucks,²⁶ MY2014-MY2018 medium- and heavy-duty trucks,²⁷ and MY2017-MY2025 passenger cars and light trucks.²⁸ In addition, EPA and NHTSA have begun drafting a second phase of fuel economy/GHG standards for FY2019 and later medium- and heavy-duty trucks; proposed standards are expected in March 2015.

NHTSA and EPA expect that combined new passenger car and light truck CAFE standards will rise to as much as 41.0 miles per gallon (mpg) in MY2021 and 49.7 mpg in MY2025, up from 34.1 mpg in MY2016. EPA and NHTSA expect that the combined National Program for MYs 2012-2016 and MYs 2017-2025 is projected to reduce U.S. oil use by more than 2 Mb/d in 2025.²⁹ Critics have challenged the Administration's assumptions, countering that the costs will be higher and could lead to a drop in new vehicle sales.

Though the standards do not require changes at the refinery level, they can affect refineries indirectly by contributing to improvements in the overall efficiency of the vehicle fleet and, therefore, reducing fuel consumption.³⁰ These standards will certainly reduce petroleum consumption in the long term, but short-term effects on fuel consumption and thus the refining industry are less clear. For example, DOE officials stated that thus far "the impact of the standards has been limited because they affect new car sales, and there are a relatively small number of new vehicles in the overall fleet."³¹ However, other stakeholders reported to GAO that

²⁴ P.L. 110-140

²⁵ 42 U.S.C. 7521 et seq.

²⁶ Environmental Protection Agency and National Highway Traffic Safety Administration, "Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; Final Rule," *75 Federal Register* 25324, May 7, 2010.

²⁷ Environmental Protection Agency and National Highway Traffic Safety Administration, "Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles; Final Rule," *76 Federal Register* 57106, September 15, 2011.

²⁸ The CAFE standards only apply through MY2021 because of stipulations in the fuel economy law. NHTSA will need to issue additional regulations for MY2022 onward, while EPA has the authority to set GHG standards for MY2025 and beyond. EPA and NHTSA, "2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards," *77 Federal Register* 62623, December 14, 2012.

²⁹ EPA, "EPA and NHTSA Set Standards to Reduce Greenhouse Gases and Improve Fuel Economy for Model Years 2017-2025 Cars and Light Trucks," Regulatory Announcement, August 2012.

³⁰ U.S. Government Accountability Office, *Petroleum Refining: Industry's Outlook Depends on Market Changes and Key Environmental Regulations*, GAO-14-249, March 2014, p. 26.

³¹ U.S. Government Accountability Office, *Petroleum Refining: Industry's Outlook Depends on Market Changes and Key Environmental Regulations*, GAO-14-249, March 2014, p. 27.

with estimated fuel savings of such magnitude, “the CAFE and GHG vehicle emissions standards have likely had a relatively large impact on petroleum demand declines in the past few years.”³²

According to the U.S. Government Accountability Office, “CAFE and GHG vehicle emission standards have contributed to reductions in the consumption of petroleum fuels, but the extent is unclear.”³³

How new and existing refinery operations—both large and small—adjust in the short and long terms to the impact of reduced domestic demand for petroleum transportation fuels will be dependent upon their respective market projections.

Renewable Fuel Standard (RFS)

The Renewable Fuel Standard (RFS) requires the use of biofuels in transportation fuel.³⁴ The RFS was established in the Energy Policy Act of 2005 (P.L. 109-58) and significantly expanded in the Energy Independence and Security Act of 2007 (P.L. 110-140). The vast majority of the mandate is met using corn-based ethanol blended into gasoline (although there is no explicit mandate to use ethanol or that it be blended). For 2013, the RFS mandated the use of 16.55 billion gallons of biofuels, of which roughly 13.3 billion gallons came from corn ethanol.³⁵ At the 2013 level, renewable fuels replace roughly 10% of overall demand for motor vehicle fuels, and displace roughly 1Mb/d of gasoline and diesel consumption. EISA requires a further increase in the use of renewables, to 36 billion gallons by 2022, further reducing demand for petroleum-based fuel.

Renewable Identification Numbers (RINs) are the compliance mechanism for the RFS.³⁶ After each year, a refiner or other obligated party must submit to EPA a sufficient number of RINs to cover its obligation (which is prorated for each obligated party based on gasoline and diesel fuel produced/supplied in that year). RINs are generated by biofuel producers and are sold with the fuel. Biofuel purchasers—generally gasoline blenders—typically “separate” the RINs from the physical fuel when they receive and blend the ethanol into gasoline. Once a RIN has been separated the owner may sell the RIN to another party, be that another obligated entity in need of additional RINs or a third-party trader.

