LCFS Refinery Investment Credit Analysis

Prepared for

NextGen Climate America, Inc.

By

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March 9, 2018

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Executive Summary

The Low Carbon Fuel Standard (LCFS) is a California greenhouse gas (GHG) regulatory program which aims to reduce the carbon intensity (CI) of energy used in California transportation. The regulation covers petroleum fuels, renewable fuels, and alternative transportation technologies. The design of the program is such that renewable fuels and alternative transportation technologies generate LCFS credits, and petroleum gasoline and diesel generate LCFS deficits. Parties with LCFS deficits must either generate or purchase LCFS credits to comply with the LCFS. California's Air Resources Board (CARB) is responsible for administering the LCFS regulation.

In its 2015 re-adoption of the LCFS, CARB introduced two pilot programs offering petroleum refineries opportunities to generate LCFS credits: The Refinery Investment Credit Pilot Program (RIC) and the Renewable Hydrogen Refinery Credit (RHRC) Pilot Program. Since then, CARB has hosted workshops on the RIC and RHRC programs. Then, on February 20, 2018 CARB released unofficial LCFS rulemaking documents and 2018 Draft Amendments to the LCFS Regulation. NextGen Climate America engaged Stillwater Associates to conduct an analysis of the potential range of future LCFS credit generation from the RIC and RHRC provisions that could impact the 2030 targets for the LCFS.

We analyzed the six types of RIC and RHRC projects provided for within the scope of CARB's draft proposed regulation:

1. Carbon Capture and Sequestration (CCS)
2. Use of Renewable or Low-CI Electricity
3. Use of Low-CI Process Energy
4. Electrification at Refineries
5. Process Improvements
6. Renewable Hydrogen

Taking into account as many factors as possible (with sometimes limited data), we determined the unconstrained credit possibilities in each project category, then applied the likely legislative, logistic, and economic constraints to produce a low, mid, and high credit generation case for 2030 in each project category. Finally, we totaled the six categories to arrive at low, mid, and high credit cases for all RIC and RHRC projects in 2030:

Possible LCFS Credits – MT CO_2e/year			
	High	**Mid**	**Low**
CCS	2,000,000	730,000	365,000
All Other RIC & RHRC	2,670,000	1,136,000	310,000
TOTAL	**4,670,000**	**1,866,000**	**675,000**

Our analysis concludes that the two most likely sources for LCFS Credits under RIC and RHRC in 2030 will be Carbon Capture and Sequestration projects and Renewable Hydrogen projects.

This study was commissioned to develop the order of magnitude range of RIC and RHRC credits considering the current and proposed regulatory framework, the equipment used in California's refineries, and Stillwater's judgement as to the economics and feasibility of possible projects. Due to the short deadline for this study, limited in-depth data about the refineries, and undefined costs of refinery modifications, we performed only limited detailed analysis to refine the range of potential credits. Thus, in most cases, the range presented is based on judgement as much as analysis.

1 Introduction

1.1 LCFS Background

California's Low Carbon Fuel Standard (LCFS) is part of a suite of legislative efforts in California to combat climate change. The LCFS was initiated in 2007 by executive order S-1-07 from California's governor, Arnold Schwarzenegger. The program was then incorporated as a California regulation in 2009 as one of the Assembly Bill 32 (AB32) programs to reduce greenhouse gas (GHG) emissions. AB32, also known as the Global Warming Solutions Act of 2006, requires the California Air Resources Board (CARB) to develop regulations and market mechanisms to reduce GHG emissions to 1990 levels by 2020. There is a broad array of regulations under the umbrella authority provided by AB32. For the sake of this paper, we will focus our discussion on the Refinery Investment Credit Pilot Program (RIC) and the Renewable Hydrogen Refinery Credit Pilot Program (RHRC) provisions of the LCFS.

1.2 2015 Re-Adoption of the LCFS

1.2.1 Refinery Investment Credit Pilot Program

In its 2015 LCFS re-adoption,[1] CARB introduced the RIC under which refineries can earn LCFS credits for reducing total GHG emissions from their facilities. Credits granted are based on "fuel volumes sold, supplied, or offered for sale in California." CARB's goal with this program was to encourage reductions in GHG emissions through major process improvements, fuel switching, and carbon capture and sequestration. Under the initial regulation, RIC projects were required to achieve a carbon intensity (CI) reduction from the comparison baseline of at least 0.1 grams carbon dioxide equivalent per mega joule (gCO_2e/MJ). RIC projects must mitigate any net increases in criteria air pollutant or toxic air contaminant emissions from the refinery in accordance with all environmental and health and safety regulations. Refinery equipment shutdowns, reductions in refinery or equipment throughput, and refinery maintenance are not eligible for RIC. Furthermore, under the original RIC program, a regulated party who generates credits under the program could use the credits to cover its deficits (refiner's obligations) but could not sell or transfer the credits to another party nor use those credits to meet more than 20 percent of its annual obligation.

According to CARB, as of late 2017 there were no projects approved under the RIC provisions despite discussions and interest from refiners to use this provision. Many factors contribute to the difficulty of making progress on any RIC projects, including the complexity of refinery operations; CARB's requirement for all possible impacts to be evaluated; GHG measurement, baseline, and reduction verification requirements; the 0.1 gCO2e/MJ reduction threshold; and the lack of specific protocols to calculate project credits.

