Turner, Mason & Company
energy consulting & advisory

Memorandum

To: Western States Petroleum Association

From: Turner, Mason & Company

Date: August 28, 2025

Subject: Analysis of Decarbonization Pathways for Washington Refineries

---

Executive Summary

Implementing the decarbonization pathways analyzed in this memo have the potential to reduce CO2e emissions ~5 MMTPA (Million Tons per Annum), a 78% reduction from current levels. Fully implementing these projects across all Washington refineries could take until the mid-2040s, with total required investment ranging from $12 to $22 billion (in $2025).

We note the following significant findings:

1) Reduction in CO2e emissions in Washington would be offset by higher emissions elsewhere in the world as products needed to balance the market in Washington would be refined and imported. Net emissions could be higher depending on the trade-off of reduced emissions from shutting down a processing unit in Washington and increased emissions from importing finished products to and exporting unfinished products from the Washington market.
2) Shutting down units, such as a naphtha reformer or delayed coker would have material negative commercial implications, with annual margin losses in the range of $0.7 to $1.2 billion depending on the unit closed. Shutting down these units could require major changes in operations and logistics, which could increase operational risks and threaten the economic viability of the refinery.
3) While workforce reductions appear somewhat small (25 to 45 FTE or "full-time equivalent" workers for each unit closed), displaced operators could face 40 – 50% reductions in compensation relative to comparable jobs in Washington.
4) Most capital projects to reduce CO2e emissions have negative economic value and are unlikely to be competitive for capital in a refining company's capital budget.
5) Planning for maintenance turnarounds before 2030 are underway already. Unless turnarounds in the next five years already includes a decarbonization capital project, such CO2e reductions could not be implemented until well into the latter

half of the 2030s. Quite likely only one such project could be implemented per turnaround given their complexity and other required work.

Background

Turner, Mason & Company (TM&C)[1] was commissioned by WSPA (Western States Petroleum Association) to evaluate decarbonization pathways for Washington refineries as presented by RMI (Rocky Mountain Institute) at the EITE (Emissions Intensive Trade Exposed) Industries Advisory Group meeting on November 14, 2024. This memo summarizes the project scope, economic implications, timelines, and key findings related to CO2e emissions reductions, with a focus on operational changes and major capital investments.

The primary differences between the analysis by RMI and TM&C are twofold. First, RMI does a top-down analysis based on theoretical estimates using information gathered from the U.S. Department of Energy, as well as a variety of other public sources. By contrast, TM&C analysis is a bottom-up analysis using operating parameters and capital cost estimates from a number of actual projects we have worked on with clients or vetted for potential financial investors. We apply these real project examples to a typical petroleum fuels refinery in the Pacific Northwest to consider potential changes in refinery configurations, operations, and capital costs. The second difference is we consider changes in global greenhouse gas emissions net of material movements required to keep the refineries and broader Pacific Northwest petroleum fuels markets in balance.

A key assumption in this analysis is that petroleum fuel demand is independent of any change of configuration or operations of a refinery. Thus any reduction in petroleum fuels production in Washington refineries would need to be imported to meet local demand.

Shutting down key processing units, such as a naphtha reformer and/or a delayed coker would increase vessel traffic to handle exports of intermediates to keep the refineries balanced and imports of finished products to keep local petroleum product markets balanced.[2] We assume there is sufficient dock and harbor capacity to handle this increase

---

[1] Turner, Mason & Company (TM&C) provides research and consulting services utilizing reasonable care and employing methodologies consistent with industry practice and applicable professional standards. Our assessments are based on our experience in the petroleum, renewable and biofuels markets and are consistent with practices commonly used in these sectors but ultimately represent our professional judgements and, in some cases, opinions. Unless explicitly stated, forward looking data and other information herein, do not include, nor should they be construed as including advice, guidance, or recommendations from TM&C to take, or not to take, any actions or decisions in relation to any matter, including without limitation, relating to investments, or the purchase or sale of any securities, shares or other assets of any kind. Should you take any such action, or decision based on information contained herein, you do so entirely at your own risk. TM&C does not guarantee the accuracy or completeness of the data or our assessments and shall have no liability whatsoever for any loss, damage, costs, or expenses incurred or suffered by you as a result of your reliance on them.

[2] Unlike the US Gulf Coast, refineries in the Pacific Northwest are not surrounded by petrochemical plants that have the potential to absorb intermediate products as feedstocks. California refineries also tend (cont'd on page 3)

in vessel traffic. Any capital investments required for additional logistics capacity or debottlenecking are not included in our estimates. We also have not factored in any potential operational risks from these material changes in logistics and supply chains.

We calculate CO2e emissions related to the imports of refined products to meet local demand, as well as the export of unfinished or intermediate products that could no longer be processed to meet local Pacific Northwest product specifications.

Decarbonization from Changing Operations

Shutting Down a Naphtha Reformer

A naphtha reformer converts low-octane straight-run naphtha from the CDU (crude distillation unit) into high-octane reformate, which is a key component of gasoline. The primary purpose of the reformer is to improve the octane rating of gasoline and to produce hydrogen, as a byproduct, which is used in other refinery processes, such as hydrotreating (reducing sulfur in a product) and hydrocracking (a process designed to crack heavier molecules into distillates).

Shutting down a naphtha reformer actually has the potential to *increase* global CO2e emissions. Shutting down a naphtha reformer would reduce unit-specific CO2e emissions 6%. However, in our representative refinery, a SMR (steam methane reformer), which is used to make hydrogen, must be run at a higher utilization to make up for the loss of hydrogen supply when the naphtha reformer is closed. In our representative refinery, CO2e emissions increase ~10% because of greater natural gas usage in the SMR.