In the case when an independent refiner is not integrated with downstream operations, an obligated party may only be able to secure RINs through this secondary market. If supplies of RINs are tight, then these parties may need to pay market prices for RINs, which could reflect the marginal cost of compliance as opposed to the industry average. If RINs are trading at a high enough price, non-integrated refiners could face higher compliance costs than their competitors. Thus, although there is no direct effect on the construction of new refineries from the RFS, the need to secure RINs may present an economic hurdle to a new, independent refinery.

³² Ibid.

³³ U.S. Government Accountability Office, *Petroleum Refining: Industry’s Outlook Depends on Market Changes and Key Environmental Regulations*, GAO-14-249, March 2014.

³⁴ For more information, see CRS Report R40155, *Renewable Fuel Standard (RFS): Overview and Issues*, by Randy Schnepf and Brent D. Yacobucci.

³⁵ Environmental Protection Agency, *2013 RFS Data*, June 7, 2014, <http://www.epa.gov/otaq/fuels/rfsdata/2013emts.htm>.

³⁶ For more information, see CRS Report R42824, *Analysis of Renewable Identification Numbers (RINs) in the Renewable Fuel Standard (RFS)*, by Brent D. Yacobucci.

Because of concerns over compliance costs, P.L. 109-58 gave small volume refineries (75,000 bpd or less) a temporary exemption from the RFS requirements through the end of 2010. EPA extended this exemption to small refiners (SBA definition, see “Tier 3 Sulfur Standards” below). Later, Congress directed the DOE to study whether the RFS would lead to differential economic hardship on some or all small refiners and that EPA should extend the exemption for those refineries. DOE found that some small refiners would face disproportionate economic hardship and that those refiners should be exempted.³⁷ For 2011 and 2012, EPA exempted 13 small refineries (with their names redacted to protect confidential business information).³⁸ EPA approved a single exemption for 2013,³⁹ and proposed no exemptions for 2014.⁴⁰

At the state level, the California legislature passed, and then-Governor Schwarzenegger signed, a 2007 law requiring statewide reductions in GHG emissions by 2020. Among other regulations to implement the law, the California Air Resources Board established a Low-Carbon Fuel Standard (LCFS) requiring refiners to reduce the carbon intensity of the fuels they provide to the California market. By 2020, the regulations require a roughly 10% reduction from 2010 levels. In general, it is expected that most of the requirement will be met using various lower-carbon biofuels, although California’s standards for lifecycle emissions are stringent, and some biofuels actually have higher emissions than gasoline or diesel fuel under the rule. The interactions between the California program and the federal Renewable Fuel Standard (RFS) could be complex. It is unclear how much the LCFS will raise refiners’ costs, as early reviews of the program have shown little effect on the market and compliance credits are currently trading at low levels. However, as the program becomes more stringent, the compliance costs are likely to increase.

Tier 3 Sulfur Standards

In April 2014, EPA finalized new gasoline sulfur standards.⁴¹ Beginning in 2017 the average sulfur content in most gasoline will be reduced from 30 parts per million (ppm) to 10 ppm. This is part of a larger strategy to reduce emissions from both new and existing passenger vehicles. The sulfur standards were issued along with new “Tier 3” emissions standards for new vehicles.⁴² The lower sulfur level limits pollutant formation in existing vehicles and allows the use of more advanced emissions systems in new vehicles—systems that are highly sensitive to the amount of sulfur in the fuel.

In general, the cost of refining gasoline is expected to increase, as investments must be made in desulfurization technology. EPA estimates that the cost of compliance will average below one cent per gallon, with some refiners facing two to three cents per gallon, although industry

³⁷ Department of Energy, *Small Refinery Exemption Study: An Investigation into Disproportionate Economic Hardship*, March 2011.

³⁸ Environmental Protection Agency, *Small Refinery Exemptions Under the Renewable Fuel Standard Program*, May 2011.

³⁹ Environmental Protection Agency, “Regulation of Fuels and Fuel Additives: 2013 Renewable Fuel Standards; Final Rule,” 78 *Federal Register* 49798, August 15, 2013, <https://federalregister.gov/a/2013-02794>.