1.2.2 Renewable Hydrogen Refinery Credit Pilot Program

In addition to the RIC program, CARB also introduced its RHRC Pilot Program in the 2015 re-adoption of the LCFS. Under the RHRC, refineries may earn LCFS credits for GHG emission reductions from the "production of CARBOB or diesel fuel that is partially derived from renewable hydrogen." Like the RIC program, RHRC program credits are based on "fuel volumes sold, supplied, or offered for sale in California." Under current rules, to qualify as an RHRC project, a refinery must replace a minimum of one percent of all fossil hydrogen in the production of CARBOB or diesel fuel with renewable hydrogen each year. Similar to the RIC program, refineries must mitigate any net air contaminants or pollutants and cannot sell or transfer RHRC credits to any other party. A regulated party who generates credits under the RHRC program may use the credits to cover its deficits (refiner's obligations) but may not sell or transfer the credits to another party nor use those credits to meet more than 10 percent of its annual obligation.

[1] California Air Resources Board. Low Carbon Fuel Standard Final Regulation Order. November 16, 2015 https://www.arb.ca.gov/regact/2015/lcfs2015/lcfsfinalregorder.pdf

1.3 Latest RIC Developments

The February 20, 2018 draft proposed regulation[2] creates a more specific outline for the RIC, providing for five project areas: carbon capture and sequestration (CCS), use of renewable or low-CI electricity, use of low-CI process energy, electrification at refineries, and process improvements. CARB has also proposed changing the 0.1 gCO2e/MJ CI reduction threshold to a 1% GHG emissions reduction from pre-project, on-site, refinery-wide GHG emissions in metric tons per year. The draft proposed regulation would allow for credits generated under the RIC provision to be sold or transferred to another party.

1.4 Latest RHRC Developments

In its February 20, 2018 draft proposed regulation, CARB leaves much of the original RHRC program in place with just a few tweaks. The proposal removes the provision requiring that renewable hydrogen replace at least 1% of the fossil hydrogen in the production of CARBOB or diesel fuel. The draft proposed regulation would also allow for credits generated under the RHRC provision to be sold or transferred to another party.

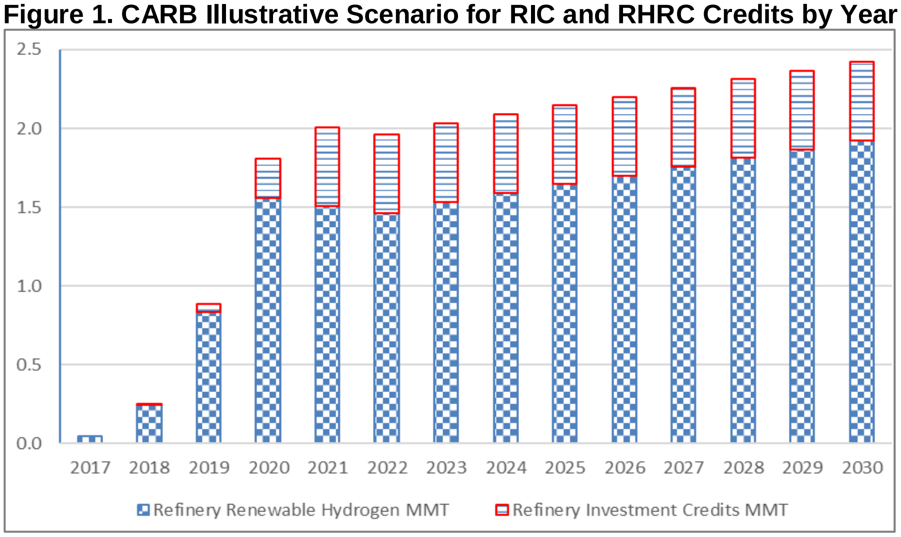
1.5 Program regulatory outlook through 2030

CARB's *Unofficial LCFS Rulemaking Documents*,[3] offered a look at where the LCFS program is headed. The primary significance of this document release is that it contained two considerable changes to the LCFS reduction schedule. First, instead of the initially mandated 10% CI reduction from the 2010 baseline in 2020, the 2020 reduction is proposed to be 7.5% with the 10% reduction delayed two years to 2022. Second, instead of the 18% LCFS reduction in 2030 from the 2010 baseline in prior CARB documents, the proposed reduction target is increased to 20% in 2030. If this release of documents is anything, it is a significant shift in the original CI reduction target, which was set back in 2010, and it represents a recognition that the fuels mix has not changed rapidly enough to insure there is a positive credit bank in 2020. In the longer term, CARB has signaled a more ambitious goal of a 20% reduction rather than the 18% reduction indicated in prior documents.

1.6 CARB RIC and RHRC Illustrative Scenarios

CARB has published a "Draft Illustrative Scenario Compliance Calculator"[4] that contains assumptions for the growth of credits generated from all sources. To establish a benchmark, CARB's assumed credit generation from RIC and RHRC is shown in Figure 1 below.

Figure 1. CARB Illustrative Scenario for RIC and RHRC Credits by Year



[2] California Air Resources Board. Proposed Regulation Order: Appendix A. February 20, 2018. https://www.arb.ca.gov/regact/2018/lcfs18/appa.pdf
[3] California Air Resources Board. LCFS Rulemaking Documents. February 20, 2018. https://www.arb.ca.gov/fuels/lcfs/rulemakingdocs.htm
[4] California Air Resources Board. Draft Illustrative Compliance Scenario Calculator. August 7, 2017. https://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/draft_illustrative_compliance_scenario_calculator.xlsx

As Figure 1 shows, CARB projects a significant amount of credits - almost 2 million metric tonnes (MT) per year by 2030 - from the RHRC provision, and projected RIC generation of about 0.5 million MT per year. The total of RIC and RHRC provisions is 2.4 million MT in 2030.