The straight-run naphtha from the CDU (that no longer goes to the naphtha reformer) would not meet gasoline blending specifications (especially octane). We assume those naphtha volumes are exported to Asia.[3] Shipping to the U.S. Gulf Coast requires the use of scarce and expensive Jones Act tankers in addition to the logistical complexity of transiting the Panama Canal. Shipping to Europe is generally more expensive than Asia because in addition to the Panama Canal fees there are longer voyage distances and EU carbon pricing fees for marine transport.

By losing the naphtha reforming, gasoline production decreases ~20% and we assume that volume needs to be replaced by imports from Asia to keep the Pacific Northwest gasoline market balanced. This assumption is consistent with the latest forecast from the Washington Transportation Economic and Revenue Forecast Council that projects gasoline sales in the state to be essentially flat for the next 10 years[4].

---

to be internally balanced so Washington refineries would need to export intermediate materials that could no longer be processed in a now closed processing unit.

[3] The US Gulf Coast or Europe could be alternative markets for sources of gasoline imports or destinations for naphtha exports. We exclude them from this analysis because each market likely has structurally higher transportation costs than sailing to/from Asia.

[4] See slide 12 (on page 16 of pdf) at: https://erfc.wa.gov/sites/default/files/2025-06/trans20250625_0.pdf

The higher utilization of the SMR to make up the hydrogen lost when the reformer is closed, as well as the CO2e emissions associated with importing gasoline and exporting naphtha, would result in a net increase in CO2e emissions of ~45% (+0.5 MMTPA).

The loss in gasoline production also compresses refinery margins about 80%, which for our representative model would be a loss of almost $700 MM per year, based on 2024 prices. Given that carbon emissions increase while the refinery loses money, calculating an implied cost of carbon is not meaningful.

Shutting Down a Coker

A coker is an oil refinery unit that processes very heavy residues from the CDU and VDU (vacuum distillation unit) and cracks them into lighter gas oils, which can be fed to conversions units, *e.g.*, such as the FCC (Fluid Catalytic Cracker) or hydrocracker to make higher value products, such as gasoline and diesel. One of the by-products from the coking process is solid petroleum coke, which can be used as a fuel, anode material for aluminum smelting, or other industrial applications.

A coker is valuable to a refinery because it can increase liquid yield from heavy crude residues, which supports processing of heavier, cheaper crude slates. The coker also helps to reduce low-value residual fuel oil production, whose use is often is limited by environmental regulations.

Shutting down a coker reduces CO2e emissions but has significant economic and operational drawbacks. In our representative refinery, shutting down the coker reduces the feed to the FCC, which reduces the production of gasoline (-15%) and jet fuel or diesel (-35%). Jet/diesel production has a larger volume loss because low-value marine (bunker) fuel oil production increases tenfold. Meeting marine fuel specifications requires blending volumes of distillates (*e.g.*, jet, diesel) with the atmospheric and vacuum residue that would no longer be used as feedstock to the coker. We assume the marine fuel oil is exported to Asia because it is the most liquid market for fuel oil bunker sales.

CO2e emissions from coker operations would decrease by 0.2 MMTPA, or 15%, due to reduced natural gas consumption. Similar to shutting down a naphtha reformer, the loss in finished product volumes compresses refinery margins. For our representative refinery this loss would be over $1.2 billon per year, assuming the refinery does not change its operations, such as its crude slate.[5] Looking at just the reduced margin associated with reducing CO2e emissions from the coker implies a carbon cost of over $7,200 per ton of CO2e reduced.

The refinery could lighten its crude slate by running less heavy crude oil, such as Western Canadian Select (diluted bitumen) and more North American light-sweet crude oils, such as those streams found in the Bakken of North Dakota. Lightening the crude slate would reduce the amount of marine fuel oil, which tends to sell at a discount to crude oil. The

[5] Losses could be potentially higher if the coker produces anode-grade coke, which is used for steel/aluminum manufacturing. Anode coke can sell for sizable premiums to typical petroleum cokes, which tend to be used as substitutes for coal. There are several cokers in Washington with the potential to make anode coke.

lighter crude slate would be more expensive but reduces the need to export large volumes of marine fuel (that sell at a discount to crude oil). This reduces the margin loss from shutting down the coker and the implicit carbon cost to about $4,200 per ton of CO2e.

However, when looking at the change in total carbon emissions including those associated with importing and exporting product volumes to keep the Washington petroleum market in balance, shutting down the coker results in a net increase in CO2e emissions. Thus, on a total carbon emissions basis the implied cost of carbon is not meaningful because the refinery loses money, but total CO2e emissions increase.

Logistical Challenges

Shutting down processing units within an integrated refinery design could require major changes in operations and logistics, such as, increased vessel traffic to handle imports. We assume sufficient dock and harbor capacity exist so no material infrastructure investments are required to close either type of unit.[6] Such changes could increase risks around the operations of the refinery and required supply chains. These risks have the potential to threaten the economic viability of the refinery and have not been incorporated in this analysis.

Workforce Implications

According to a study by Western Washington University, Washington's refineries employ approximately 2,200 permanent employees and an additional 2,000 contract workers.[7] The number of employees necessary to operate each individual process unit depends on the unit's size, technology level of automation, and site practices. Staffing levels are usually measured in FTEs (full-time equivalent) required for each shift, combining field and process control roles for continuous operation (typically several crews rotating shifts). In addition, there are additional FTEs to support equipment reliability, maintenance, and process operations. These support FTEs can be embedded on-site or on-call depending on the plant's size and automation level.

