San Francisco Bay Area Refinery Transition Analysis

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Executive Summary

This report provides information to the Contra Costa Refinery Transition Partnership about potential future refinery market scenarios associated with California's energy transition. We include quantitative and qualitative analysis of the changing future market potentially facing San Francisco Bay Area petroleum refineries ("Bay Area refineries").

We begin with a general understanding of California's petroleum refining market, focusing on the market region most relevant to the Bay Area refineries. There are two distinct markets in the California area where refined products are sold, the Northern California Northern Nevada (NCNN) market and the Southern California Southern Nevada (SCSN) market. The Bay Area refineries are situated in the NCNN market. The SCSN market is considered stronger, with about 20% greater demand than the NCNN. California is isolated from other areas of domestic crude oil and refined product supplies. Declining trends in California crude oil production have forced in-state refineries to import more than 50% of crude supplies from foreign origins, by marine tanker. Declining in-state crude production has reduced crude oil pipeline throughput to Bay Area refineries, increasing associated delivery costs and raising concern about the long-term viability of pipeline operations.

Bay Area refineries include Chevron's Richmond, PBF Energy's Martinez, Valero's Benicia, Phillips 66's Rodeo (scheduled to convert to renewable fuels), and Marathon's Martinez (currently idled, and scheduled to convert to renewable fuels) facilities. These refineries have many similarities, for example:

- All were built to process heavy sour crudes, have marine access, produce fuels that meet California Air Resource Board's (CARB) stringent emissions standards, and are owned by publicly traded Fortune 500 companies.
- Bay Area refineries all use Kinder Morgan's network of refined product pipelines to move finished fuels throughout the NCNN territory.
- Historically, these refineries focused output on CARB-compliant reformulated gasoline, CARB diesel, and jet fuel, as well as smaller amounts of non-CARB gasoline and diesel, and residual fuel.
- Bay Area refineries have typically produced more product than required in northern California, allowing volumes to be moved by pipeline to northern Nevada, and transported by marine vessel to the SCSN, out-of-state domestic ports, and foreign destinations.

Compared to exports, smaller volumes of refined product imports into the NCNN have occurred, though publicly available data was too limited to incorporate into our analysis. Reliance on limited and outdated import/export data is a limitation of this analysis, for example, because refinery capacity outages (short-term) and closures have historically impacted import and export volumes.

The quantitative analysis relies on assumptions and projections data from CARB's Final Scoping Plan Scenario, released in November 2022. This scenario incorporates existing rules and legal authorities, as well as new or in-process policies, with the aim of achieving carbon neutrality by 2045. We do not debate the merits or drawbacks of the CARB data or scenario, rather we focus on determining how CARB's projections could impact Bay Area refineries. CARB's in-state gasoline energy demand projections were disaggregated to the Bay Area refinery market region and translated into theoretical future refinery capacity needs. We focus on gasoline because it is the highest volume refinery product. These projections suggest a significant decline in the refinery capacity needed to meet gasoline market demand in 2045, specifically:

- Ignoring imports and adding export volumes static at historic volumes (an unlikely assumption) results in refinery capacity dropping 65% from 666,871 barrels per day (bpd, in 2022 including Phillips 66 Rodeo) to 232,624 bpd in 2045. **This is equivalent to one large or two smaller Bay Area refineries.**
- Ignoring imports and scaling down exports at the same rate as in-state demand, by 2045 there is a 92% reduction in required refinery capacity at 54,681 bpd. **This volume is likely too low to support any existing Bay Area refinery.**

A critical analytic uncertainty is the market-driven, dynamic nature of refined product import and export volumes, for which publicly available data is limited.

We assume refineries can respond to gasoline demand reduction in a minimum of three ways:

- **Continue to operate** – if the refinery's strengths are greater than its weaknesses and it has a competitive advantage.
- **Reinvest to produce a new product** – Convert to producing alternatives products (such as hydrogen, renewable fuels), if the opportunity is greater than the cost.
- **Shut down and address land contamination** – the least competitive refineries will be forced to close, which likely triggers regulatory requirements to address land contamination.

To understand Bay Area refinery competitive strengths and weaknesses, we explore multiple factors including select corporate financial metrics, refinery technical metrics, regulatory compliance, and land contamination status.

- **Select corporate financial metrics**. Chevron Richmond and PBF Martinez are the outliers, while the others refinery companies are similarly grouped. Chevron is financially the strongest, while PBF is comparably weaker than its peers. Chevron's financial strength also comes with heavy capital competition from vertically integrated petroleum extraction operations, while the Martinez refinery is a standout in PBF's smaller asset portfolio.
- **Refinery technical metrics** (i.e., operating factor, conversion ratio, and Nelson Complexity). Phillips 66 Rodeo is the worst overall performer followed by Valero Benicia. PBF's Martinez is likely the strongest overall refinery. Chevron Richmond has the lowest conversion capacity, which is a significant weakness for a heavy sour facility. Chevron Richmond has the highest Nelson Complexity score because it can produce base oil lubricants, diversifying products to the higher value specialty market.
- **Regulatory compliance** with the U.S. Environmental Protection Agency (EPA). Chevron Richmond had the greatest number of Clean Air Act compliance enforcement actions levied against it over the 5-years examined, while PBF Martinez had the greatest number of Clean Water Act and Resource Conservation and Recovery Act violations. Both these facilities potentially face significant future investment to achieve increasingly stringent local air quality district particulate matter emissions standards. Valero Benicia is not facing similar particulate matter investment requirements.
- **Land contamination.** Most Bay Area refineries are RCRA Corrective Action sites, meaning contamination exists, a regulatory docket of contamination characterization has been established, a public involvement process is required, and a financially viable entity is liable for certain remediation costs. The stringency of the cleanup standards, informed by public involvement, will impact remediation expenses and redevelopment opportunities. Valero's Benicia is situated in the Benicia Arsenal Superfund site, potentially complicating redevelopment pathways.

To understand possible conversion opportunities, we contextualize new market potential for refineries such as renewable diesel, hydrogen, electricity infrastructure, as well as the compliance strategy of carbon capture and storage (CCS). Regarding new products or opportunities, the following are explored:

- **Renewable Diesel** - CARB's statewide renewable diesel projections indicate demand growth through 2025, then contraction as electricity and hydrogen gain market share for fueling medium- and heavy-duty vehicles. This peak then decline in demand is consistent with the "bridge fuel" concept. When converted to theoretical renewable fuels refinery capacity needed to meet statewide demand, the capacity requirement peaks at 187 thousand bpd in 2025, then drops down to 85 thousand bpd by 2045. The planed NCNN renewable fuels facilities at Marathon Martinez (48,000 bpd) and Phillips 66 Rodeo (52,000 bpd) total 100,000 bpd of renewable fuels capacity, yielding 85,000 bpd of renewable diesel. This capacity is about enough to meet the statewide steady-state demand for renewable diesel, but not peak demand. California has historically imported significant volumes of renewable diesel from foreign origins, and many other U.S. states have invested in building renewable fuels refining capacity. *It is uncertain whether investors will devote capital towards new infrastructure to meet a temporary demand peak, and/or try to outcompete refineries with first mover advantage, or if peak volumes will be imported from domestic or foreign origins.*
- **Hydrogen** - For hydrogen, the statewide demand for all sectors is projected to reach over 2.1 million tons per year (tpy) in 2045. Data indicates the combined statewide hydrogen production potential from refineries and industrial gas companies (IGCs) serving refineries is currently around 1.69 million tpy. This production capacity is all met through natural gas-based steam methane reformation (SMR) technology, which is not low-carbon. Co-firing with biogas or installation of CCS could reduce SMR carbon emissions. However, CARB's projections do not envision a role for natural gas-based SMR in meeting California's future hydrogen demand. CARB projects all future hydrogen supply will be low-carbon, sourced from electrolysis, biomass gasification with CCS, and biogas-based SMR. Yet, the electric power and bioenergy feedstocks used to support this supply are largely assumed to be imported, raising leakage and other concerns. *While CARB does not project a role for in-state refinery SMR to produce hydrogen, there is significant uncertainty about CARB's assumptions supporting its hydrogen supply analysis.*
- **Electricity Infrastructure** – CARB's SP22 is heavily reliant on electrification of end-use technologies to achieve emissions reductions. Consequently, total electric power generation resource capacity must more than double between 2023 and 2045, representing 160 GW of new capacity. In addition, a significant build out of electric distribution and transmission systems must occur to complement these capacity additions. Electric power is projected to represent a market growth opportunity that will require significant investment and public subsidy. Although refineries are not constructed to produce power, refineries may be well suited for power generation siting given existing grid and natural gas connections, industrial zoning, proximity to load centers, and overall acreage. *It is unclear if refineries will see the electric power sector as an opportunity for conversion in the future, as product demand wanes.*
- **CCS** - CCS technology is not a driver of demand for refinery products, nor is it a new product for refineries to produce, it is a carbon emissions management strategy. The most competitive refinery(s) in the Bay Area – that remain operational in 2045 – will likely require CCS technology

to reduce facility-level emissions. CARB's projections envision CCS beginning in the refining sector in 2028, then ramping up to 60% of refinery sector emissions within 3 years. Although this 60% capture rate is held constant through 2045, overall refinery sector emissions drop significantly during this period. The result is after 2030, fewer tons of carbon are captured each year. This will reduce subsidy generation for CCS projects that rely upon the federal 45Q tax credit. *It is unclear how many CCS project will materialize in this sector, and if this ramp up then decline in CCS-captured emissions will support long-term CCS investments.*

Refineries that cannot compete or convert will be forced to close. Refinery closure is likely to trigger regulatory requirements for land remediation for which the refinery owner must fund per RCRA. Remediation costs depend on factors such as the level of contamination and the stringency of required cleanup standards. By investing in producing other products, refinery owners may have the added benefit of delaying remediation expenditures. Alternatively, selling the land for other industrial-scale operations may reduce the stringency of cleanup standards. Future commercial or residential uses of the land could be prohibited if cleanup standards restrict these uses or could place additional costs on future developers to further remediate the land for unrestricted use. Communities around refineries should explore the highest and best potential future uses of these parcels to inform regulatory discourse about cleanup standards.

Lastly, we identify examples of wild card issues – known issues with unknown probabilities of occurrence – that could meaningfully impact our analysis. These examples are categorized as:

- **Positive wild cards** – issue examples that could improve the future situation for Bay Area refineries. Examples include less stringent GHG regulation (compared to CARB's projections), pipeline conversion to directly connect the NCNN and SCSN markets or developing a robust products export market.
- **Negative wild cards** – issue examples that could make the future situation worse for Bay Area refineries. For example, more stringent GHG regulation, imposition of more stringent particulate matter controls, regulatory efforts to address market power concerns, etc.
- **Toss-up wild cards** – issue examples that could improve or make worse the future Bay Area refinery situation, depending on how they are resolved. Examples include the future of the renewable fuels markets, infrastructure constraints, approaches to emissions leakage, etc.

While there are many uncertainties, a few things are clear. For the transportation sector, limiting GHG emissions will result in decreased demand for traditional refinery products, and in turn, this will result in the reduction of refinery capacity. Since it is unclear which refineries will prevail or when the next refinery may shutter, all communities affected by refinery operations should be planning early. Planning should include, at a minimum, worker transition strategies, diversification of municipal tax base revenues, and advanced preparation and advocacy to ensure the most stringent refinery land cleanup standards are achieved. Efforts to identify the highest and best potential uses of refinery lands, for example those uses that maximize quality job creation, economic development, and environmental benefits, in alignment with community interests can guide municipal policymaking towards those end uses (e.g., ordinances). Ensuring refinery lands are remediated to standards that support unrestricted end uses will lower costs for future owner/developers, further supporting highest and best end uses.

Introduction and Scope of Work

California is a national leader in responding to the challenges posed by global climate change and is charting an ambitious path to reduce greenhouse gas (GHG) emissions. As the state further develops its climate policies, implications for fossil fuel industries grow more pronounced. Pursuant to the landmark 2006 legislation AB 32, the California Global Warming Solutions Act, the California Air Resources Board's (CARB) 2022 Draft and Final Scoping Plans identify potential pathways to achieve carbon neutrality by 2045, or sooner. In 2022, CARB also approved a requirement that all new cars sold in the state by 2035 must be zero-emission vehicles. These policies make it clear that big changes are imminent for petroleum refineries that produce products like gasoline and diesel fuels.

This report considers how California's GHG emissions reduction agenda may impact market conditions and business decision-making for the San Francisco Bay Area refineries. Using CARB's Final Scoping Plan's (November 2022) transportation energy demand projections for California, we estimate future refinery capacity needs in the Bay Area. **Our projections suggest a significant decline in the refinery capacity needed to meet market demand in 2045.** We assume refineries can respond to demand reduction for their products in a minimum of three ways: stay open, reinvest to produce a new product, or shut down and remediate refinery land. In this report we discuss the internal and external factors shaping potential refinery responses to changing market conditions, and assess challenges, opportunities, and uncertainties facing the industry.

This analysis was commissioned by the BlueGreen Alliance Foundation on behalf of the Contra Costa Refinery Transition Partnership (CCRTP), a High-Road Training Partnership funded by the California Workforce Development Board. The CCRTP is a partnership of labor and environmental justice stakeholders in Contra Costa County who aim to generate a better understanding of the effects of the energy transition on the region, and to develop shared values and strategies that can support a fair and equitable transition to clean energy.

The purpose of this analysis is to aid the CCRTP in understanding possible future transition scenarios at Bay Area refineries between now and 2050, taking into consideration industry and market trends, climate policies and regulations, changing technologies, and regional and statewide political and economic context. We ask three core questions:

- How is demand for the Bay Area's refineries' products likely to change, given California's climate strategies?
- How might Bay Area refineries respond to changing demand for their products?
- What internal and external factors could affect refineries' responses?

This analysis does not explore the strengths and weaknesses of CARB's underlying projections. Rather, CARB's projections form the basis of the analysis, which disaggregates the statewide forecasts to the Bay Area gasoline market and calculates corresponding required refinery capacity. Future refinery capacity calculations use rule-of-thumb crude-to-product conversion rates appropriate for Bay Area refineries. The resultant capacity is a theoretical number (in barrels per day of capacity) that does not necessarily correspond to levels of an operable refinery(s). A significant uncertainly in the analysis surrounds assumptions about future refined product(s) import and export volumes. Diesel volumes are not disaggregated given lack of information in CARB projections about existing and future biodiesel blend amounts, which impact heat content values critical to conversion equations. Numerous factors could impact the results of the analysis, only some examples of which are described in the Wild Cards section.

1. Background on California’s Petroleum Refining Market

This section provides readers with a general understanding of California’s petroleum refining market. It is not meant to be comprehensive or exhaustive.

A. Petroleum Administration for Defense District (PADD) 5

The Petroleum Administration for Defense District (PADD) 5 for the West Coast includes California, Arizona, Nevada, Oregon, Washington, Alaska, and Hawaii. Based on a 10-year average (2012-2021), PADD 5 was responsible for 17% of annual U.S. total gasoline (37% of U.S. reformulated, 8% conventional), 13% distillate, and 31% of jet fuel product demand [1].

PADD 5 is characterized as being isolated from other domestic petroleum processing regions, specifically from PADD 3 (Gulf Coast) where the bulk of US refining capacity is located. **Figure 1** shows refined product pipeline and marine port centers in PADD 5[2]. There is limited pipeline capacity to move refined product from other PADD regions into PADD 5. Refined product can be delivered to PADD 5 by tanker, but at a delay of 10 days from the U.S. Gulf Coast, 3 weeks from Asia, and 4 weeks from Europe[2].

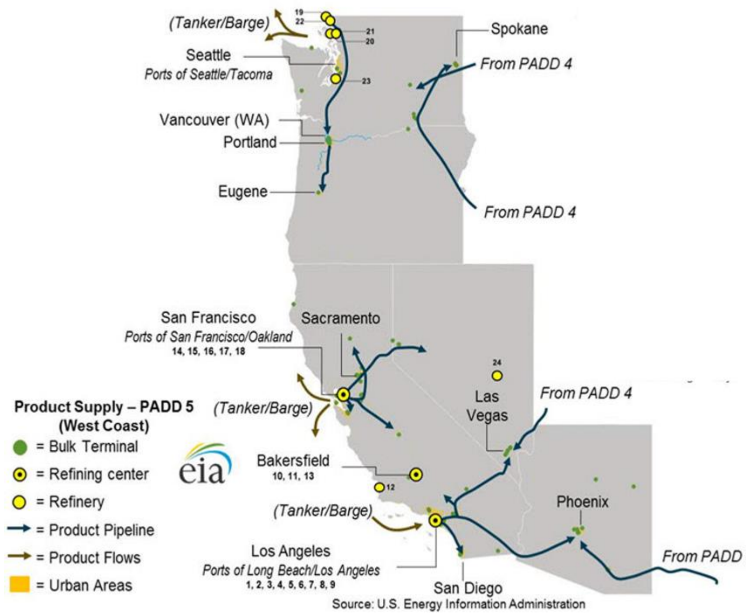

Figure 1 - Petroleum Administration Defense District 5 [2]

B. Crude Oil Supply Trends

California refineries were built to process California crude oil that is heavy (dense) and sour (high-sulfur content), making it more complex to refine. In-state crude production peaked in 1985 at 424 million barrels and has declined at an average rate of 5.6% per year since [3][4]. As a result, California refineries have been forced to rely on greater proportions of marine-delivered crude from foreign sources, namely Saudi Arabia, Ecuador, Iraq, Columbia, Brazil, and other foreign origins[5]. In 2021, 56.2% of crude processed by California refineries was sourced from foreign destinations, 28.9% from California and 14.9% from Alaska[6]. The supply shift from domestic to foreign sources is visible throughout PADD 5, with refineries increasingly reliant on marine-borne crude deliveries and comparatively less reliant on pipeline crude deliveries. As shown in **Figure 2**, marine delivery of foreign crude to PADD 5 surpassed pipeline deliveries of domestic crude around 2004 [7].

Due to logistics isolation, and because California refineries are built to process heavy sour crudes, these refineries have not directly benefitted from the increased production of domestic light sweet crude (e.g., Permian and Bakken basins).

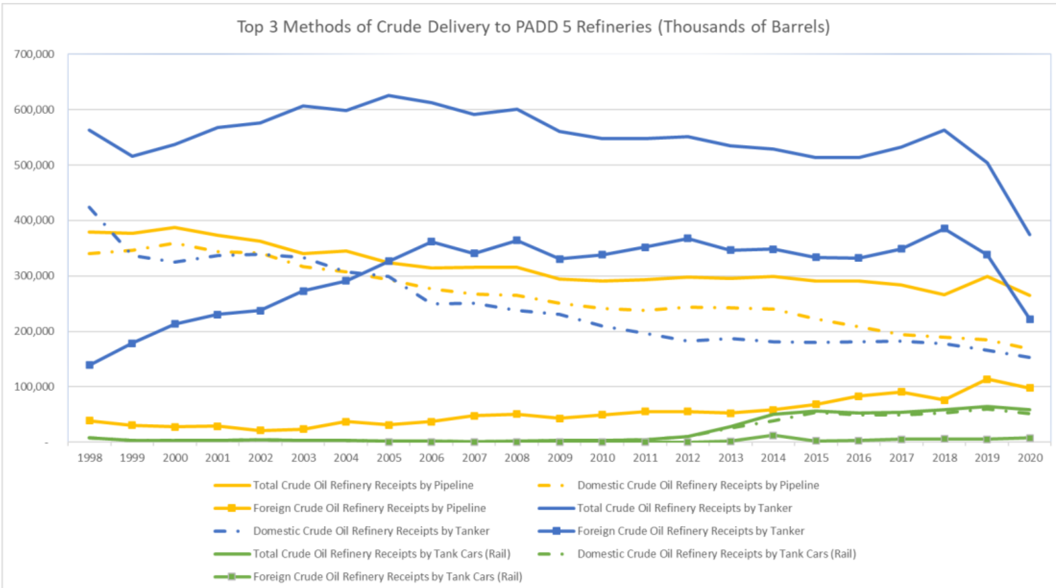

Figure 2 - Top Three Methods of Crude Oil Delivery to PADD 5 by Destination and Delivery Type. The decline in deliveries in 2019 and 2020 was related to the COVID-19 pandemic [7].

C. Northern California Northern Nevada (NCNN) Sub-Region

PADD 5 contains six discrete refined product regional markets including Southern California and Southern Nevada (SCSN), Northern California and Northern Nevada (NCNN), Pacific Northwest (Washington and Oregon), Arizona, Hawaii, and Alaska[2]. The San Francisco Bay Area refineries sell product into the NCNN market. As shown in **Figure 3**, California has two major refining centers, one in the San Francisco Bay Area serving the NCNN market (light blue), and another in the Los Angeles area serving the SCSN market (light yellow) [8]. Refined product demand and refinery production is generally over 20% greater in southern California compared to northern California[9].

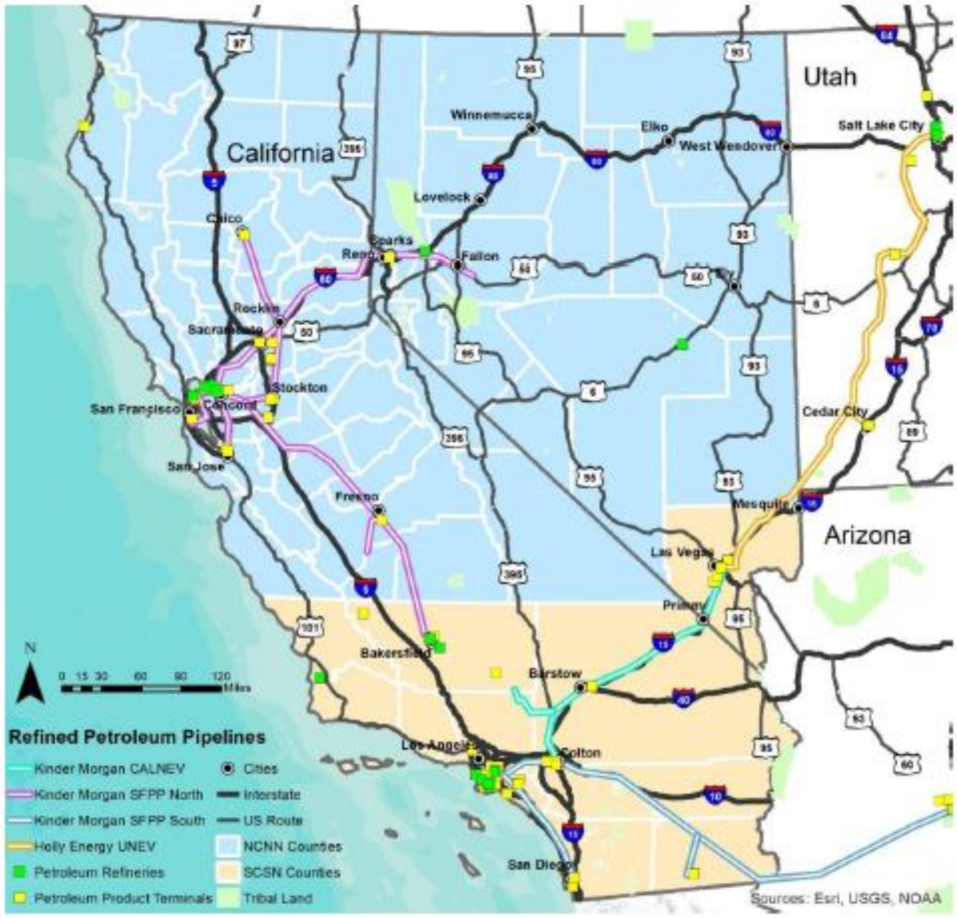

Figure 3 - California Refined Petroleum Product Market and Pipelines [8]

Kinder Morgan operates most of the refined product pipelines in the state. The Santa Fe Pacific Pipeline (SFPP) north transports refined product from the NCNN refineries while the SFPP South line moves product through southern California and into Arizona, as well as connections to the CALNEV line into Las Vegas. Currently, there is no direct connection between the northern and southern SFPP lines, therefore products must move between these markets by marine vessels, when needed. California has about 44 million gallons of refined product in the Kinder Morgan system on an average day, with over 55 percent of those volumes being in the SFPP south system[10].

The SFPP northern region map is shown in **Figure 4**[11]. Each individual pipeline can ship multiple different products by rotating in "batches". In simple terms, this means one product is shipped for a few hours before switching to a new product and shipping that product for a few hours, etc. The SFPP north lines collect product from refineries through gathering lines connected mostly to the Concord and Richmond pumping stations (stars). The Bay Area Lines (red) originate at the Richmond and Amorco stations with south and westward destinations including but not limited to the Richmond Marine and Storage Terminal (gasoline, diesel), Brisbane (gasoline, diesel, jet fuel), Oakland Airport (jet fuel) and San Francisco Airport (jet fuel)[11]. The North Line (purple) originates at the Richmond and Concord stations, with multiple northern destinations including but not limited to west capitol junction to the Sacramento Airport (jet fuel), West Sacramento (gasoline, diesel), Roseville (diesel), Chico (gasoline, diesel) and Reno (gasoline, diesel, jet fuel)[11]. This line also supplies product to the Travis Air Force Base. The Bradshaw Line (orange) connects from Richmond to Concord, then heads west to Stockton (gasoline, diesel), then north to Bradshaw (gasoline, diesel, jet fuel). The Fresno Line (yellow) extends from Richmond to Concord then west to Fresno (gasoline, diesel). The San Jose Line (green) connects from Richmond to Concord south to San Jose (gasoline, diesel) with connecting line to the San Jose airport (jet fuel)[11].