2 Study Methodology

This study was commissioned to develop the order of magnitude range of RIC and RHRC credits that might be expected in 2030 considering the current and proposed regulatory framework, the equipment used in California's refineries, and Stillwater's judgement as to the economics and feasibility of possible projects. Due to the short deadline for this study, limited in-depth data about the refineries, and undefined costs of refinery modifications, we performed only limited detailed analysis to refine the range of potential credits. Thus, in most cases, the range presented is based on judgement as much as analysis.

Generally, for each credit-generating project category, we determined an unconstrained level of credits – the level of potential credits, given no regulatory, input, resource, or economic constraints. (For example, we include the physically impossible scenario in which all electricity used in California refineries is replaced by solar power.) We then derived an estimated range of viable credits for 2030 from the unconstrained potential credits by applying regulatory constraints, likely input and resource constraints, and Stillwater's judgement as to economic viability of projects in each credit-generating category. Our conclusions would be altered significantly by changes to the regulatory, input, resource, or economic inputs.

Stillwater drew upon quarterly data from the LCFS Reporting Tool (LRT),[5] CARB's Illustrative Scenario calculator,[6] various U.S. Energy Information Administration (EIA)[7] data series, the LCFS regulation,[8] the EIA's Annual Energy Outlook,[9] and EIA[10] and Oil & Gas Journal reports of refinery capacity.[11] We employed our knowledge of California's refineries and refinery operations, as well as our experience in refinery investment decision making, to establish a sense of the viability of projects which would generate LCFS credits. An LCFS credit price of $125/MT is used to establish the LCFS-based project incentive. For lower investment projects – those for which most of the economic benefit comes from the LCFS – the economics of these projects could be highly sensitive to LCFS prices. The incentives offered by other programs (Cap and Trade, NOx RECLAIM, the Federal Renewable Fuel Standard, renewable power, etc.) are considered as a second order factor.

A benchmark for the refinery reductions of CO_2-equivalent (CO_2e) emissions for the RIC program is the total amount of emissions recorded by CARB for California refiners from the Cap and Trade program – about 35 million metric tons per year.[12] The scope of emissions from RHRC is outside the scope of facility emissions in Cap and Trade.

[5] California Air Resources Board. LCFS Quarterly Data Spreadsheet. January 31, 2018. https://www.arb.ca.gov/fuels/lcfs/dashboard/quarterlysummary/quarterlysummary_013118.xlsx
[6] California Air Resources Board. Draft Illustrative Compliance Scenario Calculator. August 7, 2017. https://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/draft_illustrative_compliance_scenario_calculator.xlsx
[7] U.S. Energy Information Administration. Petroleum & Other Liquids. Accessed May 8, 2018. https://www.eia.gov/petroleum/data.php
[8] California Air Resources Board. Low Carbon Fuel Standard Final Regulation Order. November 16, 2015 https://www.arb.ca.gov/regact/2015/lcfs2015/lcfsfinalregorder.pdf
[9] U.S. Energy Information Administration. Annual Energy Outlook 2017. January 5, 2017. https://www.eia.gov/outlooks/aeo/pdf/0383(2017).pdf
[10] U.S. Energy Information Adminstration. Refinery capacity data by individual refinery as of January 1, 2017. https://www.eia.gov/petroleum/refinerycapacity/refcap17.xls
[11] Oil & Gas Journal. Refining Capacities. December 4, 2017. https://www.ogj.com/oil-processing/refining/capacities.html
[12] California Air Resources Board. 2016 GHG Emissions Data. November 6, 2017. https://www.arb.ca.gov/cc/reporting/ghg-rep/reported-data/2016-ghg-emissions-2017-11-06.xlsx

3 RIC and RHRC Project Categories

The current LCFS regulatory text,[13] adopted in 2015, provides for RIC projects under three categories: process improvements, fuel switching, and CCS. The draft regulatory text[14] released on February 20, 2018 expands that to five project areas for the RIC: CCS, use of renewable or low-CI electricity, use of low-CI process energy, electrification at refineries, and process improvements. In addition to the five RIC areas, renewable hydrogen[15] (as outlined in the RHRC) would also benefit refineries by generating LCFS credits. In this section, we will discuss the potential for projects in each of the five areas outlined under the proposed RIC in addition to RHRC.

3.1 Carbon Capture and Sequestration

Under the draft proposed regulation, CCS projects are defined as: "CO_2 capture at refineries, or hydrogen production facilities that supply hydrogen to refineries, and subsequent geologic sequestration." More explicit and detailed protocols and provisions for CCS are included in the draft proposed regulation than had been outlined in prior CARB documents. Our analysis of potential CCS credits will focus on projects allowable under the proposed regulatory language.

Almost all the direct CO_2 emissions from a refinery are from one of two sources – fuel combustion or the creation of hydrogen gas. In every refinery, CO_2 is generated through the combustion of fuel, natural gas, or refinery gases used for process heat, steam production, and (in refineries with power generation equipment) generation of electricity. In refineries with hydrogen plants or third-party hydrogen production facilities, another source of CO_2 emissions is the reaction that produces hydrogen from methane and other light hydrocarbons.

