Climate Pathways in an Oil State – 2022

A California Environmental Justice Alliance Report

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February 2022

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Executive Summary

In climate jargon, a pathway is a road map for the array of technologies and measures to be deployed over time, and for the cumulative climate emission trajectory associated with this sequence of actions. Pathways analysis is thus an essential tool for planning effective measures to achieve climate stabilization. The petroleum fuel chain—the sequence of interdependent steps in the acquisition (extraction), conversion (refining), and use (in transportation and industry) of petroleum fuels—is the largest and most entrenched climate polluter of all activities in California.[1 2] Planning effective climate measures in the petroleum fuel chain is of paramount importance here. At this writing the State has begun the comprehensive review required to update its Climate Scoping Plan.

The California Air Resources Board (CARB) has primary responsibility for this planning.

Problem

A bias against using all the tools in the toolbox in our climate crisis crept into state policy since carbon trading, which has not cut oil refining rates, launched here in 2013.[2] CARB prioritized its cap-and-trade scheme over direct emission reduction measures. By mid-2017, when this bias was codified in a political trade-off between cap-and trade and direct emission reduction, no refinery in the state had an enforceable limit to cut its carbon emissions. AB 398 (2017) constrained, and is interpreted by many to prohibit, direct emission reduction measures at refineries under cap-and-trade. CARB explicitly decided to *exclude* refining pathway analysis from its most recent Scoping Plan Update,[3] and now vaguely proposes “phasing out” oil refining only “in line with demand.”[4]

Toward a Solution

The necessary pathway analysis can be done. Indeed, it has been modeled with a focus on the petroleum fuel chain and conservative assumptions for all other, non-petroleum emissions, as reported by Communities for a Better Environment (CBE) in 2020.[2] This report updates that 2020 all-source pathways analysis to address three questions:

(1) Could California refining rates be decoupled from California refined fuels demand when in-state demand for petroleum fuels declines?

(2) Without refining rate reductions, would all-source pathway emissions that include the petroleum fuel chain linked to California refineries exceed the state climate limit?

(3) Would delaying direct emission reductions from refineries foreclose the most feasible, least-impact pathways for total all-source emissions to meet the state climate limit?

Analysis Benchmarks

Climate limit. State climate emission reduction targets, expressed in shorthand as –40% by 2030 and –80% by 2050, are direct emission reduction goals, which "carbon neutrality" measures such as industrial or biological carbon sequestration are explicitly meant to supplement but not to replace.[5] These targets quantify a path of continuously declining emissions that add up to a total cumulative emissions limit through 2050. This climate limit is consistent with the state's share of global emission reductions for a 67 percent chance of holding global heating to between 1.5ºC and 2ºC. Pathways are compared with this climate limit based on a conservative best-case assumption that all other, non-petroleum emissions will be cut to their share of the climate limit.

Minimum emission shifting. State law requires CARB plans and policy measures to minimize emission shifting, which it defines as "a reduction in emissions of greenhouse gases within the state that is offset by an increase in emissions of greenhouse gases outside the state." Calif. Health and Safety Code §§ 38505 (j) and 38562 (b)(8). Among other examples,[16] measures that reduce petroleum fuels demand here may increase emissions elsewhere from burning fuels that refiners here export, and measures that phase out oil extraction here may increase emissions from extracting crude for imports to refiners here. In these ways, and others reviewed in the "system boundary" background in CBE (2020),[2] pathways that fail to account for import-export factors may fail to meet state climate goals. Thus, this analysis accounts for the part of the petroleum fuel chain directly linked to refining here.

Feasibility. This analysis compares climate pathways based on replacing 80–90% of petroleum with alternatives which have been proven technically feasible in practice. It reserves either 20% of refining capacity for continued air travel without jet biofuel, or 10% if the jet biofuel now proven technically feasible in practice† approaches its current blend limit of 50%. Further, it conservatively assumes no increase from the baseline crude rate or carbon intensity of the petroleum fuel chain linked to oil refined in California during 2013–2019. Pathways are compared for social feasibility based on their transition impacts as measured by annual refining capacity decommissioned, oil worker just transition costs, and an environmental justice indicator—toxic refinery greenhouse gas co-pollutant emissions.

Report Organization

Chapter 1 assesses the decoupling of California refining rates from in-state petroleum fuels demand based on interactions of petroleum fuel chain components when demand declines. California refineries import crude on top of the crude extracted here, and export refined fuels on top of those burned in transportation and industry here.[2] High quality state and federal data were used to quantify export refining rates when in-state and total domestic demand for California-refined fuels declines. Structural capacity of the petroleum fuel chain to maintain crude rates by further increasing fuels exports was quantified, and linked to changes in California, domestic West Coast, and potentially growing Pacific Rim nations' petroleum fuels demand.

† Hydrotreated esters and fatty acids (HEFA) technology, coupled with intentional hydrocracking.

Chapter 2 assesses the potential for total all-source emissions to exceed the state climate limit without refining rate cuts, due to emissions from the petroleum fuel chain linked to refining in California. The climate limit, quantified as described above, is presented in this chapter. Cumulative emissions along pathways without refining rate reductions were compared with the climate limit through 2050 for the two plausible jet fuel cases described in the feasibility benchmarks above. Results were then analyzed to inform the importance of direct emission reductions at refineries to petroleum fuel chain crude rate cuts for achieving state climate goals.

Chapter 3 assesses the potential for delayed crude rate cuts to foreclose feasible least-impact pathways for all-source emissions to meet the state climate limit. Climate pathways—along which it is now *technically* feasible to meet the climate limit—were each quantified for when sustained crude rate cuts would start and how much refining capacity would be decommissioned annually to meet the climate limit on each path. Results were analyzed for social feasibility based on the decommission rate, oil worker just transition, and environmental justice benchmarks described above. Potential tipping points in the severity of transition impacts caused by delay until currently feasible least-impact pathways would no longer be possible can be identified from this assessment.

Conservative Assumptions

All pathways analysis herein used the conservative assumptions given in the analysis benchmarks discussion above: All other, non-petroleum emissions were assumed to be cut to their share of the state climate limit. Petroleum fuel chain pathways were limited to technologies and measures that are technically feasible as proven in practice. It was further conservatively assumed that neither the crude rate nor the carbon intensity of the petroleum fuel chain directly linked to refining in California will exceed their current values, as documented based on the mean of 2013–2019 data.

Additionally, greenhouse gas emissions were quantified as carbon dioxide equivalents (CO_2e) at the 100-year climate forcing horizon. This is consistent with the approach and practices generally used in California and by CARB. It should be noted, however, that the possibility of climate system tipping points before the year 2122 suggests a 100-year impact horizon may underestimate impacts.

Supporting Materials

Data and details of methods for all pathway analysis reported herein are given in Attachment 1.[1] This includes and accounts for new and revised data from 2013–2021 that were available as of January 2022, transitory effects of the COVID-19 pandemic on cumulative petroleum emissions, and the potential addition of HEFA jet fuel in Case-2 (10% refining capacity reserve with biofuel replacing up to half of petroleum jet fuel) pathways.[1] The original pathway analysis methods this report builds upon are given and further supported in CBE (2020),[2] also appended as Attachment 2.

Findings and takeaways from this work are summarized on the next page below.

Findings and Takeaways

Finding 1

In-state demand reduction measures cannot ensure refining phase down. When in-state fuels demand declines, California oil refiners have, and likely would, protect their otherwise stranded assets by increasing refining for export sales to other Pacific Rim states and nations, in an absence of refinery-specific direct control measures. We need all the tools in the toolbox.

Takeaways

Direct control measures are needed to ensure managed refinery phase-downs.

As an immediate step, CARB should develop climate pathway analysis that explicitly includes refining and its interactions with the petroleum fuel chain.

Finding 2

Even if all other, non-petroleum emissions are cut to their share of the State's direct emissions reduction goal, this goal cannot be achieved without refining rate cuts. Without crude rate cuts, emissions from the petroleum fuel chain linked to refining in California would drive total statewide carbon emissions to exceed the State climate emissions goal.

Takeaways

Refining rate cuts are essential to achieve State climate goals.

Refinery-specific direct control measures could achieve this outcome.

Finding 3

Further delaying the start date for refinery phase-downs would foreclose the most feasible, least-impact pathways to State climate goals irreversibly, impairing the feasibility of achieving the goals substantially. Side effects of this delay would prolong and worsen environmental injustice, and increase just transition costs for oil workers, further impairing the feasibility of achieving State climate goals.

Takeaways

Refinery-specific direct control measures, including but not limited to direct emission measures, should be considered in the 2022 Climate Scoping Plan.

The California Air Resources Board (CARB) should include environmental justice impacts of refining for export in its climate pathways analysis.

CARB should support climate justice for oil workers in a meaningful way by including analysis of the Just Transition Program presented to California and endorsed by United Steelworkers refinery workers' union locals 5 and 675 last year in its Climate Scoping Plan climate pathways development.

1 Could California Refining Rates be Decoupled from California Refined Fuels Demand when In-state Demand for Petroleum Fuels Declines?

In a hypothetical perfect world, phasing out petroleum use everywhere phases out all oil refining. But CARB cannot phase out petroleum fuels demand everywhere. The assumption that California demand reduction alone will phase down oil refining here is unsupported. This chapter assesses the evidence that refiners here have the means, motive, and opportunity to export fuels to other states and nations in response to continued use of in-state petroleum fuels reduction measures alone.

1.1 Inherent features of the fuel chain linked to California refineries

The interdependence of oil extraction, refining, and refined fuels combustion rates makes these three often-distant links in the petroleum fuel chain mutually reinforcing. These fundamental features of the built infrastructure of oil mean that refiners are both able to export refined fuels and incentivized to refine fuels for export whenever that maximizes their profits. California refineries demonstrate these features of the petroleum fuel chain in practice.

California refineries are major net exporters of gasoline and diesel to other states and nations.[6] Refining for export supplies the transportation fuels link of their fuel chain in other West Coast states, primarily Arizona, Nevada and Oregon, and other nations, primarily on the Pacific Rim.[6] Refining for export accounted for approximately 14.7 billion gallons, or 21%, of total California refined fuels production during 2013–2015, rising to 17.3 billion gallons, or 24% during 2017–2019.[1] Those figures exclude jet fuel and are larger still when jet fuel burned in cross-border flights is included.[1 2] This is big business. By 2014 total petroleum products exports from California to other nations alone rose to an estimated $7.9 billion per year.[7]

Thus, the fuel chain linked to refining here is already built to protect statewide refining assets and profits when in-state—and even domestic—demand for petroleum fuels declines. Moreover, this structural asset protection mechanism is already in play.

1.2 Refining for export when demand declines here

Table 1 compares in-state fuels demand with cross-border fuels exports from California refineries between two ten-year periods. This decadal comparison describes the real structural trend, which can be masked by short-term transitory effects on demand such as economic cycles. Review of Table 1 shows that the long-term structural decline in California petroleum fuels demand envisioned by CARB has already begun—and that California refineries are exporting their way out of it.

Table 1. California-refined Gasoline and Distillate-diesel: Decadal Changes in California Demand and Exports to Other States and Nations, 2000–2019.

Total volumes reported for ten-year periods

	Volume (billions of gallons)		Decadal Change (%)	
	Demand	Exports	Demand	Exports
Gasoline				
1 Jan 2000 to 31 Dec 2009	151	15.0	—	—
1 Jan 2010 to 31 Dec 2019	137	26.4	–9 %	+76 %
Distillate-diesel				
1 Jan 2000 to 31 Dec 2009	39.5	9.88	—	—
1 Jan 2010 to 31 Dec 2019	38.8	16.2	–2 %	+64 %
Gasoline and diesel				
1 Jan 2000 to 31 Dec 2009	190	24.9	—	—
1 Jan 2010 to 31 Dec 2019	176	42.6	–7 %	+71 %

Data from CARB, *Fuel Activity Inventory* (8) and CEC *Fuel Watch* (9). Figures may not add due to rounding.

As compared with the decade from 2000–2009, during 2010–2019 in-state demand for total gasoline and distillate-diesel combined fell by approximately 14 billion gallons, or seven percent, while California refinery exports of these fuels rose by approximately 17.7 billion gallons, or 71 percent. <u>*See*</u> Table 1. Instead of phasing down their production of petroleum ground transportation fuels when in-state demand for these fuels declined, statewide refiners more than compensated for the in-state decline in demand by refining for export.

Going a bit deeper into the details of Table 1, we can notice that the volume of gasoline exports increases less than the volume of in-state gasoline demand decreases (–2.5 billion gallons), while that of distillate-diesel increases more than its demand decreases (+5.6 billion gallons). This is not a problem with the data—refinery production shifted between the two fuels—but it does show that looking at more than one fuel is better. And while Table 1 correctly includes all cross-border exports that are outside the reach of California demand reduction measures, we want to know, also, how much foreign exports across the Pacific Rim increase when demand declines across the domestic fuels market for California refineries. Table 2 shows that, for all refined petroleum fuels combined.

Table 2. West Coast (PADD 5) Finished Petroleum Products: Decadal Changes in Domestic Demand and Foreign Exports, 1990–2019.

Total volumes reported for ten-year periods

	Volume (billions of gallons)		Decadal Change (%)	
Period	Demand	Exports	Demand	Exports
1 Jan 1990 to 31 Dec 1999	406	44.2	—	—
1 Jan 2000 to 31 Dec 2009	457	35.1	+13 %	–21 %
1 Jan 2010 to 31 Dec 2019	442	50.9	–3.3 %	+45 %

Data from USEIA, *Supply and Disposition* (10).

Comparing the same ten-year periods (2010–2019 v. 2000–2009), total West Coast demand for all petroleum fuels combined fell by 15 billion gallons, or 3.3 percent, while total West Coast exports of all these refined fuels to other nations rose by nearly 16 billion gallons, or 45 percent. See Table 2. Again, refining for export more than compensated for the decline in domestic demand.

1.3 California refineries fuel the Pacific Rim

These West Coast data are highly relevant to our inquiry because the West Coast—Alaska, Arizona, California, Hawaii, Nevada, Oregon, and Washington—encompasses California refiners' domestic fuels market,[6] and California is the dominant refining center on the West Coast.[2] West Coast data reveal still more about California refineries. Their domestic fuels market peaked in the first decade of this century. See Table 2. The inverse relationship between fuels demand here and foreign export refining was established by then as well. *Id.* Indeed, foreign export refining was baked into their fuel chain by the end of the twentieth century. *Id.*

Billions of people live in nations across the Pacific Rim which have imported petroleum products from the U.S., and their per capita petroleum use, which is low compared to that here, has begun to rise.[11] This suggests exports from California refineries could grow dramatically. It signals a potential destination for increased refined fuels exports, to replace declining in-state fuel sales instead of stranding California refining capacity, if the state switches from petroleum to zero-emission cars and trucks without new policy intervention to phase down in-state refining rates.

Such large-scale shifts in petroleum flows that protected refining assets have happened before. When diesel began to dominate the passenger car fleet in parts of Europe, refiners there exported gasoline to the U.S. in amounts that contributed to the closure of major East Coast refineries. And when California-sourced crude declined far more[12] than in-state petroleum fuels demand has declined to date,[8] California refiners protected otherwise idled assets by importing crude in amounts that their exports have lagged far behind to date. By the period during 2013–2019, their crude imports grew to 1.12 million barrels per day, 68% of all crude refined in California.[1] That 1.12 million barrels per day is equivalent in volume to 90% of total in-state demand for refined fuels during the same 2013–2019 period.[1] Another such large-scale shift in petroleum flows to protect refining assets—this time, via exports—would not be unprecedented.

All of the evidence discussed above supports a clear answer to our first question: Petroleum fuels demand reduction in California alone has not cut and cannot be expected to cut refining rates or phase out refining here because California refining for export can fuel the Pacific Rim.

2 Without refining rate reductions, would all-source pathway emissions that include the petroleum fuel chain linked to California refineries exceed the state climate limit?

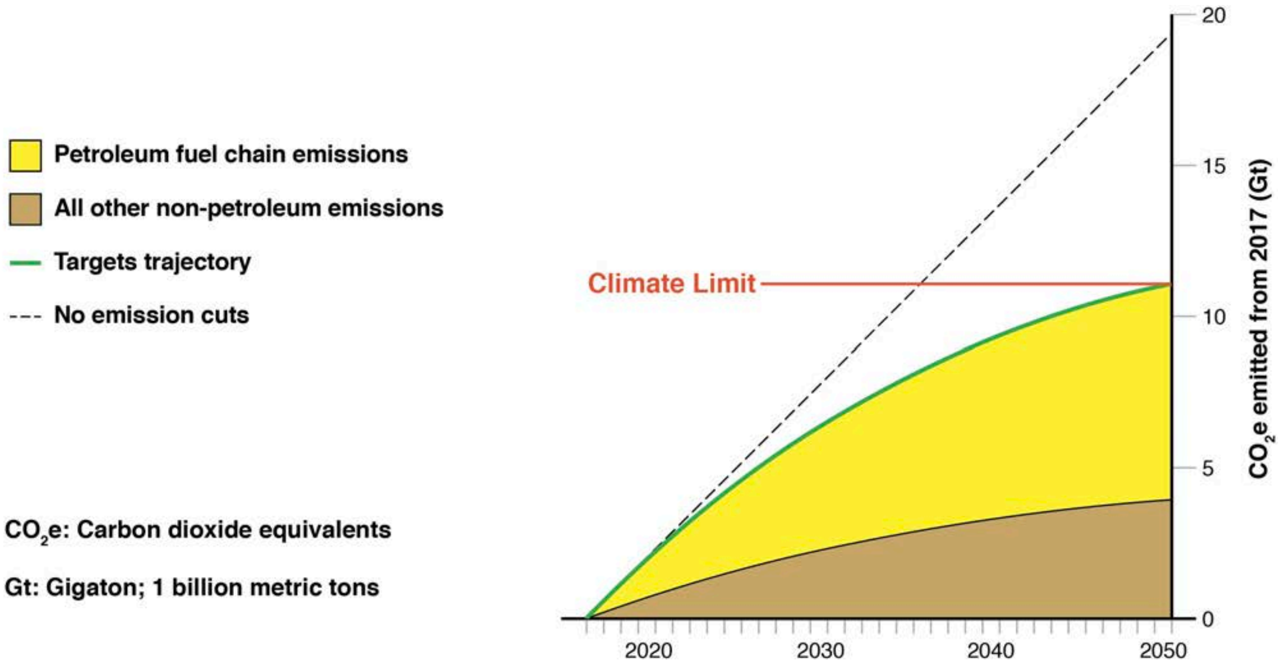
Total CO_2e emissions would exceed the state climate limit substantially without refining rate cuts. All-source emissions could exceed the climate limit by 5.3 to 5.9 billion tons, or 48 to 53 percent, through 2050. These figures assume that all non-petroleum emissions are cut to their share of the climate limit. Maintaining crude rates in the petroleum fuel chain by refining imported crude for export to avoid otherwise stranded California refining assets as other measures cut in-state fuels demand would be the primary causal factor for this climate stabilization failure. A root cause would be State failure to minimize emission shifting to outside California with measures that directly phase down in-state refining rates. Direct emission reductions at refineries are an effective measure that can force the gradual decline in crude rates needed to meet state climate goals.