⁴⁰ Environmental Protection Agency, “2014 Standards for the Renewable Fuel Standard Program; Proposed Rule,” 78 *Federal Register* 71732, November 29, 2013, <https://federalregister.gov/a/2013-28155>.

⁴¹ Environmental Protection Agency, “Control of Air Pollution from Motor Vehicles: Tier 3 Motor Vehicle Emission and Fuel Standards; Final Rule,” 79 *Federal Register* 23618, April 28, 2014, <https://federalregister.gov/a/2014-06954>.

⁴² For more information, see CRS Report R43497, *Tier 3 Motor Vehicle Emission and Fuel Standards*, by Richard K. Lattanzio and James E. McCarthy.

stakeholders contend that the price could be significantly higher—as much as six to nine cents per gallon for some refiners.⁴³ The studies generally found that refiners would expand existing desulfurization units instead of constructing new equipment, although it does not appear that they looked at the effects on the construction of completely new refineries. Again, the differential impacts of these standards may be more or less likely to affect new or small refinery vis-à-vis their competitors.

In general, small refiners are given more flexibility in compliance with fuel standards compared to larger refiners. For most fuel standards, EPA has two classes of small refiners:

- Small refiners: a refiner with 1,500 or fewer employees (Small Business Administration (SBA) definition) and annual crude oil capacity of 155,000 b/d or less; or
- Small volume refineries: a refiner with 75,000 b/d of crude capacity, regardless of the number of employees

For the Tier 3 standards, small refiners and small volume refineries will be granted an additional three years to come in compliance with the standards—until 2020—although they would be able to generate tradable credits for early compliance with the standards.

Environmental Permitting and Regulatory Requirements

As with any industrial facility involving potential air emissions, water use, and waste generation, certain environmental permitting and regulatory requirements apply to the construction and operation of refineries. The specific requirements, and the degree of difficulty or ease in meeting them, will depend not only on the nature of the project, but perhaps more importantly on the location of the project. Congress included in the Energy Policy Act of 2005 (EPAAct 2005)⁴⁴ a provisions on “Refinery Revitalization” intended to improve permitting coordination between EPA and various federal and state agencies.

In general, state or local agencies handle environmental permitting and other regulatory operations, in part because EPA has delegated authority to them for many federal environmental programs.⁴⁵ Accordingly, state and local agencies largely implement permitting, inspections, monitoring, and enforcement, and, in some cases, standards setting. In addition, many states have enacted statutes and promulgated certain requirements independent of EPA to address specific issues within their states.

⁴³ David C. Tamm and Kevin P. Milburn, *Addendum to Potential Supply and Cost Impacts of Lower Sulfur, Lower RVP Gasoline*, Baker & O’Brien Incorporated, March 2012, p. 12, <http://www.api.org/news-and-media/news/newsitems/2013/march-2013/~media/Files/News/2012/12-March/Addendum-Potential-Impacts-of-Lower-Sulfur-Lower-RVP-Gasoline-Report.pdf>.

⁴⁴ P.L. 109-58

⁴⁵ See delegation of authority by environmental act at http://www.ecos.org/section/states/enviro_actlist. Note that several state environmental agencies, including Ohio, Illinois, and California, are also called “Environmental Protection Agency,” so distinguishing between federal and state regulatory agencies is important.

While air pollution permitting and standards are typically the biggest regulatory challenge for new refineries, the specific location and situation of a proposed new refinery may pose other regulatory challenges (e.g., cooling water supply may be limited, particularly in arid areas). This report focuses on air pollution permitting and standards for new and modified refineries, as well as some additional considerations such as the requirements on the fuels produced by the refineries.

Air Pollution Permitting

Under the Clean Air Act (CAA),⁴⁶ EPA is authorized to take steps to address air emissions from stationary sources, including refineries. The agency has regulated emissions of certain air pollutants from new and modified stationary sources for several decades under the authority of various sections of the CAA, including air permitting requirements, Section 111 New Source Performance Standards (NSPS), and Section 112 National Emission Standards for Hazardous Air Pollutants (NESHAPS).

While air permitting of major sources of pollution is a requirement under the CAA, all 50 states have delegated responsibility for permitting. The Clean Air Act amendments of 1990 (P.L. 101-549, 42 U.S.C. §§7470-7479 and §§7661-7661f) require that major industrial sources of air pollutants obtain both construction and operating permits. These permits are intended to enhance compliance by detailing for each covered facility all the emission control requirements to which the facility is subject.