Recovering CO_2 from combustion sources is difficult and costly since the concentrations of CO_2 are low and stack gases are hot. Recovery of CO_2 from combustion gases is similar to recovery from power generation steam boiler cycle plants without the economies of scale or the added concentration of CO_2 when coal is the fuel. For the purposes of this study, we concluded that a $125/MT LCFS credit price is too low to incentivize CO_2 recovery from refinery combustion sources.

The most plausible source of CO_2 for capture and sequestration in refineries is from the steam-methane reforming reaction that creates hydrogen gas. This reaction generates a hydrogen-rich gas and a CO2 byproduct: $CH_4 + 4H_2O \rightarrow 4H_2 + CO_2$

To obtain a pure, concentrated hydrogen product, CO_2 is removed from the hydrogen-rich gas. Available removal technologies produce either a highly concentrated (~99%) CO_2 stream or a CO_2 stream that is diluted with unreacted methane, carbon monoxide, and some hydrogen. Older liquid absorption technologies produce the highly concentrated CO_2 streams, while the diluted stream is produced by newer solid-bed adsorption technology where the dilute stream is used as fuel for the process. With this solid-bed adsorption technology, the CO_2 from the reaction does not combust, but instead vents with the stack gases.

A good portion (we estimate 2,500 short tons per day) of the high-concentration CO_2 produced by refineries is used by industrial gas suppliers to produce liquid CO_2 for food (carbonation and packaging), medical, industrial gas, and dry ice uses. (In the U.S., another primary use of CO_2 is to enhance oil field production, but we have seen no evidence that the CO_2 from California's refineries is used in this application.) Although the CO_2 is subsequently used, these emissions are still attributed to the original source – the refinery – since after use they enter the atmosphere.

[13] California Air Resources Board. Low Carbon Fuel Standard Final Regulation Order Section 95489(f). November 16, 2015. https://www.arb.ca.gov/regact/2015/lcfs2015/lcfsfinalregorder.pdf

[14] California Air Resources Board. Proposed Regulation Order: Section 95489(e). February 20, 2018. https://www.arb.ca.gov/regact/2018/lcfs18/appa.pdf

[15] California Air Resources Board. Proposed Regulation Order: Section 95489(f). February 20, 2018. https://www.arb.ca.gov/regact/2018/lcfs18/appa.pdf

Aside from the CCS provision, hydrogen plants may be included in two other credit provisions: reduction of fossil CO_2 emissions from combustion by using biogas, and renewable hydrogen by feeding biogas. We will discuss these credit provisions in sections 3.3 and 3.6, respectively.

3.1.1 Unconstrained Possibility for CCS

There are 12 fuel-producing refineries in California. Two of these refineries are small, leaving ten major fuel-producing refineries. In addition to these refineries, there are five hydrogen production facilities (HPF) that supply hydrogen to refineries. These ten refineries and five HPFs produce a total of approximately 1,100 million cubic feet per day[16] of hydrogen. Assuming that the feedstock is all methane, these operations produce approximately 5.2 million MT of CO_2 per year.

We estimate the CO_2 produced from reaction distributes as:

- 0.9 million MT/year to food, medical, and industrial gases
- 1.7 million MT/year high concentration CO_2 vented to atmosphere
- 2.6 million MT/year dilute CO_2 from solid-bed absorption technology

Each of these categories of CO_2 distribution presents its own challenges for applying CCS technology. In order to participate in sequestration efforts, the first category's already liquefied CO_2 would need to be diverted from other uses or the contracts supplying industrial gas plants would need to be terminated. Capture and sequestration of the CO_2 in the second category would require new investment in CO_2 compression, liquefaction, storage, and logistics to produce a liquid CO_2 that can be transported to a sequestration site. The third category's primary challenge is the additional level of investment required to concentrate the CO_2 from the dilute stream prior to liquefaction.

The significant level of necessary investment notwithstanding, CCS from hydrogen plant byproduct CO_2 could represent a large source of LCFS credits.

3.1.2 High, Mid, and Low Refinery CCS Credit Generation Possibilities

Aside from the requisite investment capital and meeting the CCS protocols, CCS potential is not really supply constrained. We estimate that economically viable investment in recovering CO_2 from hydrogen plant vent gases would require credit prices higher than the $125/MT price we assume for this study because of logistical challenges, economic realities, and uncertainty around sequestration or enhanced oil recovery sites.

Our estimates for the 2030 high, mid, and low cases for CCS are displayed in Table 1. In all cases, we assumed 20% of current CO_2 liquefaction capacity is used for CCS.

Table 1. Possible CCS LCFS Credits (MT per year)

High	Mid	Low
2,000,000	730,000	365,000

3.2 Use of Renewable or Low-CI Electricity

Refineries use a significant amount of electric power in their operations. Depending on the refinery, the power might be grid-supplied, co-generated (generated simultaneously with steam), or a combination of the two. We estimate that each of the ten major California refineries use 50-100 megawatts (MW) of power.[17] The primary use of power in a refinery is for the motors which drive pumps and compressors.

While low-CI electricity technically could be generated by using biogas, we have found no evidence that biogas would be economical since it could be used directly as LNG or CNG to earn LCFS

[16] Stillwater estimate based on California hydrogen generation capacity.
[17] Stillwater estimate.

credits, and that option would be reflected in its price. Similarly, other low-CI pathways to electricity can be better monetized through means other than the RIC.