For a typical naphtha reformer FTE staffing levels are in the range of 2 – 4 FTEs per shift (across 5 rotating shifts) for a total of 10 – 20 personnel to support operations on a 24/7

However, the import of gasoline, jet, and diesel to keep Washington petroleum product market demand satisfied, combined with the export of marine fuel oil to Asia results in a net *increase* in CO2e emissions for the Washington refining system of 0.5 MMTPA.

basis. For a delayed coker operational FTEs can range 15 – 25 for the unit. Additional FTEs for technical support and maintenance can double the FTEs for each unit.

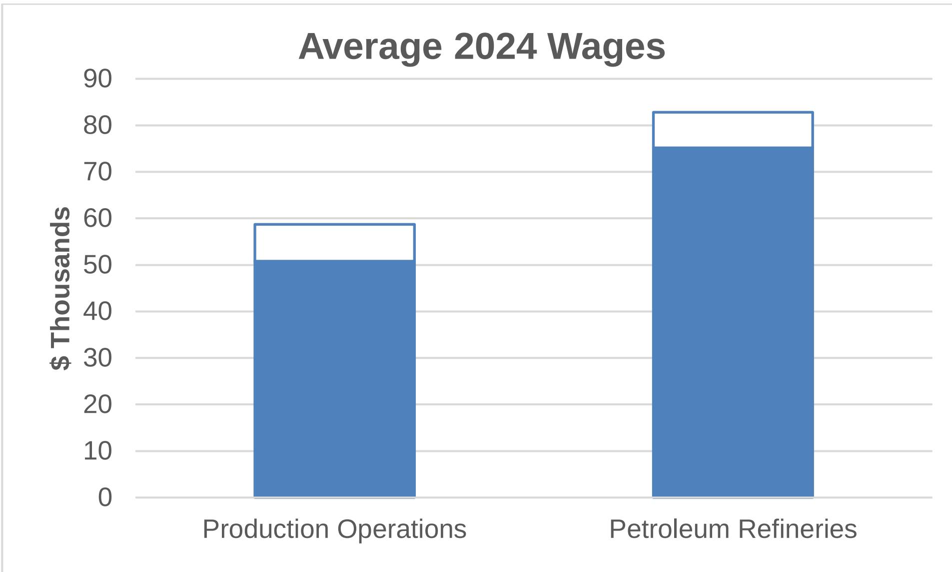
---

[6] If marine logistics investments were required, there is no guarantee such projects could be permitted. Examples of denied vessel traffic permits in Washington include the Gateway Pacific Terminal (2016) and Millennium Bulk Terminals (2017) coal export terminals. These permits were denied over environmental and vessel traffic concerns.

[7] *Washington State Refinery Economic Impact Study*, Center for Business and Economic Research, Western Washington University, February 2025.

These refineries are not only significant local employers, but also provide high wages relative to other industries in the communities where they are located. Based on State of Washington data for 2024, refinery plant workers earn wages that are 40-50% higher than comparable process operation jobs (see Figure 1).

Figure 1: Comparing Refining Wages to Other Industries



Source: TM&C analysis; *Occupational employment and wage statistics,* State of Washington, Employment Security Department, 2024

Thus, while workforce reductions appear somewhat small (25 to 45 FTE for each closed unit), displaced operators could face 40 – 50% reductions in compensation relative to comparable jobs in Washington. Many of these workers could face the dilemma of accepting a job less than half of what they currently earn (assuming they can find a job) or be compelled to leave their current location (or the state) in search of opportunities elsewhere.

Decarbonization from Capital Projects

Competing against other projects for limited capital

Many capital projects for decarbonization, such as RD (renewable diesel) or SAF (Sustainable Aviation Fuel) conversion, FCC carbon capture, and green hydrogen production have negative economic value. Even if projects could have positive value, they may not be competitive with other projects in the company's project portfolio. Therefore, without significant incentives, low-carbon projects tend to not be competitive for capital in refining companies' budgets.

Timelines are another reason low-carbon projects can be unattractive to investors. Regulatory compliance and permitting can heavily impact project timing. For example, typical permitting timing can range between 6 to 72 months depending on the jurisdiction.[8] For this analysis we assume three years and a construction window of two years (with a range of 18 to 48 months). Longer permit processes tend to erode the economics of a project for two reasons: (1) project costs tend to rise over time and typically escalate faster than the assumed price path of revenue streams in petroleum markets and (2) project NPV (Net Present Value) tends to consider a project begins with the first activity specific to the project (*e.g.*, permit applications, ordering long-lead items) rather than when construction begins. The longer the permit process, the farther in the future is the beginning of receiving benefits from the project. The benefits are discounted at a corporate hurdle rate that usually is greater than the company's cost of capital. The more distant the benefits are and/or the higher the discount rate, the less valuable those future benefits are, relative to the costs, when discounted back to the beginning of the project (*e.g.*, permit applications).

Another key aspect to the start-up timing of a new project is minimizing how much its commissioning impacts other refinery operations. Planning for a start-up window (and backtracking to when construction commences) is a function of other operations, maintenance, and turnaround activities. A delay in permitting can materially disrupt when the project can be commissioned and, by extension, when construction should begin. In the worst case, a project can be delayed by an entire turnaround cycle which could be as much as 5 years in duration.

Converting units to renewable diesel or Sustainable Aviation Fuel

Converting existing petroleum refining units to renewable diesel production is a strategic pathway for energy companies seeking to reduce carbon intensity while leveraging existing infrastructure. Refiners can retrofit hydrotreaters or hydrocrackers to process renewable feedstocks, such as used cooking oil, animal fats, and vegetable oils, into renewable diesel, a drop-in fuel chemically similar to conventional diesel but with significantly lower lifecycle greenhouse gas emissions. This approach not only extends the value of existing assets but also minimizes capital expenditures, shortens project timelines, and enables refiners to respond quickly to growing policy incentives and market demand for low-carbon fuels. Renewable diesel can be converted into SAF with additional processing steps to meet jet fuel specifications for viscosity, freezing point, and flash point.