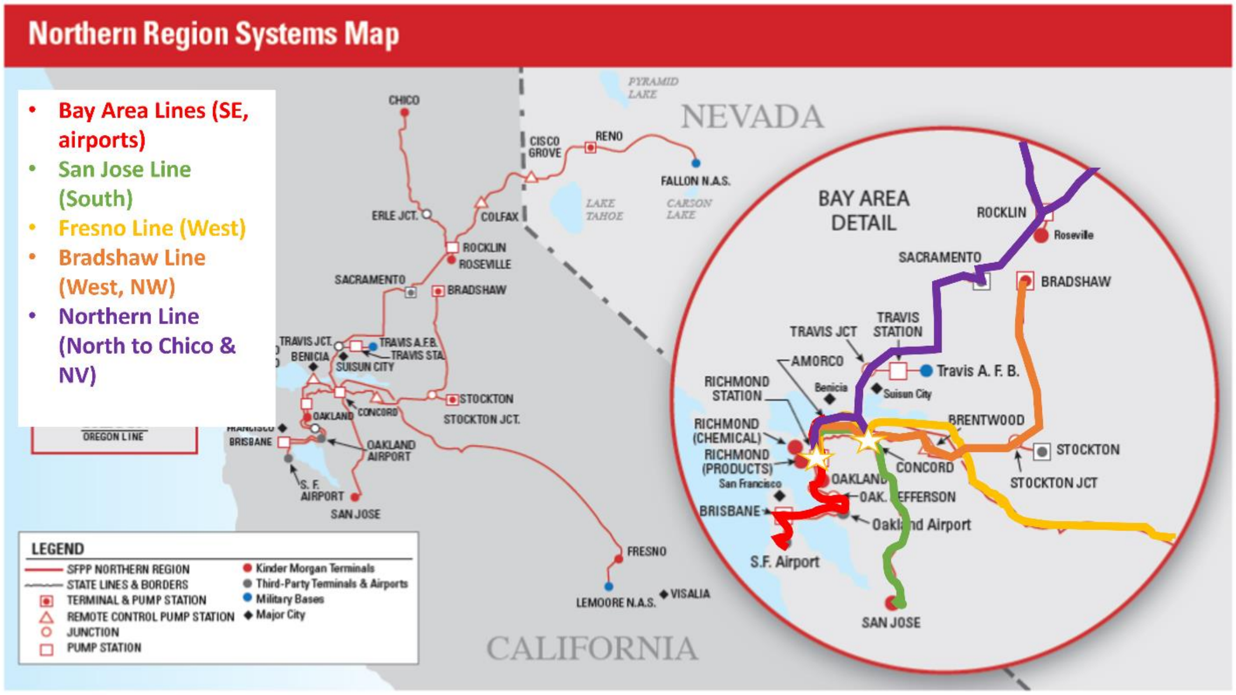

Figure 4 - Kinder Morgan SFPP Northern Pipeline System [11]

D. NCNN Refineries

In general terms, the northern California refineries in the Bay Area have many similarities. They are all considered “complex,” meaning special equipment has been incorporated to enable processing lower quality medium-to-heavy grade crudes into refined product. They have their own marine terminals connected to the refinery or access to a third party owned marine terminals to receive crude and send out products[3]. They are all equipped to produce fuels that meet stringent environmental standards set by the California Air Resources Board,[1] and are all subject to compliance with other California state-specific environmental programs. These refineries are all owned by publicly traded companies on the Fortune 500 list. While there are many general similarities, there are also many differences between these refineries. This sub-section provides a brief introduction to the five northern California refineries examined in the analysis.

[1] The California Air Resources Board (CARB) set stringent pollution control standards for gasoline and diesel fuels sold in California. These fuels are referred to as California reformulated gasoline (CaRFG or CARB gasoline) and CARB diesel. More information about these specifications can be found on the CARB website at https://ww2.arb.ca.gov/our-work/topics/fuels

i. Chevron Richmond Refinery

Chevron's (NYSE: CVX) Richmond refinery is located on approximately 2,900 acres of land in the City of Richmond and has 245,271 barrels per day (bpd) of crude capacity. Chevron maintains the it is the City's largest employer[12]. The company states the refinery supplies 60% of the jet fuel for the Bay Area airports, 20% of gasoline in Northern California, and 100% of paraffinic base oils on the West Coast[12]. The Richmond refinery originally began operations in 1902 under Pacific Coast Oil, prior to being acquired by Standard Oil in 1906, and then an earlier iteration of Chevron Corporation in 1977[3].

ii. PBF Energy's Martinez Refinery

The Martinez refinery (Martinez Refining Company, LLC) is a 156,400-bpd crude capacity facility owned by PBF Energy Inc (NYSE: PBF). PBF purchased the refinery from Equilon Enterprises (doing business as Shell Oil Products) around February 2020 for $960 million, plus other contributions including a crude oil supply and refined product offtake agreements with Shell [13]. The deal also included logistics assets such as a deep-water marine terminal, product distribution terminals, and 8.8 million barrels of storage shell capacity for crude and refined products[13]. The refinery is located on an 860-acre site in the City of Martinez that is situated approximate 30-miles northeast of San Francisco. At the time of the acquisition's closing, PBF and Shell agreed to assess the feasibility of using idled equipment at the refinery to build a renewable diesel project[13]. New Jersey based PBF Energy owns and operates both refining and logistics assets in the U.S., Canada, and Mexico. The Martinez refinery originally began operations in 1915 and has been owned by various iterations of Shell Oil Company for the majority of its lifetime[3].

iii. Valero Benicia Refinery

Valero's (NYSE: VLO) Benicia refinery was established in 1968 by Exxon and currently maintains 145,000 bpd of crude capacity [3][14]. Valero acquired the refinery in 2000, which located on 425 acres (with 475 acres of buffer zone) of land in the City of Benicia on the Carquinez Strait [15]. The refinery sits on over 400 acres of land that used to house munitions storage igloos on within the larger (2,728 acres) land plot that was once the U.S. Army's Benicia Arsenal[16].

iv. Phillips 66 Rodeo Refinery (scheduled to close and convert to renewable fuels)

The Rodeo refinery is located on 1,100 acres of land in Rodeo, in unincorporated Contra Costa County, and maintains approximately 120,200 bpd of crude capacity. The facility was originally built in 1896 by the Union Oil Company of California/Unocal, that later sold the refinery to Tosco Corp, an early predecessor of the current owner, Phillips 66 (NYSE: PSX). The Rodeo refinery is linked to Phillips's Santa Maria refinery in Arroyo Grande by a 200-mile pipeline. The main products of the refinery are gasoline, diesel, aviation fuel, pet coke, and sulfur. In August 2020, Phillips announced it would be converting the Rodeo refinery into one of the largest renewable biodiesel plants in the world (800 million gallons per year of renewable fuel), called "Rodeo Renewed"[17]. If approved by Contra Costa County and the Bay Area Air Quality District, this project could begin production in 2024[17]. The project would abandon crude processing and transport at Rodeo, and would also result in abandoning the Santa Maria facility and associated pipelines starting in 2023[17].

v. Marathon Martinez Refinery (idled, converting to renewable fuels)

The Marathon Martinez Refinery (previously referred to as the Tesoro Golden Eagle, Tosco Avon, and Philips Avon refinery) is in unincorporated Contra Costa County in the small area of Avon, east of Martinez and directly north of the City of Concord. It was originally built in 1913 by the Associated Oil Company. In 2018, Marathon (NYSE: MRO) acquired the refinery's former owner, independent refiner Tesoro (known for a short time as Andeavor) and became the owner of the refinery that is located on 2,200 acres of land and had 166,000 bpd of crude capacity. In August 2020, after two weeks of idling the facility in response to weak gasoline demand from the COVID pandemic, Marathon announced it would permanently close the refinery[18]. Marathon planned to use the facility to store oil, while evaluating conversion to a renewable diesel refinery. In March 2021, Marathon announced its Board of Directors approved plans to convert the refinery to a renewable fuels manufacturing facility with full capacity of 730 million gallons per year to be reached by 2023[19].

E. Refinery Offtake/Gathering Lines

These refineries feed product into the Kinder Morgan products delivery pipeline system through a system of gathering pipelines connecting to the Richmond, Concord, and Amorco pumping stations, shown schematically in **Figure 5** [11]. In general, a refinery with access to multiple offtake systems is better positioned than a refinery with only one option. The currently idled "Marathon" [Martinez] refinery stands out because its only connection is through the Concord station. All the remaining refineries have connections to both the Richmond (via Amorco) and Concord stations. The Kinder Morgan refined products pipelines do not allow for E10 (90% base gasoline, 10% ethanol) to be transported through its system, so ethanol is blended with piped base gasoline at distribution terminals.

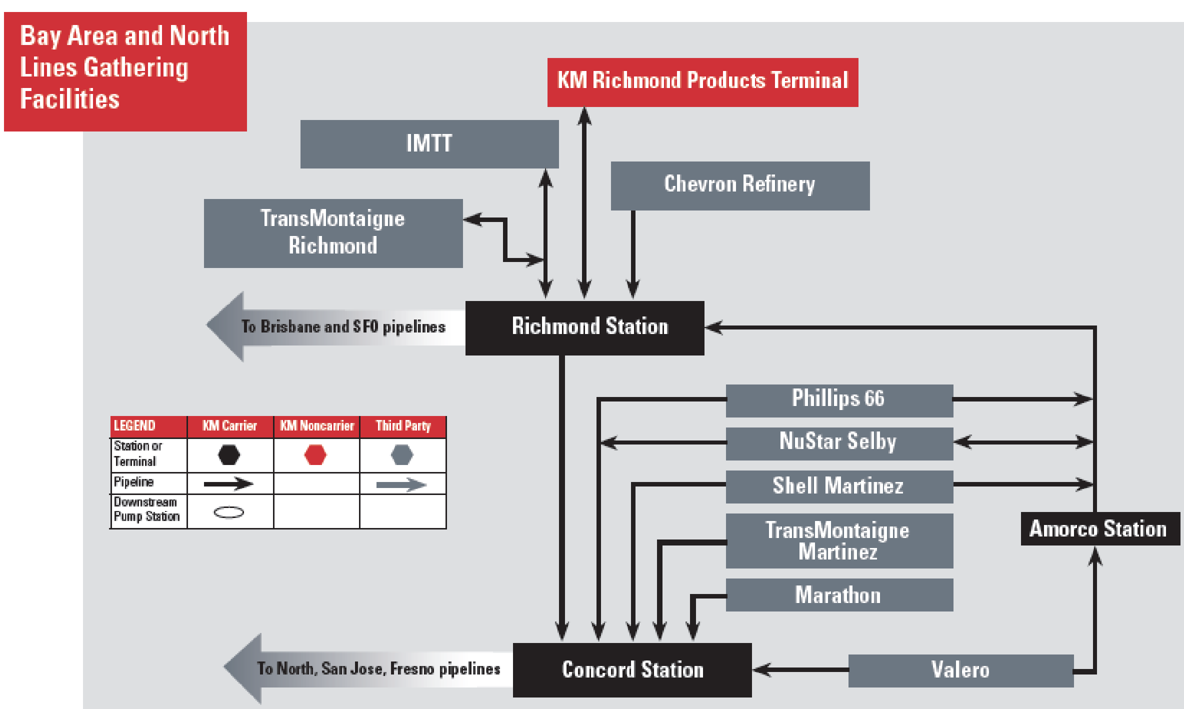

Figure 5 - Kinder Morgan Gathering Line System for Northern and Bay Area Lines [11]

F. NCNN Refinery Products

The transportation fuels output for these northern California refineries is shown in **Figure 6**, which illustrates the main outputs are CARB reformulated gasoline, CARB diesel, and jet fuel[9]. Over the period shown, average output was 52% CARB gasoline, 17% CARB diesel, 14% jet fuel, 7% non-CARB gasoline,[2] 5% other diesel, and 5% residual. A refinery's product slate can be incrementally adjusted, usually in response to market signals. For example, if diesel fuel price and demand are high, the refinery may adjust output to produce slightly more diesel. However, there are technical and economic limits to the adjustments that can be made. The CEC suggests that on average, the most applicable crack fraction to use for California refineries is the "6-3-2-1", which means 6 barrels of crude oil input will yield 3 barrels of gasoline (50%), 2 barrels of diesel (33%) and 1 barrel of jet fuel (17%)[20]. Given the output data above, it seems northern California refineries have historically optimized for CARB gasoline production.

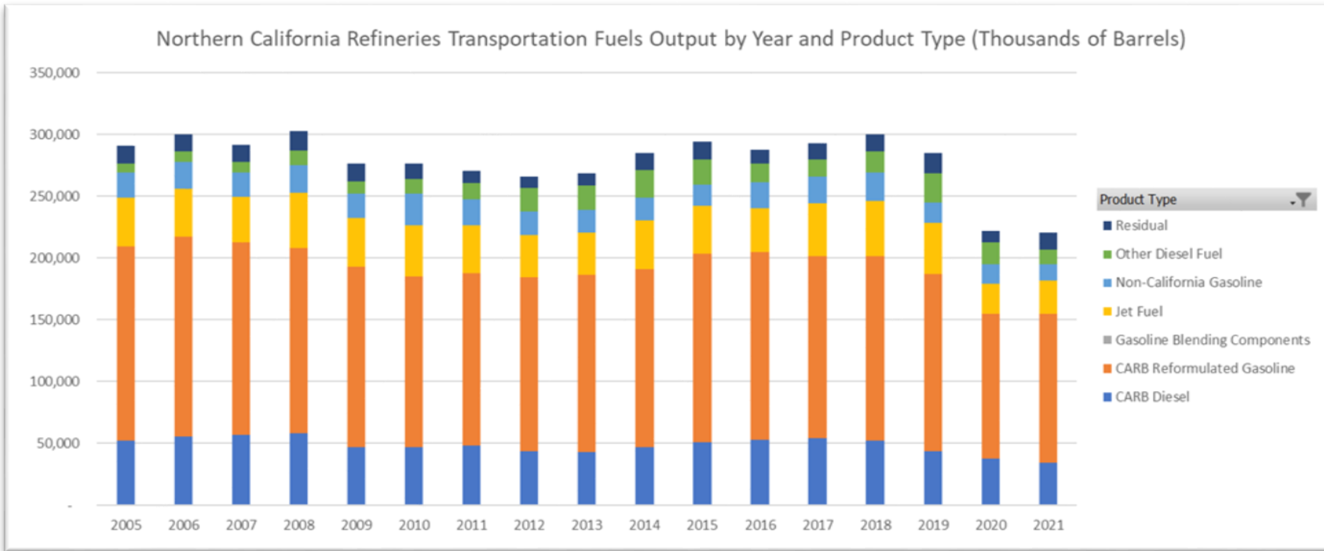

Figure 6 - Northern California Refineries Transportation Fuel Output by Year and Product Type (thousands of barrels) [9]

G. Refined Product Imports and Exports

There is limited publicly available data on export and import volumes in the NCNN. Much of the available data is older and doesn't reflect volume changes associated with the closure of the Marathon Martinez refinery. Import and export volumes can be impacted by shocks such as temporary supply disruptions and price spikes, and long-term factors such as refinery closures. This section describes what is known about import and export volumes based on historic, publicly available data. It is unlikely these data reflect the current situation.

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[2] According to the CEC, non-CARB gasoline is all other types of gasoline exported via pipeline to Nevada, or exported via marine tanker to Oregon, Washington, and other foreign destinations. This gasoline will meet the specifications of the destination states and countries. https://www.energy.ca.gov/data-reports/reports/weekly-fuels-watch/refinery-inputs-and-production accessed October 13, 2022

Historically (i.e., prior to the closure of Marathon Martinez), the NCNN refineries outputted more product (e.g., 112% in-region production compared to in-region demand) than was demanded by the sub-region[2]. Pipeline shipments of gasoline leaving Northern California for Northern Nevada averaged 500,000 barrels per month (bpm) between 2007-2016[3]. Beyond NCNN pipeline access to products markets, California refineries relied heavily on marine based exports to reach demand centers. The largest export destination for gasoline (and blendstocks) was the SCSN, with an average of 1.16 million (bpm) moved by marine tanker between 2007-2016[3]. Gasoline exports to other U.S. ports (e.g., Washington, Oregon) have been declining from an average of 955,000 bpm over the 2007-2011 period down to an average of 301,000 bpm from 2012-2016[3]. As gasoline exports to domestic locations have trended down, exports from Northern California to foreign destinations have trended up. Foreign exports averaged 502,000 bpm from 2007-2011, increasing to an average of 802,000 bpm between 2012-2016[3]. Between 2007-2016, the NCNN is also net diesel exporter moving an average of 1.89 million bpm of diesel out of the area with 1.16 million bpm exported by marine vessel to foreign sources, 468,000 bpm piped to northern Nevada, and the remainder being moved by marine vessel to other the SCSN or other domestic ports (e.g. Oregon, Washington)[3].

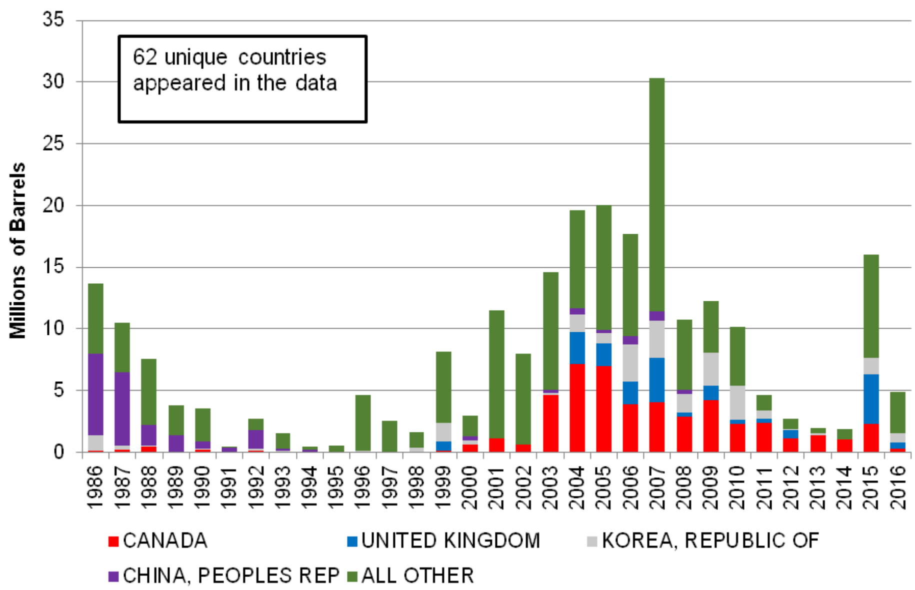

Figure 7 - Annual Imported Gasoline and Gasoline Blendstocks Volumes into California, by Country [3]

Driven by increases in pricing differentials relative to international benchmark prices (e.g., New York Harbor), California importers[3] have sourced gasoline (and gasoline blendstocks) supplies from over 62 foreign countries since 1986 [3]. As shown in **Figure 7**, prior to 2000 most gasoline-related imports into California originated from China, whereas after 2000 most imports came from Canada, the United Kingdom, and South Korea[3]. Since the phaseout of methyl tert-butyl ether (MTBE) in 2003, the bulk of these import volumes were gasoline blendstocks into the Southern California and Northern California, as well as finished gasoline into Southern California. Historically, imports into the NCNN have been less than exports out of the NCNN. Very small volumes of gasoline from foreign sources or the SCSN have historically been imported into Northern California, whereas most imported gasoline into this area is domestic supply from Washington[3]. Average import volumes of gasoline (and blendstock) imports into

[3] Importers include over 55 companies since 1986, including California refineries and nonvertically integrated import companies (e.g., Vitol) that sell product on the spot market or to refineries[3].

the NCNN from 2007-2016 where not provided. However, in 2016, imported gasoline volumes into the NCNN was 760,000 bpm[3].

Between 1986-2016, foreign imports of diesel (mostly from Japan and Canada) into California decreased dramatically, while foreign imports of renewable diesel (mostly from Singapore) and to a lesser extent biodiesel (from Canada and South Korea) have increased significantly[3]. While volume import data for renewable diesel is not available for the NCNN, it should be noted the vast majority of foreign diesel barrels imported into California from 2013-2016 were renewable diesel[3]. Northern California imports very small amounts of diesel products, averaging 278,000 bpm (2007-2016)[3]. There is significant opportunity to identify better data resources for gasoline and diesel import volumes into the NCNN.

The data referenced in the previous paragraphs were prior to the 2020 closure of Marathon Martinez, and this capacity reduction has the potential to impact long-term trends in import and export volumes. Limited data is available on imports and export volumes post-closure of Marathon Martinez. As shown in **Figure 8**, after the Marathon Martinez refinery closure in April 2020, marine-based gasoline exports declined, while marine-based imports of gasoline increased (mainly from Southern California and the Pacific Northwest)[21]. These shifts, which were similar for diesel as well, were enabled in part by reduced demand post-covid and available supply[21]. Data was not available to determine if these trends have continued in the intervening months and years.

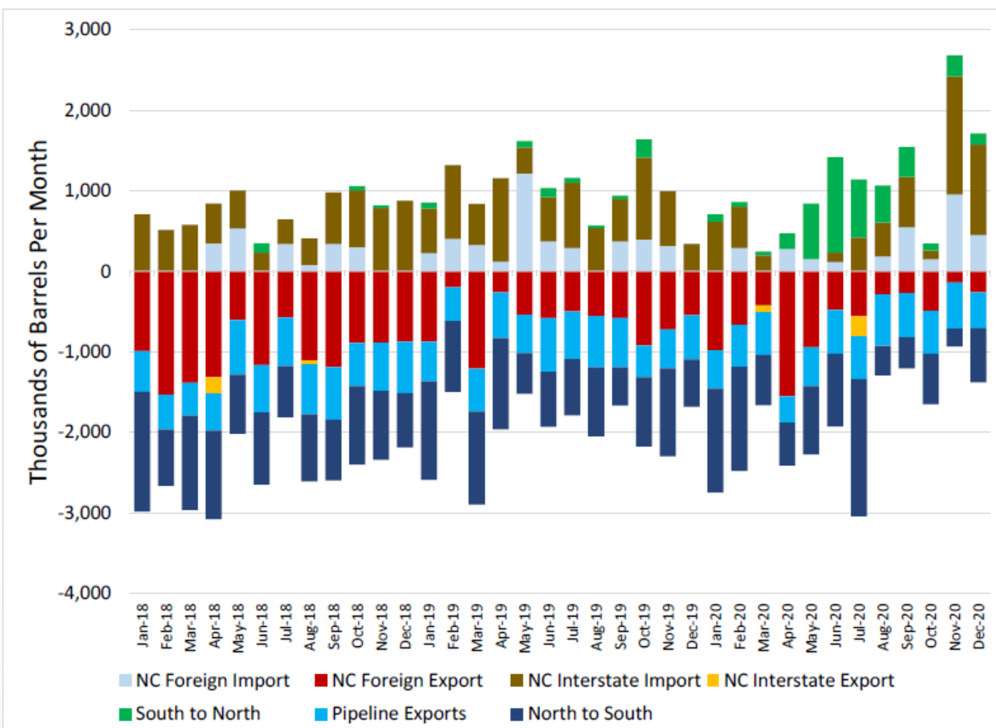

Figure 8 - Gasoline Flows in Northern California After Marathon Martinez Closure (positive values are imports, negative values are exports) [21]

Refinery closures will impact long-term import/export volume trends, while supply disruptions will cause short-term fluctuations. Supply disruptions (e.g., refinery outages) cause supply shortages and related price spikes. Supply disruptions also impact the normal flow of product, as marine terminal capacity must shift to accommodate increased product imports. For example, although gasoline typically moves from NCNN to SCSN, marine transfers of gasoline and blendstocks from SCSN to NCNN temporarily increased to 2.3 million barrels over a four month period after the Marathon Martinez outage in 2015[3]. Marine vessel imports from foreign and domestic sources take several days to weeks to arrive (e.g., 13-21 days from Asia, 13-15 days from North Canada, 19-21 days from NW Europe), exacerbating economic impacts[3].

It should be noted that refineries in the Gulf Coast region have been more competitive at serving export markets compared to all other PADD regions. Between 2010 and 2019, PADD 3 (Gulf) exports of finished petroleum products increased by 73%, followed by a 35% increase from PADD 5, 15% increase from PADD 2 (Midwest), -9% (a decrease) from PADD 1 (East Coast), and -59% from PADD 4 (Rocky Mountain)[22]. On a volume basis, the primary exports from PADD 5 have typically been petroleum coke and distillate, while the primary exports from PADD 3 have been distillate and gasoline[22].

2. CARB Projections of Future Refined Product Demand

The California Air Resources Board (CARB's) 2017 Final Scoping Plan [23] identified pathways to achieving 40% greenhouse gas (GHG) emissions reductions (from 1990 levels) by 2030, as required by the state's global warming law, AB 32. [4] Conversely, CARB's Final 2022 Scoping Plan (2022 Scoping Plan or SP22) builds upon the 2017 Scoping Plan by identifying potential pathways to carbon neutrality by 2045 or earlier, which currently is a *non-enforceable goal*. However, the Final SP22 does account for legislation, regulations, and executive orders passed after the 2017 Final Scoping Plan. CARB's Draft SP22 and Final SP22 documents dated May 10, 2022 and November 14, 2022 (respectively)[24][25], Draft and Final modeling Appendix H [26][27], and Draft SP22 greenhouse gas emissions projections inform this analysis[28]. CARB's Final SP22 greenhouse gas emissions projection data are used as the basis to estimate NCNN refinery product demand projections[29]. CARB's May Draft SP22 included a reference scenario projection and 4 alternative scenario projections that ranged in stringency, methods, and timing of economy-wide carbon reductions. CARB's November Final 22SP focused on the CARB staff-recommended scenario or Alternative #3. Information on the various scenarios considered by CARB in the Draft 22SP are included in **Appendix A**.