A Prevention of Significant Deterioration (PSD) permit applies to the construction of a new or modified facility that will have “major” and “significant” amounts of air pollution for any criteria pollutant.⁴⁷ A PSD permit is required before a new source is constructed, or before changes or modifications are made at an existing source of air pollution. Either EPA or the designated state permitting authority may issue the permit (which must specify the construction allowed, the emission limits, and frequency of operation for the equipment being permitted). PSD requires

1. installation of the Best Available Control Technology,⁴⁸
2. an air quality analysis,
3. an additional impacts analysis, and
4. public participation.

New and modified petroleum refineries are listed as a source category for PSD requirements.

⁴⁶ 42 U.S.C. 7401 et seq. For a summary of the CAA and EPA’s air and radiation activities and its authorities, see EPA’s website at <http://www.epa.gov/air/basic.html>; and CRS Report RL30853, *Clean Air Act: A Summary of the Act and Its Major Requirements*, by James E. McCarthy and Claudia Copeland.

⁴⁷ “Major” is defined as emitting or having the potential to emit 100 tons per year (tpy) or more of any criteria pollutant. “Significant” refers to thresholds assigned to each criteria pollutant and certain non-criteria pollutants (e.g., the significance threshold is 40 tpy for NO_x and 15 tpy for PM-10). “Criteria” pollutants include carbon monoxide, lead, nitrogen dioxide, ozone, particulate matter, and sulfur dioxide.

⁴⁸ Best Available Control Technology (BACT) is an emissions limitation which is based on the maximum degree of control that can be achieved at a major stationary source. It is a case-by-case decision that considers energy, environmental, and economic impact. BACT can be add-on control equipment or modification of the production processes or methods.

A Title V operating permit effectively consolidates and coordinates the often-complex permitting requirements for the various emissions sources characteristic of refinery operations.⁴⁹ Emissions from a refinery arise from various specific operations, including cracker towers, coker units, gas combustion turbines, boilers, and storage tanks. The emissions from these operations typically include criteria pollutants such as volatile organic compounds (VOCs), nitrogen oxides (NO_x), sulfur oxides (SO_x), carbon monoxide (CO), and particulate matter (PM or “soot”), as well as various hazardous air pollutants (HAPs, e.g., benzene, toluene and naphthalene). Title V permits generally address “major sources” of air pollution, defined in the CAA as stationary facilities that emit or have the potential to emit 100 tons or more per year of any regulated pollutant or combination of pollutants. Title V also covers the following:

1. sources in nonattainment areas (described below) that emit as little as 10 tons per year of VOCs, depending on the region’s nonattainment status;
2. sources subject to New Source Performance Standards (NSPS, described below);
3. regulated sources of HAP emissions (any source that emits more than 10 tons per year of an individual HAP or more than 25 tons per year of any combination);
4. sources required to have new source or modification permits under Title I of the act.

A federal Title V permit would likely be required for an “average” (approximately 140,000 BPD) new oil refinery, but may depend on the details of the State Implementation Plan where the refinery is to be located.

Specific permit requirements and conditions depend on where a potential source is located. Air pollution control requirements will be more stringent for a refinery located in a “nonattainment” area—an area where air quality does not meet the minimum National Ambient Air Quality Standards (NAAQS)⁵⁰ established to address the health impacts from exposure to the six criteria air pollutants. For example, a refinery seeking a permit in a nonattainment area (e.g., Houston-Galveston, TX, or Philadelphia, PA) could be required to meet the “Lowest Achievable Emissions Rate”⁵¹ for its processes. In addition, any expected emissions potential must be offset by sufficient Emission Reduction Credits (ERCs), which are usually generated through emissions reductions at existing sources or through the shutdown of existing sources. For example, a refinery seeking a permit in an area classified as “severe nonattainment,” may be required to seek ERCs at a rate of 1.3:1 compared to its expected emissions potential.

The permitting requirements for a small refinery will depend on the technical specifications of what is being permitted and where. The applicability of permitting requirements is based on the “potential to emit” from facilities on contiguous or adjacent properties and under the common

⁴⁹ For a full discussion of the Title V requirements, see CRS Report RL33632, *Clean Air Permitting: Implementation and Issues*, by Claudia Copeland.