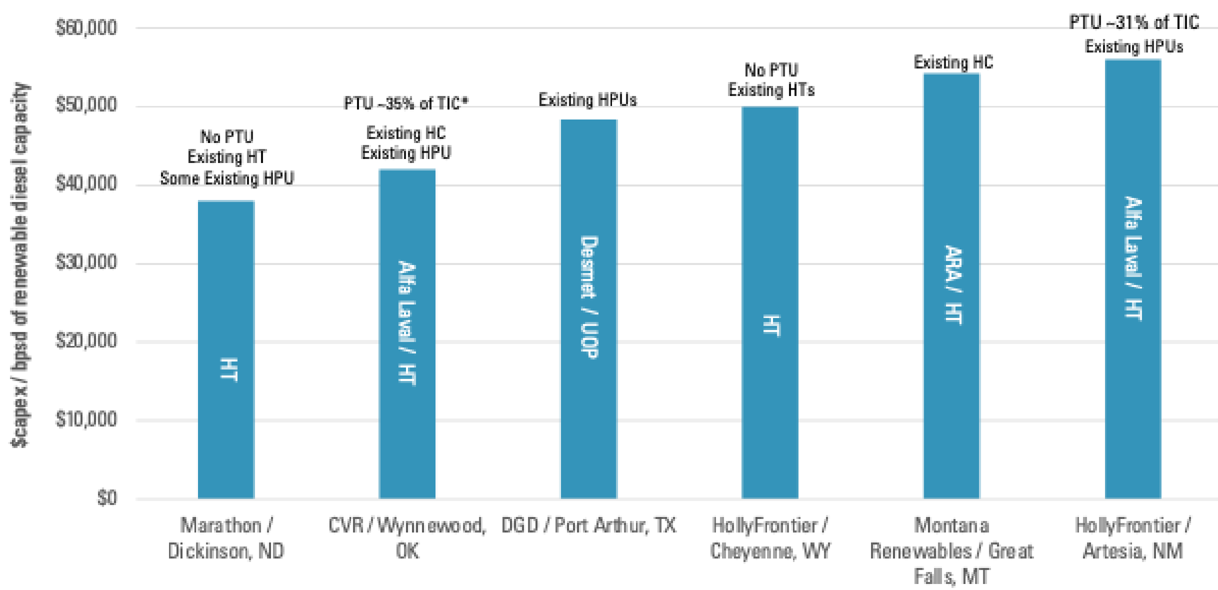
Conversion to RD/SAF production could have positive value under certain conditions, particularly with incentives like the 45Z Clean Fuel Production tax credit. The original IRA (Inflation Reduction Act) limited the credit to clean transportation fuels produced and sold between January 1, 2025 and December 31, 2027. The OBBBA (One Big Beautiful Bill

[8] Chevron's refinery in Richmond, California had a modernization project in which some of the permits took over nine years to approve. The initial permit applications were submitted to the City of Richmond during 2006, with final approval received in April 2015.

Act) extends the claim period by two years, now allowing credits for fuel produced and sold through the end of 2029. However, the OBBBA imposes new constraints on renewable fuels projects, such as feedstock origin, so combined with the difficulty to commission a major project before 2030 likely reduces the value of extending the credit period.

The following chart provides estimated capital investment for RD conversions based on our analysis of actual renewable diesel projects. Brownfield capital costs depend on what units are available for re-purposing.

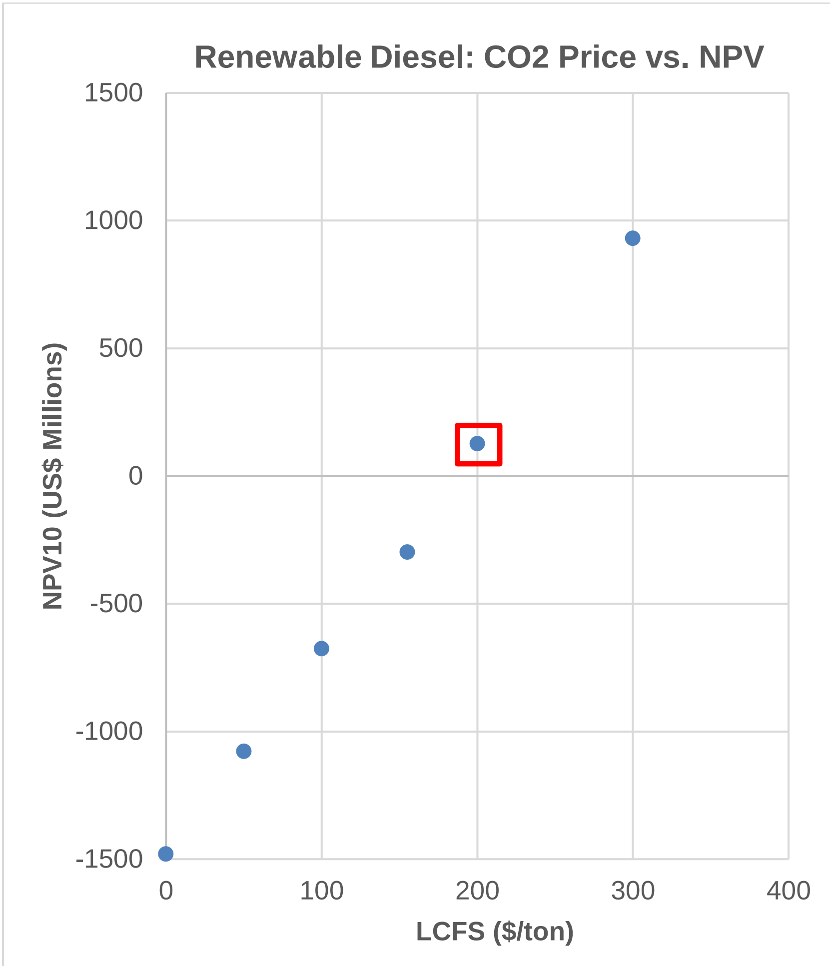
Figure 2: Renewable Diesel Capital Costs



Source: TM&C Regulatory & Renewable Fuels Outlook.

