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Regulating Greenhouse Gas Emissions under Section 111(D) of the Clean Air Act: Implications for Petroleum Refineries

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Contents

Introduction

Concern that the accumulation of greenhouse gases (GHGs) such as carbon dioxide (CO_2) in the atmosphere is contributing to global climate change has led the United States to debate policy options to decrease domestic GHG emissions. Because greenhouse gases are global pollutants—they disperse uniformly in the atmosphere and accumulate over time—and because the Clean Air Act was written with local air quality in mind, Congress has considered an economy-wide carbon market or other legislative framework for regulating them. However, as attempts to enact an alternative framework have stalled, the EPA is moving forward under the Clean Air Act (CAA).

In December 2009, the agency found that greenhouse gases endanger the public health and welfare of current and future generations and in 2010 established the first GHG standards for automobiles and permitting requirements for large emitters (EPA 2009a, 2010b). In July 2013, President Obama directed the EPA under CAA § 111(d) to regulate greenhouse gases from existing sources, starting with the electric power sector (Executive Office of the President 2013a). Accordingly, the EPA proposed GHG standards for existing power plants on June 2, 2014 (EPA 2014a). Assuming that the EPA meets the regulatory schedule outlined in the president's Climate Action Plan, it will finalize standards for existing power plants in June 2015 (EPA's Forthcoming Performance Standards 2011). Once the EPA moves forward with that rulemaking, it may turn its attention to other industries, such as petroleum refining, which in 2012 was responsible for 173.3 million metric tons of CO_2 equivalent (MMT CO_2e) or 2.6% of total U.S. GHG emissions (DOE 2011; EPA 2014c).[1]

EPA Administrator Gina McCarthy has indicated that she has no immediate plans to regulate greenhouse gases from the refining sector (Geman 2014). But in 2010 the EPA entered into a settlement agreement with a group of states and nongovernmental organizations (NGOs), suggesting that a final § 111(d) rulemaking for refineries would be completed by late 2012. Despite Administrator McCarthy's statements, many stakeholders think the refining industry may be the next sector to be regulated.

This paper aims to analyze some of the key questions the EPA would face in designing a performance standard for petroleum refineries given what is known about the parameters of the agency's CAA authority and characteristics of the refining sector, which is more complex than the electricity sector and therefore may present different challenges. These questions are organized into three topics that track the three major steps of regulation design: (1) determining the ambition of the standard or level of required emissions reduction; (2) specifying the target to be implemented by the states; and (3) considering flexible compliance mechanisms. The work was informed by conversations with industry stakeholders from oil companies, trade groups, and the EPA.

Before turning to the design of a potential regulation, this paper describes the structure of the refining industry and the proposed authority to regulate its emissions under CAA §111(d). It then discusses the three major steps for the rulemaking, policy design questions that arise at each step, the EPA's options in responding to those questions, and implications for environmental outcomes, equity, and cost effectiveness. The paper concludes by highlighting key considerations for refineries, including options for tailoring discussions from power plant regulation, maximizing cost effectiveness, taking into account differences among refineries, and—given the industry's characteristics—formatting regulation in a way that may best fit them.

Background on the Petroleum Refining Industry and Its GHG Emissions Profile

As of January 2013, the United States had 143 petroleum refineries operated by 63 corporations in 31 states (EIA 2013a). These refineries range in processing capacity from as much as 600,000 to as little as

[1] The United States emitted 6,526 million metric tons in 2012.

3,300 barrels of crude oil per day. Approximately 43% of them process more than 100,000 barrels a day; another 43%, between 10,000 and 100,000 barrels; and the rest, less than 10,000 (EIA 2013a). The largest refineries by capacity are located along the Gulf Coast in Texas (27 refineries) and Louisiana (19); California also has large capacity (18 refineries) (EIA 2013b).

Most U.S. refineries have been in operation for several decades. Only four have opened since 1990. The last refinery with a capacity of more than 100,000 barrels per day (bbl/day) was built in 1977 in Louisiana (EIA 2013d). However, U.S. refineries have undergone significant upgrades since 2012, expanding total U.S. refining capacity by 2.9%; four refineries are in various stages of planning in North Dakota and South Dakota (Scheyder 2013; Dreeszen 2013). As a whole, the industry has processed roughly 15 million barrels daily since 1998; in 2013, the daily average was 15.7 million barrels (EIA 2013e).

Inputs, Processes, and Products

Each refinery has a unique combination of crude oil input(s), process units, and "product slate" (number and type of products). The world market sells roughly 195 types of crude oil, each with a different specific gravity (weight) and sulfur content (Energy Intelligence Group 2013). Low-specific-gravity ("light") and low-sulfur ("sweet") crude are considered the highest-quality crude and therefore tend to be more expensive than high-specific-gravity ("heavy") and high-sulfur ("sour") crudes, which require more processing.

Refineries are composed of an atmospheric crude distillation unit (CDU) and any number of additional process units that separate crude oil into its components and further refine those components into final products. The configuration of each refinery is unique, because of the many types of process units. One consulting firm has compiled a list of 170 process units organized into 51 general categories on the basis of process configuration and outputs. Box 1 explains some of the key process units, which deliver more than 2,500 refinery products in three major classes: fuels (e.g., gasoline, jet fuel), finished nonfuel products (e.g., solvents, lubricants, wax, asphalt), and chemical feedstocks (e.g., naphtha, butane, benzene) (EPA 1995a,b). Fuels account for 81% of U.S. refinery outputs, of which the largest by volume is gasoline (47%), followed by heating oil and diesel (20%). Chemical feedstocks, which are used to make other consumer goods such as plastics, make up 2% of the industry output, and finished nonfuel products like asphalt (2%) and lubricants (1%) are also significant products (EIA 2013c).

Box 1. Key Refinery Processes

Dozens of process units are in use at U.S. refineries.

Atmospheric Crude Distillation Unit (CDU)
All refineries have a CDU in which the crude oil is heated. As each hydrocarbon component of the crude oil reaches its boiling point, it rises in the distillation column and is separated into "fractions" by weight. The different fractions—from gases to light hydrocarbons used for fuels to asphalt to heavy residual oil—can be sent to other units for further processing.

Conversion Processes: Fluid Catalytic Cracking Unit (FCCU), Coker
Conversion processes use a combination of high heat (700–1,000°F), pressure, and chemicals to break ("crack") hydrocarbon chains or otherwise change the chemical structure of hydrocarbons.[a] Heat is supplied by gas, oil, or oil residues burned in process heaters (furnaces or boilers). Coking is a type of cracking that breaks the heavy residual oil into components that can be used in lighter products (such as gasoline or diesel).[b]

Treating/finishing Processes: Desalting, Sweetening
Finishing or treating processes remove impurities such as salts, sulfur, nitrogen, and oxygen.[c] They often require the addition of hydrogen gas, which is supplied from a hydrogen plant or as a byproduct of other processes. Some processes, such as desalting, take place before the crude enters the CDU; others, like chemical sweetening, are used to remove some of the sulfur from sour crudes either in the middle or at the end of the refining process.

Auxiliary Services: Boilers, Sulfur Recovery Plants, Hydrogen Plants
Stationary combustion sources like boilers and heaters (furnaces) provide steam, heat, and electricity to process units across the refinery and are the largest sources of CO_2 emissions within the refinery. Sulfur recovery plants convert sulfur stripped from the crude into a useable form, and hydrogen plants supply hydrogen to process units involved in some conversion processes.[d]

Flares
Flaring vents gas into the atmosphere that may otherwise build up in process units. These safety devices can be a source of emissions.[e]

[a] U.S. Environmental Protection Agency, "Petroleum Refining," *AP 42 Compilation of Air Pollutant Emission Factors, Fifth Edition,* Vol. 1, Jan 1995.
[b] U.S. Environmental Protection Agency, "Profile of the Petroleum Refining Industry," EPA Office of Compliance Sector Notebook Project, September 1995.
[c] Ibid, note a.
[d] Ibid.
[e] U.S. Environmental Protection Agency, "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry," Oct 2010.

Refinery Types

Refineries are characterized as one of three types on the basis of onsite process units. Approximately 75–80% of U.S. refineries are considered "upgrading" refineries, which have many processes to extract final products, such as gasoline, from the crude. Upgrading refineries are also known as "complex" refineries.[2] "Topping" plants, of which there are only a few (mainly in Alaska), have only a distillation column and do not produce gasoline, which requires extra processing. Finally, "hydroskimming" refineries have enough processing equipment to produce gasoline but cannot process heavy residual oils; of the roughly 30 hydroskimming refineries in the United States, 8 produce asphalt preferentially from heavy crude oils (EPA 2010a).

Emissions

Oil refineries accounted for 173.3 million metric tons of CO_2 equivalent (MMT CO2e) in 2012, roughly 2.6% of total U.S. emissions (DOE 2011; EPA 2014c). The EPA requires refineries to report emissions from 17 processes to the Greenhouse Gas Inventory. For this purpose, refineries can measure or estimate emissions from each process. The EPA uses this information to generate refinery-level and aggregate emissions data (EPA 2011). The majority of emissions within a refinery are the result of stationary combustion sources, such as boilers, which provide heat, steam, and power for other process units such as the crude distillation unit. Stationary combustion sources account for 63% of total refinery emissions (EPA 2010a). Other major emissions sources include fluid catalytic cracking unit coke burn-off, hydrogen plants, flaring, and sulfur plants. The EPA reports that CO_2 emissions from the refining sector have declined by 29% since 2000, when emissions peaked (EPA 2013a).

Emissions Drivers

The largest driver of CO_2 emissions is energy use: refineries that use more energy generate more emissions. Thus refinery capacity is a fairly reliable indicator of emissions. In addition to size, two other factors influence energy use and therefore emissions: crude oil quality and refinery configuration. The quality of the crude oil (specific gravity and sulfur content) influences emissions because lower quality crudes require more processing (Karras 2011). Refinery configuration, or a refinery's specific combination of process units, also drives emissions because only some refineries have the process units (such as cokers) to refine the heavier components of crude oil, which will increase emissions. The addition of hydrogen also increases energy use such that refineries with crude inputs that contain less hydrogen and with outputs that contain more hydrogen (added through processing) also tend to have higher emissions (Bredson et al. 2010).