The staff-recommended scenario was chosen by CARB staff because this scenario a) most closely aligns with the existing statute and executive orders, b) is more feasible that the other scenarios because it provides more time for clean technology and fuel deployment, and c) best balances cost-effectiveness, health benefits and technology feasibility[24]. This scenario incorporates existing rules, and many newly established or in-process rules related to carbon reductions. For example, this scenario models the following actions under the authority of SB 32/AB 197/AB 32, including but not limited to[24][25]:

- **Statewide GHG target** of 40% below 1990, by 2030
- 100% **zero emissions vehicle (ZEV) light duty sales** by 2035 (EO N-79-20)
- 100% **medium- and heavy-duty vehicle (MDV/HDV) ZEV sales** by 2045 (EO N-79-20)
- 10% of **aviation fuel** demand met by batteries or H_2 fuel cells in 2045
- Phase out **oil and gas extraction** operations by 2045
- CCS on majority of **refinery operations** by 2030
- **Low carbon fuel standard (LCFS)** for transportation

[4] More information on California's AB 32 can be found on CARB's website at https://ww2.arb.ca.gov/resources/fact-sheets/ab-32-global-warming-solutions-act-2006 (accessed August 1, 2022)

- GHG **power sector** (retail sales) target of 30 million metric tons of CO2 equivalent (MMTCO2e) by 2045 (SB 350/SB 100)
- 25% of **ocean-going vessels** using H_2 by 2045
- 100% of **passenger locomotive sales** ZEV by 2030

The purpose of this analysis is not to debate the accuracy, merits or drawbacks of the CARB data, the various scenarios considered, or associated projections. Rather, the goal is to extrapolate how the regulatory agency's final scenario projections could impact Bay Area refineries.

A. Key CARB Assumptions

The following data is reviewed to understand how CARB arrived at its conclusions in the final 22SP[25]. As shown in the top of **Figure 9**, CARB projects 100% of new light duty vehicle (LDV) sales in 2035 are zero emissions vehicles (ZEV), led primarily by all-electric battery electric (BEV) at 90%, hydrogen fuel cell vehicles at 3%, and 40-mile electric range plug-in hybrid electric vehicles (PHEV40) at about 7.5% of all new LDV sales[29]. This results in the population (stocks) of LDV's on the road to change over time (bottom of **Figure 9**).

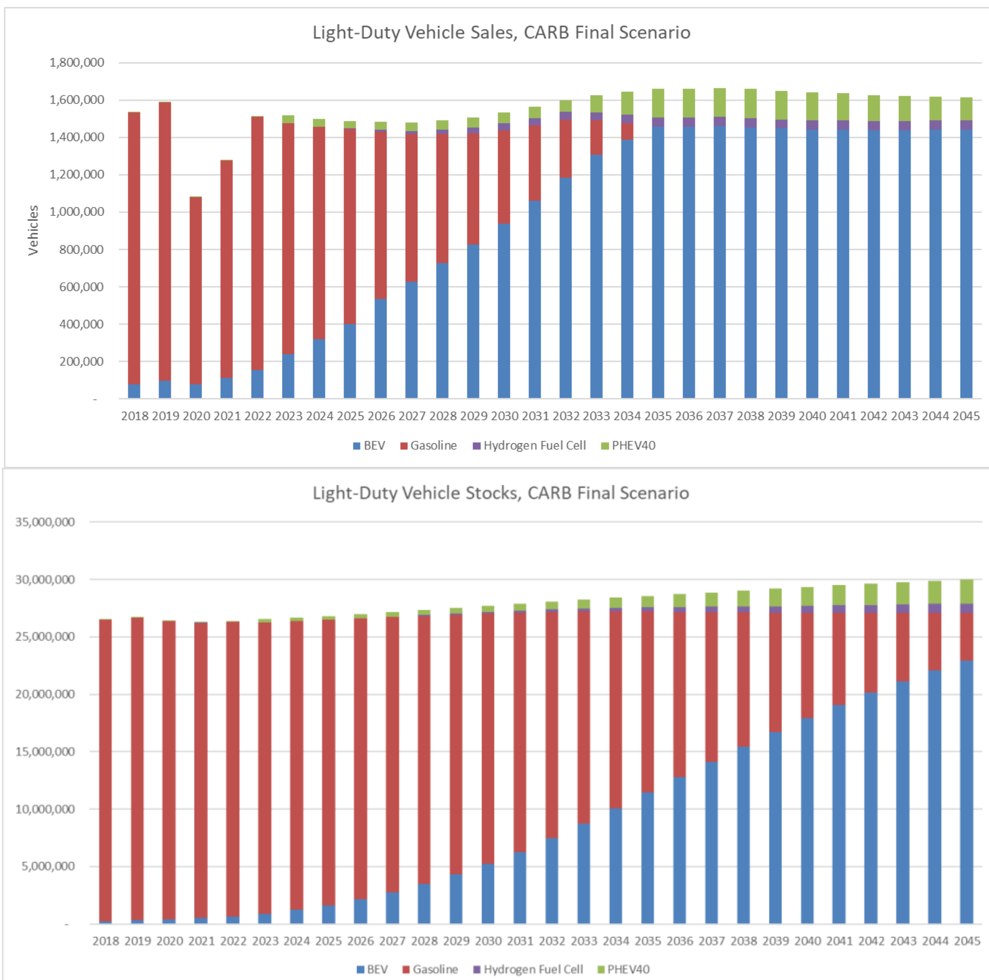

Figure 9 – Projected Light Duty Vehicle New Sales (top) and Stocks (bottom) [29]

By 2045, CARB predicts 76% of LDVs on the road (stocks) will be BEVs, 14% will be gasoline, 7% will be PHEV40, and 3% hydrogen fuel cell. For medium duty vehicles (MDVs) like delivery vans, box trucks, firetrucks, etc., the current fuel of choice is diesel and gasoline. As shown on the top of **Figure 10**, by 2045, 62% of the MDV population will be all-electric BEVs, 15% hydrogen fuel cell, 12% diesel, and 11% gasoline. For heavy-duty vehicles (HDVs) like long-haul tractor-trailers, cement mixers, and garbage trucks, diesel is by far the dominant fuel type. The bottom of **Figure 10** shows that by 2045, hydrogen becomes the dominant fuel (45%) for HDVs on the road, followed by BEVs (27%), diesel (27%) and compressed natural gas (1%).

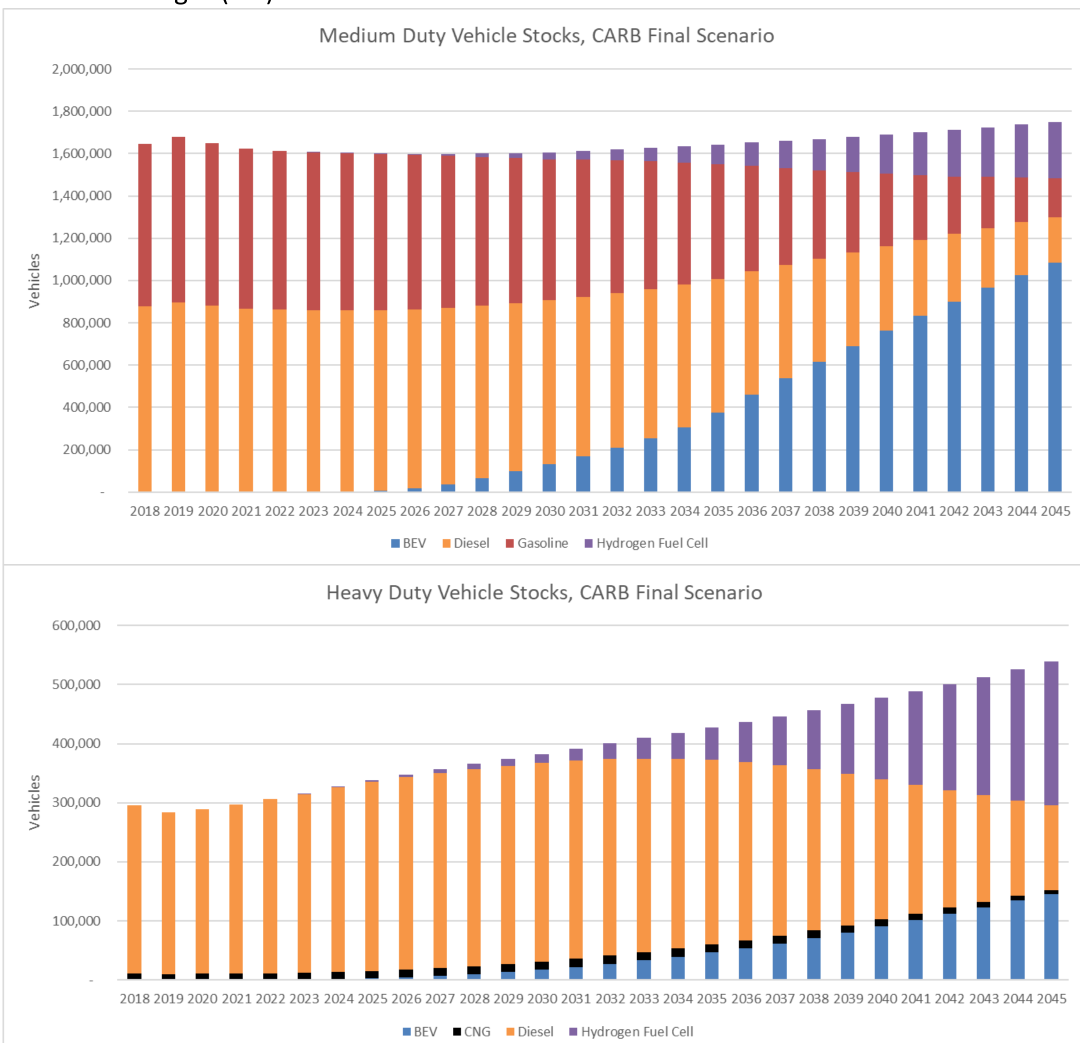

Figure 10 - Projected Medium-Duty Vehicle Stocks (top) and Heavy-Duty Vehicle Stocks (bottom) [29]

These adjustments to the predominant technology of the vehicle populations and fuels result in significant changes to the transportation fuel use and fuel mix, as shown in **Figure 11**. Most notably, in 2045 there is 64% reduction in overall transportation energy compared to 2018 levels. This is likely due to the improved conversion efficiency of electric vehicles. Specifically, electric vehicles convert 85% of electric energy to mechanical energy, while internal combustion vehicles convert only about 40% of fuel energy to mechanical energy. To a lesser extent, this reduction could be due to a 29% reduction in average vehicle miles travelled (VMT) for LDVs by 2045 (from 2015 levels), which may be partially offset by a 78% increase in HDV VMT and a 15% increase in MDV VMT[29]. Another notable change is the reduced role of E10 gasoline in 2045. By 2045, electricity is the dominant fuel (42%), followed by hydrogen (22%), renewable diesel (16%), E10 gasoline (13%), and renewable jet fuel (6.5%). The switch from gasoline to electricity and hydrogen also means the location of emissions reductions are pushed from downstream (i.e., the vehicle tailpipe) to upstream (the generator of power, or hydrogen producer). Another important observation is the reduction and eventual disappearance of conventional jet fuel, and its replacement with renewable jet fuel.

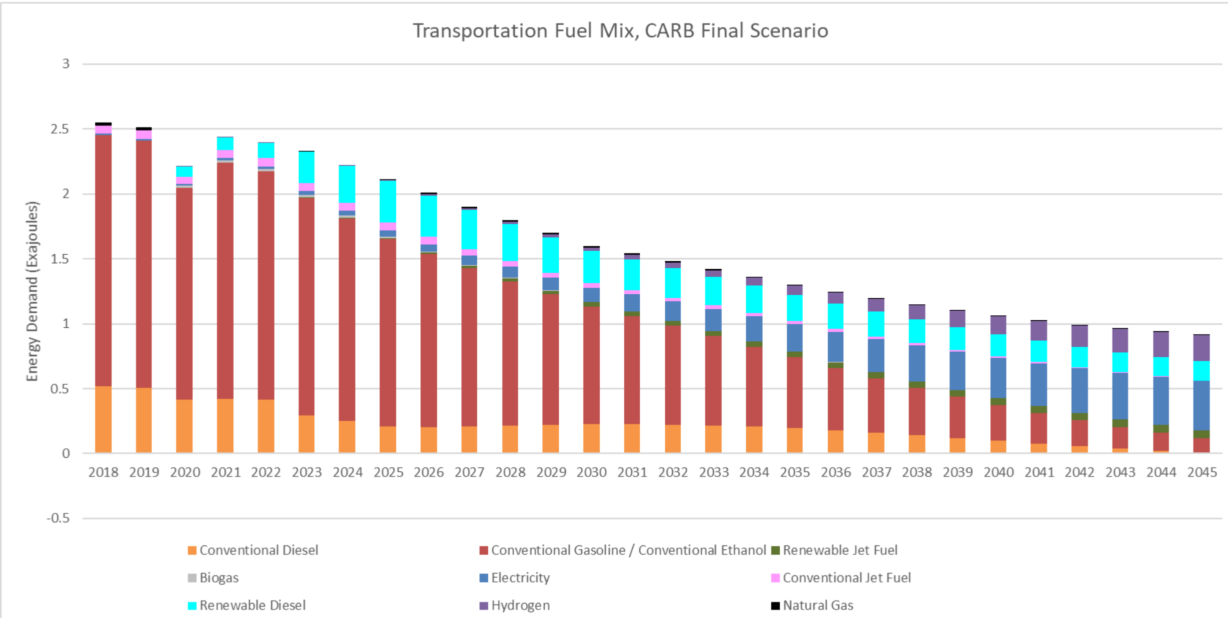

Figure 11 - Transportation Fuel Mix in Exajoules (EJ) Associated with the CARB Final Scenario [29]

Clearly, CARB envisions a future where demand for products traditionally made by petroleum refineries is severely reduced. These data in **Figure 11** are presented on a statewide basis and are not separated by northern and southern products markets. CARB only considers in-state consumption of transportation fuels and therefore excludes product exports. For the refinery sector, CARB calculates statewide refinery energy use and emissions impacts, but reductions are averaged across refineries rather than incorporating refinery closures. This is infeasible for technical and economic reasons, as refineries must maintain a certain level of utilization or throughput to remain operational. *Therefore, as demand drops, some refineries will no longer remain viable in their current form.*

B. Projection Disaggregation Methodology and Results

This section describes the methods used to translate the CARB projections into data more useful for understanding potential impacts on the Bay Area refineries. The approach disaggregates the CARB Final SP22 statewide energy consumption projection data to the NCNN market, focusing on gasoline and diesel because they are the two highest volume refinery products. The analysis begins by taking transportation "energy demand" data in exajoules (EJ) from the CARB Final SP22 modelling data spreadsheet[29]. CARB's analysis only incorporates in-state fuels consumption, therefore additional data is incorporated to estimate refinery demand associated with product exports. Imports are not factored into the analysis, given the lack of historic average data for the NCNN. Inability to consider imports will make demand look incrementally greater for NCNN refinery products.

i. Gasoline Methodology and Results

Gasoline demand disaggregation begins by converting exajoules of CARB Final SP22 "conventional gasoline/conventional ethanol" projections into gallons. California hit the ethanol blend wall between

2011-2013, therefore every gallon of gasoline includes 10% ethanol, yielding the E10 blend[30]. CARB data (E10 in EJ) were converted to gallons of E10 using 2019 U.S. EIA data for the heat content (5.052 million btu per barrel, or Mbtu) of E10 [31] and **Equation 1**.

$$\mathrm{TotalE10(gallons)} = \frac{\left(\mathrm{E10\ (EJ)} * \frac{1e^{18}\mathrm{(joules)}}{\mathrm{EJ}}\right)}{\left(\frac{\frac{5.052\ \mathrm{(Mbtu)}}{\mathrm{E10\ (barrel)}} * \frac{1000000\ \mathrm{(btu)}}{\mathrm{Mbtu}}}{\frac{\mathrm{barrel}}{42\ \mathrm{(gallons)}}}\right) * \left(\frac{1055.06\ \mathrm{(joules)}}{\mathrm{btu}}\right)} \quad \text{Eq. 1}$$

The resultant E10 gallons data were cross-referenced with motor vehicle fuel taxable gallons sales data from the California Department of Tax and Fee Administration (CDTFA) for the overlapping years (2018 – 2021)[32]. The annual gallons from **Equation 1** ranged from 3.52% (above) to -1.59% (below) the CDTFA reported gallons. This discrepancy could be due to the inclusion of aviation gasoline in the CDTFA volumes, heat rate conversion factor used, netting of various CDTFA refunds, or other factors. We deem these deviations acceptable and move forward with the analysis.

The statewide gallons of E10 gasoline were disaggregated to the county-level using 2020 annual retail fuel outlet report results data published by the CEC [33]. In-state sales data was an appropriate metric to apply to CARB's projections of in-state consumption. County-level E10 gasoline sales in gallons were averaged over a 10-year period (2010-2019). The ten-year average sales volumes were used to calculate county-level percentages of total California E10 sales. These county-level percent of total state sales values were applied to the E10 gasoline gallons projected annual totals. Then, these volumes were split into 10% pure ethanol gallons and 90% pure gasoline gallons. This is appropriate since California refineries do not produce or distribute ethanol in the pipelines serving the north and south markets. Rather, ethanol is typically blended at trucking racks before distribution to retail stations. Once pure gasoline gallons were apportioned to the county level, the counties could be grouped into those within the NCNN market and those within the SCSN market.

For each future projected year, the county-level percent-of-total statewide gasoline sales values are held constant, while total statewide California gasoline demand changes year-to-year. This simplifying assumption ignores geographic changes in gasoline demand that could occur based on income levels, electric vehicle penetration, vehicle stock turn over, and other factors. For example, counties closer to the coast and with higher incomes may see greater adoption of BEVs compared to counties that are inland and with lower-income populations [34].

Added to the sum of the California-Only, NCNN county demand ("Northern CA Total") are gasoline volumes associated with:

- pipeline exports to Nevada ("Nevada Exports"),
- marine exports to Southern CA ("Southern CA Exports"),
- marine exports to domestic locations ("Domestic Exports"), and
- marine exports to foreign locations ("Foreign Exports").

According to the CEC's 2017 Transportation Fuels Outlook, an average of 500,000 barrels of gasoline per month (2007-2016 average) were shipped from northern California refineries to Nevada (4.8% of 2018 NCNN demand), 1.16 million barrels per month (2007-2016 average) shipped via marine tanker to southern California ports (11% of 2018 NCNN demand), 301,000 barrels per month (2012-2016 average) were shipped via marine vessel to non-California U.S. ports (2.9% of 2018 NCNN demand), and 802,000 (2012-2016 average) barrels per month were marine shipped to non-U.S. ports (7.7% of 2018 NCNN demand)[3].

Two sensitivities are applied to the CARB projections to deal with exports. First, the export volumes are held constant in all future projections. Meaning, even as California gasoline demand declines and refineries close, the gasoline volumes being exported remain consistent with historic volumes. For example, the 6 million barrels annual export volume to northern Nevada (500,000 barrels per month for 12 months) is held constant for each future projection year. This is a simplifying assumption that is *not likely* to represent real world future product flows, since export volumes will likely decrease in this demand decline situation as refineries close (all things equal). The second sensitivity scales down annual export volumes at the same rate as total annual gasoline demand volumes are reduced. So, if Northern CA total gallons demanded in one year are reduced 5% from the year before, total gasoline exports are reduced 5% in that same year. This approach is used a simplistic method tied to an empirical (rather than arbitrary) scaling rate. Under certain conditions, it could be possible that in-state demand reductions make greater volumes available for export. However, at an unknown point, these volumes will be export-constrained due to infrastructure limits, unfavorable economics, or other factors. Also, at an unknown point, in-state demand reductions will trigger refinery capacity closure, therefore rebalancing volumes available for export. More complicated future potential export scenarios were not incorporated given these and other uncertainties.

To put these data in context, total refinery gasoline output is graphed alongside gasoline demand data. Refinery gasoline gallon output is calculated by applying the "6-3-2-1" crack fraction (i.e., 50% gasoline conversion rate) to each refinery's total operable capacity (in barrels per day) for a 350-day calendar year assuming 42 gallons per barrel.[5] The Marathon Martinez facility closed in 2020, which is reflected in the total refinery capacity line in the results graphs below. The remaining refineries in the total refinery capacity line include Chevron Richmond, PBF Martinez, Valero Benicia, and Phillips 66 Rodeo. Phillips 66 Rodeo is included because although the facility intends to close and retool for renewable fuel production, it had not yet done so at the time of this analysis.

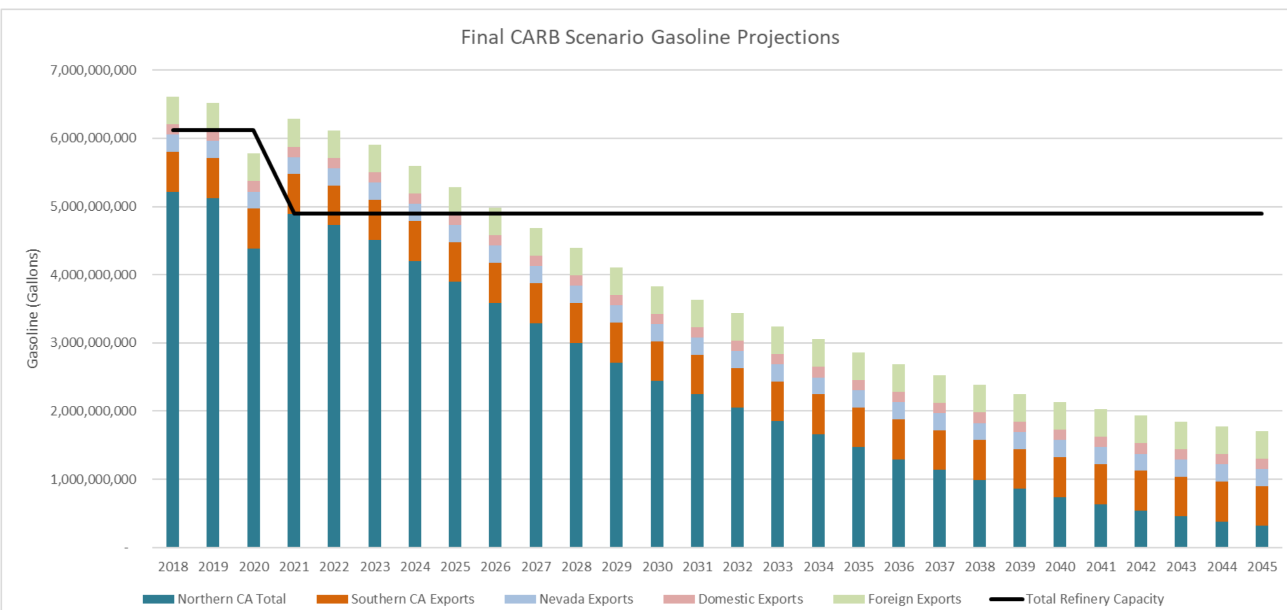

Figure 12 - NCNN Gasoline Balance Projections for CARB Final Scenario, with Static Exports. Author analysis of data from [29]

Figure 12 shows the NCNN gasoline balance projections associated with the CARB final scenario, holding export percentages static. Total refinery capacity in 2022 (including Phillips 66 Rodeo) is

[5] 42 gallons of product per barrel of crude is used, not the higher 44-45 gallons per barrel figure that reflects certain refinery production gains.

666,871 bpd. By 2045, the theoretically implied level of refinery capacity needed to meet gasoline demand is only 232,624 bpd. The word "theoretical" refinery capacity is used because refineries cannot perfectly scale to meet market demand. Only about 35% of the existing amount of refinery capacity would be needed to meet this level of gasoline demand, meaning about 65% of existing capacity (including Phillips 66 Rodeo) would be unnecessary.

Figure 13 shows the NCNN gasoline balance projections associated with the CARB final scenario, this time incorporating an export reduction adjustment. Here again, total refinery capacity in 2022 (including Phillips 66 Rodeo) is 666,871 bpd. With the proportional export reduction adjustment, the theoretical refinery capacity needed to meet 2045 demand is only 54,681 bpd, which is about 8.2% of existing capacity. This represents a 92% reduction in refinery capacity compared to 2022 levels.

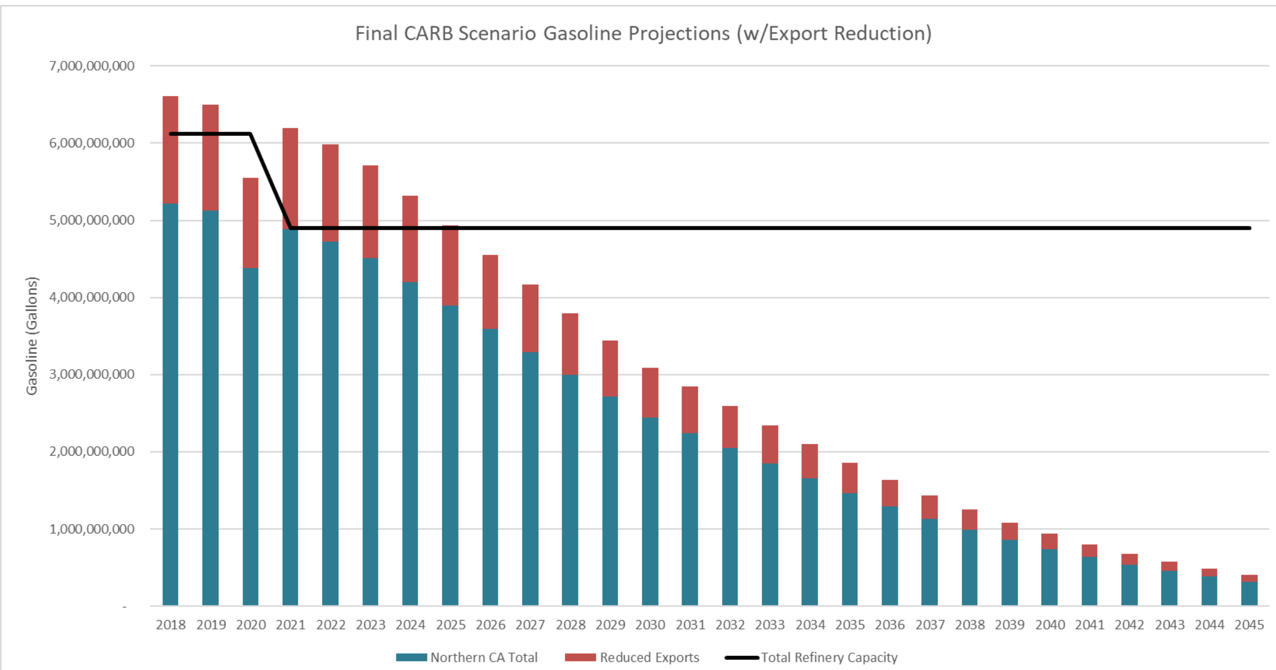

Figure 13 - NCNN Gasoline Balance Projections for CARB Final Scenario, with Export Reduction Adjustment. Author analysis of data from [29]

The left portion of **Figure 14** compares existing refining capacity to 2045 theoretical refining capacity associated with CARB Final Scenario gasoline demand using the static and adjusted export sensitivities. Theoretical refining capacity in the static gasoline exports scenario equates to one large refinery or two smaller Bay Area refineries, while demand associated with the adjusted export scenario is unlikely to support a single Bay Area refinery.