A hydrocracker is ideal, but there is only one in Washington at BP-Cherry Point. We focus on revamps of distillate or naphtha hydrotreaters. Naphtha hydrotreaters have an average capacity of 22 TBD (thousand barrels per day), while diesel hydrotreaters tend to be larger, with average capacity of 40 TBD. To help minimize capital costs, we model a hydrotreater with a capacity of 25 TBD. We assume a conversion cost of ~$46,000/bpd, which is 30% higher than a similar project in the U.S. Gulf Coast to account for less fabrication economies of scale and availability of skilled labor in the Pacific Northwest.

Figure 3: Renewable Diesel/SAF Project Economics



Source: TM&C analysis

The reduction in CO2e is about 0.2 MMTPA, which is 16% of the refinery's CO2e emission profile. The implied carbon cost that makes the project break-even on an NPV basis is just under $200/ton (net of tax credits).

FCC carbon capture

The FCC is a key processing unit designed to convert heavy fractions, such as gas oil into a blendstock for gasoline, a more valuable product. It achieves this through a process called catalytic cracking, where a catalyst and heat are used to break down longer hydrocarbon molecule chains into smaller ones.

This unit is a candidate for CCS (Carbon Capture and Storage) primarily because it is one of the largest single-point sources of CO2e in a petroleum oil refinery; about 25–35% of total refinery CO2e emissions, mainly from the regenerator during coke combustion.

The regenerator process in FCC units, which combusts coke at high temperatures, naturally concentrates emissions and makes the logistics of carbon capture more straightforward. The flue gas stream from FCC regenerators is continuous and accessible, which makes it viable for post-combustion capture technologies or alternative capture approaches.

We considered three technologies to test the potential project economics of effective carbon capture from FCC operations:

1) **Post-Combustion** - CO2 is captured from the flue gas after combustion. The most common approach uses amine-based solvents to absorb and strip CO2, which can capture 85 - 90% of CO2 emissions. It has advantages of minimizing required unit modifications and is widely proven in power and industrial sectors. Its challenges include high energy consumption and relatively high operating costs.
2) **Oxyfuel (Oxy-Firing) Combustion** - uses pure oxygen mixed with recycled CO2 instead of air. This leads to a flue gas with a much higher CO2 concentration, simplifying downstream capture, which can lead to 90 – 100% capture efficiency and flue gas with 93 – 95% CO2 concentration. This can result in lower operating costs than post-combustion, but higher capital costs due to required air separation units and modifications to the FCC regenerator. Thermal management and potential corrosion also must be addressed.
3) **Chemical Looping Combustion (CLC)** - uses oxygen carriers (typically transition metals) to combust coke in the regenerator. Its main advantages include lower energy intensity and a high purity CO2 stream (90 – 96% capture). Key challenges include significant catalyst redesign, integration of air reactor, and the technology is still largely at laboratory/pilot scale.

Table 1: Comparing Carbon Capture Technologies for FCC Emissions

Technology	Capture Rate	Capex ($/TBD)	Key Modifications	Status
Post-Combustion	85 – 95%	$3,200	Minimal	Commercial/pilot
Oxyfuel	90 – 100%	$4,700	Air separation, regenerator	Pilot/commercial
CLC	90 – 96%	$4,900	Catalyst, air reactor	Lab/pilot

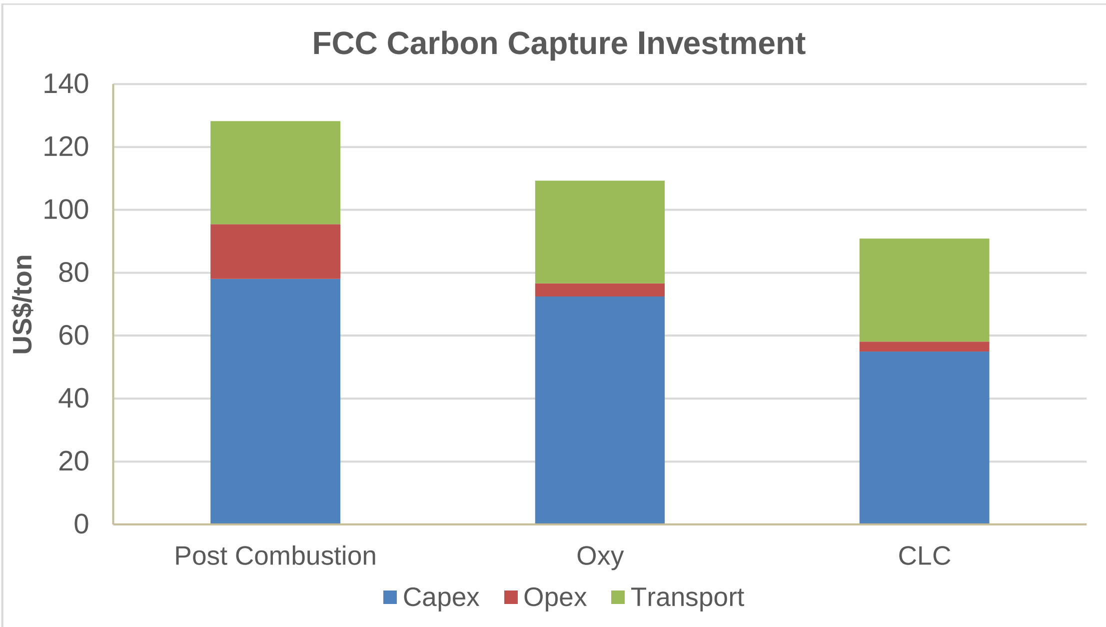
Source: TM&C analysis, industry research, “Progress in the CO2 Capture Technologies for Fluid Catalytic Cracking (FCC) Units—A Review”, *Frontier Energy Research*, vol 8, 2020;