2.1 Climate limit defined by State climate emission targets

Once emitted, CO_2e accumulates in the upper atmosphere to force climate heating for hundreds of years, so *cumulative* emission over time, not incremental up-and-down "blips" in emissions from year to year, drives climate impact. Meeting state climate goals thus requires limiting direct emissions that accumulate over time.

California's climate targets for direct emission reduction through 2050 define this climate limit. The targets seek continuous, proportionate annual cuts in direct emissions during three periods.[2] First, back to the emission rate in 1990 by 2020, then 40% below the 1990 rate by 2030, then 80% below the 1990 rate by 2050.[5] Now we are past 2020, statewide emissions were close to that first target, and we have reliable and accurate emissions data representative of current pre-COVID conditions from 2013–2019[1] to assess the proportionate annual cuts to the 2030 and 2050 targets. With these cuts, a certain amount of CO_2e will be emitted each year through 2050. The climate limit is simply the sum total of these proportionately declining annual emissions.

Chart 1 illustrates cumulative emission trajectories defined by the state climate targets. They start with actual emissions as of 2017 based on high quality state and federal data.[1] Reduced emissions



1. State Climate Limit: Cumulative emission limit through 2050 defined by state climate targets.
For data and details of methods *see* Supporting Material.[1]

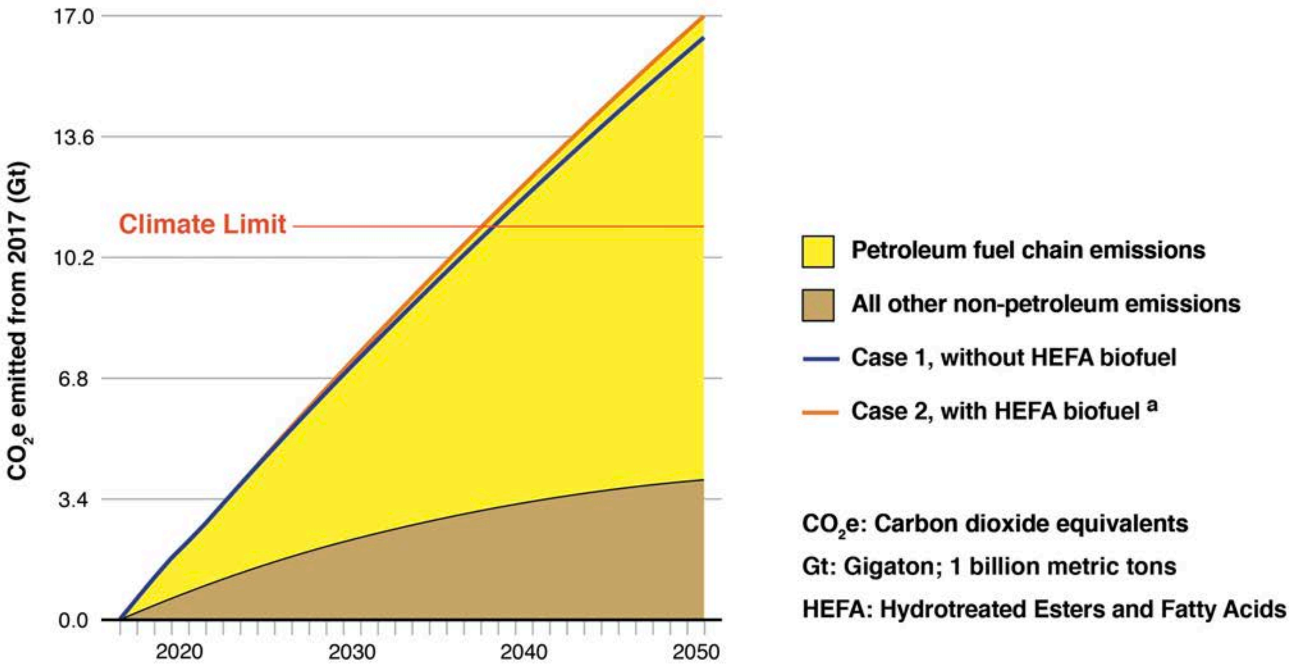
defined by the targets add to cumulative emissions in each subsequent year. The non-petroleum (brown shading), petroleum fuel chain (yellow shading), and total (green curve) trajectories bend downward because of these sustained emission cuts. The climate limit (red line) is the total emissions through 2050, approximately 11.1 gigatons (billion metric tons).[1] This cumulative emission limit is consistent with the state's share of global emission reductions for a 67 percent chance of holding global heating to between 1.5ºC and 2ºC.[1]

For comparison with our 11.1 billion ton climate limit, the dashed line in Chart 1 shows that without any future cuts in total emissions from petroleum and all other activities statewide, cumulative CO_2e emission could exceed 19 billion tons through 2050.

2.2 All-source pathway cumulative emissions without crude rate cuts

To assess climate impacts without refining rate reductions, we can compare cumulative emissions from the petroleum fuel chain linked to California refineries with the climate limit, along pathways without crude rate reductions. Uncut petroleum emissions would build up more than in the climate limit trajectory illustrated by Chart 1. But how much more?

Chart 2 illustrates potential climate impacts from the petroleum fuel chain alone, by assuming that emissions associated with all other, non-petroleum, activities statewide will be cut to their share of the climate limit. The "all other, non-petroleum" trajectory in Chart 2 below is the same as its climate limit trajectory as illustrated in Chart 1 above (brown shading in both charts).



2. Cumulative emission along petroleum fuel chain pathways without refinery crude rate cuts.
Assumes all other, non-petroleum emissions are cut to their share of the climate limit. (a) Without refinery crude rate cuts, Case 2 includes only in-state crude-to-biofuel refinery conversions which would not reduce capacity to maintain current refining rates on all climate pathways in this report. *See* Supporting Material for data and details of methods.[1]

Uncut petroleum fuel chain emissions without crude rate cuts (yellow shading in Chart 2) drive a dramatic buildup of total cumulative emissions (rising blue and orange curves) to exceed the state climate limit (red horizontal line) by a wide margin well before 2050. Pathways without crude rate cuts exceed the climate limit trajectory by 13 to 16 percent in 2030, irreversibly exceed the 2050 climate limit by 2038, and exceed the limit by 5.3 to 5.9 billion tons, or 48 to 53 percent, by 2050.[1]

This climate protection failure would occur despite cutting all other non-petroleum emissions to their share of the climate limit. Oil's dominance of our climate crisis here would further grow. From 65 percent of total statewide CO_2e emitted during 2013–2019, the fuel chain linked to refining here would emit some 69 percent, and 76 percent, of our cumulative emission profile by 2030 and 2050, respectively, along these no-crude-rate-cut pathways.[1]

Importantly, emission shifting across the fuel chain would grow as in-state fuels demand declines. Refining and burning exported fuel accounts for up to 31 percent of petroleum fuel chain emissions linked to refining here during 2013–2019.[1] That percentage could grow as dramatically as California refinery crude imports have grown, if CARB implements current plans to phase out up to 90 percent of in-state petroleum fuels demand without forcing refining rate cuts.

Refining for export would be the primary causal factor for this climate protection failure, as detailed in Chapter 1. A root cause would be State failure to minimize emission shifting to outside California with measures that directly phase down in-state refining, as further discussed in the next section.

2.3 Importance of direct emission reductions to crude rate cuts

There is a positive and hopeful flip side to our findings that in-state demand reduction alone cannot be expected to phase down California refining rates, and state climate goals cannot be met without doing so. Importing crude and exporting fuels, refining determines the flow of petroleum through California, and hence the emissions associated with the petroleum fuel chain linked to oil refining in California.[2] The flip side is that, in great contrast to extraction elsewhere for crude imports refined here and combustion elsewhere of fuels refined here for export, refineries in California are squarely within the state's jurisdictional control. California has jurisdiction to control the key link in the petroleum fuel chain where a managed decline in crude rates is essential to its climate goals.

Emissions from refineries here emit directly here. Our collective actions here can cut them. Phasing down refining rates here can achieve the deep emission cuts necessary to meet state climate goals from refineries here—and across the far-flung petroleum fuel chain linked to refineries here.

There may be other technology-forcing measures to directly manage refinery phase-downs, however, direct emission reduction measures have the crucial advantage that they are demonstrated in practice. For example, as described in CBE (2020),[2] air quality officials in California and elsewhere have established and enforced emission limits expressed as refinery throughput for decades.[2] This proven direct measure to cut harmful pollution by controlling and reducing refining rates seems especially appropriate in our present circumstance, where phasing down refining rates is essential for the deep emission cuts needed in the petroleum fuel chain, the dominant climate emitter in the state, to meet California's climate goals.

As a specific example, emissions of health-threatening combustion products such as particulate matter and oxides of nitrogen and sulfur from refineries have long been subject to emission limits expressed as refinery petroleum production ("throughput") rates. CARB, its regional air districts, or both could strengthen these direct emission reduction measures, with or without adding some or all greenhouse gases to those emission standards, and implement emission reductions gradually to manage a smooth refining phase down.[2]

The State of California thus has jurisdictional authority to implement at least one proven measure that available evidence indicates will be necessary to achieve its climate goals. This is why its failure to minimize emission shifting to outside California with measures that directly phase down in-state refining rates would be a root cause for the potential climate protection failure described in Section 2.2.

3 Would delaying direct emission reductions at refineries foreclose the most feasible, least-impact, pathways for total all-source emissions to meet the state climate limit?

Effective climate plans must consider that the impetus to put off action we can take now to begin a transition from oil, due to its transition impacts, leads to a vicious cycle: Cumulative emissions increase faster while the time left for cutting emissions to the climate limit shortens. This forces deeper emission cuts faster, to the climate limit. That increases the severity of transition impacts, reinforcing the vicious cycle. Delay, then, can be a dead-end path to climate disaster. We assess how much—and when—delaying sustained refinery crude rate cuts results in the state climate limit becoming *less* feasible to achieve in this chapter.

3.1 Near-term tipping points for climate pathways feasibility

Tipping points in the feasibility of meeting our climate limit, as measured by refining capacity lost annually along climate pathways, are different from tipping points in the climate system. Compared with the complexity and uncertainty of climate system tipping points, these climate pathway feasibility tipping points are certain to occur with delay, predictable based on simple math,[2] and quantifiable based on two factors. The factors are the cumulative emissions, and time left to cut emissions to our climate limit. Our pathways analysis gives us data for each of these factors.

Table 3 compares the refining capacity lost annually along 48 technically feasible pathways that can meet the state climate limit, and span the range of plausible starting dates and total refining capacity cuts, to identify transition impact tipping points in climate protection feasibility caused by delay.

First let's check our pathway analysis method itself. Recent data for the unprecedented short-term impact of COVID-19 on refining rates, and for a key biofuel, which were not available for the original CBE (2020) analysis, can be used to "ground truth" our method's sensitivity and reliability.

Pathways in Table 3 fall into two groups. Case 1 holds 20 percent of refining capacity in place through 2050 for potentially irreplaceable products, primarily jet fuel. Case 2 holds 10 percent in place for this, based on a technically proven jet biofuel technology,† which emerged after the CBE (2020) analysis and might replace up to half of petroleum jet fuel refined here.[13] Case 2 accounts for CARB-estimated jet biofuel emissions.[1] This is relevant to our methods check because it helps show that our pathway results capture effects of both COVID and biofuel addition to the petroleum fuel chain. The temporary slowdown in cumulative emissions buildup during the pandemic lock

† Hydrotreated esters and fatty acids (HEFA) technology, coupled with intentional hydrocracking.[13]

Table 3. Annual refining capacity loss along 48 pathways to the state climate limit, by starting date of sustained petroleum fuel chain crude rate reductions [a]

Case 1: 20% refining capacity reserve [b]

Starting date	Capacity loss (%/year) This report	Capacity loss (%/year) CBE (2020)[2]
Jan 2020	foreclosed	5.03
Jan 2021	foreclosed	5.49
Jan 2022	5.27	6.05
Jul 2022	5.51	NA
Jan 2023	5.78	6.73
Jul 2023	6.08	NA
Jan 2024	6.40	7.59
Jul 2024	6.77	8.10
Jan 2025	7.17	8.69
Jul 2025	7.63	9.37
Jan 2026	8.15	10.17
Jul 2026	8.74	11.11
Jan 2027	9.43	12.28
Jul 2027	10.25	13.67
Jan 2028	11.21	15.43
Jul 2028	12.37	17.70
Jan 2029	13.79	20.74
Jul 2029	15.57	25.03
Jan 2030	17.88	31.95
Jul 2030	21.15	43.24
Jan 2031	25.64	65.71
Mar 2031	NA	79.84
Jul 2031	32.51	
Jan 2032	44.25	
Jul 2032	67.85	
Aug 2032	79.66	

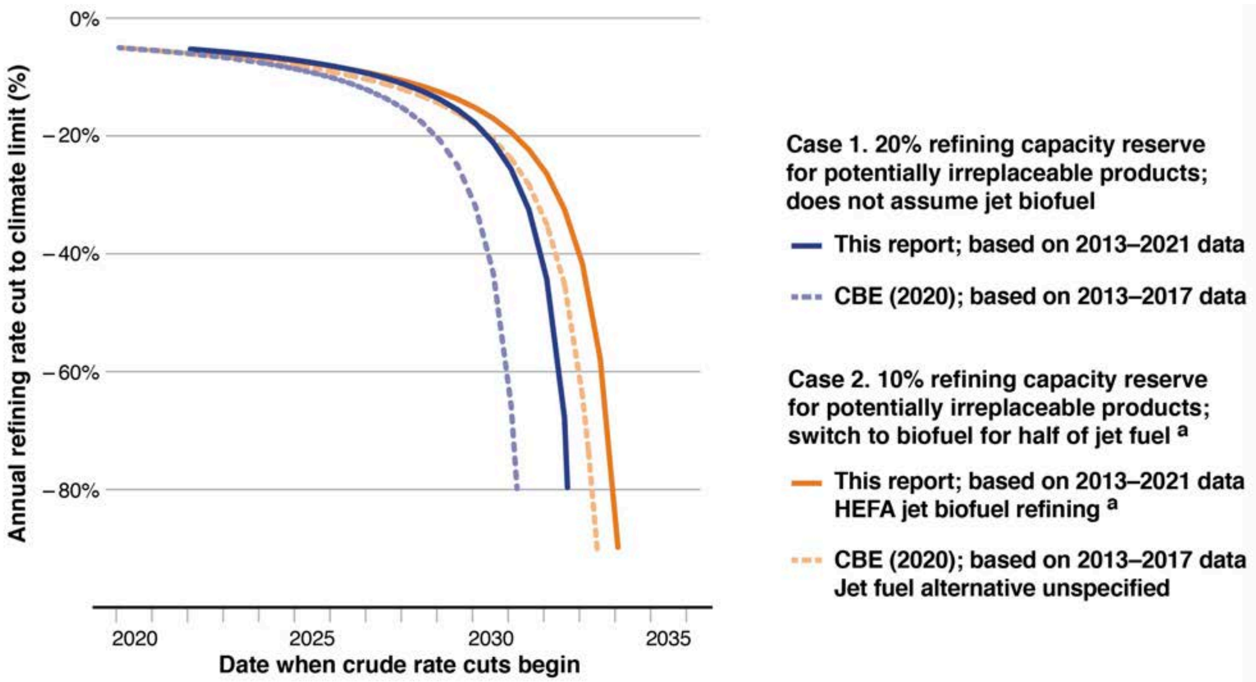
Case 2: 10% refining capacity reserve [c]

Starting date	Capacity loss (%/year) This report	Capacity loss (%/year) CBE (2020)[2]
Jan 2020	foreclosed	5.03
Jan 2021	foreclosed	5.49
Jan 2022	5.41	6.01
Jul 2022	5.67	NA
Jan 2023	5.95	6.61
Jul 2023	6.24	NA
Jan 2024	6.56	7.32
Jul 2024	6.91	NA
Jan 2025	7.31	8.16
Jul 2025	7.74	NA
Jan 2026	8.22	9.17
Jul 2026	8.73	9.77
Jan 2027	9.30	10.45
Jul 2027	9.95	11.25
Jan 2028	10.69	12.16
Jul 2028	11.55	13.25
Jan 2029	12.57	14.53
Jul 2029	13.77	16.11
Jan 2030	15.23	18.08
Jul 2030	17.03	20.54
Jan 2031	19.35	23.86
Jul 2031	22.34	28.30
Jan 2032	26.41	34.97
Jul 2032	32.48	45.15
Jan 2033	41.66	63.97
Mar 2033	NA	73.12
Jun 2033	NA	90.01
July 2033	57.76	
Jan 2034	89.80	

a. Assumes that all other non-petroleum emissions are cut to their share of the climate limit. See Supporting Material for data and methods details.[1] CBE (2020) S1 comparison results shown for method verification purposes only. Estimates in this report are based on data through 2021 while those in CBE (2020) are based only on pre-COVID-19 data through 2017. **b.** 20% of current refining capacity reserved for potentially irreplaceable products, including petroleum jet fuel demand at current rates. **c.** 10% of current refining capacity reserved for potentially irreplaceable products. Case 2 assumes alternatives to petroleum jet fuel, which were deemed unproven in CBE (2020) but now a specific jet biofuel technology (HEFA) has been proven in practice, has CARB-estimated fuel chain emissions, and is assumed—in Case 2 of this report—to replace petroleum fuel up to its 50% blend limit.

downs lengthens delays in starting crude rate cuts before refinery capacity losses of 20% and 80% or 90% would be needed to meet the climate limit *less* in Case 2 (+7 to 12 months) than in Case 1 (+17 to 18 months) because of these biofuel emission additions in Case 2. <u>See</u> the results in Table 3.