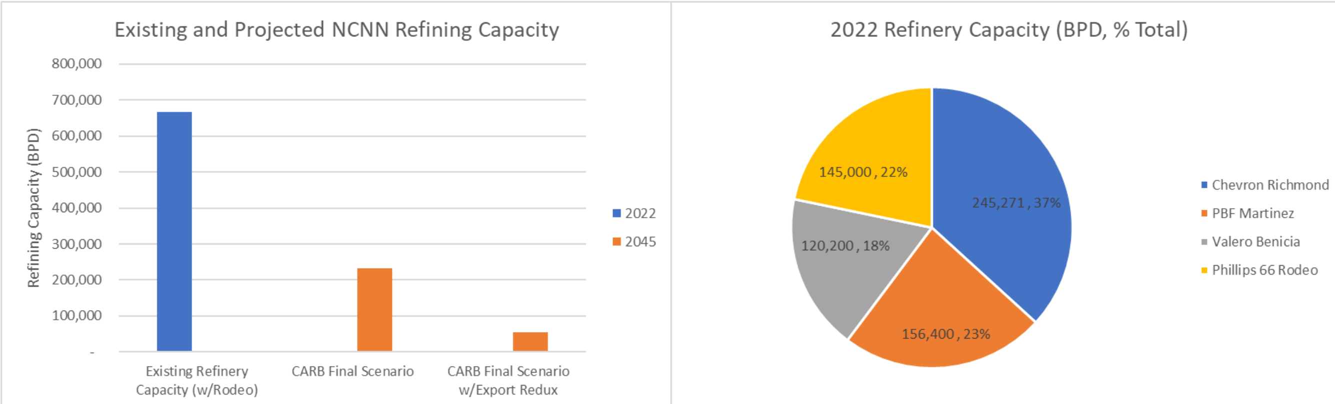

Figure 14 - Comparing existing (including Phillips 66 Rodeo) and Future Projected Refining Capacity. Author's analysis from data in [29]

ii. Diesel Methodology and Results

A diesel demand disaggregation analysis was not able to be completed for several reasons. First, although CARB's SP22 projection data reports conventional diesel and renewable diesel separately, biodiesel gallons are not separately reported. While it is known that a certain amount of lower heat content biodiesel is blended with traditional diesel each year, the exact percentage blend and corresponding biodiesel volumes are not reported in the SP22 projections. The most typical biodiesel blending levels are B5 (up to 5% biodiesel) and B20 (6-20% biodiesel). CARB's SP22 and supporting GHG inventory use CDTFA data for total diesel volumes in gallons[30]. The CDTFA data CARB accessed (2000 – 2014) on total diesel gallons sold includes separate breakdowns of both biodiesel and renewable diesel volumes[30]. However, publicly available CDFTA diesel sales volumes do not include separate biodiesel and renewable fuel breakdowns[32]. Hence, we assume the conventional diesel category (in exajoules) identified by CARB includes biodiesel, and renewable diesel is reported as its own line item in the CARB projections. The U.S. EIA publishes annual data on state-level biodiesel use in the transportation sector[35]. **Figure 15** compares the publicly available CDTFA total diesel (plus biodiesel) gallons and the EIA biodiesel only gallons and shows how biodiesel gallons sold have been increasing by volume and by percent of total diesel-type gallons sold. However, we do not have an indication of how these volumes may change in the future.

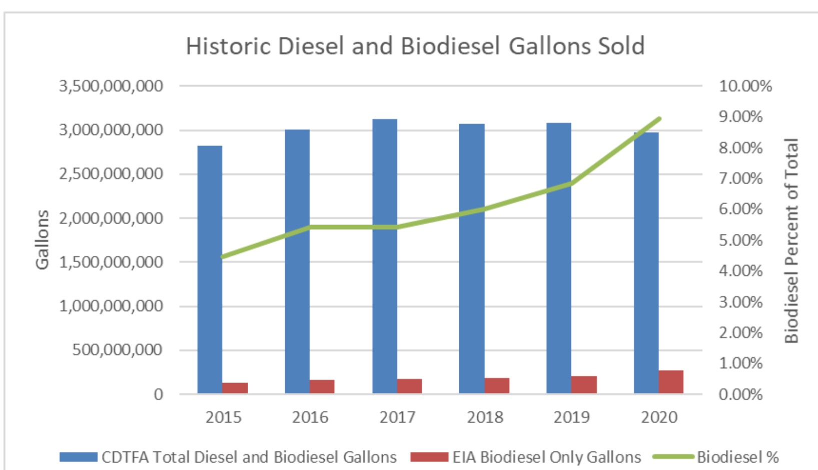

Figure 15 - Historic Diesel and Biodiesel Gallons Sold [32][35]

Furthermore, there is discrepancy pertaining to the heat content values for diesel and biodiesel. For example, the U.S. EIA uses a heat rate of 5.770 Mbtu per barrel (2020-2022) for low sulfur diesel (a sulfur content under 15 ppm) and a rate of 5.359 Mbtu/barrel for biodiesel[31]. The low carbon fuel standard data for Q2 2022 uses a heat content of 5.647 Mbtu/barrel (134.47 MJ/gal) for diesel and 5.161 Mbtu/barrel (126.13 MJ/gal) for biodiesel[36]. The GHG inventory used by CARB as a background resource for the SP22 incorporates a 5.796 Mbtu/barrel value for diesel (2014) and a 5.376 Mbtu/barrel for biodiesel[37]. Overall, this creates a situation where two unknown variables are needed for our conversion from Exajoules to gallons, the future percent of biodiesel gallons sold and the associated biodiesel heat content. Lastly, biodiesel sales are unlikely to be uniform across the state. Specifically, the percentage values in **Figure 15** show total state-level biodiesel gallon consumption as a percentage of total statewide diesel and biodiesel gallon sales. Practically, some areas of the state may consume more-or-less biodiesel than this statewide value. This complicates disaggregation of the statewide data to the county level.

As can be seen in **Figure 16**, it is clear the CARB final SP22 projections see an increased role for renewable diesel. Diesel demand decreases, with a slight rebound between 2026 - 2031, only to be eliminated totally by 2045. Renewable diesel demand grows until 2025, when hydrogen and electricity demand begin to erode the renewable diesel market share. This temporary growth in demand followed by a decline is the essence of a “bridge fuel”.

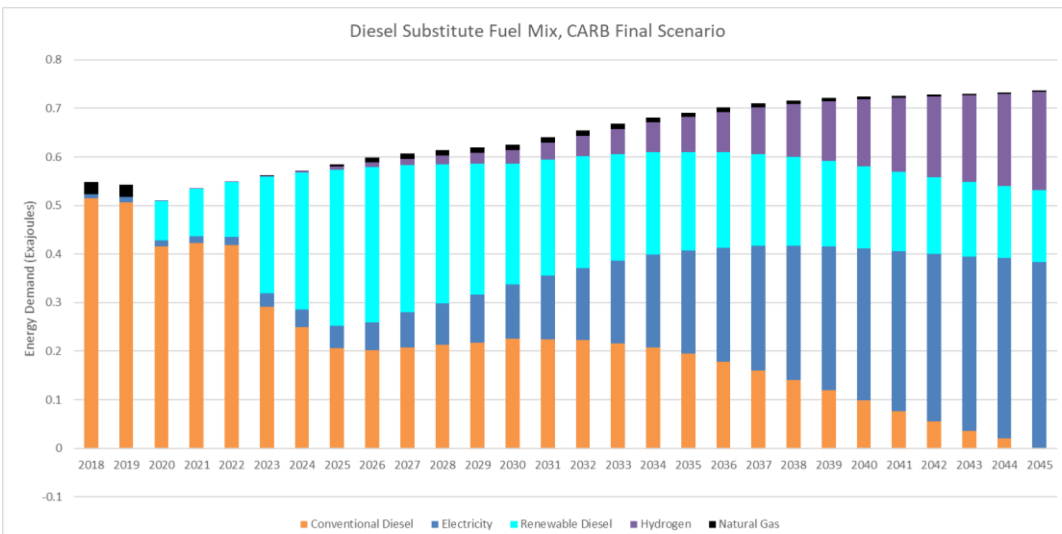

Figure 16 - Major Substitutes for Diesel Fuels in CARB Final Scenario. [29]

3. Evaluating Refinery Responses to Demand Destruction

Projection data clearly indicates significant reduction in gasoline and diesel demand, which are the first and second highest volume products of Northern California refineries, respectively. Disaggregated gasoline projection data for Northern California suggests only a fraction of existing refinery capacity will be needed in the future to serve this demand. As demand dwindles, we anticipate refineries will respond in one of three potential ways:

- **Cease Operations and Redevelop Land** – refineries that have comparatively greater weaknesses than strengths will likely be forced to close. As to be explored in the Comparative Analysis section, cessation of refinery operations will likely trigger the need to deal with remediation of land contamination.

- **Invest in Conversion** – A petroleum refinery may choose to invest in conversion to refining or processing other types of fuels (e.g., renewable diesel, hydrogen) if the opportunity is perceived to be greater than the cost. Conversion may have the added benefit of delaying certain contamination remediation expenses.
- **Continue Operations** – Refineries with greater strengths than weaknesses, especially compared to competitors, may be able to continue operating.

In addition to these three options, a refinery could close refining operations and continue to operate logistics assets (e.g., marine receiving, storage, gathering lines) using contracted supply or supply from owned refinery(s) in non-Bay Area locations. This could be a short-term strategy, for example, to fulfill contractual obligations. A long-term, profitable logistic operation would need to charge for throughput on large volume basis. In an environment characterized by demand destruction, it is not clear if such activity could persist other than if all refineries closed and California become reliant on marine imported finished fuels. It is unclear if the added costs of marine shipping product would allow for an economically competitive delivered product in large volumes, if sufficient in-state refinery capacity is still operational.

To evaluate potential refinery responses to demand destruction we conduct a series of three analysis including:

A. **Comparative Analysis:** Compare the Northern California refineries on corporate financials, refinery technology, regulatory compliance, and land contamination status.
B. **Contextualize the Opportunities:** Quantify market opportunities associated with renewable diesel, hydrogen, electricity, and carbon capture and sequestration (CCS).
C. **Identify Wild Cards:** Identify known issues that could have significant impacts if they occur, but the likelihood of future occurrence is unknown.

The following sections include information from these three analyses.

A. Comparative Analysis

This section compares the corporate financials, technology, regulatory compliance, and land contamination status of the applicable refineries.

i. Corporate Financials Comparison

Prior to examining financial data, it is important to understand the different business models represented by these companies. Chevron is considered an integrated oil company, meaning it has operations integrated throughout the fuel supply chain, from extraction (i.e., upstream), logistics, refining, and retail (i.e., downstream). Valero, Phillips 66, Marathon, and PBF Energy are independent refiners that have operations in some, but not all segments of the fuel supply chain (excluding extraction and production). Oil extraction tends to be the most capital-intensive segment of the supply chain, requiring constant reinvestment into maintaining well production.

All financial data included in this section were extracted from S&P Capital IQ Pro on August 12, 2022 [38]. **Figure 17** compares total assets and debts reported for Q2 2022, and the average daily market capitalization over that same quarter. This single-quarter snapshot approach is reasonable to give readers a general understanding of how these companies compare across categories. Metrics in the remainder of this section will include more granular time series. Although the Marathon Martinez refinery has already closed, corporate financials for Marathon are included in this comparative analysis. As shown in **Figure 17**, Chevron is the largest company with respect to market capitalization and assets and has a smallest debt-to-asset ratio at 10%. Philips, Valero, and Marathon have similar market cap values, but Marathon has considerably greater assets and debts. Marathon's debt ratio is also higher at 29% compared to Phillips (22%) and Valero (20%). PBF seems to be an outlier in the group with the smallest level of market cap, assets, and debts, and maintains a higher-end debt ratio of 28%.

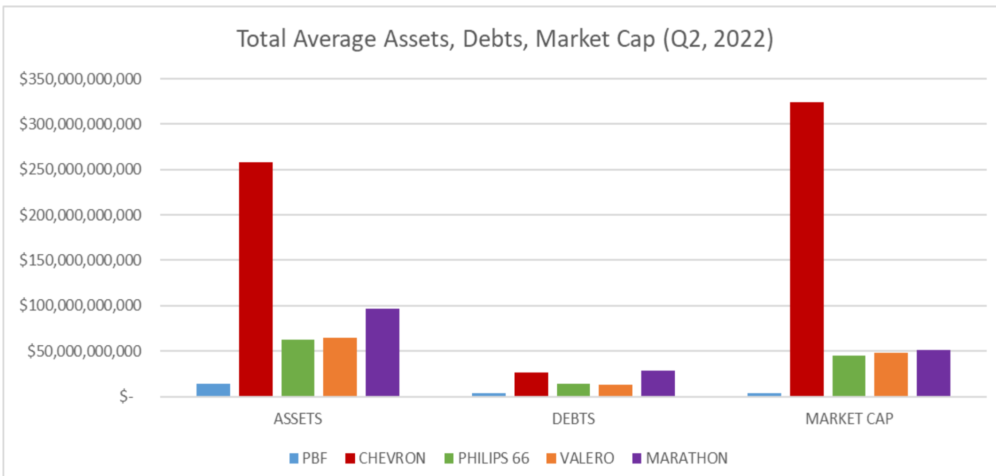

Figure 17 - Total Average Assets, Debts, and Market Capitalization (Q2, 2022) [38]

Figure 18 shows the daily percent change in stock price over a five-year period that includes the COVID pandemic. While all the firms follow generally the same patterns, PBF Energy's stock price was the most volatile with a standard deviation of 57.4, followed by Marathon (32), then Valero (30.8). Comparatively, Philips 66 (standard deviation of 20.7) and Chevron (19.1) maintained greater stock price consistency.

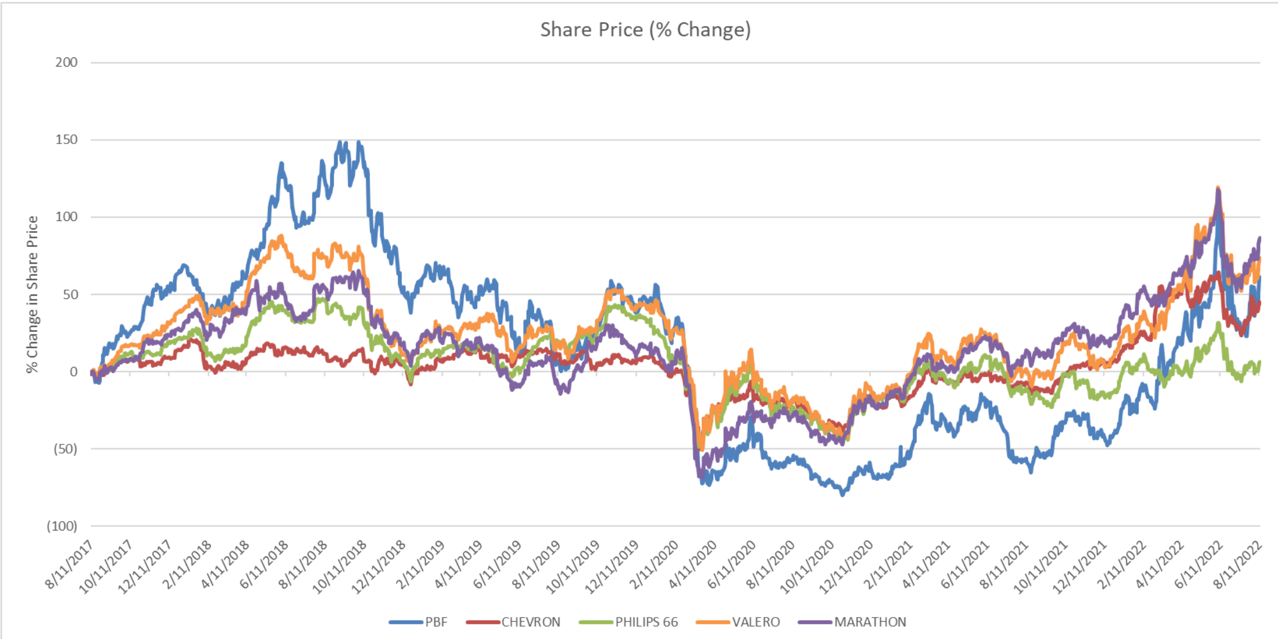

Figure 18 – Percent Change in Share Price, 5-year trailing [38]

Figure 19 shows dividend yields for each firm, again with the group following generally the same trend. However, on March 30, 2020, PBF Energy suspended quarterly dividends in an effort to preserve cash and support its balance sheet[39]. At the time these data were analyzed, PBF had not yet resumed dividend distributions. In late October 2022, PBF announced it would resume quarterly dividend distribution of $0.20 per share starting November 29, 2022[40].

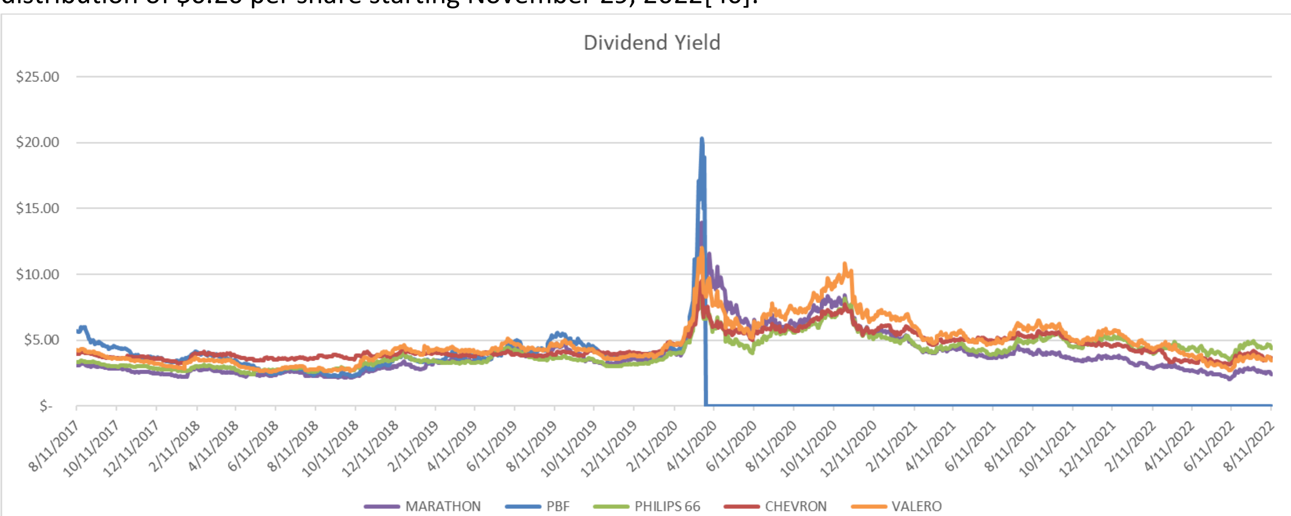

Figure 19 – Dividend Yields, 5-year trailing [38]

Figure 20 shows earnings before interest taxes, depreciation, and amortization (EBITDA), which is a valuable measure of a company's financial health before adjusting for differences in taxes, depreciation, etc. On average over the entire period, Chevron's EBITDA was highest at $7.46 billion. Valero ($1.49 billion) and Marathon ($1.92 billion) had similar earnings levels, followed by Philips 66 ($976 million) and PBF ($196 million).

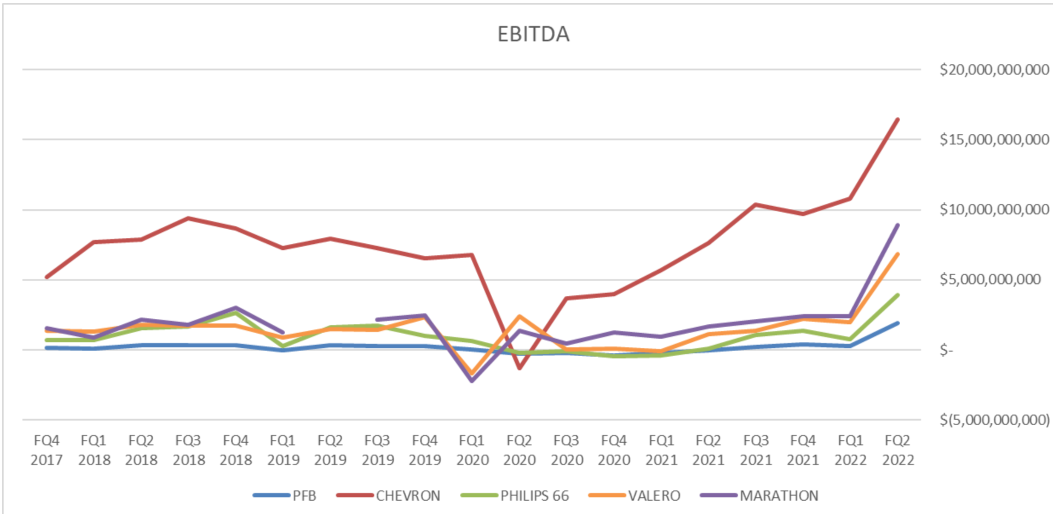

Figure 20 – Quarterly EBITDA, 5-year trailing [38]

By comparing a few select corporate financial metrics, one can see Chevron and PBF Energy are outliers: Chevron being comparatively stronger from a financial perspective and PBF Energy being comparatively weaker. Metrics for Marathon, Phillips 66, and Valero are more consistent as a group. These corporate financial metrics may or may not be good indicators of the fate of Northern California refineries. For example, Chevron's financial might doesn't necessarily mean the Chevron Richmond refinery will be immune from competitive pressures. In fact, it probably has more to do with the company being an integrated firm with capital intensive extraction operations. Chevron's myriad assets must all compete internally for the company's reinvestment dollars. Assets that generate the greatest returns will likely garner capital allocations, while low return assets will not. In northern California, a refinery's returns will be dictated by factors such as market forces (e.g., cost of inputs, price of outputs) and comparative economics with competing refineries. For this reason, the next section uses several metrics to compare technical aspects of the Northern California refineries.

ii. Refinery Technical Analysis

A brief discussion of refinery processes is warranted to better understand the refinery technical analysis. Typically, the first step in the refinery process is the atmospheric distillation unit, which separates crude oil into different "fractions" based on heating and condensation. The lightest fractions (typically higher-value) rise to the top of the distillation column and may be sent to other refinery units for finishing. The heavier fractions (typically lower-value) will fall to the bottom of the column and require additional processing.

Figure 21 is a simple depiction of the basic refinery processes[41]. Some of the lightest products at the top of the distillation tower include methane, ethane, propane, and butane. Next down the column are napthas that can go through a reformation process to become gasoline. Next down the stack are kerosene and distillates. Kerosene is used for jet fuel while distillate is turned into diesel. Gas oils can be upgraded through a catalytic cracking process to create higher value products like gasoline, and may need additional processing for octane (i.e., alkylation). The low-quality atmospheric bottoms (or residuum) can be sent to a vacuum distillation unit for further separating (not shown) or additional processing units (here, a coking unit is shown) to be upgraded to higher-value products like gasoline. Residuum can also be used to make asphalt, which is a low-value product.

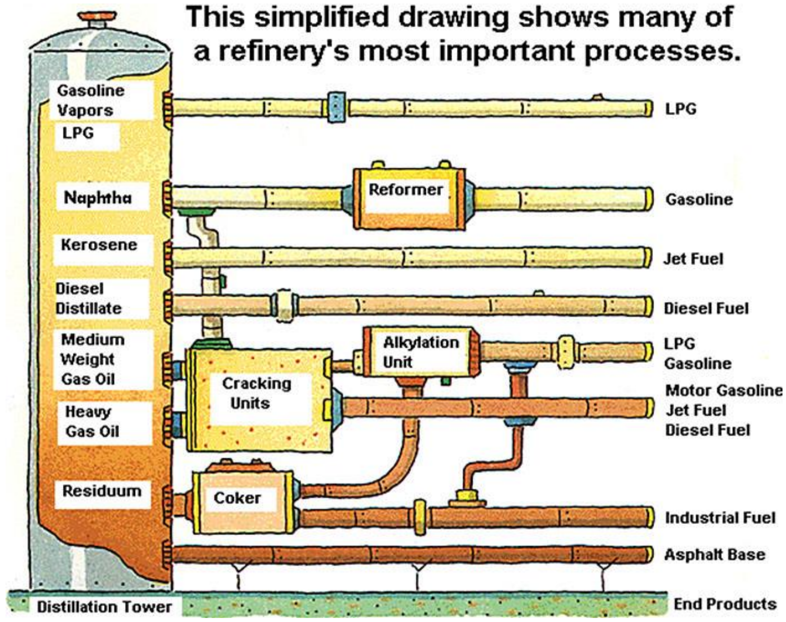

Figure 21 - Simplistic Depiction of the Most Basic Refinery Processes [41]

As can be seen in **Table 1**, Chevron's Richmond refinery has the largest total operable capacity, dictated by the size of the atmospheric distillation units, and all refineries have vacuum distillation[14]. One immediate standout is the lack of FCC capacity at the Phillips 66 Rodeo facility. The most interesting differences among these refineries relate to how they process the heavier fractions. This is particularly important because California refineries are reliant upon heavy crudes. Castaneda *et al* categorize heavy residual oil processing technologies into three general types: carbon rejection (e.g., catalytic cracking, visbreaking, and coking), hydrogen addition (e.g., hydrocracking and hydrotreating), or other (i.e., deasphalting) technologies[42]. In the U.S. in 2012, 57% of residue processing capacity was carbon removal, 36% was hydrogen addition, and 7% was deasphalting [42]. Each technology has its advantages and disadvantages, a discussion of which is beyond the scope of this paper. However, it is worth noting all NCNN refineries have hydrogen addition capacity, and all have coking capacity except for Chevron Richmond. Instead, Chevron Richmond uses deasphalting technology. Deasphalting technology is lower cost, less commonly used in the U.S., and has lower conversion yields compared to the other heavy processing technologies[42]. On the other hand, Chevron Richmond has lubricants production capacity, the benefits of which will soon be explored.