3.2.1 Unconstrained Possibility for Renewable or Low-CI Electricity

We estimate that roughly 250 MW of power is provided to refineries through co-generation and would not be replaced. So, the ten refineries in California use approximately 500 MW of grid power. Applying a 100 gCO_2/MJ carbon intensity to the grid power yields an unconstrained potential GHG reduction (if all this power were replaced with renewable solar power) of 1.6 million MT per year. The unconstrained potential for renewable or low-CI electricity is high, but for regulatory reasons, the true potential is much lower.

The 2015 re-adopted LCFS and draft proposed LCFS regulations greatly restrict the sources of renewable and low-CI electricity. These sources must be within the boundaries of the refinery or be supplied “behind the meter” while connected via a dedicated line within the utility meter for both generation and receiving facilities. Restricting renewable or low-CI electricity projects to the refinery property or adjacent properties severely limits the potential of this provision. All of California’s refineries are located in urban, developed, ecologically sensitive, or high-land-value areas where developing solar projects of the scale meaningful to a refinery’s power use would be exceedingly expensive. Additionally, most of the refineries are located in coastal areas with fog and cloud cover, reducing the effectiveness of solar generation. A solar project in a refinery setting would need to be a series of small projects to take advantage of open refinery land areas. The cost of these solar projects would be higher than other settings because of the necessary explosion-proofing and other requirements unique to the refinery setting.

3.2.2 High, Mid, and Low Refinery Renewable or Low-CI Electricity Credit Generation Possibilities

To develop the high, mid, and low LCFS credit estimates for renewable or low-CI electricity, we assumed different percentages of a typical refinery land area would be used for solar power generation and calculated the resulting solar power. We assumed a high scenario of 5%, mid scenario of 2% and low scenario of 0.5% of refinery land used for solar projects. Our resulting estimates for the 2030 high, mid, and low cases for renewable and low-CI electricity in refineries are displayed in Table 2.

Table 2. Possible Renewable and Low-CI Electricity LCFS Credits (MT per year)

High	Mid	Low
40,000	16,000	5,000

Compared to the unrestricted possibilities, the magnitude of these estimates is quite low since, unlike offsite renewable electricity, available land is limited.

3.3 Use of Low-CI Process Energy

CARB’s draft proposed regulation includes the “use of lower-CI process energy such as biomethane, renewable propane, and renewable coke, to displace fossil fuel.” Here, process energy is defined as any refinery energy used other than electricity generated or electricity or steam that is purchased.

Table 3 below lists EIA total energy consumption by energy source for PADD 5 refineries.[18] The highest carbon sources of energy (coal and marketable petroleum coke), have already been eliminated in all West Coast refineries. The next highest (residual fuel oil and crude oil), were also completely or nearly eliminated by the end of 2016. In fact, none of the residual oil used in PADD 5 is consumed in California. The vast majority of the remaining sources of energy are natural gas and still gas. Catalyst petroleum coke is a necessary byproduct of the conversion processes used to produce gasoline and diesel, so there is no opportunity to displace it with other energy sources.

[18] U.S. Energy Information Administration. Fuel Consumed at Refineries, PADD 5. June 21, 2017. https://www.eia.gov/dnav/pet/pet_pnp_capfuel_dcu_r50_a.htm

Table 3. Energy Consumed at PADD 5 Refineries

Year	Crude Oil	LPG	Distillate	Residual Fuel	Still Gas	Petroleum Coke	Marketable Petroleum Coke	Catalyst Petroleum Coke	Other Products	Natural Gas, Million SCF	Coal	Purchased Electricity (Million KWhours)	Purchased Steam (Million Pounds)
2005	0	2291	253	727	45700	15371	970	14401	1700	123271	0	4978	17956
2006	0	1468	255	770	44999	14550	110	14440	2199	126190	0	4973	17999
2007	0	1415	236	743	45553	14521	117	14404	1716	133713	0	5113	17838
2008	0	1509	292	745	43383	12360	103	12257	2027	139950	0	5125	17777
2009	0	1320	129	804	39475	11748	125	11623	1416	136221	0	4890	18687
2010	0	883	253	753	43737	10492	145	10347	1254	151808	0	4964	14030
2011	0	431	319	677	39284	11793	143	11650	1119	156599	0	5221	14349
2012	0	518	209	469	38875	12582	166	12416	1141	159849	0	5130	14426
2013	0	378	168	354	43734	12694	161	12533	1097	177103	0	4820	13143
2014	0	513	102	346	46065	12625	143	12482	733	186011	0	4705	13370
2015	0	846	110	333	44613	10981	90	10891	466	177513	0	4185	12939
2016	0	579	224	244	46604	12223	0	12223	514	184740	0	4529	13426

All units are thousands of barrels unless otherwise noted.

We know of no renewable coke in the marketplace and no announced plans to produce it at scale. Small amounts of liquefied petroleum gas (LPG) are produced in the production of renewable diesel (RD) and more would likely be created in the production of renewable gasoline (RG) at scale, but both RD and RG generate far more LCFS credits than LPG due to low LPG yield in the processes that produce those fuels. This means that the most likely source of renewable LPG production that would be used in a refinery would result from that refinery co-processing renewable feedstocks. This co-processing would be a small subset of an analysis of refinery co-processing capabilities, which is outside the scope of this study.

3.3.1 Unconstrained Possibility for Use of Low-CI Process Energy

If all the natural gas consumed in California refineries (about 60% of PADD 5 consumption) was replaced with biogas, approximately 5 million MT per year of fossil CO_2 emissions would be eliminated.