At the same time, overall results are remarkably similar across estimates and cases. Sustained annual refining capacity losses vary by less than 1% across estimates and cases starting crude rate cuts in January 2022 and 2023. *Id.* Annual capacity losses increase with delayed crude rate cuts, doubling each 5 to 6 years with delay from 2022 to 2027, each 1.6 to 3.3 years with delay from 2028–2032, and each 1.0 to 1.4 years with delays until after 2029 across pathway estimates and cases. *Id.* This suggests the method is reliable for comparing feasibility tipping points among climate pathways. Chart 3 illustrates the deeply diving downward curves of annual refining capacity losses that would be caused by delays in starting crude rate cuts along pathways to the climate limit.



3. Effect of delay on annual refinery crude rate cuts to the State climate limit, data from Table 3. Assumes non-petroleum emission cuts to their share of the climate limit. **a.** Case 2, in this report, assumes repurposing refining capacity lost along climate pathways with HEFA refining up to the 50/50 biofuel/petroleum jet fuel blending limit. HEFA: Hydrotreated esters and fatty acids; a type of biofuel. *See* Supporting Material for data and methods.[1]

Pathways that achieve the climate limit while decommissioning refinery capacity gradually at 5% to 7% per year (Chart 3, left) would be foreclosed by delaying the start date for sustained crude rate cuts in the petroleum fuel chain (from left to right along the chart's horizontal axis). Delay until after 2031 (Case 1) or 2033 (Case 2) would force refining capacity losses of 80% to 90% in a single year to meet the climate limit (chart, right). That enormous increase in sudden statewide refinery closures, hence worsening of transition impacts, would substantially and irreversibly impair the social feasibility of meeting the state climate limit.

Worse, tipping points for the feasibility of meeting the climate limit, after which delay quickly drives these transition impacts over a cliff, from around 20%, to 80% or 90% refinery capacity losses per year to meet the limit, would arrive by 2031 at the latest (orange curve in the chart) and could trigger irreversible impairment of state climate limit feasibility by 2030 (blue curve).

A recent direct emission control measure here that refiners perceive will affect their profits—as cuts to refining rates instead of refining for export surely would—is taking nearly a decade to implement from when it was first proposed.[14]

Thus, planning for the "maximum feasible" measures and pathways to achieve state climate goals means planning measures to directly ensure the gradual phase-down of refining rates and emissions now.

3.2 Environmental Justice benefits of phasing out refining for export

Low income Black and Brown populations in California communities that host refineries have long been shown[15] to face disparately worsened exposures to harmful refinery emissions of CO_2e co-pollutants, such as particulate matter (PM), nitrogen oxides (NOx), sulfur oxides (SOx), and other criteria and toxic air pollutants. Doubling down on this toxic racism, a substantial and potentially growing portion of that disparately severe exposure is being caused by refining for export of fuels that Californians do not need or use. *See* chapters 1 and 2.

The same refinery-specific direct control measures needed to reduce crude rates before our most feasible pathways to the state climate limit are foreclosed would reduce these emissions from refineries as well. These direct control measures would benefit environmental justice communities, further enhancing the feasibility of least-impact pathways to the climate limit. Conversely, further delaying them would prolong and worsen an acute social injustice in California communities that host refineries, further impairing the feasibility of delayed action pathways to the climate limit. For example, consider Table 4.

Table 4. Refining for export community emission impacts avoidable by the least-impact climate pathway starting crude rate reductions in January 2023

t (ton): metric ton **Mt** (Megaton): 1 million tons **No CCR:** no crude rate reduction

	CO_2e emitted by refining for export (Mt/y) [a]			Co-pollutant emissions from refining for export (t/y) [b]			
Year	No CRR	Climate path	Export refining	PM	NOx	SOx	Subtotal
2022	35.64	35.64	0.00	0	0	0	0
2023	35.64	33.58	2.06	129	457	263	848
2025	35.64	29.81	5.83	364	1,290	744	2,400
2030	35.64	22.13	13.51	843	3,000	1,720	5,560
2035	35.64	16.43	19.21	1,200	4,260	2,450	7,910
2040	35.64	12.20	23.44	1,460	5,200	2,990	9,650
2045	35.64	9.06	26.58	1,660	5,900	3,390	10,900
2050	35.64	7.14	28.50	1,780	6,330	3,630	11,700

PM: particulate matter; PM_{10} including $PM_{2.5}$ **NOx:** oxides of nitrogen **SOx:** oxides of sulfur **a.** CO_2e emissions from refining for export without crude rate cuts are the difference of No CRR and climate path emissions from the least-impact pathway starting CRR in Jan 2023. This assumes that in-state petroleum fuels demand would decline in line with this climate pathway to 80% below current demand by 2050—a conservative assumption compared with CARB expert advice to plan for a reduction in gasoline demand of at least 90% by 2045.[16] **b.** CO_2e co-pollutant emissions from refining for export were based on co-emission factors (eg., t PM/Mt CO_2e) derived from state refinery emissions data. *See* Supporting Material for data and details of methods.[1] The table shows only new, post-2022, potential increases in refining for export. Figures may not add due to rounding.

Compared with the least-impact climate pathway in which direct measures launch a gradual phase down of refining in 2023, delaying the phase-down start date would foreclose annual criteria air pollution cuts of approximately 5,560 metric tons by 2030, 9,650 tons by 2040, and 11,700 tons by 2050, from refining for export alone. *See* Table 4. This evidence further supports refinery-specific direct emission reduction measures for climate justice.

3.3 Just Transition benefits of early, hence smooth, refining phase down

Lastly, and by no means less importantly, at a sustained rate of 5 percent to 7 percent per year, the smooth, steady, managed phase down of petroleum fuel chain crude rates that refinery-specific direct measures starting in 2023 or 2024 could ensure (Table 3) would support just transitions. Specifically, this would support the just transition program that oil workers, in effect, presented to California when United Steelworkers refinery worker locals 5 and 675 endorsed the report by Pollin et al. (2021).[17] In fact, Pollin and colleagues present analysis that should warn us an unmanaged "episodic" phase down would be more costly.[17] Consider this excerpt from their report:

TABLE 6.11
Comparative Just Transition Program Costs under Steady versus Episodic Contraction Scenarios, 2021 – 2032
Support for 57,548 workers

	Steady contraction	Episodic contraction	Transition program costs under episodic versus steady contraction
Total costs over 12 years	$5.6 billion	$10.0 billion	+ $4.4 billion *(= +78.6%)*
Average costs per year over full 12-year period *(with 11 years of retraining and 10 years of relocation support)*	$469.2 million	$832.8 million	+ $363.6 million per year *(= +77.5%)*

Excerpt from Pollin et al. (2021).[17]

An unmanaged decline, in which each refiner decides for itself if and when to close its refinery, would in all likelihood result in the "episodic contraction" scenario that Pollin and colleagues cost out in this excerpt from their report. They estimate that it would have oil worker just transition costs $4.4 billion greater than their steady contraction scenario.[17]

The steady, smooth phase down across the petroleum fuel chain linked to refining in California that could be managed through refinery-specific direct control measures along least-impact pathways (Table 3) could avoid this $4.4 billion in oil workers' transition support costs. This would make just transitions more feasible. That would make California's climate stabilization goal more feasible.

4 Findings and Takeaways

Finding 1

In-state demand reduction measures cannot ensure refining phase down. When in-state fuels demand declines, California oil refiners have, and likely would, protect their otherwise stranded assets by increasing refining for export sales to other Pacific Rim states and nations, in an absence of refinery-specific direct control measures. We need all the tools in the toolbox.

Takeaways

Direct control measures are needed to ensure managed refinery phase-downs.

As an immediate step, CARB should develop climate pathway analysis that explicitly includes refining and its interactions with the petroleum fuel chain.

Finding 2

Even if all other, non-petroleum emissions are cut to their share of the State's direct emissions reduction goal, this goal cannot be achieved without refining rate cuts. Without crude rate cuts, emissions from the petroleum fuel chain linked to refining in California would drive total statewide carbon emissions to exceed the State climate emissions goal.

Takeaways

Refining rate cuts are essential to achieve State climate goals.

Refinery-specific direct control measures could achieve this outcome.

Finding 3

Further delaying the start date for refinery phase-downs would foreclose the most feasible, least-impact pathways to State climate goals irreversibly, impairing the feasibility of achieving the goals substantially. Side effects of this delay would prolong and worsen environmental injustice, and increase just transition costs for oil workers, further impairing the feasibility of achieving State climate goals.

Takeaways

Refinery-specific direct control measures, including but not limited to direct emission measures, should be considered in the 2022 Climate Scoping Plan.

The California Air Resources Board (CARB) should include environmental justice impacts of refining for export in its climate pathways analysis.

CARB should support climate justice for oil workers in a meaningful way by including analysis of the Just Transition Program presented to California and endorsed by United Steelworkers refinery workers' union locals 5 and 675 last year in its Climate Scoping Plan climate pathways development.

5 References cited

(1) *Supporting Material for Karras, 2022. Climate Pathways in an Oil State – 2022.* Data and details of methods, annotated tables and supporting references. Appended hereto as Attachment 1.

(2) Karras, 2020. *Decommissioning California Refineries: Climate and Health Paths in an Oil State;* A report for Communities for a Better Environment (CBE): Huntington Park, Oakland, Richmond and Wilmington, CA. Includes Supporting Material Appendix. www.energy-re-source.com/decomm Appended hereto as Attachment 2.

(3) *California Air Resources Board (CARB) Meeting to Consider the 2017 Climate Change Scoping Plan: Webcast Transcript;* 14 December 2017 Public Hearing in Sacramento, CA. California Air Resources Board: Sacramento, CA. *See* time marks 5:10:25–5:12:30; 5:14:30–5:32:17; 6:10:17–6:13:02. cal-span.org/unipage/?site=cal-span&owner=CARB&date=2017-12-14

(4) *PATHWAYS Scenario Modeling: 2022 Scoping Plan Update, December 15, 2021;* California Air Resources Board: Sacramento, CA. https://ww2.arb.ca.gov/sites/default/files/2021-12/Revised_2022SP_ScenarioAssumptions_15Dec.pdf

(5) Executive Order B-55-18 to Achieve Carbon Neutrality. Edmond G. Brown. 18 September 2018. https://www.ca.gov/archive/gov39/wp-content/uploads/2018/09/9.10.18-Executive-Order.pdf *See* also reference 16 at p. 14 ("carbon neutrality goal is layered on top of the state's existing commitments to reduce greenhouse gas emissions 40% below 1990 levels by 2030 ... and 80% below 1990 levels by 2050").

(6) West Coast Transportation Fuels Markets; PADD 5 Transportation Fuels Markets. 2015. U.S. Energy Information Administration: Washington, D.C. https://www.eia.gov/analysis/transportationfuels/padd5

(7) Brookings Institute, 2015. *Export Monitor 2015;* data for petroleum and coal products exports produced by metro area (note that the California metro centers included to not produce coal). https://www. brookings.edu/research/interactives/2015/export-m

(8) CARB GHG Inventory. Fuel Activity for California's Greenhouse Gas Inventory by Sector and Activity; 14th ed.: 2000 to 2019; California Air Resources Board: Sacramento, CA. https://ww2.arb.ca.gov/ghg-inventory-data

(9) CEC Fuel Watch. Weekly Refinery Production. California Energy Commission: Sacramento, CA. https://www.energy.ca.gov/data-reports/reports/weekly-fuels-watch/refinery-inputs-and-production

(10) USEIA, Supply and Disposition: West Coast (PADD 5); U.S. Energy Information Administration: Washington, D.C. www.eia.gov/dnav/pet/pet_sum_snd_d_r50_mbbl_m_cur.htm

(11) *New Climate Threat: Will Oil Refineries make California the Gas Station of the Pacific Rim?* Communities for a Better Environment: Huntington Park, Oakland, Richmond and Wilmington, CA. Available from https://www.cbecal.org/resources/our-research

continued next page

(12) Oil Supply Sources to California Refineries; California Energy Commission: Sacramento, CA. https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/oil-supply-sources-california-refineries

(13) Karras, 2021. *Unsustainable Aviation Fuel: An assessment of carbon emission and sink impacts from biorefining and feedstock choices for producing jet biofuel in repurposed crude refineries;* technical report prepared for the Natural Resources Defense Council (NRDC): San Francisco, CA.

(14) BAAQMD, various dates. Administrative record, 2020 amendments to Regulation 6, Rule 5. Bay Area Air Quality Management District (BAAQMD): San Francisco, CA.

(15) Pastor et al., 2010. *Minding the Climate Gap: What's at stake if California's climate law isn't done right and right away'* College of Natural Resources, Department of Environmental Science, Policy and Management, University of California, Berkeley: Berkely, CA; and Program for Environmental and Regional Equity, University of Southern California: Los Angeles, CA.

(16) Mahone et al., 2020. *Achieving Carbon Neutrality in California: PATHWAYS Scenarios Developed for the California Air Resources Board;* October 2020. Energy and Environmental Economics, Inc.: San Francisco, CA. https://ww2.arb.ca.gov/sites/default/files/2020-10/e3_cn_final_report_oct2020_0.pdf *See* p. 49. *See* also, per note 5, and emission-shifting, p. 14 (direct emission reductions not interchangeable with additional carbon neutrality measures) and pp. 20, 39 ("[E]missions from interstate and international aviation and shipping [linked to in-state activities, which represent a] significant fraction of energy consumption ... are not included in the state's emission inventory ... but will need to be mitigated to achieve national and global emission reductions").

(17) Pollin et al., 2021. *A Program for Economic Recovery and Clean Energy Transition in California;* Department of Economics and Political Economy Research Institute (PERI). University of Massachussetts–Amherst. Commissioned by the American Federation of State, County and Municipal Employees Local 3299, the California Federation of Teachers, and the United Steelworkers Local 675. https://peri.umass.edu/publication/item/1466-a-program-for-economic-recovery-and-clean-energy-transition-in-california

Supporting Material for

Climate Pathways in an Oil State — 2022
A California Environmental Justice Alliance Report

Prepared by Greg Karras
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February 2022. www.energy-re-source.com

Data and details of methods,
34 pages including 14 annotated tables and supporting references:

Table S1. Baseline CO_2e Emissions and Oil Industry Activity Data, 2013–2019*

Mt: Megaton; 1 million metric tons **b:** barrel (oil); 42 U.S. gallons; 0.15898 m^3
CO_2e: carbon dioxide equivalents (100-year Global Warming Potential)

Parameter	Measurement	Data	Units	Mean
California oil refining				
Capacity in use	Crude feed rate by volume	ARB[a]	b/d	1,647,948
Direct emissions	Mass emitted	ARB[b]	Mt/y	35.64
Extraction of feed				
In-state	Crude feed rate by volume	ARB[a]	b/d	526,958
Out-of-state	Crude feed rate by volume	ARB[a]	b/d	1,120,989
In-state	Mass emitted	ARB[b]	Mt/y	20.86
Out-of-state	Mass emitted	ARB[c]	Mt/y	32.38
Refined products				
Gasoline	In-state usage by volume	ARB[d]	b/d	902,228
Distillate / diesel	In-state usage by volume	ARB[d]	b/d	251,359
Jet fuel and kerosene	In-state usage by volume	ARB[d]	b/d	27,241
LPG and propane	In-state usage by volume	ARB[d]	b/d	40,315
Petroleum coke	In-state usage by volume	ARB[d]	b/d	3,261
Other refined products	In-state usage by volume	ARB[d]	b/d	19,846
Gasoline	Mass emitted by in-state use	ARB[d]	Mt/y	125.19
Distillate / diesel	Mass emitted by in-state use	ARB[d]	Mt/y	40.49
Jet fuel and kerosene	Mass emitted by in-state use	ARB[d]	Mt/y	4.11
LPG and propane	Mass emitted by in-state use	ARB[d]	Mt/y	3.60
Petroleum coke	Mass emitted by in-state use	ARB[d]	Mt/y	0.78
Other refined products	Mass emitted by in-state use	ARB[d]	Mt/y	2.11
Gasoline	California refinery production	CEC[e]	b/d	1,061,385
Distillate / diesel	California refinery production	CEC[e]	b/d	364,945
Jet fuel and kerosene	California refinery production	CEC[e]	b/d	293,630
LPG and propane	California refinery production	Estimated[f]	b/d	40,315
Petroleum coke	California refinery production	Estimated[f]	b/d	100,723
Gasoline	Mass emitted in and out of state	Calculated	Mt/y	147.27
Distillate / diesel	Mass emitted in and out of state	from the	Mt/y	58.79
Jet fuel and kerosene	Mass emitted in and out of state	data shown	Mt/y	44.30
LPG and propane	Mass emitted in and out of state	above[g]	Mt/y	3.60
Petroleum coke	Mass emitted in and out of state		Mt/y	24.24
Other refined products	Mass emitted in and out of state		Mt/y	2.11
	Total products use emissions	Sum	Mt/y	280.31
Petroleum fuel chain emissions baseline		Sum	Mt/y	369.19
All other (non-petroleum) statewide emissions baseline		ARB[d,h]	Mt/y	200.11
Statewide total emissions baseline including petroleum fuel chain		Sum	Mt/y	569.30

* Based on the most recent seven-year period when complete data were reported as of October 2021. Figures may not add due to rounding.