Our modeled FCC has a capacity of 60 TBD, with CO2e emissions of about 400 ktpa (thousand tons per annum) and an assumed capture rate of 90%.[9] The capital cost runs from $350MM to $530MM depending on which technology is chosen. Operating costs

[9] It is important to distinguish between design capacity and actual operational rates. In real-world practice, actual rates may be somewhat lower due to factors such as maintenance, equipment downtime, variable loads, and off-design performance. A typical capture rate over a three-year period tends to be around 75%, but improving with experience and scale.

include transportation to the nearest proposed sequestration facility (*i.e.*, Big Sky Carbon Sequestration Project) and range $93/ton to $140/ton. We assume each project qualifies for 45Q tax credit ($85/ton) and will begin construction before the tax credit is scheduled to sunset on January 1, 2033.

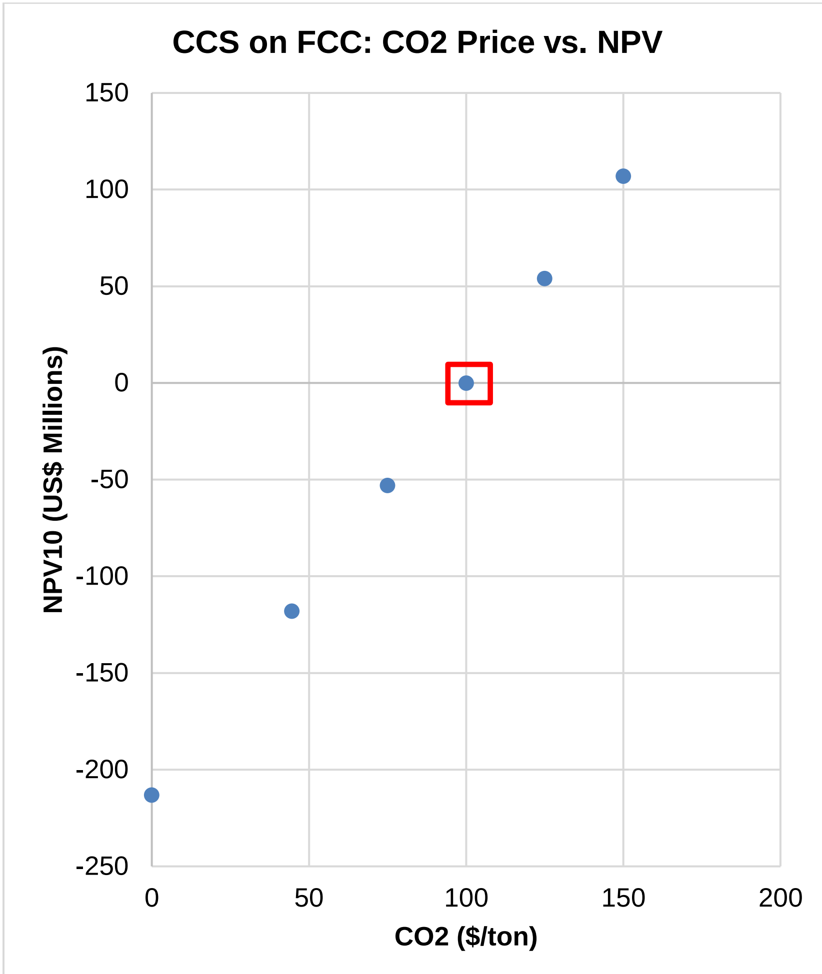
Figure 4: Comparing Technology Capital Cost for FCC Carbon Capture



Source: TM&C analysis, , industry research

The implied carbon cost that makes the project break-even on an NPV basis is about $100/ton (net of the 45Q tax credit). The CO2e reduction is 0.36 MMTPA (about 32% of the refinery's CO2e emissions).

Figure 5: CO2 Price Drives FCC Carbon Capture Project Economics



Source: TM&C analysis

Across all cases, the 45Q tax credit has a project value of about US$180 million.

Low-carbon hydrogen

Hydrogen is essential to multiple refinery processes to upgrade heavier, higher-sulfur crude fractions into lighter, cleaner transportation fuels. The major uses are: hydrotreating (removing sulfur, nitrogen, metals, and olefins/aromatics saturation to meet fuel specifications and protect downstream catalysts), hydrocracking (converting heavy gas oils to lighter, high-value products, *e.g.*, jet, diesel, naphtha, while simultaneously removing sulfur and nitrogen), isomerization (rearranging the molecular structure of light hydrocarbons to improve the octane number of gasoline components), and lubricants (improving the quality of lubricants, waxes, and other specialty products by removing impurities and saturating aromatic compounds).

The economic feasibility of a low-carbon hydrogen depends on very high carbon prices because it is typically more expensive to produce than conventional hydrogen from unmitigated steam methane reforming using natural gas (*i.e.*, “grey hydrogen”). A sufficiently high and predictable carbon price helps close that cost gap and creates bankable offtake. This is a key enabler for projects to secure financing and reach FID (Final Investment Decision).