Biomethane (or biogas) production has been growing steadily in the U.S., and credits can be created from biogas via electricity, CNG and LNG, and/or hydrogen production. These credits are only limited by biogas supply. By far, selling biogas into CNG/LNG vehicles in California offers the highest credit value because it generates valuable cellulosic Renewable Identification Numbers (RINs) under the federal Renewable Fuel Standard (RFS), as well as LCFS credits. Additionally, that fuel would avoid almost all Cap and Trade costs of selling fuel at the rack. Until now, all biogas LCFS credits have been created through CNG and LNG sales. Biogas supply must exceed CNG and LNG demand in California before it will be used for process heaters, electricity generation, or hydrogen production. Biogas creates roughly the same value when used in these three applications if done in the refinery, but refineries would also have to compete with power companies for supply.

Prospects for biogas growth are good. The U.S. Environmental Protection Agency (EPA) forecasts a 21% increase in RINs from biogas between 2017 and 2018 based on recent year-on-year increases.[19] EPA also reported 215.5 million gallons of ethanol-equivalent energy supplied by biogas for the 12 months ending September 2017. Over the same period, CARB reported 100 million diesel gallon equivalents (DGE) of biogas use,[20] which is equivalent to approximately 170 million gallons of ethanol. California is attracting nearly 80% of the transportation biogas produced in the United States, which makes sense due to the additional value biogas generates in LCFS credits.

[19] U.S. Environmental Protection Agency. Renewable Fuel Standard Program: Standards for 2018 and Biomass-Based Diesel Volume for 2019. December 12, 2017. https://www.gpo.gov/fdsys/pkg/FR-2017-12-12/pdf/2017-26426.pdf
[20] California Air Resources Board. LCFS Quarterly Data Spreadsheet. January 31, 2018. https://www.arb.ca.gov/fuels/lcfs/dashboard/quarterlysummary/quarterlysummary_013118.xlsx

3.3.2 High, Mid, and Low Refinery Use of Low-CI Process Energy Credit Generation Possibilities

To develop the high, mid, and low LCFS credit estimates for low-CI process energy in refineries, we began by estimating biogas availability going forward by extrapolating recent historical trends in California as reported in the LRT quarterly data. For our low case, we assumed the average biogas CI is 40 grams per megajoule (gCO_2/MJ), and year-on-year growth decelerates to 10% per year in the middle of the next decade. For our middle case, we assume the average biogas CI is 35 g/mj and growth decelerates to 12% per year. For both cases, we assumed that CNG and LNG demand matching CARB's illustrative scenario calculator. (The calculations and resulting balances are shown in Appendices 1 and 2.) Our results show 1.5 and 1.0 million MT of biogas supply available into California in addition to that needed for CNG and LNG for the mid and low credit cases, respectively. We assumed 10% and 5% of what is available is used for process energy, respectively. Finally, we assumed that CARB's illustrative scenario represents the high case credit scenario. It shows 1.9 million MT of credits produced from renewable hydrogen in California refineries. We assume that process energy is 10% of this.

Given our educated assumptions, the summary of projections for each case is shown in Table 4.

Table 4. Possible Low-CI Process Energy LCFS Credits (MT per year)

High	Mid	Low
190,000	150,000	50,000

3.4 Electrification at Refineries

CARB's draft proposed LCFS regulation includes "electrification at refineries that involves substitution of high-carbon fossil energy input with grid electricity" as a project type eligible for refinery investment project credits. In refineries, two types of projects could generate credits by replacing high-carbon fossil energy input with grid electricity. The first type of project is replacing fired furnaces (which provide process heat or steam generation) with electric heating. A second type is to replace steam turbines with electric motors to reduce the generation of steam from combusting fossil fuels.

Refinery furnaces usually operate at high thermal efficiencies (80%) – higher than the efficiency to produce electricity from a thermal power station (approximately 35%). Replacing direct-fired heat with electrical power would increase CO_2 emissions unless the thermal efficiency of the direct-fired furnace is lower than grid electricity. Therefore, we do not expect that any LCFS credits will be generated by electric heat projects in refineries.

Depending on the philosophy under which a refinery was designed and built, that refinery may have either turbines or motors to drive its pumps. In the mid-20th century, when many of the refineries expanded to the equipment that operates today, steam turbines were often chosen in refineries for critical applications because grid electricity was not dependable, resulting in emergency shutdowns. In today's refinery operating environment, motors are preferred because of the lower initial and ongoing cost, and grid electricity is much more stable.

For refineries operating large steam turbine drivers, the total steam cycle efficiency (water to steam to steam power to water) is low. Under the right circumstances, there will be enough operating cost and LCFS credit incentives to replace steam turbines with electric motors.

3.4.1 Unconstrained Possibility for Refinery Electrification

Accurate information on the number and horsepower (HP) of steam turbines used in California's refineries is not available. In order to estimate the steam turbines, Stillwater applied its judgement of what processes in a typical refinery may have large pump and compressor drivers, and what percent of those may be driven by steam drivers. We estimate that a maximum of 130,000 HP is provided by steam turbine drivers. If all these steam turbine drivers were replaced by electric motors, approximately 700,000 MT of LCFS credits could be generated through RIC. Not all steam turbines would be candidates for switching because of high retrofit costs.