Emissions Reductions Possibilities

Refineries could undertake many emissions reduction strategies, including onsite energy efficiency, fuel and crude switching, and end-of-pipe emissions control technology. Each of these strategies entails a different combination of emissions reduction potential, cost, and availability. The first course of action often is reducing onsite energy use through energy efficiency measures at key process units. Efficiency measures can be applied to both specific emissions sources and refinery-wide equipment such as the pipes that carry steam from boilers to process units. If used in conjunction with energy efficiency measures, energy management systems—which reflect a facility-wide view of energy use by setting efficiency targets, planning efficiency investments, and evaluating their performance—may help a refinery achieve deeper reductions (EPA 2010a). Though energy efficiency appears to be an effective way to reduce energy use and therefore emissions, some refineries (especially complex ones) may already be very efficient and may have exhausted the most cost-effective options.

Another potential emissions reduction strategy is fuel substitution, or switching the type of fuel burned in boilers to generate onsite heat, steam, and power. Refineries typically use byproducts of the refining process as their fuels but can also import natural gas or coal. Switching from a carbon-intensive fuel to a less intensive one would decrease emissions at the stationary combustion units (Hydrocarbon Publishing

[2] The term *complex* can be applied to refineries in two senses: in the informal sense that they are complicated, and in reference to the refinery's number and type of process units (a refinery's "complexity" or a "complex" refinery). In this report, per industry convention, the term *complex* will be used in the latter sense.

Co. 2010). However, this strategy may also lead to a waste problem if a portion of the refined product must be disposed of instead of burned (Stockle et al. 2008). Renewable energy could also reduce emissions, but refineries have little experience with its use.

Another strategy is crude substitution, which involves changing the quality of crude inputs. Because heavy, sour crudes require relatively more processing, switching to light, sweet crudes may be a straightforward way to reduce emissions. However, the elasticity of demand for different crudes is unknown. Refineries are dependent on locally available crudes or on the infrastructure to transport them, which may limit their switching capacity. Refineries may also be configured to process a certain range of crude characteristics and thus unable to process crudes outside that range without substantial modification.

Carbon capture and sequestration (CCS) is also a potential option for limiting emissions. This end-of-pipe technology removes CO_2 from exhaust streams. The CO_2 is then transported for use in a process such as enhanced oil recovery or stored underground. CCS is the only large-scale technology that captures CO_2 after it has been produced, but its application to petroleum refineries may have technological or practical limitations. For example, refineries have dozens of "tailpipes" from which the CO_2 must be collected and pressurized; there may also be little available space to build the required infrastructure.[3] CCS is also capital- and energy-intensive and may therefore be cost prohibitive.

Yet another option is to decrease demand for the industry's product to reduce production and thus emissions. Unlike the power sector—which has considered using demand-side reductions like end-use energy efficiency in GHG compliance efforts—the refining sector is unlikely to be able to utilize end-use emissions reductions (reductions in gasoline use), because it is not connected to the end user.

Summary

The 143 refineries in operation in the United States can be described by a number of factors that are important in designing a regulation, namely, inputs and outputs, unique configuration, and emissions reduction opportunities. Because the key driver of refinery emissions is energy use, reducing that use will be key in decreasing emissions to meet any standard. Crude and fuel switching also are options to reduce emissions, as is CCS theoretically. There are no good estimates of the percentage of CO_2 that can feasibly be reduced with each method or of cost to individual refineries or the industry as a whole. These estimates will emerge as the EPA begins to determine the level of emissions reduction required of the industry.

Background on the Clean Air Act and Legal Precedent

Congress enacted the Clean Air Act in 1970 (with major amendments in 1977 and 1990) in response to growing public outcry about the level of pollutants in the environment. At the time, concerns centered on ground level ozone or "smog," particulate matter, hazardous substances, and other pollutants with relatively local effects. For example, the act's major provisions establish programs for regulating mobile sources (automobiles), stationary sources (e.g., power plants, factories, and petroleum refineries), hazardous pollutants, and ambient air quality with a focus on protecting public health and welfare on a localized basis.[4] In recent years, the environmental consequence of GHG accumulations in the atmosphere has arisen as an important air pollution challenge. Unlike most pollutants regulated under the Clean Air Act, greenhouse gases are global pollutants—once emitted they disperse uniformly in the atmosphere and accumulate, with potentially significant consequences for global climate. Therefore, the timing and location of GHG emissions have little effect on the environmental consequences. Because of the global nature of greenhouse gases and the fact that the Clean Air Act was written with local air quality in mind, Congress has considered an economy-wide carbon market or other alternative legislative

[3] Stakeholder comments to the authors.
[4] *E.g.*, 42 U.S.C. § 7409 (2012) (National Ambient Air Quality Standards); § 7411 (New Source Performance Standards); § 7412 (Hazardous Air Pollutants);

framework for regulating them. However, as attempts to enact such a framework have stalled, the EPA is moving forward under the Clean Air Act.

The process of regulating greenhouse gases under the Clean Air Act was set in motion in 2007, when the U.S. Supreme Court held in *Massachusetts v. EPA* that the EPA has authority to regulate GHG emissions as a "pollutant" under the act. A group of states brought the case against the EPA, arguing that the Clean Air Act requires the agency to regulate GHG emissions from mobile sources in particular. In 2009, the EPA moved forward with mobile source standards. According to the EPA's interpretation of the act, regulating greenhouse gases from mobile sources triggers regulation of the gases from stationary sources as well. Recognizing the huge administrative burden that would immediately arise if all GHG sources were regulated using current threshold standards, the EPA issued the "Tailoring Rule" in 2010 to prioritize the order in which sources would be subject to GHG regulations. The rule emphasized the need to regulate large stationary sources first (EPA 2010c). With the tailoring rule, the EPA also established GHG permitting thresholds under the New Source Review Prevention of Significant Deterioration program. New facilities—including new petroleum refineries—that emit at least 100,000 tons per year (tpy) of CO_2 equivalent are now required to obtain an operating permit and install best available control technology as determined by the permitting authority. The same requirement applies to existing facilities that emit at least 100,000 tpy and that make changes that increase emissions at least 75,000 tpy.

Four years after the *Massachusetts v. EPA* decision, the Supreme Court confirmed in *American Electric Power v. Connecticut* the EPA's authority to also regulate power plants (a category of stationary sources) under § 111.[5] Here, the Supreme Court spoke directly to the issue of regulating existing stationary sources, noting that § 111(d) "requires regulation of existing sources within the same category."[6] Thus CAA § 111 provides the framework for regulating stationary sources of air emissions, such as power plants and petroleum refineries. Section 111(b) addresses emissions from new and modified stationary sources, and § 111 (d) provides for regulation of existing sources when a particular pollutant is regulated under § 111(b) but not regulated under other parts of the act that deal specifically with the concentration of common ("criteria") air pollutants in ambient air or with hazardous air pollutants.[7] Because § 111(d) applies only in this specific set of circumstances, it has been regulated under only a handful of times.

In the summer of 2013, President Obama directed the EPA to begin regulating greenhouse gases from existing sources under § 111(d), beginning with the power sector (Executive Office of the President 2013b). The EPA proposed standards for existing power plants on June 2, 2014 (EPA 2014a), and according to the regulatory schedule outlined in the president's Climate Action Plan, the agency will finalize those standards in June 2015. Although EPA Administrator Gina McCarthy has indicated that she has no immediate plans to regulate greenhouse gases from other categories of stationary sources, the EPA may turn its attention to other industries (EPA's Forthcoming Performance Standards 2011).

If so, the petroleum refining industry is a potential candidate. The EPA issued a final rule in 2008 that updated the new source performance standard (NSPS) for petroleum refineries but did not include standards of performance for greenhouse gases (EPA 2008). A group of states and NGOs subsequently challenged the NSPS rule, arguing that it should have included such standards. In 2010, the EPA entered into a settlement agreement, according to which it would develop a comprehensive approach to regulating GHG emissions from refineries.[8]

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[5] 131 S. Ct. 2527 (2011).
[6] *Id.* & n.7.
[7] 42 U.S.C. § 7411 (2012).
[8] Settlement Agreement for Petroleum Refineries (Dec. 23, 2010), http://www2.epa.gov/carbon-pollution-standards/2010-proposed-settlement-agreements-address-greenhouse-gas-emissions.

The 2010 settlement set deadlines for the EPA to submit proposed performance standards for both new and existing refineries (December 10, 2011) and final rules (November 10, 2012). The EPA has instead begun its § 111 rulemakings with power plants and has consequently fallen behind on these deadlines. If the EPA were to turn to petroleum refineries, it would follow a process to similar to the one currently under way in the power sector.

Regulating under Section 111(d)

The Clean Air Act defines a three-step process for regulating under § 111 (d). First, the EPA must develop an emissions guideline (standard) on the basis of the best system of emission reduction (BSER). The BSER must consider compliance costs as well as any "non-air quality health and environmental impact[s]" and must be "adequately demonstrated."[9] Second, the EPA must communicate the guideline to the states, which have primary authority to develop standards of performance that "reflect" the EPA guideline.[10] Third, states must submit plans to the EPA describing their proposed standards of performance and plan for implementing and enforcing them (a plan similar to a state implementation plan, or SIP, under § 110), which is subject to EPA approval. The Clean Air Act provides that states can take into account the remaining useful life of the existing sources in question, "among other factors."[11] If the state fails to submit or enforce a plan, the EPA can prescribe a federal plan.

Although § 111(d) is silent on EPA's authority to revisit its guideline, the Clean Air Act requires that standards of performance for *new* sources be reviewed and, if necessary, revised every eight years under § 111(b).[12] The act explicitly states that EPA cannot require that *new* or *modified* sources "install and operate any particular technological system of continuous emission reduction to comply with any [NSPS]."[13] Therefore, standards of performance may be based on a particular technology (achievable with the BSER), but covered sources are free to apply other system(s) of emissions reduction as long as they comply with the standards.

In explaining the role of states, § 111(d) expressly references § 110, which sets out the rules for state implementation plans for national ambient air quality standards. Therefore, provisions of § 110 may inform the process of state plan submission under § 111(d). Notable is the flexibility states have to create a program to reduce emissions. Specifically, SIPs "shall . . . include enforceable emission limitations and other control measures, means, or techniques (*including economic incentives such as fees, marketable permits, and auctions of emissions rights*)."[14] This language suggests that states have flexibility to design systems to achieve the EPA's emissions guideline.