Green hydrogen through electrolysis has a number of project challenges, such as capital cost of electrolyzers, low thermal efficiency of the process chain, difficulty to scale the project, and the uncertain availability of green electricity (unless building that generation and transmission is included in the project).

The 45V tax credit under the IRA is intended as a mechanism to address some of these challenges. To receive the full 45V tax credit of $3/kg a green hydrogen project must meet specific conditions related to lifecycle greenhouse gas emissions, production methods, and other requirements.[10] For example, under U.S. Treasury’s final rules (released December 2024), electricity used for hydrogen production must meet three pillars to ensure low-carbon intensity:

- **Additionality** - generation must be new (constructed within 36 months before the hydrogen facility is placed in service) or from a source with increased capacity to ensure it contributes to grid decarbonization;
- **Temporal Matching** - electricity must be generated at the same time as hydrogen production (annual matching is allowed until 2028 when hourly matching is required);
- **Geographic Matching** - electricity must come from the same grid region as the hydrogen production facility to ensure it reflects local grid emissions characteristics.

These additional requirements can increase significantly the cost of a low-carbon hydrogen project as the table below shows:

Table 2: Capital Costs of Low-Carbon Hydrogen Plant (US$MM)

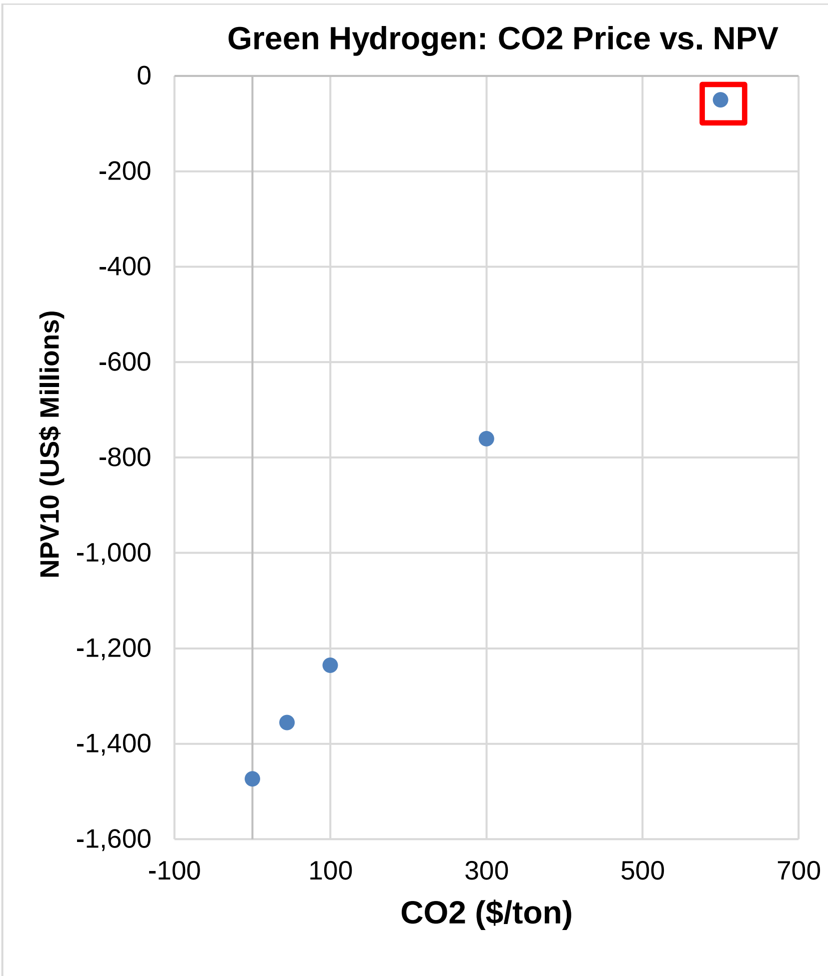
	Low	High
H2 Plant	635	1,325
Green Electricity	660	1,580
Transmission	270	750
Total	1,565	3,655

Source: TM&C analysis

[10] The OBBBA accelerates the phase-out of the 45V credit for facilities starting construction after December 31, 2027.

We model a low-carbon hydrogen project that produces enough volume to support the 25 TBD renewable diesel project described above, which is about 70 MMCFD (million cubic feet per day) or about quadruple the hydrogen required to desulfurize a similar volume of petroleum diesel.