3.4.2 High, Mid, and Low Refinery Electrification Credit Generation Possibilities

The exact number of steam-turbine-to-electric-motor projects installed under RIC will depend on the particulars of the specific retrofit projects since the cost correlates to the specifics of the project and considerations such as whether steam can be reduced or used elsewhere. For these projects, the incentives created by generating LCFS credits is large, at two to three times the financial incentive from the operating costs savings, making this class of projects promising to implement.

For the high, mid, and low cases, we estimated that 100,000, 40,000 and 10,000 HP respectively will be converted from steam turbine drive to electric motors. Given these estimates, our summary of projections for each case is displayed in Table 5.

Table 5. Possible Electrification at Refineries LCFS Credits (MT per year)

High	Mid	Low
540,000	220,000	55,000

The accuracy of these estimates is speculative since specific data on the number and rated HP of steam turbines in California's refineries are not available.

3.5 Process Improvements

The draft proposed regulation includes "process improvement projects" resulting in CI "reductions per megajoule of total CARBOB and diesel produced." Process improvement credits cannot be generated after January 1, 2025; therefore, these projects will not contribute to credit generation in 2030 and will have no impact on CI reductions achievable at that time.

3.6 Renewable Hydrogen

The most practical source for generating renewable hydrogen is steam-reforming biomethane (biogas). LCFS credits from biogas, however, can also be created via electricity, CNG and LNG, and/or hydrogen. These credits are limited by biogas supply.

3.6.1 Unconstrained Possibility for Renewable Hydrogen

If there were no supply or technical issues, all refinery hydrogen could be produced from biogas. Total California refinery hydrogen plant production is approximately 1,100 million standard cubic feet per stream day. If all the carbon from producing this hydrogen were produced from biogas, roughly 5 million MT of credits could be produced per year.

3.6.2 3.4.2 High, Mid, and Low Renewable Hydrogen Credit Generation Possibilities

Since biogas availability is constrained by supply, we used the supply analysis described in section 3.3 and appendices 1 and 2 to assess what might be available for hydrogen production versus other uses. The nature of hydrogen production is such that almost all of it can be assumed to be from methane, while process energy is supplied in several other forms. Therefore, we assume more of the available biogas creates credits from hydrogen than process energy.

Results of our supply analysis in section 3.3 show 1.5 and 1.0 million MT per year of biogas supply available into California (in addition to what is needed for CNG and LNG) for the mid and low credit cases, respectively. We assumed 50% and 20% of what is available is used for hydrogen production energy, respectively. Finally, we assumed that CARB's illustrative scenario represents the high case credit scenario, although CARB's estimate seems unlikely unless biogas is not utilized in the power sector. Given these calculations and educated estimates, our summary of projections for renewable hydrogen is displayed in Table 6.

Table 6. Possible Renewable Hydrogen LCFS Credits (MT per year)

High	Mid	Low
1,900,000	750,000	200,000

4 Results and Conclusions

4.1 Factors Affecting RIC and RHRC Investment Decisions

As noted above, there are many factors that will affect the extent to which RIC and RHRC projects will proceed and succeed. These factors fall into several areas which we highlight here.

4.1.1 Regulatory Concerns

Several regulatory constraints could affect RIC and RHRC projects. The draft proposed regulation includes thresholds and limitations which could eliminate smaller projects. “Inside-the-meter” limitations for renewable electricity constrain the amount of renewable power available to a refinery because of acreage limitations. The 2025 sunset on credits produced through process improvements eliminates any LCFS incentive for these projects after that year. For refineries in Southern California, tightening limits under RECLAIM for nitrous oxides (NOx) will add incentives to reduce combustion in Southern California refineries. On the other hand, the value of Cap and Trade allowances is an added incentive to the LCFS credits for some of these projects. For fuels (such as biogas) that are covered under the RFS, the RINs that are generated also add to the value of the fuel. Decision-makers will have to consider each of these regulatory realities when determining whether to invest in an RIC or RHRC project.

4.1.2 Resource Availability Constraints

As discussed in section 3.3, biogas is limited due to its direct use as CNG or LNG for transportation, and that use puts it in direct competition with RIC and RHRC projects.

4.1.3 Refinery Design Constraints

Refineries vary greatly in their configuration and design. Generalized assumptions do not always accurately represent the specifics and the attractiveness of an RIC project for a given refinery. Furthermore, the cost of any project will vary from refinery to refinery because of the variation in configuration and design. These RIC projects involve retrofitting process units, requiring extended downtime and associated costs. Finally, other factors specific to a refinery may add to the incentive to install an RIC project. Examples of this are the need to replace equipment or enabling shutdown or replacement of older inefficient or costly equipment which increases the economic incentives.

4.2 Total RIC and RHRC Credit Predictions for 2030

Considering as many factors as possible, Stillwater has estimated high, mid, and low LCFS credits cases for 2030 from the RIC and RHRC provisions in the current and proposed LCFS regulatory text. These estimates represent fair values considering the short timeframe and lack of specific refinery information upon which to draw.

A summary of the total RIC and RHRC credits we envision being possible in 2030 is displayed in Table 7.