However, the EPA has regulated under § 111(d) just five times, and the degree of flexibility available to it and the states is untested (EPA's Forthcoming Performance Standards 2011). Through the Clean Air Mercury Rule (CAMR), finalized in 2005, the EPA attempted to develop a market-based emissions trading system for power plant mercury emissions (EPA 2005). The D.C. Circuit Court of Appeals ultimately vacated the rule, holding that because mercury was already listed as a hazardous air pollutant, it could not be regulated under § 111(d). Consequently, the court never ruled on the legality of the specifics of CAMR—in particular, a voluntary cap-and-trade program included as a model rule and model-based mass caps for states.[15] This failed attempt does not, therefore, preclude a cap-and-trade program or a mass standard for refineries. Although the legality of CAMR's market-based approach

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[9] 42 U.S.C. § 7411(a)(1) (2012).
[10] § 7411(d)(1).
[11] *Id.*
[12] § 7411(b)(1)(B).
[13] § 7411(b)(5).
[14] § 7410(a)(2)(A) (emphasis added).
[15] *New Jersey v. EPA,* 517 F.3d 574, 583–84 (D.C. Cir. 2008) (holding that because the EPA had already regulated mercury under § 112, it could not be regulated under § 111).

under § 111 (d) was not tested, the EPA's attempt to establish a trading system for CAMR may provide some insight into what a trading system might look like for the refining sector. The EPA's proposed emissions guideline for the power sector does not identify trading as a component of the best system of emission reduction (EPA 2014a). The proposal does, however, adopt a broad interpretation of "system" that includes activities beyond the fence line of covered sources (e.g., end-use energy efficiency), and it identifies trading as an option for state plans (EPA 2014a).

Precedent for Regulating Petroleum Refinery Emissions

Although precedent for regulating under § 111(d) is limited, some non-GHG emissions from petroleum refineries are already regulated under CAA provisions. For example, under § 111(b), refineries are required to comply with a NSPS for other pollutants such as nitrogen oxides (NO_X) and sulfur dioxide (SO_2). The EPA also regulates emissions of hazardous air pollutants (HAPs) from petroleum refineries under § 112. Refineries must also apply for prevention of significant deterioration (PSD) permits when making major facility modifications or when building new refineries under CAA Part C. In addition, and distinct from CAA precedent, Washington state is drafting its own rule to regulate GHG emissions from refineries under Washington state law.

Each of these cases may provide insight into the approaches that the EPA would likely consider for regulating petroleum refineries under § 111(d). For refineries under other CAA provisions, the agency has established "differentiated" standards—different standards for categories of refineries or processes within a refinery. In addition, it has allowed averaging or "bubbling" of emissions across processes within a refinery for compliance purposes, and it has established both rate- and mass-based based standards.[16] Washington state's current GHG rulemaking may also establish precedent for a trading system, an efficiency standard, or a percentage reduction against a baseline year.

Differentiation

The EPA has established new source performance standards for petroleum refineries for particulate matter (PM), NO_X, SO_2, and carbon monoxide (CO). In doing so, it has "differentiated" or established different standards for different categories of refineries in a number of ways. One way is by process. Refineries face different performance standards depending on the point at which emissions come (i.e., fluid catalytic cracking units, fluid coking units, sulfur recovery plants, fuel gas combustion devices, process heaters). The standards are further differentiated by capacity. Sulfur recovery plants with high capacity have different emissions standards than plants with lower capacities. Finally, the NSPS are differentiated by subprocess: sulfur recovery plants of a certain capacity that incinerate are held to one standard; plants of the same capacity that do *not* incinerate are held to another standard.

Like new source performance standards, HAP regulations distinguish by process. These regulations affect only certain sources (processes) within a refinery (e.g., storage vessels, wastewater streams, gas-loading racks, marine tank vessels, and miscellaneous process vents). These regulations also allow some emissions averaging across emissions points within the plant, although new sources (process units) are excluded, and the EPA has discretion to disallow averaging for specific plants. Plants that average must submit monthly data to show annual compliance and must also meet targets for quarterly compliance.

Rate- versus Mass-Based Approaches

The EPA has established different rate-based new source performance standards for PM, NO_X, SO_2, and CO. HAP regulations are typically rate-based (e.g., particulate matter emissions from fluid catalytic cracking units are regulated in grams per 1,000 kilograms of coke burnoff, and some sulfur recovery units

[16] "Bubbling" is a specific case of averaging wherein multiple emissions points within a single plant are treated as a single emissions point (as if a bubble were drawn over the facility). The EPA has applied the concept of bubbling with respect to the Clean Air Act's New Source Review program. See *Chevron USA v. NRDC* 467 U.S. 837, 104 S. Ct. 2778, 81 L. Ed. 2d 694, 21 ERC 1049 (1984).

have a 250 ppmv limit). The Clean Air Mercury Rule, which did not survive judicial review, included mass-based limits for power plants.

Refineries built or significantly modified after January 2011 are already subject to pre-construction PSD permitting under CAA Part C. The PSD program requires major sources, including refineries, to implement the best available control technology (BACT). This technology is decided on a case-by-case basis in consideration of both the emissions reduction and its cost. Since 2012, according to EPA's RACT/BACT/LAER Clearinghouse (EPA 2014b), three petroleum refineries have made modifications significant enough to require PSD permits. Each of these facilities is subject to rate-based GHG emissions limits on a 12-month rolling average.

Washington State Rule: Trading, Efficiency Standard, or Reduction against Historical Baseline
As a result of litigation, stakeholders and Washington state government are working to create a viable regulation to limit GHG emissions from existing petroleum refineries in the state. The Sierra Club and the Washington Environmental Council sued state agencies for failing to implement section 70.94.154 of the Revised Code of Washington, which requires all existing emissions sources to have and meet reasonably available control technology (RACT) standards. Though the case was ultimately vacated, Washington continued its rulemaking. A draft of the regulation proposes that refineries would have to meet an energy efficiency standard to demonstrate compliance.[17] Direct emissions reductions would come into play if they did not meet energy efficiency requirements.[18] The direct reduction provision would require affected facilities to "implement greenhouse gas reduction projects" that reduce "cumulative annual emissions" by 10% of GHG emissions from 2010.[19]

Though the EPA is not limited to previously used options, these options pose less legal risk than untested approaches. Looking to CAA precedent to determine how other pollutants are regulated in refineries, how some parties are attempting to regulate greenhouse gases from refineries on their own, and how emissions reduction systems have worked in other contexts shed light on the range of options available to the EPA in a refinery rulemaking. The EPA's current rulemaking to establish CO_2 limits for existing power plants under §111(d) will be another important source of precedent if and when the EPA turns to other sectors. However, some aspects of the EPA's approach in the electricity sector may not transfer to the refining sector because of differences between the industries.[20]

Key Questions in a § 111(d) Rulemaking for Petroleum Refineries

If and when the EPA considers options for limiting CO_2 emissions from the petroleum refining under §111(d), it would have a wide range of options in designing the standard. As explained above, the Clean Air Act requires that the agency consider multiple factors, including legal, economic, environmental, and industry-specific outcomes, but it has discretion to select a guideline for the best system of emissions reduction for petroleum refineries. Similarly, states have discretion to make their own determinations about how to design their 111(d) plans to implement that guideline.

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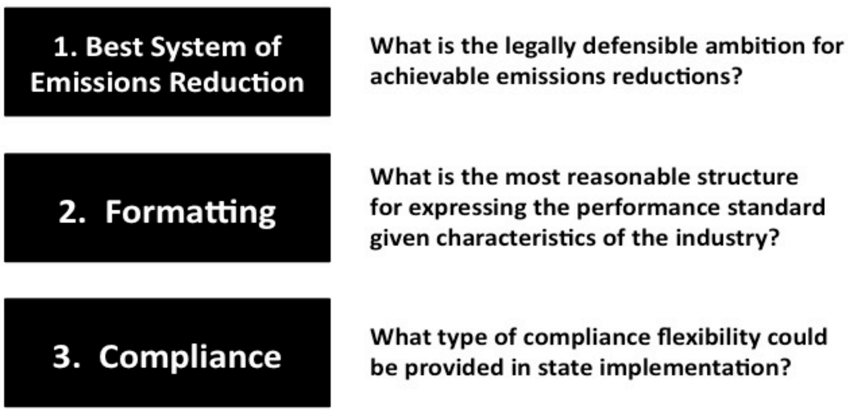
[17] WASH. ADMIN. CODE § 173-485-040(1) (Preliminary Draft, Sept. 19, 2013).
[18] *Id.* ("If a petroleum refinery is unable to or chooses not to demonstrate compliance with the energy efficiency standard in the first annual report . . . the petroleum refinery shall meet the requirements of [the section called 'Emission Reduction Requirement'] no later than October 1, 2025.").
[19] WASH. ADMIN. CODE §§ 173-485-040(2)(a), 173-485-030(1) (defining "baseline greenhouse gas emissions").
[20] For an overview of key differences between the refining sector and power sector that could influence a 111(d) rulemaking, *see* Kristie Beaudoin, Allison Donnelly, Sarah K. Adair, Brian Murray, Billy Pizer, and Tim Profeta, "Regulating Greenhouse Gases Sector by Sector under the Clean Air Act: How Well Does the Electric-Generating Unit Experience Translate to Petroleum Refineries?" NI PB 14-02, Nicholas Institute for Environmental Policy Solutions, Duke University.

Figure 1 illustrates the three-step process to establish regulations under § 111(d): (1) the EPA identifies the best system of emissions reduction (BSER), (2) it communicates this regulation to states, and (3) states develop and implement programs to comply with the regulation, a task in which they have significant flexibility.[21] Some major issues may arise at each of these steps. The discussion below addresses the EPA's options for determining the best system of emissions reduction, the formatting options available to the EPA in communicating the regulation, and state flexibility in shaping their compliance plans.

Figure 1. Steps to §111(d) Rulemaking.



Best System of Emissions Reduction

The statutory language of § 111 requires the EPA to base any standard of performance on the level of emission reductions achievable under the best system of emissions reduction. In this regard, it must make two decisions. First, it must determine the scope or the boundaries of the system. For example, the system may apply separately to individual process units within a refinery, may include subsystems that manage energy throughout individual refineries, or may include regulatory systems such as tradable performance standards that apply to many refineries. Given this notion of scope, the EPA must then determine which of the available systems of emissions reduction is "best."