Table continued next page

Table S1. Baseline CO_2e Emissions and Oil Industry Activity Data, 2013–2017,* *continued*

Mt: Megaton; 1 million metric tons **b:** barrel (oil); 42 U.S. gallons; 0.15898 m^3

CO_2e: carbon dioxide equivalents (100-year Global Warming Potential)

See page 1 of this table for parameter measurements

Annual Detail	Units	2013	2014	2015	2016	2017	2018	2019
California oil refining								
Capacity in use (crude feed rate)	b/d	1,611,656	1,677,623	1,659,586	1,590,441	1,702,046	1,709,730	1,584,550
Direct emissions	Mt/y	35.69	35.46	35.67	35.95	35.77	36.22	34.69
Extraction of feed								
In-state crude feed rate supplied	b/d	592,570	609,233	580,678	524,627	487,970	454,634	438,997
Out-of-state crude feed rate supplied	b/d	1,019,087	1,068,391	1,078,909	1,065,813	1,214,076	1,255,096	1,145,553
In-state extraction emissions	Mt/y	21.85	23.49	22.64	20.33	20.29	18.66	18.76
Out-of-state extraction emissions	Mt/y	29.9137	30.8548	31.3361	30.4730	36.9057	34.3771	32.8250
Refined products								
Gasoline burned in-state	b/d	875,123	874,471	901,346	914,835	923,721	914,617	911,481
Distillate / diesel burned in-state	b/d	250,128	262,802	261,037	252,024	254,015	251,117	228,393
Jet fuel and kerosene burned in-state	b/d	24,361	24,124	25,946	28,218	29,778	30,102	28,158
LPG and propane burned in-state	b/d	41,815	38,299	36,240	41,268	39,528	41,407	43,646
Petroleum coke burned in-state	b/d	3,427	3,801	4,224	3,656	2,576	2,702	2,439
Other refined products burned in-state	b/d	13,430	25,050	24,510	24,412	18,908	16,847	15,765
In-state Gasoline Emissions	Mt/y	121.79	121.55	125.12	127.20	127.96	126.61	126.08
In-state distillate / diesel emissions	Mt/y	40.52	42.53	42.23	40.91	39.86	40.54	36.86
In-state jet fuel and kerosene emissions	Mt/y	3.67	3.64	3.91	4.27	4.49	4.54	4.25
In-state LPG and propane emissions	Mt/y	3.73	3.42	3.23	3.68	3.55	3.69	3.89
In-state petroleum coke emissions	Mt/y	0.87	0.87	0.89	0.85	0.77	0.65	0.52
Other refined products in-state emissions	Mt/y	1.78	2.28	2.36	2.43	2.08	2.04	1.81
Calif. refinery gasoline production	b/d	1,003,842	1,043,326	1,014,112	1,107,902	1,118,271	1,102,261	1,039,978
Calif. refinery distillate / diesel production	b/d	362,597	374,592	357,586	352,426	368,986	377,493	360,932
Calif. Ref. jet fuel & kerosene production	b/d	274,299	290,762	286,088	283,393	299,099	325,844	295,925
Calif. refinery LPG and propane production	b/d	41,815	38,299	36,240	41,268	39,528	41,407	43,646
Calif. refinery petroleum coke production	b/d	103,087	99,442	96,860	98,963	102,142	104,946	99,623
Gasoline end-use emission total	Mt/y	139.70	145.02	140.78	154.04	154.92	152.58	143.85
Distillate / diesel end use emission total	Mt/y	58.74	60.62	57.84	57.20	57.91	60.94	58.25
Jet fuel & kerosene end use emission total	Mt/y	41.37	43.86	43.15	42.86	45.11	49.14	44.63
LPG and propane end use emission total	Mt/y	3.73	3.42	3.23	3.68	3.55	3.69	3.89
Petroleum coke end use emission total	Mt/y	26.09	22.67	20.47	23.05	30.63	25.44	21.36
Other refined products end use em. total	Mt/y	1.78	2.28	2.36	2.43	2.08	2.04	1.81
Refined products end use emission total	Mt/y	271.41	277.86	267.83	283.27	294.19	293.83	273.80
Petroleum fuel chain emissions baseline	Mt/y	358.86	367.67	357.49	370.02	387.16	383.09	360.07
All other (non-petroleum) emissions	Mt/y	217.79	211.42	205.31	193.43	189.31	192.19	191.29
Statewide total	Mt/y	576.65	579.09	562.79	563.44	576.47	575.28	551.36

* Based on the most recent seven-year period when complete data were reported as of October 2021.

a. Refining and extraction volume data, and data for the carbon intensity of extracting out-of-state crude fed to California refineries relative to that of in-state extraction, were taken from California Air Resources Board (ARB) Low Carbon Fuel Standard documentation reports (*RS1*). <u>*See*</u> Table S2.

b. Refining and in-state extraction emissions data were taken from third party-verified Mandatory Reporting Regulation (MRR) reports by the ARB (*RS2*). <u>*See*</u> Table S3.

c. Emissions from out-of-state extraction of California refinery crude feeds were estimated based on the relative volumes and emission intensities of in-state and out-of-state extraction (*RS1, RS2;* tables S2, S3). Out-of-state extraction emissions were calculated by applying the annual volumes of crude imports and annual import/in-state extraction carbon intensity ratios to annual in-state extraction emissions reported.

Table S1. Baseline CO_2e Emissions and Oil Industry Activity Data, 2013–2017 *continued*

d. Data for in-state use of refined products outside refining and extraction plant gates, in-state emissions from refined products outside those plant gates, and all other (non-petroleum) emissions were taken from ARB Greenhouse Gas Inventory reports (*RS3–RS5*) as detailed in Table S4. For jet fuel the reported in-state usage excludes usage for cross-border and military jet travel as well as direct exports (*see* also e).

e. California refinery production data for gasoline, distillate/diesel, and jet fuel and kerosene were taken from California Energy Commission (CEC) Fuels Watch reports (*RS6*). *See* Table S5. Total refinery production volume exceeds total oil feed volume because of volume gain. Carbon subtraction and hydrogen addition processes break ("crack") the carbon-carbon bonds of hydrocarbons in the crude and add hydrogen to them—thus creating a lighter mix of hydrocarbons and expanding its volume. In the industry's jargon, this thermal cracking, catalytic cracking and hydrocracking "fluffs the crude barrel." For jet fuel and kerosene, the large difference between in-state production and use reflects both direct exports and "exports" via cross-border and military jet travel, and emissions from the total, including in-state and export usage, was accounted for in fuel chain emissions (*see* calculation described in note g).

f. Production data for petroleum coke, LPG, propane and "other refined products" were not available from CEC Fuels Watch Reports (*RS6*). These values were estimated from other data: *see* tables S5 and S6. The pet coke estimate suggests some 97% of marketable pet coke was exported, consistent with other West Coast export data that document major exports of this extremely dirty-burning refining byproduct. The other fuels for which Fuels Watch data were not available were assumed to be produced only in the volumes burned in-state. This "no export" assumption was judged to be conservative since in addition to refinery production, in-state crude and natural gas extraction and production yield liquefied gases as byproducts, and plans have been discussed to expand California refining capacity for LPG sales outside the state.

g. Total emissions from usage of products refined in California were estimated based on total California refinery production and in-state emission intensity (emission/usage) data for each refined product. For example, refined product emissions from gasoline that was produced in California during 2019 were calculated as: 1,039,978 b/d • (126.08 Mt/y ÷ 911,481 b/d) = 143.85 Mt/y. This method conservatively assumed that the fuel-specific emission intensities of out-of-state fuels combustion are equivalent to, and do not exceed, those of in-state fuels combustion.

h. In 2016 a multi-year drought broke, hydroelectric power generation surged dramatically (*RS9*), and reduced emissions from fossil-fueled power generation led a reduction in non-petroleum emissions (*RS2;* Table S4), changing the statewide emissions profile. It was judged appropriate to include the emissions variability described by these data, which appears to be related to climate variability, in the baseline. The baseline for comparing emission trajectories along plausible future pathways was estimated as the seven-year average of 2013–2019 data. This method accounts for the mix of wet and dry years expected over time in the future better than comparing a single-year baseline to such future conditions. *See* also note k to Table S4 for more detail on this point.

Table S2. Annual California Refinery Crude Feed Extraction Data, 2013–2019 [a]

	Volume and carbon intensity* of crude feeds extracted	
	In-state oilfields	Out-of-state imports**
Crude oil volume (b/year)		
2013	216,287,874	371,966,596
2014	222,369,959	389,962,538
2015	211,947,382	393,801,666
2016	192,013,608	390,087,627
2017	178,109,048	443,137,683
2018	165,941,553	458,110,068
2019	160,233,973	418,126,839
mean	192,414,771	409,313,288
Carbon intensity (CI; g CO_2e/MJ)*		
2013	13.05	10.39
2014	13.31	9.97
2015	14.46	10.77
2016	14.73	10.87
2017	14.76	10.79
2018	16.35	10.91
2019	16.51	11.07
mean	14.74	10.68

b: barrel (oil); 42 U.S. gallons; 0.15898 cubic meters **g:** gram **MJ:** Megajoule, 1 million Joules

* Carbon intensity as reported for the Low Carbon Fuel Standard[a] is shown for crude oil extraction only.

** Imported from other states and nations; other nations account for the vast majority of imported crude oil. [a]

a. Data were taken from California Air Resources Board *Crude Average CI Value* data documentation reports for the ARB's Low Carbon Fuel Standard (*RS1).* Values shown in the table for volume averages and volume-weighted carbon intensity (extraction only) averages by extraction location were calculated from these data. The total volume of crude oil refined in California from 2013–2019 reported by the Air Resources Board (shown) is within 1.3 percent of that reported by the California Energy Commission for the same period (not shown; *RS6*).

Table S3. Annual In-state Refining and Extraction CO_2e Data, 2013–2019

Annual CO_2e emitted in metric tons	In-state oil extraction[a]	In-state oil refining[a–c]
2013	21,847,075	35,690,313
2014	23,488,708	35,463,334
2015	22,643,712	35,673,211
2016	20,326,263	35,946,578
2017	20,291,122	35,771,270
2018	18,661,559	36,220259
2019	18,760,777	34,692,545
mean	20,859,888	35,636,787

a. Data were taken from the Annual Summary of Greenhouse Gas Emissions Data Reported to the California Air Resources Board in public reports under its Mandatory Reporting Rule (*RS2*). These data are verified by independent third parties through the agency's emission certification system (*RS2*).

b. In-state refining emissions from facilities in or adjacent to refineries that supplied hydrogen, sulfur handling, heat and power, or sulfur and petroleum coke processing for refining operations and are integral to those operations, but were owned and operated by third parties, were included in the statewide refining emissions totals. These plants were the Air Liquide hydrogen plants in El Segundo and Rodeo, the Air Products hydrogen plants in Carson, Martinez, and Wilmington, Martinez Cogen in Martinez, Chemtrade West in Richmond, the Tesoro Coker Calciner in Wilmington and the Phillips 66 Carbon Plant in Rodeo/Hercules.

c. A major explosion that led to an unusually protracted outage at the PBF (then ExxonMobil) Torrance refinery from February 2015 to May 2016 (*RS10, RS11*) resulted in anomalous production and emission profiles for this refinery in these years. The Air Resources Board data (*RS2*) confirmed that Torrance refinery emissions were anomalously low in both years and only half of 2013 emissions in 2015. The anomalous Torrance 2015 and 2016 emission reports were replaced with the average of its 2013, 2014, and 2017 emissions in the total refinery emissions for these years (shown). Correcting for this anomaly changed reported statewide refinery emissions in 2015 and 2016 by 4.1% and 1.4%, respectively, and changed the statewide mean estimate for refinery emissions from 2013–2017 by less than 1 percent.

Table S4. In-state Refined Products Use, Emission, and Emission Balance Details

Mt: Megaton; 1 million metric tons **b:** barrel (oil); 42 U.S. gallons; 0.15898 m^3

In-state refined products emissions including all cogeneration (a)

Mt/y	IPCC#	2013	2014	2015	2016	2017	2018	2019
Gasoline	1A1	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00
Gasoline	1A2	1.7529E+00	1.2113E+00	1.3493E+00	6.0034E-01	6.3023E-01	1.2045E-01	1.2045E-01
Gasoline	1A3	1.1945E+02	1.1975E+02	1.2356E+02	1.2650E+02	1.2723E+02	1.2617E+02	1.2564E+02
Gasoline	1A4	5.7995E-01	5.8456E-01	2.0754E-01	9.2341E-02	9.6939E-02	3.0474E-01	3.0474E-01
Gasoline	1B2	2.7172E-03	2.7509E-03	2.7858E-03	2.8201E-03	9.2002E-03	1.6289E-02	9.2871E-03
Distillate/diesel	1A1	1.8824E-01	1.4269E-01	2.6967E-02	4.5837E-02	3.6072E-02	2.8776E-02	3.3335E-02
Distillate/diesel	1A2	8.5152E-01	7.5021E-01	7.9902E-01	6.3566E-01	6.9577E-01	5.7433E-01	5.2119E-01
Distillate/diesel	1A3	3.5528E+01	3.6784E+01	3.6156E+01	3.5506E+01	3.5542E+01	3.6200E+01	3.3458E+01
Distillate/diesel	1A4	3.9492E+00	4.8547E+00	5.2441E+00	4.7211E+00	3.5901E+00	3.7354E+00	2.8469E+00
Jet fuel and kerosene	1A1	3.3625E-03	4.7663E-03	1.4051E-03	6.0574E-03	2.1099E-03	4.6480E-03	4.7827E-03
Jet fuel and kerosene	1A2	5.3987E-04	6.9165E-03	1.3038E-03	3.6671E-04	2.4447E-04	1.7320E-04	9.1700E-05
Jet fuel and kerosene	1A3	3.6471E+00	3.5977E+00	3.8878E+00	4.2189E+00	4.4624E+00	4.5098E+00	4.2069E+00
Jet fuel and kerosene	1A4	2.3062E-02	2.9367E-02	2.2501E-02	4.2579E-02	2.6199E-02	2.5191E-02	3.5173E-02
LPG and propane	1A1	1.1347E-02	5.8998E-03	1.8716E-02	3.8084E-02	7.4955E-03	3.0499E-02	1.0936E-02
LPG and propane	1A2	1.4057E+00	1.3561E+00	1.2295E+00	1.4480E+00	1.4019E+00	1.3328E+00	1.3772E+00
LPG and propane	1A3	3.1666E-01	3.4085E-01	2.4727E-01	6.8658E-02	3.7872E-02	4.2620E-02	3.3451E-02
LPG and propane	1A4	2.0014E+00	1.7145E+00	1.7526E+00	2.1614E+00	2.1052E+00	2.3147E+00	2.4807E+00
Petroleum coke	1A1	3.5019E-01	4.4012E-01	1.8547E-01	2.4958E-01	3.0566E-01	2.7349E-01	2.5140E-01
Petroleum coke	1A2	8.4013E-01	8.4358E-01	8.1234E-01	8.5140E-01	7.7248E-01	6.5489E-01	5.2289E-01
Petroleum coke	1A3	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00
Petroleum coke	1A4	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00
Other petroleum products	1A1	2.7315E+00	3.9571E+00	3.6457E+00	3.0000E+00	3.0821E+00	3.3194E+00	3.2291E+00
Other petroleum products	1A2	1.8735E-01	2.1443E-01	2.4101E-01	2.4933E-01	2.3470E-01	2.3460E-01	2.3477E-01
Other petroleum products	1A3	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00
Other petroleum products	1A4	0.0000E+00	2.8258E-04	3.0518E-04	4.7473E-04	0.0000E+00	0.0000E+00	0.0000E+00
Other petroleum products	1B2	5.9448E-03	6.0940E-03	6.2540E-03	6.4248E-03	1.1301E-02	0.0000E+00	0.0000E+00
Other petroleum products	2D1	1.5214E+00	1.5872E+00	1.7282E+00	1.9248E+00	1.6367E+00	1.5986E+00	1.3884E+00
Other petroleum products	4D	5.1262E-05	5.3545E-05	5.6035E-05	5.8526E-05	1.0956E-03	1.2513E-03	8.1650E-04

Emissions from cogeneration used in refining and extraction (b)

Mt/y	Use of Cogen	2013	2014	2015	2016	2017	2018	2019
Distillate/diesel	Extraction	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00
Distillate/diesel	Refining	3.9681E-04	3.3592E-04	3.4494E-04	8.5427E-04	2.8315E-04	0.0000E+00	0.0000E+00
LPG and propane	Extraction	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00
LPG and propane	Refining	6.1403E-03	1.8761E-03	1.6232E-02	3.5551E-02	4.8268E-03	2.7543E-02	8.2055E-03
Petroleum coke	Extraction	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00
Petroleum coke	Refining	3.2292E-01	4.1700E-01	1.0497E-01	2.4958E-01	3.0568E-01	2.7349E-01	2.5140E-01
Other (associated gas)	Extraction	6.5735E-01	1.5697E+00	1.3135E+00	9.8119E-01	1.1171E+00	1.1011E+00	1.1616E+00
Other (associated gas)	Refining	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00	0.0000E+00
Other (refinery gas)	Extraction	2.0965E-03	2.1737E-03	3.0181E-04	8.3791E-04	1.4767E-03	0.0000E+00	0.0000E+00
Other (refinery gas)	Refining	2.0035E+00	1.9169E+00	1.9496E+00	1.7677E+00	1.7629E+00	2.0148E+00	1.8812E+00
Natural gas (PFC use)	Extraction	3.1679E+00	2.4350E+00	2.5263E+00	2.4127E+00	2.3270E+00	2.2608E+00	2.3791E+00
Natural gas (PFC use)	Refining	2.5566E+00	2.6946E+00	2.0207E+00	1.7755E+00	3.5596E+00	3.8442E+00	3.7928E+00

In-state refined products emissions excluding cogeneration used in refining and extraction (c)

Mt/y	2013	2014	2015	2016	2017	2018	2019
Gasoline	121.790	121.546	125.124	127.200	127.964	126.608	126.076
Distillate/diesel	40.517	42.531	42.226	40.907	39.864	40.539	36.860
Jet fuel and kerosene	3.674	3.639	3.913	4.268	4.491	4.540	4.247
LPG and propane	3.729	3.415	3.232	3.681	3.548	3.693	3.894
Petroleum coke	0.867	0.867	0.893	0.851	0.772	0.655	0.523
Other petroleum products	1.783	2.276	2.358	2.431	2.084	2.038	1.810

continued next page

Table S4. In-state Refined Products Use, Emission, and Emission Balance Details *continued*

Mt: Megaton; 1 million metric tons **b:** barrel (oil); 42 U.S. gallons; 0.15898 m^3

In-state refined products usage (d)							
b/d (e)	2013	2014	2015	2016	2017	2018	2019
Gasoline	875,123	874,471	901,346	914,835	923,721	914,617	911,481
Distillate/diesel	250,128	262,802	261,037	252,024	254,015	251,117	228,393
Jet fuel and kerosene (f)	24,361	24,124	25,946	28,218	29,778	30,102	28,158
LPG and propane (e)	41,815	38,299	36,240	41,268	39,528	41,407	43,646
Petroleum coke (e)	3,427	3,801	4,224	3,656	2,576	2,702	2,439
Other petroleum products (e)	13,430	25,050	24,510	24,412	18,908	16,847	15,765

In-state balance of emissions (g)							
Mt/y	2013	2014	2015	2016	2017	2018	2019
Total in-state emissions (g–k)	447.69	444.65	441.37	429.04	424.10	425.14	418.15
– in-state refining emissions (h)	35.69	35.46	35.67	35.95	35.77	36.22	34.69
– in-state extraction emissions (i)	21.85	23.49	22.64	20.33	20.29	18.66	18.76
– in-state refined product emissions (j)	172.36	174.27	177.75	179.34	178.72	178.07	173.41
All other (non-pet) in-state emissions (k)	217.79	211.42	205.31	193.43	189.31	192.19	191.29

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a. In-state refined products emissions by IPCC category, including all cogeneration and excluding all other refining and extraction emissions, were taken from the California Air Resources Board (ARB) *Greenhouse Gas Inventory by IPCC Category* (*RS3*). Emissions from out-of-state as well as in-state generation of electricity used in the state (IPCC# 1A1) were included. Emissions from fuels burned in California refining and extraction facilities were excluded to avoid double counting (*see* notes b, g–i).

b. Emissions from cogeneration used in refining and extraction in California were taken from the ARB *Disaggregation of Industrial Cogeneration Categories* documentation for its GHG Inventory (*RS4*). These emissions were not included in the estimate for refined products emissions (*see* note c).

c. In-state refined products emissions excluding cogeneration were derived by subtracting emissions associated with cogeneration used in refining and extraction (note b) from the total in-state emissions (note a) for each product. This was done to avoid double counting (*see* notes g–i).

d. In-state refined products usage data were taken from the ARB *Fuel Activity for California's Greenhouse Gas Inventory by Sector & Activity* (*RS5*). Refined products burned in California refining and extraction facilities were excluded to avoid overestimating end-use fuel volumes, and thus under-estimating end-use fuel combustion carbon intensities (*see* note g in Table S1).

e. Barrels of gaseous and solid fuels based on 0.0278 gallons/standard cubic foot of propane and 210 gallons per short ton of petroleum coke.

f. Jet fuel usage and emissions shown exclude those from cross-border and military air travel. *See* Table S1 for totals.

g. In-state balance of emissions data compare total in-state emissions with in-state refinery fuel chain emissions by subtracting refining, in-state extraction, and in-state refined products emissions to quantify non-petroleum (all other) emissions. Total in-state (included) emissions data for 2013–2019 were taken from the ARB *Greenhouse Gas Inventory by IPCC Category* (*RS3*). These totals were compared with in-state refinery fuel chain emissions because, though they include emissions from out-of-state generation of electricity used in the state, these totals exclude out-of-state emissions from oil refined in California.

h. Refining emissions were taken from the *Annual Summary of Greenhouse Gas Emissions Data Reported to the California Air Resources Board* (*RS2*) under its Mandatory Reporting Regulation (MRR). *See* also Table S3.