Table 1 – Select EIA Refinery Capacity Report Data, 2022 [14]

		PBF Energy MARTINEZ	PHILLIPS 66 RODEO	VALERO BENICIA	CHEVRON RICHMOND
	Downstream Charge Capacity, BPSD				
Fractioning	TOTAL OPERABLE CAPACITY	157,000	128,000	149,000	257,200
	VACUUM DISTILLATION	101,000	93,200	85,500	123,456
Catalytic Cracking (e.g., FCC)	CAT CRACKING: FRESH FEED	72,000		75,300	90,000
	CAT CRACKING: RECYCLED FEED				
Thermal Cracking	THERM CRACKING, DELAYED COKING	26,800	51,000		
	THERM CRACKING, FLUID COKING	22,500		29,500	
	THERM CRACKING, OTHER (INCLDNG GAS OIL)				
	THERM CRACKING, VISBREAKING				
Hydrogenation	CAT HYDROCRACKING, DISTILLATE	42,900		34,000	
	CAT HYDROCRACKING, GAS OIL		69,000		103,400
	CAT HYDROCRACKING, RESIDUAL				
Extraction	FUELS SOLVENT DEASPHALTING				56,000
Reforming	CAT REFORMING: HIGH PRESSURE		34,000	37,200	
	CAT REFORMING: LOW PRESSURE	31,000			71,300
Sulfur Removal	DESULFURIZATION, DIESEL FUEL		35,000	15,000	64,800
	DESULFURIZATION, GASOLINE	90,000		43,200	64,800
	DESULFURIZATION, HEAVY GAS OIL	80,500		39,000	65,000
	DESULFURIZATION, KEROSENE AND JET			15,400	96,000
	DESULFURIZATION, NAPHTHA/REFORMER FEED	28,000	27,500	30,000	57,600
	DESULFURIZATION, OTHER	14,500		21,700	34,000
	DESULFURIZATION, OTHER DISTILLATE	49,500		5,000	
	DESULFURIZATION, RESIDUAL				
	TOTAL DESULFUR	262,500	62,500	169,300	382,200
	Production Capacity, BPSD				
Isomerization Unit	ISOMERIZATION (ISOBUTANE)		3,800	4,200	7,200
	ISOMERIZATION (ISOPENTANE/ISOHEXANE)	15,000	10,000		46,000
Specialty product	LUBRICANTS				34,000
Cracking byproduct	PETCOKE,MARKET	9,000	14,500	6,800	
Byproduct of hydrotreating	SULFUR (SHORT TONS/DAY)	413	560	303	1,008
Alkylation unit	ALKYLATES	12,800		17,100	32,662
Specialty product	ASPHALT & ROAD OIL			9,000	
Byproduct of reforming, input to hydrocrackers & hydrotreaters	HYDROGEN (MMCFD)	179	22	135	330

With this basic background and data, the metrics included in the refinery technical analysis can be explored. As shown in **Equation 2**, the on-stream factor or operating factor of a refinery is the ratio of the number of barrels produced by the refinery's largest component (i.e., the atmospheric distillation column) on a given calendar day that recognizes downtime (measured in barrels per calendar day or bpcd) to the number of barrels that could be produced in a theoretical day when there is no downtime (measured in barrels per stream day or bpsd). Downtime could include maintenance turnarounds, unplanned outages, or other factors. Presented as a percentage, this metric provides insights to the fraction of time the plant is working each year (when using annual average data).

$$\text{OperatingFactor}(\%) = \frac{\text{BPCD } \textit{of Atmospheric Crude Distillation Capacity}}{\textit{BPSD of Atmospheric Crude Distillation Capacity}} \times 100 \quad \text{Eq. 2}$$

Using EIA data from January 1, 2022, operating factors for every U.S. refinery were calculated and shown in **Figure 22** [14]. California refineries are outlined in orange and northern California refineries are outlined and filled in orange. The PBF Martinez refinery has the highest operating factor of any other refinery in the country. This indicates low levels of down time, which is generally very positive for the refinery's economics. Phillips 66 Rodeo has the lowest operating factor of the Bay Area refineries at 93.91%, followed by Chevron Richmond (95.36%) and Valero Benicia (97.3%). The average on-stream factor for the entire U.S. refining fleet in 2021 was 93.76%, with a median rate of 95.10%. The below average on-steam factor for Phillips 66 Rodeo may be an indication of issues at the plant that negatively impact operations.

For each U.S. refinery, the conversion ratio was calculated using **Equation 3** and the conversion capacity (i.e., thermal cracking, catalytic cracking, and catalytic hydrocracking) reported in the 2022 U.S. EIA refinery capacity report[14], with fluid catalytic cracking (FCC) equivalent factors from the 2020 World Oil Review[43].[6] This ratio indicates a refinery's ability to convert low grade crude into high value light products and reduce output of lower value residual fuel.

$$\text{Conversion Ratio}(\%) = \frac{\sum\big(FCC\ Equivalent\ *\ ConversionCapacity\ (bpsd)\big)}{Atmospheric\ DistillationCapacity\ (bpsd)} \qquad \text{Eq. 3}$$

Figure 23 shows the conversion ratios for all U.S. refineries with California refineries outlined in orange and Bay Area refineries are outlined and filled in orange. Most obvious is the comparably lower conversion ratio of the Chevron Richmond refinery. This is due to Chevron Richmond's heavy reliance on catalytic hydrocracking and deasphalting. Most of the complex California refineries (that are not topping units with very low conversion ratios) incorporate a certain increment of delayed coking or fluid coking capacity, in addition to catalytic cracking and other conversion capacity. This is not the case with Chevron Richmond. Chevron Richmond uses a fuel solvent deasphalting unit (SDA) to further separate heavy oil residue components from the distillation column(s), a technology considered less complex then coking processes. EIA data suggests Phillips 66 Rodeo does not have FCC capacity and relies instead upon catalytic hydrocracking and delayed coking capacity.

Nelson Complexity Index values were calculated for each U.S. refinery using EIA refinery capacity data[14], World Oil Review Nelson Complexity Factors [43],[7] and **Equation 4**, where F_i is the Nelson Complexity Factor for the applicable unit (i), C_i is the bpsd capacity of the applicable unit, ADU is the bpsd capacity of the atmospheric distillation unit, and N is all applicable units at the refinery. As shown in **Figure 24**, the Nelson Complexity Index figures paint a different picture of the Chevron Richmond facility, identifying it as the most complex of all the California refineries examined. While Valero Benicia, Phillips 66 Rodeo, and PBF Martinez all have some form of coking capacity to upgrade heavy oil residuals, Chevron Richmond gains 60 complexity points for having lubricants production capacity.

[6] The following FCC equivalent factors from the 2020 World Oil Review were applied: catalytic cracking fresh feed (1); catalytic cracking recycled (1.9); cat hydrocracking distillate (1.3); cat hydrocracking gas oil (0.3); cat hydrocracking residual (0.4); thermal cracking delayed coking (1.35); thermal cracking fluid coking (1.35); thermal cracking other (0.65); thermal cracking visbreaking (0.25).

[7] The following Nelson Complexity Factors from the 2020 World Oil Review were applied: alklates (10); asphalt (1.5); catalytic cracking, fresh or recycled (6); catalytic hydrocracking (6), catalytic reforming (5); desulfurization (2.5); fuel solvent deasphalting (1.5); isomerization (15); lubricants (60); sulfur production (6); thermal cracking, delayed or fluid coking (6); thermal cracking, visbreaking or other (2.75); vacuum distillation (2).

Lubricants capacity can create high-value base oils, which are specialty products that can be very profitable. High capital cost lubricant capacity can convert low value vacuum residuals to small volumes of specialty products. The Phillps 66 Rodeo facility is the least complex of the NCNN refineries.

$$\text{Nelson Complexity Index } = \sum_{i=1}^{N} F_i * \frac{C_i}{ADU} \qquad \text{Eq. 4}$$

In summary, the four refineries stack up as follows:

- Chevron Richmond – Competitive advantage from access to specialty products market. Competitive disadvantage due to low conversion capacity. Overall balance may depend in part on lubricants market opportunities. Chevron Richmond's operating factor is approximately at the national median.
- Valero Benicia – This refinery has the second highest operating factor (behind PBF Martinez), and second highest conversion ratio (behind PBF Martinez). It is the second lowest on complexity, above only the Phillips 66 Rodeo facility.
- Phillips 66 Rodeo – This refinery is the least competitive on availability (operating factor), but unclear if this is due to a problem or a major turnaround conducted during the reporting year. Phillips 66 Rodeo has a lower conversion ratio than all but the Chevron Richmond refinery. Phillips 66 Rodeo is the least complex facility in the Bay Area group.
- PBF Martinez – PBF Martinez has the competitive advantage on availability to operate, has the highest conversion ratio, and is the second most complex (behind Chevron Richmond).

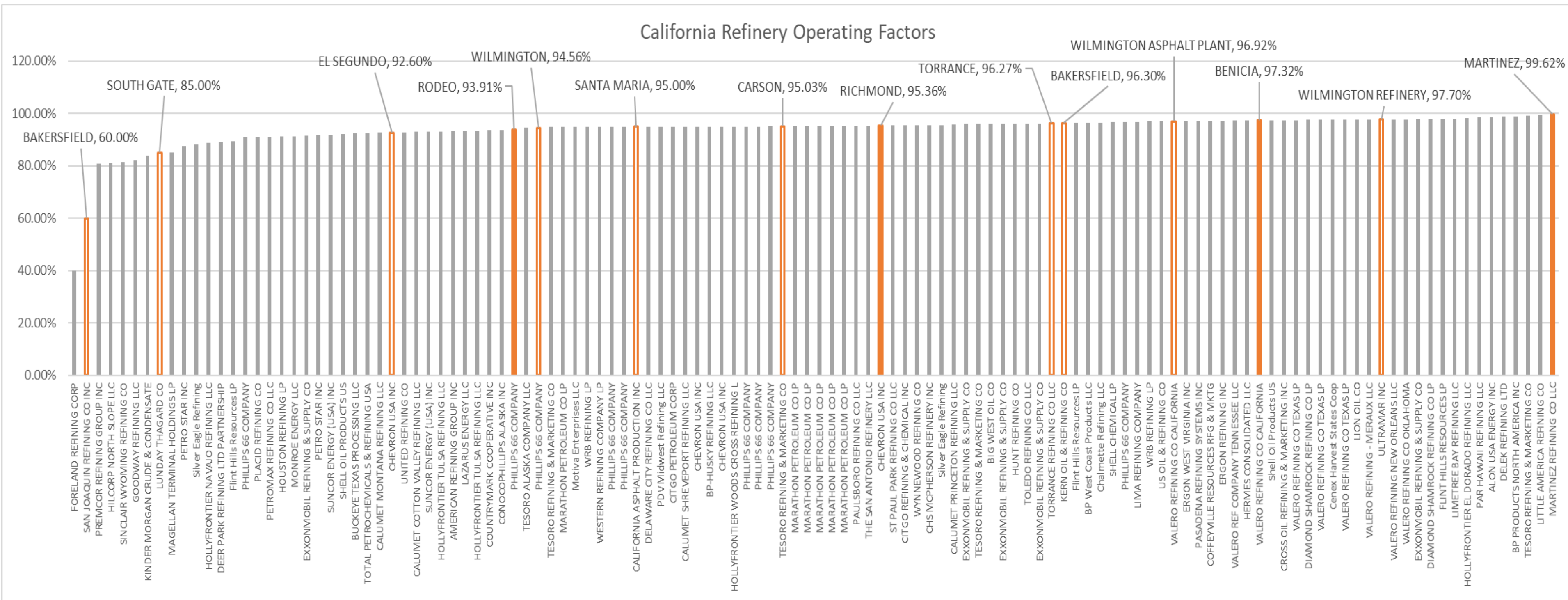

Figure 22 - Operating Factors for U.S. (grey fill), California (orange outline) and Northern California (orange fill) Refineries. Author's calculations using data from [14]

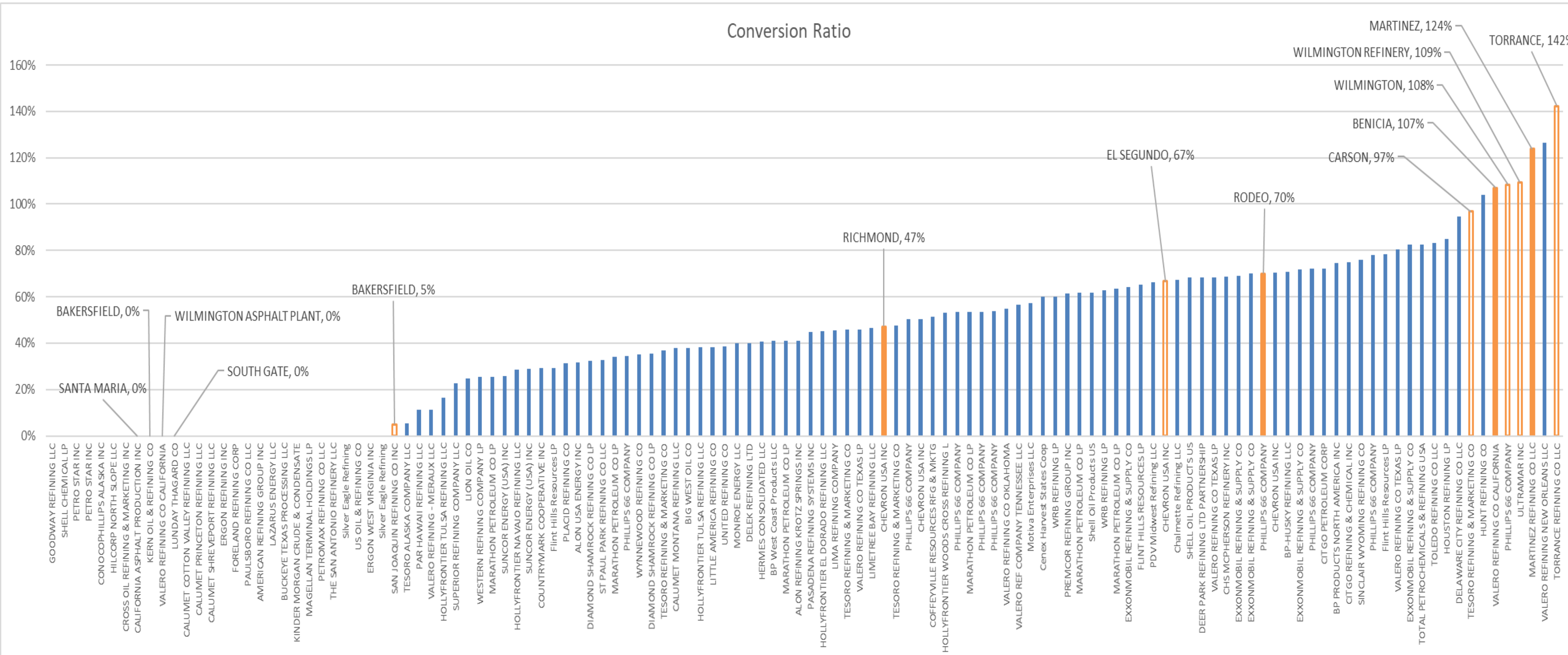

Figure 23 - Conversion Ratios for U.S. (blue fill), California (orange outline) and Northern California (orange fill) Refineries. Author's calculations using data from [14]

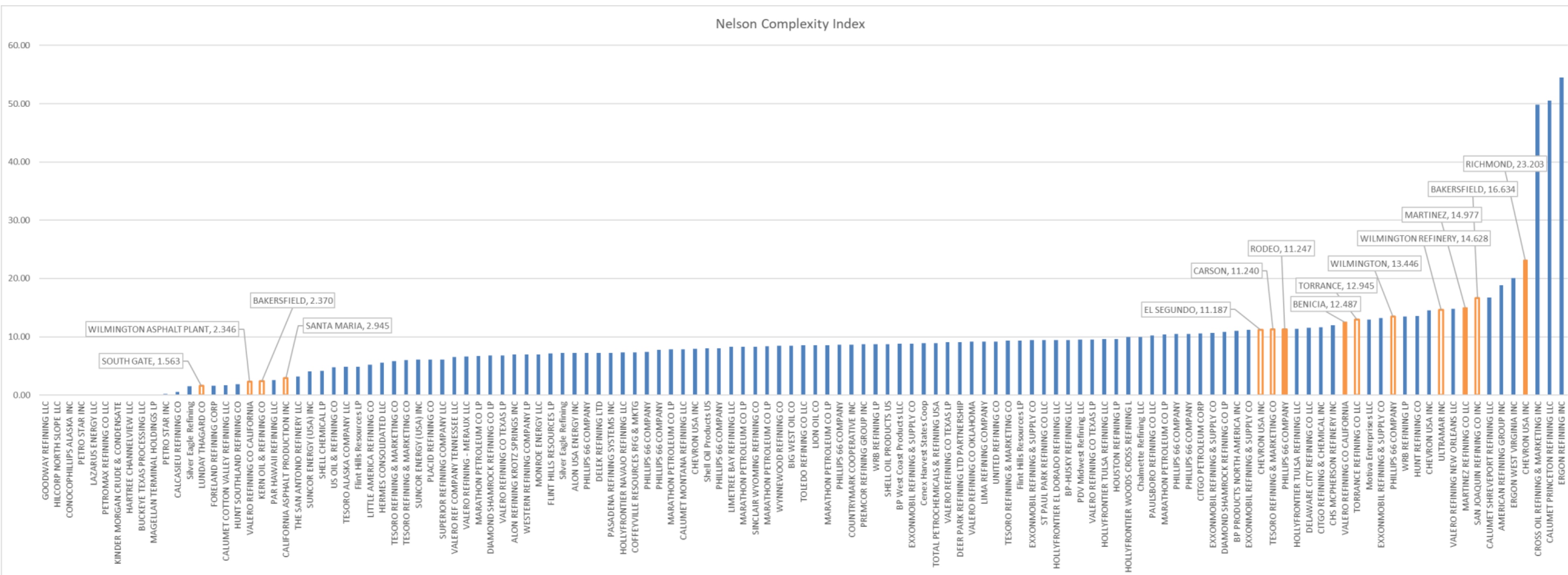

Figure 24 – Nelson Complexity Index Values for U.S. (blue fill), California (orange outline), and Northern California (orange fill) Refineries. Author's calculations using data from [14]

iii. Regulatory Considerations

This section provides insights into refinery compliance with major environmental laws and regulations, as reported in the "Detailed Facility Reports" by the U.S. EPA's Enforcement and Compliance History Online (ECHO) database in August 2022[44]. Compliance data for the past five (5) years for the Clean Air Act (CAA) Clean Water Act (CWA), and the Resource Conservation and Recovery Act (RCRA) was collected and presented in **Table 2**, as reported in ECHO's enforcement and compliance summary for each facility. The data counts for each facility and category were taken directly from EPA's website. Questions about these data can be found at each facility's individual detailed facility reports.[8] Unfortunately, for many violations the ECHO database does not provide details about the infractions.

For the CAA, it seems Chevron Richmond had a low number of compliance monitoring activities, but the greatest number of informal and formal enforcement actions. Chevron Richmond was second behind Marathon Martinez for the greatest dollar value of formal enforcement action penalties and the only refinery with an EPA enforcement case against it, which resulted in a near $2 million penalty. This was a national enforcement case that applied to Chevron Richmond and several other Chevron refineries.[9] Marathon Martinez had the second highest number of formal enforcement actions and associated penalties, but this facility is currently idled. Phillips 66 Rodeo had the lowest number of formal enforcement actions and lowest dollar value of associated penalties.

Table 2 – U.S. EPA 5-year Compliance and Enforcement Data [44]

5-Year Environmental Compliance Summary from U.S. EPA							
	Facility	Compliance Monitoring Activities	Informal Enforcement Actions	Formal Enforcement Actions	Penalties from Formal Enforcement Actions	EPA Cases	Penalties from EPA Cases
Clean Air Act	Chevron Richmond	12	326	169	$ 685,500	1	$ 1,930,300
	PBF Martinez	14	72	21	$ 215,000		
	Valero Benicia	19	93	40	$ 479,000		
	Phillips Rodeo	11	105	13	$ 99,400		
	Marathon Martinez	30	86	64	$ 918,200		
Clean Water Act	Chevron Richmond	2					
	PBF Martinez	2		3	$ 112,000	1	$ 142,664
	Valero Benicia						
	Phillips Rodeo	3		2	$ 182,500		
	Marathon Martinez	4					
Resource Conservation and Recovery Act	Chevron Richmond	2	2				
	PBF Martinez	16	10	2	$ 30,000		
	Valero Benicia	4					
	Phillips Rodeo	4	4				
	Marathon Martinez	13	5				

For CWA compliance, only Phillips 66 Rodeo and PBF Martinez were reported as having formal enforcement actions. PBF Martinez had the highest number of formal enforcement actions and one EPA enforcement case. Although this was reported as a CWA case, this action was related to violations of

[8] Detailed Facility Report in the ECHO database can be found at the following locations, all accessed on October 6, 2022: Chevron Richmond https://echo.epa.gov/detailed-facility-report?fid=110020506460; Rodeo https://echo.epa.gov/detailed-facility-report?fid=110000483487; PBF Martinez https://echo.epa.gov/detailed-facility-report?fid=110000483245 ; Benicia Refinery (listed as NuStar Logistics) https://echo.epa.gov/detailed-facility-report?fid=110033145353; Marathon Martinez https://echo.epa.gov/detailed-facility-report?fid=110021341332

[9] See U.S. EPA Civil Enforcement Case Report 09-2016-3511 at https://echo.epa.gov/enforcement-case-report?activity_id=3600831241, accessed on October 6, 2022

multiple environmental statutes discovered during a routine inspection.[10] PBF Martinez also had the highest combined total dollar value from EPA penalties. PBF Martinez also had the highest number of RCRA enforcement actions and was the only facility assessed penalties for RCRA violations. The only detailed information about this RCRA violation was that it resulted in a super consent agreement and final order.

It is clear Chevron Richmond has been issued the most CAA enforcement actions, while PBF Martinez has be issued the most CWA and RCRA violations. By comparison, Valero Benicia is in the middle of the pack on CAA violations and has experienced no CWA or RCRA violations during the period examined. However, these EPA data (federal and state jurisdiction) do not present a comprehensive picture, as there are also local regulators with jurisdiction in California. A comprehensive review of local air quality management district data for each facility was not conducted; however, review of these data could provide additional insights. For example, in one month, the Valero Benicia facility was levied several air quality violations not reflected in the EPA data. In March 2022, the Bay Area Air Quality Management District (BAAQMD) ordered Valero Benicia to cease venting of air contaminant emissions (e.g. carbon, benzene, ethylbenzene, toluene, xylene) from its hydrogen system vent[45]. Allegedly, Valero knew of the venting since at least 2003, with regulators discovering the exceedances in 2019 and estimating an average of 4,000 pounds of hydrocarbons per day over a 16-year period had been released[46].[11] In March 2022, BAAQMD settled 17 notices of violation for $345,000 in air quality regulations from 2017[47].

These historic compliance data are not the only regulatory actions to consider, potential future actions are also informative. In July 2021, the BAAQMD voted to limit particulate matter emission to 0.01 grains per dry standard cubic foot, essentially requiring refineries in the area to install wet gas scrubbers within 5 years to reduce pollution from their FCC units. This would impact Chevron's Richmond and PBF's Martinez refineries, since Valero Benicia already has installed wet scrubbers, Phillips 66 Rodeo doesn't have a FCC unit, and Marathon Martinez is retooling for renewable fuels [48][49]. Chevron hinted towards legal action, citing $1.48 billion in capital costs to comply, while BAAQMD put the compliance cost number at $241 - $579 million[49]. BAAQMD's estimated compliance capital costs for PBF Martinez to be $255 million, which analysts believe cannot be supported by PBF's stretched balance sheet[49]. While analysts believe this requirement could shut down the PBF Martinez refinery, they also note compliance is not due until 2026 and legal intervention before then is possible[49]. PBF maintains it anticipated this regulatory development and already have an emissions reduction project in the works[49]. In September 2021, Chevron and PBF filed separate lawsuits against the BAAQMD regulations in Contra Costa County Superior Court[50].

iv. Land Contamination

Information about environmental contamination and remediation status of each refinery parcel is included in this section, as this may inform a refinery's business decisions, cleanup costs, potential future uses of the site, and economic development opportunities for the local community. This

[10] See U.S. EPA Civil Enforcement Case Report number 09-2018-1007, located at https://echo.epa.gov/detailed-facility-report?fid=110021341332, accessed on October 6, 2022

[11] More information about the Valero Hydrogen System Venting issue can be found on BAAQMD's webpage at https://www.baaqmd.gov/news-and-events/page-resources/2022-news/012224-hb-valero

information is limited to corrective action status under the Resource Conservation and Recovery Act (RCRA) [12] or status as a Superfund site.[13]

A U.S. EPA RCRA corrective action (CA) site includes, but is not limited to, oil refinery properties where hazardous waste has been released and actions to characterize, stabilize, and correct such releases are required. Importantly, RCRA CA sites typically consist of operating facilities with financially viable business entities available who are legally liable for contamination remediation. All but one of the NCNN refineries are listed in the EPA RCRA CA 2020 baseline, which sets federal and state RCRA program priorities[51]. This includes Chevron Richmond[14], PBF Martinez[15], Phillips 66 Rodeo[16], and Marathon Martinez.[17] The corrective action status indicated in the 2020 RCRA CA Baseline is listed in **Table 3**, based on nationally defined values (i.e., programmatic codes)[18] where:

- **CA 725** – Current human exposures under control determination, where "YE" means it has been verified that current human exposures are under control. (In most cases this suggests exposures have been controlled, not remediated.)
- **CA 750** – Groundwater releases controlled determination, where "YE" means it has been verified that current migration of contaminated groundwater is under control. (In most cases this suggests exposures have been controlled, not remediated.)
- **CA 550** – Remedy construction.
- **CA 900** – Corrective action performance standards achieved.