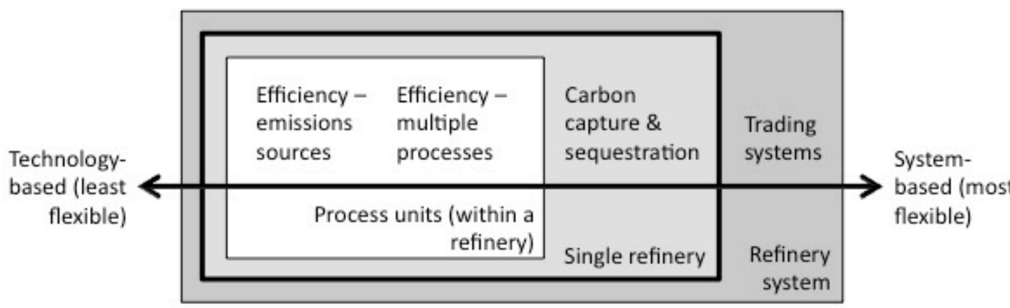
Section 111 of the Clean Air Act also specifies that the EPA, when establishing standards of performance, must take into account the cost of achieving the required reduction as well as the non-air-quality health and environmental impact of the reduction and energy system requirements (42 USC § 7411(a)(1)). The act's explicit identification of cost as a criterion for identifying the best system of emissions reduction brings into play market-based mechanisms such as emissions trading or tradable performance standard approaches if the term *system* is defined to include regulatory systems in addition to specific technologies or work practices. Market-based regulatory systems take advantage of the lowest-cost abatement opportunities across regulated sources by effectively establishing a common marginal cost of emissions—the price of an emissions allowance or credit—and by allowing individual sources to over- or under-comply, depending on source-specific opportunities for abatement. Procurement of compliance "credits"

[21] This process is based on the EPA's determination of how § 111(d) regulations are created, a determination with which some stakeholders disagree.

by sources that under-comply from those that over-comply ensure that the entire regulated system is in compliance.

The chosen emissions reduction system will not necessarily determine actual emissions reductions activities because of the role of states in implementation. Therefore, the primary consequence of EPA's BSER choice is the regulation's required level of emissions reduction, which must be based on emissions reductions achievable through application of the chosen system. The EPA has multiple plausible BSER options. It could also choose a combination of options (i.e., multiple technologies or systems), similar to the approach it takes in its June 2, 2104, proposal for regulating existing electric-generating units. The four options discussed below and pictured in Figure 2 range from technology-based systems within the refinery (least flexible) to non-technology-based systems encompassing multiple refineries (most flexible). Because flexible systems tend to reduce compliance costs relative to inflexible standards, a broader definition of *system* (i.e., one including market-based regulatory approaches) could result in a more ambitious regulation. As noted above, the EPA adopted a broad definition of "system" in its power sector proposal—including activities such as end-use energy efficiency and renewable energy investments that reduce emissions from the sector as a whole but that do not take place at a particular source (EPA 2014a). The definition does not include market-based regulatory systems such as trading.

Figure 2. Spectrum of BSER Options.



Individual Emissions Sources (Process Units)
If the EPA determines that the best system of emissions reduction refers only to technology from specific emissions sources within a refinery (i.e., process units that directly emit CO_2), it may set the standard on the basis of an achievable emissions profile for each type of process unit. The EPA can decide how many and which process units within the refinery to include. Such a narrowly defined system might result in a less ambitious standard for two reasons. First, defining a standard for multiple process units will result in exclusion of emissions from units not covered by the standard. Second, upgrading process units to the BSER level could entail relatively high costs—a factor the EPA must take into account in determining the best system of emissions reduction—and hence a relatively unambitious standard.

Suite of Efficiency Measures
A more flexible approach to a technology-based best system of emissions reduction is a refinery-wide package of efficiency measures, which could include specific emissions sources as well as the equipment that links them (i.e., a boiler and the heat exchanger network that carries the heat to other process units). This approach would encompass more of a refinery's emissions than the emitting process-based approach and could lead to a more ambitious required level of emissions reductions than a system based solely on emissions points. The EPA could determine the reduction level on the basis of emissions levels if refineries were to institute *all* reasonably available efficiency measures. Efficiency measures ("heat rate improvements") were included as one component of the BSER in the June 2, 2014 proposal for existing power plants (EPA 2014a).

The EPA could also consider emissions reductions under a typical energy management system, which allows refineries with piecemeal efficiency investments to increase their overall efficiency by setting targets, coordinating processes, and conducting performance evaluations. However, such a system does not by itself guarantee emissions reductions because it is not a technology; it aims to maximize reductions from energy efficiency activities. Nevertheless, by allowing refineries to achieve the greatest possible emissions reductions from application of efficiency measures, an energy management system could result in a more ambitious standard than a standard reflecting efficiency measures alone.

Carbon Capture and Sequestration
Carbon capture and sequestration (CCS) is a technology that captures emissions at the source (here, refineries as a whole) and transports them to either a storage facility (usually underground) or a location where they can be used in an industrial process. This technology is capable of major emission reductions, and if chosen as a best system of emissions reduction would presumably lead to a level of reductions that is much more ambitious than under other BSER possibilities. However, the EPA has not identified carbon capture and sequestration as a component of the best system of emissions reduction for existing power plants under its current rulemaking, making the technology an unlikely BSER selection for petroleum refineries (EPA 2014a). Furthermore, stakeholders have put forth two arguments against identifying CCS technology as the best system of emissions reduction. First, the technology has not been adequately demonstrated as applied to refineries—a statutory requirement for the best system of emissions reduction. Second, some stakeholders argue that selection of CCS technology as the best system of emissions reduction would functionally force refineries to adopt that technology (because no other system could achieve similar reductions), thereby violating a statutory provision that the EPA cannot require application of a particular system.[22]

Trading: Systems-wide Reductions
Finally, the EPA may look to regulatory systems such as emissions trading as the best system of emissions reduction. Trading systems are the most flexible of the five approaches described here. At the same cost as the other approaches, they would enable the sector as a whole to achieve more emissions reductions. However, there is little precedent for, and therefore a degree of legal risk associated with, a determination that a trading system constitutes the best system of emissions reduction.

Other emission reductions activities that the EPA could consider in a BSER determination for the refining sector include shifts to cleaner sources for onsite energy use (electricity, steam) or use of higher-quality crudes. Each of these activities, and the potential impact on GHG emissions, is further discussed in the following sections.[23]

BSER Summary
The language of §111(d) provides some guidance to the EPA on how to identify the best system of emissions reduction. First, the EPA must consider factors beyond level of emissions reduction. As noted above, it must take into account the cost of implementing a system as well as other "nonair quality health and environmental impact[s]." Therefore, even a system with the greatest emissions reduction capacity but with high economic and other environmental costs may not be the "best" system.

Next, the EPA must ensure that the best system of emissions reduction has been "adequately demonstrated." This clause implies that there must be some level of experience with the system in some context. As noted above, some stakeholders argue that carbon capture and storage has not been adequately demonstrated and therefore cannot be considered the best system of emissions reduction.

[22] Stakeholder comments to the authors.
[23] See "State Compliance Options" for a discussion of the potential role of on-site clean energy sources and "Differentiation—Crude Type" for a discussion of potential emission reductions from use of higher quality crude.

Ultimately, the EPA's BSER choice will determine the ambition of the standard. Although §111(d) grants states flexibility to implement the standard, this choice will influence compliance options. If, for instance, the EPA were to determine that the best system of emissions reduction is a tradable performance standard and thus establishes a relatively ambitious target, individual refineries may be unable to meet that standard without trading. On the other hand, if the EPA were to set a standard on the basis of energy efficiency measures at individual refineries, thereby establishing a relatively unambitious standard, flexible state implementation strategies would reduce the cost to achieve that standard. Some stakeholders who support this approach have argued that the best system of emissions reduction can apply only to specific technologies within a refinery but that states have flexibility in implementation. For existing power plants, the EPA has proposed a four-part best system of emission reduction that includes offsite activities that displace emissions from regulated units (e.g., renewable energy, end-use energy efficiency) but that does not specify market-based systems, such as emissions trading (EPA 2014a).

Formatting

In conjunction with identifying the best system of emissions reduction and determining the level of emission reduction achievable under that system, the EPA must also decide how to specify the performance standard to the states. For example, the agency may choose to specify different targets for different refineries on the basis of factors such as size, complexity, or historical emissions. The EPA must also decide whether to identify the target as a total allowable mass of emissions over a period of time or as an emissions rate based on some measure of production or fuel inputs. For example, in the electric power sector, the EPA has proposed a single rate-based emissions guideline that is differentiated by state and adjusted for deployment of non-emitting generation and energy efficiency. The average performance of covered units must achieve the state-specific guideline, and the choice of whether to apply standards to covered sources is left up to the states. States also have discretion to translate the guideline into a total allowable mass of emissions (EPA 2014a).

Like the best system of emissions reduction, these choices for quantifying the standard, or the format of the regulation, may influence the implementation and compliance choices of refineries. Various formats may be more or less compatible with flexible compliance options such as trading, which tend to reduce the overall cost of compliance; more or less likely to distort refinery operational choices; more or less complicated to administer; or associated with different consequences for the distribution of effort among refineries.

In writing the standard, the EPA must answer three fundamental questions (table 1):

- Whether and how the standard will be set at a single level for all refineries or differentiated across refineries;
- Whether the standard is set as a mass or a rate; and
- If a rate, whether it will be based on refinery-wide inputs or outputs or on individual refinery processes' throughput.

Depending on how the regulation is written, states may choose to revisit the format, including whether to set different standards for different types of refinery within the state, subject to EPA approval.

Table 1. Taxonomy of Regulatory Formats.

	Mass	**Rate**		
		Input	Output	Process
Single/Refinery-wide				
Differentiated				

Differentiation

Differences in refineries' combination of crude oil inputs, process unit configuration, product slate, and capacity suggest that a given standard will be easier to meet for some refineries and much more difficult for others. Therefore, the EPA may want to consider establishing different standards for different refineries. Such differentiation has a legal basis, both in precedent from existing rules as well as in the regulations in implementing § 111(d).[24] Differentiation could involve sub-categorization—grouping refineries on the basis of size, crude type, processes, and so on—or it could involve a formulaic approach whereby the standard for each refinery is established as a function of the refinery's measurable features (i.e., historical emissions).

In essence, differentiation reflects the degree to which the emissions standard would be tailored to individual refineries. If the EPA chose to set a single standard, all 143 U.S. refineries would have the same emissions limit, regardless of differences among their inputs, outputs, and processes. But if the standard were formatted as a percentage reduction in emissions over a baseline year for each refinery, a different standard for each refinery would result.