Table S4. In-state Refined Products Use, Emission, and Emission Balance Details *continued*

i. In-state extraction emissions were taken from the MRR (*RS2*). See also Table S3.

j. In-state refined products emissions were calculated as the sum of in-state products emissions for individual products that are shown in the same table above (note c). These emissions were based on ARB Inventory data (*RS3–RS5;* notes a–c).

k. Potentially significant emission variability coincided with the breaking of a multi-year drought. Hydroelectric power production surged in 2016–2017, doubling from 2013–2015 (*RS9*). As in-state hydropower supply increased by an average of 17,900 Gigawatt-hours/year over that in 2013–2015 (*RS9*), emissions from fossil-fueled electricity generation were reduced by approximately 23 Mt/y in 2016-17 from the average during 2013–2015 (see data in this table). The drought delayed at least some of the emission cuts that were ultimately realized from low-carbon electricity measures implemented starting well before 2016.

Electricity generation emissions fell by approximately 32.5 Mt/y from 2013 to 2019 (*RS3*). In the same period total non-petroleum emissions fell by approximately 26.5 Mt/y, to 35 percent of total emissions associated with all activities statewide (Table S1).

Based on these observations, it was judged appropriate to include the variability in the California emissions profile that is described by these data and appears to be related in part to climate variability in the baseline for future potential emission assessment. See also note h in Table S1.

Meanwhile, more oil was imported and refined in-state, and more fuels refined in-state were burned in and out of state from 2013 to 2019 (*Id.*). However, total petroleum fuel chain emissions changed relatively little during this period compared with those from electricity generation and non-petroleum emissions (*Id.*). Emissions associated with petroleum were the dominant share of total emissions at approximately 65 percent of total emissions of CO_2e associated with all activities statewide (*Id.*).

Table S5. California Refinery Production by Key Product and Year, 2013–2017

Product leaving the refinery gate in b/year

	2013	2014	2015	2016	2017
Gasoline[a]	366,402,200	380,814,100	370,151,000	405,492,000	408,169,000
Distillate-diesel[a]	132,348,000	136,726,000	130,519,000	128,988,000	134,680,000
Jet fuel and kerosene[a]	100,119,000	106,128,000	104,422,000	103,722,000	109,171,000
LPG and propane[b]	14,293,230	15,934,920	12,545,400	13,676,400	13,624,200
Petroleum coke[b]	37,626,720	36,296,300	35,353,740	36,220,620	37,281,860
	2018	2019			
Gasoline[a]	402,325,400	379,592,041			
Distillate-diesel[a]	137,785,000	131,740,000			
Jet fuel and kerosene[a]	118,933,000	108,012,691			
LPG and propane[b]	15,113,555	15,930,790			
Petroleum coke[b]	38,305,260	36,362,520			

b: barrel (oil); 42 U.S. gallons; 0.15898 m^3

a. Gasoline, distillate-diesel, and jet fuel and kerosene data were taken from California Energy Commission *Weekly Fuels Watch* reports (*RS6*).

b. LPG, propane and petroleum coke production was not available from California Energy Commission *Weekly Fuels Watch* reports (*RS6*). Pet coke values were estimated based on U.S. Energy Information Administration data for West Coast refinery production and *Oil & Gas Journal* data for the production capacity of California refineries relative to that of the entire West Coast. *See* Table S6. LPG and propane were assumed to be produced only in the volumes burned in-state. This "no export" assumption was judged to be conservative; in addition to refinery production, in-state crude and natural gas extraction and production yield liquefied gases as byproducts, and plans have been discussed to expand California refining capacity for LPG sales outside the state.

Table S6. Estimate Calculation Data for In-state Petroleum Coke Production

Product leaving the refinery gate in b/year

	2013	2014	2015	2016	2017
Petroleum Coke					
West Coast production[a]	43,752,000	42,205,000	41,109,000	42,117,000	43,351,000
California capacity ratio[b]			0.86		
California production[c]	37,626,720	36,296,300	35,353,740	36,220,620	37,281,860

b: barrel (oil); 42 U.S. gallons; 0.15898 m^3

a. West Coast (PADD 5) production of petroleum coke ("marketable" pet coke) data were taken from the U.S. Energy Information Administration (EIA; *RS7*).

b. California production was estimated as the ratio of California to West Coast refining capacity based on *Oil & Gas Journal* 2018 Worldwide Refining Survey data (*RS8*). A California/West Coast refining capacity ratio of 0.86 was calculated based on coking capacities. (Id.) *See* also note c.

c. The estimated values for petroleum coke suggest some 97 percent of petroleum coke was exported (*see* Table S1), consistent with other West Coast export data that document major exports of this extremely dirty-burning refining byproduct(*RS12*).

Table S7. Petroleum Fuel Chain CO_2e co-pollutant emissions data.

**Selected criteria pollutants associated with toxicity effects and, like CO_2, generated by energy consumption ("combustion emissions").*

t/y: *tonnes/year* ***t/Mt CO_2e:*** *tonnes/million tonnes CO_2e.*

	$PM_{2.5}$	PM_{10}	NO_x	SO_x
In-state mass emitted (t/y)[a]				
Oil refining	2,108	2,229	7,937	4,552
Oil extraction	759	767	4,903	463
Refined products use	14,997	16,556	482,872	8,780
GHG-weighted (t/Mt CO_2e)[b]				
Oil refining	59.0	62.4	222	127.5
Oil extraction	33.6	33.9	217	20.5
Refined products use	84.7	93.5	2,728	49.6
Refinery fuel chain	75.9	83.1	2,107	58.6
Refinery fuel chain baseline (t/y)[c]	27,900	30,500	773,000	21,500
In-state emissions from all sources[a]	123,000	465,000	572,000	25,500

(a) In-state mass emissions of fine particulate aerosol ($PM_{2.5}$), respirable particulates (PM_{10}), oxides of sulfur (SOx) and oxides of nitrogen (NOx). These data were taken from emissions reported for 2015 by the ARB in its 2017 State Implementation Plan Inventory (*RS13*). The oil refining and extraction estimates shown in the table account for all in-state refining and extraction emissions, including those that were classified as cogeneration emissions in *RS13,* based on the portions of 2013–2015 cogeneration CO_2e emissions (*RS3–RS5*) associated with refining (9.73%) and extraction (10.02%). The in-state emissions from all sources shown exclude emissions from refined products that were exported and burned outside the state and from extraction of imported crude that occurred outside the state.

(b) Statewide CO_2e co-pollutant emissions in 2015 (note a) were compared with in-state CO_2e emitted in 2015 to estimate GHG-weighted co-pollutant emissions. This estimate was based on in-state co-pollutant mass emitted (this table) and in-state CO_2e emitted in 2015 by refining (35.7 Mt/y), extraction (22.6 Mt/y) and refined products (177 Mt/y) from the ARB data given in tables S3 and S4.

(c) From baseline t/Mt CO_2e estimates (this table) and the total refinery fuel chain baseline CO_2e emitted (367 Mt/y) based on the data summarized in Table S1. These baseline refinery fuel chain values estimate total emissions from oil refined in California. Refinery fuel chain emissions can exceed in-state values due to emissions from out-of-state extraction of crude refined in California and exported refined products that were produced in the state (e.g., *compare* baseline refinery fuel chain emissions with emissions from all sources in the state for NOx).

These estimates do not include emissions caused by secondary impacts, such as wildfire smoke associated with droughts linked to climate impacts of petroleum combustion emissions. The petroleum fuel chain and all-source emission estimates shown are rounded to three significant digits.

Table S8. Post-2019 Baseline Crude Rate and CO_2e Emissions Estimate Data

A. Petroleum fuel chain crude rate and emission estimate calculation data, 2020–2022

	2021–2022 Crude Rate a	2010–2019 Range (MM b/d) a		2021–2022 CO2e emitted (Mt)		
Period	(MM b/d)	Minimum	Maximum	(kg/b) b	Period	Cumulative
01/01/20–01/31/20	1.6045	1.4186	1.7077	613.8	30.530	30.53
02/01/20–02/28/20	1.6638	1.4532	1.6523	613.8	28.594	59.12
02/29/20–03/27/20	1.5825	1.5329	1.7990	613.8	27.197	86.32
03/28/20–04/24/20	1.1468	1.5013	1.8140	613.8	19.709	106.03
04/25/20–05/22/20	1.0944	1.5719	1.8293	613.8	18.809	124.84
05/23/20–06/19/20	1.1620	1.5640	1.8220	613.8	19.970	144.81
06/20/20–07/17/20	1.2349	1.5797	1.8314	613.8	21.224	166.03
07/18/20–08/14/20	1.2410	1.5880	1.8040	613.8	21.328	187.36
08/15/20–09/11/20	1.3476	1.5971	1.8181	613.8	23.161	210.52
09/12/20–10/09/20	1.3345	1.4756	1.7848	613.8	22.935	233.46
10/10/20–11/06/20	1.2241	1.3626	1.7528	613.8	21.038	254.50
11/07/20–12/04/20	1.2269	1.4594	1.7935	613.8	21.085	275.58
12/05/20–01/01/21	1.1930	1.4660	1.7690	613.8	20.503	296.08
01/02/21–01/29/21	1.2424	1.4215	1.7246	613.8	21.352	317.44
01/30/21–02/26/21	1.2154	1.4532	1.6401	613.8	20.888	338.32
02/27/21–03/26/21	1.3541	1.5244	1.7739	613.8	23.272	361.60
03/27/21–04/23/21	1.4490	1.5047	1.8247	613.8	24.903	386.50
04/24/21–05/21/21	1.4711	1.5728	1.8273	613.8	25.284	411.78
05/22/21–06/18/21	1.5153	1.5666	1.8203	613.8	26.043	437.83
06/19/21–07/16/21	1.5006	1.5674	1.8321	613.8	25.789	463.61
07/17/21–08/13/21	1.4477	1.5880	1.8043	613.8	24.881	488.50
08/14/21–09/10/21	1.4986	1.6111	1.8244	613.8	25.756	514.25
09/11/21–10/08/21	1.4683	1.4756	1.8107	613.8	25.235	539.49
10/09/21–11/05/21	1.3973	1.3626	1.7277	613.8	24.015	563.50
11/06/21–12/03/21	1.4299	1.4556	1.7842	613.8	24.575	588.08
12/04/21–12/31/21	1.4642	1.4839	1.7623	613.8	25.164	613.24
California petroleum fuel chain cumulative CO2e emission estimate, 1 Jan 2020–31 Dec 2021 (Mt):						**613.24**

a. Crude rate data from California Energy Commission Fuel Watch *Refinery Crude Inputs* (*RS6*).

b. Full fuel chain carbon intensity (kg/b) calculated for the petroleum fuel chain during 2013–2019 from mean mass emission and crude rate data in Table S1. Mass emissions were estimated for each period shown based on the crude rate (MM b/d) and this carbon intensity (613.8 kg/b), accounting for the number of days in each period. Cumulative emissions are the running sum from the periods shown.

continued

Table S8. Post-2019 Baseline Crude Rate and CO_2e Emissions Estimate Data *continued*

B. Twelve-month Mean Crude Rate Trend from 26 Mar to 31 Dec 2021 and 2022 Estimates

Year ending:	2020–2021 c (MM b/d)	4-week Δ c (MM b/d)	wk	2022 Annual Trend Calculations (MM b/d) d Year ending:	Lower bound	Central est.	Upper bound
03/26/21	1.2326	—	4	01/28/22	1.4188 e	1.4188 e	1.4450
04/23/21	1.2548	0.0222	8	02/25/22	1.4188 e	1.4188 e	1.4712
05/21/21	1.2839	0.0290	12	03/25/22	1.4188 e	1.4188 e	1.4973
06/18/21	1.3112	0.0273	16	04/22/22	1.4188 e	1.4435	1.5235
07/16/21	1.3315	0.0203	20	05/20/22	1.4188 e	1.4682	1.5497
08/13/21	1.3477	0.0162	24	06/17/22	1.4188 e	1.4929	1.5759
09/10/21	1.3595	0.0118	28	07/15/22	1.4435	1.5177	1.6021
10/08/21	1.3696	0.0101	32	08/12/22	1.4682	1.5424	1.6283
11/05/21	1.3826	0.0130	36	09/09/22	1.4929	1.5671	1.6545
12/03/21	1.3983	0.0156	40	10/07/22	1.5177	1.5918	1.6807
12/31/21	1.4188	0.0205	44	11/04/22	1.5424	1.6166	1.6957 f
			48	12/02/22	1.5671	1.6413	1.6957 f
Mean 4-week change to 12/31/21		0.0247	52	12/31/22	1.5918	1.6660	1.6957 f
Mean 4-week change to 6/18/21		0.0262					
Estimates for year ending 12/31/22 based on 2020–2021 trend					1.5918	1.6660	1.6957 f
Minimum, 2013–2019 (MM b/d) c					**1.5845**	1.5845	1.5845
Mean, 2013–2019, (MM b/d) c					1.6479	**1.6479**	1.6479
Maximum, 2013–2019 (MM b/d) c					1.7097	1.7097	**1.7097**

c. Crude rate data (MM b/d) from California Energy Commission Fuel Watch *Refinery Crude Inputs* for the twelve months ending each date shown (*RS6*); four-week change calculated by subtracting the preceding twelve-month average crude rate value (e.g., 1.2548 – 1.2326 = 0.0222). These data were used along with carbon intensity data (page S13 note a; Table S1) to estimate emissions in 2022 assuming the scenarios wherein there would be no new, structural, and sustained crude rate cuts during 2022. *See* notes d–f below for details of the trend analysis calculations shown to the right and bottom of Table S8.B.

d. Lower bound and central trends based on 4-week change to 12/31/21 (0.0247 MM b/d); upper bound based on 4-week change to 6/18/21 (0.0262 MM b/d). Closest matching 2013–2019 annual crude rate from the data in Table S1 (**bold**) represent the central estimate and bounds.

e. Lower bound and central trends also constrained by assumed COVID-19 effects in early 2022.

f. Trend estimate constrained to 97% of the 1.7482 MM b/cd statewide crude capacity (1.6957 MM b/d).