It should be noted that the 2020 Baseline lists the Chevron Richmond refinery as having achieved CA performance standards, but the facility-specific RCRA webpage does not indicate CA 900 status has been achieved.

Table 3 - Refinery RCRA Corrective Action (CA) Status [51]

Facility	CA 725	CA 750	CA 550	CA 900

[12] More information about this program can be found at the U.S. EPA's website at https://www.epa.gov/hw/learn-about-corrective-action.

[13] More information about the U.S. EPA's Superfund program can be found at https://www.epa.gov/superfund accessed October 7, 2022

[14] For more information about the status of the Richmond Refinery RCRA site, visit U.S. EPA's website at https://ordspub.epa.gov/ords/cimc/f?p=CIMC:RCRA::::P14_RCRA_HANDLER_ID:CAD009114919 and the California Department of Toxic Substances Control's EnviroStor website at https://www.envirostor.dtsc.ca.gov/public/hwmp_profile_report?global_id=CAD009114919&starttab=

[15] For more information about the status of the Martinez Refinery RCRA site, visit U.S. EPA's website at https://ordspub.epa.gov/ords/cimc/f?p=CIMC:RCRA::::P14_RCRA_HANDLER_ID:CAD009164021 and the California Department of Toxic Substances Control's EnviroStor website at https://www.envirostor.dtsc.ca.gov/public/hwmp_profile_report?global_id=CAD009164021&starttab=

[16] For more information about the status of the Rodeo Refinery RCRA site, visit U.S. EPA's website at https://ordspub.epa.gov/ords/cimc/f?p=CIMC:RCRA::::P14_RCRA_HANDLER_ID:CAD009108705 and the California Department of Toxic Substances Control's EnviroStor website at https://www.envirostor.dtsc.ca.gov/public/hwmp_profile_report?global_id=CAD009108705&starttab=

[17] For more information about the status of the Marathon Martinez Refinery RCRA site, visit U.S. EPA's website at https://ordspub.epa.gov/ords/cimc/f?p=CIMC:RCRA::::P14_RCRA_HANDLER_ID:CAD000072751 and the California Department of Toxic Substances Control's EnviroStor website at https://www.envirostor.dtsc.ca.gov/public/hwmp_profile_report?global_id=CAD000072751&starttab=

[18] More information on RCRA Nationally Defined Values for Corrective Action Events can be found at https://rcrainfo.epa.gov/rcrainfo-help/application/ded/nationallydefinedvalues/correctiveactionmodule/ndv-caevent.htm accessed on October 7, 2022

Chevron Richmond	YE	YE	YE	YE*
PBF Martinez	YE	YE	YE	
Phillips 66 Rodeo	YE	YE		
Marathon Martinez	YE	YE		

**The 2020 Baseline indicates performance standards have been achieved, but the facility-specific RCRA page indicates performance standards have not yet been achieved.*

For RCRA CA sites, the state and federal government have shared jurisdiction over the cleanup of these facilities, and often collaborate (or EPA delegates to the state) to reduce the administrative burden of land clean ups.[19] The good news is for these sites action has likely taken place to characterize and stabilize pollutant releases, public participation in the planning and cleanup process is required, and there is a known entity with legal liability for site cleanup. The complicated news is there may be different definitions or standards for site cleanups, which may impact future uses of the land. A general example is remediating the site for unrestricted uses versus restricted uses with land covenants. Restricted use status will limit redevelopment options on applicable parcels.

Cessation of refinery operations may trigger or hasten RCRA CA remediation activities. In addition, cleanup standards may become more stringent if the refinery property is no longer operating. For example, in some states, allowable pollution cleanup levels can be determined by acceptable exposure-based health risks. Therefore, cleanup requirements for a refinery site that will continue to host heavy industrial activities with little human activity (i.e., exposure) will be less stringent than cleanup standards for a property that is intended for commercial or residential development. Cleanup standards for unrestricted use will maximize redevelopment opportunities. Therefore, it is in the best interest of local communities to engage in early planning activities to explore the highest and best potential future uses for the refinery parcels. Although these planning activities cannot compel refinery owners to follow the desires of the local community, these planning activities can inform public participation efforts required by the RCRA CA process. This may lead to more stringent cleanup standards through the RCRA process. Ensuring the polluter pays its fair share of remediation expense can also increase private sector interest in land redevelopment (i.e., reduce developer remediation costs).

The U.S. EPA lists the Benicia Valero refinery as a Superfund site that is not on the national priority list for cleanup funding.[20] The Superfund program was established by the U.S. Congress through the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) in 1980. The Superfund program assesses and cleans up sites that are highly contaminated with hazardous substances. The program attempts to make responsible parties pay the cost of cleanups but also has access to taxpayer funds for cleanups where the responsible party(s) no longer exists or cannot pay. The national priority list (NPL) is short-list of the most contaminated Superfund sites designated for priority actions. The Benicia refinery is located on 400 acres of the former 2,700+ acre Benicia Arsenal, which is

[19] For example, the California EPA'S Department of Toxic Substances Control (DTSC) implements the applicable in-state RCRA corrective action program

[20] For more information about the status of the Benicia Valero Refinery Superfund site, visit the U.S. EPA website at https://cumulis.epa.gov/supercpad/CurSites/csitinfo.cfm?id=0900063 and the California Department of Toxic Substances Control's EnviroStor website at https://www.envirostor.dtsc.ca.gov/public/profile_report?global_id=48290001

now a Superfund site. The Benicia Arsenal Superfund site is managed by the Army Corps of Engineers through the Formerly Used Defense Sites Program (FUDS).[21] The FUDS program is conducting an installation restoration program (IRP) to respond to hazardous substance releases (e.g., petroleum, hazardous or explosive chemicals), and a military munitions response program (MMRP) to deal with unexploded ordinances or discarded military munitions or related constituents at the site. More research is required to understand the public participation opportunities at a FUDS-managed Superfund site and how the refinery parcel fits into the overall Superfund site remediation approach.

v. Summary of Comparative Analysis

Each refinery and its corporate owner have its own set of strengths and weaknesses, only some of which are explored in this limited comparative analysis. Conclusions for each refinery are summarized below.

Chevron's Richmond refinery benefits from a financially robust corporate parent with low debt and large market capitalization. Chevron is the only NCNN refinery owner that is vertically integrated, to which the robust balance sheet is partially attributed. On the other hand, the refinery will have a much larger corporate portfolio of assets to compete against for the company's reinvestment capital. Richmond is disadvantaged by its low conversion capacity from lack of thermal cracking capacity, a significant weakness for a heavy sour facility that likely increases the facility's feedstock costs (towards higher quality crudes) or lowers high quality product yields. However, the facility has a significant complexity advantage from its lubricants plant, providing diversified revenue streams. It is uncertain if the lubricants advantage is sufficient to economically overcome the crude conversion disadvantage. Chevron also have the advantage of many branded retail gasoline stations in California, creating a guaranteed market for Richmond's offtake. Specifically, in 2020 about 15.3% of retail gasoline sold in California occurred at a Chevron retail station[52]. Richmond had the greatest amount of CAA compliance violations and is also potentially facing large investments to reduce particulate emissions from its FCC unit. Richmond is a RCRA CA site, information about the remediation status of the parcel was unclear.

PBF's Martinez refinery seems to be the strongest overall performer, scoring high on all refinery metrics examined. Yet, PBF Energy is financially the weakest refinery owner, with a high debt-to-asset ratio and a long-suspended dividend. While PBF's balance sheet may be stretched, it has a smaller portfolio of refinery and logistics assets. The technical and performance strength of the Martinez refinery may make it a priority for investment among PBF's other assets. Martinez is a standout for highest number of compliance challenges with the CWA and RCRA and is facing a significant regulatory investment to reduce particulate matter emissions from its FCC unit. Martinez is a RCRA CA site likely to require remediation investment upon closure.

Valero's Benicia is second to Martinez on operating factor and conversion ratio but is second lowest on complexity. Valero's corporate financial metrics are comparable to Marathon and Phillips 66. In 2020, about 2% of gasoline sales in California were from Valero branded stations, while about 14.9% occurred at Marathon's ARCO stations[52]. Unlike Richmond and Martinez, Benicia is not facing additional particulate matter emissions control investment requirements. Also, unlike Richmond and

[21] For more information about the status of the Benicia Arsenal Superfund site, visit the U.S. Army Corps of Engineers website at https://fudsportal.usace.army.mil/ems/inventory/map?id=61250
and the California Department of Toxic Substances Control's EnviroStor website at https://www.envirostor.dtsc.ca.gov/public/profile_report?global_id=48970007

Martinez, Benicia is not a RCRA CA site potentially (but not definitively) limiting remediation requirements for Valero. Rather, the refinery is located inside the boundary of the Benicia Arsenal Superfund site, the remediation of which is being managed by the Army Corps of Engineers. While potentially limiting remediation costs to Valero, the existence of the Superfund site likely complicates redevelopment of the refinery land in the instance of closure.

4. Contextualizing Opportunities

There are at least four potential reinvestment opportunities refineries in the NCNN may consider including: renewable diesel production, hydrogen production, electricity production, and carbon capture and sequestration (CCS). The renewable diesel market is driven by incentives from the federal RFS and the state low carbon fuel standard. The hydrogen market is supported by a variety of programs meant to reduce carbon emissions, not limited to the state LCFS. The federal 2021 Infrastructure Investment and Jobs Act[22] (IIJA) and the 2022 Inflation Reduction Act[23] (IRA) have the potential to advance both hydrogen and CCS deployment through lucrative financial incentives. These include but are not limited to $8 billion towards hydrogen hubs and 45V tax credits against capital expenditures (6% - 30% investment tax credit, depending on lifecycle carbon emissions) or hydrogen production ($0.6 - $3 per kg$H_2$, depending on lifecycle carbon emissions). There were also enhancements made to the 45Q tax credit program for CCS, increasing incentives, extending construction commencement window, broadening qualifying projects, and increasing the overall flexibility of the program. CARB envisions massive growth in the electric power sector, which may or may not present an opportunity for transitioning refineries.

Unlike renewable diesel or hydrogen, CCS is not a market opportunity to provide a product. Rather, CCS is a compliance strategy for reducing emissions while producing a primary product. These four "opportunities" will be reviewed and contextualized in the forthcoming sections. It should also be noted that maintaining ongoing operations at a refinery site through renewable diesel, hydrogen, or power production, even at greatly scaled back production levels compared to former petroleum operations, may have the benefit of forestalling remediation expenses. The benefits of remediation delay to parent companies have not been quantified in this analysis.

A. Renewable Diesel

As show in **Figure 16**, CARB projects demand for renewable diesel will grow, peak around 2025, and then decline. The effect of this renewable diesel "bridge" has implications for renewable diesel production capacity. CARB's energy demand projections (exajoules) for diesel for all of California (i.e., not disaggregated to the NCNN market) were converted to gallons using **Equation 5**. These gallons are assumed to all be diesel and no biodiesel, which will overstate total diesel gallons produced. These gallons also exclude volumes for export/import. The heat content value for diesel used in the CARB 2014 GHG inventory [37] underlying the Scoping Plan data was used in **Equation 5**.

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[22] More Information about the energy provisions in the Infrastructure Investment and Jobs Act of 2021 (called the Bipartisan Infrastructure Law) can be found at https://www.energy.gov/bil/bipartisan-infrastructure-law-homepage accessed October 11, 2022

[23] More information about the energy provisions in the Inflation Reduction Act of 2022 can be found at https://www.energy.gov/articles/doe-projects-monumental-emissions-reduction-inflation-reduction-act accessed October 11, 2022

$$Diesel(\text{gallons}) = \frac{\left(Diesel\ (\text{EJ}) * \frac{1\text{e}^{18}(\text{joules})}{\text{EJ}}\right)}{\left(\frac{\frac{5.796\ (\text{Mbtu})}{Diesel\ (\text{barrel})} * \frac{1000000\ (\text{btu})}{\text{Mbtu}}}{\frac{\text{barrel}}{42\ (\text{gallons})}}\right) * \left(\frac{1055.06\ (\text{joules})}{\text{btu}}\right)} \quad \textbf{Eq. 5}$$

Equation 6 converts statewide energy demand projections for renewable diesel (exajoules) to gallons using the heat content value of 34 MJ per litre for hydrotreated vegetable oil as reported by Neste Corporation[53].

$$Renewable\ Diesel(\text{gallons}) = \frac{\left(Renewable\ Diesel\ (\text{EJ}) * \frac{1\text{e}^{12}(MJ)}{\text{EJ}}\right)}{\left(\frac{34\ (MJ)}{Litre} * \frac{3.78541\ (Litre)}{gallon}\right)} \quad \textbf{Eq. 6}$$

The resultant gallons of renewable diesel were converted to theoretical renewable diesel barrels per day refining capacity for the entire state of California. This is stream year (365 day) capacity that doesn't take into consideration things like utilization, downtime, production gains, etc. Therefore, it is likely an underestimate of actual require capacity. Commercial renewable fuels facilities tend to focus on renewable diesel production, with sustainable aviation fuel production expected to increase in the future[54]. There are a variety of theoretical renewable diesel yield percentage estimates per unit of feedstock, which differ based on technology, feedstock type, and operations. One CARB-referenced study was found that estimated the theoretical renewable diesel yield from hydrotreating camelina oil to be about 82-87%[55]. We subsequently adjust renewable diesel capacity values from **Equation 7** assuming an 85% renewable diesel yield, to determine renewable fuel capacity estimates.

$$Renewable\ Diesel\ (Barrels\ per\ Day) = \frac{\frac{Renewable\ Diesel\ (gallons\ per\ year)}{\frac{42\ (gallons)}{barrel}}}{\frac{365\ days}{year}} \quad \textbf{Eq. 7}$$

Figure 25 shows annual gallons of diesel (blue line) and renewable diesel (red line) demand, clearly displaying the decline and zeroing out of diesel demand by 2045, and the growth, peak (2025), and leveling out of renewable diesel demand. The peak renewable diesel demand in 2025 equates to almost 187,423 bpd of renewable fuel capacity (or 162,976 bpd of renewable diesel production capacity) at its maximum in 2025. However, by 2045, market demand drops considerably and requires only 85,952 bpd of renewable fuel capacity (74,741 bpd renewable diesel). As a result, a significant increment of gallons (represented by the shaded area in **Figure 25**) is medium-term, temporary demand. Marathon Martinez is planning a 48,000 bpd renewable fuels (renewable: diesel, jet, and gasoline) facility to go online in 2023[19], while Phillips 66 Rodeo is planning a 52,000 bpd renewable (renewable diesel, jet, and gasoline) fuels facility to go online in 2024[17].[24] These two facilities represent a total of 100,000 bpd of renewable fuels capacity. Marathon and Phillips 66 plan to focus on renewable diesel

[24] The Phillips 66 Rodeo Draft Environmental Impact Report references different renewable fuels capacity and production numbers https://www.contracosta.ca.gov/DocumentCenter/View/72880/Rodeo-Renewed-Project-DEIR-October-2021-PDF accessed October 11, 2022

production. Their combined capacity of 100,000 bpd (85,000 bpd of renewable diesel production capacity) just about meets the statewide renewable diesel capacity needs at the end of the period.

Currently, California is heavily dependent on renewable diesel imports. The CEC reported in 2021 that California imported 383 million gallons of renewable diesel via marine tanker, mostly from the Neste facility in Singapore[56]. This is equivalent to about 29,000 bpd of renewable fuels capacity (25,000 bpd renewable diesel production capacity). In addition, there are renewable diesel facilities in other U.S. states. In 2021, the U.S. EIA identified 330,000 bpd of renewable diesel capacity located in the U.S. that could be online by 2024 if all proposed, announced, and under construction projects come to fruition[57]. Given Marathon Martinez and Phillips 66 Rodeo's developing renewable fuels facilities, competition from foreign and domestic renewable fuels facilities, and the temporary demand envisioned, it is unclear if additional in-state renewable diesel capacity investments will be economically viable. It is unclear if CARB's SP22 is factoring in foreign or domestic imports of renewable diesel.

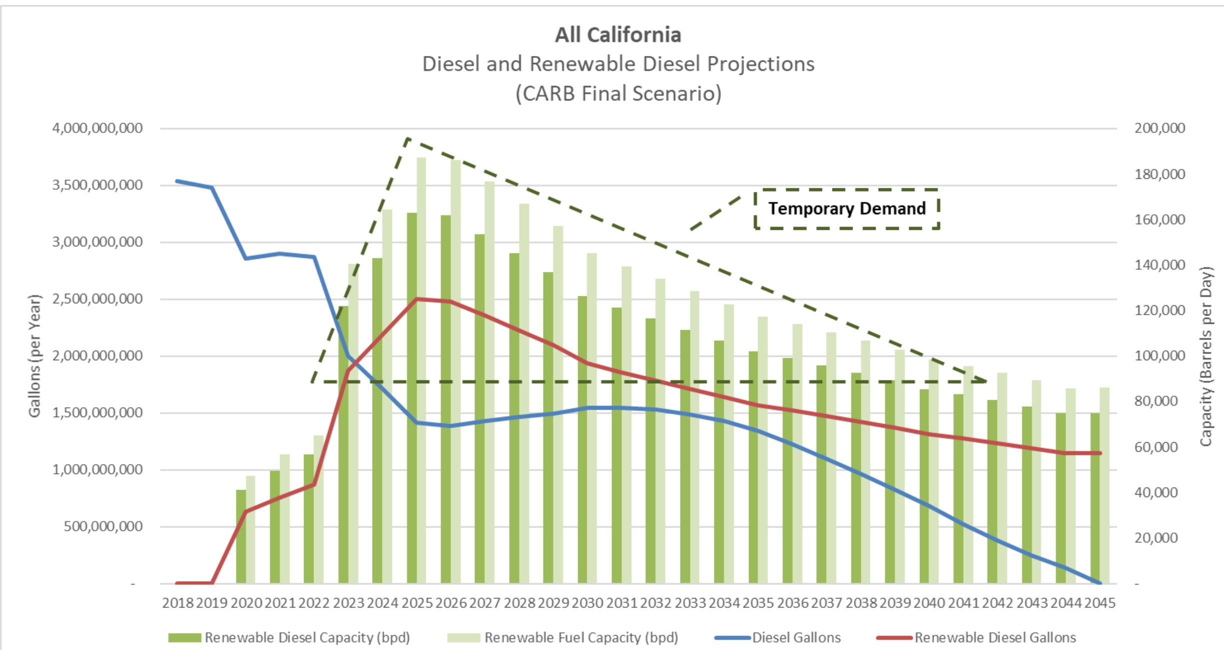

Figure 25 - Projected Diesel and Renewable Diesel Demand for California (statewide), with Implied Renewable Fuel and Diesel Capacity. Author's calculations based on data from [29]

Marathon Martinez and Phillips 66 Rodeo have first mover advantage among the California refineries for serving the renewable diesel market. This doesn't ensure their projects will be the most competitive in the long-term. Other key advantages will include cost minimization, feedstock supply, strategic partnerships, hydrogen supply (for hydrotreaters), logistics, and other factors. One example of complementary projects creating logistics advantages included the Kinder Morgan renewable diesel hub projects that include a hub in northern and southern California[58]. The northern California hub includes 15,000 bpd of blended diesel capacity at its Bradshaw terminal truck rack, to which biodiesel and renewable diesel supplies must be delivered via rail car. The southern California hub includes use of the pipeline system to ship renewable diesel from customers in the Los Angeles area to inland (to the Colton terminal) and southern (to San Diego) destinations, up to 20,000 bpd of blending throughput at Colton, and 5,000 bpd at San Diego. Presumably, the Southern project pipeline capacity provides an advantage over the Northern project.

B. Hydrogen

The CARB Final SP 2022 projects a large increase in demand for hydrogen to fuel heavy-duty vehicles, some medium duty vehicles, and for other non-transportation applications. **Figure 26** shows CARB's projections of the future supply of hydrogen, which in total is dominated by electrolysis-based hydrogen[29]. In this figure, electrolysis (blue) is powered by 10 GW of electric energy that is either imported into California or sourced from power capacity not modeling in the CARB SP22 electricity sector projections[25], [27]. The steam methane reformation (SMR) using biogas (red) is assumed to be imported, specifically, not using in-state bioenergy feedstocks that range from 21 trillion British Thermal Units (TBTU) in 2025, up to 40 TBTU in 2030[27]. Hydrogen produced with bioenergy and CCS (green) is assumed to come from biomass gasification using off grid power resources and subject to feedstock availability[27]. In the Draft SP22, CARB did not provide detailed data on hydrogen supply resource assumptions. As such, the opportunity for refineries to use existing SMR capacity to meet future hydrogen supply needs was a theoretical possibility. With these new data, only about 9.2% of the total hydrogen energy demand (EJ) over the 2023-2045 period is sourced from SMR with biogas (e.g. landfill gas, biodigester gas)[29]. CARB assumes these hydrogen supplies are imported and use bioenergy resources to fuel SMR technologies from outside of California. This suggests CARB does not envision a role for in-state refinery SMR technology to supply future hydrogen needs.

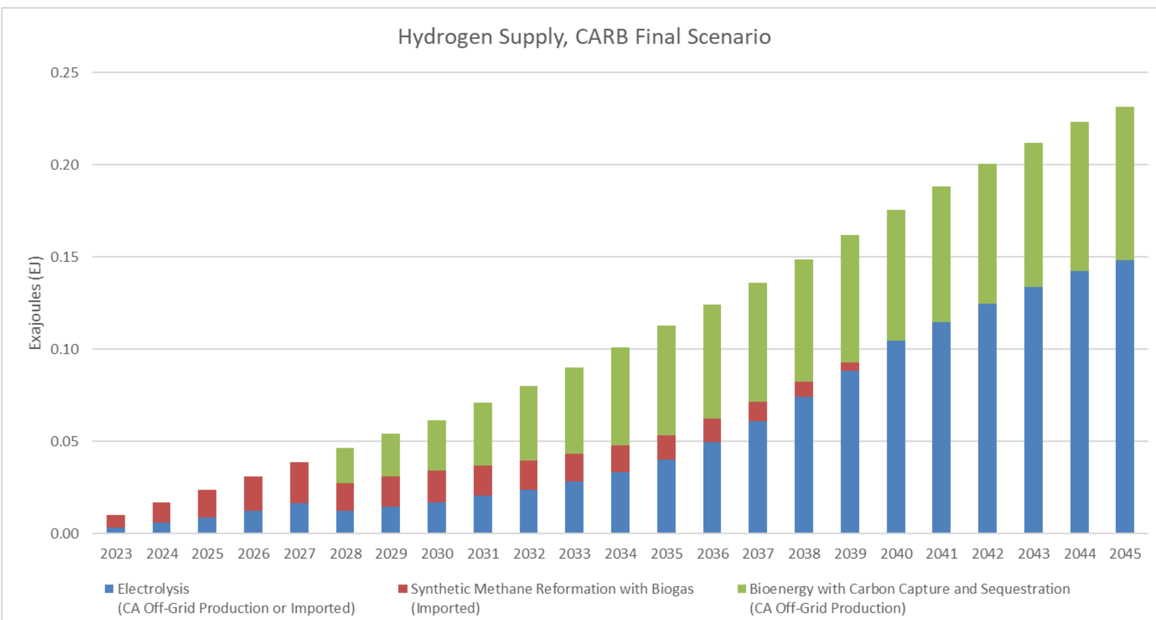

Figure 26 - CARB Final Scenario, Hydrogen Demand and Supply by Technology [29]

CARB's projected hydrogen demand in annual exajoules was translated into tons per year of demand through **Equation 8** for all-sector demand including transportation and non-transportation (i.e., commercial, industrial, refinery, residential sectors) sectors.

$$Hydrogen\ (tons\ per\ year) = \frac{\left(\frac{(Hydrogen\ (EJ)\ *\ \frac{1e^{12}(MJ)}{EJ})}{\frac{120\ MJ}{kg}}\right) * \frac{2.205\ lbs}{kg}}{\frac{2000\ lbs}{ton}} \qquad \textbf{Eq. 8}$$

As shown in **Figure 27**, the SP22 projections estimate for all California about 2,127,030 tons per year (tpy) of hydrogen will be needed in 2045 to meet California's total hydrogen demand. By comparison, EIA data shows that in 2022, all California refinery hydrogen production capacity was 921,185 tpy, all of which was steam methane reformation (SMR) technology that uses natural gas as a feedstock[14]. In 2016, EIA published an analysis showing refineries were increasing relying upon industrial gas companies (e.g., Air Products, Praxair) to provide hydrogen supply[59]. Indeed on March 30, 2020, PBF Energy announced the sale of five of its hydrogen plants (including the two steam reformation hydrogen plants at the Martinez refinery) to Air Products for $530 million as part of a portfolio of efforts to navigate pandemic-related economic challenges[39]. Based on 2016 data, industrial gas companies (IGCs) serving NCNN refineries had about 444,444 tpy of SMR-based hydrogen capacity, with total California IGC hydrogen capacity for refineries estimated at 766,604 tpy [60], [61]. Combining statewide IGC (2016) production with 2022 refinery hydrogen potential production yields about 1,687,789 tpy of SMR based-hydrogen.