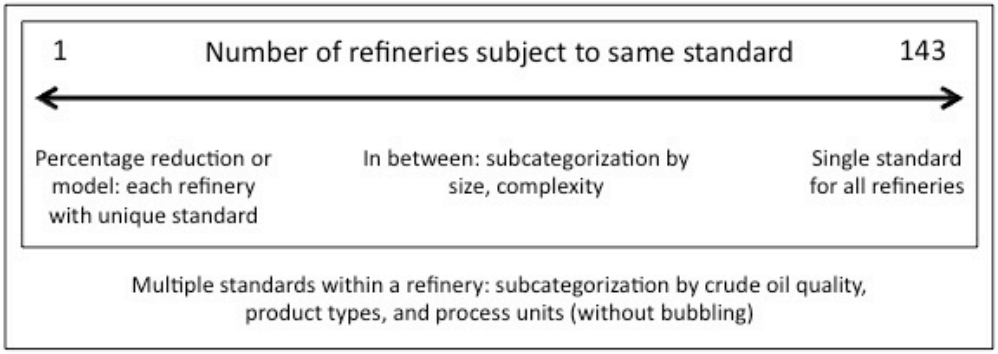
In between those extremes come many approaches reflecting how the EPA chooses to subcategorize or formulaically represent the industry. For example, if the EPA were to set three standards on the basis of subcategories of size—one for refineries with more than 100,000 barrels per day (bpd) operating capacity, one for refineries between 10,000 and 100,000 bpd, and one for refineries with less than 10,000 bpd, there would be 64 refineries in the first category, 71 in the second, and 8 in the third.

If the agency were to set standards on the basis of inputs, outputs, or process units, each refinery might have to simultaneously meet multiple standards. For example, if a standard were product based, each refinery would have to demonstrate compliance with standards for each of its product categories (gasoline, asphalt, lubricants, and so on). Such an approach could be translated into an overall limit for a single refinery through averaging.[25] The discussion below elaborates on several natural differentiation options.

[24] "The Administrator will specify different emission guidelines or compliance times or both for different sizes, types, and classes of designated facilities when costs of control, physical limitations, geographical location, or similar factors make sub-categorization appropriate." 40 C.F.R. §60.22 (b)(5)

[25] See note 17 on bubbling.

Figure 3. Spectrum of Differentiation Options.



Size

One of the most obvious differences among refineries is size; the largest refinery in the United States can process more than 600,000 barrels of crude oil per day, whereas the smallest processes just 3,300. The EPA has differentiated sources by size before: the proposed NSPS for power plants includes separate standards for gas-fired power plants of different capacities. In this instance, the EPA defined smaller units as a capacity of less than or equal to 850 mmBtu/hour. These units would face a standard of 1,100 lbs/MWh. Larger units—those with a capacity greater than the 850 mmBtu/hour—would face a more stringent standard of 1,000 lbs/MWh (EPA 2014d).

Size is distinct from the concept of "complexity," which takes into account number and types of process units. "Complex" refineries are usually defined as those with the capacity to process heavy oil residuals. Roughly 85% of U.S. refineries have this capacity (EPA 2010a). A slightly different definition arises under California's AB 32 carbon trading system, where refineries are categorized as "typical" and "atypical" on the basis of both complexity and size; an "atypical" refinery (one with fewer than 15 process units and 20 million barrels processed per year) faces a less stringent standard than a "typical" refinery (CARB 2014a).

Crude Type

Another difference among refineries is type of crude input, a major driver of emissions. Differentiating the emissions standard on refineries' use of crude type(s) could involve establishing discrete categories of crude on the basis of their quality. However, because of the large number of types of crude oil sold on the world market (roughly 195), differentiation by crude type might involve a formulaic method. For example, a standard might be set as a function of a crude's specific gravity and sulfur content. This method would effectively set a different standard for each type of crude that U.S. refineries may use.

Differentiation based on crude type requires careful consideration, because it might reduce desirable opportunities to reduce emissions through lower-quality to higher-quality crude switches (Burtraw et al. 2014). All else equal, lower-quality crudes require more processing (and more energy) and thus generate more emissions per barrel than high-quality crudes. Thus, refineries may have cost-effective opportunities to shift to higher-quality crude. However, refineries' financial gain from a switch to a less-emissions-intensive input would be reduced to the extent that the switch invokes a more stringent standard.

Crude switching becomes less relevant when refineries are less able to alter the type of crude input because of transportation (e.g. pipeline) constraints and the unique configuration of onsite process units. New process units are large capital investments, and for the purposes of existing-source CO_2 regulations, they would potentially redefine the new process unit or entire refinery as a "modified" source and take the refinery out of the "existing source" category.[26]

An additional challenge to differentiating by crude input is accounting for other refinery differences. Even among refineries that process the same blend of crude, emissions intensities may vary (and may be difficult to change) on the basis of type of onsite processing equipment, product types, or both. For example, all else equal, a barrel of West Texas Intermediate (WTI) crude oil at a refinery that creates relatively lighter products (i.e., gasoline) would be associated with higher emissions than a barrel of WTI at a refinery that produces crudes at natural fractions (i.e., allows crude oil to naturally separate out and refrains from converting some fractions to more desirable ones). Therefore, other approaches to differentiation might better address equity concerns and avoid undermining potentially cost-effective opportunities to reduce emissions through crude type switches.

Product Slate

Refineries produce roughly 2,500 products, including 40 blends of gasoline specified for different U.S. locations on the basis of local regulations at different times of year (EPA 1995a,b). These products are associated with different amounts of refining and therefore different levels of emissions. Moreover, the relative amount of products produced from a single barrel of oil—known as the product slate—differs among refineries. Therefore, multiple standards could be written to differentiate by output. However, this approach faces multiple practical challenges. First, establishing separate standards for each of the more than 2,500 refinery products is administratively infeasible. Refinery products could be grouped, and standards for product categories (e.g. fuels, petrochemical feedstocks, and finished nonfuel products like solvents) could be established, but there is no obvious method for establishing groups of products with particular emissions profiles. Moreover, it is not obvious what emissions go with what products during the refining process, given that products are jointly produced and, in some cases, a single product is produced through multiple process pathways that may be associated with different emissions levels. Thus, product-specific compliance would require (somewhat ad hoc) calculations to allocate typical emissions to each product (Bredson et al. 2010). Even if averaging were allowed across product groups, establishing an appropriate standard for a given group could be challenging.

Historical Emissions

One alternative approach to differentiation is to require a percent reduction over a baseline year, an approach similar to that proposed by most carbon legislation (and one that would work for both a mass or rate standard). This approach would result in a different target for each refinery, because each refinery has different emissions. An important part of the regulation would be the baseline year, which is the point of comparison for current emissions. Setting a baseline year too close to the present may effectively penalize refineries that have already made emissions reductions by setting higher standards; setting a baseline year too far back may unfairly benefit those same refineries.[27] Moreover, because refinery emissions differ from year to year, a low emissions year for the industry or refinery may lead to inadvertently stricter standards. One way around this problem might be to set the emissions target as average emissions across several years to take into account fluctuations.[28]

Multiple

The EPA could choose to differentiate by multiple conditions. The proposed new source performance standard for electric power plants differentiates by fuel (coal versus natural gas) and then further differentiates natural gas-fired plants by size. For refineries, this approach might appear to be a limit

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[26] 42 U.S. Code § 7411(a)(4)

[27] Recent uprates at a number of U.S. refineries could also make comparison to an earlier baseline more difficult.

[28] The EPA uses a 2012 baseline to calculate state-specific emissions guidelines for the electric power sector in its June 2, 2014, proposal. The proposal states that the EPA considered a baseline that reflects averages over a three-year period (2009–2012), but that it rejected that approach because it would have yielded a similar result as the simple 2012 baseline.

calculated as an emissions rate per barrel input, wherein the standard for each type of crude oil is given by a function of specific gravity and sulfur content, and a relatively low stringency is established for refineries below a certain capacity. Or, a multiple-condition approach might look like a percentage reduction over a baseline year, with a larger percentage requirement for large refineries than for small ones. The EPA's proposal to regulate GHG emissions from existing electric-generating units sets a unique rate-based emissions guideline for each state, which covered sources within the state must achieve on average (EPA 2014a). In developing state-specific guidelines, the EPA considers multiple factors, including (1) historical emissions, (2) capacity to re-dispatch existing fossil fuel generation, (3) regional renewable energy potential, (4) existing and under-construction nuclear capacity, and (4) potential to reduce in-state emissions through end-use energy efficiency, based on whether a state is a net importer of electricity (EPA 2014a).

Mass vs. Rate

Like the EPA determination about whether and how differentiation may be appropriate, a key question is whether to present the emissions limit(s) in terms of an emissions mass (total tons emitted over a given period) or as a rate (tons per unit of activity). A mass-based standard would function like a quota, providing an upper limit on refinery emissions. The agency could also set an emissions budget for each state, which the state could then determine how to allocate to refineries within its borders. A rate-based standard would establish the amount of emissions permissible per unit of production, input, or throughput (the emissions intensity). The EPA may also choose to communicate equivalent mass- and rate-based standards or, like its approach in its June 2, 2014, proposal for the electric power sector, guidance on how states can convert from one to the other. Regardless of format, states will have more certainty with regard to approaches that the EPA speaks to directly (Tarr et al. 2013).

Mass

The EPA could establish mass-based emissions budgets in one of three ways. First, the limits could be set as a percentage reduction of emissions over some baseline year (i.e., a 10% reduction over emissions in the year 2000). Many stakeholders have expressed support for this method, which as discussed above would differentiate refineries on the basis of historic emissions. However, it may carry legal risk because the percentage may be viewed as arbitrary, whereas performance standards are typically based on reductions achievable through application of a specific technology or system. Second, achievable reductions could be modeled across refineries through a trading system, and the resulting predictions could be used to give each state an emissions quota, an approach similar to that used in the proposed Clean Air Mercury Rule. This method would similarly differentiate refineries on the basis of the EPA's assumptions about the cost of emissions reductions from each refinery. Although accurately modeling plant-level reduction opportunities may be difficult, this method would comport with a determination that a trading system is the best system of emissions reductions. Third, the EPA could determine an emissions intensity or rate on the basis of a technological analysis and use that rate multiplied by the throughput of each refinery in a baseline year to set the mass limit. All these options would set unique standards for each refinery. To further address equity, the EPA could differentiate standards by refinery size, crude quality, product slates, or some combination of these factors.