Based on these data and analyses the mean from 2013–2019 (1.6479 MM b/d; *see* central estimate) was selected as the central near-term projection for 2022 crude rate in the absence of sustained crude rate reduction starting this year. This value is slightly below the trend based on mean 4-week change through December 2021 (1.666 MM b/d) and further below the annual maximum observed (1.7097 MM b/d). Additionally, it assumes lingering or recurrent pandemic impacts in two ways: First, and in contrast to the mean 4-week change from 26 March to 18 June 2021, the trend through December 2021 includes impacts from the Delta variant surge and the beginning of the Omicron variant surge in the COVID-19 pandemic. By using the trend through December 2021, this central estimate assumes conditions similar to the last three-quarters of 2021 throughout 2022. Second, this central estimate assumes Covid-19 effects which halt any continued upward trend for 84 days during 2022 (see note e, Table S8.b). For these reasons, 1.6479 MM b/d was judged a relatively conservative near-term "rebound" projection.

continued

Table S8. Post-2019 Baseline Crude Rate and CO_2e Emissions Estimate Data *continued*

C. Crude-to Biofuel Refinery Conversions Pathway Calculation Data in Case 2 (10% Capacity Reserve, assuming HEFA jet fuel replaces up to 50% of petroleum jet fuel) [g]

See bounding assumptions (h)

2017–2025: Existing and proposed crude-to-biofuel refinery conversions

Parameter	Units	Data input
2017–Mar 2021 Existing in-state Altair Paramount	barrels/day	3,500
HEFA total jet fuel plus diesel production (j)	million gal/d	0.14
HEFA jet fuel in 2025 (j)	MGD	0.02
HEFA diesel in 2025 (j)	MGD	0.12
Annual HEFA fuel chain emission (k)	Mt/y CO2e	0.43
May 2021–2023 Existing; add Phillips 66 Rodeo	barrels/day	15,500
HEFA total jet fuel plus diesel production (j)	million gal/d	0.62
HEFA jet fuel in 2025 (j)	MGD	0.10
HEFA diesel in 2025 (j)	MGD	0.52
Annual HEFA fuel chain emission (k)	Mt/y CO2e	1.90
2024–2025; add proposed HEFA expansions (b/d) (i)	barrels/day	183,500
HEFA total jet fuel plus diesel production (j)	million gal/d	7.32
HEFA jet fuel in 2025 (j)	MGD	1.16
HEFA diesel in 2025 (j)	MGD	6.17
Annual HEFA fuel chain emission (k)	Mt/y CO2e	22.52

2026–2050: Further HEFA biofuel growth pathways

Parameter	Units	Data input
HEFA growth to 50% jet fuel blend limit (L)		
Mean 2013–2019 jet fuel production	MGD	12.33
HEFA jet fuel at 50% of this baseline	MGD	6.17
Hydrogen production capacity for in-state HEFA refining 2026–2050 (m)		
Crude refining hydrogen capacity, 2025	MM SCF/d	1,107
In-state crude refining capacity, 2025	MM b/d	1.6280
Hydrogen capacity per barrel crude	SCF/b	680
HEFA fuels growth from crude-biofuel refinery conversions (n)		
HEFA hydrogen demand (targeting jet fuel)	SCF/b HEFA feed	2,122
HEFA growth from crude capacity converted	b HEFA feed/b crude feed cut	0.3204
Key HEFA fuels yields targeting jet fuel		
HEFA diesel and jet fuel	gal/b crude feed cut	12.04
HEFA diesel	gal/b crude feed cut	6.69
HEFA jet fuel	gal/b crude feed cut	5.35
Post-2025 HEFA fuel chain emissions per barrel crude feed rate cut		
HEFA diesel and jet fuel	kg CO2e/b crude feed cut	101.5

continued

Table S8. Post-2019 Baseline Crude Rate and CO_2e Emissions Estimate Data *continued*

g. Diesel and jet biofuels produced by Hydrotreated Esters and Fatty Acids (HEFA) technology have not replaced petroleum fuels refined in California, to date (*RS14*). Instead, crude refineries here, which had increased production for export as previous factors reduced in-state petroleum fuels demand, further increased production for export as diesel biofuels were added to the liquid combustion fuel chain (*RS14*). Conversions of idled petroleum refining assets to HEFA fuels, incentivized to protect those otherwise stranded assets and incentivized by state and federal "renewable" fuels policies, have grown to unprecedented cumulative scale here (*RS15, RS16*). Current and proposed state policies and plans would not cap this in-state production and use of HEFA biofuels, and proposed state demand reduction measures alone would not cap the resultant continued refining for export. Currently proposed crude-to-biofuel conversions in California would not further constrain the central crude rate estimate (Table B) on any plausible climate limit pathway, and future HEFA conversions of idled refining assets could further add HEFA biofuels to the combustion fuel chain in California. Moreover, currently proposed state policy envisions reliance on some combination of in-state petroleum and biofuel refining to meet future jet fuel demand. Current aviation fuel blending standards allow petroleum jet fuel replacement with up to 50% HEFA jet fuel (*RS17, RS18*). Accordingly, it was judged necessary to account for emissions from the extraction, refining and use of HEFA biofuels associated with refining in California to support future jet fuel demand in the "Case 2" (10% crude refining reserve) climate protection pathway estimates.

h. Bounding assumptions: (1) Current state policies not proposed for change, including no HEFA feedstock cap and no refining for export cap ("in-line" crude refining rates allowed to include refining for export). (2) Crop oils would be used for HEFA feedstock. The scale of proposed and potential in-state production as a portion of total lipidic feedstock production (*RS16*) supports this assumption. (3) From 2022–2025 currently proposed projects become fully operational from 2024–2025 (Rodeo, Martinez, Paramount, and Bakersfield), idling 120,000 b/d of current crude capacity at Rodeo in 2025 (other proposed projects would not idle current crude capacity). Current crude refining capacity statewide exceeds in-state petroleum fuels demand by substantially more than the 120,200 b/d current Phillips 66 Rodeo-plus-Arroyo Grande refining capacity (*RS19; Table S1*).

Bounding assumption (4): From 2026–2050 crude refinery hydrogen capacity idled along pathways is repurposed for HEFA production up to 50% of current petroleum jet fuel demand. This is consistent with the 50/50 HEFA/petroleum jet fuel blend limit, and is a conservative assumption because it assumes that no new hydrogen production capacity will be built for HEFA fuels in California. Instead, all in-state HEFA growth will replace petroleum refining—an assumption that is conservative because in-state HEFA use has not replaced petroleum to date (*RS14*). (5) HEFA fuel chain emissions would be equivalent to LCFS default factors for crop oil feedstock. This is consistent with assumption 2 and judged conservative given the unprecedented scale of new oil crop production needed to supply HEFA feedstock in all Case 2 pathways to the climate limit (*RS16;* Table S12.C).

Bounding assumption (6): From 2026–2050 new in-state HEFA production capacity will target maximum jet fuel production. This is consistent with the need to replace petroleum jet fuel in Case 2 (10% of refining capacity held in reserve through 2050 to supplement non-petroleum jet fuel). Additionally, it is a conservative assumption for two reasons. First, maximizing HEFA jet fuel yield minimizes the HEFA refining capacity and feedstock needed to replace petroleum jet fuel (*RS16*). Second, targeting jet fuel boosts the carbon intensity of HEFA refining (*RS16*). This higher carbon intensity of HEFA refining would be an additional reason why the HEFA diesel default factor (Assumption 5) may underestimate HEFA fuel chain emissions.

i. Includes currently proposed California crude-to-biofuel conversions: Phillips 66 Rodeo (*RS20*), Marathon Martinez (*RS21*), Altair Paramount (*RS22*), and GCE Bakersfield projects (*RS15, RS16*).

continued

Table S8. Post-2019 Baseline Crude Rate and CO_2e Emissions Estimate Data *continued*

j. Based on mass yields from Pearlson 2013 (*RS23*) and typical specific gravities of HEFA distillate fuels (0.780) and likely feedstock blends (0.916) from NRDC, 2021 (*RS15, RS16*). Yields shown in 2024–2025 reflect refining targeting HEFA diesel: 12.8% mass/15% volume on feed for jet fuel, and 68.1% mass/80% volume for HEFA diesel. Targeting jet fuel after 2025, the yields shift toward 49.4% mass/58% volume on feed for jet fuel and 23.3% mass/27% volume for HEFA diesel. <u>See</u> note n below.

k. Full fuel chain ("life cycle") emissions based on the California Air Resources Board Low Carbon Fuel Standard default emission factor of approximately 8.427 kg CO2e/gallon of HEFA diesel derived from crop oils (*RS24*).

L. Jet fuel demand supplied by California production through 2050 was conservatively estimated based on mean California refinery jet fuel production from 2013–2019 from Table S1. The replacement of California production from petroleum refining in California at the existing 50% maximum HEFA jet fuel blend limit was conservatively estimated without future growth in this historic jet fuel demand. Case 2 (10% crude refining kept in reserve through 2050) pathways estimated in Table S12 herein were then capped to the total HEFA jet fuel production shown (6.17 MGD HEFA jet fuel).

m. Per assumption 4 in note h, existing refinery hydrogen capacity available to be repurposed for HEFA refining in California post-2025 was assumed to depend on the amount of existing crude refining capacity idled. Total 2025 capacity assuming the Phillips 66 Rodeo HEFA project was estimated by subtracting Rodeo capacities from existing crude refining capacities based on USEIA data (*RS19*) then dividing the projected California crude refining hydrogen capacity in 2025 by the projected California crude capacity (–120,200 barrels per calendar day, without Phillips 66 "San Francisco Refinery" Rodeo and Santa Maria plants). This estimate (680 SCF hydrogen per barrel crude) was then used to relate crude feed rate reductions to post-2025 HEFA growth as described in note n directly below.

n. Also per assumption 4 in note h, emissions from post-2025 HEFA growth depend on the crude rate cuts along climate pathways from 2026–2050. HEFA process hydrogen demand targeting jet fuel was estimated at 2,122 SCF/b for the HEFA feed blend and refining mix expected (median of *RS16* scenarios), or 0.3204 b HEFA feed per b crude rate cut (680 SCF/b crude from note m ÷ 2,122 SCF/b HEFA feed). This is approximately 12.04 gallons of HEFA diesel and jet fuel production per b crude rate cut at 42 gallons per barrel and yields for that expected jet fuel feed blend and refining mix (*Id.*).[1] Resultant HEFA fuel chain emissions from the refining, feed acquisition and end-use combustion associated with the HEFA fuel, at 8.427 kg CO2e/gallon HEFA fuels (note k), total approximately 101.5 kg CO_2e/barrel crude refining converted to HEFA refining, as shown. The portion of HEFA jet fuel growth associated with these emissions, approximately 5.35 gallons HEFA jet fuel per barrel crude rate cut (at 0.3204 b HEFA feed/b crude rate cut, 42 gal./b, and expected jet fuel feed blend and refining mix (*Id.*)), was then used to constrain HEFA growth to the jet fuel blend limit per note L and assumptions 4 and 6 in note h. Data inputs shown in Table S8.C were thus used in the "Case 2, 10% capacity reserve" (10% of refining capacity held in reserve through 2050 for potentially irreplaceable products with jet biofuel partially replacing petroleum jet fuel) pathway estimates in Table S12.

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[1] This was calculated from results in Table 6 of *RS16* as the median of scenario process strategy values (i.e., 25% "No IHC", 35% "Select-IHC" and 40% "Isom-IHC") at feed blend and fuel specific gravities of 0.916 and 0.780, respectively, with mass yields on feed of 12.8% for jet fuel, 68.1% for diesel without intentional hydrocracking (IHC), and 49.4% for jet fuel, 23.3% for diesel with intentional hydrocracking. This calculation for combined HEFA diesel and jet fuel gallons per barrel HEFA feed was: (0.25*(0.128+0.681)+0.35*((0.128+0.494)/2+(0.681+0.233)/2)+0.4*(0.494+0.233))*0.916/0.78*42 = 37.58 gallons HEFA diesel and jet fuel/b HEFA feed. Converting to combined HEFA diesel and jet fuels yield per barrel crude: 37.58 • 0.3204 = 12.04 gallons combined HEFA diesel and jet fuel/barrel crude.

Table S9. Statewide Cumulative CO_2e Emission Limit Calculation Data [a]

Gt: Gigaton; 1 billion metric tons

Shading: Cumulative limits

Year	Petroleum Fuel Chain Emissions		All Other (non-petroleum) emissions		Cumulative Total (Gt)
	Annual (Gt/y)	Cumulative (Gt)	Annual (Gt/y)	Cumulative (Gt)	
2017 [b]	0.3682	0.3682	0.2034	0.2034	0.5717
2018	0.3621	0.7303	0.2001	0.4035	1.1340
2019	0.3508	1.0811	0.1938	0.5973	1.6784
2020	0.3394	1.4206	0.1875	0.7849	2.2054
2021	0.3281	1.7487	0.1813	0.9661	2.7148
2022	0.3168	2.0654	0.1750	1.1412	3.2066
2023	0.3054	2.3709	0.1688	1.3099	3.6808
2024	0.2941	2.6650	0.1625	1.4724	4.1374
2025	0.2828	2.9478	0.1562	1.6287	4.5765
2026	0.2715	3.2193	0.1500	1.7786	4.9979
2027	0.2601	3.4794	0.1437	1.9224	5.4018
2028	0.2488	3.7282	0.1375	2.0598	5.7880
2029	0.2375	3.9657	0.1312	2.1910	6.1567
2030 [c]	0.2261	4.1918	0.1249	2.3160	6.5078
2031	0.2169	4.4087	0.1199	2.4358	6.8446
2032	0.2096	4.6183	0.1158	2.5516	7.1700
2033	0.2022	4.8206	0.1117	2.6634	7.4839
2034	0.1949	5.0154	0.1077	2.7710	7.7864
2035	0.1875	5.2029	0.1036	2.8746	8.0775
2036	0.1801	5.3831	0.0995	2.9741	8.3572
2037	0.1728	5.5582	0.0954	3.0696	8.6254
2038	0.1654	5.7212	0.0914	3.1610	8.8822
2039	0.1580	5.8793	0.0873	3.2483	9.1275
2040	0.1507	6.0299	0.0832	3.3315	9.3615
2041	0.1433	6.1732	0.0792	3.4107	9.5839
2042	0.1359	6.3092	0.0751	3.4858	9.7950
2043	0.1286	6.4378	0.0710	3.5568	9.9946
2044	0.1212	6.5590	0.0670	3.6238	10.1828
2045	0.1138	6.6728	0.0629	3.6867	10.3595
2046	0.1065	6.7793	0.0588	3.7455	10.5248
2047	0.0991	6.8784	0.0548	3.8003	10.6787
2048	0.0917	6.9702	0.0507	3.8510	10.8212
2049	0.0844	7.0546	0.0466	3.8976	10.9522
2050 [c]	0.0770	7.1316	0.0426	3.9402	11.0718

Figures shown may not add due to rounding

a. California has established CO_2e emission targets that would reduce statewide emissions to the 1990 emission rate by 2020, 40 percent below the 1990 rate by 2030, and 80 percent below the 1990 rate by 2050.[1–3] State analysis of these targets related them to cumulative emissions based on consistent linear progress.[4] Data in this table show that steady progress to the targets by all emitting sectors defines a total cumulative emission limit from 2017–2050 of ≈ 11.1 Gigatons (Gt) as CO_2e.

b. Emissions in 2017, the beginning of the cumulative accounting, are petroleum fuel chain, all other (non-petroleum), and total mean baseline emissions (2013–2019), which were taken from Table S1.

continued

[1] State Health and Safety Code; Assembly Bill 32, enacted in 2006.
[2] State Health and Safety Code; Senate Bill 32, enacted in 2016.
[3] Executive Order S-3-05; Governor Schwarzenegger, 2005.
[4] *California's 2017 Climate Change Scoping Plan;* Cal. Air Resources Board. *See* pp. 18, 24, 26, figures 5, 6; and *Pathways GHGs by Measure,* "Total GHGs by sector & SP sens" tab, lines 149–151, cell F18.

Table S9. Statewide Cumulative CO_2e Emission Limit Calculation Data *continued*

c. Emission rates at the end of the target years 2030 and 2050 were calculated by subtracting 40% and 80% from the baseline emissions in the last 1/12th of 2030 and 2050, respectively. During the 13-year period from 2018 through 2030, and then the 20-year period from 2031–2050, annual mass emissions were estimated based on equivalent near-monthly (12/year) cuts to the 2030 and then the 2050 targets. Near-monthly (12/yr) increments were used to account for within-year emission rate changes: Annual mass emissions calculated by this method (shown) can differ from those based on the emission rate in the last 1/12th of a year (not shown). Cumulative emissions were calculated by adding the near-monthly emissions in each 1/12th year to the cumulative emissions from 2017 to the preceding 1/12th year. The cumulative limit was thus calculated based on steady progress to the 2030 and 2050 targets as the cumulative emission total from 2017–2050 (11.0718 Gt).

Data quality, system boundary, accumulation period and climate relevance issues were assessed to gauge the precision and accuracy of this cumulative emission limit estimate. Data quality was judged relatively high for the California CO_2e emissions data underlying this estimate (*RS1–RS5,* tables S1–S6). Applying a different system boundary that excludes out-of-state emissions associated with oil and/or electricity system import/export activities changed the absolute value of the cumulative emission limit but not its relationship to current emissions included in the system boundary: the –40% and –80% 2030 and 2050 targets yielded the same proportionate emission cuts to the cumulative emission limit through 2050.* The accumulation period issue arises because emission rate changes cannot reasonably be expected to occur only once on the same date each year, and the same rate change affects cumulative emissions buildup more strongly when it occurs earlier rather than later in the year. Comparison with an annual accounting—which assumed that all emission rate changes will occur on 31 December—showed that the more reasonable near-monthly accounting method used here changes the 2050 cumulative emission limit by only ≈ +2%.

The climate relevance issue was assessed in two steps. Since it is now well established that cumulative emission, rather than the emission rate in any one year, is the primary driver of anthropogenic climate forcing, the cumulative emission limit defined by state climate targets was judged to be the most relevant measurement of climate impacts from state emission trajectories. Then, this cumulative limit was compared with global cumulative emission limits (carbon budgets) that the Intergovernmental Panel on Climate Change found compatible with the 1.5ºC and 2ºC temperature increase limits agreed to in the United Nations 2015 "Paris Accord." <u>*See*</u> Table 10.

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* An inconsistent or exclusive system boundary could, however, affect analysis of prospective future emission trajectory pathways. Inconsistent or exclusive system boundaries could lead to false conclusions about a future pathway, obscure fuel chain interactions that affect the feasibility of a future pathway, and obscure export accounting problems which could make the future system boundary of a pathway unstable. The background section of *Decommissioning California Refineries* (*RS25*) gives examples of these problems with inconsistent and exclusive system boundaries. These considerations further supported the consistent and inclusive system boundary used in this analysis.

Table S10. Calculation data for comparison of California's cumulative emission limit through 2050 with global emissions that could meet the "Paris" Accord [a]

		Below 1.5 ºC*		Below 2.0 ºC*
Global data				
Cumulative CO_2 budget [b]	(Gt)	420		1,170
Baseline CO_2 emissions [c]	(Gt/y)		42 ± 3	
Baseline population [d]	(billions)		7.47	
California data				
Cumulative CO_2 target through 2050 [e]	(Gt)		9.25	
Baseline CO_2 emissions [e]	(Gt/y)		0.478	
Baseline population [d]	(millions)		39.5	
Cumulative limits comparisons [f]				
Equivalent emission cuts basis				
Calif. share of baseline emissions	(ratio)	0.011		0.012
Calif. share of global CO_2 budget	(Gt)	4.46		14.3
Difference from Calif. target limit	(%)	– 52 %		+ 55 %
Per-capita emission cuts basis				
Calif. share of baseline population	(ratio)	0.0053		0.0053
Calif. share of global CO_2 budget	(Gt)	2.23		6.20
Difference from Calif. target limit	(%)	– 76 %		– 33 %

Values shown in the table were rounded for simplicity and clarity of presentation.
* 67% chance of this global heating limit with medium confidence

[a] The Paris treaty calls for holding the increase in global average temperature to well below 2 degrees C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5 ºC above pre-industrial levels. Data in this table show steady progress to California's climate targets (*see* Table S9) would limit cumulative emission to the state's share of global emissions that could be compatible with the well below 2ºC threshold but could exceed the 1.5ºC threshold on an *equivalent emission cuts* basis—and that even deeper cuts would be needed here to achieve the state's *per-capita* share of effort.