Table 7. Total 2030 Potential for RIC and RHRC

Project Category	LCFS Credits – MT CO_2/year		
	High	**Mid**	**Low**
Carbon Capture and Sequestration	2,000,000	730,000	365,000
Renewable Electricity	40,000	16,000	5,000
Low-CI Process Energy	190,000	150,000	50,000
Electrification	540,000	220,000	55,000
Process Improvement	0	0	0
Renewable Hydrogen	1,900,000	750,000	200,000
TOTALS	**4,670,000**	**1,866,000**	**675,000**
TOTALS without CCS	**2,670,000**	**1,136,000**	**310,000**

5 Profiles of Report Authors

Since 1997, **Stillwater Associates** has provided extensive transportation fuels expertise to clients in the downstream market. Our associates earned their years of experience at major international petroleum corporations. Our focus is on energy policy with an emphasis on traditional and next generation fuels refining, distribution, and marketing issues. *Stillwater Associates fuels the future of transportation energy with trusted industry experience.*

Leigh Noda, Senior Associate. Leigh has a broad-based experience in the petroleum refining, petroleum products, and alternate fuels arenas. His experience covers refinery operations, technology, business planning and strategy, business and project development, finance and EH&S (environmental, health and safety).

Over the course of 28 years at ARCO, Leigh held numerous positions including key positions during the period when many critical decisions and investments were made to the two west coast refineries to address new stationary source environmental and fuel standards. While he was manager of technology and business at Carson Refinery, ARCO developed the first environmentally reformulated fuel (EC-1) that was introduced to the market in 1989. The fuel was developed in collaboration with fuels and central technology groups to demonstrate that gasoline can be cleaner-burning and can be part of the future fuels mix of the country.

After ARCO, Leigh has consulted on a wide variety of projects ranging from development of investment opportunities for a private equity firm, to evaluation of the potential of innovative new technologies, to development of an innovative project for a GTL plant in Trinidad. In support of the US Agency for International Development he authored a white paper of US laws and regulations for use by Kazakhstan in development of their regulatory and environmental laws. Since 2010, Leigh has worked with Stillwater Associates across a broad range of studies with many projects in California's Low Carbon Fuel Standard arena.

Leigh earned a Master's in Business Administration from the UCLA Anderson School and a Bachelor of Science in Chemical Engineering from the University of California at Davis. His experience and education are the basis for strong analytical skills and an ability to address complex challenges and opportunities.

Jim Mladenik, Senior Associate. Jim spent 33 years at ARCO and BP before joining Stillwater Associates. His experience at BP covered all parts of the West Coast fuel value chain. He was instrumental in developing product placement, production, and marketing strategies; setting up the distillate trading book; and establishing wholesale diesel offers and military contract bids. Jim also developed BP's compliance strategies for California's Low Carbon Fuel Standard and Carbon Cap & Trade program and the federal Renewable Fuels Standard.

During his time at ARCO, Jim served as a technical specialist supporting the company's two West Coast refineries. In this capacity, he created one of the world's first comprehensive mathematical models of the delayed coking process. He later led the technical support team in the coking area which supplied a large calcined coke marketing business.

Jim earned his Bachelor's and Master's degrees in Chemical Engineering from the University of Notre Dame and an MBA from the University of California, Irvine.

Kendra Seymour, Analyst. Kendra is the editor of and a regular contributor to Stillwater's Low Carbon Fuel Standard Newsletters. Since joining Stillwater in 2014, she has offered research, editing, and process management expertise for numerous Low Carbon Fuel Standard and Renewable Fuel Standard projects. Kendra earned her Bachelor Arts in International Relations from Northwest Nazarene University.

APPENDIX 1. Low Case Biogas Calculations

	Low Case			Biogas CI = 40 g/mj		
	Biogas Available to California, million dge	**Year on Year Growth, %**	**Illustrative Scenario total CNG/LNG Demand, million dge**	**Excess Biogas, million dge**	**Ren H2 Credits Available, million MT**	**Illustrative Scenario total credits from Renewable H2**
2013	10					
2014	29	181%	29			
2015	69	141%	68			
2016	88	27%	87			
Est. 2017	107	21%	117			0.05
2018	128	20%	146			0.24
2019	151	18%	171			0.83
2020	175	16%	193			1.56
2021	200	14%	213			1.51
2022	226	13%	234			1.46
2023	253	12%	255			1.53
2024	281	11%	284			1.59
2025	309	10%	288	21	**0.11**	1.65
2026	340	10%	295	45	**0.24**	1.70
2027	374	10%	302	72	**0.39**	1.76
2028	411	10%	307	104	**0.56**	1.81
2029	452	10%	313	139	**0.76**	1.87
2030	498	10%	319	178	**0.97**	1.92

APPENDIX 2. Middle Case Biogas Calculations

	Middle Case			Biogas CI = 35 g/mj		
	Biogas Available to California, million dge	Year on Year Growth, %	Illustrative Scenario total CNG/LNG Demand, million dge	Excess Biogas, million dge	Ren H2 Credits Available, million MT	Illustrative Scenario total credits from Renewable H2
2013	10					
2014	29	181%	29			
2015	69	141%	68			
2016	88	27%	87			
Est. 2017	107	21%	117			0.05
2018	128	20%	146	(18)		0.24
2019	151	18%	171	(20)		0.83
2020	175	16%	193	(17)		1.56
2021	200	14%	213	(13)		1.51
2022	226	13%	234	(8)		1.46
2023	253	12%	255	(2)		1.53
2024	283	12%	284	(0)		1.59
2025	317	12%	288	29	0.18	1.65
2026	356	12%	295	61	0.37	1.70
2027	398	12%	302	97	0.59	1.76
2028	446	12%	307	139	0.85	1.81
2029	500	12%	313	186	1.14	1.87
2030	559	12%	319	240	**1.47**	1.92