A standalone, refinery-specific emissions mass limit in the absence of trading is imaginable but would ignore the main reason for pursuing a mass-based approach. Theory suggests that linking refineries through a tradable mass-based approach is the most cost-effective of the options that may be available to the EPA for regulating the refinery sector under § 111(d). Under a tradable mass-based approach, plants are issued "credits" that permit one unit (e.g., ton) of emissions such that the total number of issued credits equals the emissions budget (cap), and each plant is required to hold credits equal to its total emissions. Regulated entities are allowed to trade credits to establish a market price of emissions. Regardless of how allowances are allocated (e.g., auctioned or given away for free), all regulated sources face the same decision to purchase emissions credits on the market or reduce emissions and sell credits at the market price. They would generally choose to reduce emissions up to the point that the cost of doing so equals the price they would have to pay in the market. Because all sources face the same allowance price, the marginal costs of emissions reduction are equalized industry wide, which allows the emissions cap to be met at the lowest total cost across the sector. Given the CAA cost consideration requirement for BSER selection, the trading approach, trading allows a relatively aggressive target to be set.

Emissions trading could also be used with a rate-based approach, as discussed below, but only trading with a mass-based approach would pass the cost of emissions credits through to consumers in the market price of refinery products. In theory, this pricing should encourage cost-effective reductions in consumption of refinery products that reduce the sector's overall emissions. For example, consumers may respond to allowance prices reflected in the price of gasoline by reducing automobile use or purchasing relatively efficient vehicles (Goulder and Parry 2008). For this reason, mass-based accounting systems are commonly used for CO_2 emissions trading schemes (such as the RGGI, the European Trading System, and the proposed American Clean Energy and Security Act in 2009). However, to the extent that products produced by unregulated sources can be substituted for products produced by regulated sources, the consumer price signal is undermined by emissions leakage. That is, emissions from a non-regulated sector or location increase due to outsourcing of a refinery process that partially or wholly offsets the reductions achieved in the U.S. refining sector (EPA 2009b). This possibility undermines the otherwise strong argument that trading with a mass-based approach is the most cost-effective design option.

Finally, one view regarding a mass-based approach to CO_2 regulation (with or without trading) is that it would limit total emissions, as opposed to a rate-based approach, which would fix emissions intensity but allow total emissions to fluctuate in response to changes in production. A limit on total emissions could be viewed as an advantage, in terms of environmental protection, or as a disadvantage, because it may limit industry growth. However, this particular advantage or disadvantage is misleading in the context of CAA § 111. Because the law entails separate regulatory approaches for new sources and modified sources, emissions could grow *outside* the cap in the case of new refineries or of modifications to existing refineries that expand capacity. Meanwhile, the overall fluctuation in production at existing refineries (which typically run near capacity) is likely to be minimal.

Rate

The primary advantage of a rate-based approach is that it has significant precedent in Clean Air Act rulemaking.[29] Performance standards under the Clean Air Act are almost always communicated as rates, though the denominator may change on the basis of the pollutant and industry. However, from an equity standpoint, a single rate would fail to capture much of the variation in emissions and emissions reduction opportunities across refineries. To remedy this problem, the EPA would need to differentiate refinery standards by size, number or type of process units, crude oil quality, or product slates. Alternatively, it could base the rate on an historical baseline, but this approach looses the advantage of precedent.

Rate-based approaches are still compatible with trading schemes; the emissions rate is multiplied by the refinery's throughput (measured in whatever metric is set as the rate's denominator) to get the total allowable mass of emissions prior to trading. As an economic matter, rate-based performance standards (emissions/X) in a trading scheme can be viewed as a tax on emissions and as a subsidy on X. If, say, the standard was 0.05 tons of CO_2 per barrel of crude oil flowing into a refinery, and CO_2 credits traded at \$20/ton, for every barrel of crude input, a refinery would get a credit of 0.05 tons—giving that refinery 0.05 tons/barrel × \$20/ton = \$1/barrel worth of credit. This credit amounts to a subsidy for input crude, the same as if the government was giving refineries \$1/barrel. Meanwhile, credits are required for each

[29] Precedent is not necessarily an advantage for formatting the regulation, but rates or emissions intensities are used for benchmarking within the industry because they allow for efficiency comparisons among refineries. Because rates scale for size, the relatively efficient refineries are easier to identify under a rate-based approach than under a mass-based approach, which only focuses on total emissions (and is most correlated with refinery size).

ton of emissions, in this case costing $20/ton, the same as if the government were taxing emissions at $20/ton.

The subsidy on whatever X is—various combinations of inputs or outputs—under a rate-based approach, implies a lower cost of refined products production relative to a mass-based approach. Under a rate-based approach, X is being subsidized through lower inputs costs or higher outputs prices. Under a mass-based approach, refiners still have an additional "input" of carbon emissions that they must pay for, but their other input and output prices remain unchanged, even when they receive permits free of charge, so long as the allocation is unrelated to future inputs or outputs.[30]

For rate- and mass-based policies delivering the same emission reductions, the lower cost of production induced by the subsidy implicit in the rate-based approach can have consequences for both overall costs and their distribution. As noted above, end-user prices will not fully reflect the opportunity cost of refinery emissions under a rate-based approach. As long as emission leakage is not a significant problem, less expensive opportunities to reduce the use of refined products (through more efficient cars or driving habits) will be forgone, and the cost to society will be higher than under the mass-based approach. The mass-based approach, while encouraging decreases in the use of refined products, will put more burden than a rate-based approach on those buying these products through a higher price that fully reflects the cost of emissions.[31] This higher price will likely create additional distributional burdens as permit value flows through the economy, even as overall costs are lowered.

In addition to the overall lower cost of refined products, the choice of X under the rate-based approach (e.g., barrels of crude inputs, barrels of refined product) will tend to distort choices among inputs or outputs. To maximize cost-effectiveness, the rate-based approach could be designed to minimize the relative product distortions and reduce these additional costs. The idea is to look for ways to avoid inadvertent input or output substitution. The discussion below elaborates on these and other tradeoffs associated with different rate-based approaches.

Rate: Input, Output, or Process

A refinery standard formatted as a rate raises the question of what the denominator should be. Three broad options are inputs (barrels of crude oil), outputs (barrels of refined product), and throughput for specific processes within the refinery.

Input

An input-based rate would regulate emissions (lbs of CO_2) per barrel of crude oil. One possible advantage of an input-based approach (as compared to an output-based approach, discussed below) is that it may be less distortionary. Refinery outputs are highly substitutable, having a higher degree of price responsiveness and leading to the larger distortions described above than crude inputs, which have very little substitutability with other inputs (labor, capital) and less scope to alter production decisions on the margin. However, an input-based approach that counts the number of barrels going into the refinery would tend to put complex refineries at a disadvantage relative to simple refineries. There are two reasons that this may be the case. First, complex refineries tend to have the equipment to process heavy crudes, whereas simple refineries frequently do not. Second, complex refineries may send the same barrel of oil (or fractions of the same barrel) through multiple processes, thereby adding to the emissions intensity of the original barrel relative to simply refineries, which have fewer process units. As noted above, differentiation by refinery size or complexity may be one way to address these equity concerns. Input-

[30] The free allocation is essentially a "gift" that affects neither the prices refiners face for various production inputs and outputs nor the value of their carbon permits—which can still be sold if they are unused. Therefore, the cost of producing refined products under a free versus an auctioned mass-based permit approach is unchanged (though these free allowances do benefit refinery owners).

[31] This burden is, in fact, not a real cost to society but a payment or transfer to whomever initially owns the permits. That could be the government, if permits are auctioned; refiners, if they are given to refiners for free; or any other entity.

based standards can also be differentiated by crude oil type (e.g., using a formulaic approach) to take into account the spectrum of crude oils on the market. As noted above, this approach might reduce some substitution opportunities—but this occurrence may be unlikely given the fixed nature of both pipelines and refinery configurations.

Output
Regulating emissions on the basis of unit output (e.g. barrels, gallons, or tons of product) would tie emissions to end-use products, a linkage with logical appeal in terms of emphasizing the end result—what quantity of emissions to produce the desired good. This approach is also similar to the proposed new source performance standard for coal-fired power plants (1,100 lbs CO_2/MWh). However, power plants have one product (electricity), and refineries have 2,500, suggesting that a single output-based rate may not capture the complexities of the refining industry; differentiation would most likely be required.

As noted above, a rate-based standard can be viewed as a tax on the numerator (emissions) and a subsidy on the denominator, in this case refinery product. A single output-based standard (i.e., lbs CO_2/barrel or ton) applied to all the various outputs would provide the same $/barrel subsidy to each refinery product. The effect of that subsidy, however, would be different for different products. For some products, this $/barrel will be a larger or smaller share of the initial price and thus be a larger or smaller subsidy in relative terms. In addition, even with the same price change, different products face different demand responsiveness (elasticity) to a price change. Ultimately, a given subsidy leads to a shift toward those products with the largest (most elastic) response. Such distortions create costs to society, because the relative product prices no longer reflect the relative marginal costs determined by the refinery.

In theory, one solution would be differentiation by product slate, as discussed above, to establish different standards for different refinery products. This approach would tie emissions directly to the end-use product; consumers would know exactly how much carbon dioxide was associated with refining the gasoline that powers their cars. However, there are practicality concerns with setting standards to cover 2,500 products as well as calculating emissions for products due to interdependent process pathways. Such an approach would likely be combined with averaging to avoid having refineries meet each product standard separately.

Process
An alternative approach is to establish an emissions standard for each refinery process (e.g., atmospheric distillation unit, coker, catalytic cracker). Such a standard could define, for example, an emissions rate for each barrel of process throughput or pound of process byproduct (e.g., pounds of coke burnoff for the fluid catalytic cracking unit). Absent the ability to average emissions across the refinery, process-by-process rates would be inflexible and therefore would likely increase compliance costs relative to flexible approaches. However, "bubbling" (averaging emissions across all processes within the refinery), if allowed, would effectively differentiate each refinery on the basis of its unique configuration of process units. That is, each refinery would face a unique total emissions limit that is equal to the sum of the emissions limits for each process unit as calculated by multiplying the process unit's EPA-set rate by its throughput. Focusing on throughput, rather than on inputs or outputs, would help address concern about possibly distorted choices among inputs or outputs. It would, however, potentially create incentives to favor refinery processes that produce more credits than other processes. However, because U.S. refineries already operate at a high capacity factor, this may be not a major practical concern. Mathematically, the process-by-process approach to establishing a refinery-wide standard (that allows bubbling) is similar to the complexity-weighted barrel approach advanced by industry consultants (see Table 2).