[b] Global budgets shown are limits on cumulative emissions compatible with a 67% chance of limiting increases in global mean near-surface air temperature to 1.5ºC and 2.0ºC above pre-industrial levels with medium confidence. Those budgets are expressed as CO_2 emitted from 2017, accounting for non-CO_2 climate emission impacts and for Earth System feedbacks (e.g., permafrost melt). The data were taken from the Intergovernmental Panel on Climate Change (IPCC) report *Global Warming of 1.5ºC* (*RS26*). Note that California emissions were adjusted for comparability with these global estimates which are expressed as CO_2 and account for non-CO_2 forcing, as described in note e below.

[c] Global CO_2 emissions in 2017 from the IPCC report referenced in note b (*RS26*).

[d] World population in 2018 and California population in 2017 from U.S. Bureau of the Census *(RS27).*

[e] California cumulative emission limit defined by state climate targets and baseline emissions (2013–2019 mean) from tables S1 and S9, expressed as CO_2 for comparison with the global data shown based on the portion of total CO_2e emitted in the state during 2013–2017 that was CO_2 (83.59%), which was calculated from data for all included ARB Inventory emissions (*RS3*).

continued

Table S10. Calculation data for comparison of California's cumulative emission limit through 2050 with global emissions that could meet the "Paris" Accord *continued*

[f] California's share of the global cumulative CO_2 budgets was compared with its cumulative CO_2 target through 2050 based on the state's current shares of global baseline emissions (0.011–0.012) and global baseline population (0.0053).

California shares on an equivalent emission cuts basis addressed the uncertainty in global baseline emissions (42 ± 3 Gt/y) by applying the upper bound of this estimate (45 Gt/y) in the comparison for 1.5ºC and its lower bound (39 Gt/y) in that for 2.0ºC. Thus, California shares of global baseline emissions were estimated at ratios of 0.011 and 0.012 in the 1.5ºC and 2ºC comparisons, respectively. These ratios for shares of global baseline emissions (0.011, 0.012) and that for California's share of population (0.0053) were applied to the cumulative global climate budgets shown in the table to calculate California's share of the global budgets in each comparison.

As shown, on an *equivalent emission cuts* basis, California's cumulative emission limit falls within the range for the state's share of the global climate budgets, exceeding its share of the 2ºC budget and falling short of its share of the 1.5ºC budget. On a *per capita emission cuts* basis, California's cumulative emission limit does not fall within the range for the state's share of the global climate budgets, falling short of its share of the 2ºC and 1.5ºC budgets. These results further support the cumulative emission limit based on steady progress to state targets as a minimum goal, and support seeking deeper emission cuts more quickly in relatively higher-emitting and wealthier regions such as California.

A note on uncertainty, carbon neutrality and human factors in climate stabilization: The uncertainty in estimating California's cumulative emission limit through 2050 (*see* Table S9 note c) is small compared with the 67% chance of *medium* confidence that 1.5ºC and 2.0ºC limits could be met by global emission trajectories through mid-century within –49% to +62% of this California limit (this table). And even then, getting to net-zero emissions (carbon neutrality) during this century to stabilize climate (*RS26*) is subject to still greater uncertainties. Six examples of this: First, engineered and permanent carbon capture sequestration has not been proven in practice at the necessary scale to limit heating to 2ºC, achieve carbon neutrality, or stabilize climate, especially if fossil fuels phaseouts are further delayed (*RS26*). Second, scaling up biological carbon capture sequestration could threaten land use conflicts, biodiversity losses and food supply impacts of uncertain but potentially unsustainable severity (*RS28*) which could render it infeasible at the necessary scale to stabilize climate if fossil fuels phaseouts are further delayed. (*See* also *RS26*.) Third, self-reinforcing feedbacks (e.g., permafrost melt emissions, forest fires) and droughts, floods, storms, coastal inundation, crop losses and consequent climate-forced migration will worsen through 2100 to an uncertain degree which might include runaway climate forcing. Fourth, these climate related impacts, losses and conflicts might further erode already-strained societal capacity to sustain the political will for climate stabilization actions. Fifth, as recent European and North American responses to climate migration illustrate, there is still uncertainty regarding the types and locations of societal impacts and their effects on societal cohesion. Last, and pivotal, is whether the pace of economic transformation necessary to stabilize climate will be socially sustainable; how much might further delay foreclose a "just transition" that may prove essential to break free from carbon lock-in?

These and other uncertainties present serious risks for climate stabilization pathways. But at the same time, it is known with high certainty that technology switching which cuts mass emission rates and limits cumulative emissions will limit these risks. Indeed, California's carbon neutrality commitment, as expressed in the Executive Order by then Governor Brown, is explicitly additional and complementary to, instead of alternative to, is longstanding 2030 and 2050 emission reduction targets (*RS29*). Falling short of the Paris 1.5ºC goal (which *might* be achieved by additional carbon neutrality actions) but compatible with its well-below-2ºC goal, the cumulative emission limit defined by California's 2030 and 2050 emission reduction targets could be labeled, in shorthand, as the state's "1.5–2ºC climate limit."

Table S11. Estimate Data for Case-1 Pathways

Case-1: 20% refining capacity reserve through 2050 for potentially irreplaceable products; no jet biofuel assumption

Annual (**AE**) and cumulative (**CE**) emissions in gigatons (Gt; billions of metric tons). **CI:** carbon intensity (kg/b) **CR:** crude rate (MM b/d) **CRR:** crude rate reduction (%/yr)

A. Cumulative emissions* assuming no sustained refinery crude rate reduction, unconstrained

	Petroleum Fuel Chain					Total CE
Year	CRR (%/yr) [a]	CR (MM b/d) [a]	CI (kg/b) [b]	AE (Gt) [c]	CE (Gt) [d]	(Gt) [d]
2017	0.000%	1.7020	623.2	0.3872	0.3872	0.5906
2018	0.000%	1.7097	613.9	0.3831	0.7703	1.1902
2019	0.000%	1.5846	622.6	0.3601	1.1303	1.7276
2020	0.000%	1.3120	613.8	0.2932	1.4235	2.2083
2021	0.000%	1.4188	613.8	0.3201	1.7436	2.7097
2022	0.000%	1.6479	613.8	0.3692	2.1128	3.2539
2023	0.000%	1.6479	613.8	0.3692	2.4819	3.7919
2024	0.000%	1.6479	613.8	0.3692	2.8511	4.3235
2025	0.000%	1.6479	613.8	0.3692	3.2203	4.8490
2026	0.000%	1.6479	613.8	0.3692	3.5895	5.3682
2027	0.000%	1.6479	613.8	0.3692	3.9587	5.8811
2028	0.000%	1.6479	613.8	0.3692	4.3279	6.3877
2029	0.000%	1.6479	613.8	0.3692	4.6971	6.8881
2030	0.000%	1.6479	613.8	0.3692	5.0663	7.3822
2031	0.000%	1.6479	613.8	0.3692	5.4355	7.8713
2032	0.000%	1.6479	613.8	0.3692	5.8047	8.3563
2033	0.000%	1.6479	613.8	0.3692	6.1738	8.8372
2034	0.000%	1.6479	613.8	0.3692	6.5430	9.3140
2035	0.000%	1.6479	613.8	0.3692	6.9122	9.7868
2036	0.000%	1.6479	613.8	0.3692	7.2814	10.2555
2037	0.000%	1.6479	613.8	0.3692	7.6506	10.7202
2038	0.000%	1.6479	613.8	0.3692	8.0198	11.1808
2039	0.000%	1.6479	613.8	0.3692	8.3890	11.6373
2040	0.000%	1.6479	613.8	0.3692	8.7582	12.0897
2041	0.000%	1.6479	613.8	0.3692	9.1274	12.5381
2042	0.000%	1.6479	613.8	0.3692	9.4966	12.9824
2043	0.000%	1.6479	613.8	0.3692	9.8657	13.4226
2044	0.000%	1.6479	613.8	0.3692	10.2349	13.8587
2045	0.000%	1.6479	613.8	0.3692	10.6041	14.2908
2046	0.000%	1.6479	613.8	0.3692	10.9733	14.7189
2047	0.000%	1.6479	613.8	0.3692	11.3425	15.1428
2048	0.000%	1.6479	613.8	0.3692	11.7117	15.5627
2049	0.000%	1.6479	613.8	0.3692	12.0809	15.9785
2050	0.000%	1.6479	613.8	0.3692	12.4501	16.3903

* *Baseline data:* Data for 2017–2019 are from Table S1. Data and data-based estimates for 2020 and 2021 are from Table S8.A. Near term data-based projections for 2022 are from Table S8.B. Baseline crude rate (1.6479 million barrels per day) and fuel chain carbon intensity (613.8 kg CO_2e/barrel crude) are 2013–2019 means from the data in Table S1. Case 1 pathways analyses based on these data were derived as described in the notes following Part C of this Table.

continued

Table S11. Estimate Data for Case-1 Pathways *continued*

Case-1: 20% refining capacity reserve through 2050 for potentially irreplaceable products; no jet biofuel assumption

Annual (**AE**) and cumulative (**CE**) emissions in gigatons (Gt; billions of metric tons). **CI:** carbon intensity (kg/b)
CR: crude rate (MM b/d) **CRR:** crude rate reduction (%/yr)

B. Cumulative emissions* assuming sustained refinery crude rate reductions (CRR) start January 2023, constrained to the Climate Limit and 20% Refining Capacity Reserve through 2050

	Petroleum Fuel Chain					Total CE
Year	CRR (%/yr) [a]	CR (MM b/d) [a]	CI (kg/b) [b]	AE (Gt) [c]	CE (Gt) [d]	(Gt) [d]
2017	0.000%	1.7020	623.2	0.3872	0.3872	0.5906
2018	0.000%	1.7097	613.9	0.3831	0.7703	1.1902
2019	0.000%	1.5846	622.6	0.3601	1.1303	1.7276
2020	0.000%	1.3120	613.8	0.2932	1.4235	2.2083
2021	0.000%	1.4188	613.8	0.3201	1.7436	2.7097
2022	0.000%	1.6479	613.8	0.3692	2.1128	3.2539
2023	-5.782%	1.5527	613.8	0.3478	2.4703	3.7802
2024	-5.782%	1.4629	613.8	0.3277	2.8071	4.2795
2025	-5.782%	1.3783	613.8	0.3088	3.1245	4.7532
2026	-5.782%	1.2986	613.8	0.2909	3.4235	5.2022
2027	-5.782%	1.2235	613.8	0.2741	3.7052	5.6276
2028	-5.782%	1.1528	613.8	0.2583	3.9707	6.0305
2029	-5.782%	1.0861	613.8	0.2433	4.2208	6.4118
2030	-5.782%	1.0233	613.8	0.2293	4.4564	6.7724
2031	-5.782%	0.9641	613.8	0.2160	4.6784	7.1142
2032	-5.782%	0.9084	613.8	0.2035	4.8876	7.4392
2033	-5.782%	0.8559	613.8	0.1917	5.0847	7.7480
2034	-5.782%	0.8064	613.8	0.1807	5.2703	8.0414
2035	-5.782%	0.7597	613.8	0.1702	5.4453	8.3199
2036	-5.782%	0.7158	613.8	0.1604	5.6101	8.5842
2037	-5.782%	0.6744	613.8	0.1511	5.7654	8.8350
2038	-5.782%	0.6354	613.8	0.1424	5.9117	9.0727
2039	-5.782%	0.5987	613.8	0.1341	6.0496	9.2979
2040	-5.782%	0.5641	613.8	0.1264	6.1795	9.5110
2041	-5.782%	0.5315	613.8	0.1191	6.3018	9.7125
2042	-5.782%	0.5007	613.8	0.1122	6.4171	9.9029
2043	-5.782%	0.4718	613.8	0.1057	6.5258	10.0826
2044	-5.782%	0.4445	613.8	0.0996	6.6281	10.2519
2045	-5.782%	0.4188	613.8	0.0938	6.7246	10.4113
2046	-5.782%	0.3946	613.8	0.0884	6.8154	10.5610
2047	-5.782%	0.3718	613.8	0.0833	6.9010	10.7013
2048	-5.782%	0.3503	613.8	0.0785	6.9817	10.8327
2049	-5.782%	0.3300	613.8	0.0739	7.0577	10.9553
2050	0.000%	0.3300	613.8	0.0739	7.1316	11.0718

* *Baseline data:* Data for 2017–2019 are from Table S1. Data and data-based estimates for 2020 and 2021 are from Table S8.A. Near term data-based projections for 2022 are from Table S8.B. Baseline crude rate (1.6479 million barrels per day) and fuel chain carbon intensity (613.8 kg CO_2e/barrel crude) are 2013–2019 means from the data in Table S1. Case 1 pathways analyses based on these data were derived as described in the notes following Part C of this Table.

continued

Table S11. Estimate Data for Case-1 Pathways *continued*

C. All pathway results for severity (%/yr) and duration (months) of sustained crude rate reductions constrained to the Climate Limit and 20% Refining Capacity Reserve through 2050*

Start of sustained crude rate reductions		Refinery crude rate reductions	
(month)	(year)	(%/year)	(months sustained)
January	2022	-5.27%	348
July	2022	-5.52%	340
January	2023	-5.78%	324
July	2023	-6.08%	309
January	2024	-6.40%	292
July	2024	-6.77%	276
January	2025	-7.17%	260
July	2025	-7.63%	244
January	2026	-8.15%	228
July	2026	-8.74%	212
January	2027	-9.43%	196
July	2027	-10.25%	179
January	2028	-11.21%	163
July	2028	-12.37%	147
January	2029	-13.79%	131
July	2029	-15.57%	115
January	2030	-17.88%	99
July	2030	-21.15%	82
January	2031	-25.64%	66
July	2031	-32.51%	50
January	2032	-44.25%	34
July	2032	-67.85%	18
August	2032	-79.66%	12

* It is technically feasible to meet the 11.1 Gt climate limit while holding at least 20% of current refining capacity in reserve for potentially irreplaceable products via each of the 23 pathways in Chart S11.C. However, each pathway starts sustained crude rate reductions at a different time with consequent impacts on the severity and duration of annual crude rate reductions needed to meet these climate and capacity reserve constraints. The results shown reveal how more cumulative emissions buildup coupled with less remaining time to cut emissions forces a near-exponential increase in sudden refining capacity losses with delay. Annual capacity losses increase from 5% per year to 80% of current capacity in a single year.

Results for the period during which crude rate reductions could be sustained along each pathway (months sustained) further inform the timing problem. For example, a twelve-month delay from January 2022 to January 2023 shortens the period of sustained reductions by 24 months (Chart S11.C). This is because by forcing deeper annual cuts while holding 20% of current capacity and thus emissions in reserve, the 12-month delay also shaves another year off the back end of the pathway to the climate limit that starts cuts in January 2023. <u>*See*</u> Chart S11.B. To meet the climate limit *and* hold 20% of refining capacity in reserve through 2050, starting in January 2023, sustained incremental crude rate cuts must end no later than December 2049. *Id.*

continued

Table S11. Estimate Data for Case-1 Pathways *continued*

Detail notes

[a] Crude rate (CR) is a measurement of petroleum flows through the fuel chain linked to refining in California, expressed as refining crude rate in millions of barrels per day (MM b/d). Crude rate reduction (CRR) is the incremental crude rate reduction to be sustained over time. In these tables it is reported for each pathway as a percentage reduction in the total annual crude rate in the prior year, however, it was calculated as a near-monthly change in 12 equal increments per year, as described and supported in the notes to Table S9. *See* also notes c and d below. CRR, as discussed below the table immediately above, is constrained along pathways to the climate limit by both cumulative emissions and refining capacity held in reserve for potentially irreplaceable products, primarily jet fuel. Crudes rates for 2017, 2018, and 2019 were taken from Table S1. Crude rates for 2020 and 2021 were taken from Table S8. The 2013–2019 mean crude rate from Table S1 was applied as a baseline from which CRR starts on various dates among pathways to the climate limit. Rebound from pandemic impacts to this 2013–2019 mean baseline was judged to be a reasonable and conservative assumption based on data and analysis in Table S8. This baseline conservatively assumes that crude rates will not increase from the 2013–2019 mean.

[b] CI: carbon intensity; here, the CI of the petroleum fuel chain linked to crude refined in California. The mean of 2013–2019 data in Table S1 (613.8 kg CO_2e/barrel crude) was used as a baseline, except where complete data for precise actual CI was available from 2017–2019, which were taken from Table S1. This baseline conservatively assumes that petroleum fuel chain CI will not increase.

[c] AE: annual emissions in gigatons (Gt; 1 billion metric tons). AE shown was calculated as annual mass from the sum of CI • CR over 12 equal increments/year (*see* also notes a, b, d, Table S9 note c).

[d] CE: cumulative emissions in Gt (billions of metric tons). Fuel chain and total (including all other non-petroleum emissions) CE were calculated as the sum of emissions from 2017 (*see* also notes a–c, Table S9 note c). All other (non-petroleum) emissions were taken from Table S9. These estimates therefore assume that all other (non-petroleum) emissions will make steady progress to the State's 2030 and 2050 climate targets.

[e] Here (Table S11, Capacity Reserve Case-1), 20% of baseline refining capacity was assumed to remain in service through 2050 despite proven alternatives to petroleum ground transportation, based primarily on uncertainty regarding the extent to which petroleum jet fuel could be replaced. Accordingly, Case-1 pathways shown here are not based on any specific assumption regarding jet biofuels. (An alternative assumption regarding the extent of this "capacity reserve" and potential use of emergent technically feasible biofuel technology was analyzed as well; *see* the "Case-2" results in Table S12 below.)

Table S11.A (Case-1, no sustained crude rate reduction) and S11.B (Case-1, reductions start Jan 2023) give calculation details using the data and methods described for two of many pathways. Table S11.C gives results for 23 Case-1 pathways to the climate limit, including the start date, severity of annual crude rate reductions to the climate limit, and maximum duration of incremental crude rate reductions to the climate limit. Comparison of these results reveals clear and critically important trends associated with further delayed action, as discussed directly below Table S11.C above.