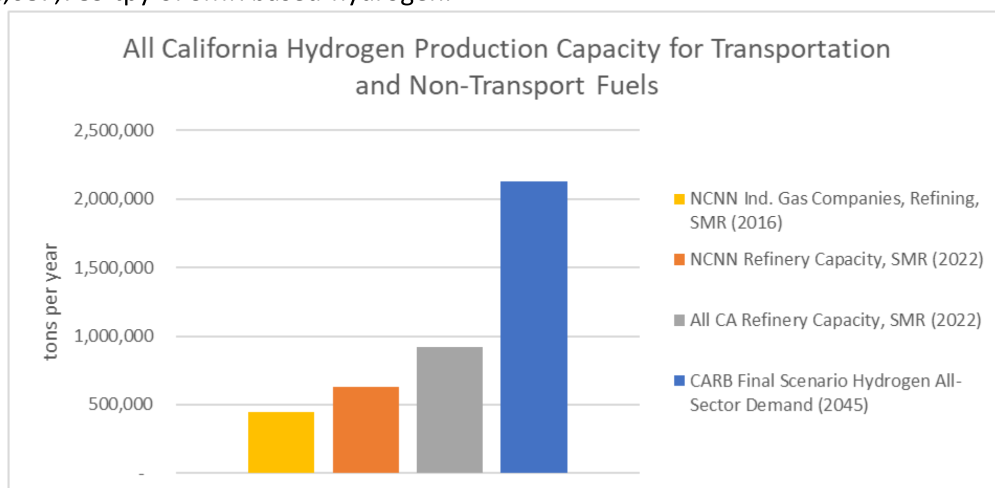

Figure 27 - California Projected Hydrogen Demand and Refinery and IGC Hydrogen SMR Capacity. Author's analysis of data from [29][14][59][60][61]

Significant questions remain about CARB's assumptions underlying its hydrogen supply analysis, especially related to "off-grid" electricity capacity and out-of-state bioenergy feedstocks. These assumptions raise questions about technical and economic viability, emissions leakage, and other quandaries. Similarly, there are uncertainties about the role existing refinery SMR capacity could play in meeting this supply, or how refineries could reinvest to produce greener forms of hydrogen.

C. Electric Power Infrastructure

CARB's Final SP22 electrifies many end-use technologies as its primary strategy to reducing carbon emissions. As a result, tremendous investments in power generation, transmission, and distribution will be required in California. For generation resources alone, as shown in **Figure 28**, CARB projects a more than doubling in electric generating capacity between 2023 to 2045 (an increase of 160 gigawatts, or GW), representing significant policy-driven market growth, and an investment opportunity. This capacity doubling still doesn't factor in the additional power resources required to support CARB's hydrogen (10 GW of solar) or carbon direct air capture (64 GW of solar) supply assumptions[25]. It is unclear if refineries will see this market growth segment as an opportunity (in addition to a threat). Bay Area refineries have certain advantages for siting power generation, including existing grid interconnections, natural gas connections, proximity to load centers, industrial zoning, and significant acreage.

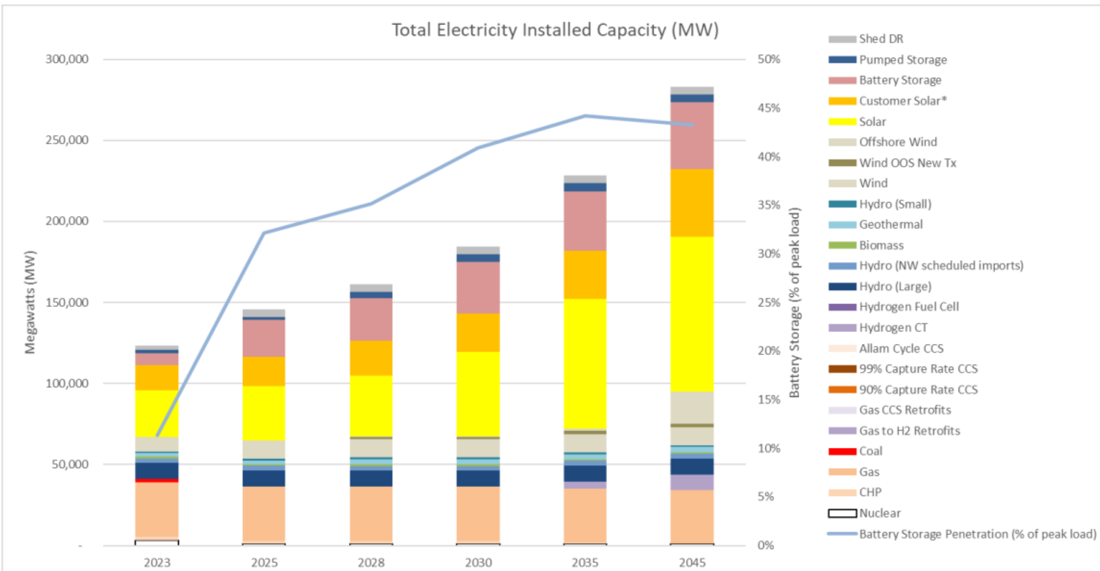

Figure 28 - CARB Final Scenario, Projected Increase in Electric Power Generating Capacity (MW). Author analysis of data from [29]

D. Carbon Capture and Storage

Carbon Capture and Storage (CCS) is not a product demand driver, rather the technology is a compliance strategy to manage carbon emissions. In theory, CCS can be added to refinery process units and hydrogen production units to reduce the carbon intensity of product outputs. Nonetheless, a low-carbon future predicts demand for refinery products will go down, even if CCS become economic and commercially deployed. This is because combustion of the final products will remain carbon intensive. In a low-carbon future, the most competitive refineries (i.e., the one with the greatest longevity) may require CCS investments to maintain ongoing operations.

CARB's CCS projections are included in **Figure 29**, where CARB averages refinery sector emissions reductions across all California refineries. More realistically, the less competitive refineries will drop out as petroleum refinery product demand declines, and emissions will drop in tranches sized to the capacity going offline. CCS at refineries does not begin until 2028 then ramps up to ~60% of total refinery sector emissions within three years (blue line). Although the remainder of the analysis period holds the capture rate steady at ~60% (blue line), total emissions captured ramps down quickly after the first three years (red line). This raises questions about CCS investment viability, given a key financial driver for CCS is the 45Q tax credit[25] that is generated on a tons-stored basis. In other words, a reduction in the tons of emissions captured will also reduce the total amount of federal subsidies generated by the facility.

It is not clear how CARB's CCS emissions projections would translate if disaggregated to individual refineries. It is reasonable to conclude not all refineries will install CCS technology. Rather, in the face of declining demand, only and handful of the most competitive refineries are likely to seriously consider CCS investment. An interested refinery(s) would seek to maximize the level and certainty of subsidy generation (i.e., hold constant the highest level of reliably captured emissions), for purposes of lowering total project and project finance costs. However, commercial scale CCS is extremely costly (CARB estimates $110 per metric ton of CO_2) [27] and the full CCS system cycle (i.e., capture-transport-injection -long term stewardship) has not been reliably proven at scale. Significant government subsidies currently available in the IIJA and IRA, along with technology and process improvements should lower these barriers. Yet, the pattern of declining refinery sector emissions may complicate CCS subsidy generation and investment decisions for refineries.

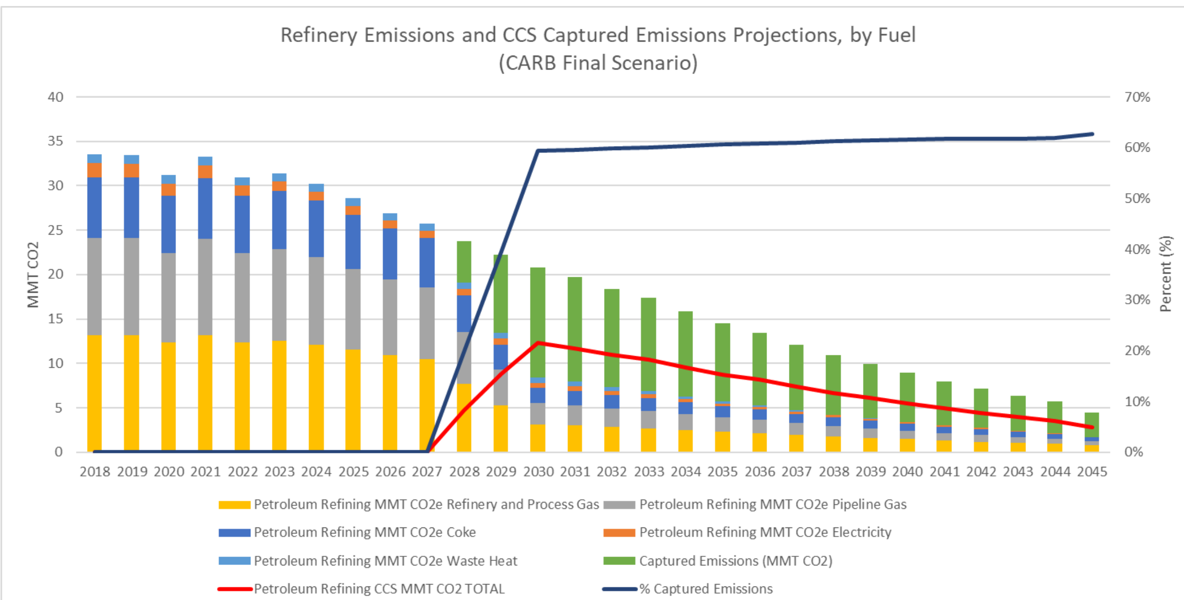

Figure 29 - CARB Final Scenario, Refinery Sector Emissions and CCS Emissions Captured Projections. Author analysis of data from [29]

5. Identifying Example Wild Cards

There are a variety of known and unknown factors that could impact our understanding of refinery markets and economics. This section attempts to identify some examples of these known "wild cards" that can have significant or incremental impacts. These wild cards are grouped by positive or negative potential impacts on NCNN refineries, as well as wild cards where the impact could be either positive or negative (i.e., a toss-up).

[25] More information about the 45Q tax credit is available at the Congressional Research Service at https://crsreports.congress.gov/product/pdf/IF/IF11639 (accessed November 22, 2022). The Inflation Reduction Act expanded and enhanced the 45Q CCS tax credit.

A. Positive Wild Cards

All things being equal, the following are examples of factors that could positively impacts NCNN refineries.

i. Less Stringent GHG Policies. If legal and regulatory requirements in California develop in a way that is less stringent than CARB's Final Scenario, refinery product demand reduction would happen slower than our analysis suggests, and therefore would positively impact NCNN refineries.

ii. Pipeline Reconfiguration. Owing to the reduction in throughput from declining California crude oil production, certain crude oil pipelines are underutilized and have been consolidated under common ownership (See **Appendix B**). It is possible these pipelines could be reconfigured for purposes other than crude oil transport, which could expand NCNN refinery markets by providing a direct connection to the stronger SCSN market. There is no refined product pipeline that directly connects the NCNN and SCSN markets. Rather, required volumes are shipped between these markets (historically, from the north to the south) via costly marine tankers. A direct pipeline connection between these two markets could 1) increase the competitiveness of in-state refineries against out-of-state imports, and 2) could create direct competition between NCNN and SCSN refineries. Most likely, the pipeline would move refined products from the NCNN refineries to the stronger SCSN market, given the NCNN has historically exported to the SCSN. This would create a significant market expansion opportunity for NCNN refineries. However, abandonment of a crude line could negatively impact Bay Area refineries if the action cuts off crude supply from the San Joaquin Valley or requires blended shipments of crude. Assuming the complementary heated crude line (San Pablo Bay Pipeline) remains operational, the KLM line could potentially be converted to a refined product line moving north to south (see **Figure 30**).

Figure 30 - Map of the Crimson Crude Oil Pipelines in California [75]

iii. Competitive Export Market. As in-state demand for refined products decreases, NCNN refineries may explore export markets for product offtake. It is uncertain if NCNN refinery products would be economically competitive in the export market at large volumes. This is because these refineries are configured to produce higher-priced CARB-compliant gasoline and diesel. As shown in **Figure 31**, the market for CARB gasoline (shown as CA RFG) is very limited in the U.S.[62]. It is unclear if there is any foreign demand for CARB-compliant gasoline. California refineries may also produce quantities of regular (non-CARB) reformulated gasoline, for which broader demand may exist. However, it is uncertain how much these refineries can adjust output towards lower specification gasoline, or if these volumes will be competitively priced with products from other U.S. or foreign refiners. The flexibility to produce competitively priced non-CARB reformulated or conventional gasoline and other products could create export market opportunity for NCNN refineries.

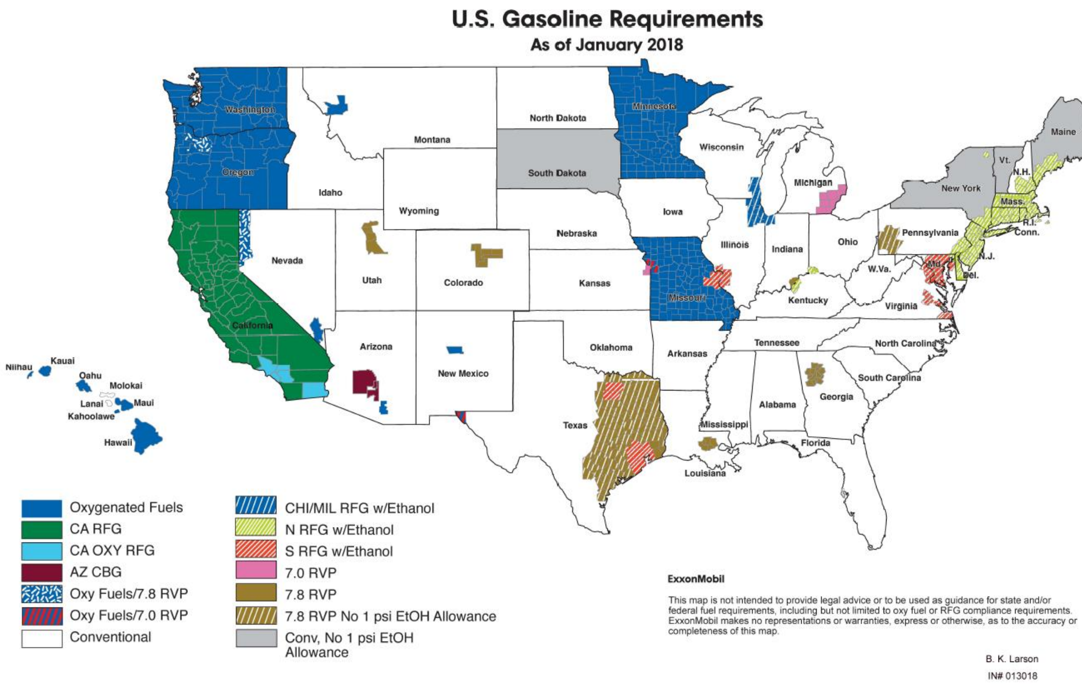

Figure 31 - U.S. Gasoline Specification Requirement. Areas in white use conventional gasoline [62]

B. Negative Wild Cards

All things being equal, the following are examples of factors that could negatively impact NCNN refineries.

i. More Stringent GHG Policies. There are a host of regulatory considerations that could impact outcomes for NCNN refineries. More stringent state regulation of GHGs (e.g., beyond the staff recommended scenario), or a federal GHG reduction requirement, could hasten demand destruction for petroleum products and require facility-level emissions reductions. Conversely, regulatory steps to slow the transition to lower-carbon fuels could extend the life of NCNN refineries. The phaseout of in-state oil extraction is just one example of a regulatory policy currently under consideration that would negatively impact NCNN refineries.[26] Phaseout of in-state oil production would result in increased marine port activity and new infrastructure investments to store and deliver imported crude to NCNN refineries[25]. This would also likely raise feedstock costs to refineries.

ii. Particulate Matter Control Requirement. Bay Area Air Quality Management District actions, specifically implementation of the FCC wet scrubber requirement would negatively

[26] Office of California Governor Newsom, "Governor Newsom takes action to phase out oil extraction in California", April 23, 2021, located at https://www.gov.ca.gov/2021/04/23/governor-newsom-takes-action-to-phase-out-oil-extraction-in-california/ (accessed November 22, 2022)

impact Chevron Richmond and PBF Martinez. This rule is currently being legally challenged. If the rule survives, it could require significant emissions reduction investments or closure of the facility(s) if a refinery owner determines the required investments are not economically justified. This rule would benefit Valero Benicia.

iii. Market Power and Retail Prices. If efforts to address market power result in lower profit margins for refineries, this would negatively impact NCNN refineries. In 2019, California retail gasoline prices averaged $1.00 higher than the national average[63]. The CEC found - after adjusting for additional costs associated with California policy programs (e.g., Cap-and-Trade, LCFS) and taxes - an additional premium remained that was not well explained by refinery margins, outages, crude oil prices, retail margins or other factors[63]. It was eventually concluded this residual premium was likely due to retail gasoline outlets - led especially by large branded retail stations like 76, Chevron, and Shell - charging higher prices[63]. As shown in **Figure 32**, California's retail gasoline market is dominated by branded retailers including higher-priced (e.g., Chevron, 76 and Shell with an average $0.28 premium) and lower-priced (e.g., ARCO, Hypermart with an average $0.08 cent premium) versions, as well as unbranded retailers (average $0.13 cent premium)[63]. Market power concerns arose as these higher-priced retailers were not losing market share to lower-priced competitors, a phenomenon expected in a truly competitive marketplace. CEC determined that despite the claims associated with the benefits of proprietary additives used by these higher priced brands, insufficient product differentiation existed to explain the price differential between the low- and high-priced brands[63]. CEC identified potential legitimate explanations for the higher prices, but also raised concerns about illegal practices such as false advertising and price fixing.

In March 2022, California Attorney General Rob Bonta sent a letter to California refineries warning against actions to manipulate prices for financial gain during Russia's war against Ukraine[64]. This was after retail gasoline prices rose about $5.75 per gallon. In September 2022, in response to rising gasoline prices in the face of lowering crude oil costs, Governor Newsom proposed a Windfall Tax on oil companies[65]. In the same month, the CEC also sent a letter to California refinery CEO's asking specific questions about why California gasoline prices had risen to $2.50 per gallon over the U.S. average unit price[66]. In October 2022, a U.S. District Court judge dismissed a class action lawsuit accusing oil companies (e.g. BP, Chevron, ExxonMobil, Phillips 66, Tesoro, Alon USA) of price-fixing collusion that significantly raised costs to consumers[67]. It is expected this decision will be appealed to a higher court. It is not known whether illegal activity is occurring in these markets and/or if policy or legal actions to address real or perceived injustices will be implemented. Imposition of such legal or policy actions would likely have a negative impact on NCNN refineries.

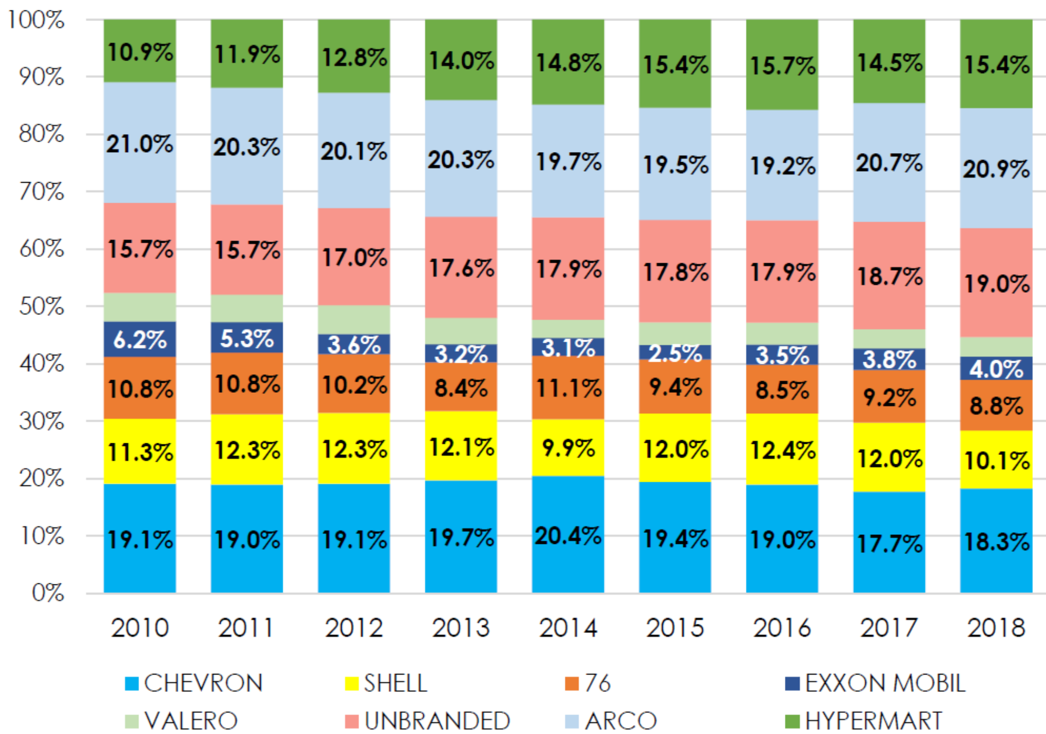

Figure 32 - California Retail Gasoline Market Share (2010-2018) [63]

iv. Specialty Products. Future demand for the Chevron Richmond refinery's specialty lubricants products will have a meaningful impact on the competitiveness of the facility, especially given its competitive disadvantage on crude conversion. Data from the U.S. EIA in **Figure 33** suggests a significant, long-term downward trend in the demand for lubricants on the west coast PADD 5[68]. EIA's lubricants data is inclusive of all grades of lubricating oils (spindle to cylinder) and those used in greases. It is assumed continuation of this downward trend would negatively impact the Chevron Richmond refinery. However, there may (or may not) be additional lubricants markets Chevron Richmond serves as well as pricing changes that ameliorate for these declines.

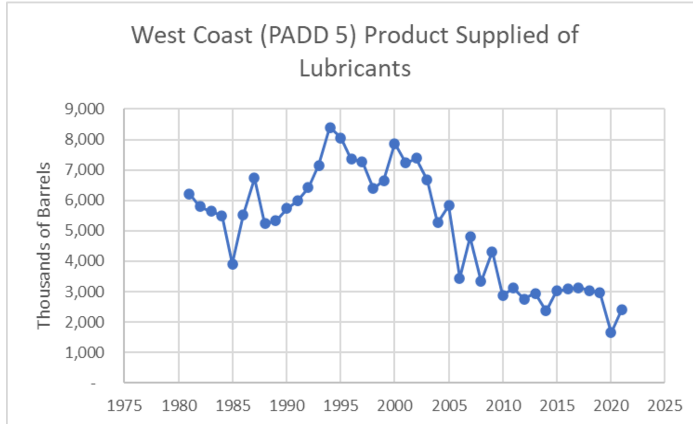

Figure 33 - PADD 5 Historic Product Supplied (i.e., demand) of Lubricants [68]

C. Toss-Up Wild Cards

The following factors are examples of known issues that could positively or negatively impact NCNN refineries, depending on how the future unfolds.

i. Future Market for Renewable Fuels. The future market for renewable fuels will have impacts on NCNN refineries. Specifically, the relationship between demand, supply, and price. Factors that could hasten conversion to alternative/renewable fuels include increases in demand (e.g., related to policy), increases in supply (e.g., related to subsidies), and lowering of prices. Factors that could slow transition to these fuels include tempered demand growth, lagging supply, and higher prices to consumers. There are several programs that promote alternative and renewable fuels including: the federal corporate average fuel economy (CAFE) standards that promote fuel efficiency and vehicle electrification; the federal renewable fuel standard (RFS) program that promotes ethanol and other renewable fuels, and California's low carbon fuel standard (LCFS). The LCFS requires a 20% reduction by 2030 in the carbon intensity of transportation fuels. Compliance entities like refiners and blenders can either produce lower carbon fuels or purchase credits to demonstrate compliance. As seen in **Figure 34** (separate from the Scoping Plan Staff Recommended Scenario), electricity and renewable diesel are projected to dominate LCFS credit in the future, while the roles of ethanol and biodiesel are projected to decline[21]. Both renewable diesel and biodiesel are made from similar feedstocks, but use different technologies. Biodiesel is made from a transesterification process and must be blended with traditional diesel, while renewable diesel is made by hydrotreating and can be a stand alone fuel. Renewable diesel is becoming more popular than biodiesel in California for a number of reasons. First, renewable diesel margins are 4 times greater than petroleum diesel margins[69]. Second, renewable diesel is manufactured in similar ways to petroleum diesel (e.g., hydrotreating), whereas biodiesel relies on a methanol-based chemical reaction. As a result, unlike biodiesel, renewable diesel is highly compatible with petroleum diesel (e.g., high blending levels, co-processing) and does not create quality concerns. Third, renewable diesel has a lower carbon intensity and therefore generates a greater number of LCFS credits and can create more RFS credits (i.e., RINs) because it can be blended in greater fractions. Lastly, the market for renewable diesel on the west coast is expanding given California, Oregon, Washington, and British Columbia all have a form of LCFS policy, creating a massive west coast market for renewable fuels.