Complexity-Weighted Emissions Rate
In response to concerns that simple measures of emissions rates per unit of input or output would fail to capture the diversity of the refining industry, the consulting firm Solomon Associates devised a method to compare emissions rates across refineries with varying complexities. Their complexity-weighted barrel

(CWB) approach is mathematically similar to the above-described process-based approach with bubbling and is used in the European Union's Emissions Trading System and California's AB 32 cap-and-trade system as the basis for allocating tradable emissions allowances.[32]

The CWB approach uses a weighting factor based on the emissions intensity of different process units to normalize a refinery's output into a single "product," the CWB, which can be easily compared across refineries. The CWB approach first benchmarks the average emissions intensity of each refinery process against the average emissions intensity of an atmospheric crude distillation unit to establish the "process complexity factor" or "process CWB factor." The total number of CWBs for each refinery is calculated by multiplying the throughput of a process unit by its calculated complexity factor and summing the CWBs of all process units, with some corrections for electricity and steam generated offsite or sold (see Box 2). The refinery's emissions are divided by the total CWBs to obtain an emissions rate in tons per CWB for the refinery.

Box 2. Formula for Calculating Solomon Associates' Complexity Weighted Barrel.

$$\boxed{\text{CWB} = \Sigma \text{ (Daily Throughput Barrel} \times \text{Process CWB Factor)} + \text{Adjustments}}$$

The CWB calculation for refineries—in terms of emissions per CWB—is currently used for benchmarking and emissions allocations in trading systems, but it could be used to set an emissions rate for the refinery standard (e.g., a limit of x lbs of CO_2 per CWB). Compared with the rate in a process-based approach with bubbling, this single rate (scaled by the process CWB factor) would replace multiple emissions rates for each type of refinery process.

Many major stakeholders favor the CWB approach.[33] However, the CWB method is proprietary; it is owned by Solomon Associates. The company sells the method to industry associations—CONCAWE in Europe, the Western States Petroleum Association in California—which can then partner with an agency creating a regulation to incorporate the CWB. More importantly, the process complexity factors are calculated in a so-called black box. Although the factors are visible to the public, their derivations are not. The factors are calculated from Solomon's Carbon Emissions Index, which in turn is calculated from Solomon's Energy Intensity Index, which in turn is derived from the results of Solomon's *Fuels Study* and *Lubricant Study* from operating year 2006 (Solomon Associates 2013). To circumvent this lack of transparency, some stakeholders have suggested that the EPA devise its own similar process-based weighting system (see "Process," above for a potential method).

Table 2 illustrates how the process-based approach with bubbling is mathematically similar to the CWB approach devised by Solomon Associates. Instead of weighting the denominator (barrels of throughput) by the emissions intensity of each process unit, a process-based approach would establish distinct emissions rates for each refinery process and allow individual refineries to over- and under- comply at specific units as long as they meet the same average emissions rate per barrel throughput. This illustrative example shows that if the ratios between the process-specific emissions rates and the emissions rate for a crude distillation unit are equal to the CWB factors for each type of process unit, the effective emissions limit for the entire refinery is the same.

[32] In metric units, it is referred to as the Complexity-Weighted Tonne (CWT).
[33] Stakeholder comments to the authors.

Table 2. Equivalence of Process-Based with Bubbling Method and Complexity-Weighted Barrel Method.

CWB Method[a]			
	Atmospheric Crude Distillation Unit	Process 1	Process 2
Regulation-set emissions rate	100 lbs CO_2/CWB		
CWB factor	1 CWB/barrel	1.2 CWB/barrel	0.8 CWB/barrel
Barrels for Refinery A	200,000	5,000	2,000
Process with Bubbling Method[b]			
	Atmospheric Crude Distillation Unit	Process 1	Process 2
Regulation-set Emission Rate	100 lbs CO_2/Barrel	120 lbs CO_2/Barrel	80 tons lbs CO_2/Barrel
Barrels for Refinery A	200,000	5,000	2,000

[a] Emissions allowed for Refinery A (before trading) = 100 tons/CWB× (200,000 barrels x 1 CWB/barrel + 5,000 barrels x 1.2 CWB/barrel + 2,000 barrels x 0.8 CWB/barrel) = 207,600,000 lbs CO_2

[b] Emissions allowed for Refinery A (after bubbling, before trading) = (200,000 barrels x 100 lbs/barrel) + (5,000 barrels x 120 lb/barrel) + (2,000 barrels x 80 lbs/barrel) = 207,600,000 lbs CO_2

One difference between the process-based approach with bubbling and the CWB approach is the specific rates the EPA would set. Using the CWB approach, Solomon would establish the complexity factors using proprietary data, and the EPA would establish an overall standard of emissions per CWB. Using the process-based approach with bubbling, the EPA would set emissions rates for each covered process unit, which would then be averaged across the refinery. Furthermore, Solomon Associates adjusts a refinery's total CWBs on the basis of multiple factors such as electricity purchased from offset or energy (electricity or heat) sold. As part of any regulatory approach, the EPA could also consider adjustment factors to account for potential leakage of emissions into other sectors.

The CWB approach and the process-based rate with bubbling approach are two of the seven regulatory formats that the EPA could potentially use in designing a GHG standard for refineries. These seven formats are summarized in Table 3.

Table 3. Summary of Alternative Regulatory Formats.

Format	Previous Regulations (Format)	Summary	Important Points	Potential Differentiation
1. Mass	Clean Air Mercury Rule	Total mass of CO_2 a refinery can emit over a time period	• Most economically efficient when combined with a trading system (ignoring leakage) • Does not incentivize one reduction activity over another—allows for refinery flexibility • Legal concern—little precedent, especially for a percentage reduction over a baseline year	• Inherently differentiated • Each refinery receives a an emissions limit based on its historical emissions or modeled achievable reduction
2. Rate: Input (single input category)	SO_2 limit for existing power plants (pounds SO_2 per MMBtu)	Emissions intensity for processing a barrel of crude oil	• Does not account for inter-refinery trades in unfinished products • Allows for refinery flexibility in deciding emissions reduction activities	• Sets a single standard for all refineries • Can be subcategorized by size/complexity on the refinery level and/or product slate on the sub-refinery level • Subcategorization by input is discussed in number 3 below
3. Rate: Input (categor-ized by crude type)	1997 NO_X new source performance standards for electric generating units (rates differentiated by fuel type)	Multiple emissions intensities for processing a barrel of crude oil based on the crude's quality	• Crude quality is a major emissions driver • Eliminates potential cost-effective opportunities for crude feedstock switching • Involves subcategorizing or benchmarking crude types to set standards	• Differentiates by crude quality—either into discrete categories or benchmarked against one crude to set standards using a formula • Can be further subcategorized by size/complexity on the refinery level and/or product slate on the sub-refinery level
4. Rate: Output (single output category)	§ 111(b) rulemaking for electric generating units—CO_2	Emissions intensity for producing a unit of product	• "Unit of product" is nebulous and differs from refinery to refinery • Does not account for	• Sets a single standard for all refineries • Can be subcategorized by size/complexity on the refinery level and/or

	(pounds per MWh)		inter-refinery trades in unfinished products	crude quality on the sub-refinery level • Subcategorization by output is discussed in number 5 below
5. Rate: Output (categori-ized by product type)	Volatile organic compound (VOC) limits for architectural coatings, such as paint (61 standards for different products)[a]	Multiple emissions intensities for producing a unit of a specific product	• Ties emissions to the end-use product • Faces practical challenges due to the number of refinery products and processes • Does not account for inter-refinery trades in unfinished products • Does not take into account differences in crude oil input	• Differentiates by product slate into categories • Can be further subcategorized by size/complexity on the refinery level and/or crude quality on the sub-refinery level
6. Rate: Process	Refinery new source performance standard—particulate matter (FCCU and FCU, kilograms per megagram coke burnoff)	Emissions intensities for a number of specific emissions points within the refinery	• Absent "bubbling," much less flexibility than other formats • With "bubbling" effectively differentiates on basis of complexity • Similar to the CWB approach below and avoids transparency concerns	• Absent "bubbling," sets single standards for process units that each process unit must meet individually • With "bubbling," differentiates on the basis of complexity by giving each refinery an emissions limit based on its process units • Can be further subcategorized by size/complexity on the refinery level
7. Rate: Complex-ity-weighted	California AB 32; European Union Emissions Trading System (for allocation, not establishing compliance)	Emissions intensity for a single refinery product, normalized using a score of the refinery's complexity (configuration)	• Takes into account differences in refinery configurations • Concerns about transparency	• Differentiates on basis of complexity by giving each refinery an emissions limit based on its process units • Can be further subcategorized by size/complexity on the refinery level

[a] CFR §59 Subpart D, Appendix A: Subpart D -- National Volatile Organic Compound Emission Standards for Architectural Coatings. Updated 7/24/03.

Compliance Options
Once the EPA issues a standard under § 111(d), each state submits an implementation plan to the EPA stating how it will meet the guideline. The language in § 111(d) and the EPA's proposal for existing power plants appear to grant states substantial flexibility in how to meet the standard; however, each plan is subject to EPA approval. States may choose to demonstrate compliance through equivalent approaches that better fit the conditions within their borders. However, they face the risk that the EPA will disapprove any proposed approaches that it has not specifically indicated are available during its rulemaking process.

To address this risk, the EPA could give states guidance regarding their implementation options and encourage them to pursue flexible implementation approaches that it deems acceptable under § 111(d). For example, the EPA could give states a formula for mass- and rate-based standard conversions or input, output-, or process-based rate conversions. The EPA could also give states one or more model rules.

State implementation plans could reflect multiple options, including trading, bubbling, and—potentially—offsets. Each of these options would give refineries greater flexibility than a non-tradable refinery-by-refinery- (or even process-by-process-) based approach and would therefore tend to increase the cost-effectiveness of state implementation plans to the extent that refineries can take advantage of the lowest-cost emissions reduction activities, regardless of where they occur.