⁵⁰ The Clean Air Act requires EPA to set National Ambient Air Quality Standards (40 CFR part 50) for pollutants considered harmful to public health and the environment. EPA has set National Ambient Air Quality Standards for six principal pollutants, which are called “criteria” pollutants, and include carbon monoxide, lead, nitrogen dioxide, ozone, particulate matter, and sulfur dioxide. For a list of current standards, see EPA at <http://www.epa.gov/air/criteria.html>.

⁵¹ Lowest Achievable Emissions Rate (LAER) is the most stringent emission limitation derived from either of the following: (1) the most stringent emission limitation contained in the implementation plan of any State for such class or category of source; or (2) the most stringent emission limitation achieved in practice by such class or category of source.

control of a person or entity. Thus, certain operations—depending upon their size, status, and “potential to emit”—may not require a Title V permit and could be permitted under other state permitting regulations (e.g., synthetic minor permit). The number and kinds of permitting required by a small refinery and its specific equipment will rest on these case-specific determinations.

While these air permitting issues pertain to any facility, not solely refineries, with a similar potential to emit, they are summarized here because they are often viewed as a limitation to the construction of a new refinery or the modification of an old one. In some cases, the availability of offsets may pose a constraint to refinery permitting in certain nonattainment areas. In addition, the often-complex calculations may require a significant investment in technical expertise by both the facility operator seeking a permit and the permitting agency, typically at the state or local level.

Air Pollution Standards

One of the significant air pollution regulatory requirements for a new or modified refinery includes industry-specific New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS).

Industry-specific NSPS requirements have been promulgated by EPA to implement Section 111(b) of the CAA and are issued for categories of sources that cause, or contribute significantly to, air pollution, which may reasonably be anticipated to endanger public health or welfare. The existing NSPS for petroleum refineries address PM, CO, and SO₂ emissions.⁵² The standards include emissions limitations and work practice standards for fluid catalytic cracking units, fluid coking units, delayed coking units, fuel gas-combustion devices, and sulfur recovery plants, as well as requirement for monitoring and recordkeeping, among other things. An NSPS sets an emission rate limit on a given piece of equipment or activity that is equivalent to the “best system of emission reductions” that is currently and adequately demonstrated by industry practice, taking into account cost and other factors. NSPS must be implemented by all refineries, regardless of size.

Industry-specific NESHAPS requirements have been promulgated by EPA to implement Section 112 of the CAA and are issued for categories of new, reconstructed, or existing sources that emit HAPs as defined under Section 112(b) of the CAA.⁵³ EPA has promulgated National Emission Standards for Petroleum Refineries, including National Uniform Emission Standards for Heat Exchange Systems (Refinery MACT 1) and Catalytic Cracking, Catalytic Reforming, and Sulfur Plant Units (Refinery MACT 2).⁵⁴ The rules establish emission limits for HAPs from petroleum refineries and requirements to demonstrate initial and continuous compliance with the emission limitations and work practice standards. On May 15, 2014, EPA issued a proposed rule

⁵² 40 C.F.R. 60 Subparts J and Ja—Standards of Performance for New Stationary Sources.

⁵³ Hazardous air pollutants, also known as HAPs, toxic air pollutants or air toxics, are those pollutants that cause or may cause cancer or other serious health effects, such as reproductive effects or birth defects, or adverse environmental and ecological effects. EPA is required to control 187 hazardous air pollutants that are listed in Section 112 (b) of the CAA.

⁵⁴ 40 C.F.R. 63 Subpart CC—National Emission Standards for Petroleum Refineries (Includes National Uniform Emission Standards for Heat Exchange Systems) and 40 C.F.R. 63 Subpart UUU—National Emission Standards for Petroleum Refineries (Catalytic Cracking, Catalytic Reforming, and Sulfur Plant Units).

that would further control HAPs from petroleum refineries.⁵⁵ The rule proposes additional emission control requirements for storage tanks, flares, and coking units at petroleum refineries as well as the monitoring of air concentrations at the fence-line of refinery facilities to ensure proposed standards are being met and that neighboring communities are not being exposed to unintended emissions. As with the NSPS, the refinery NESHAPS must be implemented by all refineries, regardless of size, to the extent they are categorized as either a major or area source of HAPs.

Starting in 2011, new refinery construction, refinery expansion, or modification of certain existing refineries became subject to the use of the “best available control technology” for greenhouse gas (GHG) emissions. The best available control technology is determined for each facility based on an analysis of available technologies considering cost and other factors. According to EPA, in most cases, the best available control technology selected for GHGs is energy efficiency improvements. For example, for refineries, this could involve the installation of heat recovery units, which capture and use otherwise wasted heat in the refinery process. Such energy efficiency improvements can lower GHG emissions and other pollutants while reducing fuel consumption and saving money.