Table S12. Estimate Calculation Data for Case-2 Pathways

Case-2: 10% refining capacity reserve through 2050 for potentially irreplaceable products; assumes up to half of current petroleum jet fuel will be replaced by hydrotreated esters and fatty acids (HEFA) biofuel

Annual (**AE**) and cumulative (**CE**) emissions in gigatons (Gt; billions of metric tons). **CI:** carbon intensity (kg/b) **CR:** crude rate (MM b/d) **CRR:** crude rate reduction (%/yr)

A. Cumulative emissions* assuming no refinery crude rate reduction, unconstrained

Year	Petroleum Fuel Chain CRR (%/yr) [a]	CR (MM b/d) [a]	CI (kg/b) [b]	AE (Gt) [c]	CE (Gt) [d]	Total CE (Gt) [d]
2017	0.000%	1.7020	623.2	0.3872	0.3872	0.5906
2018	0.000%	1.7097	613.9	0.3831	0.7703	1.1902
2019	0.000%	1.5846	622.6	0.3601	1.1303	1.7276
2020	0.000%	1.3120	613.8	0.2932	1.4235	2.2083
2021	0.000%	1.4188	613.8	0.3201	1.7436	2.7097
2022	0.000%	1.6479	613.8	0.3692	2.1128	3.2539
2023	0.000%	1.6479	613.8	0.3692	2.4819	3.7988
2024	0.000%	1.6479	613.8	0.3692	2.8511	4.3417
2025	0.000%	1.6479	613.8	0.3692	3.2203	4.8897
2026	0.000%	1.6479	613.8	0.3692	3.5895	5.4314
2027	0.000%	1.6479	613.8	0.3692	3.9587	5.9668
2028	0.000%	1.6479	613.8	0.3692	4.3279	6.4960
2029	0.000%	1.6479	613.8	0.3692	4.6971	7.0189
2030	0.000%	1.6479	613.8	0.3692	5.0663	7.5355
2031	0.000%	1.6479	613.8	0.3692	5.4355	8.0471
2032	0.000%	1.6479	613.8	0.3692	5.8047	8.5546
2033	0.000%	1.6479	613.8	0.3692	6.1738	9.0581
2034	0.000%	1.6479	613.8	0.3692	6.5430	9.5574
2035	0.000%	1.6479	613.8	0.3692	6.9122	10.0527
2036	0.000%	1.6479	613.8	0.3692	7.2814	10.5440
2037	0.000%	1.6479	613.8	0.3692	7.6506	11.0311
2038	0.000%	1.6479	613.8	0.3692	8.0198	11.5142
2039	0.000%	1.6479	613.8	0.3692	8.3890	11.9933
2040	0.000%	1.6479	613.8	0.3692	8.7582	12.4682
2041	0.000%	1.6479	613.8	0.3692	9.1274	12.9391
2042	0.000%	1.6479	613.8	0.3692	9.4966	13.4059
2043	0.000%	1.6479	613.8	0.3692	9.8657	13.8687
2044	0.000%	1.6479	613.8	0.3692	10.2349	14.3273
2045	0.000%	1.6479	613.8	0.3692	10.6041	14.7820
2046	0.000%	1.6479	613.8	0.3692	10.9733	15.2325
2047	0.000%	1.6479	613.8	0.3692	11.3425	15.6790
2048	0.000%	1.6479	613.8	0.3692	11.7117	16.1214
2049	0.000%	1.6479	613.8	0.3692	12.0809	16.5597
2050	0.000%	1.6479	613.8	0.3692	12.4501	16.9940

* *Baseline petroleum data:* Data for 2017–2019 are from Table S1. Data and data-based estimates for 2020 and 2021 are from Table S8.A. Near term data-based projections for 2022 are from Table S8.B. Baseline crude rate (1.6479 million barrels per day) and fuel chain carbon intensity (613.8 kg CO_2e/barrel crude) are 2013–2019 means from the data in Table S1. *Baseline biofuel data* are from Table S8.C as described in the notes following part C of this Table. Case 2 pathways analyses based on these data were derived as described in the notes following Part C of this Table.

continued

Table S12. Estimate Calculation Data for Case-2 Pathways *continued*

Case-2: 10% refining capacity reserve through 2050 for potentially irreplaceable products; assumes up to half of current petroleum jet fuel will be replaced by hydrotreated esters and fatty acids (HEFA) biofuel

Annual (**AE**) and cumulative (**CE**) emissions in gigatons (Gt; billions of metric tons). **CI:** carbon intensity (kg/b)
CR: crude rate (MM b/d) **CRR:** crude rate reduction (%/yr)

B. Cumulative emissions* assuming sustained refinery crude rate reductions (CRR) start January 2034, constrained to the Climate Limit and 10% Refining Capacity Reserve through 2050, accounting for jet biofuel

	Petroleum Fuel Chain					Total CE
Year	CRR (%/yr) [a]	CR (MM b/d) [a]	CI (kg/b) [b]	AE (Gt) [c]	CE (Gt) [d]	(Gt) [d]
2017	0.000%	1.7020	623.2	0.3872	0.3872	0.5906
2018	0.000%	1.7097	613.9	0.3831	0.7703	1.1902
2019	0.000%	1.5846	622.6	0.3601	1.1303	1.7276
2020	0.000%	1.3120	613.8	0.2932	1.4235	2.2083
2021	0.000%	1.4188	613.8	0.3201	1.7436	2.7097
2022	0.000%	1.6479	613.8	0.3692	2.1128	3.2539
2023	0.000%	1.6479	613.8	0.3692	2.4819	3.7988
2024	0.000%	1.6479	613.8	0.3692	2.8511	4.3417
2025	0.000%	1.6479	613.8	0.3692	3.2203	4.8897
2026	0.000%	1.6479	613.8	0.3692	3.5895	5.4314
2027	0.000%	1.6479	613.8	0.3692	3.9587	5.9668
2028	0.000%	1.6479	613.8	0.3692	4.3279	6.4960
2029	0.000%	1.6479	613.8	0.3692	4.6971	7.0189
2030	0.000%	1.6479	613.8	0.3692	5.0663	7.5355
2031	0.000%	1.6479	613.8	0.3692	5.4355	8.0471
2032	0.000%	1.6479	613.8	0.3692	5.8047	8.5546
2033	0.000%	1.6479	613.8	0.3692	6.1738	9.0581
2034	-89.804%	0.1680	613.8	0.0376	6.3057	9.3003
2035	0.000%	0.1680	613.8	0.0376	6.3433	9.4416
2036	0.000%	0.1680	613.8	0.0376	6.3810	9.5787
2037	0.000%	0.1680	613.8	0.0376	6.4186	9.7118
2038	0.000%	0.1680	613.8	0.0376	6.4562	9.8408
2039	0.000%	0.1680	613.8	0.0376	6.4939	9.9658
2040	0.000%	0.1680	613.8	0.0376	6.5315	10.0867
2041	0.000%	0.1680	613.8	0.0376	6.5692	10.2035
2042	0.000%	0.1680	613.8	0.0376	6.6068	10.3163
2043	0.000%	0.1680	613.8	0.0376	6.6445	10.4249
2044	0.000%	0.1680	613.8	0.0376	6.6821	10.5296
2045	0.000%	0.1680	613.8	0.0376	6.7197	10.6301
2046	0.000%	0.1680	613.8	0.0376	6.7574	10.7266
2047	0.000%	0.1680	613.8	0.0376	6.7950	10.8190
2048	0.000%	0.1680	613.8	0.0376	6.8327	10.9073
2049	0.000%	0.1680	613.8	0.0376	6.8703	10.9916
2050	0.000%	0.1680	613.8	0.0376	6.9080	11.0718

* *Baseline petroleum data:* Data for 2017–2019 are from Table S1. Data and data-based estimates for 2020 and 2021 are from Table S8.A. Near term data-based projections for 2022 are from Table S8.B. Baseline crude rate (1.6479 million barrels per day) and fuel chain carbon intensity (613.8 kg CO_2e/barrel crude) are 2013–2019 means from the data in Table S1. *Biofuel data* are from Table S8.C as described in the notes following part C of this Table. Case 2 pathways analyses based on these data were derived as described in the notes following Part C of this Table.

continued

Table S12. Estimate Calculation Data for Case-2 Pathways *continued*

C. All pathway results for severity (%/yr) and duration (months) of sustained crude rate reductions (CRR) constrained to the Climate Limit and 10% Refining Capacity Reserve through 2050, accounting for jet biofuel

Start of sustained crude rate reductions		Refinery crude rate reductions	
(month)	(year)	(%/year)	(months sustained)
January	2022	-5.41%	348
July	2022	-5.67%	342
January	2023	-5.95%	336
July	2023	-6.24%	330
January	2024	-6.56%	324
July	2024	-6.92%	318
January	2025	-7.31%	312
July	2025	-7.74%	306
January	2026	-8.22%	300
July	2026	-8.73%	294
January	2027	-9.30%	283
July	2027	-9.95%	263
January	2028	-10.69%	244
July	2028	-11.55%	225
January	2029	-12.57%	205
July	2029	-13.77%	186
January	2030	-15.23%	167
July	2030	-17.03%	148
January	2031	-19.35%	128
July	2031	-22.35%	109
January	2032	-26.41%	90
July	2032	-32.48%	70
January	2033	-41.66%	51
July	2033	-57.76%	32
January	2034	-89.80%	12

* It is technically feasible to meet the 11.1 Gt climate limit while holding at least 10% of current refining capacity in reserve for potentially irreplaceable products via each of the 25 pathways in Chart S12.C. However, each pathway starts sustained crude rate reductions at a different time with consequent impacts on the severity and duration of annual crude rate reductions needed to meet these climate and capacity reserve constraints. The results shown reveal how more cumulative emissions buildup coupled with less time left to cut emissions forces a near-exponential increase in sudden refining capacity losses with delay.

Results for the period during which crude rate reductions could be sustained along each pathway (months sustained) further inform the timing problem. For example, a twelve-year delay from January 2022 to January 2034 shortens the period of sustained reductions by 28 years (336 months, review of Chart S12.C shows). To meet the climate limit *and* hold 10% of refining capacity in reserve through 2050, waiting until January 2043, the twelve-year delay forces 90% of current refining capacity to be lost in single year. <u>See</u> Chart S12.B.

continued

Table S12. Estimate Calculation Data for Case-2 Pathways *continued*

Detail Notes

Jet fuel accounts for more than 10% of California refinery fuels production (Table S1). Case 2 pathways reduce the 20% refining capacity reserve in Case 1 to 10% and account for potential emissions from replacing up to half of current in-state petroleum jet fuel production with biofuel refined in-state using hydrotreated esters and fatty acids (HEFA) technology. Refiners here have begun to repurpose idled assets for HEFA diesel and jet fuel production, and are incentivized to do so when climate constraints strand their refining assets (*RS15*). Aviation standards allow HEFA jet fuel to be 50% of the jet fuel blend (*RS16*). HEFA fuel chain emissions can be significant (*RS15, RS16*).[2] This report does not endorse that particular biofuel, and there are many reasons not to do so (*RS15, RS16*).[3] Instead, it was judged appropriate to assess potential impacts on climate pathways *if* this technically feasible biofuel is added to the combustion fuel chain as a partial alternative to petroleum jet fuel.

[a] Crude rate (CR) and crude rate reduction (CRR) were assessed based on the same data and methods as in Case 1 (<u>*see*</u> p. 25). However, added HEFA emissions, and decreased refining capacity kept in place through 2050, affect the timing and extent of crude rate cuts in Case 2 pathways to the climate limit.

Pathway HEFA data inputs are detailed in Table S8.C. Existing and proposed in-state HEFA production and emissions were added to all pathways with proposed projects assumed to scale up from 2024–2025. After 2025 further HEFA growth would be linked to pathway-specific crude rate reductions, and was limited by several conservative assumptions: HEFA growth was constrained to the current 50% jet fuel blend limit (*Id.*). Post-2025 HEFA growth was assumed to target jet fuel rather than diesel yield (*Id.*), thereby minimizing HEFA diesel by-production emissions. New HEFA growth was further constrained to *existing* refinery hydrogen production capacity idled by crude rate cuts in pathways (*Id.*). Since HEFA process hydrogen demand exceeds that of crude refining substantially, these assumptions limit post 2025 HEFA growth to approximately 12.04 gallons HEFA diesel and jet fuel per barrel crude rate cut (*Id.*).

[b] Data and methods for carbon intensity (CI) of the petroleum fuel chain are the same as those in Case 1 (p. 25). HEFA CI was taken from the CARB default emission factor for HEFA diesel from oil crops, 8.427 kg CO_2e/gal. fuel, and was conservatively applied to future HEFA diesel *and* jet fuels. At 12.04 gal./b crude (note a), HEFA CI *per barrel crude rate cut* was calculated as 8.427 • 12.04 or approximately 101.5 kg CO_2e per barrel of sustained crude rate reduction in a given pathway. <u>*See*</u> Table S8.C.

[c] Petroleum fuel chain annual emissions (AE) data and methods are the same as in Case 1 (p. 25). HEFA mass emissions, also assessed over 12 equal increments/year, were estimated based on HEFA CI • CRR (101.5 kg CO_2e per barrel of sustained crude rate reduction *times* barrels of that crude rate reduction). Note that these HEFA emission increments are added into the "total CE" columns in Chart S12.A and B.

[d] Cumulative emission (CE) was calculated by the same method as in Case 1 (p. 25), except that HEFA emissions were included as described in note c. Total CE in Case 2 was thus calculated as the sum of petroleum fuel chain, all other (non-petroleum), and HEFA emissions from 2017. Again, these estimates assume all other (non-petroleum) emissions will make steady progress to the State climate targets.

Table S12.A (Case-2, no sustained crude rate reduction) and S12.B (Case-2, reductions start Jan 2034) give calculation details using the data and methods described for two of many pathways. Table S12.C gives results for 25 Case-2 pathways to the climate limit, including the start date, severity of annual crude rate reductions to the climate limit, and maximum duration of incremental crude rate reductions to the climate limit. Comparison of these results reveals clear and critically important trends associated with further delayed action, as discussed directly below Table S12.C above.

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[2] Existing and proposed in-state HEFA projects alone could emit some 0.6 Gt through 2050 (tables S12.A *v.* S11.A).
[3] For example, cropland expansion to grow feed for 50% HEFA jet fuel globally could threaten natural carbon sinks.

Table S13. Refining for Export Co-emission Estimate Detail Supporting Report Table 4.

Direct refinery emissions from refining for export, calculation data for difference between no crude rate reduction and sustained crude rate reductions starting January 2023 in Case 1, example for the year 2045

t (ton): metric ton **Mt** (megaton): 1 million metric tons

Pollutant	**Co-emission factor** [a] (units)	(value)	**Emission difference in 2045** (units)	(value)
CO_2e [b]	—	—	Mt/year	26.58
Nitrogen oxides	t/Mt CO_2e	222.0	t/year	5,901
Particulate matter [c]	t/Mt CO_2e	62.4	t/year	1,659
Sulfur oxides	t/Mt CO_2e	127.5	t/year	3,389

a. Co-emission factors calculated from State data as shown in Table S7. For example, with the difference between these pathways, 222 t NOx/Mt CO_2e • 26.58 Mt CO_2e = 5,901 tons of NOx emitted in 2045. Co-emission estimates represent statewide refining averages; individual refinery emissions may vary. These estimates conservatively assume 80% reduction in statewide petroleum fuels demand via the implementation of State plans and policies through 2045. <u>*See*</u> tables S11, S12, and the main report text for information supporting the potential for exports growth in pathways without crude rate reductions.

Please note that Table S13 does not include emissions from *current* refining for export—it estimates only the *future potential increase* in emissions from refining for export, compared with the current baseline.

b. Difference, during 2045, in CO_2e emitted directly from refining, estimated based on the 2013–2019 mean from Table S1 (35.64 Mt/yr) minus the product of this mean and the crude rate fraction of the baseline reached in 2045 by crude rate reductions to the climate limit starting January 2023. This fraction was taken from the 2013–2019 mean in Table S1 (1.6479 MM b/d) and the reduced crude rate in Table S11.B for 2045 (0.4188 MM b/d). Calculation: 35.64 – (35.64 • (0.4188 ÷ 1.6479)) = 26.5824 Mt.

c. Particulate matter shown is PM_{10} including $PM_{2.5}$

Table S14. Fuel Chain Emissions Associated with California Petroleum Fuels Exports

A. Petroleum fuels refined in California for in-state use and exports, 2013–2019 [a]

Millions of gallons per day (MGD)	Gasoline, all grades	Distillate-diesel	Jet fuel & kerosene	Petroleum coke	Other fuels	All with jet fuel	Excluding jet fuel
Production							
2013–2019	44.6	15.3	12.3	4.23	1.69	78.2	65.8
2013–2015	42.9	15.3	11.9	4.19	1.63	75.9	64.0
2017–2019	45.6	15.5	12.9	4.29	1.74	80.1	67.2
In-State Use							
2013–2019	37.9	10.6	1.14	0.14	2.53	52.3	51.1
2013–2015	37.1	10.8	1.04	0.16	2.51	51.7	50.6
2017–2019	38.5	10.3	1.23	0.11	2.47	52.6	51.3
Net Exports							
2013–2019	6.68	4.77	11.2	4.09	–0.83	25.9	14.7
2013–2015	5.74	4.49	10.9	4.03	–0.88	24.3	13.4
2017–2019	7.15	5.23	11.7	4.19	–0.72	27.5	15.8

B. Fuel chain emissions associated with California-refined petroleum fuels exported, 2013–2019 [b]

Millions of metric tons/year (Mt/yr)	All California-refined fuels	Cross-border exports	
	(Mt/yr)	(Mt/yr)	(%)
Including jet fuel	369	133	36 %
Excluding jet fuel	311	84	27 %

Figures may not add due to rounding.

a. Exports to other states and nations account for the differences between in-state production and in-state use. Data for 2013–2019 shown in this table were taken from Table S1. For 2000–2019 exports of gasoline and diesel calculated from additional historic data (*RS5, RS6*) see Report, Table 1. Jet fuel exports include jet fuel that was fueled in California and burned in cross-border air travel.

b. Emissions of CO_2e are shown. Fuel chain emissions associated with exports include, for the portion of total production exported, in-state refining, and extraction of in-state and imported crude oil. Data from Table S1.

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