Averaging within a Refinery, Firm, State, Region
If the EPA were to establish individual standards for refineries or refinery processes (as opposed to state-wide averages, as it has proposed for existing power plants), states might wish to allow averaging across refinery units, across all refineries owned by a single company in a single state, or—by coordinating with other states—across all refineries owned by a single company in multiple states. The narrowest instance of averaging, "bubbling" across refinery units, has already been used to regulate refineries (particularly for hazardous air pollutants, or HAPs) under the Clean Air Act. Unclear is whether more expansive—and thus more cost-effective—averaging programs are legally viable under § 111(d). The outcome of the current power sector rulemaking—which, as proposed, provides emissions guidelines for each state as an average rate for covered sources and which allows for multi-state plans—is likely to inform this possibility (EPA 2014a).

Trading
A tradable standard—whether a mass-based system or tradable performance standard—would establish a common marginal price of emissions equal to the market price of an emissions credit. Even if the EPA does not identify an emissions trading scheme as the best system of emissions reduction, or speak to the availability of trading under § 111(d), states with existing trading systems, including California and the RGGI states, may consider utilizing or expanding these systems to demonstrate their equivalency with § 111(d). These states have requested that the EPA recognize their programs and allow state-level compliance to also count as federal-level compliance in the context of the EPA's current rulemaking for existing power plants. Industry stakeholders have expressed interest in this approach.[34] States without existing trading systems could consider joining a regional trading program or establishing systems of their own. The legality of trading schemes under section 111(d) has not yet been tested in court, but the statutory language of the Clean Air Act expressly allows states to include "economic incentives such as fees, marketable permits, and auctions of emissions rights" within their § 111(d) plans.[35] The EPA's proposal for existing power plants identifies trading systems as one optional component of state plans (EPA 2014a).

[34] Oil industry stakeholder comments to the authors.
[35] § 110(a)(2)(A)

Offsets
Carbon offsets are another compliance strategy that may be of interest to stakeholders and state policy makers. They would allow refineries to reduce emissions by participating in offsite projects to decrease atmospheric CO_2. These projects—for example, carbon sequestration through tree planting—would generally be managed by non-regulated entities and typically in non-regulated sectors. Offsets are a common component of carbon trading schemes—the California Air Resources Board allows for four types of offsets (forest projects, urban forest projects, livestock projects, and ozone-depleting substance projects) to count toward compliance with the California cap-and-trade program (CARB 2014b). Whether offsets would be a legally viable compliance possibility is unclear. Section 111 focuses on source categories as opposed to general air pollutant concentration, and therefore compliance with it may be incompatible with the basic premise of offsets.

Other Options
Other compliance strategies that states may consider include temporal (multiyear) averaging, financial incentives, negotiated agreements, and renewable energy. Temporal averaging might involve states allowing refineries to average their emissions over several years to meet the compliance standard.[36] Other regulatory schemes that allow temporal averaging, such as ozone or particle pollution limits under the national ambient air quality standards, allow averaging to occur over three years. The EPA's 111(d) proposal for existing power plants, if finalized as proposed, would require states to meet their final emissions goal on average over the three-year period 2030–2032 (EPA 2014a). As some stakeholders have pointed out, this approach may make sense for the refining industry because production (and emissions) may differ from year to year due to weather, routine upkeep, and large maintenance projects. The long-lived nature of CO_2 also makes annual variations in emissions unimportant.

States could also experiment with subsidies or a carbon tax (as noted above, the Clean Air Act expressly allows states to include economic incentives such as fees, marketable permits, and auctions of emissions rights). Reasons for considering economic incentives include cost-effectiveness and (in the case of a tax) a potential state revenue stream. To demonstrate the compliance equivalency of a tax or subsidy program (as opposed to a tradable emissions rights program) to EPA-approved approaches, a state would need to show that the level of tax or subsidy is sufficient to produce the desired level of emissions reduction.

As compliance options, both negotiated agreements and renewable energy have also been discussed with respect to §111(d) rulemaking for power plants. They could also be considered in the refining industry, depending on the outcome of the power section rulemaking. For example, states could negotiate with refineries to use different fuel sources—much like Colorado's approach in the state's Clean Air Clean Jobs Act for power plants (Monast et al. 2012). States may also consider allowing refineries to reduce emissions with renewable energy. For example, a refinery may generate renewable electricity onsite for use in the refinery, displacing electricity that was generated by burning fossil fuels and thereby reducing emissions. However, if the displaced fossil fuels are byproducts like residual oil, the refinery is left with a waste problem in discarding the fuels instead of burning them. In an alternative scenario, the refinery would build a renewable energy facility offsite and either export that electricity back to the refinery or to the grid, and the emissions avoided by generating that amount of electricity from a zero-emissions source would be credited to the refinery. However, crediting offsite renewable energy or renewable energy exported to the grid may test the boundaries of state flexibility to the extent that the Clean Air Act requires emission reductions to occur within the source category under §111(d) (Wannier et al. 2011).

[36] Multiyear averaging is also often used in trading systems, including California's AB 32 program and Europe's ETS. Corporate average fuel economy (CAFE) standards also employ multiyear averaging, and the §111(b) proposal included a provision allowing 30-year averaging for coal plants with carbon capture and sequestration.

Conclusion

If, following its electricity sector rulemaking, the EPA decides to regulate other major stationary sources of CO_2 emissions under §111(d) of the Clean Air Act, it would potentially focus on the petroleum-refining sector. This sector contributes 2.6% of total domestic GHG emissions, and the EPA agreed to regulate these emissions in a 2010 settlement agreement. This paper explores four key issues that would arise in regulation of the refining sector: (1) translating BSER options from the power sector to the refining sector, (2) maximizing cost effectiveness given the sector's characteristics, (3) taking differences among refineries into account, and (4) determining the denominator of a rate-based standard.

Translating BSER Options

The process for determining the best system of emissions reduction is the same for refineries as it is for power plants, and precedent from the power plant regulation will influence what can be done for refineries. This process includes determination of stringency, which is largely based on how the best system of emissions reduction is interpreted—either as narrowly focused on specific technologies (less ambitious) or as expansively referring to a system including multiple emissions sources (more ambitious). In the power sector, the EPA is proposing that the best system of emissions reduction for power plants include multiple emissions reduction activities: (1) on-site efficiency (heat rate) improvements at coal units, (2) increased dispatch of existing gas units (and decreased dispatch of coal and oil), (3) new investments in non-emitting generation, and (4) end-use energy efficiency (EPA 2014a). As the legal parameters for the best system of emissions reduction are tested during formulation of the power plant regulation, they will become clearer for refineries.

Maximizing Cost Effectiveness

The Clean Air Act allows the EPA to take cost into account when establishing regulations under §111(d). In general, flexible compliance mechanisms increase the cost effectiveness of a regulation by providing an opportunity and incentive for regulated entities to pursue the low-cost emissions reduction activities first. Trading, for example, effectively equalizes the marginal cost of compliance for different refineries by establishing a market price of emissions. Because there are large differences among refineries, it is likely that different refineries will face different opportunities for emissions abatement. Regulatory designs that do a better job of smoothing otherwise unequal marginal costs will be more economically efficient overall (and will achieve a given level of emissions reduction at a lower total cost). A similar dynamic exists within each refinery. Different opportunities for reducing emissions will arise at different points within a refinery (e.g., where efficiency measures may be possible). To the extent that each refinery can take advantage of the lowest-cost abatement opportunities facility-wide, the total cost of emission reductions will be lower.

Considering Differences among Refineries

No two petroleum refineries are exactly alike. The refining sector has a multitude of inputs, outputs, and components (process units) that each influence a refinery's unique configuration, emissions profile, and potential for as well as costs of emission reductions. Differentiating standards across refineries would influence distribution of the compliance burden. Refineries can be differentiated on the basis of their complexity (number/type of process unit), product slate, crude oil inputs, historical emissions/modeling, or some combination of these options. Several of the options are relevant to power plants, and several—complexity, product slate, and crude oil inputs—are unique to refineries. Regulation for the refining sector may warrant consideration of the latter, which along with cost distribution, may also affect cost-effectiveness.

Of the potential regulatory formats considered here, two appear to have the greatest capacity to reflect differences among refineries. The first uses a process-based rate with "bubbling," which functions as an analogue to the Solomon Associates' complexity-weighted barrel (CWB) approach. This format would set rate-based standards for multiple process units within a refinery, multiply the rates by the throughput of each process to get total emissions from each unit, and allow the refinery to sum those individual emissions limits to obtain a limit for the entire refinery. The refinery would not have to meet each process limit individually. The process-based format effectively differentiates refineries on the basis of their complexity, but does so in a way that perhaps circumvents transparency concerns with direct use of the proprietary CWB. The second format—the mass-based format—uses a percentage reduction over a baseline year, an approach similar to that of other legislative regulations like cap-and-trade programs. A reduction against a baseline would differentiate refineries on the basis of their historical emissions, which likely reflect major differences in refinery configuration. This approach is similar to that of other market-based CO_2 regulatory programs, but it comes with a degree of legal risk because it has not been tested under §111(d). Stakeholders have identified both the CWB approach and the reduction against an historical baseline approaches as their favored approaches.

Determining the Denominator of a Rate-Based Standard

The denominator of a rate-based standard, if chosen as a regulatory format, is not obvious for the refining sector. The options are regulating emissions per unit input (crude oil), output (products), or throughput (process unit capacities). When rate-based regulation is flexible (through trading or even bubbling), all three choices have the potential to distort behavior and raise costs relative to a mass-based approach. This potential holds whether the standard is a single-rate standard or differentiated standard that attempts to address equity or other concerns. For example, making the standard easier for heavier crudes may address concerns that regulation is overly burdensome for those refiners who use heavier crudes—but it will also reduce refiners' incentive to consider switching to a lower-emissions crude, which would be held to a more ambitious standard. Throughput standards—when coupled with bubbling, as described above in a process-based rate—appear to do a better job of accounting for differences among refineries that would otherwise make regulation more burdensome for some and less for others.

Looking Forward

The proposed carbon pollution standard for existing power plants was announced in June 2014. Reaction to and discussion of that standard may clarify the issues raised here for refineries. Refinery performance under California's AB 32 cap-and-trade program and Washington state's proposed regulations would also be instructive, if and when the EPA turns to regulating the refining sector under §111(d). In the meantime, gathering the data needed for the regulation—the information already reported to the EPA plus additional information that will allow the agency to construct a standard in tune with the realities of the sector—would help answer some of this paper's questions concerning differences among refinery emissions and abatement opportunities, and how regulatory design might effect each.

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