Figure 6: Low-carbon Hydrogen Project Economics



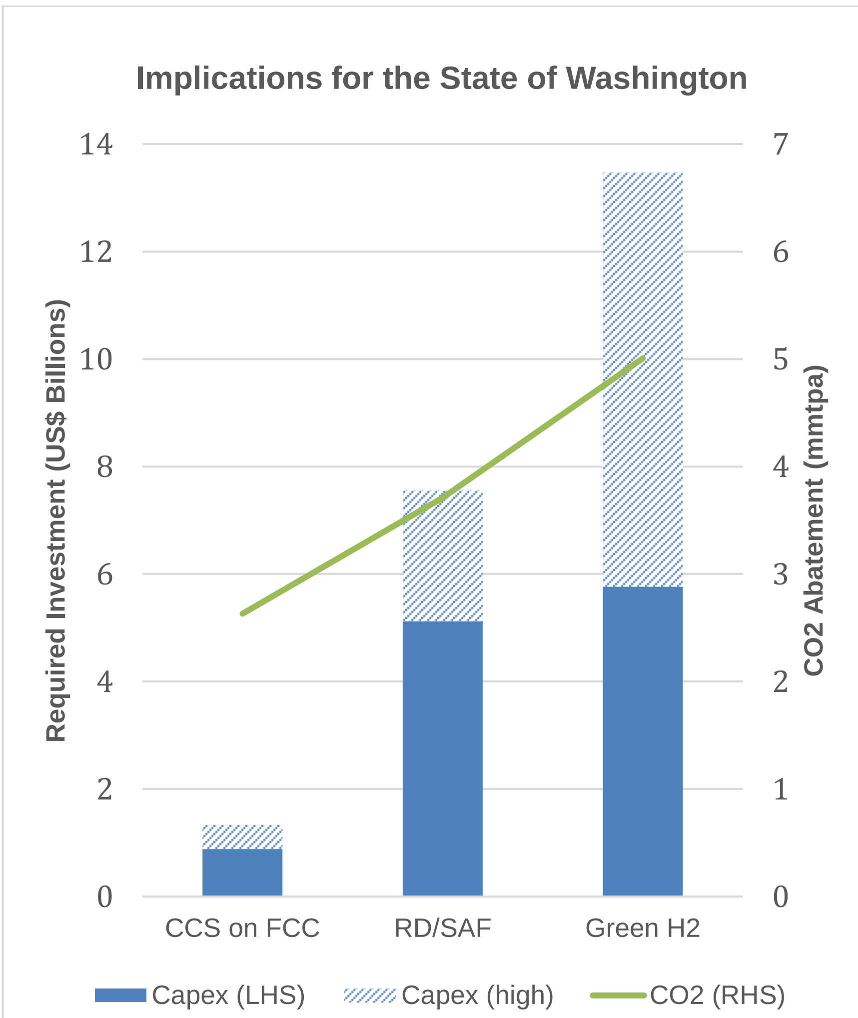
Source: TM&C analysis

The implied carbon cost that makes the project break-even on an NPV basis is about \$600/ton (net of the 45V tax credit). The CO_2e reduction is 0.36 MMTPA (about 32% of the refinery's CO_2e emissions). Configurations becomes more attractive as qualification for tax credit incentives improve.

Global CO2e Emissions Implications

Fully implementing these projects across all Washington refineries could take until the mid-2040s. We assume each refinery would be able to implement no more than one capital project per turnaround cycle given their complexity and other work required around integrating the project with the rest of the refinery. Total required investment could range $12 to $22 billion (in $2025) based on economics of actual projects TM&C has examined across the U.S. If all suggested pathways were implemented, CO2e emissions could be reduced ~5 MMTPA, a 78% reduction from current levels.

Figure 7: Summary of Project Costs and Impact



Source: TM&C analysis

Reducing emissions in Washington by shutting down units like cokers or naphtha reformers does not yield a net reduction in global CO2e emissions. The shortfall in local production would require importing refined products from Asia or the Middle East, which increases global emissions due to shipping and potentially less efficient foreign refineries. When processing units in Washington are shut, exporting unfinished intermediates from Washington to other regions could further increase net emissions. It is ironic that shutting down a naphtha reformer or coker could result in intermediate products being exported to a foreign refinery, processed into finished products, and then imported back to meet local Washington demand. The CO2e emissions savings from shutting the unit would be swamped by the increase in emissions from shipping unfinished volumes to a foreign refinery and then returning finished product to Washington.

Recommendations

- **Re-evaluate Operational Changes** - shutting down cokers or naphtha reformers is not a cost-effective decarbonization strategy due to high margin losses ($0.8–$1.4 billion annually) and workforce impacts;
- **Prioritize Incentives** - projects, such as FCC carbon capture and RD/SAF conversion, may become economically viable with enhanced incentives. Policymakers could consider continuing, restoring, or expanding these incentives to improve project economics;
- **Global Perspective** - address the lack of net global CO2e reductions by exploring local renewable fuel production or carbon capture technologies that minimize reliance on imported products;
- **Further Analysis** - conduct detailed studies on RD/SAF conversion costs and green hydrogen economics to better assess their feasibility with current incentives.

Conclusions

Decarbonizing Washington refineries presents significant economic and operational challenges. While operational changes, such as shutting down a coker might reduce local CO2e emissions, they incur substantial margin losses and potentially increase global emissions due to the need to increase product imports to keep the Pacific Northwest market in balance.

Capital projects, such as converting to RD/SAF or FCC carbon capture achieve greater reductions than shutting down the units studied, but require significant investment and incentives to be viable.

TM&C recommends a balanced approach that leverages incentives and prioritizes projects with the greatest ***net*** CO2e reduction potential and economic feasibility.

Methodology

Our analysis focuses on refinery CO2e emissions, plant economics, and the timing of decarbonization pathways. Pathways are divided into operational changes (*e.g.*, shutting down units such as naphtha reformers or delayed cokers) and capital-intensive projects (*e.g.*, RD/SAF conversion, green hydrogen production, and carbon emissions capture on units, such as the FCC).

We used TM&C's proprietary refinery modeling system to create a complex refinery representative of a typical Washington refinery. To design the configuration of the refinery, we used EIA (Energy Information Agency of the U.S. Department of Energy) unit capacity data of the five petroleum fuel refineries in Washington. Capacities of key processing units include:

- Crude Distillation Unit: 150 TBD
- Naphtha Reformer: 25 TBD
- Naphtha Hydrotreater: 22 TBD
- Distillate Hydrotreater: 40 TBD
- Fluid Catalytic Cracker: 60 TBD
- Coker: 30 TBD
- Other units sized as needed to balance the refinery

We modeled a simplified refinery crude slate based on EIA foreign imports, inter-PADD transfers, and State of Washington data.

We use 2024 average prices in our analysis. Results are based on our knowledge of industry practices and assumptions based on our collective years of experiences. We also compare our results to a representative USGC Coking Refinery.