Currently, there are no federal GHG emissions control standards for petroleum refineries. If promulgated, however, such control requirements standards could affect the refining industry, depending on the nature and timing of the standards.⁵⁶ In December 2010, EPA entered into two proposed settlement agreements to issue rules that will address GHG emissions from fossil fuel-fired power plants and refineries.⁵⁷ In the settlement, EPA agreed to promulgate by November 10, 2012, NSPS for GHG emissions from new and modified petroleum refineries, as well as guidelines for existing petroleum refineries. However, this deadline has since passed and it is unclear when EPA will issue a proposal or a final rule or what it would look like. Although it is unclear when, or if, federal regulations would be proposed, California’s requirements under A.B.32 are expected to affect refineries there and other states may follow.

Conclusions

The United States is experiencing an energy renaissance in producing light crude oil and natural gas. Unforeseen just a few years ago, these new resources present some challenges as well as new opportunities to U.S. refiners. Rather than U.S. refiners having to chase import suppliers, as has been the past case, some U.S. producers now find foreign brokers chasing them.

The refining industry has largely chosen to reduce the number of refineries, increase the capacity of existing refineries rather than construct new ones, and utilize foreign markets to meet domestic demands for various petroleum products when demand is high and to optimize capacity

⁵⁵ Environmental Protection Agency, “Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards, Proposed Rule,” 79 *Federal Register* 36879, June 30, 2014, <https://federalregister.gov/a/2014-12167>.

⁵⁶ Following several states that had previously promulgated mandatory reporting of GHG emissions, EPA promulgated a rule on October 30, 2009, requiring reporting of GHG emissions from most refineries (i.e., sources that in general emit 25,000 metric tons or more of carbon dioxide equivalent per year). See U.S. Environmental Protection Agency, “Mandatory Reporting of Greenhouse Gases; Final Rule,” 74 *Federal Register* 56260, October 30, 2009.

⁵⁷ Environmental Protection Agency, “Settlement Agreement for Petroleum Refineries—December 23, 2010,” <http://www2.epa.gov/sites/production/files/2013-09/documents/refineryghgsettlement.pdf>.

utilization rates when domestic demand is reduced. Given the significant expansions of refineries in the industry consolidations during the past decades, there appears to be little general evidence that such growth in refinery capacity has been impeded significantly by state and federal environmental permitting requirements. Complex refineries that locked into imported heavy crude oils to run through their cracking and coking plants are taking the new light crudes and adapting their refining economics to run them. The shift could spell more competition for smaller refineries that had depended on light crudes and that returned to profitability with the crudes' increased availability. The possibility of bypassing conventional refining altogether and exporting light crude (condensate) directly is a newly emerging development. The latter case presents possible opportunities for small businesses to enter the petroleum supply sector upstream of refining.

In light of the restrictions on exporting U.S.-produced crude oil and condensate, Congress may consider whether the definition of a refinery includes similar processes that produce product streams based on their physical properties. Congress may also wish to assess whether small business enterprises face unique challenges to entering refining, or unique opportunities now that the United States has become a net exporter of refined petroleum products.

Further Reading

For further reading on refining, we suggest the following CRS reports:

CRS Report R41478, *The U.S. Oil Refining Industry: Background in Changing Markets and Fuel Policies*, by Anthony Andrews et al.

CRS Report R43263, *Petroleum Coke: Industry and Environmental Issues*, by Anthony Andrews and Richard K. Lattanzio.

CRS Report R43390, *U.S. Rail Transportation of Crude Oil: Background and Issues for Congress*, by John Frittelli et al.

For further reading on CAFE, RFS, and Fuel Standards, we suggest the following CRS reports:

CRS Report R42721, *Automobile and Truck Fuel Economy (CAFE) and Greenhouse Gas Standards*, by Brent D. Yacobucci, Bill Canis, and Richard K. Lattanzio.

CRS Report R43497, *Tier 3 Motor Vehicle Emission and Fuel Standards*, by Richard K. Lattanzio and James E. McCarthy.

CRS Report R40155, *Renewable Fuel Standard (RFS): Overview and Issues*, by Randy Schnepf and Brent D. Yacobucci.

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