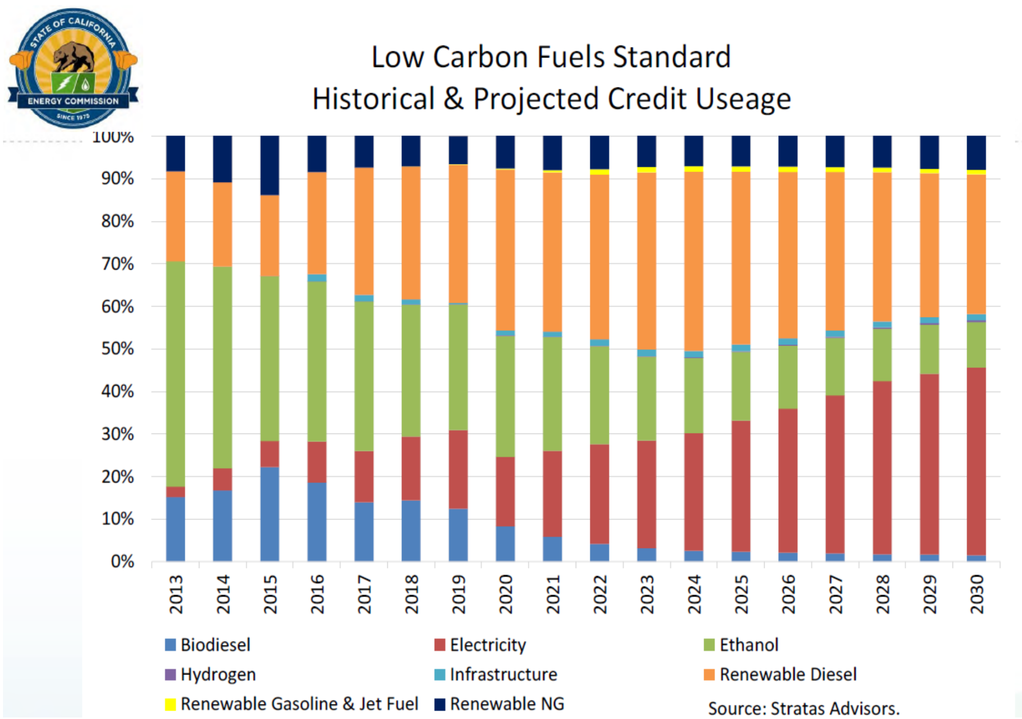

Figure 34 - Past and Projected Future LCFS Credit Usage (May 5, 2021) [21]

ii. Infrastructure Constraints and Subsidies. Infrastructure constraints may serve to slow the transition to lower carbon fuels and reduce the rate of refined product demand destruction. For example, the market for hydrogen fuel may be slow to develop if the required infrastructure for retail distribution materializes slower than CARB projects. One study found over 50% of the total price at the pump for hydrogen was related to station costs, which in turn were driven by financing costs[70]. In general, infrastructure costs are sensitive to the cost of money, so increases in interest rates can serve to raise costs and slow infrastructure investments. San Francisco Bay Area airports depend on area refineries for jet fuel supply, augmented by waterborne deliveries. Existing marine terminals and pipeline connections in the area are not configured to adjust to sustainable jet fuel importer status[21]. Therefore, infrastructure investments are required if NCNN refineries cease producing traditional jet fuel and/or are not capable of producing sustainable jet fuel. While infrastructure costs may delay alternative energy transition, historic federal investments into energy infrastructure represented by the IJIA and IRA may serve to hasten infrastructure buildouts.

iii. Uneven Geographic Adoption of Alternative Fuel Vehicles. It is unlikely the adoption of alternative fueled vehicles will be geographically homogenous. For example, studies indicate electric vehicle adoption in California is happening at greater rates in urban coastal areas within higher income zip codes[34]. All things equal, areas with higher levels of alternative vehicle adoption are likely to see faster rates of refined product demand reduction. This may impact refineries based on the concentration of retail gas stations or supply contracts. For example, a refinery supplying product to its branded retailer with locations concentrated in an area of high alternative fuel vehicle adoption may see greater demand reduction than anticipated. The uneven adoption of alternative fuel vehicles, including alternatively fueled heavy and medium duty vehicles, could result in uneven impacts to refineries based on supply contracts, logistics contracts, and other factors.

iv. Regulatory Response to Emissions Leakage. Pertaining to GHG emissions reduction policy, the concept of "emissions leakage" refers to when an emitting activity shifts outside of the regulatory jurisdiction after imposition of emissions restrictions. In this context, California's efforts to reduce refinery emissions could result in refineries shuttering in NCNN only to have refinery products imported into the NCNN from areas that have no emissions reduction requirement. Or efforts to promote use of alternative fuels in California result in greater imports instead of greater in-state investments in alternative fuel capacity. Emissions leakage is a well-known phenomenon in GHG regulation that can be controlled for through policies such as lifecycle accounting, border adjustments, or other strategies. The regulatory response to emissions leakage, or lack thereof, can significantly impact costs and opportunities. If emissions leakage is ignored, impacts will likely be worse for Bay Area refineries. Meaning, GHG emissions are shifted to out-of-state locations at the expense of in-state refineries (e.g., with an increase in emission-intensive imports) and unknown impacts on net emissions. If emissions leakage is addressed, in-state refineries will compete on a more level playing field and net emissions reductions will be pursued.

v. Timing, Subsidies, and Investment Decisions. Refinery investment decisions are informed by many factors, including timing. All things equal, capital deployed should deliver a return of and on the investment made. In this context, the applicable investment must be operational for enough time to deliver these returns. This concept is particularly relevant for the renewable diesel and CCS opportunities explored earlier. It is also applicable to refinery operation and maintenance turnarounds. For example, suppose a refinery analyst estimates there is at least 5 years of strong market demand for the refinery's products. However, in year 2 of the 5-year period a major equipment turnaround is due that requires millions of dollars of capital investment. These investments will only have 3 years to deliver returns, which may be insufficient. In this scenario, the refinery may choose to close in year 2 of 5, even though market demand still exists. In this sense, uncertainty, demand destruction, and limited time to earn a return on capital are aspects of timing working against refineries. On the other hand, historic levels of federal subsidies available from the IJIA and IRA are aspects of timing working in favor of the refineries.

6. Conclusions

For the transportation sector, limiting greenhouse gas emissions to address climate change requires a reduction in petroleum combustion and a move towards fuels with lower or zero emissions. By 2045, CARB predicts electricity, hydrogen, and renewable diesel will be the top three overall transportation fuels. This will have a profound and negative impact on the demand for traditional petroleum refinery products. In turn, this demand reduction will threaten the viability of traditional petroleum refineries in the Bay Area.

- Holding gasoline export volumes at historic levels, CARB's gasoline projections for 2045 imply only one larger or two smaller Bay Area refineries will be needed to meet residual gasoline demand.
- If export volumes decline at rates similar to overall gasoline demand reduction, it is unlikely that residual gasoline demand could support a single refinery.

Each NCNN refinery has comparative strengths and weaknesses. Chevron's Richmond refinery benefits from a strong parent company balance sheet, robust network of in-state retail distribution stations, and product diversification through the lubricants market. Chevron Richmond's weaknesses are related to low conversion capacity, exposure to upcoming particulate emissions control requirements, and higher internal capital competition for reinvestment. PBF's Martinez benefits by having the strongest overall refinery based on technical refinery metrics. Drawbacks include exposure to upcoming particulate emissions control requirements, lack of dedicated distribution off-take, and a weaker corporate balance sheet. Valero's Benicia benefits from being a solid technical performer, having some dedicated retail distribution outlets, solid corporate financials, lack of exposure to new particulate controls, and may not have land remediation expense exposure. On the other hand, the facility is not technically complex, distribution off-take is quite limited, and its main competitive advantage against its peers may be lack of exposure to the particulate emissions rule.

In response to refinery product demand reduction, refineries can try to stay open, invest to produce new products, or may close and remediate refinery land.

- CCS investments for carbon emissions management at surviving refineries will be bolstered by federal subsidies in the IJIA and IRA. However, significant barriers exist due to the technology's expense, lack of commercially successful deployment, and pattern of reduced emissions captured that is envisioned in the CARB Final SP22.
- Renewable fuels conversion of the Marathon Martinez and Phillips 66 Rodeo refineries are nearly sufficient to meet projected steady-state renewable diesel demand for the California market, but not peak demand. Depending on how emissions leakage is addressed, peak demand may likely be supplied by imports from foreign or domestic capacity rather than additional in-state investments at refineries.
- While CARB's Final SP22 projects a massive increase in future hydrogen demand, its supply projections rely almost entirely on imported hydrogen, electricity, and bioenergy feedstocks. CARB does not see a role for the 1.69 million tpy of SMR technology hydrogen capacity available at in-state refineries or companies that serve these refineries. There are significant uncertainties associated with the underlying assumptions of CARB's hydrogen supply analysis.
- CARB projects electric power generation capacity resources will have to more than double between 2023 and 2045, requiring massive investment and subsidies. Electrification is displacing demand for petroleum products, threatening the economic viability of California refineries.

However, NCNN refineries may be well positioned to host power generation resource investments and capture related returns.

If a refinery can't outcompete rival refineries or pivot to a new product, it will be forced to close. Refinery closure is likely to trigger regulatory requirements for land remediation for which the refinery owner (likely excluding Valero's Benicia) must fund per RCRA. Remediation costs depend on factors such as the level of contamination and the stringency of required cleanup standards. By investing in producing other products, refinery owners may have the added benefit of delaying remediation expenditures. Alternatively, selling the land for other industrial-scale operations may reduce the stringency of cleanup standards. Future commercial or residential uses of the land could be prohibited if cleanup standards restrict these uses or could place additional costs on future developers to further remediate the land for unrestricted use. Communities around refineries should begin planning early and explore the highest and best potential future uses of these refinery parcels to inform regulatory discourse about cleanup standards.

We identify examples of several known issues with unknown probabilities of occurrence, dubbed wild cards. These wild card issues could meaningfully impact the conclusions of our analysis. Wild card examples are categorized by issues that could help NCNN refineries (i.e., positive wild cards), hurt NCNN refineries (i.e., negative wild cards) or could hurt or harm NCNN refineries depending on how the issues materialize (i.e., toss-up wild cards). Perhaps the most meaningful wild card is the stringency of future GHG emissions reductions requirements. A less stringent regulatory regime, compared to the CARB staff recommended scenario, would help NCNN refineries. A more stringent regulatory regime, which could include increased federal regulation of GHGs, may further harm NCNN refineries.

While there are many uncertainties, a few things are clear. Limiting GHG emissions will result in decreased demand for traditional refinery products, and in turn, this will result in a reduced amount of required refinery capacity. It is unclear which refineries will prevail or when the next refinery may shutter. As such, all communities affected by refinery operations should be preparing early. Preparation and planning activities should take place in at least three key areas:

- Worker transition – How political leaders, unions, and communities support refinery workers and local supply chain business that will be negatively impacted by the refinery's closure?
- Diversification of municipal tax base – If the municipality is over-reliant on tax revenues from the refinery, how can it plan to diversify its tax revenue base?
- Maximizing refinery land redevelopment opportunities - Ensuring refinery lands are remediated to standards that support unrestricted end uses will lower costs for future owner/developers, further supporting highest and best end uses. Highest and best uses can benefit communities through job creation, economic development, broadening the tax base, etc. Planning efforts to identify the highest and best potential uses of refinery lands - for example those uses that maximize high quality job creation, economic development, and environmental benefits aligned with local community visions - can guide municipal policymaking towards those end uses (e.g., ordinances to restrict or encourage certain end uses). Planning should take place to prepare for and advocate to ensure the most stringent refinery land cleanup standards are achieved.

These early planning efforts may serve to limit the negative consequences of imminent refinery closure and prepare surrounding communities for a thriving, post-refining future.

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Appendix A – CARB Draft Scoping Plan Scenarios

The California Air Resources Board (CARB's) 2017 Final Scoping Plan [23] identified pathways to achieving 40% greenhouse gas (GHG) emissions reductions (from 1990 levels) by 2030, as required by the state's global warming law, AB 32. [27] Conversely, CARB's 2022 Draft Scoping Plan (Draft SP22) released in May 2022 [24] identifies potential pathways to carbon neutrality by 2045 or earlier, which currently is a *non-enforceable goal*. However, the Draft SP22 does account for legislation, regulations, and executive orders passed after the 2017 Final Scoping Plan.

GHG emissions data used to inform the Draft SP22 came from CARB's 2000-2019 Greenhouse Gas Emissions Inventory [71], then potential future scenarios are projected using the California PATHWAYS model. The PATHWAYS model is an economy-wide energy and GHG modeling tool using a device and vehicle stock rollover method that was developed by Energy and Environmental Economics (E3).[28] Energy demand projections are used to determine energy supply, while energy prices and emissions associated with this supply are informed by incorporation of low and zero carbon fuels. Emissions reductions associated with reduced petroleum product demand are calculated on a statewide basis, then applied equally to all refineries.

Four (4) future carbon neutral scenarios were modelled along with a Reference Scenario that is limited to GHG reductions associated with existing required policies. The four scenarios have many similarities, but important differences related to:

- The year carbon neutrality is achieved (2035 or 2045).
- Deployment rate of clean technology and production and distribution of zero carbon energy.
- Residual fossil energy demand in the year carbon neutrality is achieved.
- Constraints on technology and fuels deployed in certain sectors.
- Consumer adoption rates of clean technologies and fuels.
- Degree of reliance on CO_2 removal (from the air) and CCS (from a facility).

The following four scenarios developed after public input. **Figure 35** shows the refinery-wide sector emissions impacts of each scenario. CARB's Final Scoping Plan (November 2022) [25]uses Alternative #3 as the basis of its analysis.

[27] More information on California's AB 32 can be found on CARB's website at https://ww2.arb.ca.gov/resources/fact-sheets/ab-32-global-warming-solutions-act-2006 (accessed August 1, 2022)

[28] More information on the Pathways model can be found at https://www.ethree.com/tools/pathways-model/

- **Alternative 1: Carbon Neutral by 2035.** Near complete phase out of all combustion, limited reliance on engineered carbon removal and CCS, limited use of bio-based fuels. Phases out all combustion including from fossil, biomass-derived, or hydrogen fuels. Refining (as well as oil and gas extraction) operations would be phased out by 2035, requiring buy-back or early retirement of internal combustion engine vehicles (ICEV) and only zero-emissions vehicles (ZEV) would be available for sale.

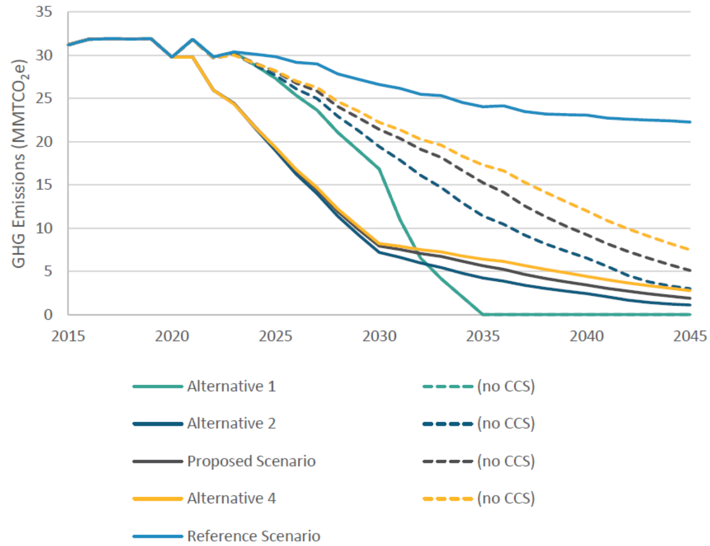

Figure 35 - CARB Draft SP22 Figure on Oil Refining Emissions by Scenario, with and without CCS [24]

- **Alternative 2: Carbon Neutral by 2035.** Aggressive deployment of full suite of technology and energy options including engineered carbon removal and CCS. Does not phase out combustion of fuels (fossil, bio-based, hydrogen), and therefore places higher reliance on carbon removal and CCS. Refining and oil and gas operations are scaled down with demand and paired with CCS where appliable.
- **Alternative 3 (Staff-Proposed Scenario): Carbon Neutral by 2045.** Deploy broad suite of new and existing fossil fuel alternatives and clean technologies. Align with statues and executive orders. Modeling assumes CCS for refineries that will stay open to meet in-state fuel demand. This scenario also relies on transitioning some fossil fuel combustion to hydrogen, the latter of which cannot solely be derived from renewable-fueled electrolysis. Oil and gas extraction related emissions could be reduced by 85% from 2020 levels by 2045, assuming all in-state crude demand is met by in-state extraction. Conversely, all residual in-state demand could be met by marine-based crude imports. In both scenarios, crude would be processed by in-state refineries. CARB is concerned about the leakage associated with the import scenario. This scenario would result in an 83% reduction from 2020 levels of refinery emissions by 2045. If in-state refining is phased down to zero, but demand still exists for refined petroleum products, California would have to rely on marine-based imports. There could be a two- to five-fold increase in refined product imports depending on source of demand (i.e., California and neighboring states). Marine infrastructure (e.g., receiving, tankage, pipeline) reconfiguration would also be needed, and emission leakage would be a concern.
- **Alternative 4: Carbon Neutral by 2045.** Deploy broad suite of new and existing fossil fuel alternatives and clean technologies. Slower deployment and adoption rates than Alternative 3. Does not phase out fuel combustion (fossil, bio-based, hydrogen), therefore greater reliance on carbon removal and CCS. Refining and oil and gas operations are scaled down with demand and paired with CCS after 2045 where appliable.

Appendix B – Pipeline Consolidation and Reconfiguration

Owing to the reduction in throughput from declining California crude oil production, certain crude oil pipelines are underutilized and have been consolidated under consolidated ownership. It is possible these pipelines could be reconfigured for purposes other than crude oil transport, which could impact refinery markets. There are at least two related outcomes that can be theorized:

- Abandonment – If crude throughput levels decrease below minimum technical operational levels and/or transportation rates become uneconomic, a crude oil pipeline may be abandoned. Potentially, crude volumes could be consolidated to parallel lines. The abandoned line could be reconfigured for other purposes. If all crude lines were to be abandoned, NCNN refineries would become 100% reliant on imported feedstocks, which would likely increase costs.
- Direct Products Connection - There is no refined product pipeline that directly connects the NCNN and SCSN markets. Rather, required volumes are shipped between these markets via costly marine tankers. A direct pipeline connection between these two markets could 1) increase the competitiveness of in-state refineries against out-of-state imports, and 2) could create direct competition between NCNN and SCSN refineries. Most likely, the pipeline would move refined products from the NCNN refineries to the stronger SCSN market. This would create a significant market expansion opportunity for NCNN refineries.

As shown in **Figure 36**, crude oil pipeline miles have consolidated under Crimson Pipeline LP's ownership since 2016, with Crimson's mileage increases corresponding to mileage decreases from Exxon, Chevron, Phillips 66, and Shell[72]. In 2016, Crimson acquired ownership (from Chevron) of the 295-mile KLM pipeline, which at that time brought crude from the San Joaquin Valley (SJV) to Tesoro

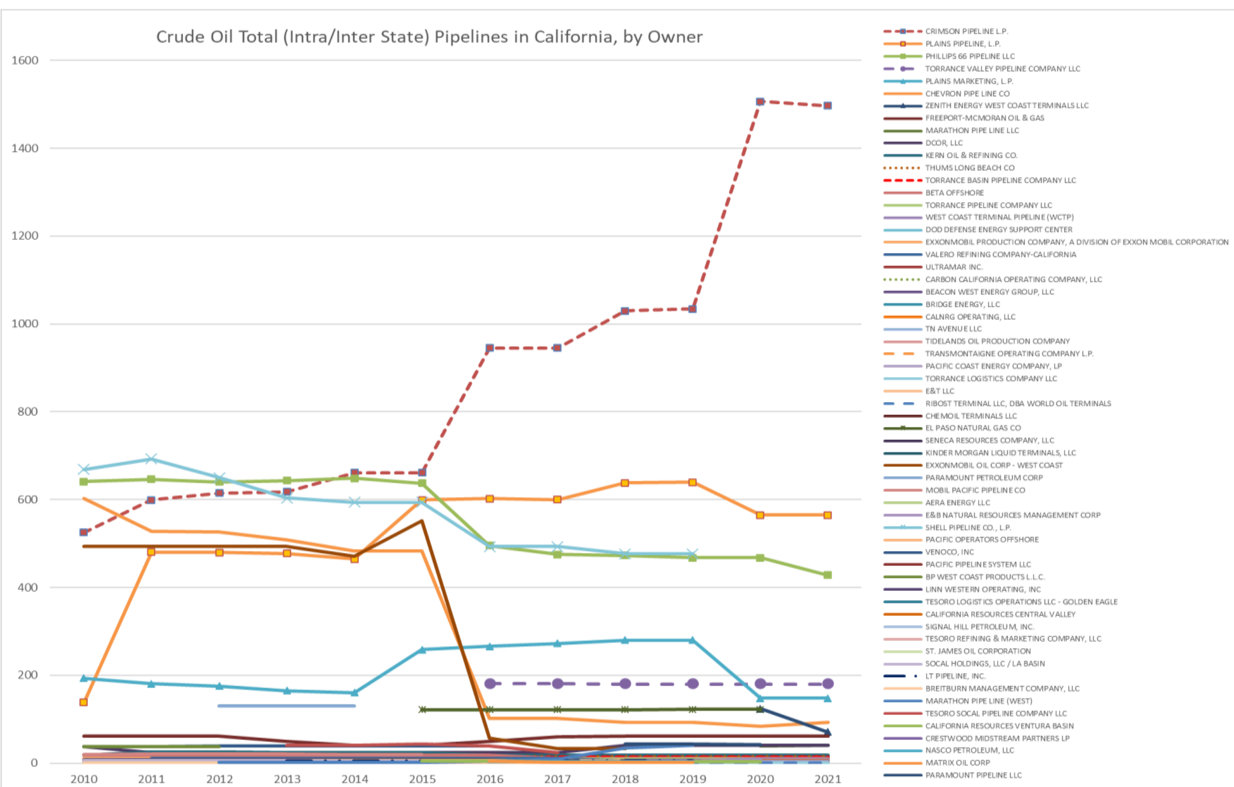

Figure 36 - Total Crude Pipeline Miles (Inter/Intra) in California, by Owner. Author analysis of data from [72]

Golden Eagle, Valero Benicia, and Shell Martinez refineries in the San Francisco Bay Area[73]. In April 2019, Crimson filed an application with the CPUC for authority to acquire control of the San Pablo Bay Pipeline Company (SPBPC) from Shell/Equilon[74]. At the time, the 265-mile SPBP pipeline transported heated crude oil from the San Joaquin Valley to Bay Area refineries owned by Shell, Tesoro, Valero, and Chevron. The 2019 application to the CPUC revealed that much of the SPBP and KLM pipeline capacity was "substantially underutilized", noting two-thirds of the KLM line was unutilized and the SPBP was approaching its minimum flow requirements[74]. The falling utilization was attributed to declining oil production in the SJV and a shift in SJV crude volumes being shipped to the Los Angeles area refineries. A map of the Crimson crude pipelines is include in **Figure 30** [75]. The filing with the CPUC states Bay Area refineries prefer neat (unblended) heavy crude, which the SPBC accommodates by heating the crude to allow it to flow, this line can also send crude in batches. The KLM line was not able to heat the crude or batch, so the crude would require the inferior option of blending with lighter crude to allow for transport. The application warned further volume reductions on SPBC would require investments to add more heat (to lower the minimum flow levels) or abandoning heated service and requiring blending. The application proposed to operationally interconnect KLM with SPBC, then move KLM blended volumes in batch on the SPBC line, and eventually abandon the KLM line north of Kettleman[74].[29]

In June 2020, Crimson filed a 10% rate increase application stating volumes on the KLM line had decreased from 12.6 million barrels in 2017 down to 7.7 million barrels in 2019[76]. In this application, Crimson describes itself as a,"…limited partnership for the specific purpose of owning, operating, and managing smaller, marginal, or idle pipelines and providing pipelines transportation services to the public."[76]. Correspondingly, Crimson's crude pipeline serving Southern CA refineries ("California Crimson") had been submitting rate increase requests annually to the CPUC between 2016 and 2019. In aggregate, these requests represented a 60% increase from the 2009 rates in effect at the time of the initial 2016 rate increase request[77]. Crimson attributed the need for these rate increases to reduced throughput volumes that declines from 53.5 million barrels in 2015 down to 35.2 million barrels in 2018[77]. The CPUC ultimately approved the 60% rate increase in 2020[77].

It is clear from these data the decline in California crude oil production is having a profound impact on crude oil pipeline operations and rates. Continued throughput volume declines risk further rate increases and potential idling or abandonment of lines. In February 2021, Crimson was bought by CorEnergy Infrastructure Trust Inc. for $350 million[78], representing a 49.5% majority interest in the company and the right to acquire the remaining 50.5% interest upon receiving CPUC approval[79]. CorEnergy states that in 2021 its revenues were concentrated in several major customers including Chevron Products Co. (20%), Shell Trading US Co. (17%), PBF Holdings Co. (13%), and Phillips 66 (12%)[79]. CorEnergy also notes its assets "…have strategic rights-of-way that may have alternative use

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[29] Several parties protested the application and joined an alternative dispute resolution process underway since 2018 on other issues involving the SPBC line. Specifically, dispute resolution process underway involved an October 2017 SPBC rate increase request of 10% (Docket A.17-10-019), an April 2018 application to suspend heated service on the SPBC line (Docket A.18-04-011), and now the ownership change to Crimson (Docket A.19-04-008). In August 2019, a settlement agreement on all three dockets was reached that among other things: allowed for the ownership change, reduced and froze for 3 years the per barrel shipping rate on SPBC, required SPBC to invest $5 million in heater upgrades to lower the minimum flow requirement, required coordination on operational integration between KLM and SPBC lines, and committed Crimson to state they have no intention to abandon the KLM line in whole or part[80]. In February 2020, the CPUC approved the settlement.

value in association with energy transition."[79]. In December 2021, CorEnergy petitioned the PUC to approve acquisition of the remaining 50.5% interest in Crimson[79].